DRAFT for Federal Land Manager Review

North Dakota State Implementation Plan
for
Regional Haze

A Plan Revision for Implementing the Regional Haze Program Requirements
of
Section 308 of 40 CFR Part 51, Subpart P - Protection of Visibility

North Dakota Department of Health
Adopted: **DRAFT**

Division of Air Quality
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Executive Summary

The federal Regional Haze Rule (RHR) requires North Dakota to address regional haze in each mandatory Class I Federal area (CIA) located within North Dakota and in each mandatory CIA located outside North Dakota, which may be affected by emissions from within North Dakota. Under the RHR, North Dakota is required to submit a State Implementation Plan (SIP) addressing the specific elements required by the RHR. This document includes the State of North Dakota's SIP submittal to the U.S. Environmental Protection Agency (EPA) Region 8 to meet the requirements of RHR Section 308 (40 CFR Part 51, Subpart P, Section 51.308). This submittal is a revision to the regional haze SIP that North Dakota submitted for the first round of the RHR. Adoption of the North Dakota SIP revision for regional haze amends the Implementation Plan for the Control of Air Pollution for the State of North Dakota.

The RHR requires North Dakota to demonstrate the progress made to date and determine any additional progress needed to achieve the visibility improvement goals established for this planning period. North Dakota is required to set reasonable progress goals which 1) must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and 2) ensure no degradation in visibility for the least impaired days over the same period. This SIP revision analyzes the current rate of progress needed to attain natural visibility CIAs by the year 2064 and examines the need to implement additional emission reduction measures on any sources which are reasonably anticipated to contribute to visibility impairment. This examination is known as a four-factor analysis and consists of four criteria: 1) cost of compliance, 2) time necessary for compliance, 3) energy and non-air quality environmental impacts, and 4) remaining useful life.

North Dakota reviewed all sources of significance in the state and chose ten existing sources for four-factor consideration. North Dakota chose these sources based on recent representative emissions of nitrogen oxides (NO_X) plus sulfur dioxide (SO_2) and proximity to CIAs, known as a Q/d screening analysis. Projected future emissions were also considered when evaluating North Dakota impacts to in- and out-of state CIAs. Of the ten facilities selected, six are coal fired electrical generating utilities (EGUs) and four are non-EGUs.

During the first round of RHR, three of the six coal fired EGU facilities were subject to the RHR's Best Available Retrofit Technology (BART) requirements. The three remaining coal fired EGUs were not subject to BART requirements, but were required by North Dakota to undertake projects necessary for reasonable progress. The BART and reasonable progress requirements significantly reduced NO_X and SO_2. The total reductions from North Dakota EGUs were approximately 102,000 tons of SO_2 (down 72%) and 41,600 tons of NO_X (down 55%) from 2002 to current representative emissions.

Of the three non-BART EGU sources, one is committed to retire coal by 2022 (Heskett Station) and the other two are projected to remain online and continue to operate consistently with recent operations (Antelope Valley Station and Coyote Station). For these two sources, additional controls were selected for evaluation using model simulations to project the impact additional controls on these sources would have on visibility in North Dakota CIAs. The controls selected for review were determined based on the source's existing level of control, recent NO_X and SO_2 emission rates, and costs as compared to round 1 costs incurred by similar sources (adjusted to 2018 dollars). In short, the controls selected for modeling on these two sources would reduce the NO_X and SO_2 performance rates to levels more consistent with the North Dakota BART EGU sources.

The Department used modeling to project the 2028 visibility conditions at the CIAs located within and around North Dakota. The 2017 revisions to the RHR added a provision that allows states to propose an adjustment to the glidepath to account for impacts from anthropogenic sources outside the United States. In evaluating the causes and contributions of visibility impairment in North Dakota CIAs, North Dakota determined that anthropogenic sources outside the United States contribute a minimum of 40% of the total projected 2028 light extinction at North Dakota CIAs, meaning this adjustment is significant to North Dakota. As such, North Dakota exercised its authority to adjust its glidepaths pursuant to 40 CFR §51.308(f)(1)(vi)(B). The baseline 2028 visibility condition projections (no additional controls) for CIAs in and around North Dakota indicates that all areas are expected to meet the 2028 planning goals (i.e., the adjusted glidepath point in 2028).

Modeling of the 2028 visibility conditions with additional controls on two sources (Antelope Valley Station and Coyote Station) did not show a significant change or improvement in the projected 2028 visibility conditions. The additional controls modeling was conducted using two scenarios. The first scenario included over 22,000 tons of combined NO_x and SO_2 reductions at a capital cost of approximately $150 million and an annualized cost of approximately $30 million. The first scenario resulted in a projected improvement to 2028 visibility of 0.1 deciview at Lostwood Wilderness Area and 0.08 deciviews at Theodore Roosevelt National Park. The second scenario included over 7,000 tons of combined NO_x and SO_2 reductions at a capital cost of approximately $0.5 million and an annualized cost of approximately $2 million. The second scenario resulted in a projected improvement to 2028 visibility of 0.04 deciview at Lostwood Wilderness Area and 0.03 deciviews at Theodore Roosevelt National Park. Neither additional controls scenario indicated the North Dakota CIAs would experience a meaningful improvement to projected visibly resulting from the installation of the potential additional controls. The modeling analysis also indicated there will be no degradation during the clearest days.

North Dakota is currently projected to meet its 2028 visibility goals and is projected to remain on track to meet the 2064 visibility goals (below the adjusted glidepath). Continuing to remain below an adjusted glidepath and showing improvement on the most impaired days for each planning period will accomplish the 2064 end goals. North Dakota has determined that the additional controls evaluated will not have a meaningful impact on the 2028 visibility projections. Therefore, the Department determined that it is not reasonable to require additional controls during this planning period. Accordingly, the 2028 reasonable progress goals for the most impaired days in the North Dakota CIAs are established at 15.8 deciviews for Lostwood Wilderness Area and 13.6 deciviews for each unit of Theodore Roosevelt National Park. The Department will continue to monitor North Dakota's CIA visibility progression and provide an update in its 2025 progress report.

This proposed SIP revision meets the statutory requirements of 40 CFR Part 51, Subpart P, Section 51.308. This proposed SIP revision describes and documents rules, regulations, and additional measures that are included in the long-term strategy. The information contained in this SIP revision supports

North Dakota’s determination that additional controls during the second-round planning period are not reasonable.

Finally, the RHR requires each State to consult with other states and Federal Land Managers (FLM) as part of the regional haze SIP development process. States are required to share information with other states that have CIAs that are reasonably anticipated to be impacted by emissions from North Dakota. States are also required to evaluate (though not necessarily implement) control measures requested by other states and document actions taken to resolve disagreements. Additionally, North Dakota chose to consult with Tribal partner stakeholders in and near North Dakota. Doing so allows North Dakota sufficient time to meaningfully engage and gather input from our Tribal partners. State and sector category source apportionment modeling indicated that neighboring state CIAs are not significantly impacted by emissions from North Dakota. Additionally, the modeling indicated that neighboring state sources were not significantly impacting visibility in North Dakota CIAs. Documentation is included in Section 3 and Appendix C. North Dakota requested feedback from the states of Minnesota, Montana, and South Dakota on these determinations in June 2021. North Dakota has not received responses from neighboring states regarding this determination. North Dakota also held consultation webinars in late 2020 with National Park Service and the US Forest Service to share preliminary modeling results, the method for selecting sources for four-factor analysis, the sources selected, and North Dakota current strategy based on the information available. Documentation is included in Appendix E.

Air Quality in North Dakota

The federal Clean Air Act (CAA) establishes “a comprehensive national program that makes the States and the Federal government partners in the struggle against air pollution”.[1] The CAA also recognizes that “air pollution prevention (that is, the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source) and air pollution control at its source is the primary responsibility of States and local governments.”[2] In North Dakota, the North Dakota Department of Environmental Quality (NDDEQ) is the agency that designs and implements State and Federal air quality programs.[3] North Dakota has successfully designed, implemented, and enforced air quality programs which has resulted in North Dakota being one of four States that comply with all National Ambient Air Quality Standards (NAAQS).[4] NAAQS are determined using scientific studies for the purpose of protecting human health and the environment. NDDEQ develops an annual ambient monitoring network plan and data summary report containing the detailed information on North Dakota’s ambient air quality monitoring.[5]

For the CAA’s Visibility Protection Program in Sections §§169, 169A, and 169B, North Dakota relies on the Interagency Monitoring of Protected Visual Environments (IMPROVE) network to monitor and determine the visibility conditions in Theodore Roosevelt National Park (TRNP) and Lostwood National Wildlife Refuge Wilderness Area (LWA). North Dakota will continue to rely on the IMPROVE network for its monitoring strategy for the RHR. In addition to the IMPROVE data covered in Sections 3.2, 3.3, 5.1, and Appendix C, North Dakota is supplementing this with data from North Dakota’s ambient air quality monitors that operate at TRNP (North Unit “NU” and South Unit “SU”), LWA, Bismarck and Fargo (North Dakota’s two largest cities). Bismarck and Fargo are being presented for comparison of the population centers to the CIAs with respect to the NAAQS. The supplemental data includes the monitoring of Nitrogen Dioxide (NO_2), SO_2, particulate matter with diameters that are generally less than 2.5 micrometers. ($PM_{2.5}$), and Ozone, which are the species of interest for regional haze planning in North Dakota.

This information is being provided to demonstrate North Dakota is well in compliance with all NAAQS standards, to show air quality trends since the early 2000’s, and as additional support of North Dakota’s stance in this SIP revision. North Dakota takes pride in maintaining high quality air and being in attainment/unclassifiable with all NAAQS standards. The NAAQS data is presented in Figure 1 through Figure 7 as follows:

- NO_2
    - Primary 1-hour. 98th percentile of 1-hour daily maximum concentrations, averaged over 3-years. Standard of 100 parts per billion (ppb).
    - Primary and Secondary 1-year. Annual mean concentration. Standard of 53 ppb.

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[1] General Motors Corp. v. United States, 496 U.S. 530, 532 (1990)

[2] 42 U.S.C. § 7401(a)(3)

[3] N.D.C.C. section 23.1-06 and N.D.A.C Article 33.1-15.

[4] Available at: https://www3.epa.gov/airquality/greenbook/ancl.html (Last visited July 21, 2021)

[5] Available at: https://www.deq.nd.gov/AQ/monitoring/ (Last visited July 21, 2021)

- SO_2
  - Primary 1-hour. 99th percentile of 1-hour daily maximum concentrations, averaged over 3-years. Standard of 75 ppb.
  - Primary 1-year. Annual mean concentration. Standard of 30 ppb.[6]
- $PM_{2.5}$
  - Primary 1-year. Annual mean averaged over 3-years. Standard of 12 micrograms per meter cubed (µg/m^3).
  - Primary and Secondary 24-hour. 98th percentile of 24-hour average, averaged over 3-years. Standard of 35 µg/m^3.
- Ozone
  - Primary and Secondary 8-hour. Annual 4th highest daily maximum 8-hour concentration averaged over 3-years. Standard of 70 ppb.

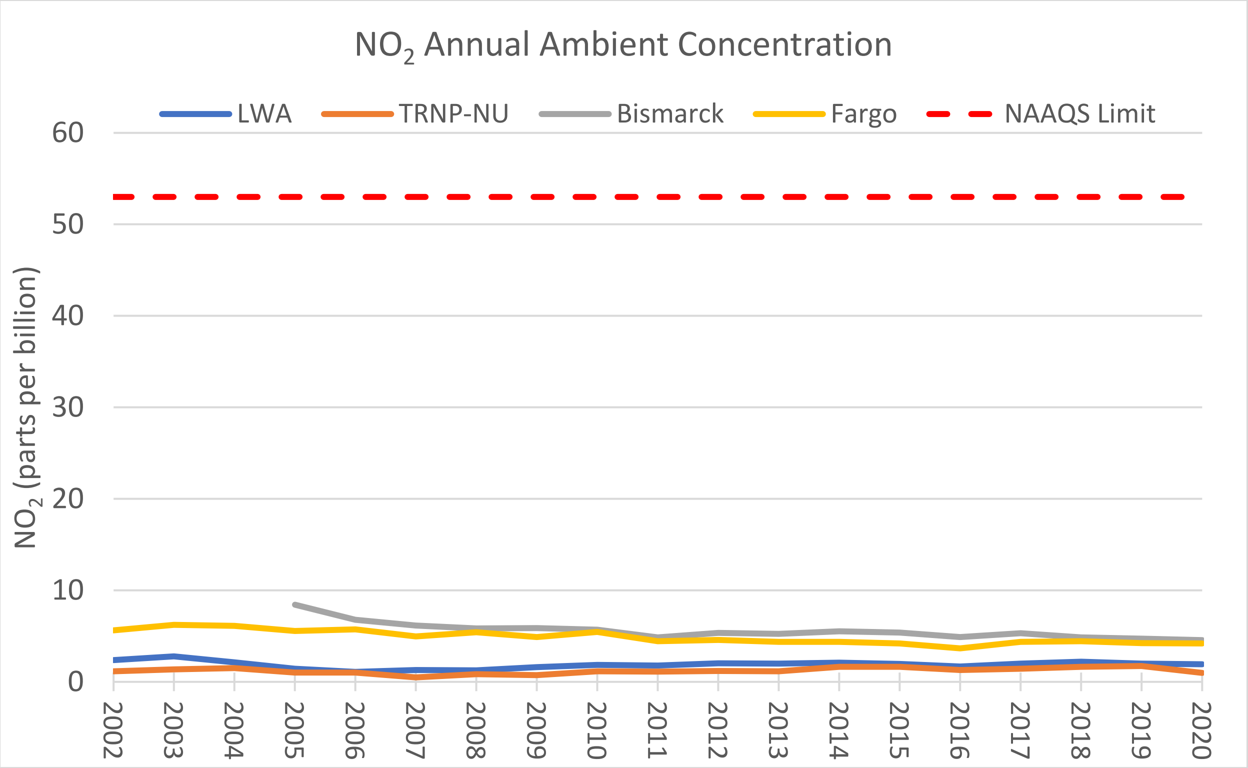

Figure 1: NO_2 Annual Average Ambient Concentrations

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[6] Shown for informational purposes. Standard was revoked with 77 FR 35520. Available at: https://www.govinfo.gov/content/pkg/FR-2010-06-22/pdf/2010-13947.pdf (Last visited June 22, 2021).

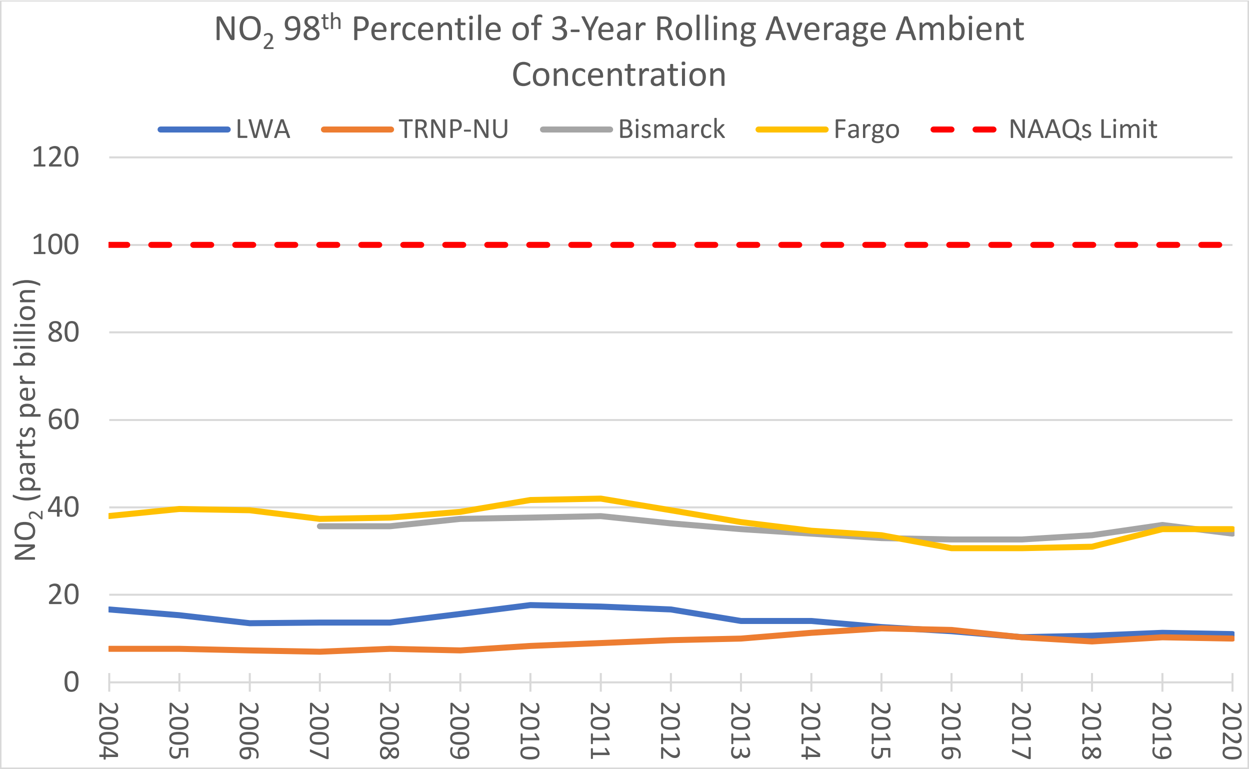

Figure 2: NO_2 98th Percentile of Daily Maximum 1-hour Concentration

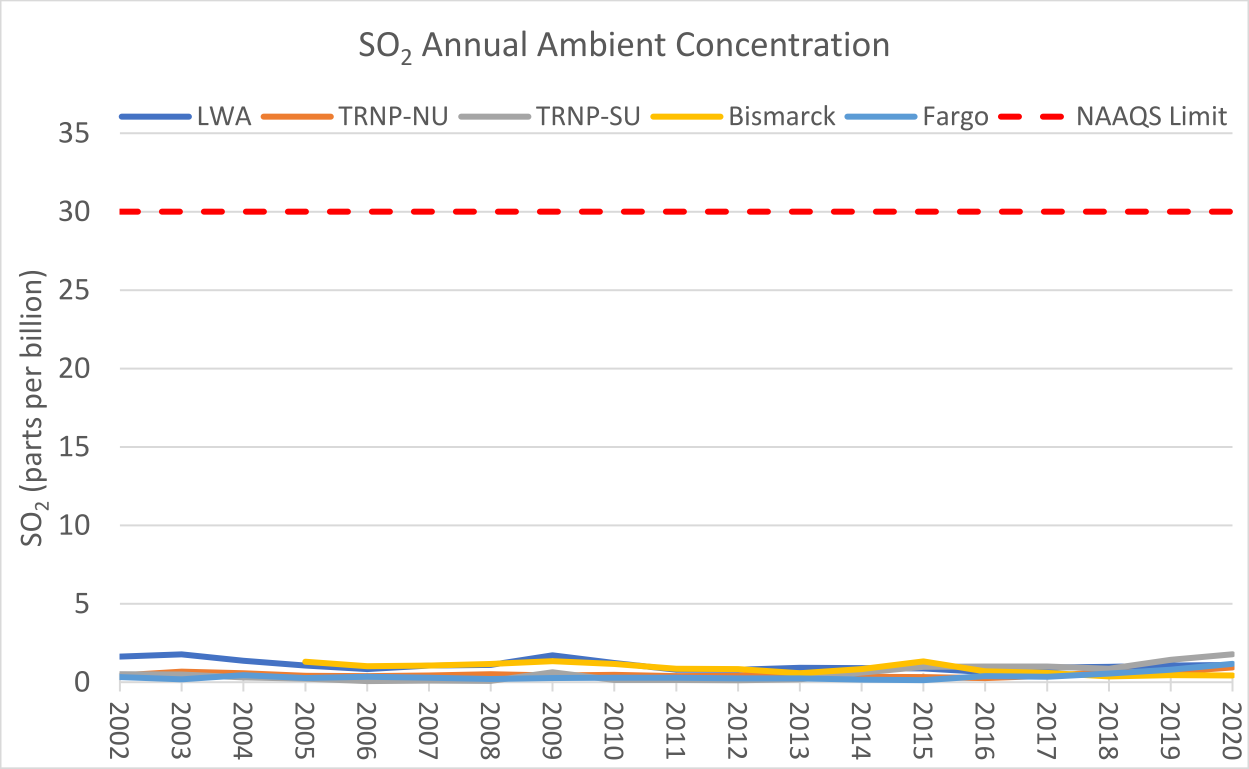

Figure 3: SO_2 Annual Average Ambient Concentrations

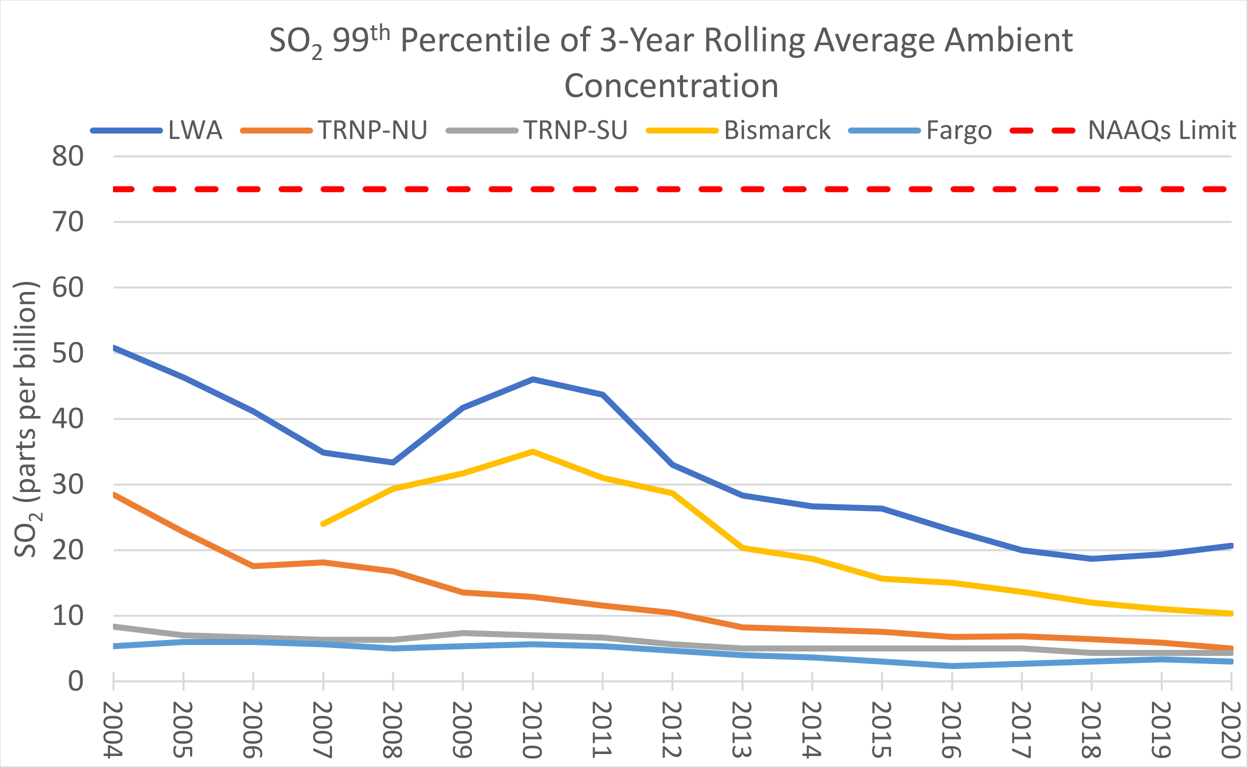

Figure 4: SO_2 99th Percentile of Daily Maximum 1-hour Concentration

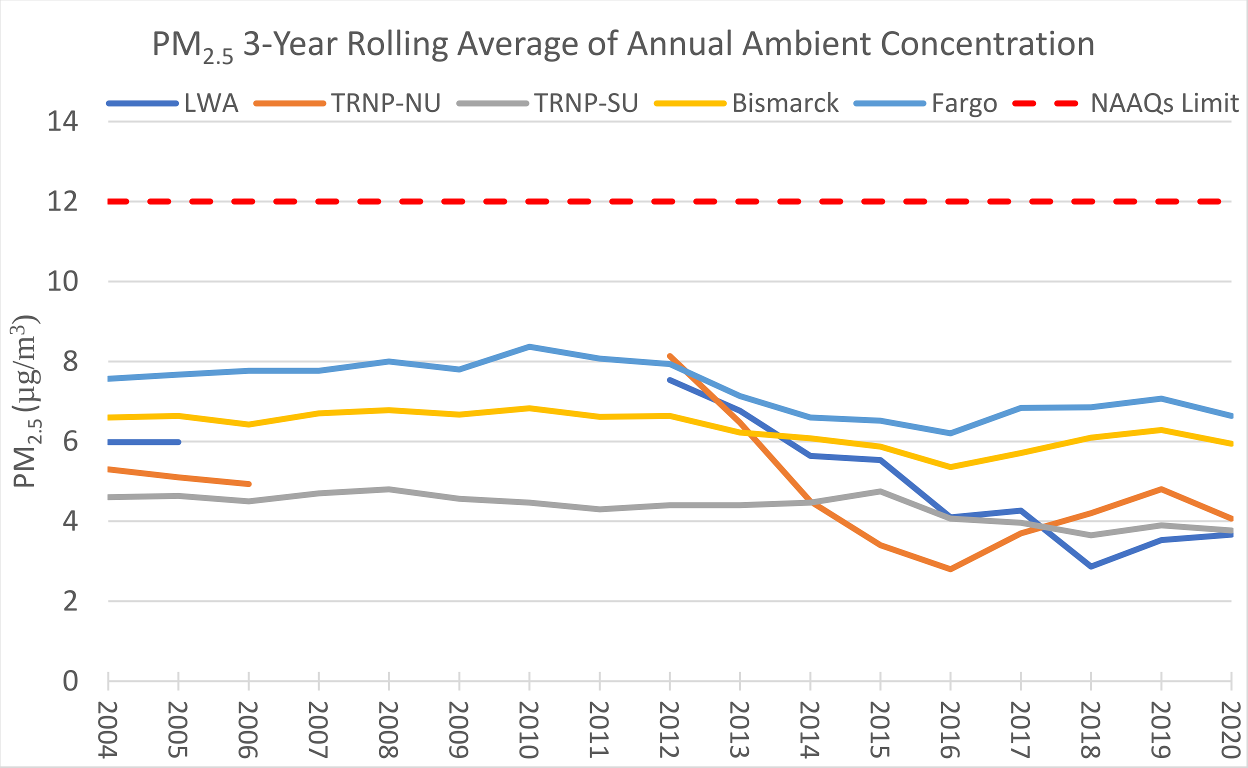

Figure 5: $PM_{2.5}$ Annual Average Ambient Concentration

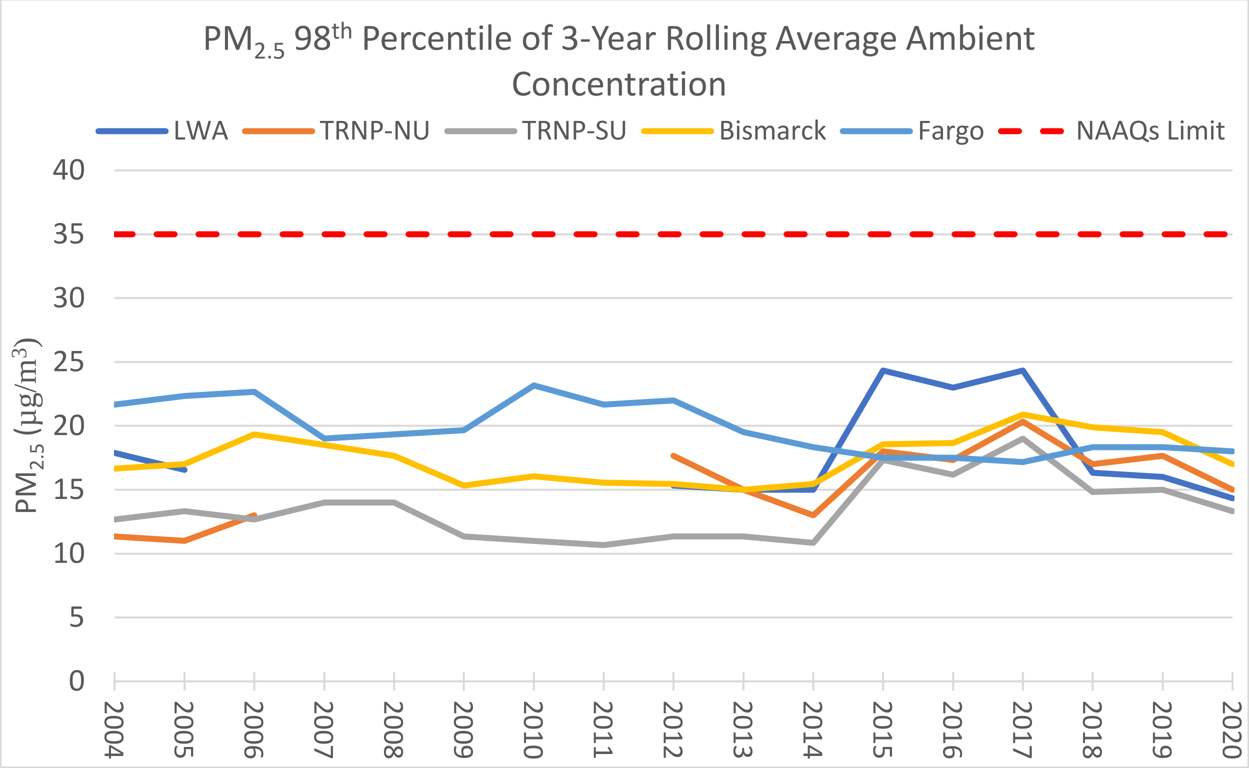

Figure 6: PM$_{2.5}$ 98th Percentile of Average 24-hour Concentration

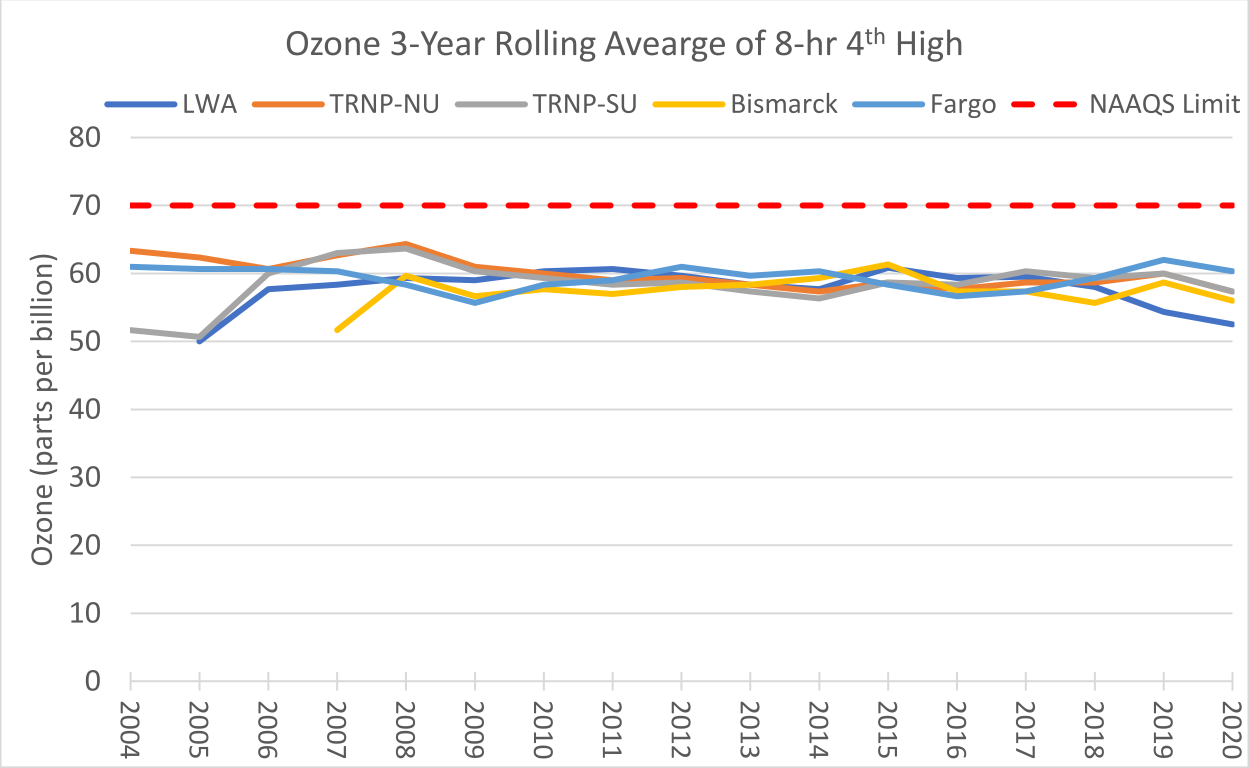

Figure 7: Ozone 4th High of 8-hour Concentration

As illustrated in Figure 1 through Figure 7 for the ambient monitors located at TRNP (North and South Units), LWA, Bismarck and Fargo, North Dakota is meeting all NO_2, SO_2, $PM_{2.5}$, and Ozone NAAQS standards.

The NO_2 data shown in Figure 1 and Figure 2 demonstrates North Dakota is well in compliance with the NO_2 NAAQS. For the years of 2002–2020:

- Figure 1, LWA and TRNP-NU have each averaged an annual NO_2 concentration of under 2ppb, significantly below the 53ppb standard.
- Figure 2, LWA and TRNP-NU have an average 98th percentile of daily maximum 1-hour concentrations of 14ppb and 9ppb, respectively, significantly below the 100ppb standard.
- For both the annual and the 98th percentile standards, NO_2 concentrations have remained very stable since 2002.

The SO_2 data shown in Figure 3 and Figure 4 demonstrates North Dakota is well in compliance with the SO_2 NAAQS. For the years of 2002–2020:

- Figure 3, LWA, TRNP-NU, and TRNP-SU have each averaged an annual SO_2 concentration of 1ppb or lower, significantly below the revoked 30ppb standard.
- Figure 4, LWA, TRNP-NU, and TRNP-SU have an averaged 99th percentile of daily maximum 1-hour concentrations of 33ppb, 12ppb, and 6ppb, respectively, significantly below the 75ppb standard. These averages are even smaller for the years of 2014–2020.
- For the 99th percentile standards, SO_2 concentrations have been on a downward trend since 2010. A pronounced decline is seen from 2010–2014, with less of a decline from 2014–2020. SO_2 annual ambient concentrations have remained very stable since 2002.

The $PM_{2.5}$ data shown in Figure 5 and Figure 6 demonstrates North Dakota is well in compliance with the $PM_{2.5}$ NAAQS. For the years of 2002–2020:

- Figure 5, LWA, TRNP-NU, and TRNP-SU have each averaged an annual $PM_{2.5}$ concentration of 5 $\mu g/m^3$ or lower, significantly below the 12 $\mu g/m^3$ standard.
- Figure 6, LWA, TRNP-NU, and TRNP-SU have an averaged 98th percentile of daily maximum concentrations of 18 $\mu g/m^3$, 16 $\mu g/m^3$, and 14 $\mu g/m^3$, respectively, significantly below the 35 $\mu g/m^3$ standard.

The ozone data shown in Figure 7 demonstrates North Dakota is well in compliance with the ozone NAAQS. For the years of 2002–2020:

- Figure 7, LWA, TRNP-NU, and TRNP-SU have an averaged 4th highest daily maximum 8-hour concentration of 58ppb, 60ppb, and 58ppb, respectively, significantly below the 70ppb standard.
- The 4th highest daily maximum 8-hour ozone concentration has remained very stable since 2002.

North Dakota continues to achieve excellent levels of air quality for NO_2, SO_2, $PM_{2.5}$, and ozone. Trends show ambient monitor concentrations have remained stable or declined since the early 2000’s, indicating recent developmental activity in North Dakota has not adversely affected the air quality in TRNP, LWA, or at any other state approved ambient monitoring locations. North Dakota anticipates these monitoring trends will continue. North Dakota will continue to monitor the ambient air and utilize the IMPROVE network data to track the air quality conditions in North Dakota and, if necessary, take further action in the 2025 progress report.

1 Background and Overview of The Federal Regional Haze Rule

Section 169(A) of the Clean Air Act (CAA) establishes the national visibility goal of "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory CIAs which impairment results from manmade air pollution." Based on the requirements of Section 169(A), the North Dakota Department of Environmental Quality (Department)[7] developed a State Implementation Plan (SIP) to address the national visibility goal. The first round Regional Haze SIP was submitted to the EPA in March 2010. The first periodic progress update was submitted in January 2015. The second round RH SIP with an updated progress report is included with this SIP revision.

The RHR was promulgated by EPA in July 1999. The RHR has subsequently been amended, with the most recent amendment in January 2017. The RHR requires that States adopt State Implementation Plans (SIPs) to address visibility impairment in each of the 156 Mandatory CIAs across the nation, Figure 8.

The RHR's two key requirements are to improve visibility in CIAs for the days that have the most impaired visibility and to ensure that there is no degradation in visibility for the days that have the least impaired visibility. The end goal of the RHR is to attain natural visibility conditions in all CIAs by 2064.

Figure 8: Class I areas in the United States[8]

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[7] On April 29, 2019, the Department of Environmental Quality went into effect and assumed authority for the environmental protection programs that had previously been under the former Department of Health Environmental Health Section's authority. See 2017 N.D. Sess. Laws ch. 199, §1. The air pollution control statutes have moved from N.D.C.C. ch. 23-25 to 23.1-06, and the rules have moved from N.D. Admin. Code art. 33-15 to 33.1-15.

[8] Available at: https://www.epa.gov/visibility/regional-haze-program (Last visited February 23, 2021)

North Dakota's RH SIP for the first planning implementation period was submitted to EPA on March 3, 2010. The EPA determined the SIP submittal was complete on April 13, 2010. Supplement No. 1 to the SIP was submitted to EPA on July 27, 2010 and Amendment No. 1 was submitted on July 28, 2010. On September 21, 2011, the EPA proposed a partial approval and partial disapproval of the SIP. At the same time, EPA proposed a Federal Implementation Plan (FIP). On April 6, 2012, EPA finalized its approval of various portions of the SIP and a FIP for those items not considered approvable.[9] The FIP established NOx limits for Coal Creek Station different than those the Department had proposed. However, the Coal Creek best available retrofit technology (BART) FIP was vacated by the Eighth Circuit Court of Appeals.[10] On April 26, 2018 EPA proposed to approve North Dakota's BART determination for Coal Creek.[11] EPA did not take final action on the proposed approval. North Dakota, EPA, and Coal Creek were working to address this until Great River Energy announced the retirement of Coal Creek Station. On June 30, 2021 Great River Energy announced it had an agreement with Rainbow Energy Center, LLC (REC) to purchase Coal Creek. As a result, the Department has determined the appropriate course of action is to move forward with proposing a NO_X BART for Coal Creek Station. This proposed action is included with this SIP revision. Section 8 provides the supplemental information regarding the Department's proposed NO_X BART for Coal Creek Station. Also included with this SIP revision is a proposed permit to construct which includes the enforceable conditions needed to satisfy the BART requirements.

The RH SIP for the first planning implementation period identified both current visibility impairment and natural conditions for the 20% haziest days (now the most impaired days) and the 20% best days (also known as the clearest days or least impaired days). Based on these results, the amount of visibility improvement that is required to achieve the national visibility goal and the uniform rate of progress were calculated (Section 3).

Pursuant to 40 CFR §51.308(f), each periodic comprehensive revised SIP is intended to meet the requirements of the EPA's RHR that were adopted to comply with CAA Section 169A. As is required by 40 CFR §51.308, this SIP addresses:

- The requirements for State and Federal Land Manager coordination of 40 CFR §51.308(i), Section 2.1.1
- Calculation of baseline and current natural visibility conditions (40 CFR §51.308(d)(2)), Section 3.2.
- Calculation of baseline visibility conditions for the most impaired and clearest days (40 CFR §51.308(f)(1)(i)), Section 3.2.1.
- Calculation of natural visibility conditions for the most impaired and clearest days (40 CFR §51.308(f)(1)(ii)), Section 3.2.2.

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[9] Available at: https://www.govinfo.gov/content/pkg/FR-2012-04-06/pdf/2012-6586.pdf (Last visited June 7, 2021)
[10] Available at: https://caselaw.findlaw.com/us-8th-circuit/1644956.html (Last visited February 23, 2021)
[11] Available at: https://www.federalregister.gov/documents/2018/04/26/2018-08623/approval-and-promulgation-of-air-quality-implementation-plans-north-dakota-regional-haze-state (Last visited February 23, 2021)

- Calculation of current visibility conditions for the most impaired and clearest days (40 CFR §51.308(f)(1)(iii)), Section 3.2.3.
- Progress to date for the most impaired and clearest days (40 CFR §51.308(f)(1)(iv)), Section 3.2.4.
- Differences between the current visibility condition and the natural visibility condition (40 CFR §51.308(f)(1)(v)), Section 3.2.5.
- The uniform rate of progress and adjusted uniform rate of progress (40 CFR §51.308(f)(1)(vi)), Section 3.2.6 and Section 3.2.7.
- The requirements to document the technical bases for the emissions information relied upon (40 CFR §51.308(f)(2)(iii), Section 4.
- Development of a long-term strategy to address issues facing North Dakota (40 CFR §51.308(d)(3)), Section 5.
- The requirements for determination of the adequacy of the existing implementation plan of 40 CFR §51.308(h), Sections 5.2, 5.3, and 6.1.
- Reasonable progress goals for each CIA pursuant to 40 CFR §51.308(d)(1), Section 6.1.
- Development of a monitoring strategy (40 CFR §51.308(d)(4)), Section 6.8.
- The requirements to document the technical bases for the modeling relied upon (40 CFR §51.308(f)(2)(iii), Section 7.
- The Best Available Retrofit Technology (BART) requirements of 40 CFR §51.308(e), Section 8.
- The requirements for periodic reports describing progress towards the reasonable progress goals of 40 CFR §51.308(g), Section 9.

1.1 Class I Areas (CIAs) in North Dakota

The CIAs in North Dakota are: the Theodore Roosevelt National Park (TRNP) which consists of three separate, distinct units and the Lostwood Wildlife Refuge Wilderness Area (LWA). Each of these CIAs are displayed in Figure 9.

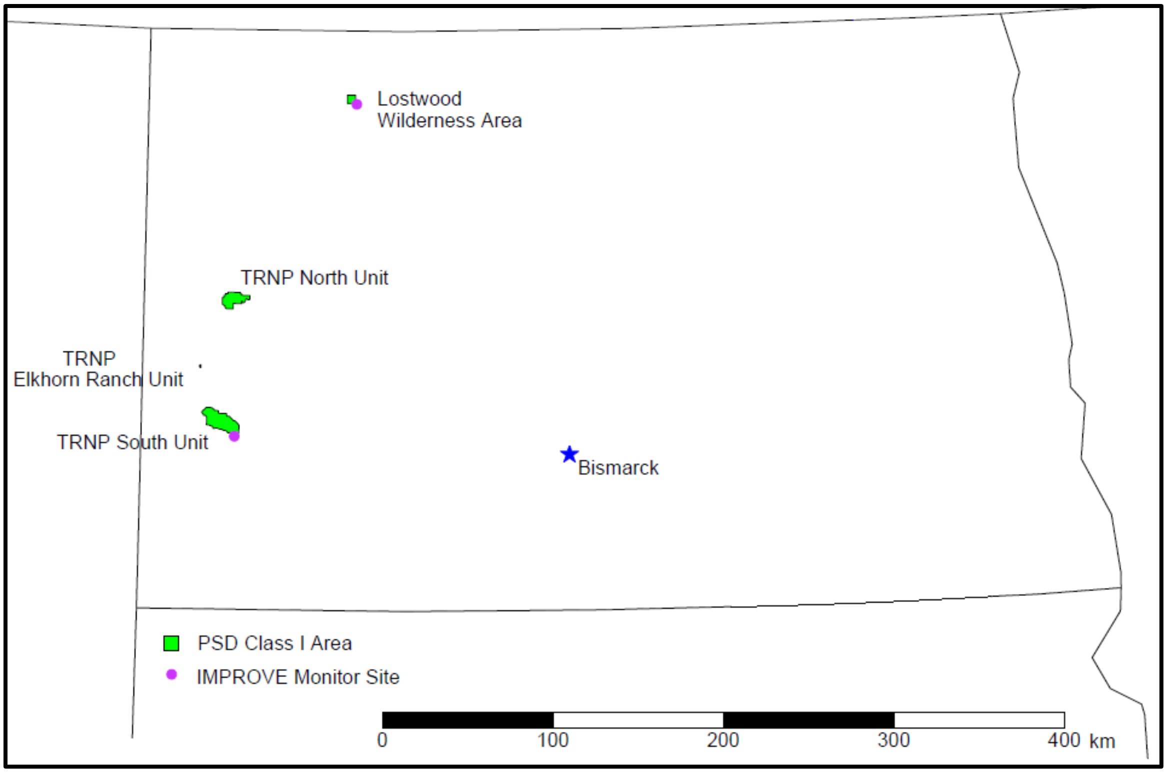

Figure 9: Class I areas in North Dakota

1.1.1 Theodore Roosevelt National Park (TRNP)

TRNP is located within Billings and McKenzie Counties in North Dakota. The colorful badlands and Little Missouri River of western North Dakota provide the scenic backdrop to the park which memorializes the 26th president for his enduring contributions to the conservation of our nation’s resources. The Park contains 70,447 acres divided among three separate, distinct units: South Unit, Elkhorn Ranch and North Unit. TRNP is managed by the National Park Service. TRNP is comprised of badlands, open prairie and hardwood draws that provide habitat for a wide variety of wildlife species including bison, prairie dogs, elk, deer, big horn sheep and many other wildlife species. The Little Missouri River passes through the three units of the park.

1.1.2 Lostwood National Wildlife Refuge Wilderness Area (LWA)

LWA is located in Burke County in the northwestern part of the State. Created by an act of Congress in 1975, LWA covers an area of 5,577 acres. LWA is managed by the U.S. Fish and Wildlife Service. LWA was designated in order to preserve a region well known for numerous lakes and mixed grass prairie and is home to one of the finest waterfowl breeding regions in North America.

1.2 Regional Haze Characteristics and Effects

1.2.1 Interagency Monitoring of Protected Visual Environments (IMPROVE) Program

The IMPROVE program[12] was initiated in 1985. The IMPROVE program established baseline visibility conditions in all 156 CIAs at the time of the program's initiation. The IMPROVE program has since created a long-term monitoring program that tracks changes in visibility through time and works to determine the causal mechanisms for any visibility impairment in CIAs.

The IMPROVE program is operated and maintained through a formal cooperative relationship between the EPA, the National Park Service (NPS), the U.S. Fish and Wildlife Service (FWS), the Bureau of Land Management (BLM), National Oceanic and Atmospheric Administration (NOAA), and the U.S. Forest Service (USFS). Several additional organizations joined the effort in 1991 including the National Association of Clean Air Agencies, the Western States Air Resources Council (WESTAR), the Mid-Atlantic Regional Air Management Association (MARAMA), and the Northeast States for Coordinated Air Use Management (NESCAUM).

IMPROVE sites are located across the United States (Figure 10). Note the zoomed in view of the locations of the two IMPROVE sites in North Dakota shown in Figure 9. Each CIA in North Dakota has an IMPROVE site. North Dakota CIA IMPROVE sites were installed on December 15, 1999 at LWA and TRNP.

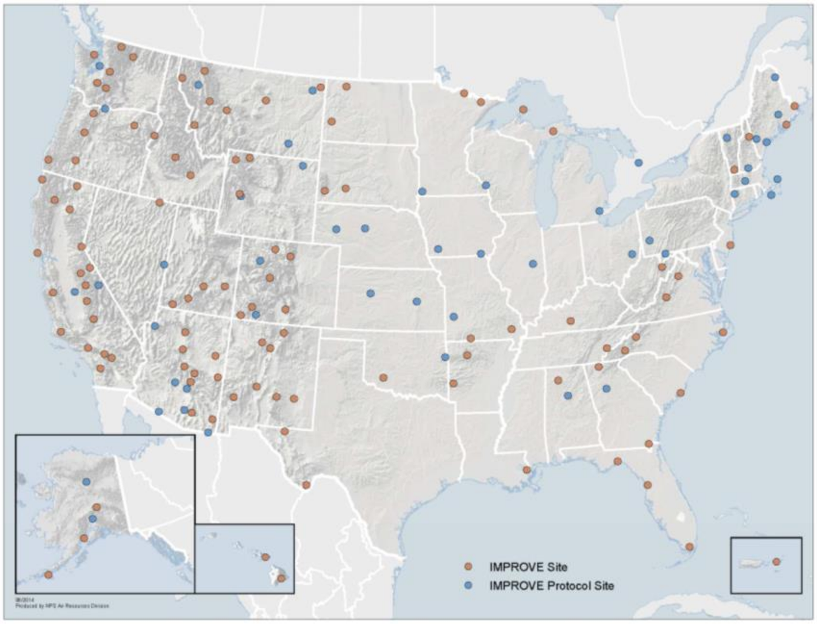

Figure 10: Locations of IMPROVE monitoring sites.[13]

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[12] Available at: http://vista.cira.colostate.edu/Improve/ (last visited July 6, 2021)

[13] Figure Available at: http://vista.cira.colostate.edu/Improve/improve-program/. Note that the map includes both "IMPROVE Sites" and "IMPROVE Protocol Sites". The IMPROVE protocol sites are separately sponsored by state, regional, tribal, and national organizations. Both the IMPROVE sites and the IMPROVE protocol sites use identical samplers and analysis protocols by the same contractors, allowing all data to be treated equally.

The IMPROVE program has developed methods for estimating light extinction from speciated aerosol and relative humidity data. The three most common metrics used to describe visibility impairment are illustrated in Figure 11 and described below:

- Extinction (b_{ext}): Extinction is a measure of the fraction of light lost per unit length along a sight path due to scattering and absorption by gases and particles. Extinction is expressed in inverse Megameters (Mm^{-1}). Extinction is used to represent the contribution of each aerosol species to visibility impairment and can be practically thought of as the units of light lost over a distance of one million meters.
- Visual Range: Visual range is the greatest distance a large black object can be seen on the horizon. Visual range is expressed in kilometers (km) or miles (mi).
- Deciview (dv): Deciviews are the metric used for tracking regional haze in the RHR. The deciview index was designed to be linear with respect to human perception of visibility. A one deciview change is approximately equivalent to a 10% change in extinction in either direction. One deciview of change in visibility is generally considered to be the minimum change that the average person can detect with the naked eye.

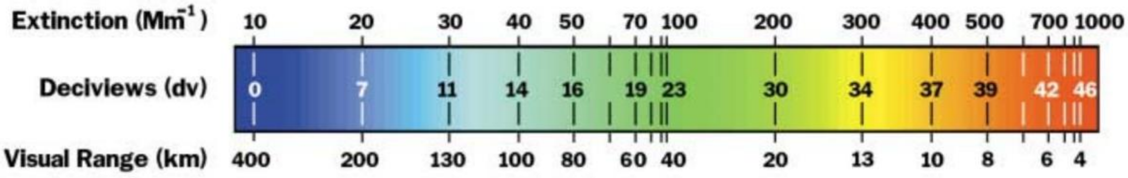

Figure 11: Comparison of extinction (Mm^{-1}), deciview (dv), and visual range (km) [14]

1.3 Regional Haze in North Dakota

Visibility in North Dakota's CIAs is impaired by both natural and manmade (anthropogenic) emission sources. Anthropogenic emissions sources include electric utility steam generating units (EGUs), area and point source oil and gas (O&G) operations, agricultural production and processing, on-road and non-road mobile sources, rail operations, prescribed burning, fugitive dust, and other minor sources. Naturally occurring emissions include U.S. and international wildfires, windblown dust, biogenic NO_X and volatile organic compounds (VOC), lightning NO_X, and other minor sources. The predominant emissions that may lead to visibility impairment are SO_2, NO_X, particulate matter (PM_{10} and $PM_{2.5}$), VOCs, and ammonia (NH_3).

1.3.1 Anthropogenic Emissions Reductions from Round 1 of the RHR

During the first implementation period of the RHR, North Dakota accomplished significant reduction in anthropogenic emissions of PM, NO_X and SO_2 from coal fired EGUs. The applicable requirement, emissions limit, and date these controls were installed are included in Table 1.

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[14] Available at: http://vista.cira.colostate.edu/Improve/wp-content/uploads/2016/03/Intro_to_Visibility.pdf. (Last Visited May 18, 2021)

Table 1: BART and Reasonable Progress Success since Round 1 Implementation

Source	Unit	Pollutant	Applicable Requirement	BART/RP Limit [A]	Date Implemented (Month Year)
Antelope Valley	1	NO_x	RP (FIP)	0.17 lb/10^6 Btu	May 2014
Antelope Valley	2	NO_x	RP (FIP)	0.17 lb/10^6 Btu	June 2016
Leland Olds	1	SO_2	BART	0.15 lb/10^6 Btu [B]	June 2013
		NO_x	BART	0.19 lb/10^6 Btu	August 2015
		PM	BART	0.07 lb/10^6 Btu	June 2013
Leland Olds	2	SO_2	BART	0.15 lb/10^6 Btu [B]	October 2012
		NO_x	BART	0.35 lb/10^6 Btu	August 2015
		PM	BART	0.07 lb/10^6 Btu	October 2012
M.R. Young	1	SO_2	BART	95% reduction; or	December 2011
		NO_x	BART	0.36 lb/10^6 Btu	December 2011
		PM	BART	0.03 lb/10^6 Btu	December 2011
M.R. Young	2	SO_2	BART	95% reduction [C]	December 2010
		NO_x	BART	0.35 lb/10^6 Btu	December 2010
		PM	BART	0.03 lb/10^6 Btu	December 2010
Coyote		NO_x	RP	0.50 lb/10^6 Btu	June 2016
Stanton	1	SO_2	BART	0.16 lb/10^6 Btu	May 2017 - Plant Shutdown and Demolished
		NO_x	BART	0.23 lb/10^6 Btu	
		PM	BART	0.07 lb/10^6 Btu	
Coal Creek	1	SO_2	BART	0.15 lb/10^6 Btu [B]	April 2017
		NO_x	BART	0.15 lb/10^6 Btu	Pending, proposed with this SIP Revision
		PM	BART	0.07 lb/10^6 Btu	April 2017
Coal Creek	2	SO_2	BART	0.15 lb/10^6 Btu [B]	April 2017
		NO_x	BART	0.15 lb/10^6 Btu	Pending, proposed with this SIP Revision
		PM	BART	0.07 lb/10^6 Btu	April 2017
R.M. Heskett [D]	2	SO_2	RP	0.60 lb/10^6 Btu	June 2016

[A] Based on a 30-day rolling average unless otherwise noted.

[B] As an alternative, the source may comply with a 95% reduction requirement.

[C] As an alternative, M.R. Young 2 may comply with an alternative limit of 0.15 lb/10^6 Btu and 90% reduction.

[D] MDU is shutting down R.M. Heskett Units 1 and 2 in 2022.

The BART and reasonable progress requirements listed in Table 1 significantly reduced NO_X and SO_2. The total reductions from North Dakota EGUs were approximately 102,000 tons of SO_2 (down 72%) and 41,600 tons of NO_X (down 55%) from 2002 to current representative emissions[15]. These reductions are depicted in Figure 12 and listed in Table 2.

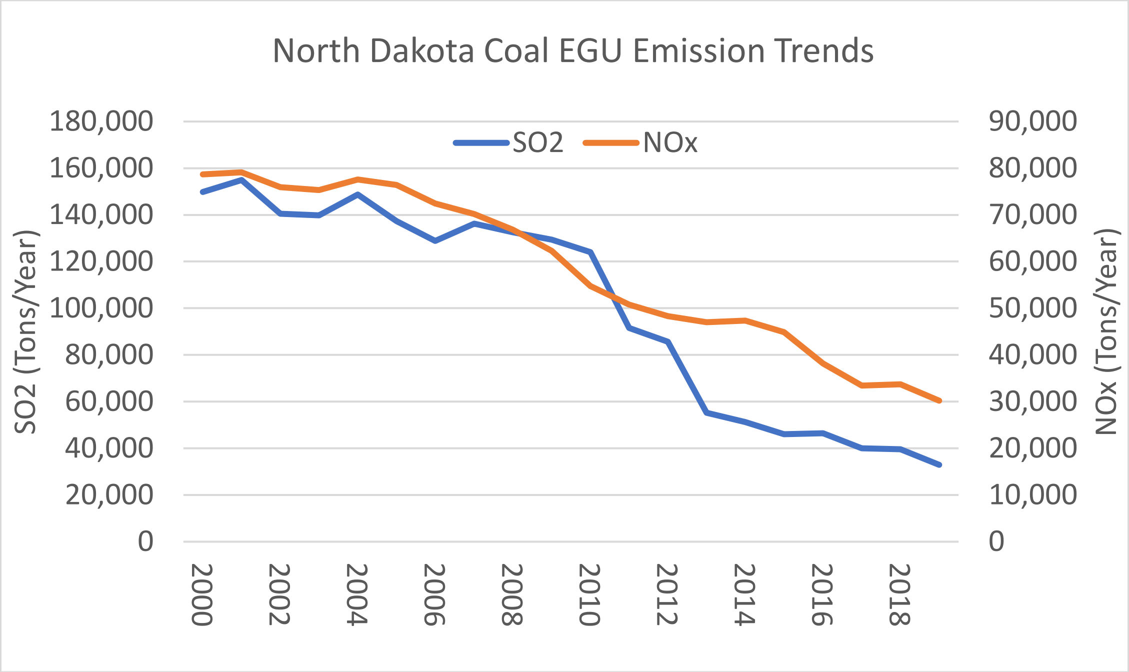

Figure 12: North Dakota Coal Fired EGU Emissions since from 2002-2019.

Table 2: North Dakota Coal Fired EGU Emissions and Reductions since 2002.

		NO_X Emissions			**SO_2 Emissions**		
Facility	**Unit**	**2002**	**RepBase**	***Reduction***	**2002**	**RepBase**	***Reduction***
Coyote	1	13,173	7,363	*44%*	14,069	12,994	*8%*
Antelope Valley	1	5,840	1,697	*71%*	6,580	6,279	*5%*
Antelope Valley	2	5,953	1,708	*71%*	7,283	6,319	*13%*
Leland Olds	1	2,581	1,059	*59%*	16,655	636	*96%*
Leland Olds	2	11,184	4,192	*63%*	30,744	1,258	*96%*
Coal Creek	1	4,863	3,987	*18%*	11,910	3,458	*71%*
Coal Creek	2	5,492	3,010	*45%*	12,518	3,400	*73%*
Milton R. Young	1	8,510	3,435	*60%*	19,858	766	*96%*
Milton R. Young	2	14,335	5,735	*60%*	8,707	2,165	*75%*
RM Heskett Station	1	180	209	*-16%*	622	753	*-21%*
RM Heskett Station	2	918	978	*-7%*	2,189	1,214	*45%*
Stanton Station	1	2,209	0	*100%*	8,900	0	*100%*
Stanton Station	10	890	0	*100%*	1,122	0	*100%*
	Total	**76,127**	**33,373**	***56%***	**141,156**	**39,242**	***72%***

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[15] Current representative emissions are detailed in Section 4.1.4.

1.3.2 Anthropogenically Most Impaired Days Conflict with Actual Visibility Impairment

The Department compiled the National Park Service's visitation statistics[16] at TRNP and compared the visitation to the EPA selected Most Impaired Days (MID)[17] and the average light extinction experienced at TRNP. When reviewing this data, it is apparent that focusing on the MID for TRNP will not meaningfully improve visibility or a visitor's experience in TRNP. Figure 13 displays the average monthly recreational visitors to TRNP from the years of 2014–2018 compared to the total number of MID and the average monthly light extinction.

As illustrated in Figure 13, TRNP receives 75% of the yearly visitation in the months of June, July, August, and September. During these same months there were a total of four MIDs identified, accounting for less than 4% of the total MIDs from 2014–2018. This indicates that during the highest levels of visitation, TRNP visibility is not being significantly impaired by anthropogenic emissions. This is supported when looking at the average light extinction over the same high visitation months versus the low visitation months. During high visitation months, TRNP experiences an average of 28 Mm^{-1} of light extinction versus 19 Mm^{-1} during low visitation months. The primary reason for the increased visibility impairment is from out of state wildfire activity. Further, the primary months which North Dakota has the highest number of MIDs (November–March) are months where the prevailing wind directions throughout much of North Dakota are from the West and Northwest. In other words, it is reasonable to assume the MIDs are attributable to international transport and not from North Dakota sources as many of the sources are downwind of the CIAs. The supporting wind rose data from North Dakota's ambient network can be found in NDDEQ's" Annual Reports & Monitoring Network Plans".[18]

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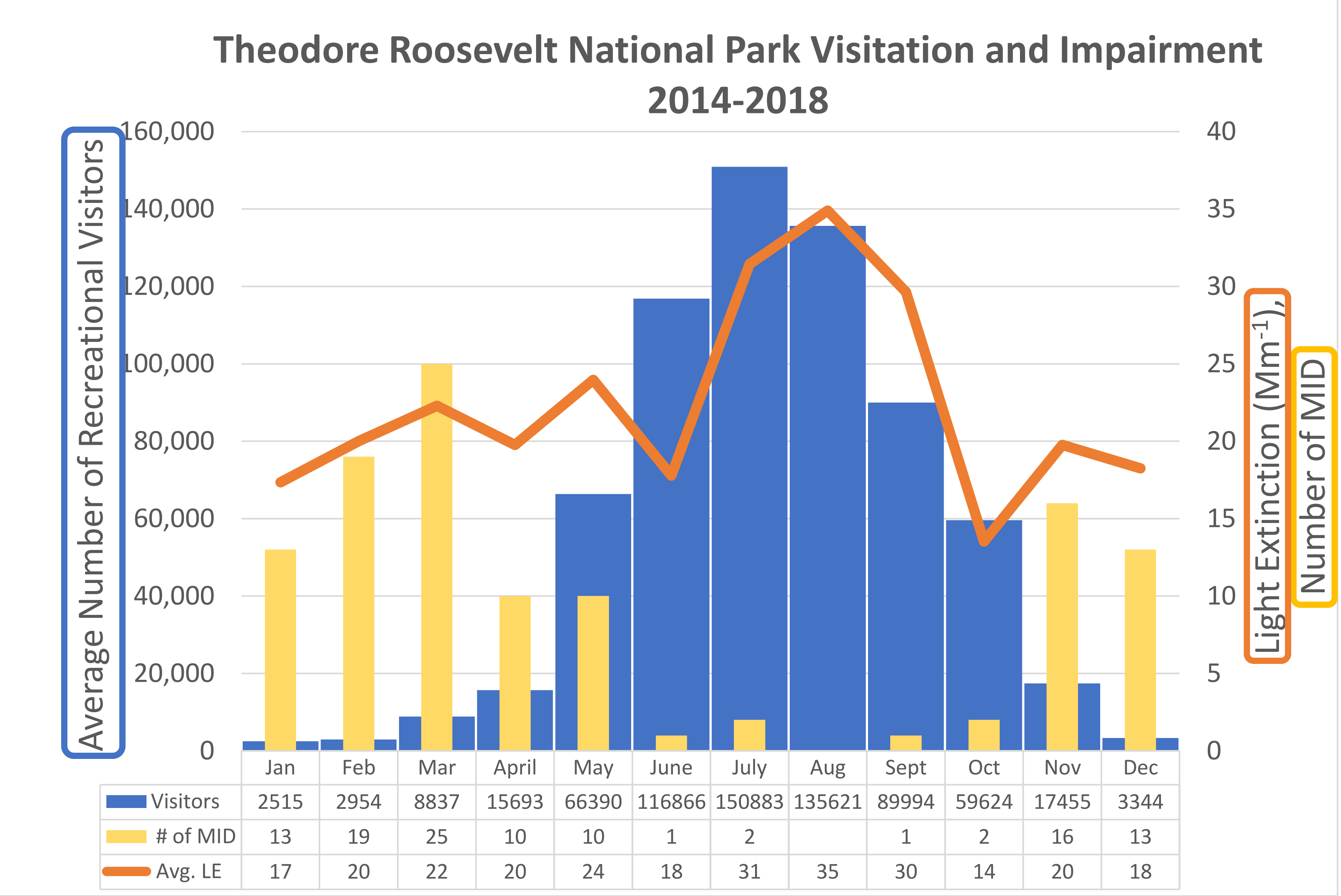
[16] Available at: https://irma.nps.gov/STATS/SSRSReports/Park%20Specific%20Reports/Visitation%20by%20Month (Last visited July 21, 2021)

[17] Most impaired days means the twenty percent of monitored days in a calendar year with the highest amounts of anthropogenic visibility impairment.

[18] Available at: https://www.deq.nd.gov/AQ/monitoring/. Under "Annual Reports & Monitoring Network Plans", select report year. See Appendix D, "Wind and Pollution Roses". (Last visited July 21, 2021)



	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Visitors	2515	2954	8837	15693	66390	116866	150883	135621	89994	59624	17455	3344
# of MID	13	19	25	10	10	1	2		1	2	16	13
Avg. LE	17	20	22	20	24	18	31	35	30	14	20	18

Figure 13: Monthly TRNP Visitation, Identified MIDs, and Average Light Extinction from 2014–2018.

1.4 General Planning Provisions

1.4.1 SIP Submission Dates

40 CFR §51.308(f) requires that States revise and submit their regional haze plan revisions to the EPA by July 31, 2021, July 31, 2028, and every 10 years thereafter. 40 CFR Section §51.308(g) requires that states submit a progress report five years after each SIP revision in order to evaluate progress toward the reasonable progress goals (RPG) for each applicable mandatory CIA. North Dakota's first progress report was submitted in January 2015 as a formal SIP revision and has not been approved by EPA at the time this SIP revision is being drafted. A progress report update is included with this SIP revision in Section 9. Future progress reports are due by January 31, 2025, July 31, 2033, and every 10 years thereafter.

1.4.2 North Dakota State Authority

This section will be completed upon the conclusion of the FLM consultation period and public comment period.

2 North Dakota Regional Haze SIP Development Process

The Western Regional Air Partnership (WRAP) assisted in the documentation of the technical basis, including modeling, monitoring, cost, engineering, and emissions information relied on by North Dakota. As allowed under 40 CFR 51.308(d)(3)(iii) and 40 CFR 51.308(f)(2)(iii), North Dakota relied on the technical analysis developed by a regional planning process (e.g. WRAP) for use during the second round planning period for regional haze when determining what is necessary to make or achieve reasonable progress in each CIA affected by North Dakota. Extensive issues in the modeling were experienced during the planning process, leading to a significant delay in receipt of this vital information. Modeling information is vital to the RHR as it is the only tool available to determine what future visibility impairment in the CIAs is projected to be, what impact additional controls may have on CIA visibility projections, and to determine the impact individual states and sectors (e.g., coal fired EGUs) have on visibility in the CIAs. Since the RHR is focused on improving visibility in CIAs, North Dakota was obligated to wait for this information to become available to perform a thorough analysis. Once available, North Dakota performed a detailed review and incorporated the applicable results into this SIP revision.

The modeling contractor, Ramboll U.S. Contracting – Environment and Health unit, provided a memo and letter to WRAP on February 8, 2021 detailing and explaining the litany of reasons which led to the delays in completing the regional haze modeling. Mainly, the delays were attributed to: COVID-19, delays in data processing decisions at EPA, various bugs in the model platform, wildfires causing power outages in both 2019 and 2020, errors and double counting in emissions inventories, and many other issues. Complete details and a copy of this information can be found in Appendix C. For context, the 2018–2019 WRAP board approved workplan projected the regional haze modeling to be completed in Quarter 2 of 2020, with results available for state use in Quarter 3 of 2020.[19] The modeling was completed and made available for state use in March 2021. On April 1, 2021, a results meeting was held

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[19] Available at: https://www.wrapair2.org/pdf/2018-2019%20WRAP%20Workplan%20update%20Board%20Approved%20April.3.2019.pdf (Last visited June 1, 2021)

to present the final data needed for incorporation into the SIP revision.[20] North Dakota has been actively working with the data to interpret and incorporate the information into this SIP revision. North Dakota has provided this information to further explain the situation to interested parties and explain why North Dakota missed the July 31, 2021 deadline.

2.1 Consultation with Federal Land Managers (FLM), Neighboring States, and Tribes

For each of the entities consulted in Section 2.1.1 through 2.1.6, the Department kept a communications log. The communications log is included in Appendix E.

2.1.1 Federal Land Managers

Per 40 CFR §51.308(f)(2)(ii), §51.308(i)(2), and §51.308(i)(4), North Dakota consulted with FLMs for all in-state CIAs and affected out-of-state CIAs on an ongoing basis through WRAP and separate calls. The National Park Service (NPS) requested that North Dakota evaluate nine sources for reasonable progress. The nine sources requested were included in North Dakota's four factor evaluations, see Section 5.2, Appendix A, and Appendix B.

The Department met with the NPS and USFS via Microsoft Teams to discuss impairment in CIAs and provide an overview of North Dakotas regional haze situation and plan in during the SIP Revision for Round 2 of regional haze (PowerPoint[21]). The Department met via video conference with the National Park Service on November 6, 2020 and on December 15, 2020. The Department met via video conference with the United States Forest Service on November 23, 2020.

Upon the Department sharing a draft SIP revision for the FLM consultation, the Department offered to meet with the NPS and USFS via video conference to discuss the draft SIP revision and answer any questions.

2.1.2 Minnesota

The Department consulted with Minnesota on March 22, 2021 to discuss the status of the draft SIP revisions for North Dakota and Minnesota. At the time of the discussion, both Minnesota and North Dakota were waiting for the respective regional planning organizations to complete photochemical grid modeling. No additional information has been requested between either party.

2.1.3 Montana

The Department participated in routine engagement with Montana during development of this SIP Revision. The first meeting was held on June 12, 2019, where source selection and international impacts were discussed. On June 2, 2020, the Department met again with Montana to review weighted emissions potential and area of influence modeling results. Starting in October of 2020, Montana and North Dakota met approximately every two weeks to discuss the utilization of WRAP products and SIP

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[20] Available at: https://www.wrapair2.org/RHPWG.aspx. See April 1, 2021 – Meeting 8. (Last visited June 1, 2021)

[21] PowerPoint can be found in Appendix E, pages E.2-63–94

development. Engagement also happened though WRAP regional haze workgroup meetings. Montana did not identify any sources or areas of concern regarding visibility impacts from North Dakota.

2.1.4 South Dakota

The Department participated in routine engagement with South Dakota during development of this SIP Revision. Engagement happened primarily though WRAP regional haze workgroup meetings. North Dakota and South Dakota also met directly on October 6, 2020 to discuss sources, controls, and general SIP development. South Dakota did not identify any sources or areas of concern regarding visibility impacts from North Dakota.

2.1.5 Other States

The Department participated in routine engagement with EPA Region 8 states and all WRAP states during development of this SIP Revision. Engagement happened primarily though WRAP regional haze workgroup meetings. No states identified any sources or areas of concern regarding visibility impacts from North Dakota.

2.1.6 Collaboration with Tribes

The Department will also work to consult its Tribal partners in North Dakota during the consultation period required under 40 CFR 51.308(i)(2). A copy of the draft RH SIP revision to: Mandan, Hidatsa & Arikara Nation, Standing Rock Sioux Tribe, Sisseton Wahpeton Oyate, Turtle Mountain Tribe, and Spirit Lake Tribe, inviting them to consult with the Department on the SIP Revision.

2.2 Western Regional Air Partnership (WRAP) Engagement

WRAP is a voluntary partnership of states, tribes, federal land managers, local air agencies and the United States EPA. The purpose of the partnership is to understand current and evolving regional air quality issues in the western United States. The WRAP assists state air agencies in preparing plans to meet the requirements of the federal RHR. The WRAP region encompasses the 15-state area of Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming.

The Department participates in WRAP planning to assist with the preparation of North Dakota's regional haze SIP revision. The WRAP Regional Haze Planning Work Group provided ample support for the development of various elements required for the regional haze SIP revisions, such as:

- Current and future emissions inventories, including growth projection methodologies by source categories
- Development of a transparent and complete monitoring data metric for planning and model projection purposes
- Database management, including the TSSv2 database detailed in Section 2.2.4
- 4-factor analysis for control measures
- Regional photochemical modeling
- Assessment of "unknowns" and uncertain categories, including natural conditions, international emissions, fire and dust emission, etc.

- Development of Regional Haze SIP revision content and progress report template
- Development of a control strategies menu for major western state sources

Full details of the support provided were documented and can be found on the Regional Haze Planning Work Group webpage: https://www.wrapair2.org/RHPWG.aspx.

In addition to the WRAP planning workgroup, the Department participated in various other WRAP workgroups which developed materials in support of the WRAP State's regional haze SIP revisions. These include the Oil and Gas Work Group, Regional Technical Operations Work Group, Fire and Smoke Group, and the Tribal Data Work Group. Each of these work groups are summarized in Sections 2.2.1 through 2.2.4.

2.2.1 Oil and Gas Work Group

The overview of the Oil and Gas Work Group on the WRAP webpage (https://www.wrapair2.org/ogwg.aspx) states:

"The oil and gas sector is rapidly changing due to variations in commodity prices, technology innovations, and emerging regulatory programs. The Intermountain Region is especially impacted by exploration and production emissions from the oil and gas industry, and the West more broadly by emissions from the transport and use of those fuels. National Ambient Air Quality Standards (NAAQS) exceedances during winter in production regions of Utah and Wyoming have demonstrated localized effects, while the contributions from exploration and production in the wider region on summer ozone is still being assessed. In addition, this sector must be considered for Regional Haze planning. Studies point to improvements in the emissions inventory as being one of the most needed products to improve performance of the air quality models and will be a key focus of this work group."

Development of a more accurate emissions inventory for upstream North Dakota oil and gas operations was the most significant undertaking by North Dakota for this work group. North Dakota supported this initiative by providing updated information on current production. North Dakota also provided future forecasted production using North Dakota Industrial Commission projections. North Dakota also assisted in the development of the revised emissions inventory through collection of survey data from operators in the state of North Dakota. The survey results supported the development of the work products produced by the Oil and Gas Work Group.[22]

North Dakota's oil and gas sector is discussed in Section 5.2.11.

2.2.2 Regional Technical Operations Work Group

The Regional Technical Operations Work Group compiled emissions data from the various sectors and performed the modeling used to support the Department's long term strategy and selection of RPGs in Section 6. These modeling results were also used to support the visibility analysis in Section 3.

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[22] Available at: https://www.wrapair2.org/pdf/WRAP_OGWG_Report_Baseline_17Sep2019.pdf (Last visited February 23, 2021)

The Regional Technical Operations Work Group webpage (https://www.wrapair2.org/rtowg.aspx) lists the following bullet points as the overview of the group:

- *"Regional analyses in support of planning activities related to emissions and modeling for regional haze, ozone, PM, and other indicators.*
- *Evaluation of background and regional transport, international transport, sensitivity and other analyses of emissions data focused on the western U.S.*
- *Perform and leverage modeling, data analysis, and contribution assessment studies.*
- *Investigation of "background ozone" impacts to western U.S. locations.*
- *Coordination and collaboration with other WRAP member-sponsored regional air quality modeling groups including Intermountain West Data Warehouse (IWDW), NW-AirQuest, EPA-Office of Air Quality Planning and Standards, Bay Area Air Quality Management District, and other state and local agencies performing regional ozone modeling.*
- *Provide guidance on more complete and uniform model performance evaluations (MPEs).*
- *Develop and implement a protocol to use the IWDW- Western Air Quality Study capabilities as the WRAP Regional Technical Center."*

2.2.3 Fire and Smoke Group

Complete details of the Fire and Smoke Group (FSWG) can be found on the WRAP webpage (https://www.wrapair2.org/fswg.aspx). A summary of the Fire and Smoke Group (FSWG) is as follows:

The FSWG focused on analysis and planning activities related to IMPROVE activity data to support emissions inventories for fire and smoke emissions. Both natural, unplanned wildfires and planned, prescribed fire are important air pollution sources in the western United States.

The FSWG developed the emissions inventories used to in the modeling to support the regional haze planning efforts. Fire impacts on North Dakota are discussed in Section 3.3 and emissions are addressed in Section 4.8.

2.2.4 Technical Information and Data on TSSv2

WRAP partners help operate and manage the Technical Support System (TSS). The TSS provides air quality data related to regional haze to agency planners, land managers, and the public. The TSS offers interactive displays showing technical data and measurements for the WRAP states, such as:

- the location of CIAs and IMPROVE monitor sites;
- visibility conditions at CIAs over time (i.e., how much light is being scattered and thus preventing people from seeing clearly over long distances and time);
- the number of visibility-impairing particles in the air at CIAs;
- the quantity of pollutants that contribute to visibility impairment for each source in each state;
- results of computer modeling showing how emissions travel long distances from an anthropogenic or natural source, how they contribute to the formation of visibility impairing particles, and how visibility is impaired happens as a result;

- results of computer modeling showing how air pollution control measures might affect visibility conditions at CIAs.

The technical data on the WRAP TSSv2 was used significantly by North Dakota for many of the figures, graphs, and tables used to support North Dakota's regional haze SIP revision. This includes the technical data displayed in Section 3:§51.308(f) - North Dakota Visibility Analysis, Section 4: Emissions Inventory, Section 5: §51.308(f)(2) - Long Term Strategy for North Dakota, Section 6: §51.308(f)(3) – Modeling of Long-Term Strategy to Set Reasonable Progress Goals, and Section 9: Five-Year Progress Report.

The WRAP TSS version 2 can be found at: https://views.cira.colostate.edu/tssv2/.

2.3 Coordinated Emission Management Strategies

Due to the insignificant impacts from North Dakota sources on out of state CIAs, there was no need for any coordinated emission management strategies. North Dakota notes oil and gas production on the Fort Berthold Indian Reservation accounts for at least 20% of the total oil production from the entire state of North Dakota. Should there be a need in the future to reduce visibility impacts from the oil and gas sector, a coordinated approach between EPA, the MHA Nation, and the Department would be necessary.

2.4 North Dakota sources identified by downwind states that are reasonably anticipated to impact CIAs

Due to the insignificant impacts from North Dakota sources on out of state CIAs, no sources were identified as reasonably anticipated to impact out of state CIAs. Wrap produced Weighted Emissions Potential (WEP) and Area of Influence (AOI) products (Section 7.5) which were used to help determine impacts from North Dakota sources to out of state CIAs and determine impacts to North Dakota CIAs from out of state sources. A summary of these results is included in Appendix C.

2.5 Public Comment Information

This section will be completed upon the conclusion of the FLM consultation period.

2.6 Review and Commitment to Further Planning

Public comments, including those from federal agency staff, will be provided on the Department's regional haze webpage. If adopted by the Department, the final SIP revision would incorporate public comments and the Department's responses, as required per 40 CFR 51.308(i)(3).

3 §51.308(f) - North Dakota Visibility Analysis

To assess haze most effectively in mandatory CIAs, the causes of haze must first be determined. This section summarizes the causes of haze in North Dakota CIAs, details the progress made since the baseline period, breaks down the Natural and International impairment contributions, breaks down the US anthropogenic contributions by state and sector, and discusses the impacts of U.S. wildfires on North Dakota visibility.

3.1 Visibility Summary

Visibility on the MIDs at LWA and TRNP is adversely impacted by many different sources, most of which are outside of North Dakota's ability to regulate. Figure 14 and Figure 15 display a graphical breakdown of the contributors to visibility impairment. Table 3 and Table 4 display the numerical percentages associated with Figure 14 and Figure 15. As displayed in these figures and tables, only 20% of the total impairment at LWA and 13% of the total impairment at TRNP is from sources within North Dakota. The remaining impairment on the MIDs comes from international, natural, and US sources outside of North Dakota.

The 13 different sources contributing to visibility impairment are shown in Figure 14 and Figure 15. Some of the source values are very small and therefore do not show up significantly in the figures. The sources contributing to visibility impairment include North Dakota EGU (ND EGU), North Dakota Oil and Gas (ND OilGas[23]), North Dakota Mobile (ND Mobile), North Dakota non EGU (ND NonEGU), Remaining North Dakota (ND RemainAnthro), Boundary Conditions from US sources (BCUS), all other US Anthro (Remaining US), International Anthropogenic (Int_Anthro), Canadian-Mexican Fire (CanMexFire), Natural, US prescribed wildland fires (US_RxWildland Fire), US wildfires (US_Wildfire), and Rayleigh. The species contributing to visibility impairment include ammonium nitrate, ammonium sulfate, coarse mass, elemental carbon, organic mass, sea salt, and soil. These are displayed in Table 3 and Table 4. The sources make up the 2028 column displayed in Figure 14 and Figure 15.

Also shown in Figure 14 and Figure 15 are the baseline visibility conditions from 2000-2004 (Baseline '00-'04), IMPROVE 5-yr rolling average trendline, unadjusted uniform rate of progress (Glidepath), and adjusted uniform rate of progress (Adjusted Glidepath). For the North Dakota "ND" sources, the visibility impairment species only includes ammonium nitrate and ammonium sulfate, the species of most interest from anthropogenic sources. All ND impairment from coarse mass, elemental carbon, organic mass, sea salt, and soil are combined with the Remaining US category.[24] This helps show the most controllable portion of visibility impairment from North Dakota anthropogenic sources.

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[23] The oil and gas sector consists of area sources, point sources, and tribal oil and gas operations. Oil and gas area sources, which includes tribal operations, are comprised of over 15,000 individual wells spread across roughly 8,000 locations.

[24] Ammonium nitrate and ammonium sulfate were the only species tracked when determining the US State and sector contributions to light extinction. See Section 7.4 for details.

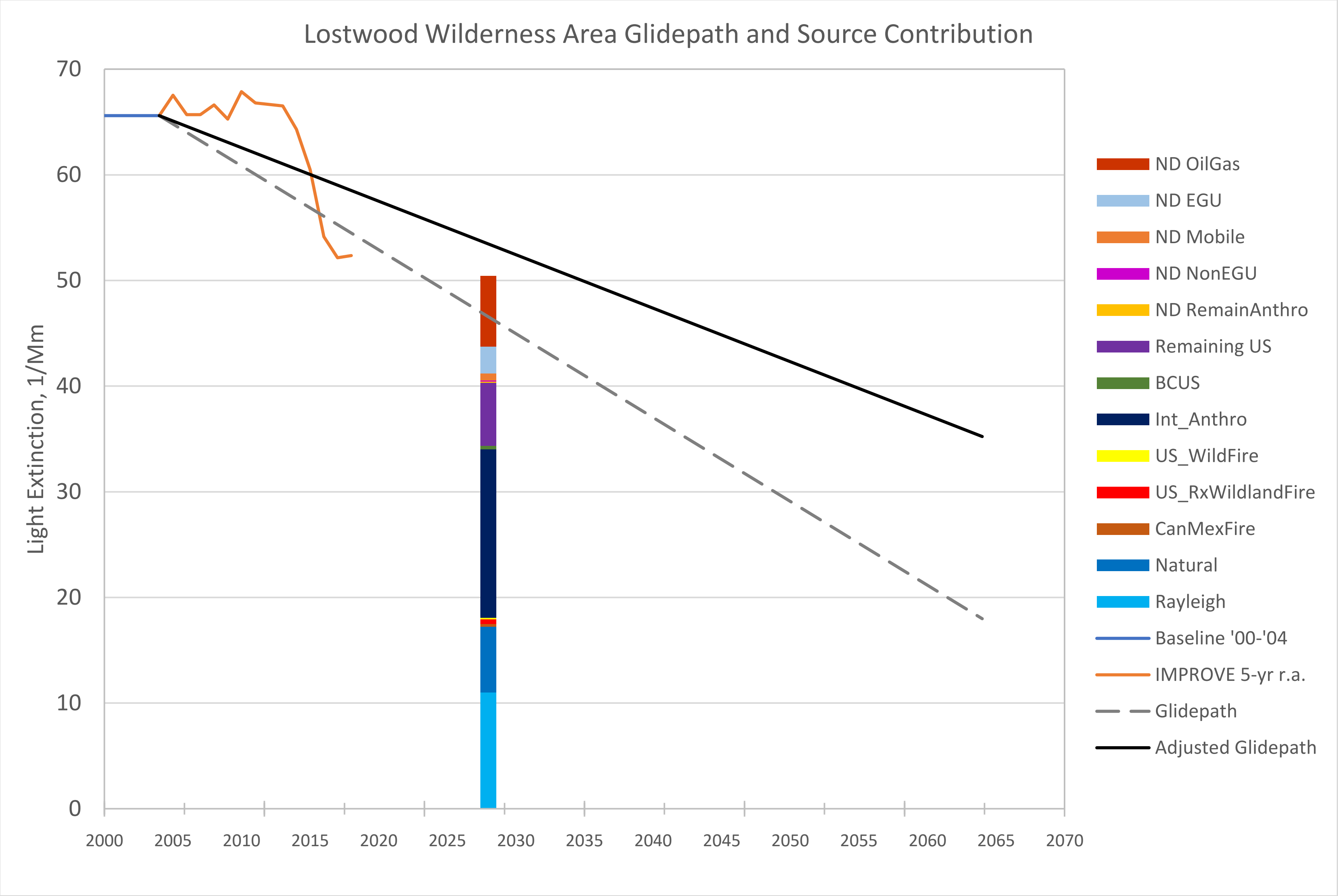

Figure 14: LWA contributors to visibility impairment, overall progress since baseline period, and 2028 projection

Table 3: LWA percent breakdown of 2028 projected visibility impairment

Sector	Ammonium Nitrate	Ammonium Sulfate	Coarse Mass	Elemental Carbon	Organic Mass	Sea Salt	Soil	Grand Total
ND EGU	1%	4%	--	--	--	--	--	5%
ND OilGas	8%	6%	--	--	--	--	--	13%
ND Mobile	1%	0%	--	--	--	--	--	1%
ND NonEGU	0%	0%	--	--	--	--	--	0%
ND RemainAnthro	0%	0%	--	--	--	--	--	0%
BCUS	0%	0%	--	--	--	--	--	1%
Remaining US	4%	2%	2%	1%	2%	0%	0%	12%
Int_Anthro	15%	13%	1%	1%	1%	0%	0%	32%
CanMexFire	0%	0%	0%	0%	0%	0%	0%	1%
Natural	5%	4%	1%	0%	2%	0%	0%	12%
US_RxWildlandFire	0%	0%	0%	0%	0%	0%	0%	1%
US_WildFire	0%	0%	0%	0%	0%	0%	0%	0%
Grand Total (non-Rayleigh)	35%	30%	4%	3%	6%	0%	0%	78%
Rayleigh								22%
							Sources Plus Rayleigh	100%

“--", speciated breakdown not available, included with "Remaining US" sector

Table 3 lists the percent breakdown of projected visibility impairment for LWA on the MIDs. Table 3 shows that Int_Anthro is the largest contributor to visibility impairment and accounts for 32% of the overall light extinction, 28% of which is from ammonium nitrate and ammonium sulfate. The largest North Dakota contributor is the oil and gas sector at 13% of the overall impairment, 8% from ammonium nitrates and 6% from ammonium sulfates. The next largest North Dakota sector is EGU at 5%, 4% from ammonium sulfates and 1% from ammonium nitrates. Collectively, these sources contribute only 18% of the ammonium nitrate and sulfate light extinction projection on the MIDs. Natural sources account for 12% of the total light extinction and Rayleigh light scattering contributes to 22% of the total light extinction.

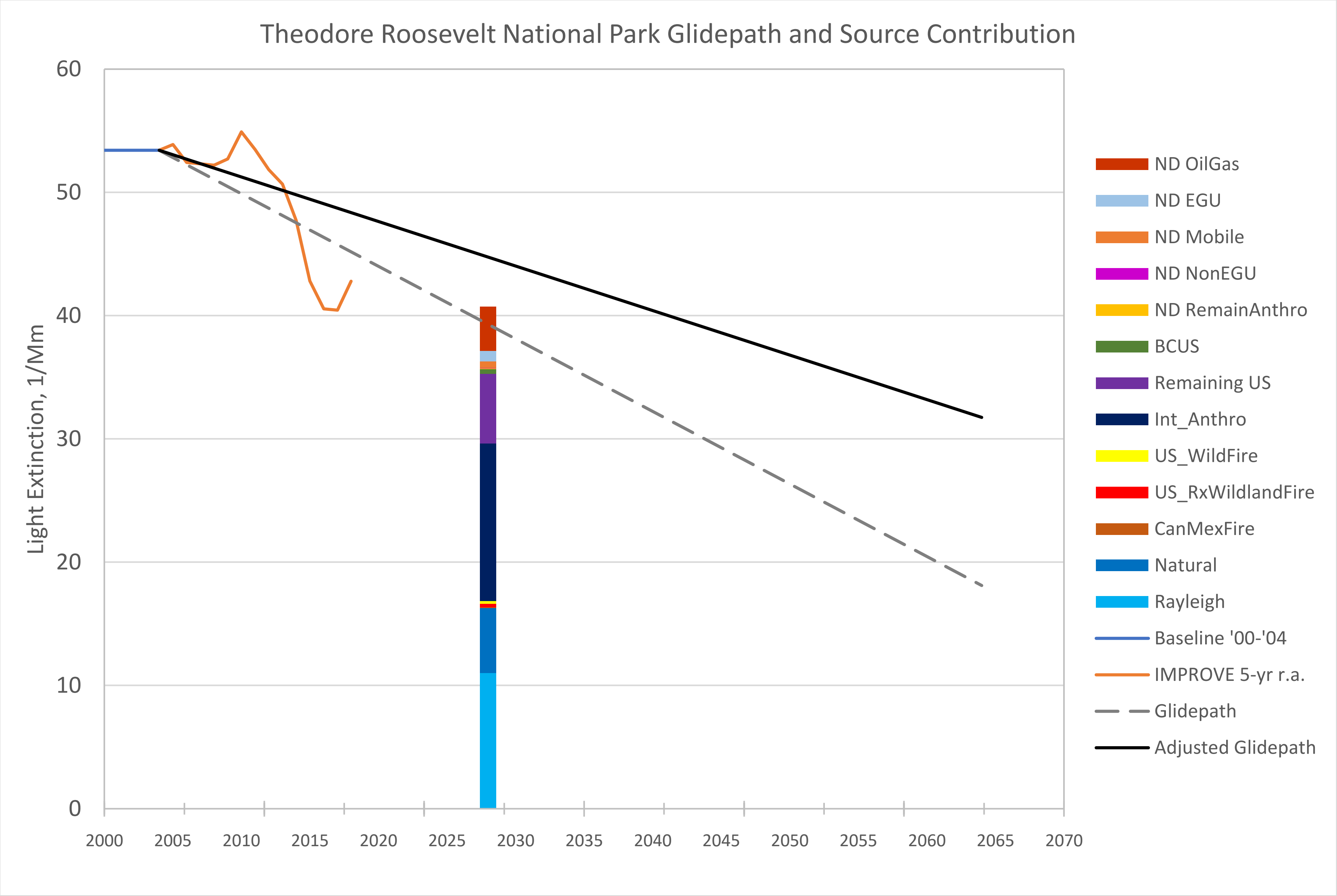

Figure 15: TRNP contributors to visibility impairment, overall progress since baseline period, and 2028 projection

Table 4: TRNP percent breakdown of 2028 projected visibility impairment

Sector	Ammonium Nitrate	Ammonium Sulfate	Coarse Mass	Elemental Carbon	Organic Mass	Sea Salt	Soil	Grand Total
ND EGU	0%	2%	--	--	--	--	--	2%
ND OilGas	5%	4%	--	--	--	--	--	9%
ND Mobile	1%	0%	--	--	--	--	--	1%
ND NonEGU	0%	0%	--	--	--	--	--	0%
ND RemainAnthro	0%	0%	--	--	--	--	--	0%
BCUS	0%	1%	--	--	--	--	--	1%
Remaining US	4%	3%	3%	1%	3%	0%	0%	14%
Int_Anthro	11%	17%	1%	1%	1%	0%	0%	31%
CanMexFire	0%	0%	0%	0%	0%	0%	0%	0%
Natural	4%	6%	1%	0%	2%	0%	0%	13%
US_RxWildlandFire	0%	0%	0%	0%	0%	0%	0%	1%
US_WildFire	0%	0%	0%	0%	0%	0%	0%	0%
Grand Total (non-Rayleigh)	26%	33%	5%	2%	6%	0%	1%	73%
Rayleigh								27%
							Sources Plus Rayleigh	100%

"--", speciated breakdown not available, included with "Remaining US" sector

Table 4 lists the percent breakdown of projected visibility impairment for TRNP on the MIDs. Table 4 shows that Int_Anthro is the largest contributor and accounts for 31% of the overall light extinction, 28% of which is from ammonium nitrate and ammonium sulfate. The largest North Dakota contributor to visibility impairment is the oil and gas sector at 9% of the overall impairment, 5% from ammonium nitrates and 4% from ammonium sulfates. The next largest North Dakota sector is EGU at 2%, 1.7% from ammonium sulfates and 0.4% from ammonium nitrates.[25] Collectively, these sources contribute only 11% of the ammonium nitrate and sulfate light extinction projection on the MIDs. Natural sources account for 13% of the total light extinction and Rayleigh light scattering contributes to 27% of the total light extinction.

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[25] One additional significant figure displayed for informational purposes.

Combined impairment at LWA from sources outside of North Dakota's control accounts for roughly 80% of the total light extinction.[26] The remaining 20% of the total light extinction (ammonium nitrate and ammonium sulfate) is from North Dakota sources, spread mainly between ND OilGas and ND EGU.

Combined impairment at TRNP from sources outside of North Dakota's control accounts for roughly 87% of the total light extinction.[27] The remaining 13% of the total light extinction (ammonium nitrate and ammonium sulfate) is from North Dakota sources, mainly attributable to ND OilGas.

The supporting details for Figure 14, Figure 15, Table 3, and Table 4 can be found in Sections 3.2, and Appendix C. Additionally, the most significant problem impacting CIA visibility, extreme episodic wildfire events, are discussed in Section 3.3.

Note: the modeling data displayed in Figure 14, Figure 15, Table 3, Table 4, and Appendix C has been normalized. Meaning the photochemical grid model results have been scaled to correlate to the 2028 visibility projections. Where the 2028 visibility projections were determined following EPA recommended methodology.[28] As stated in the whitepaper "*The projection procedure uses the CAMx RepBase2 and 2028OTBa2 modeling results in a relative fashion to scale the observed IMPROVE concentrations from the 2014-2018 MID to obtain 2028 future year MID concentrations. The model derived scaling factors are called Relative Response Factors (RRFs) and are obtained as the ratio of the CAMx future (2028OTBa2) to current (RepBase2) year modeling results averaged across several days, where the EPA default projection approach uses days from the base year IMPROVE MID.*" WRAP determined the overall 2028 visibility projections but did not further breakdown the 2028 projection into source and sector contributions (i.e. international and state sector fractions). The Department performed this normalization in order for the modeled source apportionment results (CAMx) to correlate to the 2028 visibility projections. For North Dakota, this increased the absolute (e.g. inverse megameters of light extinction) contribution to visibility impairment from all categories and has the added benefit of displaying the data consistently throughout the SIP revision. The normalized procedure used by the Department has been documented and is included in Appendix C.

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[26] Note: Remaining US sources includes impairment from all US_Anthro species minus ammonium nitrates and ammonium sulfate from the North Dakota sectors.

[27] Note: Remaining US sources includes impairment from all US_Anthro species minus ammonium nitrates and ammonium sulfate from the North Dakota sectors.

[28] Available at: https://www.wrapair2.org/pdf/2028_Vis_Proj_Glidepath_Adj_2021-03-01draft_final.pdf, page 5. (Last Visited May 17, 2021)

3.2 Calculations of Baseline, Current, and Natural Visibility Conditions; Progress to Date; and the Uniform Rate of Progress

40 CFR §51.308(f)(1)(i)–(iv) requires states to determine the baseline, current and natural visibility conditions for the 20 percent clearest and 20 percent most impaired days. The 2017 RHR revisions updated the definition of the "most impaired days", which are now defined as the 20 percent most impaired days based on daily anthropogenic impairment and no longer on the overall 20 percent worst (haziest) days.[29] Baseline, current and natural visibility conditions were calculated based on the methodology provided in EPA's Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program.[30] The baseline visibility period is the average of the annual deciview index values for the calendar years from 2000–2004, for both the 20 percent MIDs and the 20 percent clearest days. The 20 percent MIDs and the 20 percent clearest days were calculated for the current conditions using the average annual deciview index values for the most recent 5-year period. Natural visibility was calculated by considering only the natural contributions to the annual means on the 20 percent clearest and MIDs from 2000 through 2014.

Table 5 provides reference information for the IMPROVE sites that track visibility conditions at North Dakota's and neighboring state's nearby CIAs. IMRPOVE sites in western Montana were therefore not included in this section.

Table 5: North Dakota and Nearby State IMPROVE Sites

Site ID	Class I area Name	Representative IMPROVE Site
LOST1	Lostwood National Wildlife Refuge	Lostwood
THRO1	Theodore Roosevelt National Park	Theodore Roosevelt
MELA1	Medicine Lake Wilderness Area (MT)	Medicine Lake
ULBE1	UL Bend Wilderness Area (MT)	U.L. Bend
BADL1	Badlands National Park (SD)	Badlands
WICA1	Wind Cave National Park (SD)	Wind Cave
VOYA2	Voyageurs National Park (MN)	Voyageurs
BOWA1	Boundary Waters Canoe Area Wilderness (MN)	Boundary Waters

3.2.1 §51.308(f)(1)(i) - Baseline visibility for the most impaired and clearest days (2000–2004)

The 5-year average baseline visibility for the clearest and most impaired visibility days for each CIA was calculated using data from the IMPROVE monitoring sites and are shown in Table 6. The calculations were made in accordance with 40 CFR 51.308(f)(1)(i) and EPA's Technical Guidance document.

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[29] Final Rule: Protection of Visibility: Amendments to Requirements for State Plans, 82 FR 3101, January 10, 2017.

[30] Available at: https://www.epa.gov/sites/production/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf

Table 6: IMPROVE Sites Clearest and Most Impaired Days Values[31]

Site ID	Class I area	Clearest Days (dv)	Most Impaired Days (dv)
LOST1	Lostwood National Wildlife Refuge	8.2	18.3
THRO1	Theodore Roosevelt National Park	7.8	16.4
MELA1	Medicine Lake Wilderness Area (MT)	7.3	16.6
ULBE1	UL Bend Wilderness Area (MT)	4.8	12.8
BADL1	Badlands National Park (SD)	6.9	15
WICA1	Wind Cave National Park (SD)	5.1	13.1
VOYA2	Voyageurs National Park (MN)	7.2	17.9
BOWA1	Boundary Waters (MN)	6.5	18.4

3.2.2 §51.308(f)(1)(ii) - Natural visibility for the most impaired and clearest days

Natural visibility conditions for each CIA were calculated by estimating the average deciview index considering only natural contributions for the most impaired and clearest days. These calculations were based on IMPROVE monitoring data from 2000–2014 for each site and used EPA's recommended data analysis techniques. The natural visibility for the clearest days and MIDs is shown in Table 7.

Table 7: Natural Visibility for the Most Impaired and Clearest Days

Site ID	Class I area	Clearest Days (dv)	Most Impaired Days (dv)
LOST1	Lostwood National Wildlife Refuge	2.9	5.9
THRO1	Theodore Roosevelt National Park	3.0	5.9
MELA1	Medicine Lake Wilderness Area (MT)	3.0	6.0
ULBE1	UL Bend Wilderness Area (MT)	2.5	5.9
BADL1	Badlands National Park (SD)	2.9	6.1
WICA1	Wind Cave National Park (SD)	1.9	5.6
VOYA2	Voyageurs National Park (MN)	4.3	9.4
BOWA1	Boundary Waters (MN)	3.5	9.1

3.2.3 §51.308(f)(1)(iii) - Current (2014–2018) visibility for the most impaired and clearest days

40 CFR 51.308(f)(1)(iii) specifies that current visibility be calculated using the average of the annual deciview index values for the most recent 5-year period, ending with the most recently available data. Table 8 shows the values that were calculated for each CIA on the 20 percent clearest and 20 percent MIDs from 2014–2018.

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[31] Available at: https://www.epa.gov/sites/production/files/2020-06/documents/memo_data_for_regional_haze_technical_addendum.pdf

Table 8: Current (2014–2018) Visibility for the Most Impaired and Clearest Days

Site ID	Class I area	Clearest Days (dv)	Most Impaired Days (dv)
LOST1	Lostwood National Wildlife Refuge	7.5	16.2
THRO1	Theodore Roosevelt National Park	5.9	14.1
MELA1	Medicine Lake Wilderness Area (MT)	6.2	15.3
ULBE1	UL Bend Wilderness Area (MT)	3.7	10.9
BADL1	Badlands National Park (SD)	5.4	12.3
WICA1	Wind Cave National Park (SD)	3.5	10.5
VOYA2	Voyageurs National Park (MN)	5.3	14.2
BOWA1	Boundary Waters (MN)	4.5	14.0

3.2.4 §51.308(f)(1)(iv) - Progress to date for the most impaired and clearest days

40 CFR 51.308(f)(1)(iv) requires the demonstration of actual progress made towards the natural visibility condition for the most impaired and clearest days since the baseline period. 40 CFR 51.308(f)(1)(iv) also requires the demonstration of actual progress made during the previous implementation period up to and including the period for calculating current visibility conditions. This progress can be seen by the difference between 1) the average visibility condition in the 5-year baseline, 2) the previous implementation period, and 3) each subsequence 5-year period up to and including the current period, shown in Table 9. Table 9 only displays the previous implementation period as 2008–2012, all 5-year rolling average data since 2004 is addressed in Section 3.2.6.

Table 9: Progress to Date for the Most Impaired and Clearest Days

Site ID	2000-2004 Baseline		2008–2012 Previous Implementation Period		2014–2018 Current	
	Clearest Days (dv)	Most Impaired Days (dv)	Clearest Days (dv)	Most Impaired Days (dv)	Clearest Days (dv)	Most Impaired Days (dv)
LOST1	8.2	18.3	8	18.6	7.5	16.2
THRO1	7.8	16.4	6.4	16	5.9	14.1
MELA1	7.3	16.6	6.4	16.6	6.2	15.3
ULBE1	4.8	12.8	4.1	12.2	3.7	10.9
BADL1	6.9	15	6.2	14.6	5.4	12.3
WICA1	5.1	13.1	4.1	12.5	3.5	10.5
VOYA2[32]	7.2	17.9	6	17.3	5.3	14.2
BOWA[11]	6.5	18.4	5.1	16.9	4.5	14.0

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[32] 2008-2012 five year rolling averages for VOYA2 and BOWA1 were Available at: https://public.tableau.com/profile/mpca.data.services#!/vizhome/RegionalHaze_visibility_metrics_public/Visibility progress (Last visited March 1, 2021)

3.2.5 §51.308(f)(1)(v) -Differences between current and natural visibility conditions for the most impaired and clearest days

Per 40 CFR 51.308(f)(1)(v), Table 10 shows the differences between current visibility conditions and natural visibility conditions for the most impaired and clearest days at each CIA.

Table 10: Difference Between Current and Natural Visibility for the Most Impaired and Clearest Days

Site ID	2014-2018 Current		Natural Visibility		Difference	
	Clearest Days (dv)	Most Impaired Days (dv)	Clearest Days (dv)	Most Impaired Days (dv)	Clearest Days (dv)	Most Impaired Days (dv)
LOST1	7.5	16.2	2.9	5.9	4.6	10.3
THRO1	5.9	14.1	3.0	5.9	2.9	8.2
MELA1	6.2	15.3	3.0	6.0	3.2	9.3
ULBE1	3.7	10.9	2.5	5.9	1.2	5.0
BADL1	5.4	12.3	2.9	6.1	2.5	6.2
WICA1	3.5	10.5	1.9	5.6	1.6	4.9
VOYA2	5.3	14.2	4.3	9.4	1.0	4.8
BOWA1	4.5	14.0	3.5	9.1	1.0	4.9

3.2.6 §51.308(f)(1)(vi)(A) - Uniform rate of progress

The uniform rate of progress (URP) glidepath is the rate of progress over time needed to achieve the 2064 visibility end goals. For the 20% MIDs, the goal is to achieve natural visibility conditions by 2064. For the clearest days, the goal is to provide no degradation from the 2000–2004 baseline visibility conditions on the clearest days. This URP analysis is being provided to meet the requirements of §51.308(f)(1)(vi)(A). Section 3.2.7 details the information for the option to adjust the glidepath, as allowed under §51.308(f)(1)(vi)(B). North Dakota is adjusting the glidepath with this SIP revision and Section 3.2.7 contains the data pertinent to reflect this action.

The URP glidepath for each Class 1 area for the MIDs is determined from the five-year baseline visibility condition (Table 6) and the natural visibility condition (Table 7). The five-year baseline visibility condition is the average of the MID from 2000–2004. The natural visibility condition is the average estimated impairment under natural conditions for the MID. The URP glidepath is a linear line drawn from the 2004 baseline visibility starting point to the 2064 natural visibility conditions estimate. For the clearest days, the glidepath is a straight line from the 2000–2004 baseline to 2064.

On June 3, 2020, EPA released a technical addendum which included updated visibility data for the clearest days and the MIDs through 2018.[33] This data was used for this SIP revision.

3.2.6.1 Most Impaired Data

Figure 16 and Figure 17 show the unadjusted URP glidepath for the MIDs at LWA and TRNP, respectively. This data can be found at: https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx. Products 4 and/or 5 on this webpage can be used to recreate the figures used in this section.

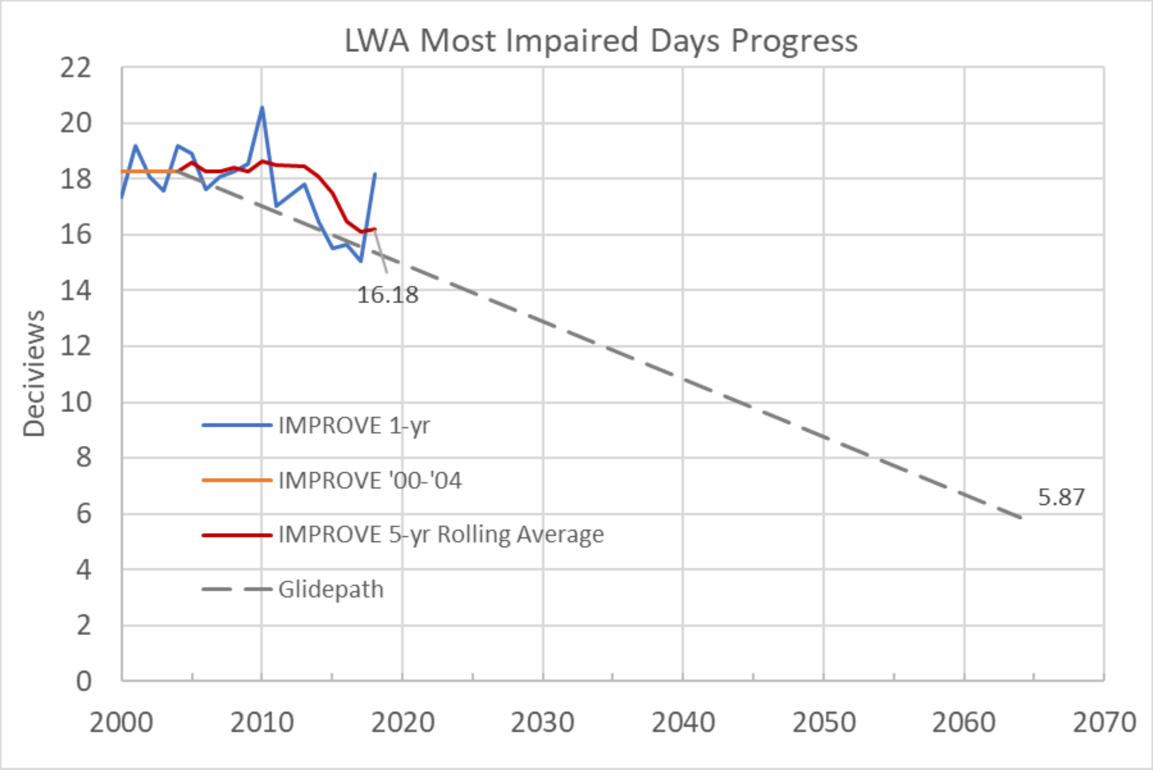

Figure 16: LWA Most Impaired Days Progress from 2000–2018

Figure 16 indicates LWA is making continuous progress toward the 2064 end visibility goal. The five-year rolling average IMPROVE data from 2014–2018 indicates LWA is 0.80 deciviews above the URP, however, Figure 16 does not account for visibility impairment from international emissions and wildland prescribed fires. Refer to Section 3.2.7 for graphical representation of these impacts.

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[33] Available at: https://www.epa.gov/sites/production/files/2020-06/documents/memo_data_for_regional_haze_technical_addendum.pdf (Last visited March 1, 2021)

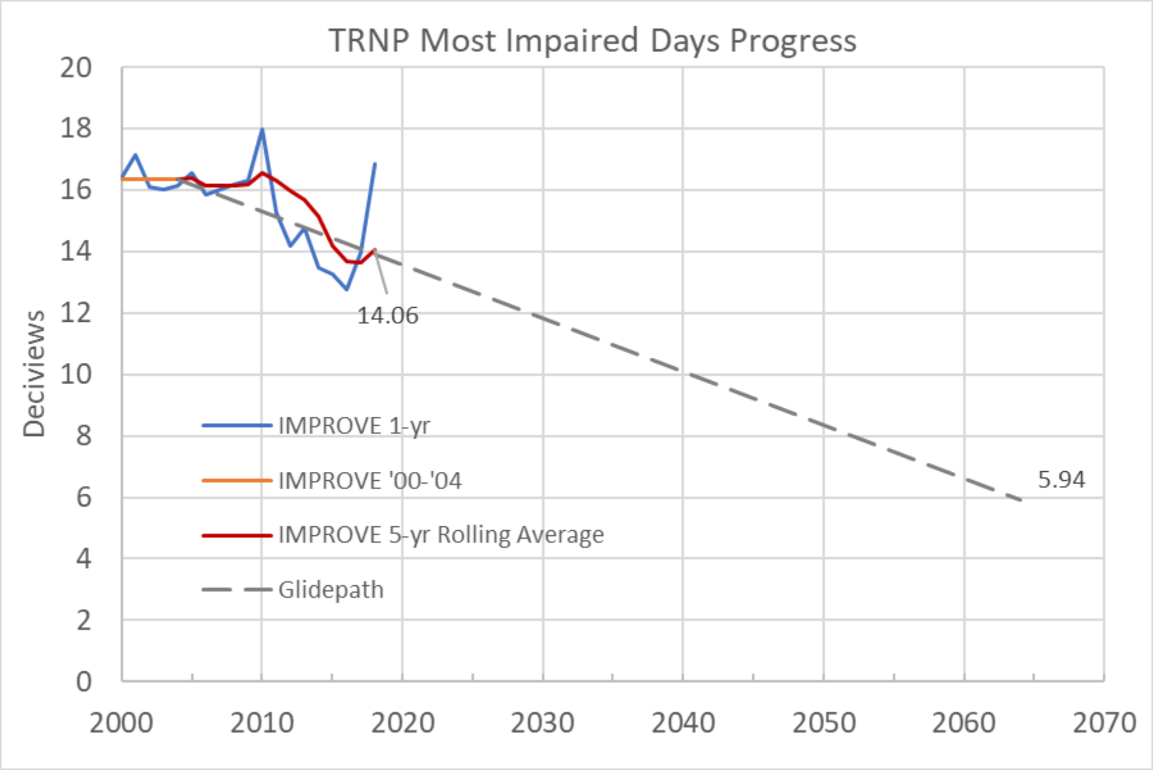

Figure 17: TRNP Most Impaired Days Progress from 2000–2018

Figure 17 indicates TRNP is making continuous progress toward the 2064 visibility goal. The five-year rolling average IMPROVE data from 2014–2018 indicates TRNP is 0.14 deciviews above the URP, however, Figure 17 does not account for visibility impairment from international emissions and wildland prescribed fires. Refer to Section 3.2.7 for graphical representation of these impacts.

3.2.6.2 Clearest Days

Figure 18 and Figure 19 show the glidepath for the 20% clearest days at LWA and TRNP, respectively. This data can be found at: https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx. Products 4 and/or 5 on this webpage can be used to recreate the figures used in this section. The data displayed is truncated at 2030 on the x-axis for more clear visual aesthetics.

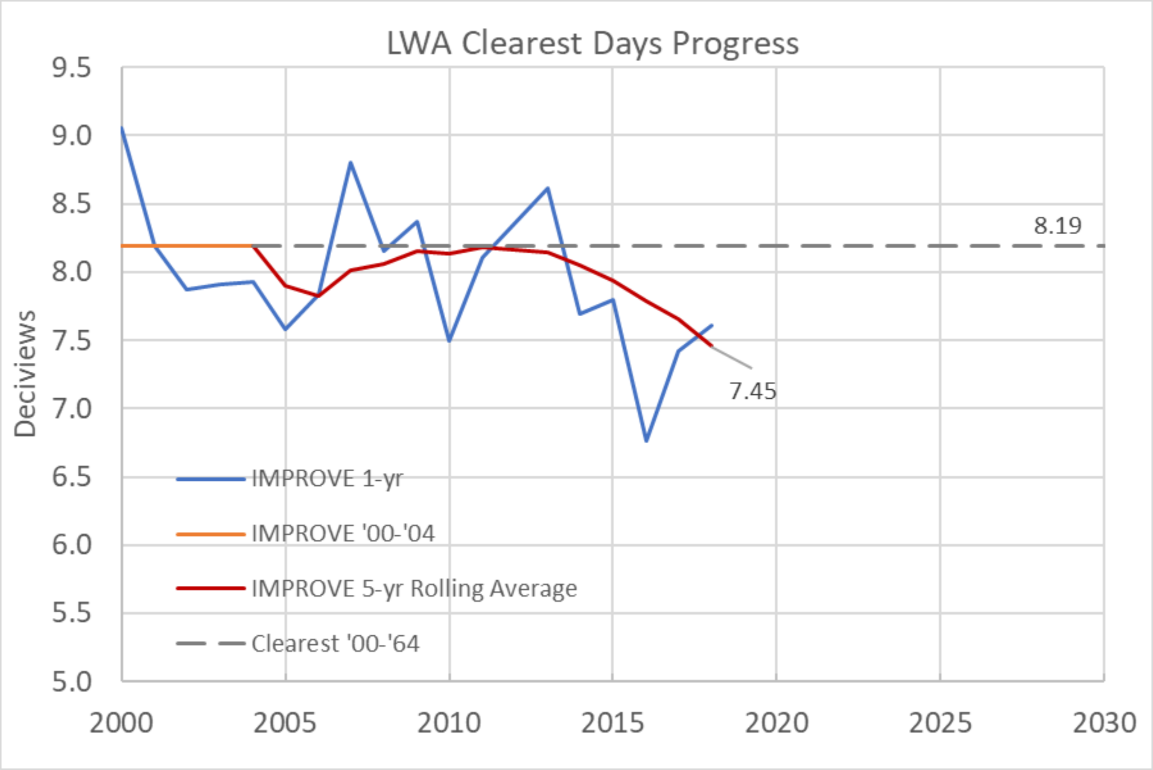

Figure 18: LWA Clearest Days Progress from 2000–2018

Figure 18 shows that LWA is meeting the requirement of showing no degradation in visibility for the clearest days since the baseline period of 2000–2004. The five-year rolling average IMPROVE data from 2014–2018 indicates LWA is at 7.45 deciviews for the clearest days, below the requirement of 8.19 deciviews.

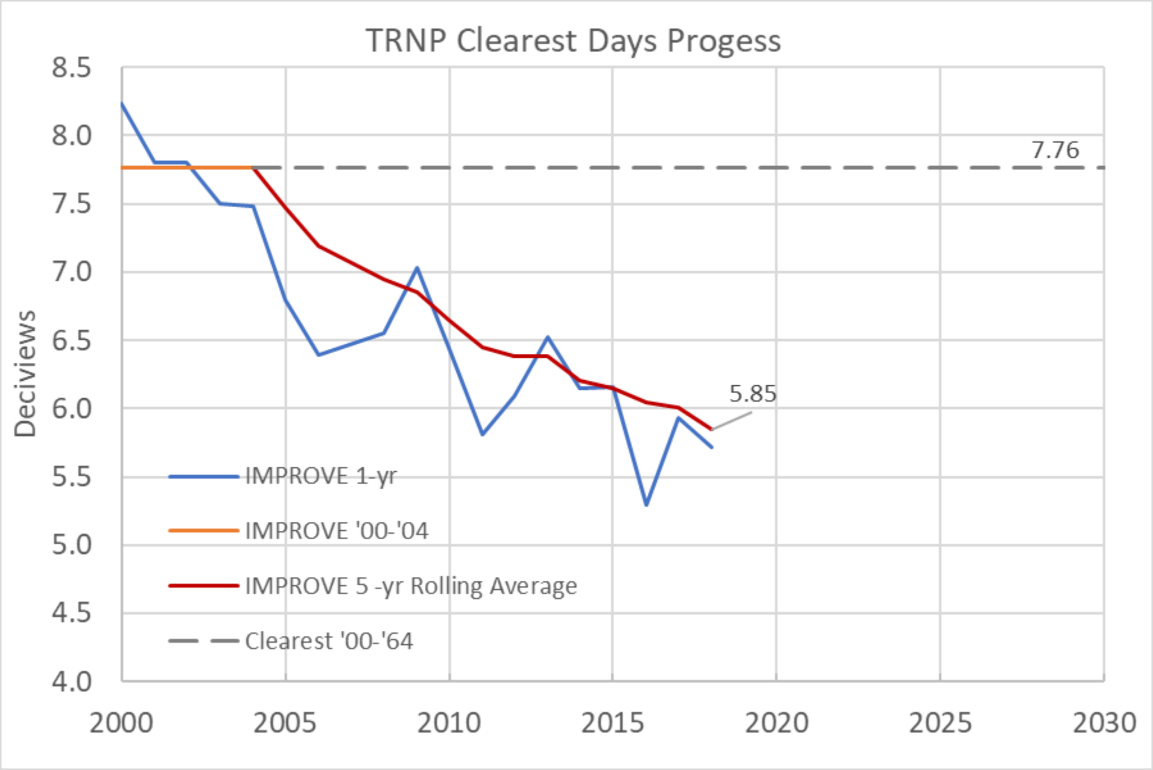

Figure 19: TRNP Clearest Days Progress from 2000–2018

Figure 19 shows that TRNP is meeting the requirement of showing no degradation in visibility for the clearest days since the baseline period of 2000–2004. The five-year rolling average IMPROVE data from 2014–2018 indicates TRNP is at 5.85 deciviews for the clearest days, below the requirement of 7.76 deciviews.

3.2.7 §51.308(f)(1)(vi)(B)(1) and (2) - North Dakota Adjustments to the uniform rate of progress to account for international impacts and prescribed fire

The 2017 RHR revisions authorize states to make an optional adjustment to the URP glidepath to account for impacts from anthropogenic sources outside of the United States and to account for impacts from wildland prescribed fires.[34] To calculate the proposed adjustment, the State must add the estimated impact(s) to the natural visibility conditions estimate for the MID at the 2064 end goal.[35] The natural conditions estimate plus the adjustment for international anthropogenic emissions and wildland prescribed fires provides the adjusted 2064 end goal. This adjustment is critical for North Dakota CIAs since North Dakota shares a boarder with Canada and is heavily impacted by international emissions. North Dakota is also impacted by wildland prescribed fires and is also proposing to take these visibility impairing emissions into consideration. The proposed glidepath adjustment considers both international anthropogenic and wildland prescribed fire contributions.

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[34] 40 CFR 51.308(f)(1)(vi)(B)

[35] Available at: https://www.epa.gov/sites/production/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf, page 17 (Last visited March 1, 2021)

International anthropogenic and wildland prescribed fire combined contributions are based on projected 2028 modeling results normalized to the monitoring data and added to the EPA estimated natural conditions for 2064.

Figure 20 and Figure 21 show the URP glidepath with adjustments for international anthropogenic and wildland prescribed fire (Adjusted Glidepath) for the MIDs at LWA and TRNP, respectively. This data can be found at: https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx. Product 5 on this webpage can be used to recreate the figures used in this section. WRAP provided adjustment options for two scenarios. One for international, and one for international plus wildland prescribed fire. The adjusted glidepath figures only display the international and wildland prescribed fire results.

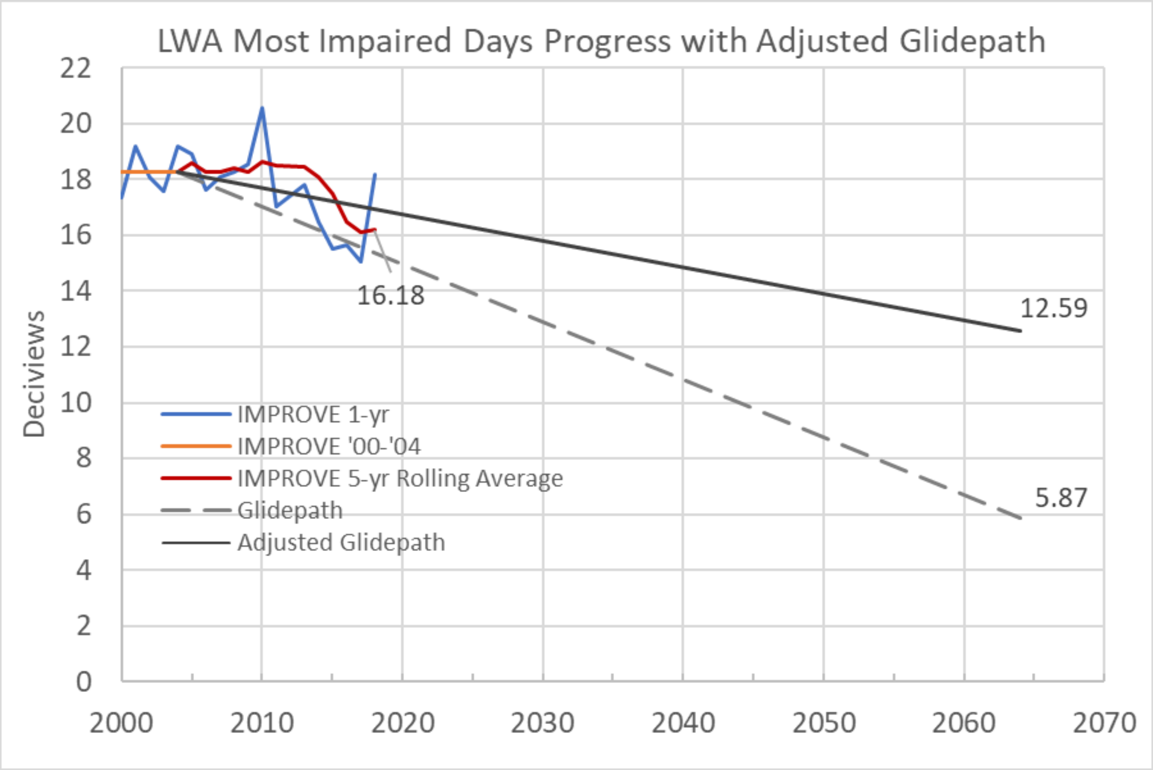

Figure 20: LWA Most Impaired Days Progress with Adjusted Glidepath from 2000–2018

Figure 20 indicates LWA is making meaningful progress toward the adjusted 2064 end visibility goal. The five-year rolling average IMPROVE data from 2014–2018 indicates LWA is 0.77 deciviews below the Adjusted Glidepath.

Figure 20 demonstrates the impact international and wildland prescribed fires have on LWA and the importance of using the proposed Adjusted Glidepath. A significant part of the adjustment is due to international sources, not from wildland prescribed fires. When looking strictly at the impacts from international sources, the 2064 end point for LWA is 12.46 deciviews. Meaning, the difference of 0.13 deciviews (12.59 - 12.46) is attributed to the wildland prescribed fires. This is supported by the source category breakdown of visibility impairment discussed in Appendix C.

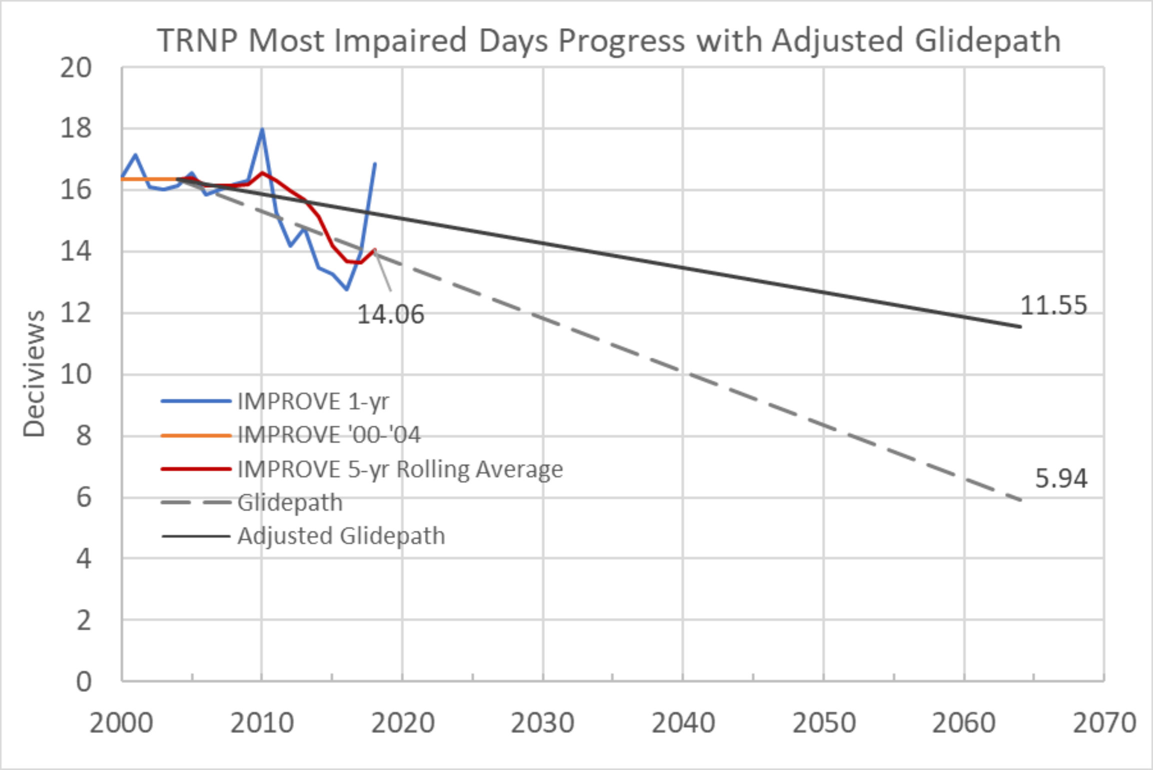

Figure 21: TRNP Most Impaired Days Progress with Adjusted Glidepath from 2000–2018

Figure 21 indicates TRNP is making meaningful progress toward the adjusted 2064 end visibility goal. The five-year rolling average IMPROVE data from 2014–2018 indicates TRNP is 1.17 deciviews below the Adjusted Glidepath.

Figure 21 demonstrates the impact international and wildland prescribed fires have on TRNP and the importance of using the proposed Adjusted Glidepath. A significant part of the adjustment is due to international sources, not from wildland prescribed fires. When looking strictly at the impacts from international sources, the 2064 end point for TRNP is 11.46 deciviews. Meaning, the difference of 0.09 deciviews (11.55 - 11.46) is attributed to the wildland prescribed fires. This is supported by the source category breakdown of visibility impairment discussed in Appendix C.

3.3 U.S. Wildfire Impacts on North Dakota Visibility

North Dakota does not have large forested areas and therefore, does not have significant wildfire events when compared to other western States such as California, Oregon, and Washington. However, North Dakota's visibility is noticeably impacted by extreme wildfire events emanating from other western States and internationally. For example, 2020 was adversely impacted by record-breaking wildfires on the west coast[36,37] causing visibility impairment throughout much of the United States[38], including North Dakota. As a result of this significantly adverse fire activity, North Dakota experienced long episodes of perceptible visibility impairment from summer through fall of 2020. While 2020 was one of the worst fire years on record, it was not unusual regarding noticeable adverse impacts to North Dakota's visibility in recent years. Many of the Department's air quality press releases over recent years are directly tied to out of state or international wildfire smoke.[39,40,41] As of the writing of this SIP revision in 2021, North Dakota is also experiencing significant adverse wildfire impacts to heath based and visual air quality from out of state fire activity.[42] Due to the extreme drought conditions throughout much of the western united states, this trend is likely to continue.[43] The Department typically receives many questions, comments, and/or complaints regarding these issues and has recently started to issue press releases to inform the public of the ongoing situation. Looking forward, the magnitude of impacts from extreme wildfire events are anticipated to continually increase in the coming years. Reducing the size, intensity, duration, and number of wildfires on the west coast or internationally would have the greatest impact on improving visibility at North Dakota's CIAs, especially during the months when the CIAs experience the most visitation (summer and fall).

When the MIDs are compared to the haziest days on a seasonal basis for the years of 2014–2018, it is easy to see that the worst visibility days are the days with wildfire activity. The seasonal data in Figure 22 and Figure 23 is averaged over the years of 2014–2018. If the data from years 2014 and 2016 was removed, as these were not as significant wildfire years, the difference in light extinction on the haziest days versus the MIDs for the summer and fall months would be even more pronounced. The green portion of the bar chart reflects light extinction contributed by organic mass, which is primarily associated with wildfire events. When organic mass impairment is from wildfires, it is typical to see the elemental carbon and coarse mass also increase.

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[36] Available at: https://www.nytimes.com/interactive/2020/09/24/climate/fires-worst-year-california-oregon-washington.html (Last visited December 29, 2020)

[37] Available at: https://www.washingtonpost.com/weather/2020/09/30/western-wildfire-nasa-satellite/ (Last visited December 29, 2020)

[38] Available at: https://earthobservatory.nasa.gov/images/event/146855/2020-fire-season-in-the-western-us (Last visited December 29, 2020)

[39] Available at: https://deq.nd.gov/PressReleases/2018-08-17-Wildfire-Smoke.pdf (Last visited December 29, 2020)

[40] Available at: https://deq.nd.gov/PressReleases/2018-08-09-Wildfire-Smoke.pdf (Last visited December 29, 2020)

[41] Available at: https://www.deq.nd.gov/AQ/News/2019-05-29WildfireSmokePR.pdf (Last visited December 29, 2020)

[42] Available at: https://deq.nd.gov/PressReleases/2021-07-14-637622872677570278.pdf (Last visited July 21, 2021)

[43] Available at: https://earthobservatory.nasa.gov/images/148419/western-soils-and-plants-are-parched (Last visited July 21, 2021)

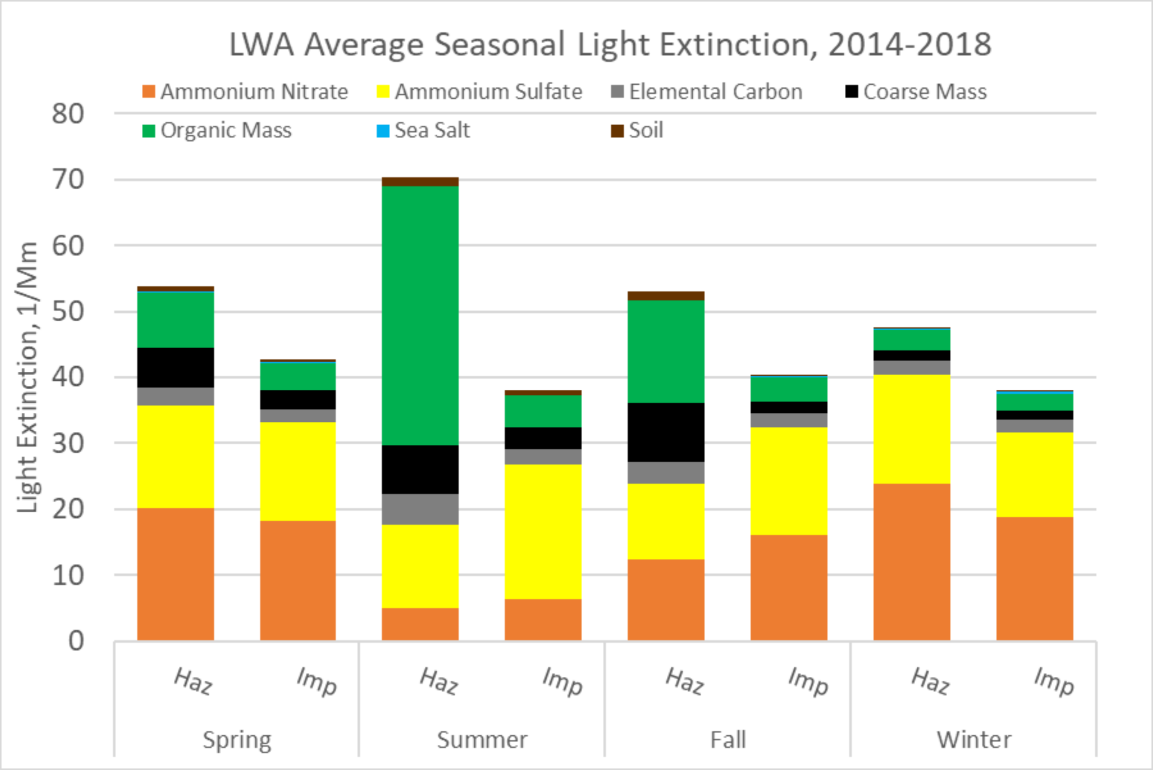

Figure 22: 2014–2018 Average Seasonal Haziest Days (Haz) and Most Impaired Days (Imp) data for LWA

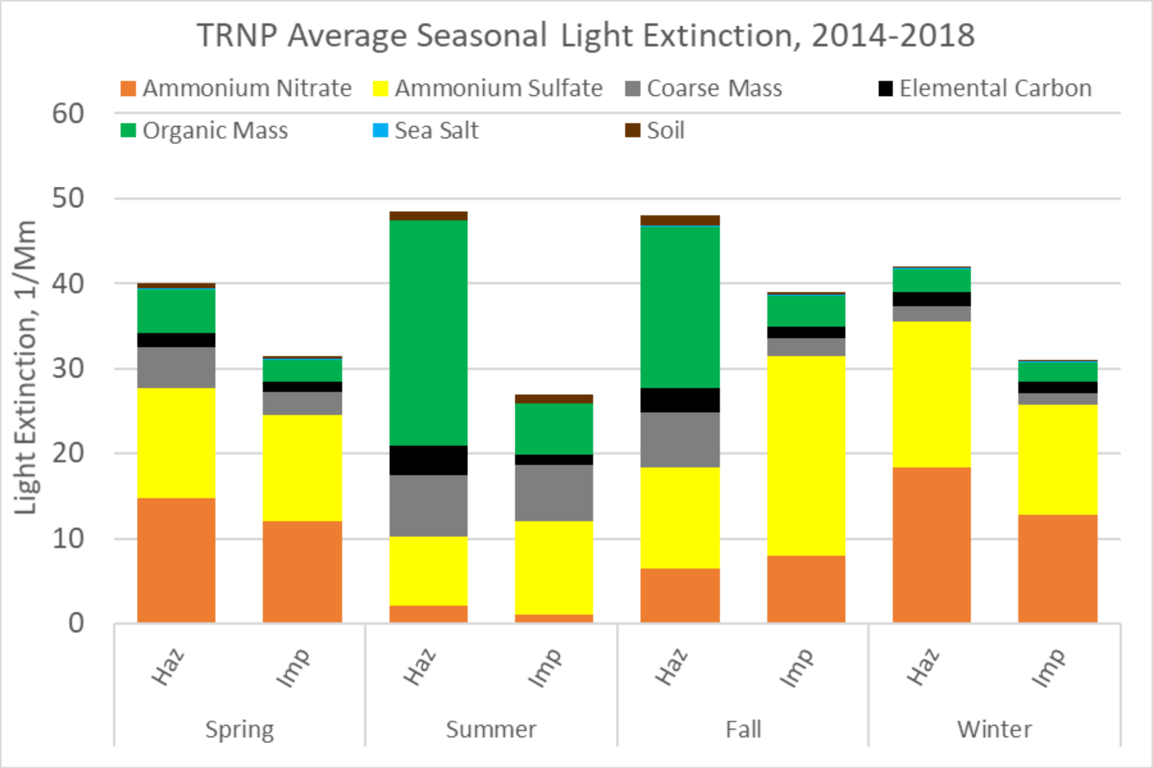

Figure 23: 2014–2018 Average Seasonal Haziest Days (Haz) and Most Impaired Days (Imp) data for TRNP

There is no distinction between a diminished visual experience caused by anthropogenic sources or natural events[44], as visual experiences can be impacted by either, or both. However, the largest contributor to visibility impairment in North Dakota CIAs results from wildfires emanating outside of North Dakota. The federal government, applicable state governments, federal land managers, private industry, community groups, nongovernmental organizations, and other stakeholders need to work collaboratively to take on the forest management challenges through implementation of practical and effective measures.[45,46] These measures will reduce the size, intensity, and duration of extreme wildfires. This is especially needed considering the intense drought much of the western United States in currently experiencing coupled with the projections of increasing extreme wildfire activity in years to come. Emissions inventory estimates resulting from wildfires from the WRAP states have been included in this RH SIP revision to show how significant emissions from these events are, Section 4.8. The emissions inventory estimates are for the 2014 baseline year and a representative fire year (average of 2014–2018 fire estimates).

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[44] Some ‘natural’ events are not truly ‘natural’ in origin, but rather, the result of decades long forest management malpractices and political policies leading to the problem of today.

[45] Forest Management is More Effective Than Climate Virtue-Signaling, Jason Hayes, October 6, 2020. Available at: https://www.mackinac.org/forest-management-is-more-effective-than-climate-virtue-signaling (Last visited March 23, 2021)

[46] Extinguishing the Wildfire Threat, Lessons from Arizona, October 6, 2020. Available at: https://www.mackinac.org/archives/2020/s2020-08.pdf. (Last visited March 23, 2021)

4 Emissions Inventory

The RHR requires that emissions inventories (EI) be used to compare past emissions, present emissions, and future projected emissions; necessary to evaluate changes over time and determine if any additional progress is needed to meet the state's RPGs. The emissions inventories include all pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any CIA. The specific sections of the RHR addressing the need for EIs include: §51.308(d)(3)(iii), §51.308(d)(4)(v), §51.308(f)(2)(iii), §51.308(f)(6)(v), and §51.308(g)(4). Each of these sections is subtly different, with the overall purpose being to document the basis for the emissions used in the SIP revision. Emissions are broken down by pollutant and source category.

The source categories used in the inventory analysis include point sources, area and non-point sources, non-road mobile sources, on road mobile sources, natural sources, and international anthropogenic emissions. A list of the modeled source categories is displayed in Table 11.

Table 11: Emissions Categories included in the WRAP modeling.

Sector/Source Category	**Sector Code**	***Type***
Agricultural Fire	ag_flaming	Anthropogenic
Agricultural Operations	ag	Anthropogenic
Fugitive Dust (area-source)	afdust	Anthropogenic
Oil & Gas Nonpoint	np_oilgas	Anthropogenic
Rail	rail	Anthropogenic
Remaining Nonpoint	nonpt	Anthropogenic
Residential Wood	rwc	Anthropogenic
Non-road Mobile	nonroad	Anthropogenic
Onroad Mobile	onroad	Anthropogenic
Electricity Generating	ptegu	Anthropogenic
Oil & Gas Point	pt_oilgas	Anthropogenic
Industrial Point	ptnonipm	Anthropogenic
Commercial Marine Vehicle	cmv_c1c2c3	Anthropogenic
Prescribed Fire	rxfire	Anthropogenic
Biogenic	biogenic	Natural
Wildfire	wildfire	Natural
Lightning NOx	ltnox	Natural
Non US Fire	nonus_fire	Natural
Sea Salt and Dimethyl Sulfide (DMS)	oceanic_seasalt	Natural
Windblown Dust	wbdust	Natural

The reported emissions that have the potential to impair visibility include sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM_{10} and $PM_{2.5}$), volatile organic compounds (VOCs), and ammonia (NH_3).

Section 4.1 includes a discussion on the inventories used in this analysis.

Sections 4.2 through 4.8 address important categories and potential contributors to visibility impairment in North Dakota.

4.1 Emission Inventories and Projections

The emission inventories addressed in this section include: 2002, 2011, 2014 (2014v2), Representative Baseline (RepBase), 2017, 2028 projections with planned reductions "on the books" (2028OTB), and 2028 projections with planned reductions on the books along with further potential additional controls (2028PAC). Each emissions inventory is detailed in the following sections.

The data presented in Sections 4.1.1 through 4.1.7 contain the summary of emissions for each inventory year and from each category analyzed. Summary emissions from 2014v2, RepBase, 2028 OTB, and 2028 PAC are included to show the emissions data from each category which was used in the WRAP modeling. Summary emissions from the 2017 NEI were included for comparison purposes to the 2014v2 and RepBase scenarios. Summary emissions from 2002 and 2011 were also included for comparison to the recent years.

4.1.1 2002 Inventory

The 2002 emissions used in this SIP revision are consistent with the 2002 emissions used in the March 3, 2010 SIP submittal by North Dakota. These data are provided for informational purposes and to show North Dakota's emissions progress since 2002 per §51.308(f)(6)(v) and §51.308(g)(4).

The complete emissions data for the inventory year 2002 is displayed in Table 12. The sector data from 2002 was not compiled using the same sectors as the data from the current inventories used in the modeling (2014v2, RepBase, 2028OTB, and 2028PAC). The Department adjusted the 2002 data to best match the current sector data. Notable differences between the 2002 inventory and the current inventories include:

- North Dakota's point source emissions in 2002 were for all point sources. To better align the data with the current breakdown for point sources (i.e. EGU, Non-EGU, and Oil and Gas), the Department allocated the 2002 emissions between "Electricity Generating Point" and "Industrial Point", mainly to separate out EGUs. Specifically, "Electricity Generating Point" emissions of NO_X and SO_2 were itemized as these are the pollutants of most interest for regional haze and were the focus of additional reasonable progress controls.
- 2002 Fire data in Table 12 is for all fires, since the 2002 data was not broken down by types of fire (i.e. wildfire, prescribed fire, and agricultural fire).
- Ammonia emissions from the 2002 inventory were moved from the area source category (Remaining Nonpoint) to the "Agricultural Operations" category for the current inventories. The agriculture operations category was not a category used in 2002.

Table 12: 2002 Emissions Inventory for North Dakota (tons/year)

Sector	SO_2	NO_X	VOC	NH_3	PM_{10}	$PM_{2.5}$
Fugitive Dust (area-source)	0	0	0	0	359,522	57,079
Agricultural Operations	29	43	0	118,398	0	0
Biogenic	0	44,569	233,561	0	0	0
Remaining Nonpoint	5,557	10,833	60,455	0	199	1,617
Non-road Mobile	7,246	55,502	13,515	33	0	0
Oil & Gas Nonpoint	4,958	4,631	7,740	0	0	0
Onroad Mobile	812	24,746	12,814	732	0	0
Electricity Generating Point [A]	141,158	75,362	-	-	-	-
Industrial Point [B]	15,911	12,076	2,086	518	565	2,002
Fire	540	1,774	3,849	812	0	0
Total	**176,211**	**229,536**	**334,020**	**120,493**	**360,286**	**60,698**

[A] VOC, NH_3, PM_{10}, and $PM_{2.5}$ emissions are included with the "Industrial Point" Sector

4.1.2 2011 Inventory

The 2011 emissions used in this SIP revision are from the 2011 NEI and are consistent with the 2011 emissions used in the January 2015 progress report submitted by North Dakota. These data are provided to show North Dakota's emissions progress over time per §51.308(f)(6)(v) and §51.308(g)(4). Consistent with the 2002 source categories as discussed in Section 4.1.1, the 2011 source categories were adjusted to be consistent with the current categories used in the modeling. The complete emissions data for inventory year 2011 is displayed in Table 13.

Table 13: 2011 Emissions Inventory for North Dakota (tons/year)

Sector	SO_2	NO_X	VOC	NH_3	PM_{10}	$PM_{2.5}$
Fugitive Dust (area-source)	0	0	0	0	262,739	55,228
Agricultural Operations	0	0	0	92,715	0	0
Biogenic	0	32,938	248,782	0	0	0
Remaining Nonpoint	655	18,149	21,163	0	146	1,821
Non-road Mobile	68	31,183	10,452	30	0	0
Oil & Gas Nonpoint	2,073	25,277	252,920	0	0	0
Onroad Mobile	95	21,193	8,377	346	0	0
Electricity Generating Point [A]	92,614	51,015	-	-	-	-
Industrial Point [B]	10,046	10,251	3,812	5,724	1,419	4,006
Fire	3,168	7,245	47,601	2,698		
Total	**108,719**	**197,251**	**593,107**	**101,513**	**264,304**	**61,055**

[A] VOC, NH_3, PM_{10}, and $PM_{2.5}$ emissions are included with the "Industrial Point" Sector

4.1.3 2014 Inventory (2014v2)

The 2014 NEI was used as the basis for the 2014v2 emissions scenario. 2014v2 is also the baseline emissions scenario used in modeling for round 2 planning purposes. The 2014 NEI was chosen as the starting point since this was the most complete emissions inventory available at the time planning began (i.e. 2017 NEI was not available). The “v2” is representative of data corrections made by states.[47] WRAP states reviewed the 2014 NEI and made corrections to ensure the most accurate data was used in the modeling (Section 6). The RepBase and 2028 OTB inventories were constructed from the 2014v2 data. The future modeling scenarios, which use 2014v2 emissions data, have three important aspects to help ensure the most accurate results: 1) state reviewed/corrected NEI data, 2) quality assured IMPROVE data, 3) and metrological data. 2014v2 data was used in the model to determine the model’s accuracy when compared to the IMPROVE data, known as checking the model performance. A webpage was developed by WRAP outlining the model platform description and the model performance.[48] Model Performance is discussed in Section 7.1. The 2014 emissions data used in the modeling are included in Table 14.

Table 14: 2014 Emissions Inventory for North Dakota (tons/year)

Sector	**SO_2**	**NO_X**	**VOC**	**NH_3**	**PM_{10}**	**$PM_{2.5}$**
Fugitive Dust (area-source)	0	0	0	0	186,929	32,975
Agricultural Operations	0	0	1,249	36,130	0	0
Agricultural Fire	402	1,187	1,655	6,399	5,252	3,457
Biogenic	0	44,573	179,876	0	0	0
Commercial Marine Vehicle	0	0	0	0	0	0
Lightning NOx	0	34,491	0	0	0	0
Remaining Nonpoint	171	1,194	17,144	133	878	778
Non-road Mobile	44	26,182	8,585	31	2,207	2,132
Non-US Fire	2	3	89	0	44	37
Oil & Gas Nonpoint	4,043	43,237	664,297	0	1,129	1,129
Sea Salt and DMS	0	0	0	0	0	0
Onroad Mobile	91	33,305	10,753	343	1,884	1,320
Electricity Generating Point	50,900	46,410	635	190	3,744	2,647
Industrial Point	6,716	7,734	3,722	1,085	3,004	2,372
Oil & Gas Point	1,314	2,702	2,025	0	126	126
Rail	9	14,758	749	8	468	430
Residential Wood	31	126	1,404	60	1,329	1,327
Prescribed Fire	225	301	6,924	646	3,812	3,231
Windblown Dust	0	0	0	0	3	1

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[47] Available at: https://www.wrapair2.org/pdf/WRAP%20Regional%20Haze%20SIP%20Emissions%20Inventory%20Review%20Documentation_for_Docket%20Feb2019.pdf (Last visited March 23, 2021)

[48] Available at: https://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx (Last visited March 23,2021)

Sector	SO_2	NO_X	VOC	NH_3	PM_{10}	$PM_{2.5}$
Wildfire	17	32	600	45	288	242
Total	**63,965**	**256,235**	**899,707**	**45,070**	**211,097**	**52,204**

4.1.4 Representative Baseline (RepBase)

The Representative Baseline (RepBase) emissions reflect known changes to emissions relative to the 2014v2 data. Changes include items such as a facility installing controls post-2014 or emissions changes needed to better reflect normal/routine operations. For example, if a source was not operating in 2014, the emissions might need an upwards adjustment to better reflect current actual operations. Therefore, this scenario accurately reflects the current emissions profile for each source potentially impacting CIA visibility and can generally be thought of as a 3-year[49] (2016–2018) average of a stationary source's emissions. Another difference between the RepBase and 2014v2 emission scenarios is the use of RepBase average fire data vs actual 2014 fire data.[50] The RepBase emissions also serve as the most recent 'year' for which data are available and reviewed for accuracy.

The 2014v2 natural emissions (i.e., Biogenic, Sea Salt, lightning NOx, and windblown dust) were used for the RepBase emissions inventory. The Representative Baseline emissions data used in the modeling are included in Table 15.

Table 15: Representative Baseline Emissions Inventory for North Dakota (tons/year)

Sector	SO_2	NO_X	VOC	NH_3	PM_{10}	$PM_{2.5}$
Fugitive Dust (area-source)	0	0	0	0	186,929	32,975
Agricultural Operations	0	0	1,249	36,130	0	0
Agricultural Fire	403	1,188	1,655	6,399	5,253	3,459
Biogenic	0	44,573	179,876	0	0	0
Commercial Marine Vehicle	0	0	0	0	0	0
Lightning NOx	0	34,491	0	0	0	0
Remaining Nonpoint	171	1,194	17,144	133	878	778
Non-road Mobile	40	28,060	7,208	37	2,278	2,201
Non-US Fire	0	0	0	0	0	0
Oil & Gas Nonpoint	9,391	62,190	400,646	0	1,116	1,116
Sea Salt and DMS	0	0	0	0	0	0
Onroad Mobile	91	33,305	10,753	343	1,884	1,320
Electricity Generating Point	39,323	33,712	633	172	3,575	2,553
Industrial Point	2,856	4,517	2,885	112	2,044	1,554
Oil & Gas Point	5,814	5,179	2,927	972	1,034	929

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[49] The three years of 2016-2018 are most typical, but not necessarily exact. For specific details regarding the four-factor sources, refer to Appendix B.

[50] Available at: https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/Run_Spec_WRAP_2014_Task2.3-RepBase_Task%204.4-2028_CAMx_v3.pdf

Sector	SO_2	NO_X	VOC	NH_3	PM_{10}	$PM_{2.5}$
Rail	9	14,758	749	8	468	430
Residential Wood	31	126	1,404	60	1,329	1,327
Prescribed Fire	214	593	6,605	279	2,542	2,369
Windblown Dust	0	0	0	0	3	1
Wildfire	60	221	1,518	55	564	541
Total	**58,403**	**264,107**	**635,252**	**44,700**	**209,897**	**51,553**

4.1.5 2017 Inventory

A summary of the 2017 emissions from the NEI are presented in Table 16. These emissions were not used in any of the modeling completed by WRAP for this SIP revision but are being presented for comparative purposes and to meet the requirement of 40 CFR 51.308(g)(4). Note that natural emissions from sea salt, lightning NOx, windblown dust, non-U.S. fires are not included in the 2017 NEI. Emissions from these categories are mostly insignificant except for lighting NOx. Anthropogenic emissions from commercial marine vehicle are also not included in the 2017 NEI.

Table 16: 2017 National Emissions Inventory for North Dakota (tons/year)

Sector	SO_2	NO_X	VOC	NH_3	PM_{10}	$PM_{2.5}$
Fugitive Dust (area-source)	0	0	0	0	392,393	60,803
Agricultural Operations	0	0	628	51,036	0	0
Agricultural Fire	313	830	2,945	4,922	3,221	2,075
Biogenic	0	36,109	121,047	0	0	0
Remaining Nonpoint	56,289	26,386	28,863	280	22,441	5,126
Non-road Mobile	42	27,773	7,041	39	2,238	2,162
Oil & Gas Nonpoint	2,493	17,626	362,287	2	468	462
Onroad Mobile	66	16,583	7,631	316	1,018	613
Electricity Generating Point	40,606	33,650	595	149	3,452	2,838
Industrial Point	2,161	4,357	2,445	208	1,705	1,384
Oil & Gas Point	6,494	4,511	1,316	1,760	566	559
Rail	8	11,231	520	7	330	320
Residential Wood	10	42	343	13	326	324
Prescribed Fire	736	1,369	22,428	1,560	9,727	8,243
Wildfire	58	112	1,688	117	739	627
Total	**109,274**	**180,579**	**559,779**	**60,409**	**438,624**	**85,536**

4.1.6 2028 Inventory Projection (2028OTB)

The 2028OTB emissions reflect planned changes to emissions from the RepBase scenario scheduled to occur before 2028. The “OTB” stands for “on the books”, meaning that any controls, reductions, or facility shutdowns scheduled to occur prior to 2028 have been accounted for in this scenario. RepBase to 2028OTB differences include planned changes to coal fired EGUs and anticipated changes to upstream oil and gas operations, discussed in Sections 4.2.1 and 4.3.1, respectively. This scenario is also used as the baseline starting point for review of additional controls that may be needed for North Dakota to meet its RPGs. The 2028OTB emissions projections used in the modeling are included in Table 17.

Table 17: 2028 Emissions Projections for North Dakota (tons/year)

Sector	SO_2	NO_X	VOC	NH_3	PM_{10}	$PM_{2.5}$
Fugitive Dust (area-source)	0	0	0	0	186,929	32,975
Agricultural Operations	0	0	1,249	36,130	0	0
Agricultural Fire	403	1,188	1,655	6,399	5,253	3,459
Biogenic	0	44,573	179,876	0	0	0
Commercial Marine Vehicle	0	0	0	0	0	0
Lightning NOx	0	34,491	0	0	0	0
Remaining Nonpoint	171	1,194	17,144	133	878	778
Non-road Mobile	32	12,200	4,762	38	852	819
Non-US Fire	0	0	0	0	0	0
Oil & Gas Nonpoint	15,203	57,269	416,111	0	562	562
Sea Salt and DMS	0	0	0	0	0	0
Onroad Mobile	53	8,051	3,831	259	808	308
Electricity Generating Point	35,962	31,539	625	172	3,338	2,317
Industrial Point	2,856	4,517	2,885	112	2,016	1,531
Oil & Gas Point	5,814	5,179	2,857	972	1,034	929
Rail	7	8,244	348	7	216	209
Residential Wood	31	126	1,404	60	1,329	1,327
Prescribed Fire	214	593	6,605	279	2,542	2,369
Windblown Dust	0	0	0	0	3	1
Wildfire	60	221	1,518	55	564	541
Total	**60,806**	**209,385**	**640,870**	**44,616**	**206,324**	**48,125**

4.1.7 2028 Inventory with Potential Additional Controls (2028PAC)

The 2028PAC emissions reflect the “potential additional controls” North Dakota evaluated to determine the impact these controls have on modeled visibility. The controls selected and associated emissions reductions were derived from North Dakota’s review of the four factor reports submitted by each company (Section 5.2, Appendix A, and Appendix B). The controls reviewed and selected for modeling are specific to NO_X and SO_2. The additional controls were selected on a rate basis (e.g. lb/MMBtu) and the associated tonnage was calculated using representative capacity factors for the unit. The anticipated tonnage reductions with the potential additional controls are displayed in Table 18. Any corresponding emissions changes of other visibility impairing pollutants were assumed insignificant. North Dakota had WRAP evaluate PAC at two levels.

The first iteration of PAC (2028PAC1) modeling evaluated the reduction of approximately 18,100 tons of SO_2 and approximately 4,100 tons of NO_X. These reductions came from the evaluation of additional controls at Otter Tail Power Company – Coyote Station (Section 5.2.1) and Basin Electric Power Cooperative – Antelope Valley Station (Section 5.2.2). Additionally, Unit 1 NO_X controls came online at Great River Energy – Coal Creek Station in spring 2020 and are included in the PAC1 controls. These controls came online post- 2028OTB WRAP modeling deadline for 2028 projected inventory submittal. The NO_X controls installed on Unit 1 in 2020 are consistent with the proposed NO_X BART detailed in Section 8. Great River Energy was also evaluating options to upgrade Coal Creek Station's WFGD scrubber operations to reduce SO_2 and requested this scenario be included in the modeling. Overall, the 18,000 tons of modeled SO_2 reductions comprises of approximately 11,600 tons from Coyote Station, 5,800 tons from Antelope Valley Station, and 700 tons from Coal Creek Station. Due to the anticipated change in ownership at Coal Creek Station, the 700 tons of SO_2 reductions from Coal Creek Station are no longer being considered with this SIP revision. The 4,100 tons of modeled NO_X reductions comprises of approximately 3,100 tons from Coyote Station and 1,000 tons from Coal Creek Station. The 2028PAC1 scenario is representative of the maximum potential controls originally considered for this planning period.

The second iteration of PAC (2028PAC2) modeling evaluated the reduction of approximately 6,000 tons of SO_2 and approximately 1,000 tons of NO_X. These reductions came from the evaluation of upgraded controls at Otter Tail Power Company – Coyote Station (Section 5.2.1) and the same controls for Coal Creek included in 2028PAC1. Overall, the 6,000 tons of modeled SO_2 reductions comprises of approximately 5,300 tons from Coyote Station and 700 tons from Coal Creek Station. The 1,000 tons of NO_X reductions comes from the controls already installed at Coal Creek Unit 1. The 700 tons of SO_2 - reductions from Coal Creek Station are no longer being considered with this SIP revision.

Table 18: 2028OTB Emissions with PAC reductions

			OTB - PAC	
Scenario	**SO_2**	**NO_X**	**SO_2**	**NO_X**
2028OTB	35,900	32,186	--	--
2028PAC1	17,779	28,059	*18,121*	*4,127*
2028PAC2	29,819	31,152	*6,081*	*1,034*

Table 18 only includes the emissions from the coal fired EGUs expected to remain operational beyond 2028. This includes Coyote Station, Antelope Valley Station, Leland Olds Station, Coal Creek Station, and Milton R. Young Station.

Note that 2028PAC1 and 2028PAC2 emissions are only included in Section 4.2.1 since all potential additional controls evaluated by North Dakota were specific to point source coal fired EGUs. A breakdown of the North Dakota coal fired EGU emissions is included in Section 4.2.1.1.

4.2 North Dakota Point Sources

Point sources are any large, stationary (non-mobile), identifiable sources of emissions that release pollutants into the atmosphere. A point source is a facility that is a major source under 40 CFR part 70 for one or more of the pollutants for which reporting is required by 40 CFR §51.15(a)(1).

Point sources in North Dakota include, but are not limited to: coal fired EGUs, petroleum refining, gas processing and transmissions facilities, ethanol manufacturing, and agricultural processing facilities. Section 4.2.1 details the coal fired EGU emissions and Section 4.2.2 details all other point source emissions.

The visibility impairing pollutants for each of the emission inventory years from all North Dakota's point sources are listed in Table 19 and graphed in Figure 24.

Table 19: North Dakota Point Source Emissions (tons/year)

Pollutant	2002	2011	2014v2	RepBase	2028OTB
SO_2	157,069	102,660	58,930	47,993	44,632
NO_X	87,438	61,266	56,846	43,408	41,235
VOC	2,086	3,812	6,382	6,445	6,367
NH_3	518	5,724	1,275	1,256	1,256
PM_{10} [B]	565	1,419	6,874	6,653	6,388
$PM_{2.5}$ [A]	2,002	4,006	5,145	5,036	4,777

[A] For 2002 and 2011, $PM_{2.5}$ ≈ Fine PM (FPM)

[B] For 2002 and 2011, PM_{10} ≈ Coarse PM (CPM)

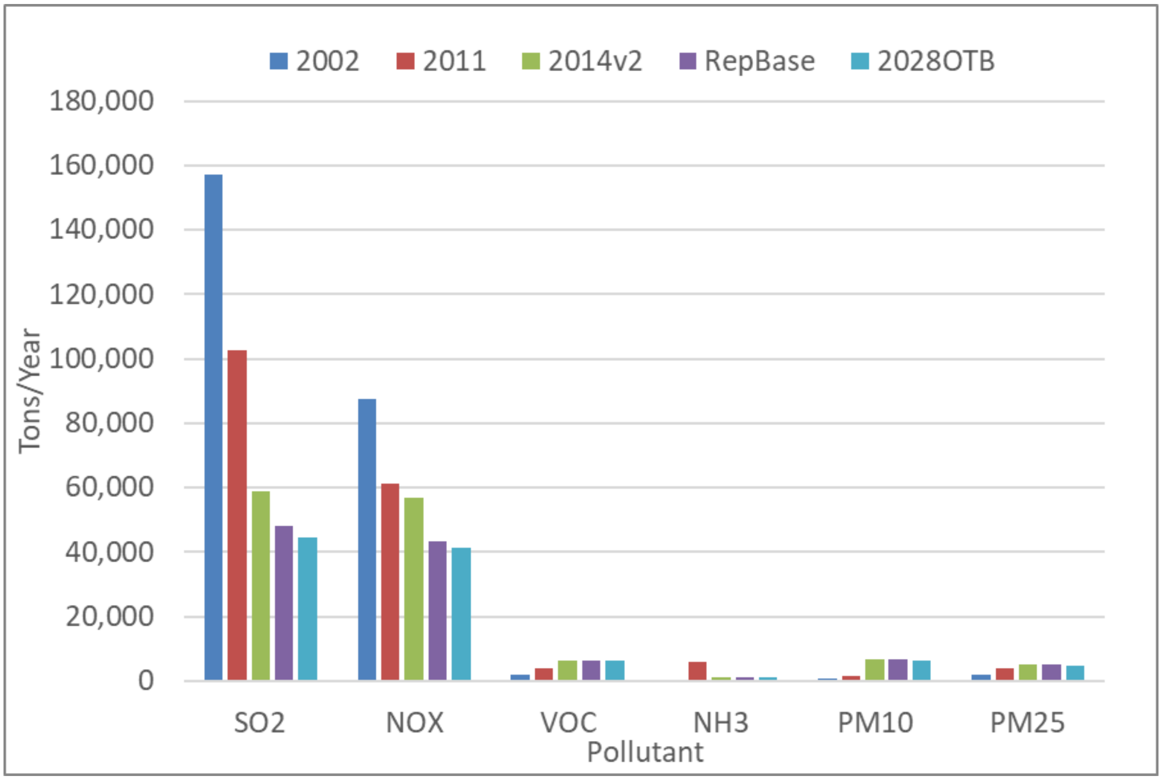

Figure 24: North Dakota Point Source Emissions

As displayed in Table 19 and in Figure 24, emissions of NO_X and SO_2 have historically been the most significant visibility impairing pollutants in North Dakota and, relatively speaking, continue to be highest emitted pollutants. As outlined in Section 5.1.1, ammonium nitrates and ammonium sulfates are the largest contributors to visibility impairment on the MIDs and also contribute to impairment on the clearest days. The emissions data paired with the visibility impairment supports North Dakota's four-factor evaluation that focused on NO_X and SO_2 controls on coal fired EGUs and other point sources.

4.2.1 North Dakota Coal Fired EGUs

The visibility impairing pollutants for each of the emissions inventory years from North Dakota's coal fired EGUs are listed in Table 20. NO_X emissions from coal fired EGUs accounted for 78% of the point source emissions and SO_2 emissions accounted for 82% of the point source emissions during the RepBase years.

Table 20: North Dakota Coal Fired EGU Emissions (tons/year)

Pollutant	2002	2011	2014v2	RepBase	2028OTB	2028PAC1	2028PAC2
SO_2	141,158	92,614	50,900	39,323	35,962	17,779	29,875
NO_X	75,362	51,015	46,410	33,712	31,539	28,059	31,482
VOC	NA [B]	NA [B]	635	633	625	625	625
NH_3	NA [B]	NA [B]	190	172	172	172	172

Pollutant	2002	2011	2014v2	RepBase	2028OTB	2028PAC1	2028PAC2
PM_{10}	NA [A]	NA [A]	3,744	3,575	3,338	3,338	3,338
$PM_{2.5}$	NA [A]	NA [A]	2,647	2,553	2,317	2,317	2,317

[A] PM species for 2002 and 2011 tracked as FPM and CPM, included in Table 19.

[B] VOC and NH_3 were not separated out in 2002 or 2011, total included in Table 19.

NO_x and SO_2 are the most significant visibility impairing pollutants and Figure 25 displays the significant progress North Dakota has made to reduce impacts from these pollutants.

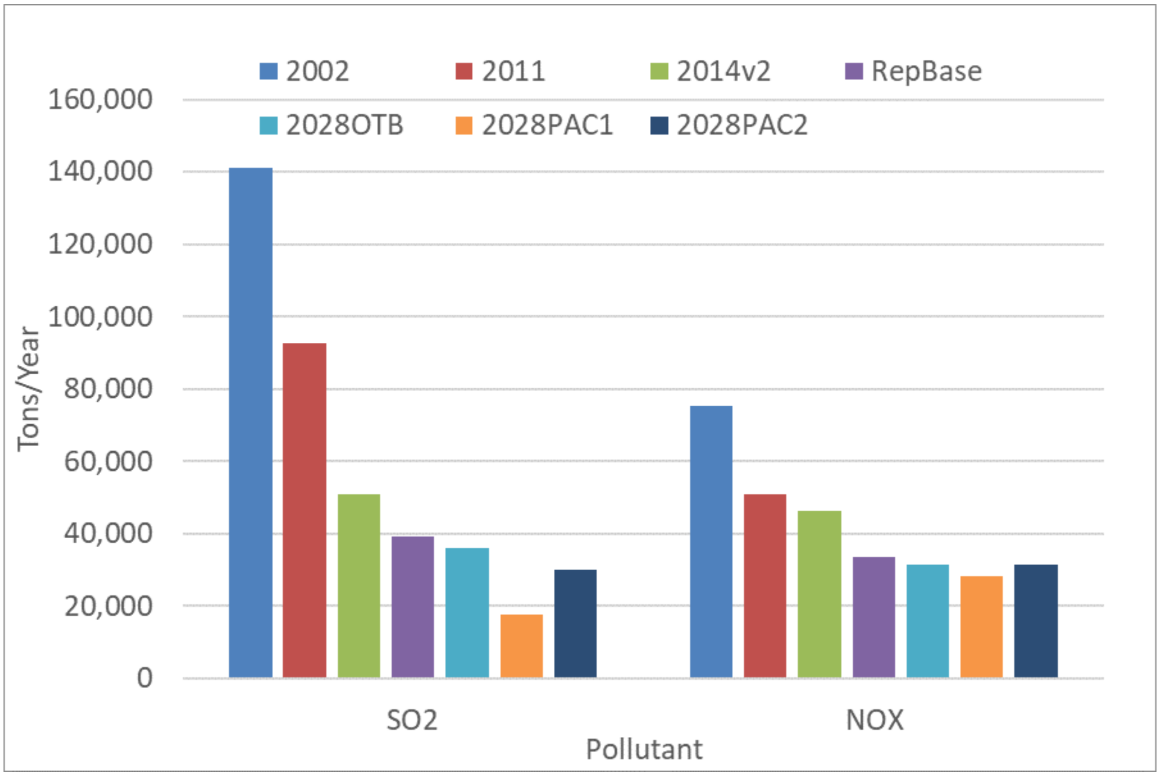

Figure 25: North Dakota coal fired EGU NO_X and SO_2 Emissions

Emissions of NO_X and SO_2 have historically been the most significant visibility impairing pollutants emitted from North Dakota coal fired EGUs. This continues to be true. As outlined in Section 5.1.1, ammonium nitrates and ammonium sulfates are the largest contributors to visibility impairment on the MIDs and also contribute to impairment on the clearest days. The emissions data paired with the visibility impairment supports North Dakota's four-factor evaluations of additional NO_X and SO_2 controls on the coal fired EGUs. The projected 2028 visibility impact from the EGU sector is summarized in Section 3.1. The results of the additional controls evaluated for implementation is included in Section 6.1.1. A breakdown of the NO_X and SO_2 emissions, limits, and controls for each of the units at the five coal fired EGUs planned to be operating in 2028 is located in Section 4.2.1.1. For additional comparative purposes, North Dakota also quantified coal fired EGU emissions from nearby Canadian Power Stations from previous years. This information is discussed in Section 4.7.1.

4.2.1.1 North Dakota Coal fired EGU Facility Emissions

Section 4.2.1.1.1 and 4.2.1.1.2 contain a breakdown of SO2 and NOx emissions, respectively, for the North Dakota coal fired EGUs.

4.2.1.1.1 SO_2 Emissions from North Dakota Coal Fired EGUs

For direct comparison of emissions and controls at each individual coal fired EGU, see Table 21 and Table 22. Table 21 displays the SO_2 emissions history and future projections from each major unit for the coal fired EGUs in North Dakota.

Table 21: Individual Unit Past, Current, Future Projected SO_2 Emissions Profiles

Facility	Unit	2002	2014	RepBase	2028 OTB	2028 PAC1	2028 PAC2
Coyote	1	14,069	12,777	12,994	12,994	1,373	7,625
Antelope Valley	1	6,580	5,509	6,279	6,279	3,405	6,279
Antelope Valley	2	7,283	6,975	6,319	6,319	3,405	6,319
Leland Olds	1	16,655	412	636	636	636	636
Leland Olds	2	30,744	1,025	1,258	1,258	1,258	1,258
Coal Creek	1	11,910	7,885	3,458	2,740	2,384	2,384
Coal Creek	2	12,518	7,940	3,400	2,743	2,387	2,387
Milton R. Young	1	19,858	361	766	766	766	766
Milton R. Young	2	8,707	1,710	2,165	2,165	2,165	2,165
RM Heskett Station	1	622	1,030	753	0	0	0
RM Heskett Station	2	2,189	2,338	1,214	0	0	0
Stanton Station	1	8,900	2,493	0	0	0	0
Stanton Station	10	1,122	98	0	0	0	0
	Total	**141,156**	**50,551**	**39,242**	**35,900**	**17,779**	**29,819**

Coyote Station has seen little change in routine SO_2 emissions since 2002 and is expecting operations to remain consistent through 2028. The Department selected additional controls for modeling evaluation to determine the impacts these controls have on overall visibility. Two varying levels of additional controls were reviewed and are displayed in the '2028PAC1' and '2028PAC2' columns in Table 21. For discussion on the controls selected for review, see Section 5.2.1. For discussion on the visibility impacts these potential controls had, see Section 6.1.1.

Antelope Valley Station Units 1 and 2 have seen little change in routine SO_2 emissions since 2002 and is expecting operations to remain consistent through 2028. The Department selected additional controls for modeling evaluation to determine the impacts these controls have on overall visibility. Additional controls were only evaluated in the '2028 PAC1' modeling run. For discussion on the controls selected for review, see Section 5.2.2. For discussion on the visibility impacts these potential controls had, see Section 6.1.1.

Leland Olds Station Units 1 and 2 have achieved significant reductions in emissions since 2002, each reducing SO_2 emissions by 96% from 2002 to RepBase. Each of these units currently emits below an annual rate of 0.10 lb SO_2 per MMBtu. No additional controls were selected for review on either unit. For discussion on the four factors review, see Section 5.2.3.

Coal Creek Station Units 1 and 2 have achieved significant reductions in emissions since 2002. Unit 1 and Unit 2 reduced SO_2 emissions by 71% and 73%, respectively, from 2002 to RepBase. Each of these units currently emits below an annual rate of 0.15 lb SO_2 per MMBtu. Prior to Great River Energy's end of coal announcement, the Department was working with Great River Energy on establishing lower allowable operating limits (near a rate of 0.10 lb SO_2 per MMBtu). As a result of these discussions, the Department evaluated 700 tons of SO_2 reductions for 2028 based on operational improvements the facility was expecting to undertake at the time. Due to the anticipated change in ownership, the improvements are no longer being considered with this SIP revision.

Milton R. Young Units 1 and 2 have achieved significant reductions in emissions since 2002. Unit 1 and Unit 2 reduced SO_2 emissions by 96% and 75%, respectively, from 2002 to RepBase. Unit 1 currently emits below an annual rate of 0.1 lb SO_2 per MMBtu while Unit 2's annual rate is below 0.15 lb SO_2 per MMBtu. No additional controls were selected for review on either unit. For discussion on the four factors review, see Section 5.2.5.

Table 22: Individual Unit Projected 2028 SO_2 Emissions, Representative Performance Rate, Current Emissions Limits and Control Device

Facility	Unit	2028 Projected Emissions (tons)[A]	Representative Annual Performance Rate (lb/MMBtu)	Emissions Limit [B]	Control Device
Coyote	1	12,994	0.85	1.2 lb/MMBtu (3-hr rolling average)	Dry Flue Gas Desulfurization w/ Fabric Filter
Antelope Valley	1	6,279	0.36	1.2 lb/MMBtu (3-hr rolling average)	Dry Flue Gas Desulfurization w/ Fabric Filter
Antelope Valley	2	6,319	0.36	1.2 lb/MMBtu (3-hr rolling average)	Dry Flue Gas Desulfurization w/ Fabric Filter
Leland Olds	1	636	0.09	0.15 lb/MMBtu (30-day rolling average) [C]	Wet Flue Gas Desulfurization
Leland Olds	2	1,258	0.08	0.15 lb/MMBtu (30-day rolling average) [C]	Wet Flue Gas Desulfurization
Coal Creek	1	3,458	0.14	0.15 lb/MMBtu (30-day rolling average) [C]	Wet Flue Gas Desulfurization w/ reheat system
Coal Creek	2	3,400	0.14	0.15 lb/MMBtu (30-day rolling average) [C]	Wet Flue Gas Desulfurization w/ reheat system
Milton R. Young	1	766	0.07	0.15 lb/MMBtu (30-day rolling average) [C]	Wet Flue Gas Desulfurization

Facility	Unit	2028 Projected Emissions (tons)[A]	Representative Annual Performance Rate (lb/MMBtu)	Emissions Limit [B]	Control Device
Milton R. Young	2	2,165	0.13	0.15 lb/MMBtu (30-day rolling average) [C,D]	Wet Flue Gas Desulfurization

[A] Based off representative performance rate and operating capacity

[B] Most strict emissions limits displayed. Other limits may apply as identified in the facility Title V Permit to Operate.

[C] Or 95% reduction from inlet sulfur concentration

[D] Or 90% reduction from inlet sulfur concentration and 0.15 lb/MMBtu (30-day rolling average)

Table 22 shows a comparison of the SO_2 performance rates and emissions limits from each of the units expected to be operating beyond 2028. Six of the nine units are subject to a limit of 0.15 lb SO_2 per MMBtu on a 30-day rolling average basis, established by the BART requirements of round 1. The BART facilities were Leland Olds Station, Coal Creek Station, and Milton R. Young Station. The three remaining units are subject to a limit of 1.2 lb SO_2 per MMBtu on a 3-hr rolling average basis, established by NSPS Subpart D. Each of these units is expected to operate in 2028 consistent with the information displayed in Table 22.

4.2.1.1.2 NO_X Emissions from North Dakota Coal Fired EGUs

For direct comparison of emissions and controls at each individual coal fired EGU, see Table 23 and Table 24. Table 23 displays the NO_X emissions history and future projections from each major unit for the coal fired EGUs in North Dakota.

Table 23: Individual Unit Past, Current, Future Projected NO_X Emissions Profiles

Facility	Unit	2002	2014	RepBase	2028 OTB	2028 PAC1	2028 PAC2
Coyote	1	13,173	11,375	7,363	7,363	4,270	7,363
Antelope Valley	1	5,840	3,127	1,697	1,697	1,697	1,697
Antelope Valley	2	5,953	5,866	1,708	1,708	1,708	1,708
Leland Olds	1	2,581	1,396	1,059	1,059	1,059	1,059
Leland Olds	2	11,184	5,174	4,192	4,192	4,192	4,192
Coal Creek	1	4,863	4,697	3,987	3,987	2,980	2,980
Coal Creek	2	5,492	3,287	3,010	3,010	2,983	2,983
Milton R. Young	1	8,510	3,195	3,435	3,435	3,435	3,435
Milton R. Young	2	14,335	4,998	5,735	5,735	5,735	5,735
RM Heskett Station	1	180	351	209	0	0	0
RM Heskett Station	2	918	984	978	0	0	0
Stanton Station	1	2,209	1,068	0	0	0	0
Stanton Station	10	890	603	0	0	0	0
	Total	**76,127**	**46,120**	**33,373**	**32,186**	**28,059**	**31,152**

Coyote Station has achieved significant reductions in emissions since 2002, reducing NO_X by 44% from 2002 to RepBase. The Department selected additional controls for the modeling evaluation to determine the impacts these controls have on overall visibility. Additional controls were only evaluated in the ‘2028 PAC1’ modeling run. For discussion on the controls selected for review, see Section 5.2.1. For discussion on the visibility impacts these potential controls had, see Section 6.1.1.

Antelope Valley Station Units 1 and 2 have achieved significant reductions in emissions since 2002, each reducing NO_X emissions by 71% from 2002 to RepBase. Each of these units currently emits at an annual rate of approximately 0.11 lb NO_X per MMBtu. No additional controls were selected for review on either unit. For discussion on the four factors review, see Section 5.2.2.

Leland Olds Station Units 1 and 2 have achieved significant reductions in emissions since 2002. Unit 1 and Unit 2 have reduced NO_X emissions by 59% and 63%, respectively, from 2002 to RepBase. Unit 1 currently emits at an annual rate of 0.16 lb NO_X per MMBtu while Unit 2’s annual rate is 0.29 lb NO_X per MMBtu. Each unit has SNCR installed and the difference in rate is attributed to the boiler type (wall fired versus cyclone). No additional controls were selected for review on either unit. For discussion on the four factors review, see Section 5.2.3.

Coal Creek Station Units 1 and 2 have achieved significant reductions in emissions since 2002. Unit 1 and Unit 2 reduced NO_X emissions by 18% and 45%, respectively, from 2002 to RepBase. Unit 1 has since reduced emissions further from the RepBase inventory, through installation of additional NO_X controls. Unit 1 NO_X controls were installed in the spring of 2020. Unit 2 currently emits an annual rate of 0.13 lb NO_X per MMBtu. Unit 1 is expected achieve similar annual NO_X performance rates as Unit 2. At the time of the WRAP modeling for 2028 OTB emissions, this project was not finalized and the reduction in NO_X for the Unit 1 was not included in the 2028 OTB projections. These reductions were incorporated for the 2028 PAC1 and 2028 PAC2 runs. The controls on Unit 1 result in an approximate 1,000 ton per year reduction in emissions. Prior to Great River Energy’s end of coal announcement, the Department was working with Great River Energy and EPA Region 8 toward submittal of a revised BART analysis to lower the allowable operating limits (proposed rate of 0.15 lb NO_X per MMBtu on a 30-day rolling average basis). The Department has determined the appropriate course of action is to move forward with proposing a NO_X BART for Coal Creek Station. This proposal in included in Section 8.

Milton R. Young Units 1 and 2 have achieved significant reductions in emissions since 2002, each reducing NO_X emissions by 60% from 2002 to RepBase. Each of these units currently emits at an annual rate of approximately 0.33 lb NO_X per MMBtu. No additional controls were selected for review on either unit. For discussion on the four factors review, see Section 5.2.5.

Table 24: Individual Unit Projected 2028 NO_X Emissions, Representative Performance Rate, Current Emissions Limits and Control Device

Facility	**Unit**	**2028 Projected Emissions (tons)** [A]	**Representative Annual Performance Rate (lb/MMBtu)**	**Emissions Limit** [B]	**Control Device**
Coyote	1	7,363	0.46	0.50 lb/MMBtu (30-day rolling average)	Separated Overfire Air w/ Low-NOx Burners
Antelope Valley	1	1,697	0.11	0.17 lb/MMBtu (30-day rolling average)	Separated Overfire Air w/ Low-NOx Burners
Antelope Valley	2	1,708	0.11	0.17 lb/MMBtu (30-day rolling average)	Separated Overfire Air w/ Low-NOx Burners
Leland Olds	1	1,059	0.16	0.19 lb/MMBtu (30-day rolling average)	Low-NOX Burners w/ Selective Non-Catalytic Reduction and Separated Overfire Air
Leland Olds	2	4,192	0.29	0.35 lb/MMBtu (30-day rolling average)	Selective Non-Catalytic Reduction w/ Separated Overfire Air
Coal Creek	1	3,987	0.13 [C]	Proposed: 0.15 lb/MMBtu (30-day rolling average) [D] Current: 5,104 lb/hr (12-month rolling average)	Low-NOX Burners w/ closed coupled overfired air w/ expanded overfired air registers in conjunction with DryFining™
Coal Creek	2	3,010	0.13	Proposed: 0.15 lb/MMBtu (30-day rolling average) [D] Current: 5,104 lb/hr (12-month rolling average)	Low-NOX Burners w/ closed coupled overfired air w/ expanded overfired air registers in conjunction with DryFining™

Facility	Unit	2028 Projected Emissions (tons) [A]	Representative Annual Performance Rate (lb/MMBtu)	Emissions Limit [B]	Control Device
Milton R. Young	1	3,435	0.33	0.36 lb/MMBtu (30-day rolling average)	Selective Non-Catalytic Reduction w/ Advanced Separated Overfire Air
Milton R. Young	2	5,735	0.33	0.35 lb/MMBtu (30-day rolling average)	Selective Non-Catalytic Reduction w/ Advanced Separated Overfire Air

[A] Based off representative performance rate and operating capacity

[B] Most strict emissions limits displayed. Other limits may apply as identified in the facility Title V Permit to Operate. All limits are current unless otherwise specified.

[C] Unit 1 controls came online in May 2020, 0.13 lb/MMBtu is the annual expected performance rate.

[D] NO_X BART proposed with this SIP revision.

Table 24 shows a comparison of the NO_X performance rates and emissions limits from each of the units expected to be operating beyond 2028. Six of the nine units were BART eligible and installed controls to meet the BART requirements. Leland Olds Station and Milton R. Young have installed controls and currently meet the BART requirements. Coal Creek Station has installed controls and complies with the North Dakota proposed NO_X BART requirements, included with this SIP revision in Section 8. Antelope Valley Station and Coyote Station were subject to reasonable progress requirements of regional haze round 1 and have meet these limits. Each of these units is expected to operate in 2028 consistent with the information displayed in Table 24.

4.2.2 North Dakota Other Point Sources

The visibility impairing pollutants for each of the emissions inventory years from North Dakota's remaining point sources are listed in Table 25. Included in these emissions totals are the point source Oil and Gas emissions from North Dakota facilities. NO_X emissions from these sources accounted for 22% of the point source emissions and SO_2 emissions accounted for 18% of the point source emission during the RepBase years.

Table 25: North Dakota non-EGU Point Source Emissions (tons/year)

Pollutant	2002	2011	2014v2	RepBase	2028OTB
SO_2	15,911	10,046	8,030	8,670	8,670
NO_X	12,076	10,251	10,436	9,696	9,696

Pollutant	2002	2011	2014v2	RepBase	2028OTB
VOC	NA [B]	NA [B]	5,747	5,812	5,742
NH_3	NA [B]	NA [B]	1,085	1,084	1,084
PM_{10}	NA [A]	NA [A]	3,130	3,078	3,050
$PM_{2.5}$	NA [A]	NA [A]	2,498	2,483	2,460

[A] PM species for 2002 and 2011 tracked as FPM and CPM, included in Table 19.

[B] VOC and NH_3 were not separated out in 2002 or 2011, total included in Table 19.

Of the visibility impairing pollutants, NO_x and SO_2 are the most significant, emissions are displayed in Figure 26.

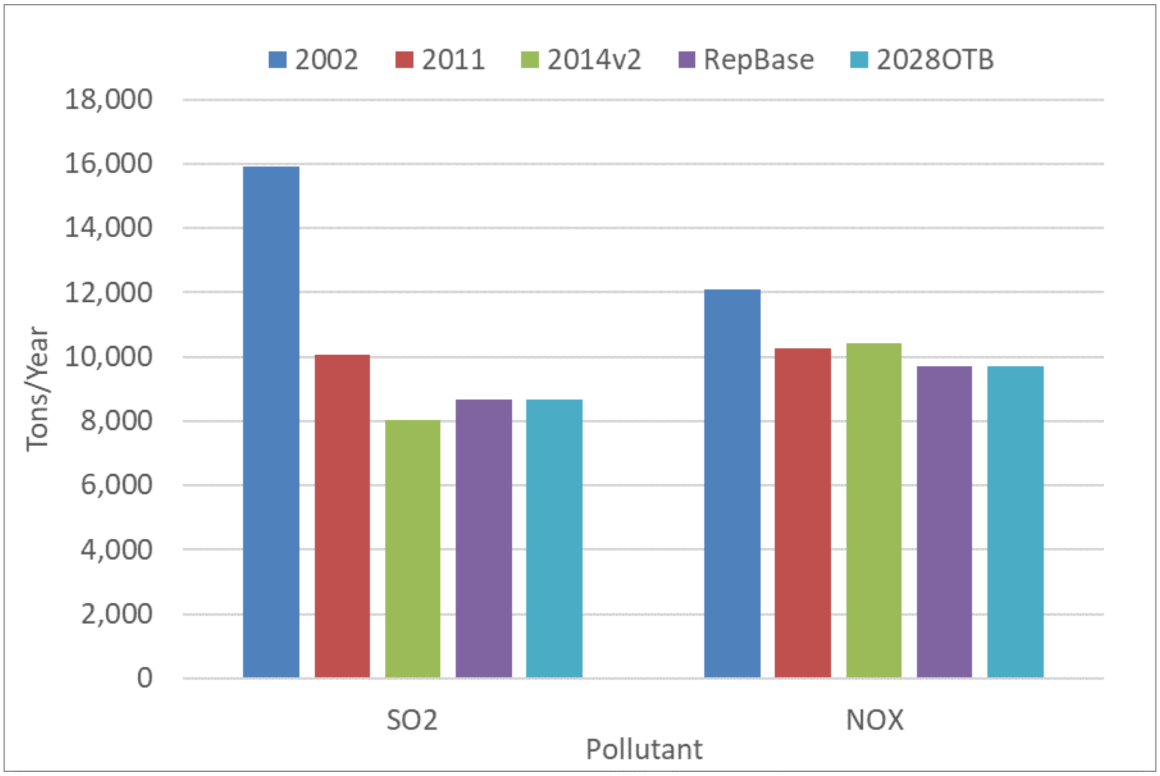

Figure 26: North Dakota non-EGU Point Source NO_X and SO_2 Emissions

As displayed in Table 25, emissions of NO_X and SO_2 have historically been the most significant visibility impairing pollutants emitted from the non-EGU point sources in North Dakota. As is outlined in Section 5.1.1, ammonium nitrates and ammonium sulfates are the largest contributors to visibility impairment on the MIDs and also contribute to impairment on the clearest days. The emissions data paired with the visibility impairment supports North Dakota's four-factor evaluations of NO_X and SO_2 controls on the sources addressed in Sections 0 through 5.2.10. North Dakota notes that emissions from the point sources evaluated in Sections 0 through 5.2.10 are considerably smaller than the emissions from the coal fired EGU sector and any reductions from these sectors would likely be less impactful on improving visibility.

4.3 North Dakota Area and Non-Point Sources

All stationary sources not identified as point sources are classified as area or non-point sources. This includes emissions from minor stationary sources of air pollution and many of the sources of the Williston Basin oil and gas field within the Bakken Formation.

The visibility impairing pollutants for each of the emissions inventory years from all North Dakota's non-point and area sources are listed in Table 26 and graphed in Figure 27.

Table 26: North Dakota Area and Non-Point Source Emissions (tons/year)

Pollutant	2002	2011	2014v2	RepBase	2028OTB
SO_2	10,515	2,728	4,214	9,562	15,374
NO_X	15,464	43,426	44,431	63,384	58,463
VOC	68,195	274,083	681,441	417,790	433,255
NH_3 [A]	NA	NA	133	133	133
PM_{10} [C]	199	146	2,007	1,994	1,440
$PM_{2.5}$ [B]	1,617	1,821	1,907	1,894	1,340

[A] NH_3 was not tracked for 2002 and 2011.

[B] For 2002 and 2011, $PM_{2.5}$ ≈ FPM

[C] For 2002 and 2011, PM_{10} ≈ CPM

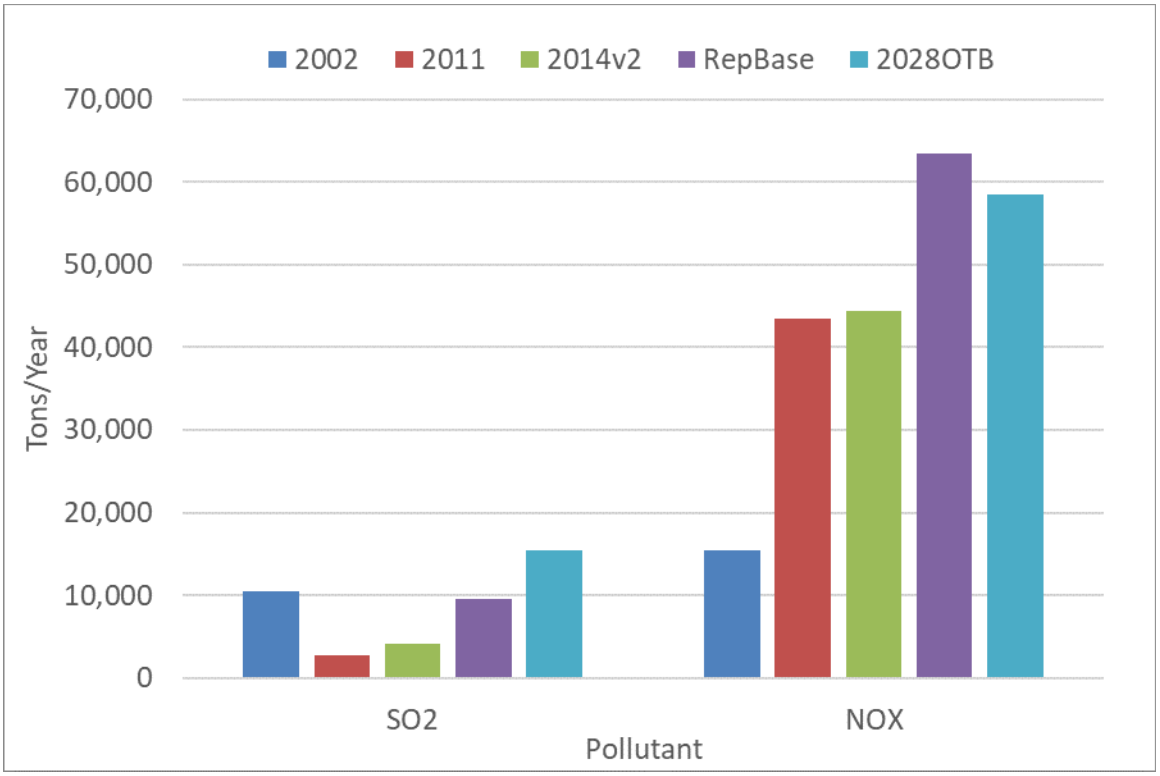

Figure 27: North Dakota Area and Non-Point Source NO_X and SO_2 Emissions

As detailed in Section 4.3.1 and as shown in Figure 28, a significant majority of the North Dakota's area and non-point source emissions are the result of upstream oil and gas operations. North Dakota reviewed the impacts from the oil and gas development in the state. This review is discussed in Section 5.2.11. North Dakota did not evaluate the visibility impacts from the remaining area and non-point sources since these emissions are insignificant when compared to the upstream oil and gas emissions.

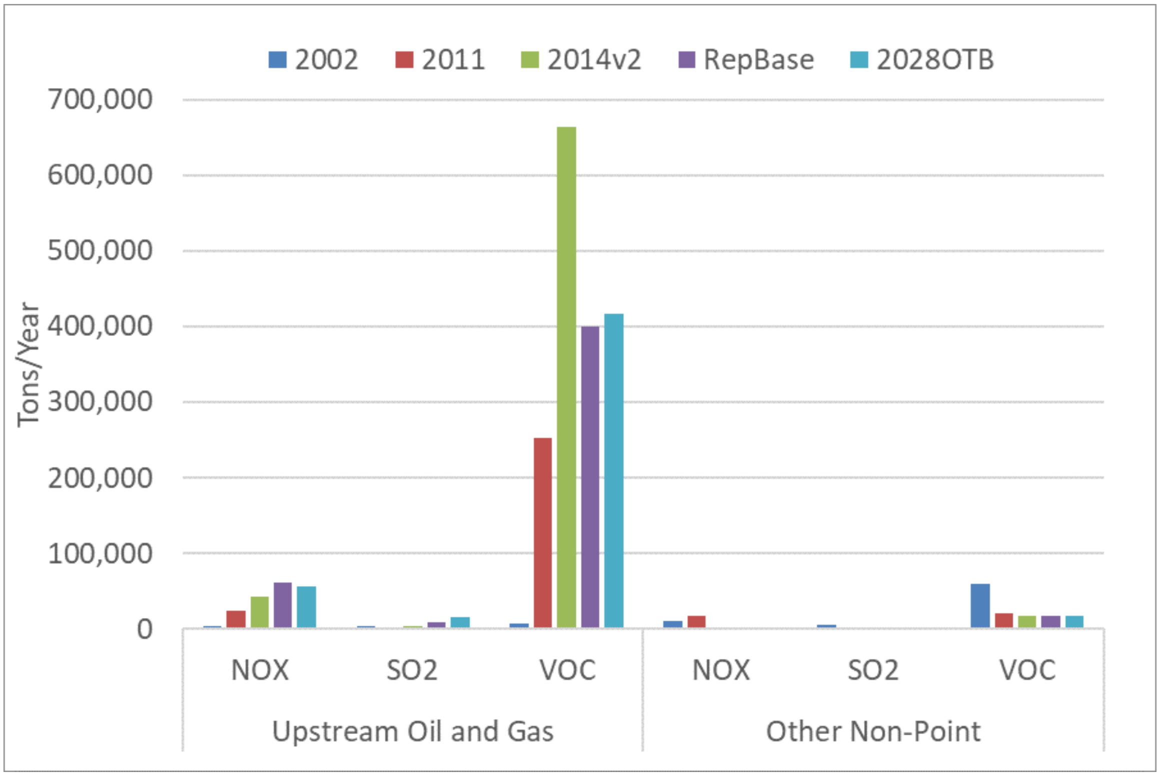

Figure 28: North Dakota Upstream Oil and Gas and Other Non-Point Emissions

4.3.1 North Dakota Oil and Gas Upstream

The visibility impairing pollutants for each of the emissions inventory years from all of North Dakota's upstream oil and gas sector are listed in Table 27 and graphed in Figure 29. NO_X and SO_2 emissions from upstream oil and gas operations each accounted for 98% of the emissions of the total RepBase inventory for area and non-point sources. VOC emissions from this industry account for 96% of the area and non-point total. VOC emissions are also included in Figure 29.

Table 27: North Dakota's Upstream Oil and Gas Emissions (tons/year)

Pollutant	2002	2011	2014v2	RepBase	2028OTB
SO_2	4,958	2,073	4,043	9,391	15,203
NO_X	4,631	25,277	43,237	62,190	57,269
VOC	7,740	252,920	664,297	400,646	416,111
PM_{10}	NA [A]	NA [A]	1,129	1,116	562
$PM_{2.5}$	NA [A]	NA [A]	1,129	1,116	562

[A] PM species for 2002 and 2011 were not separated for the oil and gas source category.

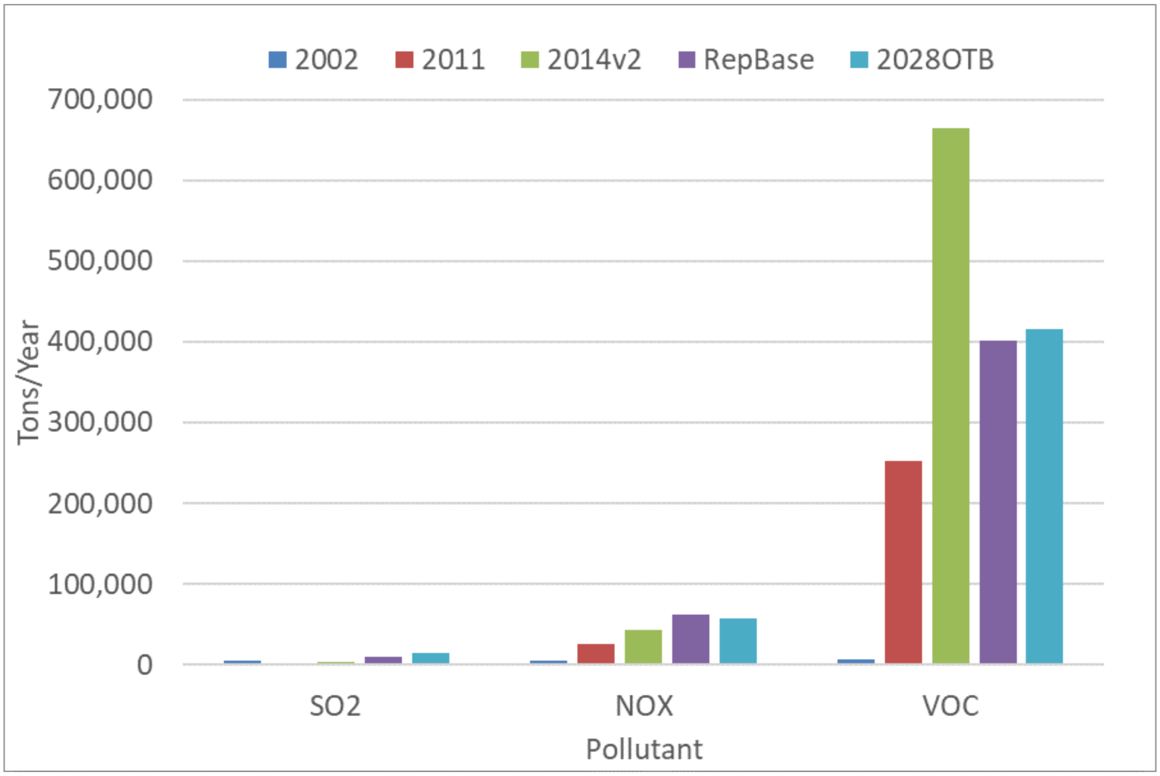

Figure 29: North Dakota Upstream Oil and Gas SO_2, NO_X, and VOC Emissions

As is displayed in Table 27 and Figure 29, emissions of NO_X, SO_2, and VOC have historically been the most significant visibility impairing pollutants emitted from North Dakota's upstream oil and gas operations. As is outlined in Section 5.1.1, ammonium nitrates and ammonium sulfates are the largest contributors to visibility impairment on the MIDs and also contribute to impairment on the clearest days. The emissions data paired with the visibility impairment data supports North Dakota's review of the impacts from the oil and gas operations (Section 5.2.11). For comparative purposes, North Dakota also quantified upstream oil and gas emissions from Canadian oil and gas operations from previous years. This information is discussed in Section 4.7.2.

4.4 North Dakota Non-Road Mobile

The visibility impairing pollutants for each of the emissions inventory years from all North Dakota's non-road mobile sources are included in Table 28 and graphed in Figure 30. This information was prepared by WRAP for use in regional haze planning and modeling. The project overview states: *"For western U.S. regional analysis using photochemical modeling for Regional Haze, WESTAR-WRAP is assisting state and local air agencies to review and, to the extent necessary and feasible, revise the 2028 future year mobile sources (i.e., on-road, off-road equipment, rail, marine, and airport) emission inventories. The basis of the future year 2028 mobile source emission inventories will utilize both the WRAP 2014NEIv2 dataset as well as the 2014-2016 National Emissions Modeling Collaborative 2016v1 future year 2028 inventory, with revisions per state agency input. The process allows participants to review and provide updates to these emissions inventories. Feedback and revisions to the inventories will be incorporated into air* *quality modeling by the WRAP for regional photochemical modeling."*[51] A memorandum which discusses detailed information regarding the baseline inventory and future year inventory was also developed to support the WRAP states.[52] North Dakota did not recommend any changes to these inventories.

Table 28: North Dakota Non-Road Mobile Emissions (tons/year)

Pollutant	2002	2011	2014v2	RepBase	2028OTB
SO_2	7,246	68	44	40	32
NO_X	55,502	31,183	26,182	28,060	12,200
VOC	13,515	10,452	8,585	7,208	4,762
NH_3	33	30	31	37	38
PM_{10}	NA ^{A}	NA ^{A}	2,207	2,278	852
$PM_{2.5}$	NA ^{A}	NA ^{A}	2,132	2,201	819

^{A} PM species for 2002 and 2011 tracked as FPM and CPM.

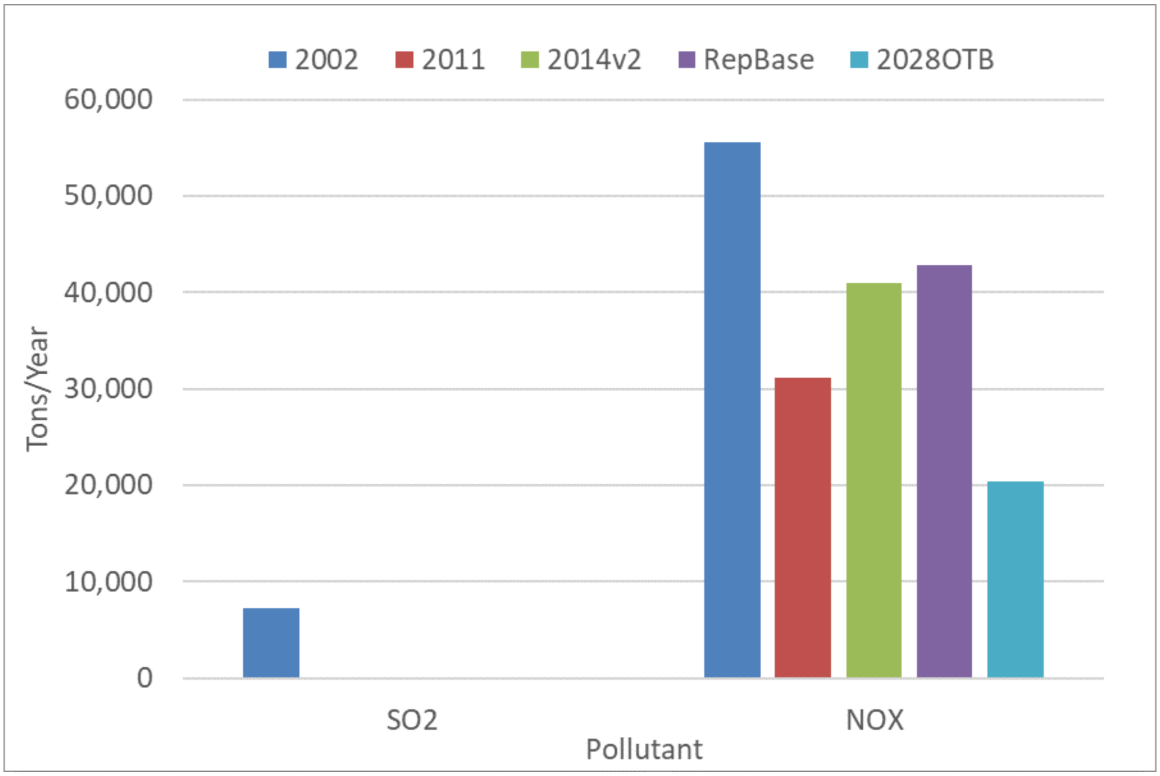

Figure 30: North Dakota Non-Road Mobile NO_X and SO_2 Emissions

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[51] Available at: http://views.cira.colostate.edu/wiki/wiki/11203/mobile-source-emissions-inventory-projections-project (Last visited December 28, 2020)

[52] Available at:https://views.cira.colostate.edu/docs/wrap/mseipp/WRAP_MSEI_Summary_Memo_13Mar2020.pdf (Last visited December 28, 2020)

As seen in Table 28, implementation of federal low sulfur fuel standards has nearly eliminated SO_2 emissions from this sector. The SO_2 emissions from 2011, 2014v2, RepBase, and 2028OTB were too small to show up in Figure 30. Note the 2028OTB NO_X emission value in Table 28. Significant reductions are projected for future NO_X emissions as less efficient engines are replaced with higher efficient combustion engines and/or are replaced with electric engines, as is detailed in Section 5.3.1.2.5.

4.5 North Dakota On-Road Mobile

The visibility impairing pollutants for each of the EI years from all North Dakota's on-road mobile sources are included in Table 29 and Figure 31. This information was prepared by WRAP for use in regional haze planning and modeling.[53] A memorandum which discusses detailed information regarding the baseline inventory and future year inventory was also developed to support the WRAP states.[54] North Dakota did not recommend any changes to these inventories.

Table 29: North Dakota On-Road Mobile Emissions (tons/year)

Pollutant	2002	2011	2014v2	RepBase	2028OTB
SO_2	812	95	91	91	53
NO_X	24,746	21,193	33,305	33,305	8,051
VOC	12,814	8,377	10,753	10,753	3,831
NH_3	732	346	343	343	259
PM_{10}	NA ^{A}	NA ^{A}	1,884	1,884	808
$PM_{2.5}$	NA ^{A}	NA ^{A}	1,320	1,320	308

^{A} PM species for 2002 and 2011 tracked as FPM and CPM

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[53] Available at: http://views.cira.colostate.edu/wiki/wiki/11203/mobile-source-emissions-inventory-projections-project (Last visited December 28, 2020)

[54] Available at: https://views.cira.colostate.edu/docs/wrap/mseipp/WRAP_MSEI_Summary_Memo_13Mar2020.pdf (Last visited December 28, 2020)

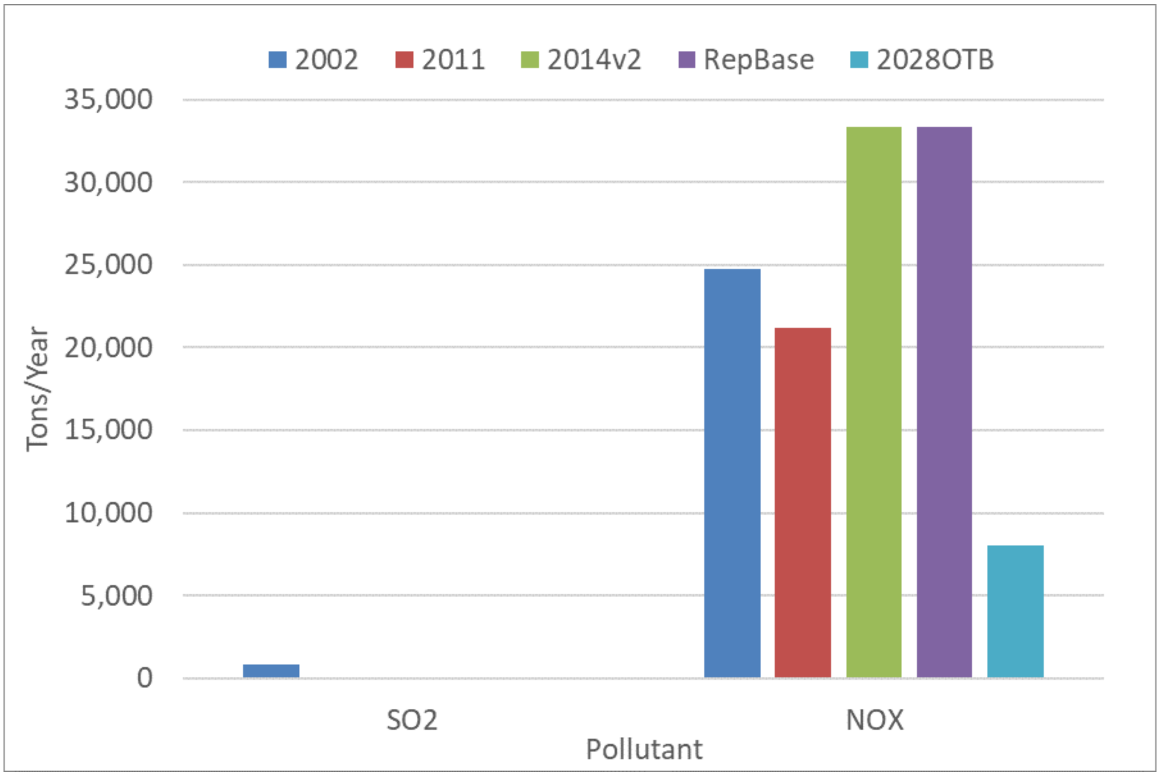

Figure 31: North Dakota On-Road Mobile NO_X and SO_2 Emissions

As seen in Table 29, implementation of federal low sulfur fuel standards has nearly eliminated SO_2 emissions from this sector. The SO_2 emissions from 2011, 2014v2, RepBase, and 2028OTB were too small to show up in Figure 31. Note the 2028OTB NO_X emission value in Table 29. Significant reductions are projected for future NO_X emissions as less efficient engines are replaced with higher efficient combustion engines and/or are replaced with electric engines (Section 5.3.1.2).

4.6 North Dakota Natural Emissions

Natural sources of visibility impairing emissions include biogenic, lightning NOx, windblown dust, sea salt, non-US fires and US wildfires. North Dakota emissions from each emissions inventory year and for each of these source categories are included in Section 4.1 (Table 12 through Table 17).

For North Dakota CIAs, it should be noted that impacts from wildfires outside of North Dakota are generally eliminated from consideration when using the MIDs metric versus the haziest days. Due to the haziest days being typically associated with wildfire events and the MIDs attempts to focus on anthropogenic emissions. Emissions from wildfires for all the WRAP states can be found in Section 4.8.

4.7 International Emissions from Canada

North Dakota shares an international border with the Canadian Provinces of Manitoba and Saskatchewan. The anthropogenic NO_X, SO_2, and VOC emissions from these provinces have been summarized in Table 30 and are displayed in Figure 32. These emissions have been included with this analysis to show the magnitude of these provinces' emissions compared to North Dakota. The inventory years displayed in Table 30 were selected because they align well with the inventory years used for North Dakota emissions and WRAP modeling. 2002 emissions from US and Canada are directly comparable. 2014 emissions from Canada are comparable to the 2014v2 scenario used by North Dakota. 2017 emissions from Canada are comparable to the RepBase scenario used by North Dakota. The magnitude of the 2017 international emissions helps support the use of an adjusted glidepath for North Dakota CIAs (Section 3.2.7). Also included in Table 30 are total emissions from the Canadian provinces of Alberta and British Columbia, both provinces are upwind of the prevailing wind direction in North Dakota and have the potential to cause visibility impairment in North Dakota CIAs. North Dakota obtained the Canadian emissions data online from the government of Canada website.[55]

Table 30: Total Canadian and North Dakota Anthropogenic Emissions (tons/year)

		Year		
Source	**Pollutant**	**2002**	**2014**	**2017**
Alberta	NOx	852,170	750,454	703,884
	SO_2	516,596	318,555	264,988
	VOC	655,958	722,539	595,413
British Columbia	NOx	387,105	298,608	303,225
	SO_2	104,568	113,350	80,728
	VOC	314,759	180,296	168,170
Manitoba	NOx	69,449	50,501	48,013
	SO_2	419,587	174,678	131,559
	VOC	78,212	63,919	60,477
Saskatchewan	NOx	185,937	164,949	159,831
	SO_2	150,848	116,920	125,633
	VOC	222,835	260,964	272,978
Total of four the Canadian Provinces	**NOx**	**1,494,661**	**1,264,512**	**1,214,953**
	SO_2	**1,191,599**	**723,503**	**602,907**
	VOC	**1,271,763**	**1,227,719**	**1,097,038**
North Dakota	**NOx**	**183,150**	**160,764**	**168,157**
	SO_2	**175,642**	**63,279**	**57,686**
	VOC	**96,610**	**707,161**	**442,196**

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[55] Available at: https://pollution-waste.canada.ca/air-emission-inventory/ (Last Visited May 17, 2021).

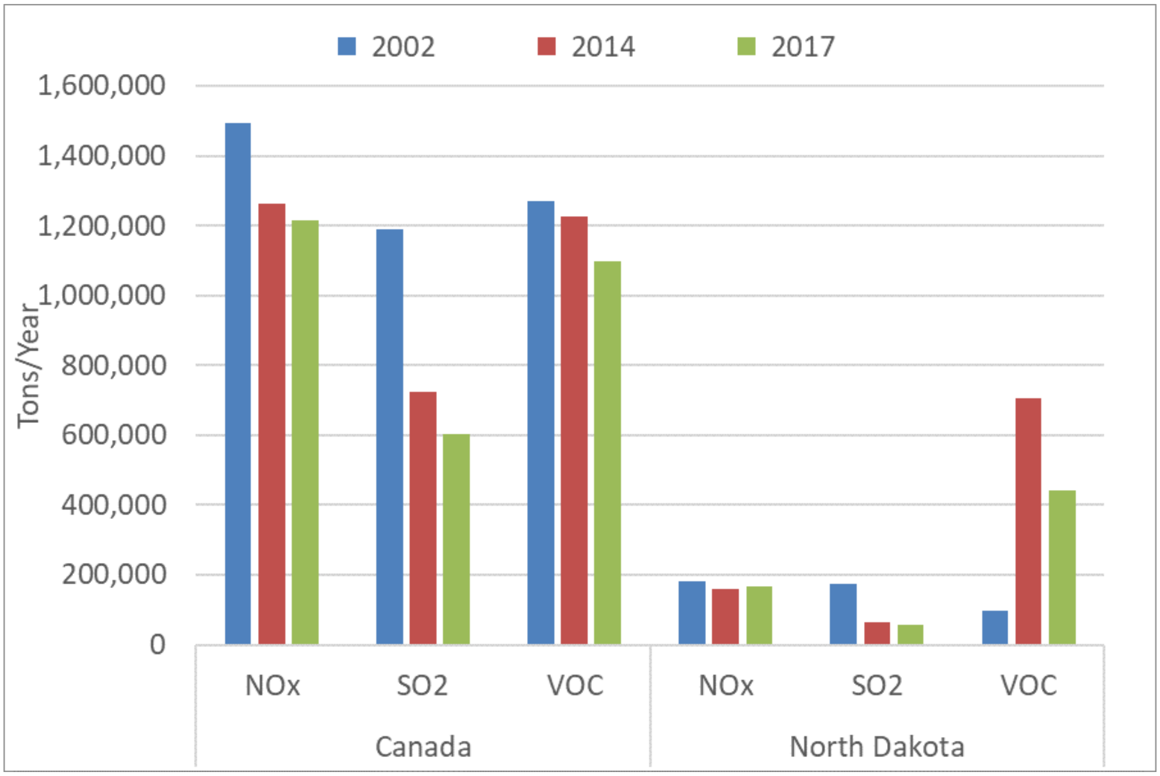

Figure 32: Anthropogenic Emissions from the Four Combined Canadian Provinces and North Dakota

4.7.1 Nearby Canadian Coal fired EGUs

Table 31 and Figure 33 compare North Dakota coal fired EGU emissions to nearby Canadian coal fired EGUs. The three nearby Canadian facilities were included in this analysis since North Dakota's CIAs are likely impacted by emissions from these sources because they have significant NO_X and SO_2 emissions, are near North Dakota CIAs, and are upwind from the local prevailing wind direction. The locations of Boundary Dam Power Station (813 MWe), Shand Power Station (279 MWe), and Poplar River Power Station (630 MWe) are displayed in Figure 34 along with the North Dakota four factor sources.

Table 31: Nearby Canadian and North Dakota Coal fired EGU Emissions (tons/year)

Source	Pollutant	2002	2017	*Difference (2017 - 2002)*
Boundary Dam Power Station	SO_2	47,338	30,037	*-17,302*
	NO_X	18,950	14,009	*-4,941*
Poplar River Power Station	SO_2	47,098	44,589	*-2,509*
	NO_X	12,862	13,574	*+712*
Shand Power Station	SO_2	13,383	10,507	*-2,876*
	NO_X	6,080	3,419	*-2,661*
	SO_2	**107,819**	**85,133**	***-22,686***

Source	**Pollutant**	**2002**	**2017**	***Difference (2017 - 2002)***
Total of three nearby Canadian Coal fired EGUs	**NO_X**	**37,892**	**31,002**	***-6,889***
Total From North Dakota Coal fired EGUs	**SO_2**	**141,158**	**39,323**	***-101,835***
	NO_X	**75,362**	**33,712**	***-41,650***

As of 2017, the three Canadian facilities had the potential to generate 1,722 MWe of electricity. 2017 emissions of NO_X and SO_2 totaled just over 116,000 tons. North Dakota coal fired EGUs had the potential to generate over 4,000 MWe. 2017 emissions of NO_X and SO_2 totaled approximately 73,000 tons. Overall, from the years of 2002 through 2017, North Dakota's coal fired EGUs have achieved a combined NO_X and SO_2 emissions reduction of 66% while these Canadian EGU's decreased only 20%. Figure 33 shows the magnitude of the reductions achieved in North Dakota since 2002 as compared to the Canadian EGUs.

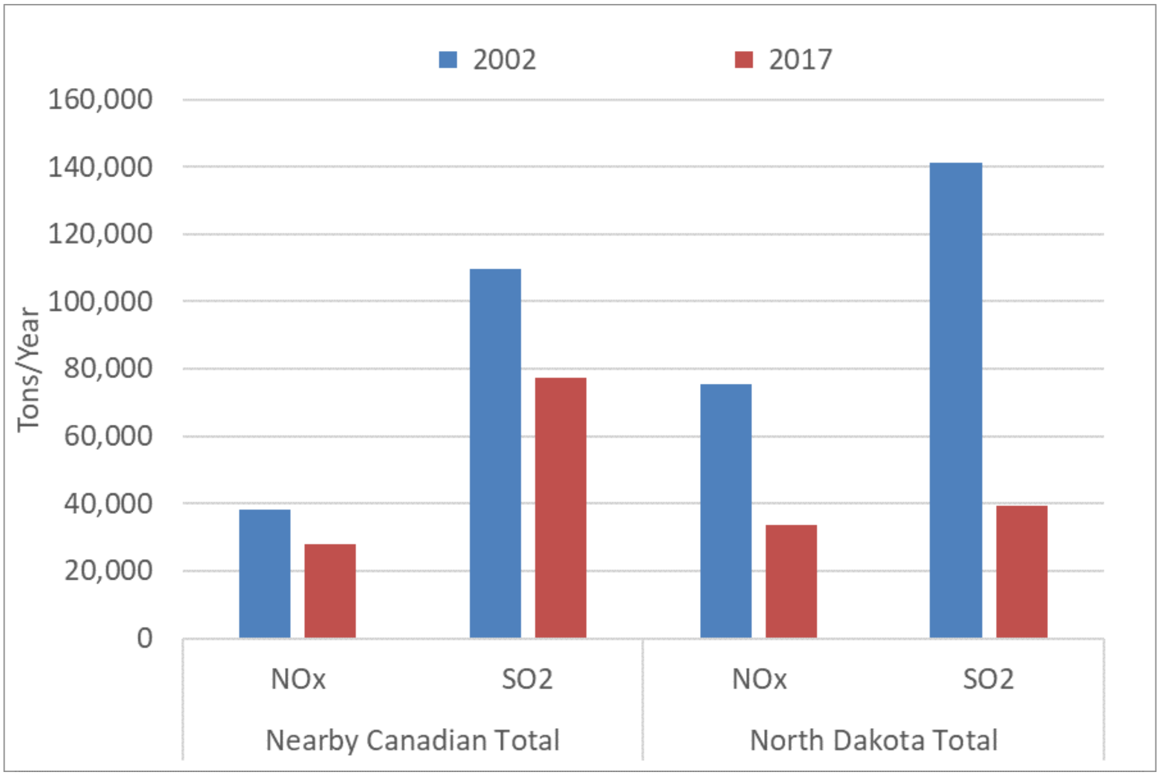

Figure 33: Nearby Canadian and North Dakota Coal fired EGU Emissions (tons/year)

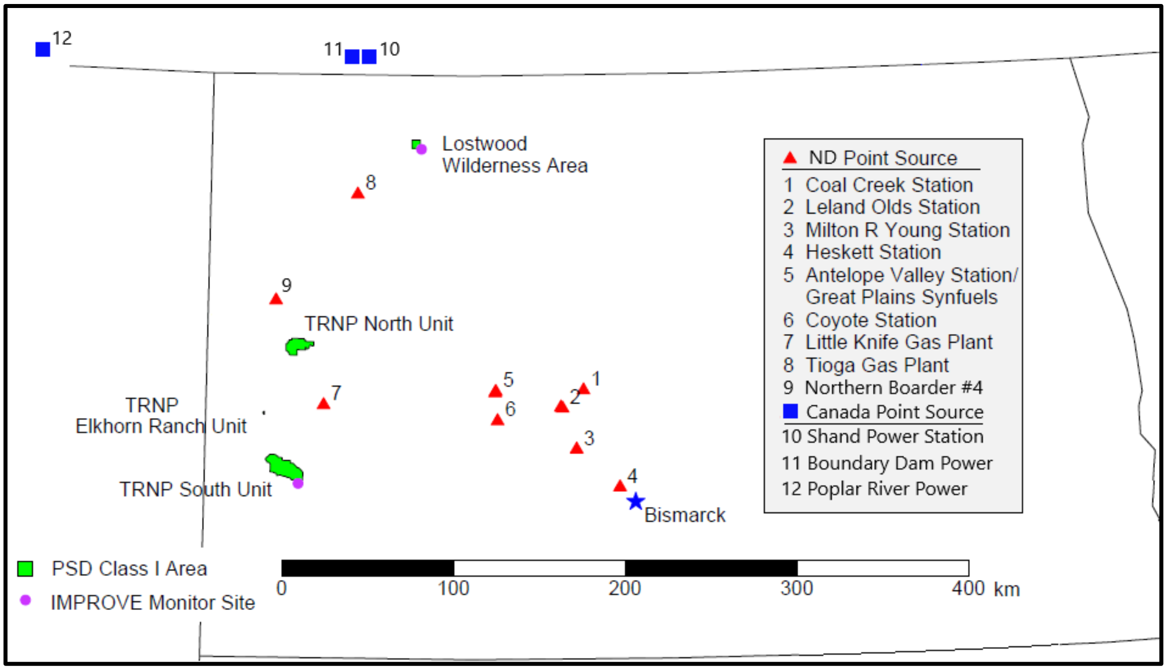

Figure 34: North Dakota Four Factor Sources and Nearby Canadian Coal fired Power Plants

4.7.2 Canadian Upstream Oil and Gas

Table 32 and Figure 35 illustrate a comparison between North Dakota upstream oil and gas emissions and Canadian upstream oil and gas emissions. North Dakota's CIAs are likely impacted by emissions from these Canadian sources since they have significant VOC, NO_X and SO_2 emissions and are upwind from the prevailing wind direction. The data were gathered from the Environment and Climate Change Canada website.[56] Emissions attributable to natural gas production and processing, natural gas transmission and storage, petroleum liquids storage and petroleum liquids transportation were not included in Table 32 because these subsectors are not included North Dakota's upstream oil and gas inventory. North Dakota's emissions from these activities are quantified in the point source emissions and non-point source emissions.

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[56] Available at: https://pollution-waste.canada.ca/air-emission-inventory/ (Last Visited May 17, 2021).

Table 32: Canadian and North Dakota Upstream Oil and Gas Emissions (tons/year)

Source	**Pollutant**	**2002**	**2017**	***Difference (2017-2002)***
Alberta	NOx	78,338	119,402	*+41,064*
	SO2	147,531	90,700	*-56,831*
	VOC	303,801	300,851	*-2,949*
British Columbia	NOx	4,777	3,548	*-1,229*
	SO2	3,044	1,188	*-1,856*
	VOC	10,918	5,196	*-5,722*
Manitoba	NOx	46	234	*+187*
	SO2	409	1,154	*+746*
	VOC	3,682	7,614	*+3,932*
Saskatchewan	NOx	8,125	10,876	*+2,750*
	SO2	7,649	12,483	*+4,833*
	VOC	104,491	171,528	*+67,037*
Total of the four Canadian Provinces	**NOx**	**91,287**	**134,059**	***+42,772***
	SO2	**158,633**	**105,525**	***-53,108***
	VOC	**422,892**	**485,190**	***+62,298***
North Dakota	**NOx**	**4,631**	**62,190**	***+57,559***
	SO2	**4,958**	**9,391**	***+4,433***
	VOC	**7,740**	**400,646**	***+392,906***

As shown in Table 32, most of the Canadian upstream oil and gas emissions come from Alberta and Saskatchewan. Alberta and Saskatchewan account for over 97% of all $SO_{2,}$ NO_X, and VOC emissions from the Canadian upstream oil and gas sector. These emissions primarily result from the Canadian oil sands, the third-largest proven oil reserve in the world.[57] The oil sands are primarily located in Alberta, northeast of Edmonton.[58]

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[57] Available at: https://www.nrcan.gc.ca/our-natural-resources/energy-sources-distribution/clean-fossil-fuels/what-are-oil-sands/18089

[58] Available at: http://history.alberta.ca/energyheritage/sands/origins/the-geology-of-the-oil-sands/the-location-of-oil-sands.aspx

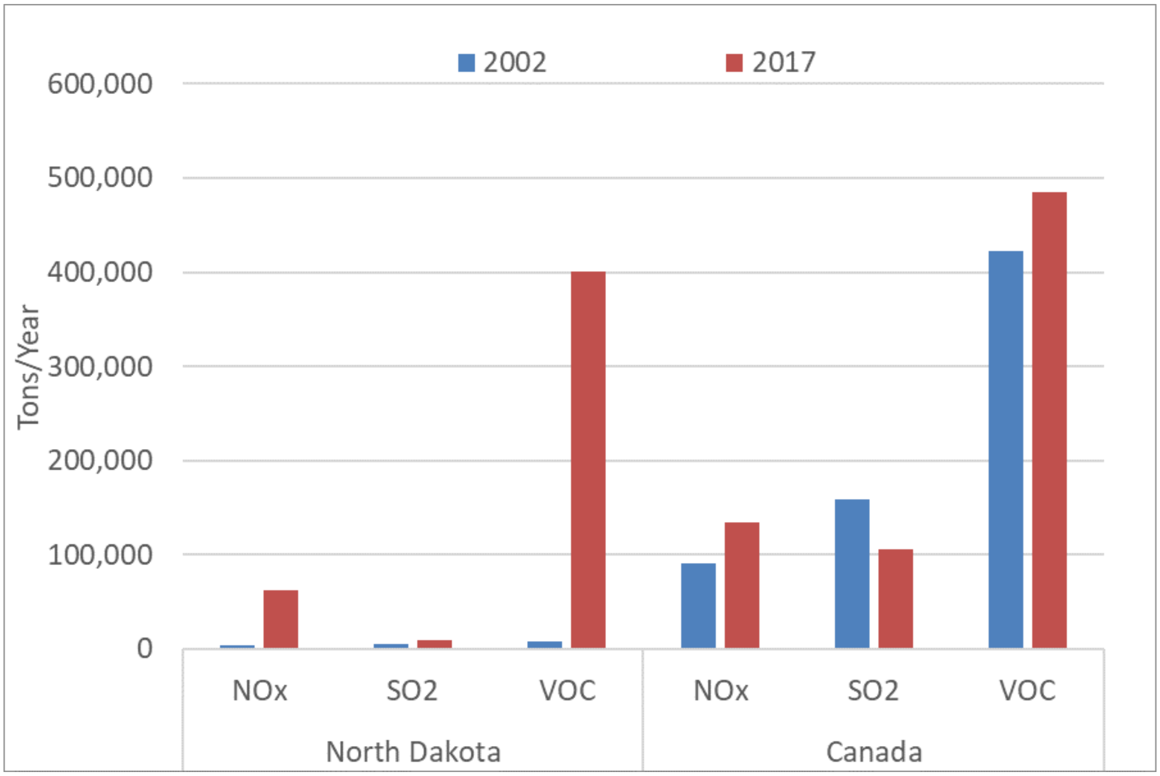

Figure 35: Canadian and North Dakota Upstream Oil and Gas Emissions (tons/year)

4.8 Wildfire Emissions from WRAP States

The WRAP Fire and Smoke Workgroup developed emissions profiles for the 2014v2 and the RepBase inventories. The 2014 base year inventory used EPA's 2014 Wildland Fire EI, version 2 as the starting point.[59] WRAP state and stakeholder input was received starting from this inventory. North Dakota had no comments regarding the data for North Dakota or other states. The RepBase inventory was developed starting from the 2014v2 data and serves as a typical or average fire year observed during the period of 2014–2018. Wildfire activity across the United States can vary greatly from year to year across three primary degrees of freedom: space, time, and magnitude. Therefore, building a single-year inventory dataset that captures "average" wildfire activity over the multi-year baseline period is difficult, but was completed for this exercise. Full details of how this was done can be found in the detailed report outlining this project. [60]

The visibility impairing pollutant emissions for the 2014v2 and RepBase scenarios are shown in Table 33 and Table 34, Respectively. Particulate matter (PM_{10} and $PM_{2.5}$) are the largest visibility impairing pollutants from this activity. To help show the magnitude in differences of these emissions from each state, a pie chart comparing the $PM_{2.5}$ emissions from all the WRAP states is shown in Figure 36. Figure 36 includes $PM_{2.5}$ from both the 2014v2 and RepBase inventories. When comparing 2014v2 to RepBase

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[59] Available at: ftp://newftp.epa.gov/air/nei/2014/doc/2014v2_supportingdata/wild_and_prescribed_fires/ (Last visited August 23, 2018)

[60] Available at: https://www.wrapair2.org/pdf/fswg_rhp_fire-ei_final_report_20200519_FINAL.PDF (Last visited December 30, 2020)

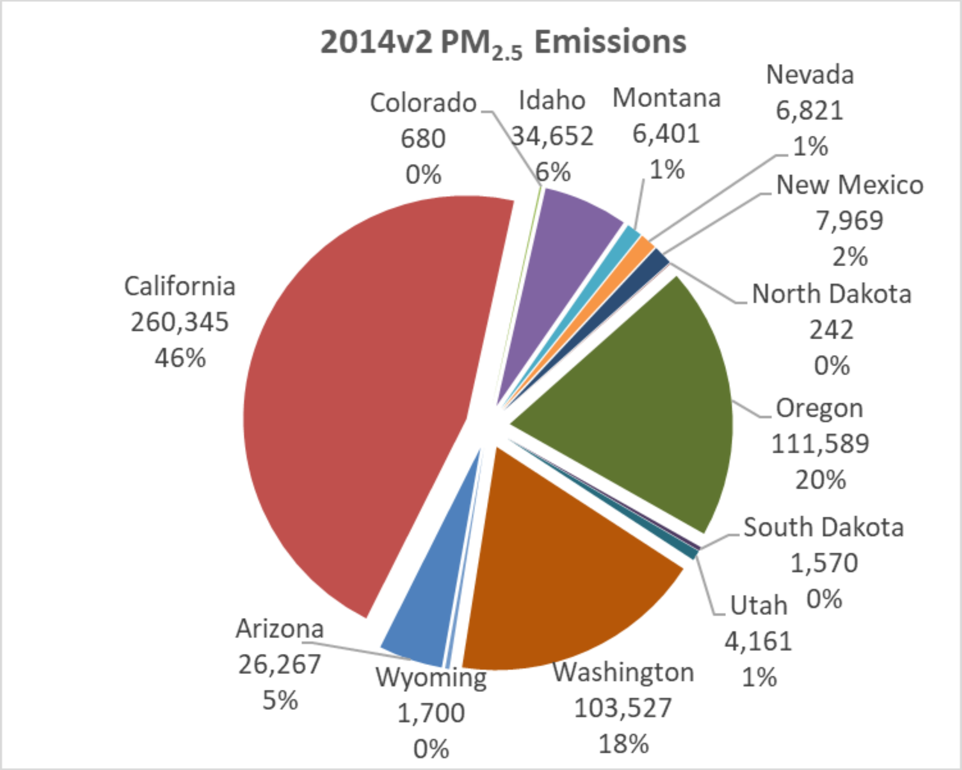
fire emission inventories, it is easily noticed that 2014 was a low fire activity year and the RepBase inventory is likely more representative of actual wildfire activity. The low 2014 fire activity was supported by the IMPROVE data, as discussed in Section 3.3.

Table 33: 2014v2 Wildfire Emissions from WRAP States (tons)

State	VOC	NO_X	SO_2	PM_{10}	$PM_{2.5}$
Arizona	62,341	5,133	2,556	30,995	26,267
California	652,655	32,023	20,209	307,205	260,345
Colorado	1,586	132	66	802	680
Idaho	85,238	5,112	2,921	40,889	34,652
Montana	14,519	723	479	7,553	6,401
Nevada	16,496	1,150	614	8,048	6,821
New Mexico	19,593	1,182	673	9,403	7,969
North Dakota	600	32	17	288	242
Oregon	274,420	15,794	9,225	131,674	111,589
South Dakota	3,733	178	118	1,853	1,570
Utah	10,062	704	375	4,910	4,161
Washington	248,579	14,231	8,444	122,170	103,527
Wyoming	4,039	224	136	2,006	1,700

Table 34: RepBase Wildfire Emissions from WRAP States (tons)

State	VOC	NO_X	SO_2	PM_{10}	$PM_{2.5}$
Arizona	22,318	981	549	8,619	7,230
California	1,501,452	32,477	33,131	510,987	450,518
Colorado	302,963	6,429	6,684	102,919	90,939
Idaho	132,774	3,614	2,989	46,254	40,131
Montana	135,502	5,915	3,498	49,466	43,838
Nevada	25,760	1,754	674	10,641	8,344
New Mexico	45,934	3,098	1,225	18,938	15,094
North Dakota	1,518	221	60	564	541
Oregon	516,471	11,871	11,451	176,734	155,221
South Dakota	84,371	8,049	2,910	33,282	30,800
Utah	54,614	2,063	1,295	20,318	17,381
Washington	445,834	9,347	9,830	151,506	133,868
Wyoming	80,425	7,359	2,627	32,137	28,563



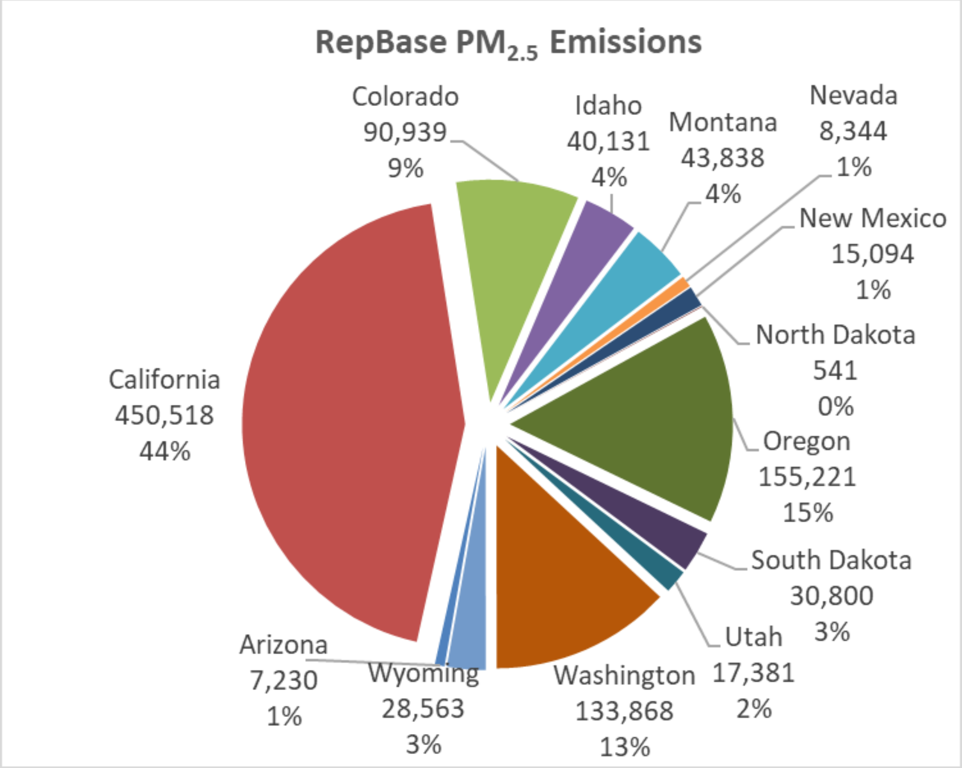


Figure 36: $PM_{2.5}$ Emissions, in Tons, from WRAP States. The Top Pie Chart Contains 2014v2 Emissions. The Bottom Pie Chart Contains RepBase Emissions.

5 §51.308(f)(2) - Long Term Strategy for North Dakota

5.1 §51.308(f)(2)(i) - Source Screening

The Department focused its control strategy analysis on emissions of NO_X and SO_2 for the second planning period. NO_x and SO_2 are the two main species which react to form ammonium nitrates and ammonium sulfates, the main visibility impairing species that affect visibility at CIAs in North Dakota (Section 5.1.1) on the MIDs. On an individual unit basis, point sources are the largest contributors to SO_2 and NO_X. Therefore, the Department elected to focus on existing point sources in this planning period. The Department also evaluated oil and gas upstream operations in North Dakota (Section 5.2.11). Weighted emissions potential (WEP) and area of influence (AOI) modeling using projected 2028 emissions was completed by WRAP.[61] These products support the Department's focus on existing point sources and oil and gas upstream operations during this planning period. Refer to Appendix C for the WEP/AOI analysis for North Dakota and nearby CIAs.

5.1.1 Ammonium Sulfates and Ammonium Nitrates

5.1.1.1 Most Impaired Days

On the MID, LWA and TRNP were both primarily impacted by ammonium nitrates and ammonium sulfates from 2000–2018. Figure 37 displays the annual average light extinction information for LWA and Figure 38 displays this information for TRNP. These data indicate the Department should focus four-factor analysis reviews on controls to reduce sulfur dioxide (SO_2) and nitrogen oxides (NO_X) from anthropogenic sources in North Dakota.

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[61] Available at: https://views.cira.colostate.edu/tssv2/WEP-AOI/ (Last visited February 22, 2021)

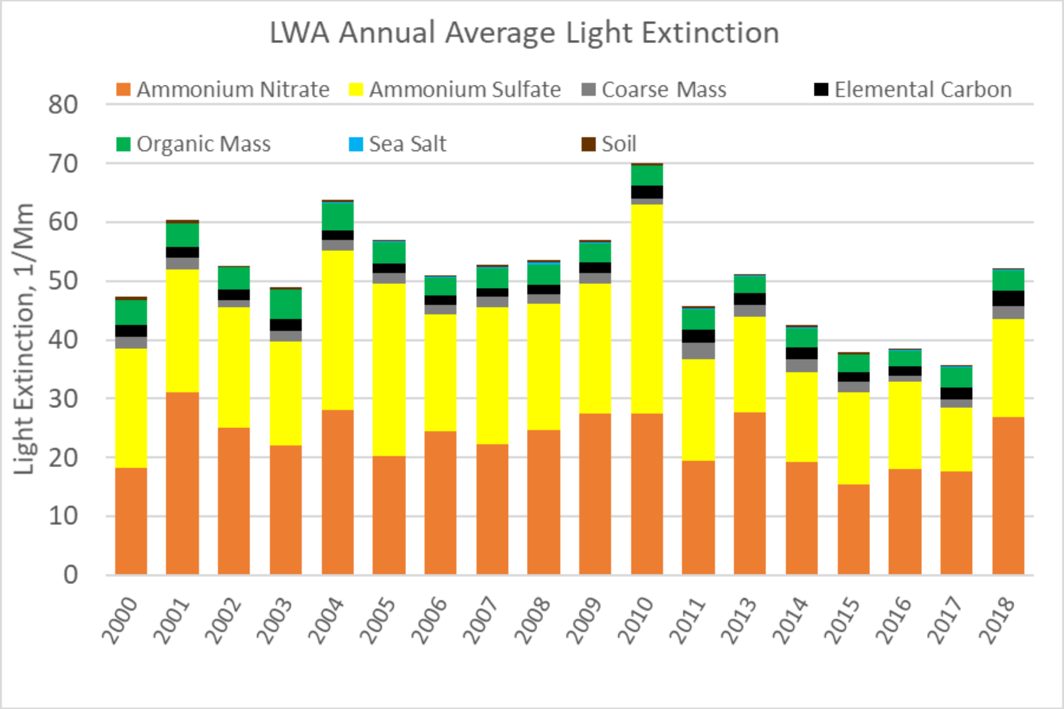

Figure 37: Annual Average Light Extinction at LWA for the Most Impaired Days from 2000–2018.[62]

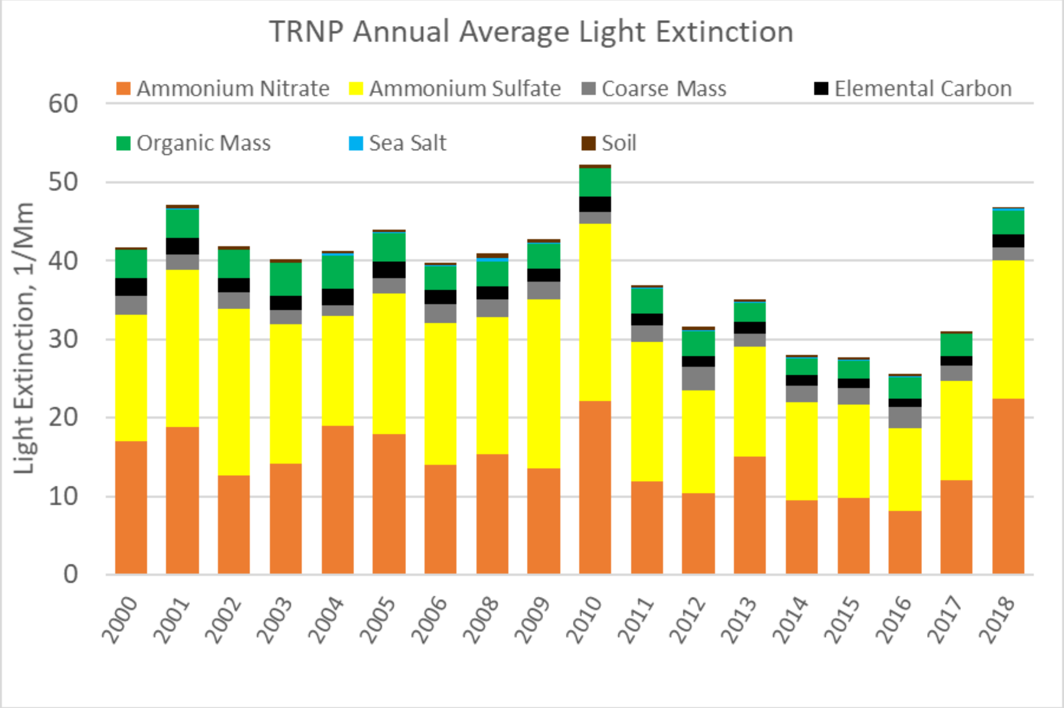

Figure 38: Annual Average Light Extinction at TRNP for the Most Impaired Days from 2000–2018.[63]

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[62] Available at: https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx

[63] Available at: https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx

5.1.1.2 Clearest Days

LWA and TRNP were most significantly impacted by ammonium sulfates from 2000–2018 on the clearest days. Organic mass, coarse mass, elemental carbon, and ammonium nitrates also contribute to visibility impairment on the clearest days at LWA and TRNP. Figure 39 displays this information for LWA and Figure 40 displays this information for TRNP.

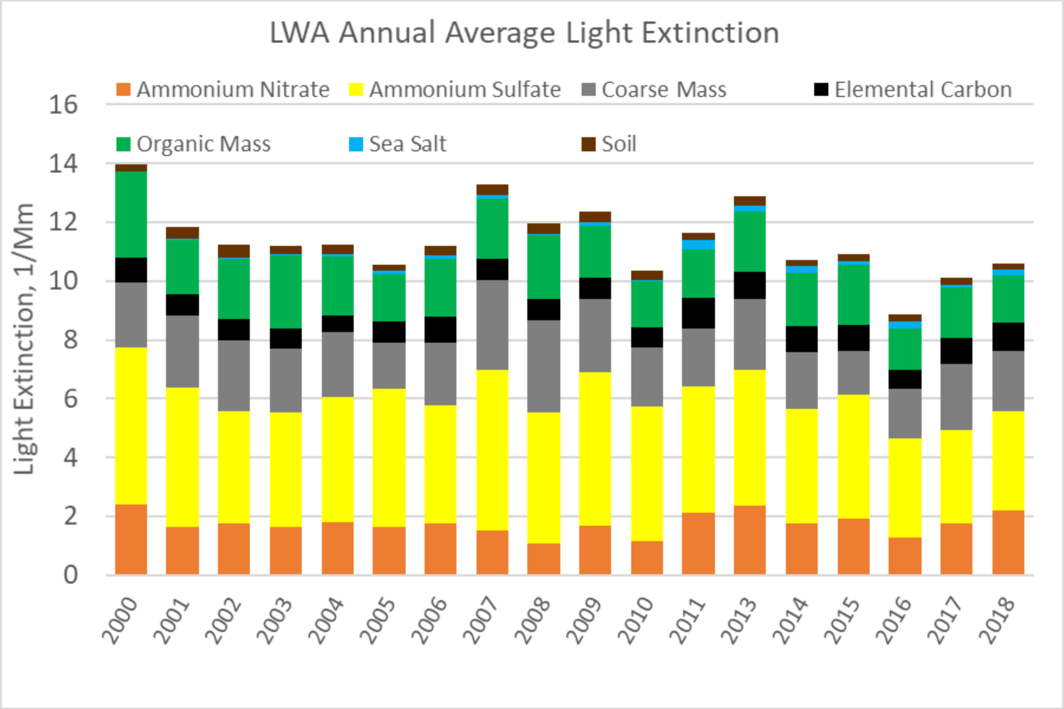

Figure 39: Annual Average Light Extinction at LWA for the Clearest Days from 2000–2018.[64]

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[64] Available at: https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx

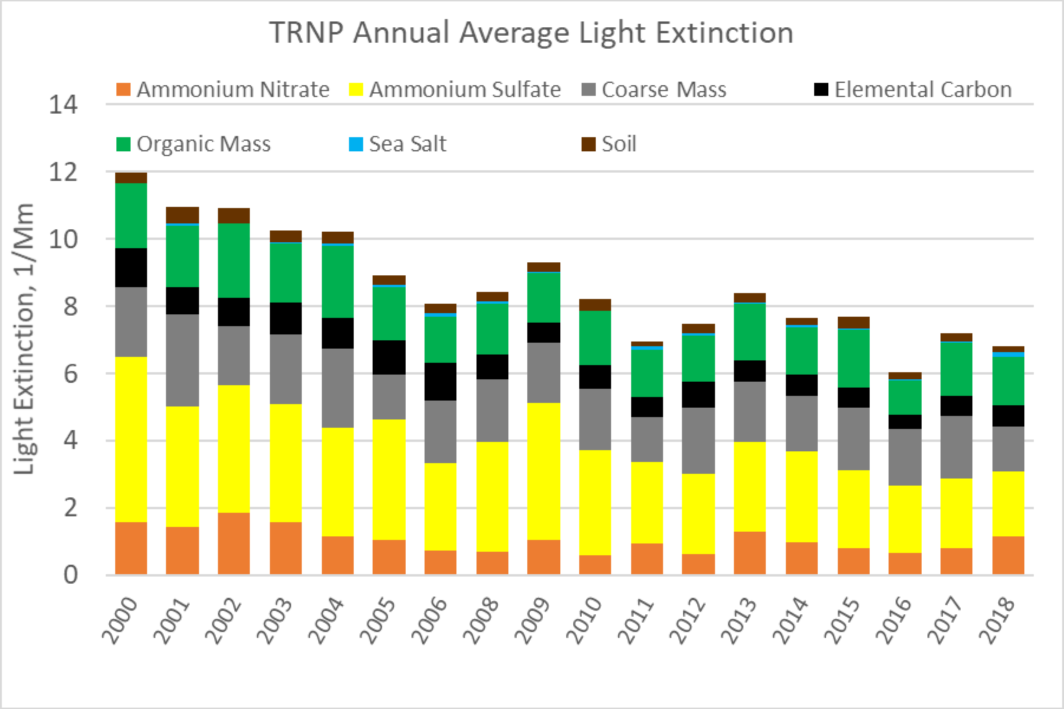

Figure 40: Annual Average Light Extinction at TRNP for the Clearest Days from 2000–2018.[65]

There are no significant recent anomalies with the annual average light extinction on the clearest days.

5.1.2 Determination of Subject Facilities

Initial planning stages for the second planning period for regional haze required that North Dakota determine how to choose facilities that would be required to submit a four factors analysis. The facilities required to submit a four factors analysis were selected based on their recent average annual emissions of SO_2 and NO_X and their distance to the nearest CIA. This is also known as Q/d, where "Q" represents emissions, in tons, and "d" represents distance, in kilometers. Sulfur dioxide (SO_2) and nitrogen oxides (NO_X) were the primary focus since these are the pollutants which contribute the most to anthropogenic visibility impairment in North Dakota CIAs (Section 5.1.1). Table 35 lists the primary facilities that North Dakota evaluated. The facilities in Table 35 were initially chosen based on their proximity to CIAs and their total emissions of SO_2 and NO_X. All electrical generating utilities (EGUs) were included in the Department's initial screening to determine if the company should submit a four factors analysis. The emissions used to determine Q/d were average annual emissions for 2012 through 2016. The Department then considered other point sources near CIAs. After reviewing the facilities listed in Table 35, the Department determined that the cutoff for facilities that the Department would require to submit a four factors analysis would be if any emission unit at the facility has a Q/d of 10. As such, Great River Energy was not required to submit a four factors analysis for the Spiritwood Station. Although the Great River Energy Stanton Station was operational between 2012 and 2016, as is shown in Table 35, the facility was shut down on May 1, 2017. Therefore, a letter requesting a four factors analysis was not

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[65] Available at: https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx

sent to Great River Energy for the Stanton Station. Although the Northern Border Pipeline Company has a Q/d of 9, they were still required to submit a four factors analysis to the Department since the facility was close to the Q/d threshold.

Table 35: Facility emissions relative to distance from Class I areas.

Permittee	Facility	$SO_2 + NO_X$ Emissions (tons) [A]	Nearest Class I area	Distance to Nearest Class I area (km)	Q/d to Nearest Class I area
Basin Electric Power Cooperative	Antelope Valley Station (Unit 1)	10,592	TRNP (NU) [B]	117	91
Basin Electric Power Cooperative	Antelope Valley Station (Unit 2)	12,188	TRNP (NU) [B]	117	104
Basin Electric Power Cooperative	Leland Olds (Unit 1)	6,650	TRNP (NU) [B]	157	42
Basin Electric Power Cooperative	Leland Olds (Unit 2)	9,967	TRNP (NU) [B]	157	63
Minnkota Power Cooperative	Milton R. Young (Unit 1)	3,877	TRNP (SU) [C]	161	24
Minnkota Power Cooperative	Milton R. Young (Unit 2)	6,863	TRNP (SU) [C]	161	43
Ottertail Power Company	Coyote Station (Unit 1)	21,096	TRNP (NU) [B]	129	164
Montana Dakota Utilities	Heskett (Unit 1)	1,269	TRNP (SU) [C]	185	7
Montana Dakota Utilities	Heskett (Unit 2)	2,941	TRNP (SU) [C]	185	16
Great River Energy	Stanton (Unit 1) [D]	3,218	TRNP (NU) [B]	156	21
Great River Energy	Stanton (Unit 10) [D]	701	TRNP (NU) [B]	156	4
Great River Energy	Coal Creek (Unit 1)	12,675	TRNP (NU) [B]	168	75
Great River Energy	Coal Creek (Unit 2)	10,631	TRNP (NU) [B]	168	63
Great River Energy	Spiritwood (Unit 1) [E]	142	TRNP (SU) [C]	366	0
Dakota Gasification Company	Great Plains Synfuels Plant	6,550	TRNP (NU) [B]	107	61
Hess Corporation	Tioga Gas Plant	1,920	LWA [F]	35	55
Petro-Hunt, LLC	Little Knife Gas Plant	475	TRNP (NU) [B]	39	12
Northern Border Pipeline Company	Compressor Station No. 4	157	TRNP (NU) [B]	18	9

[A] Emissions are based on the average annual emissions from 2012 through 2016

[B] Theodore Roosevelt National Park (North Unit)

[C] Theodore Roosevelt National Park (South Unit)

[D] Shut down on May 1, 2017; no letter requesting a four factors analysis was sent

[E] No letter requesting a four factors analysis was sent due to the low Q/d

[F] Lostwood National Wildlife Refuge Wilderness Area

5.2 §51.308(f)(2)(i) - Four Factors Analyses for Point Sources

As is illustrated in Table 35, the point sources shown in Figure 41 submitted a four factors analysis to the Department as part of North Dakota's long-term strategy planning, as required by 40 CFR §51.308(f)(2)(i). Ten facilities were required to submit a four factors analysis. These ten facilities are addressed in Sections 5.2.1 through 5.2.10. In addition to these ten facilities, North Dakota upstream oil and gas development was reviewed and is discussed in Section 5.2.11. Oil and gas upstream sources are considered nonpoint sources and are part of a "group of sources". Oil and gas point sources (e.g. Hess Tioga Gas Plant) are, however, included in the oil and gas sector category for modeling. The combined NO_X and SO_2 emissions from this category are similar to the aggregate emissions from the coal fired EGU sector (See Sections 4.2.1 and 4.3.1).

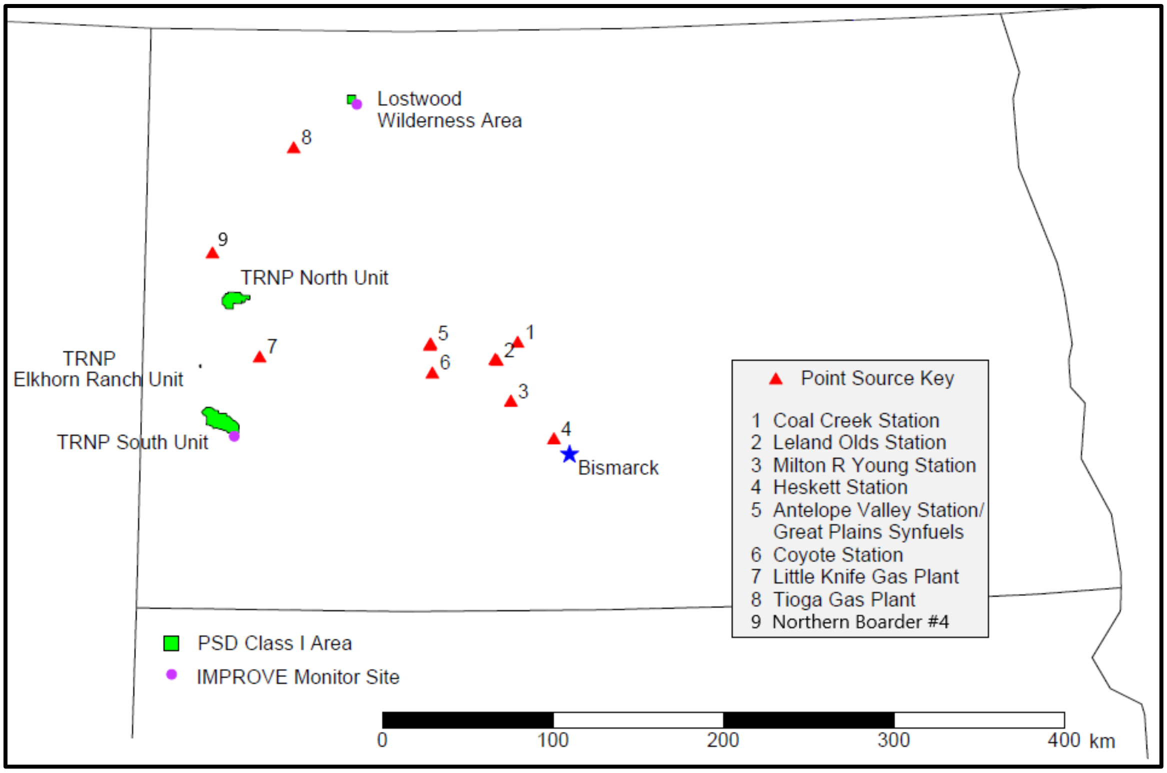

Figure 41: Locations of the point sources that submitted a four factors analysis as part of North Dakota's long-term strategy planning.

5.2.1 Otter Tail Power Company – Coyote Station

Otter Tail Power Company – Coyote Station (Coyote) is a single unit EGU with a capacity to produce approximately 450 megawatts (MW) per hour of electricity. The boiler is a Babcock and Wilcox cyclone fired boiler with a heat input capacity of 5,800 million British thermal units (MMBtu) per hour. Coyote commenced operation in 1981. Coyote is located in Mercer County about three miles southwest of the town of Beulah, North Dakota. Coyote is a mine-mouth power plant which receives coal from North American Coal Company – Coyote Creek Mine.

As documented in Table 35, Coyote Station has a Q/d of 164, which is above the threshold of 10. Therefore, the Department sent a letter to Otter Tail Power Company on May 2, 2018 requesting a four factors analysis for Coyote Station.[66] The letter required that the four factors analysis be submitted to the Department on or before January 31, 2019. Otter Tail Power Company submitted their original four-factors analysis to the Department on January 30, 2019. A revised four factors analysis was submitted on May 10, 2019 in response to comments from the Department, which were submitted to Otter Tail Power Company on March 20, 2019. [67] Another revised four factors analysis was submitted to the Department on January 6, 2020 to update the costs for the installation and operation of selected non-catalytic reduction (SNCR) and rich reagent injection (RRI). A final update to the four factors analysis was submitted to the Department on June 8, 2020 to update the analysis associated with some of the SO_2 controls evaluated. A copy of each submittal by Otter Tail Power Company can be found in Appendix B.1.b of this SIP. The Department summary analysis of Coyote Station's four factors analysis can be found in Appendix A.1 of this SIP revision. Based on the information reviewed, future operations and emissions profiles are expected to remain consistent with current conditions.

Additional SO_2 and NO_X controls were selected to be included in the 2028 potential additional controls (PAC) visibility modeling based on the Department's review of the four-factor analysis. The Department evaluated additional controls for Coyote using two scenarios.

The first additional controls modeling scenario contained the selection of controls in line with the control technologies and emissions rates of similar EGUs which were subject to the BART requirements. The SO_2 controls selected for the first modeling evaluation included a reduction of approximately 11,600 tons from the baseline emissions. This reduction could be accomplished by replacing the existing SO_2 absorber module. The replacement SO_2 absorber module's capital cost is approximately $110 million, annualized cost is approximately $21 million, and the cost per ton of SO_2 reduced is approximately $1,800. The NO_X controls selected for this evaluation included a reduction of approximately 3,000 tons from the baseline emissions. This reduction could be accomplished by the installation of a selective non-catalytic reduction (SNCR) controls. The SNCR's capital cost is approximately $20 million, annualized cost is approximately $5 million, and the cost per ton of NO_X reduced is approximately $1,700. Also included in the first scenario modeling were reductions from Antelope Valley Station, see Section 5.2.2.

The second additional controls modeling scenario contained the selection of controls based on limited capital expenditure and facility modifications, while still achieving sizable reductions. This resulted in selecting modifications of the flue gas desulfurization (FGD) controls to improve the efficiency of the unit. The second modeling evaluation included a reduction of approximately 5,300 tons of SO_2 from the baseline emissions. The FGD improvements capital cost is approximately $500,000, annualized cost approximately $2.1 million, and cost per ton of SO_2 reduced is approximately $400. There were no NO_X controls selected with this modeling scenario. There were also no additional reductions from other sources included in this scenario. Therefore, in this modeling scenario, the second additional controls

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[66] Appendix B.1.a.

[67] Appendix B.1.c.

modeling shows the impact reducing 5,300 tons of SO_2 from Coyote has on the overall 2028 projected visibility.

The results of the visibility modeling evaluation for the 2028 first and second potential additional controls scenarios are addressed in Section 6.1.1. The first scenario resulted in a projected improvement of 0.08 deciviews at TRNP and 0.1 deciviews at LWA on the IMRPOVE MIDs. Again, the first scenario also includes reductions from Antelope Valley Station (Section 5.2.2). The second scenario resulted in a projected improvement of 0.03 deciviews at TRNP and 0.04 deciviews at LWA on the IMPROVE MIDs. The second scenario reflects the projected visibility improvement from SO_2 reductions only at Coyote Station. These visibility improvements modeled for the first and second potential additional controls scenarios are not considered significant since the improvements are smaller than what is perceptible by an unaided human eye.

Since the modeling has indicated no expected significant change in visibility (Section 6.1.1) and TRNP and LWA are projected to achieve the adjusted uniform rate of progress required by 2028 (Section 3.2.7), the Department does not believe any additional SO_2 or NO_X controls at Coyote should be required for installation during this planning period. The Department will re-evaluate this decision during the 2025 progress report.

5.2.2 Basin Electric Power Cooperative – Antelope Valley Station

Basin Electric Power Cooperative – Antelope Valley Station (AVS) is a two-unit electrical generating utility (EGU). Each unit has the capacity to produce approximately 470 megawatts (MW) per hour of electricity. Unit 1 and Unit 2 are identical Combustion Engineering boilers firing pulverized lignite coal tangentially. Unit 1 and Unit 2 each have a heat input capacity of 6,275 MMBtu per hour. Unit 1 began commercial operation in 1984. Unit 2 began commercial operation in 1986. AVS is located in Mercer County about eight miles northwest of the town of Beulah, North Dakota and approximately six miles north of US Highway 200. AVS receives most of its lignite coal from the coal that is too fine-grained to be used by the Great Plains Synfuels Plant (GPSP). GPSP is located just south of AVS. The remaining coal is delivered from the nearby Freedom Mine, which is located approximately two miles north of AVS.

As documented in Table 35, AVS Unit 1 has a Q/d of 91 and AVS Unit 2 has a Q/d of 104. Therefore, the Department sent a letter to Basin Electric Power Cooperative (Basin) on May 2, 2018 requesting a four factors analysis for AVS.[68] The letter required that the four factors analysis be submitted to the Department on or before January 31, 2019. Basin's original four-factor analysis was submitted to the Department on January 31, 2019.[69] The Department provided comments to Basin regarding Basin's four-factor analysis on June 20, 2019.[70] Basin submitted a response to the Department's comments on July 12, 2019.[71] A copy of each submittal by AVS can be found in Appendix B.2.b of this SIP. The Department summary analysis of AVS's four factors analysis can be found in Appendix A.2 of this SIP. Based on the

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[68] Appendix B.2.a.

[69] Appendix B.2.b.

[70] Appendix B.2.c.

[71] Appendix B.2.c.

information reviewed, future operations and emissions profiles are expected to remain consistent with current conditions.

Additional SO_2 controls were selected to be included in the 2028 potential additional controls visibility modeling based on the Department's review of the four-factor analysis. No NO_X controls were selected for the modeling evaluation since the facility operates at a low baseline NO_X rate and none of the controls were deemed economically reasonable for evaluation.

The first additional controls modeling scenario contained the selection of controls in line with the control technologies and emissions rates of similar EGUs which were subject to the BART requirements. The SO_2 controls selected in the first modeling evaluation included a reduction of approximately 5,800 tons from the baseline emissions. Unit 1 and Unit 2 would each experience roughly 2,900 tons of reductions. The 2,900 tons of reductions for each unit could be accomplished by increasing the stoichiometric ratio (Ca:S) on the existing flue gas desulfurization unit. These upgrades come at a capital cost of approximately $10 million, annualized cost of approximately $2 million, and the cost per ton of SO_2 reduced is approximately $700. Also included in the first scenario modeling were reductions from Coyote Station, see Section 5.2.1.

No controls were selected for the second additional controls modeling scenario for AVS since the Department did not consider any remaining control options to be economically reasonable for evaluation.

The results for the visibility modeling evaluation of the 2028 first potential additional controls scenarios are addressed in Section 6.1.1. The first scenario resulted in a projected improvement of 0.08 deciviews at TRNP and 0.1 deciviews at LWA on the IMRPOVE MIDs. Again, the first scenario also includes reductions form Coyote Station (Section 5.2.1). The visibility improvements modeled for the first scenario are not considered significant since the improvements are smaller than what is perceptible by an unaided human eye.

Since the modeling has indicated no expected significant change in visibility (Section 6.1.1) and TRNP and LWA are projected to achieve the adjusted uniform rate of progress required by 2028 (Section 3.2.7), the Department does not believe additional SO_2 controls at AVS should be required during this planning period. The Department will re-evaluate this decision during the 2025 progress report.

5.2.3 Basin Electric Power Cooperative – Leland Olds Station

Basin Electric Power Cooperative – Leland Olds Station (LOS) is a two-unit electrical generating station. Unit 1 and Unit 2 both primarily fire lignite with a small amount of subbituminous coal combusted. Unit 1 began commercial operation in 1966 and is a Babcock & Wilcox opposed wall-fired boiler that has the capacity to produce approximately 216 Megawatts (MW) per hour of electricity. Unit 2 began commercial operation in 1975 and is a Babcock & Wilcox cyclone-fired boiler that has the capacity to produce approximately 440 MW per hour of electricity. LOS is located on the banks of the Missouri River in eastern Mercer County, approximately four miles southeast of the town of Stanton, North Dakota. LOS receives lignite from the Coteau Properties Freedom Mine, which is located approximately thirty miles west of LOS.

As documented in Table 35, LOS Unit 1 has a Q/d of 42 and LOS Unit 2 has a Q/d of 63. Therefore, the Department sent a letter to Basin on May 2, 2018 requesting a four factors analysis for LOS.[72] The letter required that Basin's four factors analysis be submitted to the Department on or before January 31, 2019. Basin's original four-factor analysis was submitted to the Department on January 31, 2019.[73] The Department provided comments to Basin regarding Basin's four-factor analysis on April 15 and April 22, 2019.[74] Basin submitted a response to the Department's comments on July 26, 2019.[75] On November 20, 2019, Basin submitted an update to the steam cost that was used to develop the operating costs for the technically feasible NO_X reduction technologies.[76] A copy of each submittal by LOS can be found in Appendix B.3.b of this SIP. The Department summary analysis of LOS's four factors analysis can be found in Appendix A.3 of this SIP. Based on the information reviewed, future operations and emissions profiles are expected to remain consistent with current conditions.

During the first round of regional haze, the Department determined that BART for LOS Unit 1 and Unit 2 included new wet limestone flue gas desulfurization (WFGD) for SO_2 control and selective non-catalytic reduction (SNCR) and separated overfire (SOFA) air for NO_X control.[77] Review of the four-factor analysis confirmed that these BART controls operate effectively. Therefore, no additional measures were selected for the modeling evaluation and the Department does not believe additional controls are warranted during this planning period. The Department will re-evaluate this decision during the 2025 progress report.

5.2.4 Coal Creek Station

Note: The regional haze analysis for Coal Creek Station has been separated into two sections due to the unresolved BART approval from the first round. Section 8 contains a NO_X BART determination relating to the unresolved NO_X BART approval and also serves as a reasonable progress determination for round 2. This section contains a reasonable progress analysis for additional SO_2 measures for round 2 of the RHR. This section also contains the emissions information specific to current and future expected operations which were utilized in the modeling evaluations for Round 2 planning.

Coal Creek Station (CCS) is a two-unit, approximately 1,200 gross MW mine-mouth power plant consisting primarily of two steam generators and associated coal and ash handling systems. Unit 1 and Unit 2 are identical Combustion Engineering boilers firing pulverized lignite coal tangentially. Unit 1 has a heat input capacity of 6,015 MMBtu per hr. Unit 2 has a heat input capacity of 6,022 MMBtu per hr. Unit 1 began commercial operation in 1979. Unit 2 began commercial operation in 1980. The facility is located in south central McLean County about five miles south of the town of Underwood, North Dakota and three miles west of US Highway 83. CCS receives lignite coal from the Falkirk Mine that is operated by the Falkirk Mining Company, a subsidiary of the North American Coal Corporation.

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[72] Appendix B.3.a.

[73] Appendix B.3.b.

[74] Appendix B.3.c.

[75] Appendix B.3.c.

[76] Appendix B.3.b., PDF page 504.

[77] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, Appendix B.4.

As documented in Table 35, Coal Creek Unit 1 has a Q/d of 75 and Coal Creek Unit 2 has a Q/d of 63. Therefore, the Department sent a letter to Great River Energy on May 2, 2018 requesting a four factors analysis for Coal Creek Station.[78] The letter required that Great River Energy's four factors analysis be submitted to the Department on or before January 31, 2019. The Department emailed Great River Energy on December 18, 2018 to inform Great River Energy that they should focus on completing an updated BART analysis for the first round of Regional Haze planning.[79] On September 12, 2019, Great River Energy submitted an updated BART analysis associated with the first round of Regional Haze planning.[80]

5.2.4.1 CCS SO_2 Emissions

After submission of the updated NOx BART analysis (Section 8), CCS completed a four-factor analysis for round 2 planning. CCS submitted their four factor analysis for the second round of Regional Haze planning on December 23, 2019.[81] SO_2 and NOx were addressed in the four-factor submittal. The Department summary analysis of CCS's four factors analysis for SO_2 can be found in Appendix A.4 of this SIP. Based on the information reviewed, future operations and SO_2 emissions profiles are expected to remain consistent with current conditions.

As outlined in the four-factor submittal and at Great River Energy's request, the Department evaluated lower allowable operating limits (near a rate of 0.10 lb SO_2 per MMBtu). This resulted in the Department including 700 tons of SO_2 reductions in the modeling evaluation for 2028. Due to the anticipated change in ownership the improvements are no longer being considered with this SIP revision. These potential improvements were voluntary and are not necessary since the Departments believes the existing level of SO_2 controls operate effectively. Review of the four-factor analysis confirms this position.

5.2.4.2 CCS Emissions for WRAP Modeling for Round 2 Planning

CCS completed installation of additional low-NOx combustion controls on Unit 1 in 2020. These controls result in an anticipated reduction of approximately 1,000 tons of NO_X per year, details provided in Section 8. These controls were not included in the 2028OTB projected emissions as the Department was not aware of this project when the 2028OTB emissions modeling data was submitted to WRAP. However, the 1,000 tons NO_X per year reduction was included in the 2028PAC modeling since these controls will continue to operate in the future. Additionally, through operational improvements on the existing WFGD, Great River Energy anticipated they could reduce approximately 700 tons per year of SO_2. The 700 tons SO_2 per year reduction was included in the 2028PAC. For a description of the emissions inventory data and emissions nomenclature, see Section 4.

5.2.5 Minnkota – Milton R. Young Station

Minnkota Power Cooperative, Inc. – Milton R. Young Station (MRYS) is a two-unit electrical generating station. Unit 1 and Unit 2 are both Babcock & Wilcox cyclone-fired boilers fired on lignite coal. Unit 1 commenced commercial operation in 1970. Unit 1 has a turbine-generator nameplate rating of 257 megawatts (MW) and a nominal rated heat input capacity of 3,200 MMBtu per hour. Unit 2 commenced

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[78] Appendix B.4.a., PDF page 573.

[79] Appendix B.4.c., PDF page 1082.

[80] Appendix B.4.b., PDF page 576.

[81] Appendix B.4.b., PDF page 1038

commercial operation in 1977. Unit 2 has a turbine-generator nameplate rating of 477 MW and a nominal rated heat input capacity of 6,300 MMBtu per hour. MRYS is located approximately five miles southeast of the town of Center, North Dakota. MRYS receives lignite from BNI Coal, Ltd's Center Mine, which is located adjacent to the facility.

As documented in Table 35, MRYS Unit 1 has a Q/d of 24 and MRYS Unit 2 has a Q/d of 43. Therefore, the Department sent a letter to Minnkota Power Cooperative, Inc. (Minnkota) on May 2, 2018 requesting a four factors analysis for MRYS.[82] The letter required that Minnkota's four factors analysis be submitted to the Department on or before January 31, 2019. Minnkota's original four-factor analysis was submitted to the Department on January 31, 2019.[83] The Department provided comments to Minnkota regarding their four-factor analysis on March 18, 2019.[84] Minnkota submitted a response to the Department's comments, along with a revised four-factor analysis, on May 29, 2019.[85] A copy of each submittal by MRYS can be found in Appendix B.5.b of this SIP. The Department summary analysis of MRYS's four factors analysis can be found in Appendix A.5 of this SIP. Based on the information reviewed, future operations and emissions profiles are expected to remain consistent with current conditions.

MRYS Unit 1 and Unit 2 are equipped with Advanced Separated Over Fire Air (ASOFA) and SNCR for NO_X control. These were the BART controls selected in the first round of the Regional Haze program.[86] On April 24, 2006 Minnkota entered into a Consent Decree that required MRYS to install BACT for NO_x, which was determined to be SNCR along with the already installed ASOFA.[87,88] MRYS Unit 1 is equipped with WFGD for SO_2 control. Unit 1 WFGD control technology was installed in 2011 as a result of the BART determination made in the first round of the Regional Haze program.[89] MRYS Unit 2 is also equipped with WFGD for SO_2 control. Unit 2 WFGD control technology was installed prior to the first round of the Regional Haze program. Review of the four-factor analysis confirmed that these BART controls operate effectively, and the Department has no reason to believe effective operation of the BART controls will change in the future. Therefore, no additional controls were selected for the modeling evaluation and the Department does not believe additional controls are warranted during this planning period. The Department will re-evaluate the adequacy of this decision during the 2025 progress report.

5.2.6 Montana Dakota Utilities – Heskett Station

Montana Dakota Utilities – Heskett Station (Heskett) is a two-unit electrical generating station. Unit 1 is a 25 MW Riley Stoker boiler fired on lignite coal. Unit 1 went online in 1954 and has a rated heat input

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[82] Appendix B.5.a.

[83] Appendix B.5.b.

[84] Appendix B.5.c.

[85] Appendix. B.5.b.

[86] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 74.

[87] Available at: https://www.epa.gov/enforcement/minnkota-power-cooperative-and-square-butte-electric-cooperative-settlement (Last visited December 28, 2020)

[88] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, Appendix B.4, p.16-19.

[89] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 71.

of 387 MMBtu per hour. Unit 2 is a 75 MW Babcock & Wilcox atmospheric fluidized bed boiler fired on lignite coal. Unit 2 went online in 1963 and has a rated heat input of 917 MMBtu per hour. Heskett is located in Mandan, North Dakota and receives lignite from the Dakota Westmoreland Mine south of Beulah, North Dakota.

As documented in Table 35, Heskett Unit 1 has a Q/d of 7 and Heskett Unit 2 has a Q/d of 16. Since the facility has a Q/d greater than 10, the Department sent a letter to Montana Dakota Utilities (MDU) on May 2, 2018 requesting a four factors analysis for Heskett.[90] The letter required that MDU's four factors analysis be submitted to the Department on or before January 31, 2019. MDU submitted their four factors analysis to the Department on January 31, 2019.[91]

On February 19, 2019, MDU submitted an official notification to the Department that MDU plans to retire Unit 1 and Unit 2 at Heskett around the end of 2021.[92] MDU plans to replace Unit 1 and Unit 2 with a new natural gas unit in early 2023. A detailed analysis of Heskett's four factors analysis was not needed due to the impending shutdown of the Unit 1 and Unit 2 at Heskett. A copy of the submittal by Heskett can be found in Appendix B.6.b of this SIP. For information and in lieu of a four factor summary analysis, a copy of the permit to construct issued for the new gas unit can be found in Appendix A.6. The permit to construct, APC-17983v1.0, requires the coal plant equipment to be removed or permanently decommissioned prior to commencement of the new gas turbine.

The Department included the emissions reductions from Heskett in this proposed SIP as a result of the upcoming retirements of Unit 1 and Unit 2. The shutdown of Unit 1 and Unit 2 will result in approximately 2,000 tons of SO_2 reductions and 900 tons of NO_X reductions and were included in the 2028 inventory projection.

5.2.7 Petro-Hunt, L.L.C. – Little Knife Gas Plant

Petro-Hunt, L.L.C. – Little Knife Gas Plant (LKGP) is comprised of numerous fuel gas combustion units, process equipment, tankage, flares, and a sulfur recovery process controlled by an incinerator. The major emissions source onsite is the 2-stage 2-bed Cold Bed Absorption (CBA) sulfur recovery unit (SRU) tail gas incinerator. The LKGP is located approximately 18 miles southwest of Killdeer, North Dakota in Billings County.

As documented in Table 35, the LKGP has a Q/d of 12. Therefore, the Department sent a letter to Petro-Hunt, L.L.C. (Petro-Hunt) on May 2, 2018 requesting a four factors analysis for the LKGP.[93] The letter required that Petro-Hunt's four factors analysis be submitted to the Department on or before January 31, 2019. Petro-Hunt submitted a response to the Department's request on November 29, 2018.[94] The Department responded to Petro-Hunt's submittal on December 5, 2018 indicating that Petro-Hunt's submittal did not adequately address the requirements of the Regional Haze program.[95] Petro-Hunt

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[90] Appendix B.6.a.
[91] Appendix B.6.b.
[92] Appendix B.6.c.
[93] Appendix B.7.a.
[94] Appendix B.7.c.
[95] Appendix B.7.c.

submitted their four factors analysis to the Department on January 25, 2019.[96] A copy of each submittal by LKGP can be found in Appendix B.7.b of this SIP. The Department summary analysis of LKGP's four factors analysis can be found in Appendix A.7 of this SIP. Based on the information reviewed, future operations and emissions profiles are expected to remain consistent with current conditions.

For SO_2 control, LKGP operates a sulfur recovery unit (SRU) consisting of a two-stage Claus unit with cold bed absorption. The SRU recovers approximately 94% of the sulfur entering the unit. SO_2 emissions are the only significant pollutant emitted from the facility. Therefore, NO_X controls were not evaluated for this source.

Based on the Department's review of the four-factor analysis and LKGP having effective controls already in place, no additional controls for LKGP were selected to include in the first or second additional controls modeling scenario. Additionally, the magnitude of remaining SO_2 reductions available from this source is minimal when compared to a typical North Dakota coal fired EGU. Petro hunt's SO_2 baseline is approximately 300 tons and the average of a single unit for North Dakota coal fired EGUs is over 4,000 tons.[97] The Department will re-evaluate the adequacy of this decision during the 2025 progress report.

5.2.8 Hess Tioga Gas Plant, LLC – Tioga Gas Plant

Hess Tioga Gas Plant, LLC – Hess Tioga Gas Plant (TGP) is comprised of numerous boilers, heaters, compressor engines, turbines, storage tanks, process equipment, flares, and a sulfur recovery process controlled by an incinerator. Most of the emissions are sourced from the compressor engines and the amine gas sweetening unit (the SRU tail gas incinerator). Tioga is located just to the east of Tioga, North Dakota in Williams County.

As documented in Table 35, Tioga has a Q/d of 55. Therefore, the Department sent a letter to Hess Corporation (Hess) on May 18, 2018 requesting a four factors analysis for TGP.[98] The letter required that Hess's four factors analysis be submitted to the Department on or before January 31, 2019. Hess's original four-factor analysis was submitted to the Department on December 20, 2018.[99] The Department provided comments to Hess regarding their four-factor analysis on January 16, 2019.[100] Hess submitted a revised four factors analysis on March 13, 2019.[101] A copy of each submittal by TGP can be found in Appendix B.8.b of this SIP. The Department summary analysis of TGP's four factors analysis can be found in Appendix A.8 of this SIP.

TGP operates a sulfur recovery unit (SRU) consisting of a two-stage Claus unit with cold bed absorption for SO_2 controls. The SRU recovers approximately 96% of the sulfur entering the unit. TGP has not recently installed any significant NO_X controls at the facility. The most significant source of NO_X emissions (91%) come from the operation of 1950's era compressor engines. Controls were evaluated for these engines but were determined to be not necessary for installation during this planning period

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[96] Appendix B.7.b.

[97] Representative emissions from Coyote, AVS, LOS, Coal Creek, and MRYS on a per unit basis.

[98] Appendix B.8.a.

[99] Appendix B.8.b.

[100] Appendix B.8.c.

[101] Appendix B.8.b.

due to cost and limited expected reduction in mass-based emissions. Hess TGP also anticipates the Clark engine utilization will become less and less over time and will slowly switch from the current gas-fired units to electric driven compression.[102] This will inherently reduce NO_X emissions over time without a mandatory requirement from the Department. As of the writing of this SIP Revision, the Department is working with Hess TGP to replace the 1950's era compressor engines with new state of the art compressor engines. This project will significantly reduce NO_X emissions from the facility, but these reductions will occur for purposes outside of the RHR since the facility is not a significant contributor to visibility impairment.

For regional haze purposes, based on the Department's review of the four-factor analysis and TGP having effective controls already in place, no additional controls for the TGP were selected to include in the first or second additional controls modeling scenario. Additionally, the magnitude of SO_2 and NO_X reductions available from this source is minimal when compared to a typical North Dakota coal fired EGU. TGP's SRU SO_2 baseline is approximately 700 tons and the average of a single unit at a North Dakota coal fired EGU is over 4,000 tons.[103] TGP's NO_X baseline from the non-modified Clark engines is approximately 180 tons per engine and the average of a single unit at a North Dakota coal fired EGU is over 3,500 tons.[104] The Department will re-evaluate the adequacy of this decision during the 2025 progress report.

5.2.9 Northern Border Compressor Station No. 4

Northern Border Pipeline Company – Compressor Station No. 4 (CS4) is a compressor station with the majority of emissions being sourced from a 20,000 horsepower simple cycle natural gas-fired combustion turbine (Unit CE1), which drives a natural gas compressor. The turbine is a Cooper-Rolls Model Coberra 2648S Avon. CS4 is located approximately nine miles west of Watford City, North Dakota in McKenzie County.

As documented in Table 35, Northern Border Pipeline Company (Northern Border) Unit CE1 has a Q/d of 9. Although Northern Border's CS4 had a Q/d below the threshold of 10, the Department sent a letter to Norther Border requesting a four factors analysis for CS4 since CS4's Q/d was sufficiently close to the Q/d threshold and CS4 is located only 18 km from the nearest CIA. Therefore, the Department sent a letter to Northern Border on May 2, 2018 requesting a four factors analysis for CS4.[105] The letter required that Northern Border's four factors analysis be submitted to the Department on or before January 31, 2019. Northern Border's original four factors analysis was submitted to the Department on December 10, 2018.[106] The Department provided comments to Northern Border regarding Northern Border's four factors analysis on December 28, 2018.[107] Northern Border submitted a response to the Department's comments on March 1, 2019.[108] A copy of each submittal by CS4 can be found in Appendix

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[102] Appendix B.8.b., Appendix B 2

[103] Representative emissions from Coyote, AVS, LOS, Coal Creek, and MRYS on a per unit basis.

[104] Representative emissions from Coyote, AVS, LOS, Coal Creek, and MRYS on a per unit basis.

[105] Appendix B.9.a.

[106] Appendix B.9.b.

[107] Appendix B.9.c.

[108] Appendix B.9.b. and Appendix B.9.c.

B.9.b of this SIP. The Department summary analysis of CS4's four factors analysis can be found in Appendix A.9 of this SIP. Based on the information reviewed, future operations and emissions profiles are expected to remain consistent with current conditions.

CS4 has not recently installed any significant NO_X controls at the facility. The NO_X emissions come from the operation of a 20,000 horsepower simple cycle natural gas-fired combustion turbine. Controls were evaluated for this turbine but were determined to be not necessary for installation during this planning period due to excessive cost and limited expected reduction in mass-based emissions. With the limited mass-based emissions, it is reasonable to assume the facility is a small contributor to visibility impairment and any additional controls will have an insignificant impact improving visibility.

Based on the Department's review of the four-factor analysis, no additional controls for CS4 were selected to include in the first or second additional controls modeling scenario. Additionally, the magnitude NO_X reductions available from this source is minimal when compared to a typical North Dakota coal fired EGU. CS4's NO_X baseline from the turbine is approximately 130 tons and the average of a single unit at a North Dakota coal fired EGU is over 3,500 tons.[109] The Department will re-evaluate the adequacy of this decision during the 2025 progress report.

5.2.10 Dakota Gasification Company – Great Plains Synfuels Plant

Dakota Gasification Company (DGC) – Great Plains Synfuels Plant (GPSP) is owned and operated by Basin Electric Power Cooperative (Basin). DGC is a for-profit subsidiary of Basin and produces synthetic natural gas, fertilizers, and other byproducts resulting from the gasification of lignite coal. GPSP also captures carbon dioxide, which is transported via pipeline to oil fields in Saskatchewan Canada. The GPSP is the only facility of its kind in the United States. The GPSP commenced operation in 1984. The GPSP consists of many emissions units and emissions points. The significant sources of NO_X and SO_2 emissions include:

- Three Riley boilers each rated at 763 MMBtu per hour
- Two superheaters each rated at 169 MMBtu per hour
- One package boiler rated at 318 MMbtu per hour
- The main flare and the start-up flare

The DGC GPSP is located approximately six miles northwest of the town of Beulah, North Dakota in Mercer County. The GPSP receives lignite coal from the Coteau Properties Freedom Mine located approximately two miles north of the GPSP. Coal which is too fine for gasification is sent back to the Antelope Valley Station (AVS) electrical generating utility (EGU).

As is documented in Table 35, the DGC GPSP has a Q/d of 61. Therefore, the Department sent a letter to DGC on May 2, 2018 requesting a four factors analysis for the GPSP.[110] The letter required that DGC's four factors analysis be submitted to the Department on or before January 31, 2019. DGC's four factors analysis was submitted to the Department on January 31, 2019.[111] A copy of the submittal by DGC can be found in Appendix B.5.b of this SIP. The Department summary analysis of DGC's four factors analysis

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[109] Representative emissions from Coyote, AVS, LOS, Coal Creek, and MRYS on a per unit basis.
[110] Appendix B.10.a.
[111] Appendix B.10.b.

can be found in Appendix A.10 of this SIP. Based on the information reviewed, future operations and emissions profiles are expected to remain consistent with current conditions.

Based on the Department's review of the four-factor analysis, no additional controls for DGC GPSP were selected to include in the first or second additional controls modeling scenario. For SO_2 control, GPSP operates a WFGD unit to control emissions from the main stack. The WFGD unit removes approximately 97% of the SO_2 from the flue gas stream. GPSP has not recently installed any SO_2 controls or made any significant modification to the WFGD unit. GPSP has not installed any add-on NO_X controls at the facility. The most significant source of NO_X emissions (94%) comes from the main stack. The main stack receives flue gas from Riley boilers and superheaters. NO_X controls were evaluated for the Riley boilers and superheaters, none were determined to be technically feasible during this planning period. The Department will re-evaluate the adequacy of this decision during the 2025 progress report.

DGC GPSP is currently evaluating the viability of discontinuing the coal gasification process and replacing it with a primary natural gas reformer for economic reasons. DGC GPSP incurred net losses of $70.5 million in 2019 and has recorded a loss of $89.5 million in the first nine months of 2020.[112] Eliminating the coal gasification process would significantly lower the NO_X and SO_2 emissions from this facility, as the gasification process provides much of the fuel consumed in the Riley boilers and the combustion of these fuels results in a significant portion of the baseline emissions.

5.2.11 North Dakota Upstream Oil and Gas Development (Area Sources)

In addition to the point sources reviewed in Table 35, the Department considered the impacts to visibility from the upstream oil and gas development in North Dakota. Much of North Dakota's oil and gas production occurs in the western third of the state, which is the same geographical area of both of North Dakota CIAs.

A Q/D type analysis does not work well for oil exploration or production facilities. Unlike point sources which can have large emissions from a single stack, upstream oil and gas consists of many small sources. These individual facilities generally have very low SO_2 and NO_X emissions, making an individual facility four factor analysis unnecessary. However, when all facilities' emissions are aggregated (entire source group), they become significant enough to warrant evaluation of the source group. The Q/D analysis in Section 5.1.2 includes the larger compressor stations and natural gas processing plants (sources subject to Title V). North Dakota also permits minor oil and gas sources including small compressor stations (greater than 500 hp), natural gas processing plants, and tank batteries. The Q/D analysis indicates that only the larger facilities (i.e. larger Title V sources) have a potential impact on visibility in North Dakota CIAs. SO_2 emissions from future oil and gas activities are not a concern because most new oil and gas production is from the Bakken formation which contains sweet oil and gas with very low sulfur content. In addition, all future engines are required by Federal rule to use ultra-low sulfur gasoline and diesel fuel (Section 5.3.1.2). Therefore, NO_X emissions are the primary concern. NO_X emissions occur from vehicles, drilling rig engines, glycol dehydrators, flares, compressor engines, and other combustion sources.

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[112] Available at: https://www.basinelectric.com/about-us/annual-meeting/financial-report (Last visited January 4, 2021)

Stationary engines are subject to several New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards which help limit NO_X emissions. Emissions from upstream oil and gas activity are included in Section 4.3.1. These emissions were developed by the WRAP Oil and Gas Workgroup with input from the Department.[113]

Following the emissions inventory work, the WRAP Oil and Gas Workgroup developed a memorandum providing information on potential additional controls strategies for oil and gas emission sources.[114] The analysis focused on stationary oil and gas emission sources (e.g. lift engines and flares) and did not include mobile sources (e.g. drill rigs or hydraulic fracturing engines). The Department does not have regulatory authority over mobile sources, therefore, these sources were not considered in developing this SIP revision. Drill rigs and hydraulic fracturing engines account for 28% (~16,000 of ~57,500 tons) of the total upstream NO_X emissions. Sources within the states control, such as, well site engines, wellsite heaters and boilers, and flaring accounts for the remaining 72% of nonpoint NO_X emissions. Wellsite engines, flaring, and wellsite heaters account for 50%, 19%, and 3% of the NO_X emissions, respectively.[115] Wellsite engines and flaring are addressed in the Sections 5.2.11.1 and 5.2.11.2, due to the small emissions from wellsite heaters, these will not be evaluated during this planning period.

5.2.11.1 Wellsite Engines

Wellsite engines are used to extract oil and gas from the well. North Dakota has roughly 15,000 active operating wells. These 15,000 wells have a projected emissions of 29,000 tons of NO_X. Averaged across the total wellsite's in North Dakota, this is less than 2 tons of NOx per well. The Department determined that individual engine controls are not reasonable during this planning period. This determination was based on the limited emissions footprint from any single wellsite and relatively small contribution to visibility impairment from this sector.

5.2.11.2 Associated Gas Flaring

Flaring in North Dakota happens in two ways, high and low pressure. High pressure flaring contributes significantly more to total flared volume. High pressure flaring primarily occurs when there is no infrastructure (e.g. pipeline) available to transport the gas produced offsite or when the infrastructure available is at capacity. Low pressure flaring occurs when oil stored onsite releases light hydrocarbons which are routed to a flare. The Department believes the most practical and effective way to reduce visibility impairing emissions from this sector is by reducing the volume of high pressure gas flared at the wells. Reducing the volume of high pressure gas flared is accomplished by the continued development of the infrastructure needed to handle the gas production associated with oil well development. Pipelines, compressor stations, and gas plants are continuing the be constructed and expanded in effort to reduce the flared gas amounts. North Dakota Industrial Commission Order 24665 sets policy goals to increase the volume of captured gas and reduce the percentage of flared gas. The order also

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[113] Additional details available at: https://www.wrapair2.org/ogwg.aspx (Last visited December 28, 2020)

[114] Available at: https://www.wrapair2.org/pdf/WRAP_OGWG_ARCS_Memo_23Mar2020.pdf (Last visited June 14, 2021)

[115] Available at: https://www.wrapair2.org/pdf/WRAP_OGWG_ARCS_Memo_23Mar2020.pdf (last visited June 14, 2021)

incentivizes the investment in gas capture infrastructure.[116] A capture goal of 91% beginning in November 1, 2020 is a stated goal of the policy. As of October 2020, a 93% gas capture rate was achieved statewide.[117] Continuing to meet the capture goals set by the policy will be beneficial to reducing the visibility impact these sources have on North Dakota CIAs.

A breakdown of the amount of gas produced, sold, flared, and the percent of gas flared is displayed in Figure 42. This information is updated through December 2020. The average monthly flared percent in 2020 was 10%, with September, October, and November each below 8%. Followed by December achieving the lowest percent of flared gas at 6.4% since significant development of the Bakken formation.[118]

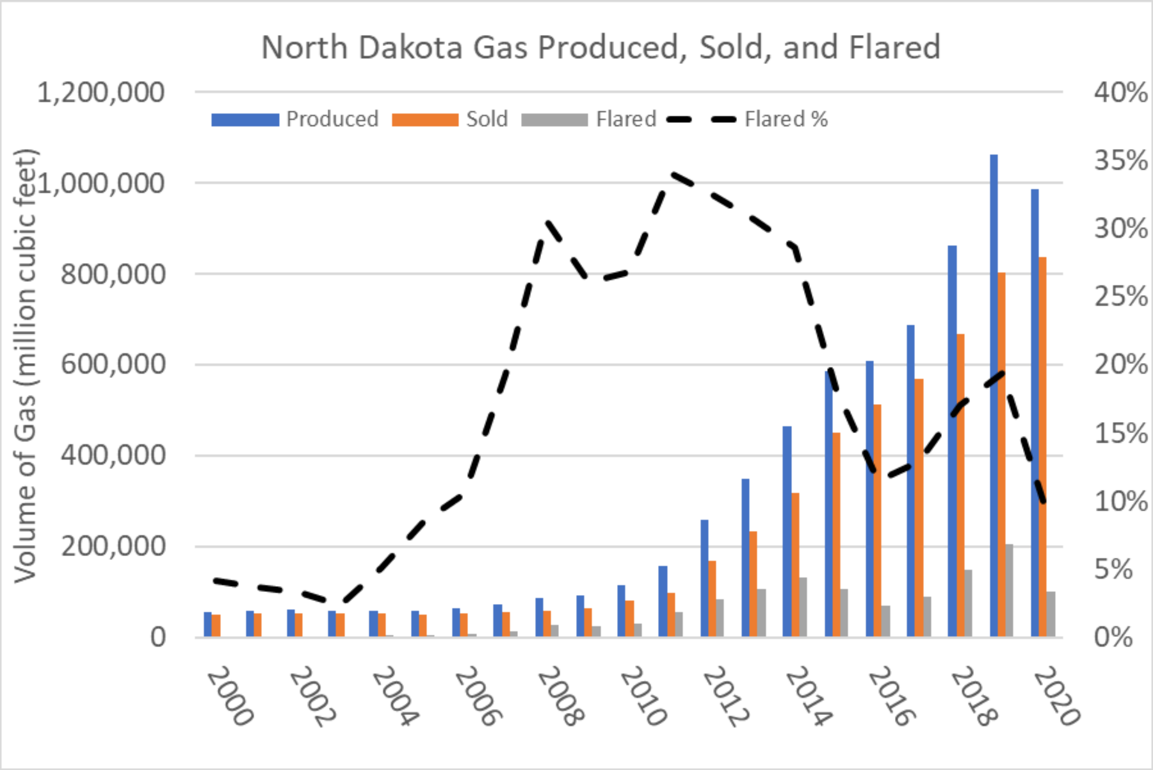

Figure 42: Volume of Gas Produced, Sold, Flared, and Flared Percent from 2000–2020.

5.2.11.3 Upstream Oil and Gas Conclusion

Collectively, emissions from wellsite engines in North Dakota are the largest source of NO_X emission from upstream oil and gas development. Individually, emissions from any one wellsite engine are minor,

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[116] Available at: https://www.dmr.nd.gov/oilgas/112018GuidancePolicyNorthDakotaIndustrialCommissionorder24665_2.pdf (Last visited December 28, 2020)

[117] Available at: https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2020-12-14.pdf (Last visited December 28, 2020)

[118] Available at: https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2021-02-12.pdf (Last visited February 23, 2021)

making any single sites contribution to visibility impairment insignificant. North Dakota oil producers are currently meeting the gas capture goals put in place by the North Dakota Industrial Commission. With increased infrastructure being continually developed in North Dakota, it is reasonable to expect this trend to continue. Finally, North Dakota is currently making progress to improve visibility, and this is expected to continue through this planning period. For these reasons, the Department does not believe it is reasonable to implement additional controls on sources in this sector during this planning period.

The Department will continue to monitor the development of the Bakken Formation and the impacts to North Dakota's CIA visibility progression and provide an update in the 2025 progress report.

5.3 §51.308(f)(2)(iv) - Additional Factors in Development of Long-Term Strategy

40 CFR 51.308(f) details that five additional factors must be considered and described within the periodic comprehensive revisions of state implementation plans for regional haze in terms of development of the long-term strategy:

(A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
(B) Measures to mitigate the impacts of construction activities;
(C) Source retirement and replacement schedules;
(D) Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs; and
(E) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

These five additional factors are discussed in Sections 5.3.1 through 5.3.5.

5.3.1 §51.308(f)(2)(iv)(A) - Emission Reductions Due to Ongoing Air Pollution Control Programs

Air pollution control programs that assist in reducing emissions and help to achieve reasonable progress toward the national visibility goal include state and federal programs, which are both detailed below. In addition, NDDEQ takes enforcement actions against entities found to be in violation of the air pollution control program requirements. Enforcement actions taken by NDDEQ since 2000 are displayed in Figure 43.

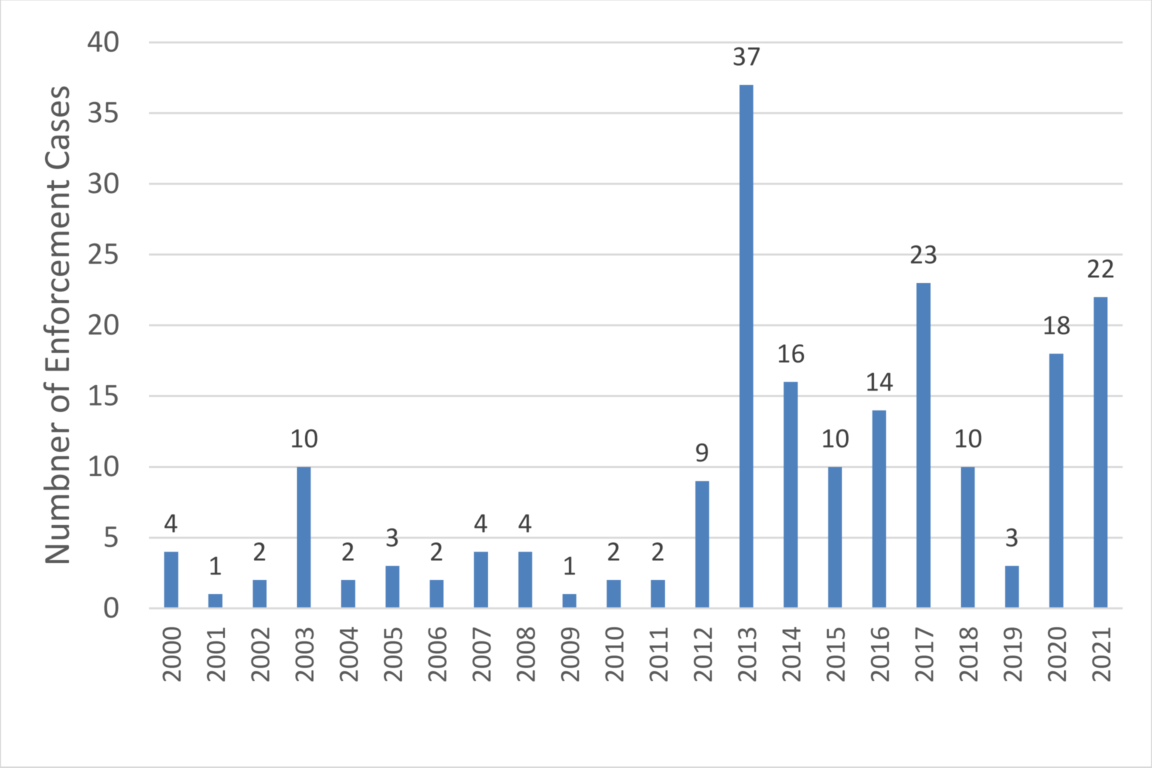

Figure 43: NDDEQ Air Quality Enforcement Actions from 2000 through June 30, 2021.

Figure 43 shows that NDDEQ has increased the number of enforcement cases since the year 2000, with a more notable uptick starting in 2012. Many of these enforcement actions since 2012 were directed toward the oil and gas development in North Dakota.

It should be noted that unless specifically stated in the text, all reference to enforcements, existing rules or emission control programs are intended only to provide information about various aspects of the program described and are neither being submitted to EPA for approval nor being incorporated into the SIP as Federally enforceable measures if they have not previously been incorporated.

This SIP is North Dakota's comprehensive visibility plan. It addresses all aspects of North Dakota's visibility improvement program.

This SIP Revision documents those programs, rules, processes, and controls deemed appropriate as measures needed to reduce regional haze and protect visibility in North Dakota in order to meet the RPGs established in the RHR and the CAA.

5.3.1.1 State Regulations from the North Dakota Administrative Code (NDAC)

North Dakota has state emission control programs and rules that focus on the protection of visibility. In addition, North Dakota has state emission control programs and rules that were not specifically written to address visibility impairment but still work to improve and protect visibility in CIAs by controlling the emissions of pollutants that cause or contribute to visibility impairment. Both programs that specifically address visibility impairment and programs not specific to visibility impairment that still improve visibility are detailed in Sections 5.3.1.1.1 through 5.3.1.1.17.

5.3.1.1.1 NDAC 33.1-15-02: Ambient Air quality Standards

Chapter 33.1-15-02 aims to maintain the current quality of the air within the boundaries of North Dakota.[119] Specific to the protection of visibility, Section 33.1-15-02-03 states in part:

> *"In keeping with the purpose of these ambient air quality standards, the quality should be such that:*
>
> *4. Visibility will be protected.*
>
> *7. Natural scenery will not be obscured."*

5.3.1.1.2 NDAC 33.1-15-03: Restriction of Emission of Visible Air Contaminants

Chapter 33.1-15-03 restricts the degree of opacity that can be discharged into the ambient air from both new and existing installations.[120] The restriction of opacity, or visible emissions, has a direct impact on visibility.

5.3.1.1.3 NDAC 33.1-15-04: Open Burning Restrictions

Chapter 33.1-15-04 aims to maintain air quality by restricting the types of material that may be burned in North Dakota.[121] Section 33.1-15-04-02 states in part:

> *"2. The following conditions apply to all types of permissible burning listed in subsection 1.*
>
> *h. Except in an emergency, burning may not be conducted in such proximity of any Class I area, as defined in chapter 33.1-15-15, that the ambient air of such area is adversely impacted.*
>
> *i. Except in an emergency, the visibility of any Class I area cannot be adversely impacted as defined in chapter 33.1-15-19."*

5.3.1.1.4 NDAC 33.1-15-05: Particulate Matter Restricted

Chapter 33.1-15-05 aims to maintain air quality through the restriction of particulate matter.[122] Particulate matter has a direct impact on visibility impairment. Therefore, Chapter 33.1-15-05 has a direct impact on maintaining visibility in North Dakota.

5.3.1.1.5 NDAC 33.1-15-06: Emissions of Sulfur Compounds Restricted

Chapter 33.1-15-06 aims to maintain air quality through the restriction of sulfur compounds.[123] SO_2 and other sulfur oxides can react with other compounds in the atmosphere to form fine particles that impair visibility. Therefore, Chapter 33.1-15-06 has a direct impact on maintaining visibility in North Dakota.

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[119] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-02.pdf?20150602082326

[120] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-03.pdf?20150202141005

[121] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-04.pdf?20150202141022

[122] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-05.pdf?20150202141044

[123] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-06.pdf?20150202141137

5.3.1.1.6 NDAC 33.1-15-07: Control of Organic Compounds Emissions

Chapter 33.1-15-07 aims to maintain air quality through the control of organic compounds.[124] Volatile organic compounds (VOCs) can react with nitrogen oxides to form smog, which reduces visibility. Therefore, Chapter 33.1-15-07 has a direct impact on maintaining visibility in North Dakota.

5.3.1.1.7 NDAC 33.1-15-08: Control of Air Pollution from Vehicles and Other Internal Combustion Engines

Chapter 33.1-15-08 aims to maintain air quality through the control of vehicles and other internal combustion engines.[125] Section 33.1-15-08-01 states:

> *"No person shall operate, or cause to be operated, any internal combustion engine which emits from any source any unreasonable and excessive smoke, obnoxious or noxious gases, fumes or vapor."*

The proper operation of internal combustion engines has a direct impact on maintaining visibility in North Dakota.

5.3.1.1.8 NDAC 33.1-15-12: Standards of Performance for New Stationary Sources

North Dakota has adopted many subparts and appendices of 40 CFR 60.[126] Many of these subparts require compliance with performance standards which inherently controls pollutants that contribute to visibility impairment. For example, any subpart which restricts the amount of NO_X, SO_2, VOC, or PM would also have a beneficial impact on reducing visibility impairment. The subparts adopted by North Dakota are contained within Chapter 33.1-15-12.

5.3.1.1.9 NDAC 33.1-15-13: Emission Standards for Hazardous Air Pollutants

North Dakota has adopted multiple subparts and appendices of 40 CFR 61.[127] All subparts and appendices adopted by North Dakota are contained within Chapter 33.1-15-13. The subparts adopted by North Dakota which require the control of pollutants that contribute to visibility impairment include:

- Subpart J – National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene
- Subpart V – National Emission Standard for Equipment Leaks (Fugitive Emission Sources)
- Subpart FF – National Emission Standard for Benzene Waste Operations

5.3.1.1.10 NDAC 33.1-15-14: Designated Air Contaminant Sources, Permit to Construct, Minor Source Permit to Operate, Title V Permit to Operate

North Dakota operates a permitting program that evaluates new construction projects for their impact on air quality.[128] Once a permit to construct is issued, a facility may be built. Once construction is completed, a facility inspection is performed to ensure construction was in line with the permit to

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[124] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-07.pdf?20150202141202
[125] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-08.pdf?20150202141225
[126] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-12.pdf?20150202141441
[127] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-13.pdf?20150202141536
[128] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-14.pdf?20150202141623

construct and then an appropriate permit to operate is issued. Non-Title V sources receive a Department issued minor source permit to operate after construction permit inspection. Title V sources must apply for a Title V permit within a year of completed construction and initial operation. The primary goal of the permitting program is to maintain compliance with both federal and state regulations. Although the primary goal of the permitting program is not to protect visibility, maintaining compliance with federal and state regulations inherently helps to protect visibility.

5.3.1.1.11 NDAC 33.1-15-15: Prevention of Significant Deterioration of Air Quality

Chapter 33.1-15-15 requires that a visibility analysis be prepared in accordance with Chapter 33.1-15-19 for any permit to construct that meets the requirements of the prevention of significant deterioration program.[129] Since one of the primary goals of the Prevention of Significant Deterioration (PSD) program is to preserve, protect, and enhance the air quality in national parks and national wilderness areas, Chapter 33.1-15-15 has a direct impact on maintaining visibility in North Dakota.

5.3.1.1.12 NDAC 33.1-15-17: Restriction of Fugitive Emissions

Chapter 33.1-15-17 restricts the release of fugitive emissions, which is inherently designed to maintain both air quality and visibility.[130] Section 33.1-15-17-02 states in part:

> *"No person shall emit or cause to be emitted into the ambient air from any source of fugitive emissions as specified in section 33.1-15-17-01 any particulate which:*
> 5. *Would have an adverse impact on visibility, as defined in chapter 33.1-15-19, on any class I federal area."*

5.3.1.1.13 NDAC 33.1-15-19: Visibility Protection

The federal visibility regulations (40 CFR 51, Subpart P) detail a two-phased process to determine existing impairment in each CIA, how to remedy such impairment, and how to establish goals to restore visibility to natural conditions by the year 2064 in each CIA. Phase 1 of the visibility regulations addresses impacts in CIAs by establishing a process to evaluate source specific visibility impacts, or plume blight, from individual sources or small groups of sources. Part of that process relates to the evaluation of sources prior to construction through the prevention of significant deterioration (PSD) permit program for major stationary sources (Chapter 33.1-15-15). The plume blight part of the Phase 1 program also allows for the evaluation, and possible control, of reasonably attributable visibility impairment (RAVI) from existing sources. The Phase 1 program addresses major source PSD permitting, source specific haze and plume blight aspects of visibility impairment. Chapter 33.1-15-19[131], in conjunction with Chapters 33.1-15-12, 33.1-15-14, and 33.1-15-15, make up North Dakota's SIP for Phase 1 of the visibility program, which was approved by the EPA and has an effective date of October 1, 1987. North Dakota's RAVI monitory strategy can be found in Section 6.6. The existing RAVI program, with the existing permitting and emissions rules listed in this section are compatible with those needed for regional haze and no revisions are needed or planned at this time.

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[129] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-15.pdf?20150202141650

[130] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-17.pdf?20150202142045

[131] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-19.pdf?20150202142145

5.3.1.1.14 NDAC 33.1-15-20: Control of Emissions from Oil and Gas Well Production Facilities

Chapter 33.1-15-20 includes requirements for the control of emissions from oil and gas well production facilities.[132] Most of the oil and gas production in North Dakota is contained within the western third of the state, which is also where North Dakota's CIAs are located. Therefore, emissions from oil and gas well production facilities in North Dakota may have an impact on visibility in North Dakota's CIAs. Although many of the oil and gas well production facilities in North Dakota do not emit significant amounts of pollution from any single source, the number of sources have increased over time (Section 5.2.11). NDAC Section 33.1-15-20-03 details the applicability and source information requirements of oil and gas well production facilities that may be subject to the prevention of significant deterioration:

> *"Any oil or gas well production facility that is a major stationary source or a major modification as defined in chapter 33.1-15-15, shall comply with the permitting requirements of chapter 33.1-15-15."*

5.3.1.1.15 NDAC 33.1-15-21: Acid Rain Program

Chapter 33.1-15-21 details North Dakota's plan to control the pollutants that lead to the production of acid rain.[133] Since the acid rain program was first developed at the federal level, details regarding the impact of this program are covered in Section 5.3.1.2.3.

5.3.1.1.16 NDAC 33.1-15-22: Emissions Standards for Hazardous Air Pollutants for Source Categories

North Dakota has adopted many subparts and appendices of 40 CFR 63. Many subparts and appendices require the control pollutants that directly or indirectly contribute to visibility impairment. The subparts adopted by North Dakota are contained within Chapter 33.1-15-22.[134]

5.3.1.1.17 NDAC 33.1-15-25: Regional Haze Requirements

Chapter 33.1-15-25 has an effective date of January 1, 2019[135] and implements the BART provisions of the federal RHR.[136] A revision was needed to address the reasonable progress requirements for round 2 and future planning periods. This amendment took effect on July 1, 2020.

5.3.1.2 Federal Programs

The EPA has several existing emission control programs and rules that do not specifically address visibility impairment. However, the programs control the emission of pollutants that cause or contribute to visibility impairment in North Dakota. Therefore, these programs have an impact on North Dakota's CIAs. These programs are described in the following sections.

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[132] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-20.pdf?20150202142208

[133] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-21.pdf?20150202142230

[134] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-22.pdf?20150202142330

[135] Original effective date was January 1, 2007. Date was revised upon transition from the Department of Environmental Health Section to the Department of Environmental Quality. See Footnote 8.

[136] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-25.pdf?20150202142452

5.3.1.2.1 Volkswagen Environmental Mitigation Trust

On October 25, 2016, a Partial Settlement and Consent Decree was finalized between the United States Department of Justice and the Volkswagen Corporation (VW) regarding the installation and use of emissions testing defeat devices in over 500,000 VW vehicles sold and operated in the United States beginning in 2009. These devices violated the federal Clean Air Act and increased air emissions of the pollutant nitrogen oxide (NO_X).

An environmental mitigation trust (trust) has been established as part of the consent decree to provide funds to the states to mitigate the negative air quality impacts of the violations. North Dakota's total share of the trust is $8.1 million. The trust establishes a process for states to receive the funds and develop environmental mitigation plans. The trust also identified the mitigation projects that are eligible for funding.

North Dakota has set up an application process to fund projects that reduce NO_X emissions. North Dakota recently finished the second round of funding for the VW Settlement funding program. Nine buses and five trucks were funded to be replaced by newer vehicles in the first round. Fifteen buses and ten trucks were funded to be replaced by newer vehicles in the second round. As a requirement of the trust, the older vehicle must be scrapped. North Dakota also funded the installation of electric vehicle charging stations at 17 sites during the first round of funding.

More information and future updates on North Dakota's funding for the trust can be found at https://www.vwenvironmentalmitigationtrust.com/state-trust/north-dakota.

5.3.1.2.2 EPA's Diesel Emissions Reduction Act (DERA)

The EPA allocates funds within the DERA program to individual states each year to help fund the replacement of older diesel-powered vehicles that do not operate as efficiently as newer engines. The amount of funds varies yearly and the program provides up to 25% of the cost of the replacement vehicle. The DERA program began in 2008. Emission reductions since the initiation of the program are included in Table 36.

Table 36: Emission Reductions since initiation of DERA program

Year	Number of Vehicles Funded	NO_X (tons)	PM (tons)	VOC (tons)	CO (tons)
2008	8	21.9	1.0	1.5	6.2
2009	2	6.4	0.2	0.2	1.2
2010	16	39.9	2.0	2.8	11.8
2011	8	15.7	0.7	1.0	4.2
2012	5	11.8	0.6	1.0	3.9
2013	5	10.7	0.5	0.9	3.9
2014	4	1.7	0.1	0.3	0.6
2015	6	2.1	0.2	0.4	0.9
2016	8	2.4	0.2	0.4	1.0
2017	9	2.0	0.1	0.2	0.6
2018	12	2.6	0.2	0.4	1.1
Total	83	117.3	5.6	8.9	35.4

Emission reductions were largest at the start of the DERA program when the least efficient vehicles were being replaced within the program. The decrease in emission reductions in the more recent years of the program illustrate the success of the early years of the program and the improvements in vehicle efficiencies as a result of more stringent national vehicle emission standards detailed in Section 5.3.1.2.7. In 2019, ten vehicles were funded for replacement. At the time of this SIP revision, not all these vehicle replacements have been completed, and therefore, were not included in Table 36. Once all ten replacements are completed, the NO_X reductions are anticipated to be between 2.0 and 2.6 tons.

5.3.1.2.3 Acid Rain Program (ARP)

In addition to being the two primary emissions contributing to visibility impairment in North Dakota, SO_2 and NO_X are the two primary precursors of acid rain. The Acid Raid Program (ARP) was established under Title IV of the 1990 Clean Air Act Amendments and requires significant reductions in SO_2 and NO_X emissions from the power sector.[137] The ARP was released in two phases, with Phase I beginning in 1995 and Phase II beginning in 2000. The ARP set a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. The ARP also set a goal of a two-million-ton reduction in NO_X emissions below 1980 levels by the year 2000. Although the ARP is not solely focused on SO_2 and NO_X reductions within North Dakota, SO_2 and NO_X reductions throughout the United States also benefit visibility within North Dakota CIAs, since air is not contained within state boundaries. Significant reductions have occurred throughout the United States, with the majority of SO_2 and NO_X reductions achieved in the eastern and southeastern portion of the United States, where much of the affected power sector is located. When winds are from an easterly or southeasterly direction, North Dakota CIAs will see some benefit. Figure 44 shows NO_X emissions across the continental United States in 1990 relative to 2019. Figure 45 shows the same for SO_2 emissions. It should be noted that Figure 44 and Figure 45 illustrate total NO_X and SO_2 emission reductions across the continental United States. Although the ARP and the CSAPR have resulted in significant reductions in NO_X and SO_2 emissions, other programs have contributed to NO_X and SO_2 emissions reductions, as is detailed in this SIP revision.

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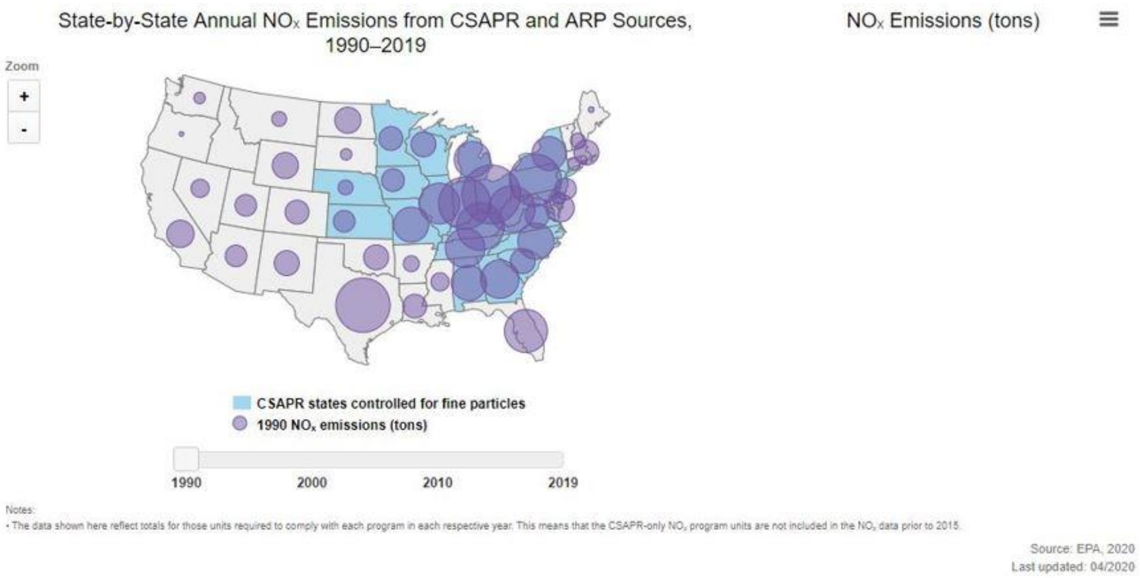
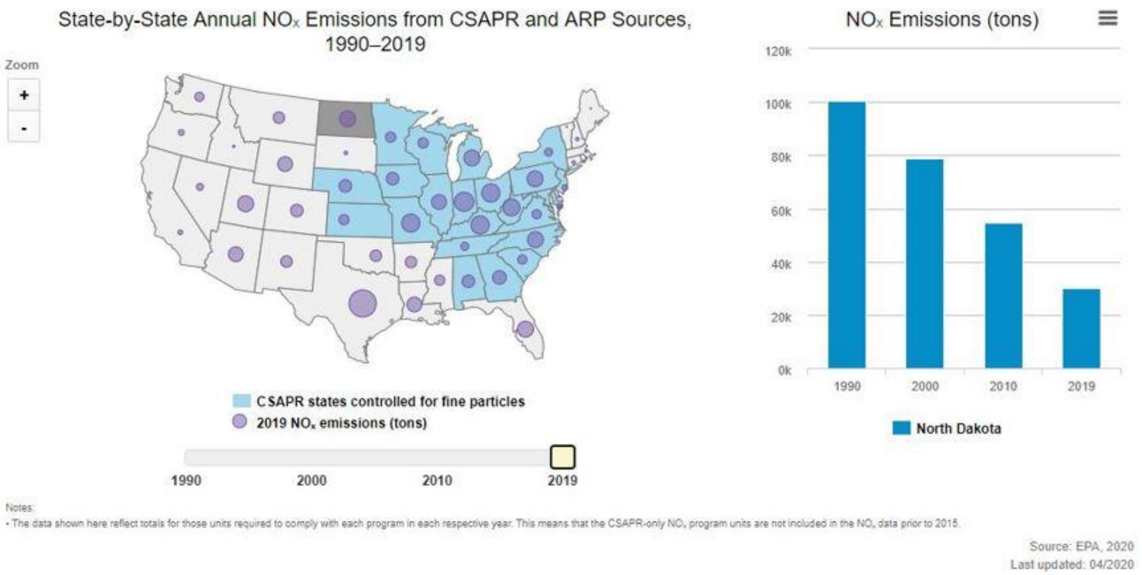
[137] Available at: https://www.epa.gov/acidrain/acid-rain-program (Last visited December 28, 2020)


State-by-State Annual NO_x Emissions from CSAPR and ARP Sources, 1990–2019

NO_x Emissions (tons)

Notes:
• The data shown here reflect totals for those units required to comply with each program in each respective year. This means that the CSAPR-only NO_x program units are not included in the NO_x data prior to 2015.

Source: EPA, 2020
Last updated: 04/2020

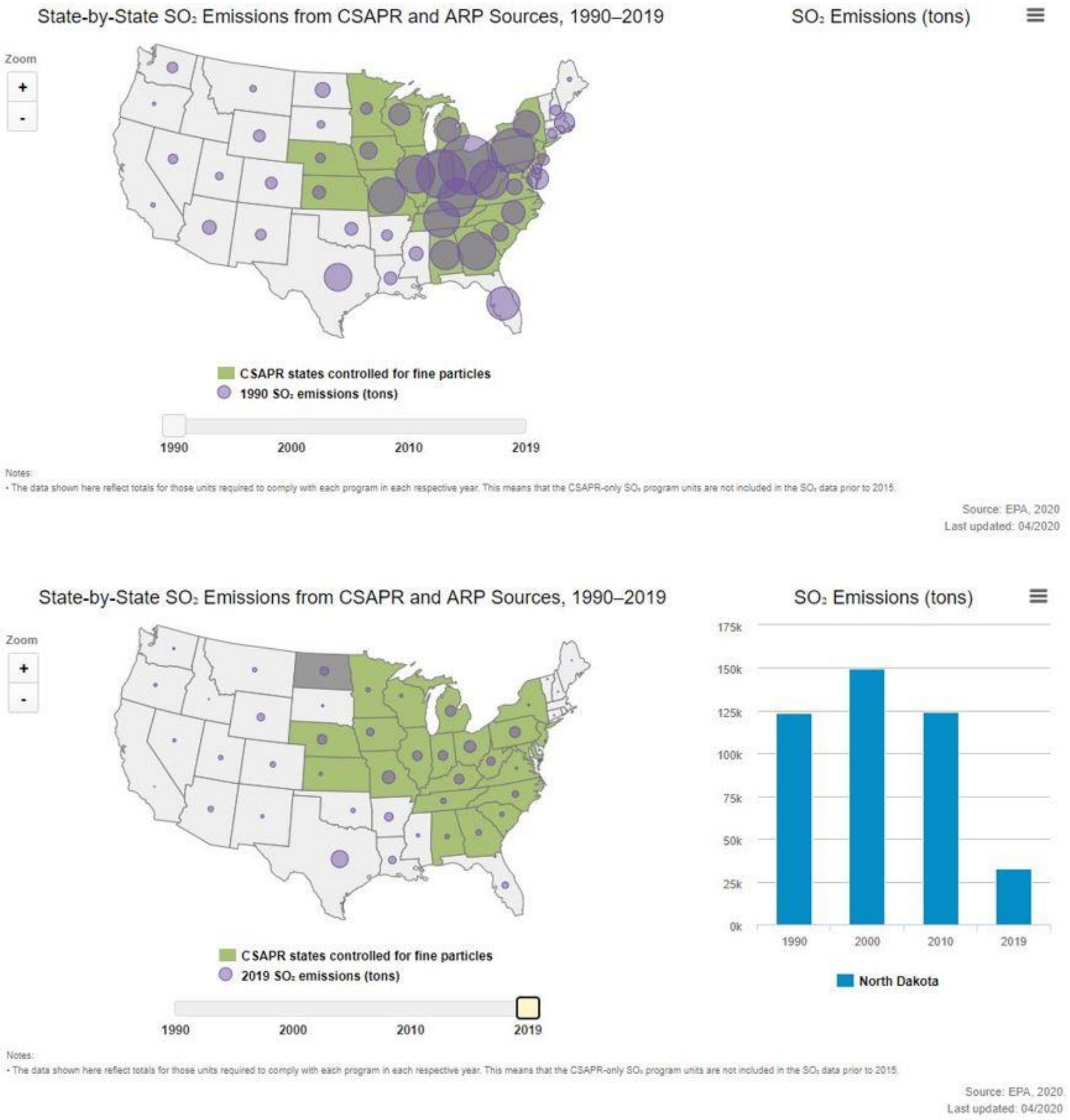

State-by-State Annual NO_x Emissions from CSAPR and ARP Sources, 1990–2019

NO_x Emissions (tons)

Notes:
• The data shown here reflect totals for those units required to comply with each program in each respective year. This means that the CSAPR-only NO_x program units are not included in the NO_x data prior to 2015.

Source: EPA, 2020
Last updated: 04/2020

Figure 44: Annual NO_X reductions across the continental United States from 1990–2019. The size of the circle over each state represents a relative scale of emissions. NO_X emissions from North Dakota sources from 1990–2019 is also shown.


State-by-State SO_2 Emissions from CSAPR and ARP Sources, 1990–2019

SO_2 Emissions (tons)

Notes:
- The data shown here reflect totals for those units required to comply with each program in each respective year. This means that the CSAPR-only SO_2 program units are not included in the SO_2 data prior to 2015.

Source: EPA, 2020
Last updated: 04/2020

State-by-State SO_2 Emissions from CSAPR and ARP Sources, 1990–2019

SO_2 Emissions (tons)

Notes:
- The data shown here reflect totals for those units required to comply with each program in each respective year. This means that the CSAPR-only SO_2 program units are not included in the SO_2 data prior to 2015.

Source: EPA, 2020
Last updated: 04/2020

Figure 45: SO_2 reductions across the continental United States from 1990–2019. The size of the circle over each state represents a relative scale of emissions. SO_2 emissions from North Dakota sources from 1990–2019 is also shown.

5.3.1.2.4 Tier 3 Motor Vehicle Emission and Fuel Standards

Tier 3 vehicle standards were established in 2014.[138] The action established more stringent vehicle emissions standards and reduced the sulfur content of gasoline beginning in 2017. Under the Tier 3 program, federal gasoline cannot contain more than 10 ppm of sulfur on an annual average basis after January 1, 2017. The vehicle standards reduced both tailpipe and evaporative emissions from passenger cars, light-duty trucks, medium-duty passenger vehicles, and some heavy-duty vehicles. The tailpipe

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[138] Available at: https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-control-air-pollution-motor-vehicles-tier-3 (Last visited December 28, 2020)

standards include different phase-in schedules ranging between model years 2017 and 2025, depending on vehicle class. It is expected that the Tier 3 vehicle standards will result in a 60–80% reduction of NO_X, VOC, CO, $PM_{2.5}$, and air toxics throughout the country. As such, North Dakota's CIAs will experience less visibility impairment when newer vehicles are operating within or near the CIAs. 2028 emissions projections from non-road and on-road engines were generated using the Motor Vehicle Emission Simulator (MOVES) look-up tables generated by EPA, starting from the 2016v1 platform.[139] See Sections 4.4 and 4.5 for the current emissions from these sectors and projected emissions for 2028.

5.3.1.2.5 Tier 4 Emission Standards for Nonroad Diesel Engines

The EPA finalized Tier 4 emission standards for nonroad diesel engines and sulfur reductions in nonroad diesel fuel in 2004. The new emission standards took effect for new engines beginning in 2008 and were fully phased in by the end of 2015. The rule set standards reducing NO_X and PM emissions by more than 90 percent from nonroad diesel equipment and reduced sulfur emissions from nonroad diesel fuel by more than 99 percent. A reduction on NO_X, PM, and sulfur emissions from nonroad diesel engines benefits visibility across the United States.

5.3.1.2.6 Emission Standards for New Nonroad Engines

The EPA adopted new standards for NO_X, CO, and hydrocarbons emissions from previously unregulated nonroad large industrial spark-ignition engines and recreational vehicles in 2002. The new standards also include requirements for diesel marine engines. The rule was fully phased in by 2012. It is estimated that the rule resulted in a 72 percent reduction in hydrocarbon emissions, an 80 percent reduction in NO_X emissions, and a 56 percent reduction in CO emissions. These reductions benefit visibility across the United States.

5.3.1.2.7 Heavy Duty Highway Engine and Vehicle Standards

The EPA set a PM emissions standard for new heavy-duty engines of 0.01 grams per brake-horsepower-hour (g/bhp-hr), to take full effect for diesel engines in the 2007 model year. The rule also includes standards for NO_X and non-methane hydrocarbons (NMHC) of 0.20 g/bhp-hr and 0.14 g/bhp-hr, respectively. These NO_X and NMHC standards were phased in together between 2007 and 2010 for diesel engines.[140] Sulfur in diesel fuel was lowered to enable modern pollution control technology to be effective on trucks and buses. The EPA required a 97 percent reduction in the sulfur content of highway diesel fuel from its previous level of 500 parts per million (low sulfur diesel) to 15 parts per million (ultra-low sulfur diesel).[141]

The EPA announced plans for the Cleaner Trucks Initiative (CTI) on November 13, 2018. The purpose of the CTI is to update standards for NO_X emissions from highway heavy-duty vehicles and engines. An advanced notice of proposed rulemaking was posted to the Federal Register on January 21, 2020

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[139] Available at: https://views.cira.colostate.edu/docs/wrap/mseipp/WRAP_MSEI_Summary_Memo_13Mar2020.pdf. (Last visited December 28, 2020)

[140] Available at: https://www.federalregister.gov/d/01-2/p-284. (Last visited December 28, 2020)

[141] Available at: https://www.federalregister.gov/d/01-2/p-279. (Last visited December 28, 2020)

requesting comments on the CTI.[142] Comments on the proposed rule were due by February 20, 2020. No further updates have been released, but a reduction in NO_X emissions from highway heavy-duty vehicles and engines would improve visibility across the United States.

5.3.1.2.8 Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone (NO_X SIP Call)

The EPA finalized the NO_X SIP Call in October 1998. Since NO_X is a major precursor to ozone, the NO_X SIP Call focuses on NO_X reductions. The NO_X SIP Call was designed to mitigate significant transport on NO_X. Phase I of the NO_X SIP Call applies to EGUs and large non-EGUs, including industrial boilers and turbines, and cement kilns in the eastern United States. The NO_X SIP Call is expected to reduce NO_X emissions by 90%. When winds are from the easterly direction, North Dakota CIAs will likely experience an improvement in visibility.

5.3.1.2.9 National Emission Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR 63, Subpart DDDDD)

The EPA issued final rules to substantially reduce emissions of toxic air pollutants from industrial, commercial, and institutional boilers and process heaters (40 CFR 63, Subpart DDDDD) in 2004. The rule reduced emissions of several toxic air pollutants including hydrogen chloride, manganese, lead, arsenic, and mercury. Regulations within the rule also reduced emissions of SO_2 and PM. The rule has been updated several times, with the most recent update being finalized in 2015. The District of Columbia Circuit remanded several of the emission standards to the EPA in 2016 and 2018. The EPA proposed amendments to the rule in 2020 to update the issues identified when the rule was remanded.

5.3.1.2.10 National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (40 CFR 63, Subpart UUUUU)

The EPA issued final rules to substantially reduce emissions of toxic air pollutants from coal- and oil-fired EGUs in 2012, known as the Mercury and Air Toxics Standards (MATS). The MATS reduces emissions of HAPs, including mercury, from the electric power industry. As a co-benefit, the emissions of certain $PM_{2.5}$ precursors such as SO_2 also declined.[143] The rule has been updated several times, with the most recent update being finalized in 2020.[144]

5.3.1.2.11 Various Other Maximum Achievable Control Technology (MACT) Standards

Various MACT standards have been promulgated by the EPA that will limit or reduce various visibility impairing pollutants, including PM, NO_X, SO_2, and VOC which were not discussed above. Table 37 provides a listing of MACT standards for source categories where controls are to be installed after 2002. This list does not include items covered above (i.e. MACT DDDDD and MACT UUUUU).

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[142] Available at: https://www.federalregister.gov/d/2020-00542/p-3. (Last visited December 28, 2020)

[143] Available at: https://www.epa.gov/sites/production/files/2020-09/documents/matsriafinal.pdf (Last visited December 28, 2020)

[144] Available at: https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants (Last visited December 28, 2020)

Table 37: Other MACT Standards Impacting Visibility Impairing Pollutants

Source Category	**Subpart**	**Date Promulgated**	**Existing Source Compliance Date**	**Pollutants Affected**
Hazardous Waste Combustion (Phase I)	Parts 63 (EEE), 261 and 270	9/30/1999	9/30/2003	PM
Oil & Natural Gas Production	HH	6/17/1999	6/17/2002	VOC
Polymers and Resins III	OOO	1/20/2000	1/20/2003	VOC
Portland Cement Manufacturing	LLL	6/14/1999	6/10/2002	PM
Publicly Owned Treatment Works (POTW)	VVV	10/26/1999	10/26/2002	VOC
Secondary Aluminum Production	RRR	3/23/2000	3/24/2003	PM
Combustion Sources at Kraft, Soda and Sulfate Pulp & Paper Mills (Pulp and Paper MACT II)	MM	1/21/2001	1/12/2004	VOC
Municipal Solid Waste Landfills	AAAA	1/16/2003	1/16/2004	VOC
Coke Ovens	L	10/27/1993	Phased from 1995–2010	VOC
Coke Ovens: Pushing, Quenching and Battery Stacks	CCCCC	4/14/2003	4/14/2006	VOC
Asphalt Roofing Manufacturing and Asphalt Processing (two source categories)	LLLLL	4/29/2003	5/1/2006	VOC
Metal Furniture (Surface Coating)	RRRR	5/23/2003	5/23/2006	VOC
Printing, Coating and Dyeing of Fabrics	OOOO	5/29/2003	5/29/2006	VOC
Wood Building Products (Surface Coating)	QQQQ	5/28/2003	5/28/2006	VOC
Lime Manufacturing	AAAAA	1/5/2004	1/5/2007	PM & SO_2
Site Remediation at treatment, storage, and disposal facilities	GGGGG	10/8/2003	10/8/2006	VOC
Iron & Steel Foundries	EEEEE	4/22/2004	4/23/2007	VOC
Taconite Iron Ore Processing	RRRRR	10/30/2003	10/30/2006	PM & SO_2
Miscellaneous Coating Manufacturing	HHHHH	12/11/2003	12/11/2006	VOC
Metal Can (Surface Coating)	KKKK	11/13/2003	11/13/2006	VOC
Plastic Parts and Products (Surface Coating)	PPPP	4/19/2004	4/19/2007	VOC
Miscellaneous Metal Parts and Products (Surface Coating)	MMMM	1/2/2004	1/2/2007	VOC

Source Category	**Subpart**	**Date Promulgated**	**Existing Source Compliance Date**	**Pollutants Affected**
Industrial, Commercial and Institutional Boilers and Process Heaters for Area Sources	JJJJJ	2/1/2013	3/2/2014	PM & SO_2
Plywood and Composite Wood Products	DDDD	7/30/2004	10/1/2007	VOC
Reciprocating Internal Combustion Engines	ZZZZ	6/15/2004	6/15/2007	NO_x & VOC
Auto and Light-Duty Truck (Surface Coating)	IIII	4/26/2004	4/26/2007	VOC
Wet Formed Fiberglass Mat Production	HHHH	4/11/2002	4/11/2005	VOC
Metal Coil (Surface Coating)	SSSS	6/10/2002	6/10/2005	VOC
Paper and Other Web Coating (Surface Coating)	JJJJ	12/4/2002	12/4/2005	VOC
Petroleum Refineries	UUU	4/11/2002	4/11/2005	VOC
Miscellaneous Organic Chemical Production (MON)	FFFF	11/10/2003	5/10/2008	VOC

5.3.2 §51.308(f)(2)(iv)(B) - Measures to Mitigate the Impacts of Construction Activities

As part of the long-term strategy requirements, 40 CFR 51.308(f)(2)(iv)(B) requires the consideration of measures to mitigate the impacts of construction activities. North Dakota regulates fugitive emissions by rule using NDAC Chapter 33.1-15-17. Section 33.1-15-17-01(2) states:

> *"No person shall cause or permit fugitive emissions from any source whatsoever, including a building, its appurtenances, or a road, to be used, constructed, altered, repaired, or demolished; or activities such as loading, unloading, storing, handling, or transporting of materials without taking reasonable precautions to prevent such emissions from causing air pollution as defined in section 33.1-15-01-04."*

NDAC Section 33.1-15-17-02 also states, in part:

> *"No person shall emit or cause to be emitted into the ambient air from any source of fugitive emissions as specified in section 33.1-15-17-01 any particulate matter which:*
>
> *2. Exceed the ambient air quality standards of chapter 33.1-15-02 at or beyond the property line of the source.*
>
> *3. Exceed the prevention of significant deterioration of air quality increments of chapter 33.1-15-15 at or beyond the property line of the source for sources subject to chapter 33.1-15-15.*
>
> *4. Exceed the restrictions on the emission of visible air contaminants of chapter 33.1-15-03, at or beyond the property line of the source, except as provided in section 33.1-15-03-04.*

5. *Would have an adverse impact on visibility, as defined in chapter 33.1-15-19, on any class 1 federal area."*

The Department requires permits for asphalt concrete plants in addition to rock, sand and gravel plants, which are generally associated with major construction projects. The Department requires notification of the relocation of asphalt plants in order to track any emissions from these facilities.

The CIAs in North Dakota are located in the western and northwestern portion of the State. The largest population centers in North Dakota are Fargo and West Fargo (combined population of ~160,000), Bismarck (population of ~80,000), and Grand Forks (population of ~60,000). Of North Dakota's largest population centers, Bismarck is the closest to North Dakota's CIAs and is just over 200 km from the south unit of Theodore Roosevelt National Park. Watford City is the closest population center to any of North Dakota's CIAs. Watford City has a population of ~8,000 and is ~40 km from the north unit of Theodore Roosevelt National Park.

Most potential impacts on visibility in North Dakota CIAs due to construction activities would likely be associated with road development, oil and gas well pads, compressor stations, and gas processing plants. Combustion emissions of NO_X and SO_2 (and other common visibility impairing pollutants) from the operation of the non-road engines used to support construction activity are included in Section 4.4. There is also a potential for dust formation during construction of these source types due to the arid conditions of North Dakota. Owners of sources subject to permitting requirements, including facilities such as compressor stations and gas processing plants, are subjected to fugitive dust control requirements included in the permit issued for the construction of the facility. These emissions are generally ground level emissions and dissipate quickly. Therefore, the emissions do not typically travel very far. All sources, included those not permitted, are subject to the requirements of NDAC Chapter 33.1-15-17. In addition, NDAC Section 33.1-15-17-03 lists measures considered to be reasonable precautions for abating and preventing fugitive dust. These include:

"1. Unpaved roads and unpaved parking areas. Abatement and preventive measures include frequent watering, addition of dust palliatives, detouring, paving, closure, speed control, or other means such as surface treatment with penetration chemicals (ligninsulfonates, oil, water, cutbacks, etc.) or methods of equal or greater effectiveness in reducing the air contamination produced.

2. Demolition, wrecking and explosive detonation activities, earth and construction material moving, mining, and excavation activities.

   a. Abatement and preventive fugitive particulate control measures include:

      (1) Wetting down, including prewatering.
      (2) Landscaping and replanting with native vegetation.
      (3) Covering, shielding, or enclosing the area.
      (4) Paving, temporary or permanent.
      (5) Treating, the use of dust palliatives and chemical stabilization.
      (6) Detouring.
      (7) Restricting the speed of vehicles on sites.
      (8) Preventing the deposit of dirt and mud on improved streets and roads.

(9) Minimizing topsoil disturbance and reclaiming as soon as possible.

b. Sequential blasting be employed whenever or wherever feasible to reduce the amounts of particulate matter.

c. Such dust control strategies as revegetation, delay of topsoil disturbance until necessary, or surface compaction and sealing, be applied.

d. Haulage equipment be washed or wetted down, treated, or covered when necessary to minimize the amount of dust becoming airborne in transit and in loading.

e. Stockpile of materials be treated to prevent blowing or the material be contained in silos or other suitable enclosures.

f. Waste disposal sites be so operated and constructed as to prevent particulate matter from becoming airborne.

g. All conveyors, transfer points, crushers, screens, and dryers be so constructed, protected, or treated as to prevent particulate matter from becoming airborne.

h. These measures also be used during period when actual construction work is not being conducted, such as on weekends and holidays."

5.3.3 §51.308(f)(2)(iv)(C) - Source Retirement and Replacement Schedules

As part of the long-term strategy requirements, 40 CFR 51.308(f)(2)(iv)(C) requires that each state consider any source retirement and replacement schedules in developing its long-term strategy.

Great River Energy's 160 MWe Stanton Station was shut down on May 1, 2017. Unit 1 had a nominal heat input capacity of 1,800 MMBtu/hr and Unit 10 had a nominal heat input capacity of 642 MMBtu/hr. As documented in Table 35, the average annual combined SO_2 and NO_X emissions from 2012 through 2016 were 3,218 tons for Unit 1 and 701 tons for Unit 10. Stanton Station's Unit 1 had a Q/d of 21 and Unit 10 had a Q/d of 4. These pollutants are no longer being emitted into the atmosphere and visibility in North Dakota's CIAs could improve as a result. On October 11, 2018, Stanton Station was demolished in a planned implosion[145] and restoration of the site has since been completed[146].

In February of 2019, Montana Dakota Utilities Company announced that the 100 MWe R.M. Heskett Station will be replaced by a natural gas-fired combustion turbine in 2023. Unit 1 has a nominal heat input capacity of 388 MMBtu/hr and Unit 2 has a nominal heat input capacity of 917 MMBtu/hr. As documented in Table 35, the average annual combined SO_2 and NO_X emissions from 2012 through 2016 were 1,269 tons for Unit 1 and 2,941 tons for Unit 2. The R.M. Heskett Station's Unit 1 has a Q/d of 7 and Unit 2 has a Q/d of 16. The switch will result in a significant reduction in visibility impairing emissions. Start-up of the new natural gas-fired combustion turbine is contingent upon coal plant equipment being removed or permanently decommissioned.

In May of 2020, Great River Energy announced that the 99 MWe Spiritwood Station will be modified to be fueled by only natural gas.[147] Unit 1 has a nominal heat input capacity of 1,280 MMBtu/hr and can be

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[145] Video Available at: https://www.youtube.com/watch?v=ebLV5_81E0k (Last visited August 9, 2021)

[146] Available at: https://greatriverenergy.com/stanton-station-demolition-restoration-complete/ (Last visited August 9, 2021)

[147] Available at: https://greatriverenergy.com/major-power-supply-changes-to-reduce-costs-to-member-owner-cooperatives/ (Last visited December 29, 2020)

currently fired with coal, natural gas, or propane. As documented in Table 35, the average annual combined SO_2 and NO_X emissions from 2012 through 2016 were 142. Unit 1 has a Q/d of 0. Although the reduction in emissions resulting from the transition to only natural gas-fired combustion is not yet known, the switch will result in a reduction in emissions and potential visibility improvement across North Dakota.

The 2028 modeling conducted by WRAP included the retirement of Great River Energy's Stanton Station and R.M Heskett Station coal units but did not include the future fuel switch at Spiritwood Station. Emissions are displayed in Section 4 and the modeling results are covered in Section 6.

5.3.4 §51.308(f)(2)(iv)(D) - Basic Smoke Management Practices

As part of the long-term strategy requirements, 40 CFR 51.308(f)(2)(iv)(D) requires that each state consider basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs. North Dakota has a land area of approximately 69,000 square miles (44 million acres). Of this total, 28 million acres is crop land, 10 million acres is pastureland and 203,000 acres is woodland.[148] The five State forests of North Dakota comprise a total of 13,613 acres. The North Dakota State Implementation Plan contains rules which govern prescribed burning on crop land, pasture/rangeland and woodland. NDAC Section 33.1-15-04-02(2) lists the conditions that apply to any prescribed burning, which include:

> "a. *Air pollution, as defined in section 33.1-15-1-04, will not be created.*
> c. *Care must be used to minimize the amount of dirt on the material being burned and the material must be dry enough to burn cleanly.*
> d. *Oils, rubber, and other materials that produce unreasonable amounts of air contaminants may not be burned.*
> e. *The burning may be conducted only when meteorological conditions favor smoke dispersion and air mixing.*
> h. *Except in an emergency, burning may not be conducted in such proximity of any Class I area, as defined in chapter 33.1-15-15, that the ambient air of such area is adversely impacted.*
> i. *Except in an emergency, the visibility of any Class I area cannot be adversely impacted as defined in chapter 33.1-15-19.*
> j. *Burning activities must be attended and supervised at all times burning is in progress.*
> k. *If state or local fire officials determine conditions to be unsafe for open burning, such burning must cease until conditions are deemed safe by such officials."*

In addition, NDAC Section 33.1-15-04-02(1)(e) requires that "*Fires purposely set to forest or rangelands for a specific reason in the management of forest, rangeland, or game in accordance with practices recommended by state or federal agencies, as appropriate…*" be "*…approved in advance by the department*". Although agricultural crop burning does not require advanced approval by the

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[148] 2017 Census of Agriculture State Profile for North Dakota Available at: https://www.nass.usda.gov/Publications/AgCensus/2017/Online_Resources/County_Profiles/North_Dakota/cp99038.pdf. (Last visited December 29, 2020)

Department, most of this burning occurs in the eastern two thirds of North Dakota. North Dakota's CIAs are in the western and northwestern portions of the state. WRAP has estimated the 2014 annual emissions from fire in North Dakota as shown in Table 38. Fire emissions estimations for each of the emissions inventories are included in Section 4.1. For comparison to other western states, wildfire activity emissions from all the WRAP states are included in Section 4.8.

Table 38: 2014 emissions from fire in North Dakota (tons)

Source	Sector	NO_X	SO_2	PM_{10}	$PM_{2.5}$
Anthropogenic	ag_flaming	1,187	402	5,252	3,457
Anthropogenic	rxfire	301	225	3,812	3,231
Natural	wildfire	32	17	288	242
	Total	**1,520**	**644**	**9,352**	**6,930**

5.3.5 §51.308(f)(2)(iv)(E) - Anticipated Net Impact on Visibility due to Projected Emissions Changes over the Long-term Strategy Period

As part of the long-term strategy requirements, 40 CFR 51.308(f)(2)(iv)(E) requires that each state consider the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy. The anticipated net change in visibility due to projected changes in emissions through 2028 is discussed in Section 0, and the visibility projections are covered in Sections 3.1 and 6.1.

6 §51.308(f)(3) – Modeling of Long-Term Strategy to Set Reasonable Progress Goals

40 CFR §51.308(f)(3)(i) of the RHR requires the Department to establish a reasonable progress goal (RPG) for each CIA located within North Dakota, expressed in deciviews, that reflects the visibility conditions that are projected to be achieved by the end of the implementation period as a result of the long-term strategy (LTS). The LTS contains the measures adopted as a result of the four-factor analysis required under 40 CFR §51.308(f)(2) (Section 5.2), control measures that other contributing states have determined to be necessary to make reasonable progress (Section 2.3), and state or federal measures adopted to meet other requirements of the CAA (Section 5.3) to determine the necessary RPG for the implementation period.

The Department evaluated projected future visibility conditions using photochemical grid modeling (PGM) completed by WRAP, Section 3.1 and Appendix C. The modeling protocols and framework were developed by the WRAP Regional Technical Operations Work Group and are consistent with the US EPA RHR Guidance.[149]

6.1 Establishment of RPGs

The LTS and RPGs for CIAs must provide for improvement of visibility for the MIDs since the baseline period and ensure no degradation of visibility for the clearest days since the baseline period.[150] As stated in the July 1, 1999 final regional haze rule: *"EPA was mindful of the balance that must be maintained between the need for strategies that will achieve meaningful improvements in air quality and the need to provide appropriate flexibility for States in designing strategies that are responsive to both air quality and economic concerns."*[151] The two factors, "*meaningful improvement in air quality*" and "*economic concerns*" are very important during this planning period. The Department has significant economic and energy security concerns regarding the sources and industries evaluated. The Department addresses the meaningful improvement in air quality (visibility) in this Section by evaluating the projected impact additional controls have on overall visibility. Additionally, North Dakota remains in compliance with all national ambient air quality standards. Therefore, any potential projects recommended for regional haze will not have the added benefit of helping North Dakota achieve compliance with ambient air quality standards.

Also, as stated in the July 1, 1999 final rule: "*the CAA national visibility goal and ''reasonable progress'' provisions do not mandate specific rates of progress, but instead call for ''reasonable progress'' toward the ultimate goal of returning to natural background conditions*".[152] In other words, a RPG is a projected outcome, rather than visibility conditions established directly, and meeting an RPG is not an enforceable requirement of the RHR. RPGs are still a useful metric for evaluating progress. The Department believes the current rate of visibility improvement projected by the end of the planning period is reasonable for

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[149] Available at: https://www.epa.gov/visibility/visibility-guidance-documents (Last visited January 27, 2021)

[150] 40 CFR 51.308(f)(3)

[151] 64 FR 35731

[152] 64 FR 35731

making progress toward the 2064 visibility goal, supported by the Department's visibility analysis in Section 3. Therefore, the Department is not requiring additional progress beyond what is already expected during this planning period. The Department came to this conclusion through the WRAP PGM modeling of current and potential additional controls and the current economic and energy production outlook. The modeling results provided in Section 6.1.1 help to further support this position.

When establishing the RPGs, the Department considered the four statutory factors for the affected sources (Section 5.2). The Department also analyzed and determined the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the Department compared baseline visibility conditions to natural visibility conditions in the CIAs and determined the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained in order to attain natural visibility conditions by 2064 (Section 3.2.6 and Section 3.2.7). In establishing the RPGs, the Department considered the uniform rate of visibility improvement and any emission reduction measures needed for the period covered by the implementation plan. It was determined that no additional emissions reductions measures are needed to achieve the RPGs for this planning period. The PGM results for LWA and TRNP show that each CIA is projected to provide for an improvement in visibility for the MIDs over the implementation plan.

Additionally, IMPROVE data at LWA and TRNP have shown no degradation in visibility for the clearest days from 2000–2018 (Section 3.2.6.2). The PGM results also show no expected degradation for the clearest days in 2028. The 2014–2018 average IMPROVE data for the clearest days at LWA and TRNP shows total species light extinction of 10.2 Mm^{-1} and 7.1 Mm^{-1}, respectively. The 2028 projected visibility on the clearest days at LWA and TRNP shows total species light extinction of 10 Mm^{-1} and 6.7 Mm^{-1}, respectively.[153] The 2014–2018 IMPROVE data can be found in Section 5.1.1.2.[154] The 2028 visibility projections for the MIDs can be found in Section 3.1.

6.1.1 Modeling of Potential Additional Controls

The Department projected the future 2028 baseline visibility conditions assuming no changes to the current emissions controls on the stationary sources in North Dakota.[155] The Department then selected potential additional controls (PAC) at two stationary sources for the 2028 visibility modeling evaluation. Each of these sources was subject to the reasonable progress requirement from the first-round planning period. Two scenarios of controls were reviewed to determine the PACs impact on the visibility projections for 2028 (i.e. how much improvement over the 2028 baseline is expected with these controls). Modeling with two different scenarios also helps show how sensitive the model is to the potential reductions being evaluated. These two scenarios, along with the 2028 OTB scenario, give the Department three future data points. 1) What is the current projected visibility for 2028 with no additional changes outside of what is expected? 2) What impact to the projected 2028 visibility conditions do the potential additional control have, for each PAC1 and PAC2? 3) With the three points

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[153] Available at: https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx. See Model Results Product 3.
[154] Also available at: https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx. See Charts Product 2.
[155] Section 4.2.1.1.1 discusses Coal Creek Station's expected SO_2 reductions prior to 2028. These are no longer being considered as a result of the pending ownership change to Rainbow Energy Center.

(2028OTB, 2028PAC1, and 2028PAC2), how sensitive is the model to the magnitude of reductions evaluated and will this meaningfully impact future visibility?

All the sources evaluated in Section 5.2 were considered for additional controls during this planning period. Two sources were identified as candidates for potential additional controls. The candidates evaluated for additional reasonable controls were the Coyote Station coal fired EGU and the Antelope Valley Station coal fired EGU. The emission reductions expected with the controls evaluated are addressed in Section 4.1.7. The controls selected for modeling review and supporting rational is addressed in Section 5.2.1 for Coyote Station and 5.2.2 for Antelope Valley Station.

Figure 46 and Figure 47 display the 2028OTB (2028 baseline), 2028PAC1, and 2028PAC2 projected visibility conditions for LWA and TRNP, respectively.

The recommended procedure to project 2028 visibility with and without added controls is the EPA default visibility projection procedure without fire impacts (EPA w/o fire). The other options available are the EPA recommended default (EPA default) visibility projection procedure and the modeled MIDs procedure. As described throughout this SIP Revision, North Dakota experiences significant adverse impacts that result from wildfires outside of North Dakota. However, North Dakota is not heavily impacted by fire events on the IMPROVE MIDs. Therefore, as expected, the difference between the EPA default procedure and the EPA w/o fire procedure is small. The 2028 visibility projection using the EPA default is 0.02 deciviews greater than the 2028 projection using the EPA default w/o fire, meaning the modeled fire contribution on the MIDs was 0.02 deciviews. The 0.02 deciviews is for TRNP and LWA. The modeled MIDs procedure produced 2028 visibility impairment projections lower than the EPA w/o fire (also lower than EPA default). The modeled MIDs procedure uses the results from the source apportionment modeling to select the MIDs. The first two options use the IMPROVE observed (or monitored) MIDs. In addition to the EPA w/o fire procedure being the WRAP RTO recommendation, this procedure yielded the second most conservative (less projected improvement) results and the difference between EPA default and EPA default w/o fire is insignificant.

As outlined in Section 3.2.7, the recommended procedure to adjust the glidepath endpoint was the procedure accounting for international emissions and prescribed wildland fires. Also as noted in Section 3.2.7, a significant majority of the adjustment is due to international sources, not from wildland prescribed fires. Similar to the difference in 2028 visibility projections between the EPA default and the EPA default w/o fire, the impact from prescribed wildland fires is minimal to the glidepath endpoint. Prescribed wildland fires account for 0.13 deciviews of the overall 6.72 deciview adjustment at LWA. Prescribed wildland fires account for 0.09 deciviews of the overall 5.61 deciview adjustment at TRNP. Representing less than two percent of the overall adjustment.

For complete details of these procedures, see the white paper produced by the WRAP RTO group at: https://www.wrapair2.org/pdf/2028_Vis_Proj_Glidepath_Adj_2021-03-01draft_final.pdf.

For visual aesthetics, Figure 46 and Figure 47 only show the 2028 visibility projections and glidepath adjustment produced using the recommended procedures by the WRAP RTO.[156]

Figure 46 and Figure 47 each display multiple important elements. The five-year rolling average IMPROVE monitor network data shows the progress made to date. The unadjusted glidepath and the adjusted glidepath demonstrate the impact international emissions and prescribed wildland fires have on hampering North Dakota's ability to achieve the end goal without an adjusted glidepath. There are three projected visibility outcomes based on projected 2028 emissions scenarios, which can be summarized as a baseline 2028 projection "2028OTB", a projection with strict emissions controls on selected units "2028PAC1", and a projection lower cost control options "2028PAC2".

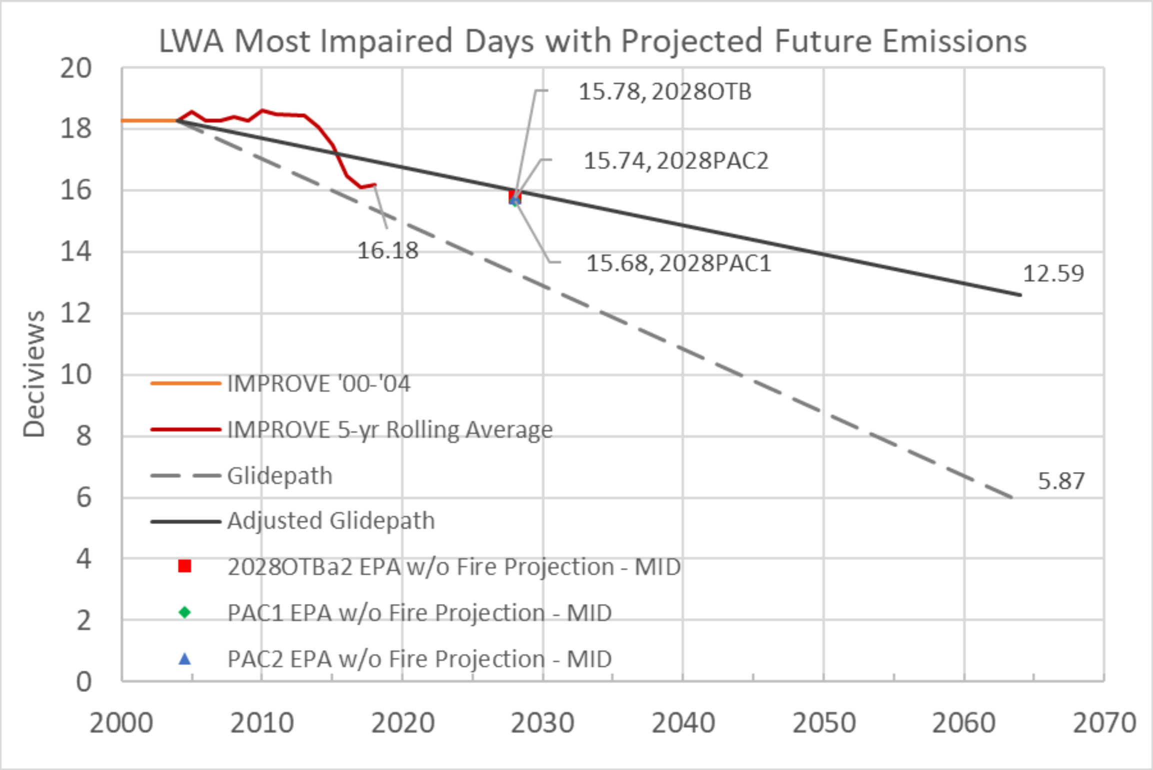

Figure 46: LWA Visibility Projection for the Most Impaired Days with 2028 Emissions Scenarios

The 2028OTB projection in Figure 46 shows a modeled cumulative visibility impairment of 15.78 deciviews. The emissions data which produced this projection can be found in Section 4.1.6. Comparing the 2028OTB projection against the adjusted glidepath indicates that LWA is anticipated to remain below the adjusted glidepath through 2028. The adjusted glidepath slope indicates LWA needs to be below 16.0 deciviews to remain below the adjusted uniform rate of progress. If no additional reductions beyond what is already planned are implemented during this planning period, LWA can reasonably expect to have a visibility impairment of 15.78 deciviews in 2028. The 2028OTB projection of 15.78 deciview impairment is lower than the most recent 16.18 deciview impairment resulting from the five-

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[156] Available at: https://www.wrapair2.org/pdf/2028_Vis_Proj_Glidepath_Adj_2021-03-01draft_final.pdf (Last visited March 17, 2021)

year IMPROVE monitor network average from 2014–2018. Overall, this demonstrates LWA is projected to provide for an improvement in visibility for the MIDs over the period of the implementation plan, meeting the requirements of 40 CFR 51.308(d)(1) and 40 CFR 51.308(f)(3)(i).

Figure 46 also displays two additional significant points, the additional controls selected for modeling evaluation resulting from the four factor analysis summarized in Section 5.2. The emissions data and controls selected for review which produced this projection can be found in Section 4.1.7. The source specific information can be found in Section 5.2.

The 2028PAC1 projection in Figure 46 shows a modeled cumulative visibility impairment of 15.68 deciviews. Comparing the 2028PAC1 projection against the 2028OTB projection indicates that LWA would be anticipated to experience a cumulative improvement in visibility of 0.1 deciview resulting from the installation of the controls evaluated under this scenario. *For context, one deciview of change in visibility is generally considered to be the minimum change that the average person can detect with the naked eye.* This 0.1 deciview improvement was derived from the reduction of over 22,200 tons of combined NO_X plus SO_2 emissions. The 0.1 deciview improvement and over 22,000 tons of reductions come at a combined capital cost of approximately $150 million and a combined annualized cost of approximately $30 million. Individual unit controls and cost details are covered in Sections 5.2.1, 5.2.2, and 4.1.7. In summary, if North Dakota were to require the 2028PAC1 (emissions reductions) it would come at a very significant cost while not meaningfully impacting the overall visibility projection for 2028.

The 2028PAC2 projection in Figure 46 shows a modeled cumulative visibility impairment of 15.74 deciviews. Comparing the 2028PAC2 projection against the 2028OTB projection indicates that LWA would be anticipated to experience a cumulative improvement in visibility of 0.04 deciview resulting from the installation of the controls evaluated under this scenario. This 0.04 deciview improvement was derived from the reduction of over 7,000 tons of combined NO_X plus SO_2 emissions. The 0.04 deciview improvement and over 7,000 tons of reductions come at a capital cost of approximately $0.5 million and an annualized cost of approximately $2 million. Individual unit controls and cost details are covered in Sections 5.2.1 and 4.1.7. In summary, if North Dakota were to require the 2028PAC2 (emissions reductions) there would be no meaningful projected improvement to the overall visibility projection for 2028. Although the cost for this scenario is considerably lower than 2028PAC1, there is also no meaningful projected improvement to visibility resulting from the controls, a key factor in the Department's analysis.

LWA is currently projected to meet its 2028 RPGs and is on track to accomplish the 2064 visibility goals. With the modeled control scenarios providing no meaningful improvement to visibility, the Department determined that it is not reasonable to require additional controls during this planning period. The Department will continue to monitor LWA's visibility progression and will provide an update in the 2025 progress report.

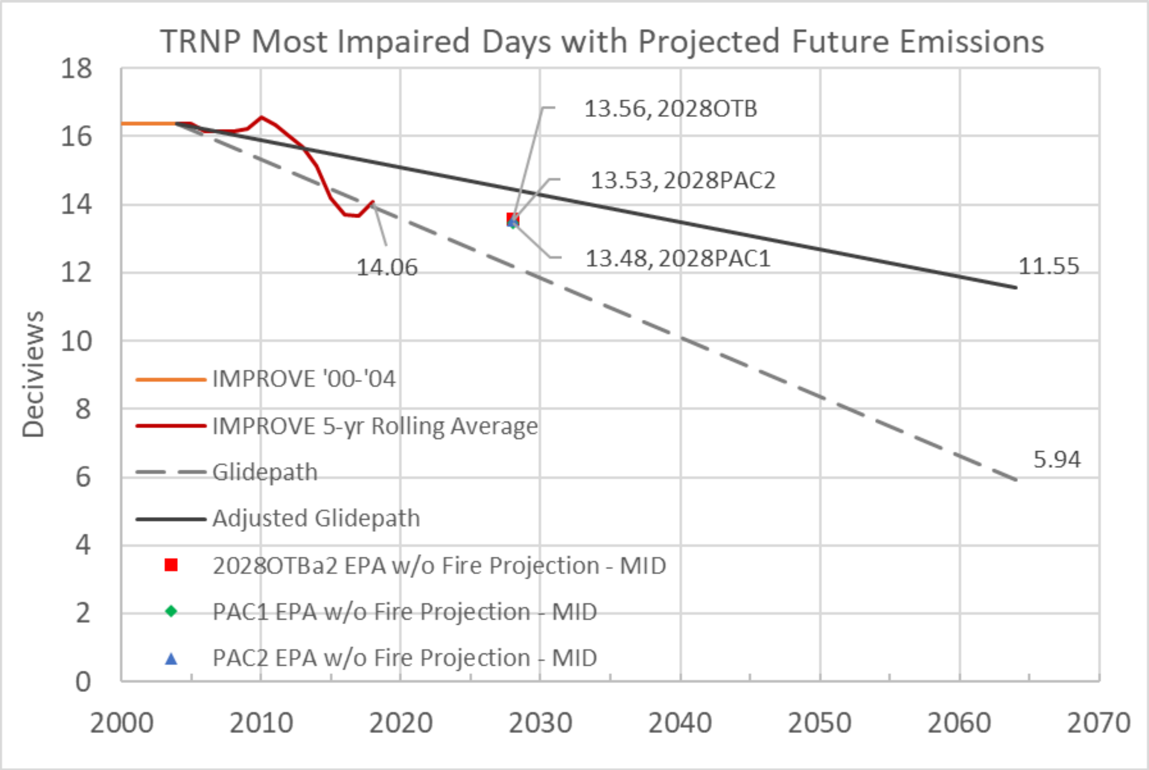

Figure 47: TRNP Visibility Projection for the Most Impaired Days with 2028 Emissions Scenarios

The 2028OTB projection in Figure 47 shows a modeled cumulative visibility impairment of 13.56 deciviews. The emissions data which produced this projection can be found in Section 4.1.6. Comparing the 2028OTB projection against the adjusted glidepath indicates that TRNP is anticipated to remain below the adjusted glidepath through 2028. The adjusted glidepath slope indicates TRNP needs to be below 14.43 deciviews to remain below the adjusted uniform rate of progress. If no additional reductions beyond what is already planned are implemented during this planning period, TRNP can reasonably expect to have a visibility impairment of 13.56 deciviews. The 2028OTB projection of 13.56 deciview impairment is lower than the most recent 14.06 deciview impairment resulting from the five-year IMPROVE monitor network average from 2014–2018. Overall, this demonstrates TRNP is projected to provide for an improvement in visibility for the MIDs over the period of the implementation plan, meeting the requirements of 40 CFR 51.308(d)(1) and 40 CFR 51.308(f)(3)(i).

Figure 47 also displays two additional significant points, the additional controls selected for modeling evaluation resulting from the four factor analysis summarized in Section 5.2. The emissions data and controls selected for review which produced this projection can be found in Section 4.1.7. The source specific information can be found in Section 5.2.

The 2028PAC1 projection in Figure 47 shows a modeled cumulative visibility impairment of 13.48 deciviews. Comparing the 2028PAC1 projection against the 2028OTB projection indicates that TRNP would be anticipated to experience a cumulative improvement in visibility of 0.08 deciview resulting from the installation of the controls evaluated under this scenario. This 0.08 deciview improvement was derived from the reduction of over 22,200 tons of combined NO_X plus SO_2 emissions. The 0.08 deciview improvement and over 22,000 tons of reductions come at a combined capital cost of approximately $150 million and a combined annualized cost of approximately $30 million. Individual unit controls and cost details are covered in Sections 5.2.1, 5.2.2, and 4.1.7. In summary, if North Dakota were to require the 2028PAC1 (emissions reductions) it would come at a very significant cost while not meaningfully impacting the overall visibility projection for 2028.

The 2028PAC2 projection in Figure 47 shows a modeled cumulative visibility impairment of 13.53 deciviews. Comparing the 2028PAC2 projection against the 2028OTB projection indicates that TRNP would be anticipated to experience a cumulative improvement in visibility of 0.03 deciview resulting from the installation of the controls evaluated under this scenario. This 0.03 deciview improvement was derived from the reduction of over 7,000 tons of combined NO_X plus SO_2 emissions. The 0.03 deciview improvement and over 7,000 tons of reductions come at a combined capital cost of approximately $0.5 million and an annualized cost of approximately $2 million. Individual unit controls and cost details are covered in Sections 5.2.1 and 4.1.7. In summary, if North Dakota were to require the 2028PAC2 (emissions reductions) there would be no meaningful projected improvement to the overall visibility projection for 2028. Although the cost for this scenario is considerably lower than 2028PAC1, there is also no meaningful projected improvement to visibility resulting from the controls, a key factor in the Department's analysis.

TRNP is currently projected to meet its 2028 RPGs and is on track to accomplish the 2064 visibility goals. With the modeled control scenarios providing no meaningful improvement to visibility, the Department determined that it is not reasonable to require additional controls during this planning period. The Department will continue to monitor TRNP's visibility progression and will provide an update in the 2025 progress report.

6.2 §51.308(f)(3)(ii)(A) – Reasonable Progress Goals Above the Uniform Rate of Progress

Without the adjustment of the uniform rate of progress to account for international and wildland prescribed fire impacts, it would be impossible for North Dakota to reduce anthropogenic emissions enough to meet the uniform rate of progress needed to show the State is making reasonable progress to improve visibility, see Section 3.2.6. Once the uniform rate of progress is adjusted, both TRNP and LWA are below the glidepath. Meaning they are tracking to meet the 2064 natural visibility end goals, see Section 3.2.7 and Section 6.1.1. Overall, the current visibility impairment and the 2028 visibility impairment projections are on track to reach the 2064 natural visibility goals for the MIDs and the least impaired (or clearest) days at both North Dakota CIAs.

6.3 §51.308(f)(3)(ii)(B) - Upwind (out-of-state) Impact on Reasonable Progress Goals

Section 2.1 contains the communications and consultations the Department had with FLMs and neighboring states. None of the neighboring states have provided input regarding any North Dakota impacts to visibility in their respective CIAs nor have they requested additional controls on North Dakota sources.

6.4 §51.308(f)(3)(iii) - Enforceability of Reasonable Progress Goals

The RPGs established in Section 6.1.1 are not directly enforceable but should be considered by the EPA when evaluating the adequacy of the measures included in this SIP revision. The Department believes LWA and TRNP are making reasonable progress toward achieving natural conditions by 2064.

6.5 §51.308(f)(3)(iv) - Evaluation of RPG

The PGM modeling for the projected 2028 baseline visibility condition and modeling with potential additional controls associated with significant emissions reductions (2028PAC1) resulted in no meaningful visibility improvement on the MIDs (Section 6.1.1).

6.6 §51.308(f)(4) – Reasonably Attributable Visibility Impairment (RAVI)

The FLMs for TRNP and LWA have not identified any reasonably attributable visibility impairment from North Dakota. The FLMs for the CIAs that North Dakota's emissions impact in other states have not identified any reasonably attributable visibility impairment caused by North Dakota sources. For these reasons, the Department does not have reasonably attributable visibility impairment to address.

6.7 §51.308(f)(5) – Progress Report

51.308(f)(5) requires the State to address the progress made towards the RPGs identified by the State and to submit a report evaluating the progress made. North Dakota submitted its first five-year periodic progress report in January 2015. With this Regional Haze SIP revision North Dakota has completed an update to the progress report, this update can be found in Section 9.

6.8 §51.308(f)(6) - Monitoring Strategy

40 CFR §51.308(f)(6) of the RHR requires the Department to submit with the implementation plan a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment that is representative of all CIAs within the State. Compliance with this requirement may be met through participation in the Interagency Monitoring of Protected Visual Environments network. North Dakota depends on the IMPROVE program to collect and report aerosol monitoring data for long-term reasonable progress tracking as specified in the RHR.

6.8.1 §51.308(f)(6)(i)

North Dakota does not believe additional monitoring sites or equipment is needed to assess whether RPGs to address regional haze for the CIAs within the state are being achieved.

6.8.2 §51.308(f)(6)(ii)

North Dakota does not directly collect, or handle IMPROVE data. North Dakota relies on the IMPROVE program to meet the monitoring requirements and data collection obligations necessary to determine the contribution of emissions from within North Dakota to regional visibility impairment at CIAs in and outside of North Dakota.

6.8.3 §51.308(f)(6)(iii)

North Dakota has two CIAs (Section 1.1), therefore, this section is not applicable to North Dakota.

6.8.4 §51.308(f)(6)(iv)

North Dakota does not directly collect, or handle IMPROVE data. North Dakota relies on the IMPROVE program to meet the monitoring requirements and data collection obligations necessary to meet the reporting requirements of this section.

6.8.5 §51.308(f)(6)(v)

The emissions inventories used for this regional haze SIP revision are addressed in Section 4. North Dakota commits to update these emissions inventories periodically, as required by the section.

6.8.6 §51.308(f)(6)(vi)

The Department has not identified any other elements, including reporting, recordkeeping, or other measures necessary to assess and report on visibility. Since the Department does not participate in the data collection, quality assurance, or give any input regarding the IMPROVE monitor network operation, it is of the upmost importance to ensure the proper quality assurance and control of the data is maintained. Given that this system is now over 20 years old, North Dakota suggests the FLMs and EPA conduct a comprehensive review to determine if system upgrades are necessary to improve the quality of technical data and performance.

7 Overview of WRAP Modeling Scenarios

WRAP conducted significant modeling which was used to evaluate visibility impairment throughout the western United States. This assisted the Department in determining source and sector contributions to visibility impairment and helped establish the RPGs for North Dakota CIAs. Photochemical modeling was also used to evaluate the impact potential emission reductions had on visibility in North Dakota and nearby CIAs. Additionally, weighted emissions potential and area of influence modeling was completed and assisted in determining which regions and point source emissions may contribute to visibility impairment at CIAs on the MIDs. A brief discussion on the modeling scenarios and references to the supporting technical specification can be found in Sections 7.1 through 7.5.

7.1 Western Region Model Performance Evaluation

WRAP developed a webpage dedicated to the model platform description and model performance evaluation (MPE), https://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx.

This webpage contains the detailed information used in the final base case 2014 (2014v2) CAMx modeling platform and the configuration used in the 2014v2 modeling scenario. This includes discussion on model sensitivities, tendencies, performance results, and summaries.

7.2 Representative Baseline and 2028 On-the-Books

WRAP completed RepBase and 2028OTB CAMx modeling in addition to the 2014v2 modeling. The RepBase and 2028OTB modeling is primarily used to determine the 2028 visibility projection, as described in Section 7.3. The RepBase and 2028OTB modeling results were also used for the particulate matter source apportionment modeling to separate contributions of natural, various fires, US anthropogenic emissions, and international anthropogenic emissions. The international anthropogenic emissions and prescribed wildland fire components of the source apportionment results are also used to adjust the uniform rate of progress glidepath. Complete details on this modeling can be found in the run specification sheet.[157] These details include a description, the source apportionment specifications, and the emissions inventories.

7.3 2028 Visibility Projections and Adjusting Glidepaths

Using the information from the RepBase and 2028OTB CAMx modeling, WRAP completed 2028 visibility projections and adjustments to the uniform rate of progress glidepath. The RepBase and 2028OTB modeling results are used to derive model scaling factors known as relative response factors (RRFs). The RRFs are multiplied by the 2014–2018 IMPROVE MIDs to project 2028 visibility conditions. 2028 visibility projections can be compared to the uniform rate of progress glidepath to visually see if a CIA is on track to meet its 2064 visibility goals. Also included with this modeling product, is the methodology used to adjust the uniform rate of progress glidepath to account for international anthropogenic emissions and prescribed wildland fires. For North Dakota's CIAs, the 2028 visibility projections, the uniform rates of progress glidepath, and the adjusted uniform rate of progress glidepath are displayed in Sections 3.1

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[157] Available at: https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/EmissionsSpecifications_WRAP_RepBase2_and_2028OTBa2_RegionalHazeModelingScenarios_Sept30_2020.pdf (Last visited May 18, 2021)

and 6.1.1. Complete details on the procedures followed for making the visibility projections and adjustments to the glidepath can be found in the whitepaper “Procedures for Making Visibility Projections and Adjusting Glidepaths using the WRAP-WAQS 2014 Modeling Platform”.[158]

7.4 Regional, State, and Sector Source Apportionment Modeling using the 2028 On-the-Books Emissions Scenario

The RepBase and 2028 OTB CAMx modeling results were further separated to determine the individual contributions from natural sources, fires, and anthropogenic emissions. These include both the US and International sources and is known as the Regional source apportionment or the high-level source apportionment. The results from the 2028OTB regional source apportionment modeling are included in Section 3.1 and Appendix C. Results from the RepBase regional source apportionment modeling can be found on the TSSv2 under the Modeled Data Analysis using source apportionment products 10 through 16.

The 2028 OTB CAMx modeling results were further separated to determine the ammonium nitrate and ammonium sulfate contributions for the 13 consecutive WRAP states for five sector categories. The 5 sectors included in the modeling were: EGU, OilGas (oil and gas point and area sources with tribal oil and gas assigned to the state), NonEGU (all other point), Mobile (mobile on-road, non-road, rail, commercial marine vessels), and RemainAnthro (all remaining anthropogenic emissions including fugitive dust, agricultural, agricultural fire, residential wood combustion, and all other remaining nonpoint sources). These results are known as the State and Sector source apportionment or the low-level source apportionment. The results from the 2028OTB regional source apportionment modeling are included in Section 3.1 and Appendix C. Results from the 2028OTB State and Sector source apportionment modeling can also be found on the TSSv2 under the Modeled Data Analysis using source apportionment product 9.

Complete details on this modeling including a description and the source apportionment specifications can be found in the run specification sheet.[159]

7.5 2028 Weighted Emissions Potential (WEP) / Area of Influence (AOI)

Weighted Emissions Potential (WEP) and Area of Influence (AOI) analysis were completed for Regional Haze planning uses in the western U.S. The analysis was performed for the MID during each year of the 5-year period from 2014 through 2018 at 76 IMPROVE monitoring sites representing 116 CIAs in the 13 states of the contiguous WESTAR-WRAP region and neighboring states.

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[158] Available at: https://www.wrapair2.org/pdf/2028_Vis_Proj_Glidepath_Adj_2021-03-01draft_final.pdf. (Last Visited May 17, 2021)

[159] Available at: https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/SourceApportionmentSpecifications_WRAP_RepBase2_and_2028OTBa2_High-LevelPMandO3_and_Low-Level_PM_andOptionalO3_Sept29_2020.pdf. (Last Visited May 19, 2021)

These products were used qualitatively to assist the Department in selection of the appropriate source categories that have the highest potential to contribute to visibility impairment from NO_X and SO_2. Potential visibility impairment was evaluated using the 2028OTB emissions inventory for the CIAs in North Dakota and nearby out of state CIAs. The Department's summary analysis can be found in Appendix C. A detailed description of this task and access to the complete products is available at: https://views.cira.colostate.edu/tssv2/WEP-AOI/.

These products confirmed that the Department's selection of sources for four factor evaluation using the Q/d approach was appropriate.

8 Coal Creek Station BART

This section addresses Best Available Retrofit Technology (BART) from Round 1 of the RHR. North Dakota has currently completed all the BART requirements from Regional Haze Round 1 Implementation apart from NO_X BART for Great River Energy's Coal Creek Station Unit 1 and Unit 2.

Coal Creek Station (CCS) is a two-unit, approximately 1,200 gross MW mine-mouth power plant consisting primarily of two steam generators and associated coal and ash handling systems. Unit 1 and Unit 2 are identical Combustion Engineering boilers firing pulverized lignite coal tangentially. Unit 1 has a heat input capacity of 6,015 MMBtu per hr. Unit 2 has a heat input capacity of 6,022 MMBtu per hr. Unit 1 began commercial operation in 1979. Unit 2 began commercial operation in 1980. The facility is located in south central McLean County about five miles south of the town of Underwood, North Dakota and three miles west of US Highway 83. CCS receives lignite coal from the Falkirk Mine that is operated by the Falkirk Mining Company, a subsidiary of the North American Coal Corporation.

The Department emailed Great River Energy on December 18, 2018 to inform Great River Energy that they should focus on completing an updated BART analysis for the first round of Regional Haze planning.[160] On September 12, 2019, Great River Energy submitted an updated BART analysis associated with the first round of Regional Haze planning.[161] Great River Energy announced plans to retire Coal Creek in the second half of 2022 on May 7, 2020.[162] With this retirement announcement, the Department halted work on the updated NO_X BART proposal. On June 30, 2021 the Department learned Great River Energy reached an agreement with Rainbow Energy Center (REC) for the sale of Coal Creek Station.[163] Therefore, the Department continued work on an updated NO_X BART and decided the most reasonable path forward was to include this determination with this SIP revision. This section provides the objective of the NOx BART determination, a more detailed accounting of the background and history for this facility, and an overview of the BART determination.

Appendix F contains the Department's detailed NOx BART analysis, the proposed permit to construct incorporating the NOx BART limits, and additional supporting documentation. This BART determination also serves as the round 2 reasonable progress determination. Appendix B.4.b contains the NO_X BART analysis received by Great River Energy, Coal Creek Station. On August 5, 2021 REC agreed to adopt the NO_X BART analysis submitted by Great River Energy on September 12, 2019.

8.1 BART Objective

The Department's objective with this action is to receive a federally approved SIP imposing BART limits for NOx emissions from CCS Unit 1 and Unit 2. This updated BART determination for Unit 1 and Unit 2 NOx emissions at CCS supersedes any previously submitted material. The Department has conducted

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[160] Appendix B.4.c., PDF page 1082.

[161] Appendix B.4.b., PDF page 576.

[162] Appendix B.4.c., PDF page 1084. Also available at: https://greatriverenergy.com/major-power-supply-changes-to-reduce-costs-to-member-owner-cooperatives/ (Last visited December 29, 2020)

[163] Available at: https://greatriverenergy.com/rainbow-energy-center-to-purchase-coal-creek-station/ (Last visited July 6, 2021)

this new stand-alone BART analysis and BART determination for CCS Unit 1 and Unit 2 NO_X emissions to remove any confusion regarding previously submitted SIP information.

8.2 BART Applicability and History

The BART guidelines apply to CCS Units 1 and 2 because they are part of a fossil-fuel steam electric plant with a total generating capacity in excess of 750 megawatts (MW). Units 1 and 2 are each rated at more than 250 million British thermal units per hour (MMBtu/hr) of heat input. In addition, CCS has the potential to emit more than 250 tons per year (tpy) or more of a visibility-impairing pollutant. This specifically includes SO_2, NOx, and inhalable particulate matter with a diameter of 10 microns or less (PM_{10}) at CCS. CCS was also determined to have a significant impact on visibility in North Dakota's CIAs (see Section 7.3 of the regional haze SIP submitted in March 2010).

The first proposed regional haze SIP amendment was submitted by North Dakota to EPA Region 8 in March 2010. This SIP amendment was initially deemed complete by the EPA R8 in April 2010. However, during the EPA's review, errors were discovered in the submission, which were specific to the Great River Energy's CCS BART analysis for NOx emissions. In June 2012, North Dakota received a revised NOx BART analysis from CCS which addressed the errors raised by the EPA. In January 2013, North Dakota submitted "Supplement No. 2" to EPA which addressed errors in the NOx BART analysis for CCS. "Supplement No. 2" provided updated and corrected information to the NOx BART analysis but did not change the original BART determination. In the spring of 2018, the EPA concurred with North Dakota and proceeded with the required public comment period prior to making a final determination on the Department's NOx BART determination, including the Department's submitted "Supplement No. 2". EPA received comments[164] on North Dakota's proposed BART determination, which were deemed to have merit. The EPA decided not to proceed with final approval of the Department's BART determination until the comments were adequately addressed. Since the EPA's decision to not proceed with a final approval, North Dakota, EPA Region 8, and CCS have been engaged to resolve the issues raised by the commenters and provide an updated BART determination. The updated BART analysis from CCS is included in Appendix B.4.b.[165]. The Department's BART determination is included in Appendix F.

8.3 BART Summary

Coal Creek Station Unit 1 and Unit 2 are identical tangentially-fired pulverized coal boilers combusting North Dakota lignite coal. The existing NO_X control equipment for both Unit 1 and Unit 2 is LNC3+. LNC3+ is a combination of closed coupled overfired air, separated overfired air, and low NOx burners (LNC3) in conjunction with DryFining^{TM} and expanded overfire air registers (the "+" in LNC3+). LNC3+ was operational on Unit 2 in 2010 and on Unit 1 in 2020. The existing NOx controls were determined to be BART for Unit 1 and Unit 2 at CCS. The BART limit determined by the Department for each unit is a limit of 0.15 pounds per million Btu of heat input on a 30-day rolling average basis. This is lower than the proposed BART limit of 0.17 pounds per million Btu included in the "Supplemental No. 2" update provided in January 2013. The limit is to be achieved using the existing LNC3+ controls.

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[164] Available at: https://www.regulations.gov/, Docket ID: EPA-R08-OAR-2010-0406-0427

[165] Appendix B, PDF page 576. Appendix B.4.b also contains CCS's four factor analysis for Round 2 planning.

The selection of LNC3+ as BART is supported by the information contained in Appendix F. The key supporting factors are: LNC3+ is cost feasible at $700 per ton of NO_X reduced while providing a 28% reduction from the baseline emissions rate, and LNC3+ has negligible energy and non-air quality environmental impacts. Cost, technical feasibility concerns, added non-air quality environmental impacts, and limited modeled visibility improvement were the key factors in eliminating the consideration of add-on SNCR or SCR for CCS.

The proposed permit to construct putting in place the enforceable NOx emissions limits is included in Appendix F.2. The proposed limit of 0.15 lb NO_X per MMBtu on a 30-day rolling average is less than the presumptive BART limit established in Table 1 of the BART guidelines for tangential-fired lignite units. Table 1 of the guidelines indicates a presumptive BART limit of 0.17 lb NO_X per MMBtu on a 30-day rolling average.[166]

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[166] 40 CFR Part 51 Appendix Y, Guidelines for BART Determinations under the RHR

9 Five-Year Progress Report

9.1 Federal Requirements

Section 169(A) of the Clean Air Act (CAA) establishes the national visibility goal of “the prevention of any future, and the remedying of any existing, impairment of visibility in CIAs which impairment results from manmade air pollution.” Based on the requirements of Section 169(A), the Department developed a State Implementation Plan (SIP) to address the national visibility goal. The Regional Haze SIP for the first planning implementation period was submitted to the U.S. Environmental Protection Agency (EPA) in March 2010.

The RHR in 40 CFR 51.308(g) requires that each state develop periodic progress reports describing their progress toward the RPGs established in the RH SIP. The first periodic progress report is due to EPA five years after submittal of the RH SIP for the first planning implementation period with the next Progress Report due January 31, 2025 (40 CFR 51.308(g)). In 40 CFR 51.308(f)(1)(iv), EPA requires states to address the progress made towards the national visibility goal by stating:

> *“Progress to date for the most impaired and clearest days. Actual progress made towards the natural visibility condition since the baseline period, and actual progress made during the previous implementation period up to and including the period for calculating current visibility conditions, for the most impaired and for the clearest days”.*

In its document “Guidance on Regional Haze State Implementation Plans for the Second Planning Implementation Period” EPA states the required progress report elements:

> *“Section 51.308(f)(5) of the Regional Haze Rule requires a state to address in the plan revision the requirements of paragraphs 51.308 (g)(1) through (5), so that the plan revision due in 2021 will serve also as a progress report addressing the period since submission of the progress report for the first planning implementation period. The progress report for the first implementation period was only able to report on visibility levels, emissions, and implementation status up to a date sometime before it was submitted. To fully inform the public and EPA about past implementation activities, we recommend that the 2021 SIP cover a period approximately from the first full year that was not actually incorporated in the previous progress report through a year that is as close as possible to the submission date of the 2021 SIP.”*

To comply with this requirement, each section of the rule is addressed separately

- Status of Control Strategies in the Regional Haze SIP (40 CFR 51.308(g)(1))
- Emissions Reductions from the Regional Haze SIP Strategies (40 CFR 51.308(g)(2))
- Visibility Progress (40 CFR 51.308(g)(3))
- Emissions Progress (40 CFR 51.308(g)(4))
- Assessment of Changes Impeding Visibility Progress (40 CFR 51.308(g)(5))

The first periodic report, which was submitted to EPA in January 2015, has not been approved by EPA at the time this SIP revision is being drafted. Therefore, to better inform the public, data is being supplied from 2000–2018 rather than just the last five years.

9.2 Round 1 Background Information

In the RH SIP for the first planning implementation period, it was demonstrated that even if all North Dakota emissions of SO_2 and NO_x were removed, the uniform rate of progress could not be achieved (see RH SIP for the first planning implementation period, Section 8.6.3.3). The Department established RPGs based on its hybrid modeling approach for the first planning period of 16.9 dv for TRNP and 18.9 dv for LWA. However, it should be noted that based on WRAP's modeling approach, the RPGs would be 17.2 dv for TRNP and 19.1 dv for LWA (see first planning implementation period RH SIP, Table 9.14).

Both the Department's modeling approach and WRAP's modeling indicated that significant emissions reductions in North Dakota (60% for SO_2 and 25% for NO_x) would not have a significant impact ($\leq$5%) on the baseline visibility impairment for the 20% haziest days. The reasons for this small improvement are apparent by reviewing Section 3.1 and Appendix C. North Dakota sources contribute a small portion to the ammonium sulfate and ammonium nitrate light extinction in North Dakota's CIAs, meaning even significant changes in emissions are unlikely to significantly improve visibility. The RPGs established in the RH SIP were disapproved by EPA (77 FR 20944) because EPA disagreed with the NO_x BART determination for the Coal Creek Station and the NO_x reasonable progress determination for the Antelope Valley Station. Antelope Valley Station is now in compliance with the FIP NO_X limits. The Department has proposed a new BART limit for Coal Creek Station, included with Section 8 of this SIP revision.

The Department has submitted a SIP revision for Antelope Valley Station, which would replace the FIP for the Antelope Valley Station. On March 12, 2021 EPA proposed to approve the SIP revision submitted by the Department on August 3, 2020 which adopted the FIP requirements. In conjunction with this proposal, EPA also proposed to withdraw the portions of the 2012 FIP which applied to Antelope Valley Station.[167]

The EPA did not establish new RPGs in terms of deciviews in their FIP for regional haze in North Dakota. Technically, there are no RPGs established for North Dakota's CIAs. Since the proposed SIP revision for Antelope Valley Station will have a small effect on visibility impairment, the RPGs established in the RH SIP for the first planning implementation period will be utilized for this assessment. However, this SIP revision establishes new RPGs based on regional modeling (Section 6.1: Establishment of RPGs).

In order to achieve reasonable progress toward the national visibility goal, the RH SIP for the first planning implementation period relied primarily on SO_2 and NO_x reductions from existing coal fired EGUs. The requirements for the reductions were based on both the BART requirements in 40 CFR 51.308(e) and the reasonable progress requirements in 40 CFR 51.308(d).

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[167] 86 FR 14055. Available at: https://www.govinfo.gov/content/pkg/FR-2021-03-12/pdf/2021-04402.pdf

In addition to the BART and reasonable progress requirements, the RH SIP for the first planning implementation period relied on Federal programs such as:

- Heavy Duty Diesel Engine Standard
- Tier 2 Tailpipe Standards
- Large Spark Ignition and Recreational Vehicle Rule
- Nonroad Diesel Rule
- Industrial Boiler MACT
- NSPS and MACT Standards for Combustion Turbines, Reciprocating and Internal Combustion Engines

The SIP also relies on several on-going State emissions control programs in the North Dakota and non-SIP rules. These include the State's major and minor new source review program, fugitive dust control requirements, open burning restrictions, control requirements for sulfur dioxide and particulate matter from point sources, and State specific requirements for oil and natural gas production facilities. The list of emission control programs provided here is a summary of the RH SIP for the first planning implementation period and may not be comprehensive; please refer to this RH SIP revision for the second planning period for more details (Section 5.3).

9.3 Periodic Progress

9.3.1 Status of Control Strategies in the Regional Haze SIP - §51.308 (g)(1)

40 CFR 51.301(g)(1) states that the progress report shall include "*A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class I Federal areas both within and outside the State.*" The EPA expects states to describe: 1) BART and reasonable progress limits for individual sources; and 2) additional control measures that the state relied on to meet the requirements of the regional haze program that were to take effect in the first planning period.

The BART control requirements were implemented as expeditiously as possible but no later than five years after EPA approved the SIP (May 7, 2012). Therefore, different compliance dates applied for different sources and different pollutants. The BART and reasonable progress limits have been incorporated into the Title V Permits to Operate for the affected sources except the NO_x limits for Coal Creek Station, see Table 1 in Section 1.3. Coal Creek Station NO_X BART limits are addressed with this SIP revision under Section 8.

For a comparison of individual unit projected 2028 emissions, current representative performance rate, current emissions limits, and current SO_2 and NO_X control devices; see Table 22 for SO_2 (Section4.2.1.1.1) and Table 23 for NO_X (Section 4.2.1.1.2).

Additional control measures that the state relied on to meet the requirements of the regional haze program that were to take effect in the first planning period are included in Section 5.3. This includes State and Federal regulations and programs.

9.3.2 Emissions Reductions from Regional Haze SIP Strategies - §51.308 (g)(2)

The RHR require that a summary of emissions reductions achieved throughout the State through implementation of the control measures in the SIP be included in the periodic report.

Since the baseline period (2000–2004), significant emissions reductions of most visibility impairing pollutants have occurred in North Dakota. The reductions can be attributed to reductions in both the point and mobile source categories. Implementation of new controls at coal fired EGUs and new Federal requirements for on- and off-road engines are the main reasons for the reductions. Sections 4.1.1, 4.1.2, and 4.1.5 show the results of emission inventories for WRAP's 2002 Plan 02d, and the 2011 and 2017 National Emissions Inventory (NEI), respectively. The 2011 NEI data were the latest available for the initial progress report submitted in January 2015 and the 2017 NEI is included in this SIP revision for informational purposes. With any inventory, a change in estimation methodology or emission factors can greatly change the results. However, as shown in Section 4.2.1, the overall emission reductions at the EGUs, as measured by continuous emission monitors, are real. SO_2 and NO_X reductions from individual coal fired EGUs can be found in Sections 4.2.1.1.1 and 4.2.1.1.2, respectively. The coal fired EGUs were the sources subject to BART and reasonable progress in the first planning period.

The increase in VOC emissions is due primarily to increases in oil and gas area sources and fire events.

9.3.3 Visibility Progress - §51.308 (g)(3)

To satisfy the requirements of 40 CFR 51.308(g)(3), a state must assess the following visibility conditions and changes, with values for most impaired and/or clearest days expressed in terms of 5-years average of the annual values, for each CIA within the State:

- The current visibility conditions for the most impaired and clearest days,
- The difference between the current visibility for the MIDs and the clearest days and the baseline conditions; and
- The change in visibility impairment for the MIDs and the clearest days over the past 5 years.

Visibility impairment in North Dakota's CIAs on the MIDs is primarily due to ammonium sulfate and ammonium nitrate (Section 5.1.1). This is true whether the visibility metric is the haziest days, MIDs, or clearest days, see Section 3. North Dakota's SIP for the first implementation period focused primarily on controlling sources of sulfur dioxide and nitrogen oxides which form the ammonium sulfates and ammonium nitrates in the atmosphere, see Section 1.3. Organic carbon aerosols in North Dakota generally originate from fire (wildfire or prescribed burning) and fugitive sources. The Regional Haze SIP demonstrated that controls in-place for sources of fire and fugitive dust were adequate for the first planning period, Section 5.3.2 and 5.3.4.

The contribution of North Dakota sources to visibility impairment in nearby CIAs is shown in Table 39. North Dakota's CIAs are also included in Table 39. The sulfate and nitrate contributions to impairment in nearby CIAs are generally small, at less than 10%.

Table 39: North Dakota's Contribution to Light Extinction in Nearby Class I Areas

State	Class I Area	Total Light Extinction (Mm^{-1})	North Dakota Ammonium Nitrate	North Dakota Ammonium Sulfate
North Dakota	LOST1	39	13%	12%
North Dakota	THRO1	30	9%	8%
Montana	MELA1	35	8%	6%
South Dakota	BADL1	22	2%	5%
South Dakota	WICA1	17	1%	1%
Minnesota	VOYA2	28	2%	1%

The significant emissions reductions achieved by the EGUs in North Dakota equal or exceed those of surrounding states from the first implementation period of the RHR. The emissions reductions achieved in North Dakota likely assisted surrounding states in meeting their RPGs.

9.3.4 Emissions Progress - §51.308 (g)(4)

This section of the RHR requires each state to submit an analysis tracking the change over the past 5 years in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source of activity. The analysis must be based on the most recent updated emissions inventory, with estimates projected forward as necessary and appropriate to account for emissions changes during the applicable 5-year period.

Section 4.1 provides emissions inventory data for 2002, 2011, 2014, 2017, current representative, and projected future emissions. Discussion on where these data originate is also included in Section 4.1**.**

9.3.5 Assessment of Changes in Anthropogenic Emissions Impeding Visibility Progress - §51.308 (g)(5)

This section of the RHR requires "an assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred since the period addressed in the most recent plan…and whether they have limited or impeded progress in reducing pollutant emissions and improving visibility." The most obvious source category where emissions have increased in North Dakota is the oil and natural gas production sector. Beginning in 2008, development of the Bakken formation in North Dakota increased significantly. In 2008 there was an average of 3,869 active producing wells. The number average producing wells increased to 5,546 in 2011 and to 15,412 in 2019. In 2028, this number is projected to be at least 24,000. With the increase in production, emissions increased not only from oil and gas well operations, but also from well development, local infrastructure development, increased traffic, transportation of the oil and natural gas, treatment of the oil and gas, well maintenance, oil and condensate storage, and flaring of the natural gas when a pipeline or capacity within the pipeline is not available. Another, but less obvious source impeding visibility progress is North Dakota's population increase. North Dakota's pollution has increased by nearly 16% since 2010.[168] A significant portion of the increase in attributable to the support needed for the operation of the Bakken in the western North Dakota.

Emissions changes from the oil and gas sector have been quantified and are addressed in Section 4.3.1. The pollutants with the most significant increase are VOCs and NO_X. Bakken crude (from the Bakken, Sanish and Three Forks formations) typically contains a high concentration of lighter end components which have the potential to produce increased flash and fugitive hydrocarbon emissions. Flash emissions are the hydrocarbons emitted when the pressure of the crude oil is decreased, or the temperature is increased. In May 2011, the Department published its "Bakken Pool Oil and Gas Production Facilities Air Pollution Control Permitting and Compliance Guidance".[169] The Bakken Guidance established the expected air pollution control requirements for oil and gas production from the Bakken formation in order to comply with NDAC 33.1-15-07, Control of Organic Compounds Emissions and NDAC 33.1-15-20, Control of Emissions from Oil and Gas Well Production Facilities. The guidance is applicable to all areas of North Dakota except tribal areas. On March 22, 2013, the EPA finalized a Federal Implementation Plan (FIP) which established air pollution control requirements for oil and gas well production facilities on the Fort Berthold Indian Reservation. Both the North Dakota Air Pollution Control Rules, the Bakken Guidance, and the FIP were expected to reduce emissions of volatile organic compounds. Although emissions of volatile organic compounds have increased, they would likely have increased more substantially without these air pollution control requirements. Furthermore, it appears these emissions are having little effect on visibility in the CIAs, see Section 3.

Similar to VOC emissions, NOx emissions from area oil and gas facilities have increased as a result of the Bakken development. Much of the increase is attributed to the well drilling and completion phases of a wellsite. Another potentially significant source of emission is from the flaring of associated gas. As stated in Section 5.2.11, the North Dakota Industrial Commission adopted a policy to reduce flaring in the oil fields. This plan took effect beginning June 1, 2014. The policy was updated in September 2020.[170] This policy has been helpful in reducing the percentage of produced gas being flared. Figure 42 displays the amount and percent of flared gas since the Bakken development.

Since the baseline (2002), total Anthropogenic NOx emissions have not changed significantly (2002 vs. RepBase). North Dakota EGUs achieved over 41,000 tons of NO_X reductions from 2002 to RepBase. These reductions were displaced by the increase of over 57,000 tons of NO_X attributable to the area source oil and gas development. North Dakota is anticipating a reduction of over 50,000 tons of NO_X

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[168] Available at: https://apnews.com/article/census-2020-north-dakota-1750bbfe4ffc3749e71900ab63e08298#:~:text=The%20state's%20rate%20of%20growth,total%20population%20to%20779%2C094%20people. (Last visited May 19, 2021)

[169] Available at: https://www.deq.nd.gov/publications/AQ/policy/PC/20110502_OilGas_Permitting_Guidance.pdf (Last visited December 22, 2020)

[170] Available at: https://www.dmr.nd.gov/oilgas/112018GuidancePolicyNorthDakotaIndustrialCommissionorder24665_2.pdf (Last visited December 22, 2020)

from the current levels by 2028. These projections come from decreases in the EGU sector, area source oil and gas, and on-road and non-road engines.

The five-year rolling average nitrate extinction at TRNP has decreased 24% from the baseline (2002–2004) to the 2014-18 period on the 20% MIDs and 42% on the clearest days (Section 3.2.5). At LWA, nitrate extinction has decreased 22% on the MIDs and 4% on the clearest days (Section 3.2.5).

Although ozone is not a visibility impairing pollutant, the increase of volatile organic compounds and nitrogen oxides emissions have been speculated to cause increased ozone concentrations. The Department has established ozone monitoring stations at TRNP-SU, TRNP-NU, LWA and at various other sites across North Dakota. The monitor data indicates that ozone design concentrations at each CIA have remained stable since the baseline period (see Air Quality in North Dakota section). The increase in volatile organic compounds and nitrogen oxides from the oil and gas sector does not appear to be affecting ozone concentrations in the CIAs or any other regions of North Dakota.

Appendix A – Department Four-Factor Summaries

A.1 – Coyote Station

1 Introduction and Representative Operations

Otter Tail Power Company – Coyote Station (Coyote) is a single unit electrical generating utility (EGU) with a capacity to produce approximately 450 megawatts (MW) per hour of electricity. The boiler is a Babcock and Wilcox cyclone fired boiler with a heat input capacity of 5,800 million British thermal units (MMBtu) per hour. Coyote commenced operation in 1981. Coyote is located in Mercer County about three miles southwest of the town of Beulah, North Dakota. Coyote is a mine-mouth power plant which receives coal from North American Coal Company – Coyote Creek Mine.

The average annual amount of North Dakota lignite coal combusted at Coyote from 2009 through 2018 was 2.2 million tons. See Table 1 for detailed information.

Table 1: Yearly Coal Combusted (tons)

Year	Coal Combusted (tons)
2009	2,032,400
2010	2,445,773
2011	2,444,280
2012	1,824,595
2013	2,105,090
2014	2,248,483
2015	1,959,351
2016	2,011,974
2017	2,154,856
2018	2,501,698
Average	**2,172,850**

Over the same 10-year period (2009–2018), Coyote operated at a 60% annual capacity factor (ACF), as determined on an actual heat input basis. Future operations are expected to be consistent with this 10-year period and the 60% annual capacity factor was used when calculating the baseline and future projected emissions discussed in Section 2.

Table 2 displays the operational information from 2009–2018. The ACF is calculated by dividing the actual heat input by the maximum potential heat input of 50.8×10^6 MMBtu per year.

Table 2: Utilization and Annual Capacity Factor

Year	Actual Heat Input (MMBtu/yr)	Annual Capacity Factor (ACF)
2009	28,835,063	0.57
2010	35,201,254	0.69
2011	35,579,248	0.70
2012	27,008,173	0.53
2013	31,206,229	0.61
2014	32,197,996	0.63

Year	Actual Heat Input (MMBtu/yr)	Annual Capacity Factor (ACF)
2015	22,757,213	0.45
2016	27,102,662	0.53
2017	29,849,117	0.59
2018	34,550,493	0.68
Average	**30,428,745**	**0.60**

2 NO$_X$ and SO$_2$ Emissions Controls and History

Coyote commenced operation in 1981. Coyote was not a BART eligible source since construction of the facility commenced after the August 7, 1977 end date for facilities in existence. Coyote was, however, subject to the reasonable progress requirements during the first round of the regional haze program.

2.1 NOx

2.1.1 NO$_X$ Emissions Controls

Coyote's cyclone boiler is equipped with separated overfire air (SOFA) to reduce the formation of NO$_X$ during the combustion process. The Department reached an agreement with Coyote for the installation of SOFA during the first planning period of the regional haze program. Under Permit to Construct No. PTC10008, Coyote was required to install SOFA by July 1, 2018 and meet an emissions limit of 0.50 pounds NO$_X$ per MMBtu on a 30-day rolling average. This construction permit was incorporated as Appendix A.4 to the July 2011 Amendment No. 1 to the North Dakota State Implementation Plan for Regional Haze. On June 15, 2016 Coyote commenced start-up of the SOFA system to comply with the requirements of Permit to Construct No. PTC10008. No add-on NO$_X$ controls have been installed at Coyote.

2.1.2 NO$_X$ Emissions History

The time period from July 2016 through December 2018 was used to determine the NOx baseline emissions rate from Coyote. This information is displayed in Table 3.

Table 3: Annual NO$_X$ emissions rate

Year	Emissions Rate (lb/MMBtu)
2016	0.50
2017	0.42
2018	0.45
Average	**0.46**

The average emissions rate of 0.46 lb NO$_X$ per MMBtu is representative of future expected operations. This value is used as the starting point when determining the cost of compliance for the add-on controls evaluated in Section 3.2.

2.2 SO_2

2.2.1 SO_2 Emissions Controls

Coyote is equipped with dry flue gas desulfurization (DFGD) and a fabric filter (FF) baghouse for SO_2 and particulate matter control. The DFGD and FF baghouse were installed during the construction of the facility and have not been significantly modified since. Coyote was not required to install any SO_2 controls during the first round of the regional haze program.

2.2.2 SO_2 Emissions History

The time period from January 2013 through December 2018 was used to determine the SO_2 baseline emissions rate from Coyote. 2015 was removed from the baseline period since Coyote experienced operational issues in 2015 and this year was not considered representative of normal operations.[1] This information is displayed in Table 4.

Table 4: Annual SO_2 emissions rate

Year	Emissions Rate (lb/MMBtu)
2013	0.81
2014	0.79
2015[A]	0.77
2016	0.88
2017	0.90
2018	0.86
Average	**0.85**

[A] Not included in average.

3 NOx Analysis

3.1 NO_X Technologies

The reasonable progress controls evaluated by Coyote are listed in Table 5. Performance rate and expected annual emissions are included for each control technology that was determined to be technically feasible. Expected annual emissions were calculated using the performance rate, potential heat input, and the ACF (Table 2).

Table 5: Reasonable Progress NO_X Controls

Control Technology	Control Technology Abbreviation	Performance Rate (lb/MMBtu)	Emissions (tons/year)
Separated Overfire Air (baseline)	SOFA	0.46	7,015
Combustion Optimization	--	0.42	6,405
Selective Non-Catalytic Reduction	SNCR	0.28	4,270
SNCR + Rich Reagent Injection	SNCR + RRI	0.20	3,050
Selective Catalytic Reduction	SCR	--	--

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[1] Appendix B.1.b, p. 4-1. PDF page 33.

3.1.1 Combustion Optimization

Optimization of the combustion process through tuning the cyclone boiler has a small beneficial impact on reducing the formation of NO_X emissions. Tuning the boiler can lower the baseline performance rate from 0.46 to 0.42 lb NO_X per MMBtu, reducing the NO_X emission by approximately 9%. There is no cost associated with this technology since tuning the boiler primarily deals with optimization of the air-to-fuel ratio into the boiler. Combustion optimization would occur prior to the installation of any add-on controls.

3.1.2 Selective Non-Catalytic Reduction (SNCR)

Installation of SNCR post combustion add-on control equipment has a significant impact on removing NO_X emissions from the flue gas. SNCR is anticipated to provide approximately a 39% reduction in NO_X emissions from the baseline scenario, lowering the expected performance rate from 0.46 to 0.28 lb NO_X per MMBtu. Installation of SNCR on Coyote’s cyclone boiler is technically feasible and will be evaluated further.

3.1.3 Rich Reagent Injection (RRI)

RRI is a technology similar to SNCR, where a nitrogen-containing additive is injected to promote NO_X removal. The main differences are RRI is physically located in the lower part of the furnace near the cyclone boilers where SNCR is further downstream and RRI is done through one injection port where SNCR typically has many ports.

RRI is technically feasible at high load operations but has limitations at low loads due to the difficulty in maintaining the proper air-to-fuel ratio. RRI is typically installed after SNCR is installed for additional NO_X control. RRI is not commonly used as an individual NO_X control in lieu of SNCR since SNCR is better and more established. Therefore, RRI is evaluated as add-on control in addition to SNCR but not as a stand-alone add-on control by itself.[2]

Installation of SNCR + RRI has a significant impact on removing NO_X emissions from the flue gas. SNCR + RRI is anticipated to provide approximately a 57% reduction in NO_X emissions from the baseline scenario, lowering the expected performance from 0.46 to 0.20 lb NO_X per MMBtu. Installation of SNCR + RRI on Coyote’s cyclone boiler is technically feasible and will be evaluated further.

3.1.4 Selective Catalytic Reduction (SCR)

SCR is post combustion add-on control equipment. SCR, when feasible, typically has the greatest impact on removing NO_X emissions from a flue gas stream. SCR is traditionally installed in one of three configurations: high-dust, low-dust, or tail-end. During the first regional haze program planning period in North Dakota the Department determined that installation of SCR, in any configuration, is not a technically feasible control technology since it has not been demonstrated in practice on North Dakota lignite coal.[3] The determination of technical feasibility has not changed since the first regional haze program planning period; therefore, SCR will not be evaluated further.

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[2] Appendix B.1.b, p. 5-26. PDF page 60.

[3] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, Appendix B.5.

3.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost for the reasonable progress controls are listed in Table 6.

Table 6: NO_X Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
SOFA (Baseline)	0.46				
SOFA Optimization	0.42	610	0	0	
SNCR + Optimization	0.28	2,745	4,753,933	1,732	
SNCR + RRI + Optimization	0.20	3,965	12,690,135	3,200	6,505

A detailed breakdown of the costs listed in Table 6 can be found in Coyote's submitted four factors analysis.[4] The Department has reviewed these costs and believes them to be accurate.

As displayed in Table 6 and stated in Section 3.1.1, there is no cost associated with optimization of the combustion process. The 0.04 lb NO_X per MMBtu improvement over the baseline performance would be required as the first step for any of the remaining technologies evaluated.

If SNCR is installed in conjunction with combustion optimization, a performance rate improvement of 0.18 lb NO_X per MMBtu could be achieved. This equates to a potential reduction of approximately 2,750 tons NO_X per year from the baseline emissions. Fiscally, SNCR installation requires an estimated annualized cost of $4.75 million and NO_X removal cost of roughly $1,700 per ton.

The addition of RRI to SNCR and combustion optimization results in an expected performance improvement of 0.26 lb NO_X per MMBtu from the baseline performance rate. This equates to a potential reduction of approximately 3,970 tons NO_X per year from the baseline emissions. Fiscally, SNCR + RRI installation requires an estimated annualized cost of $12.7 million and NO_X removal cost of $3,200 per ton. To determine the appropriate reasonable progress control selection between SNCR and SNCR + RRI, the Department determined the stand-alone cost of installing RRI after SNCR is installed. This stand-alone cost is referred to as the incremental cost of compliance. Incremental cost of compliance is a key factor to consider when selecting reasonable progress controls since it details the cost effectiveness of RRI installation. A cost breakdown indicates approximately $8 million of the annualized cost is attributable to the installation of RRI, and results in the potential for an additional 1,220 tons of NO_X to be removed. This results in an incremental cost of compliance of roughly $6,500 per ton.

3.3 Step 2 – Time Necessary for Compliance

A summary of the anticipated timelines for the installation of controls is provided in Table 7.

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[4] Appendix B.1.b, Appendix C. PDF page 102.

Table 7: Time Required for NO_X Controls

Control Technology	Total time after SIP approval (months)
SOFA Optimization	0
SNCR + Optimization	22
SNCR + RRI + Optimization	22

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

3.4.1 Energy

Small changes to onsite energy consumption are likely to be experienced with the implementation of any add-on NO_X controls.[5] The impact not significant enough to eliminate add-on NO_X controls as a control option.

3.4.2 Non-Air Quality Environmental Impacts

SNCR use ammonia as a reagent. Ammonia slip emissions will result in the flue gas stream on the exhaust side of the control equipment due to the operation of the SNCR (~10 ppm). The ammonia slip emissions from the operation of SNCR would likely combine with the dry FGD solids. The ammoniated dry FGD solids would require that further safety precautions are taken for Coyote staff who perform maintenance on the ash handling system or staff who dispose of waste.

Similar to the energy impacts for add-on NO_X controls, the non-air quality environmental impacts are not significant enough to eliminate add-on NO_X controls as a control option.

3.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, Coyote is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

4 SO_2 Analysis

4.1 SO_2 Technologies

The reasonable progress controls that were evaluated by Coyote are listed in Table 8. Performance rate and expected annual emissions are included for each control technology that was determined to be technically feasible. Expected annual emissions were calculated using the performance rate, potential heat input, and the ACF (Table 2).

Table 8: Reasonable Progress SO_2 Controls

Control Technology	Control Technology Abbreviation	Performance Rate (lb/MMBtu)	Emissions (tons/year)
Dry Flue Gas Desulfurization (baseline)	DFGD	0.85	12,963
Dry Sorbent Injection	DSI	0.58	8,845
Dry Flue Gas Desulfurization Improvements	DFGD Improvements	0.5	7,625

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[5] Appendix B.1.b, p. 8-2 – 8-4. PDF page 84-86.

Control Technology	Control Technology Abbreviation	Performance Rate (lb/MMBtu)	Emissions (tons/year)
DFGD Improvements + DSI	DFGD Improvements + DSI	0.33	5,033
Absorber Replacement	--	0.09	1,373
New Dry Flue Gas Desulfurization and Fabric Filter	DFGD + FF	0.09	1,373
Wet Flue Gas Desulfurization	WFGD	0.06	915

4.1.1 Dry Sorbent Injection (DSI)

DSI is a proven technology which provides a moderate reduction of SO_2 in the flue gas stream. Sorbent is injected into the ductwork downstream of the boiler and upstream of the existing DFGD unit. Sorbent reacts with SO_2 to form particulate matter which is removed in the downstream fabric filter. DSI lowers the concentration of SO_2 entering the DFGD unit, allowing for an overall increase in SO_2 removal. Calcium- and sodium-based sorbents are the most common to reduce SO_2, each of which has pros and cons depending on the site and control equipment characteristics. The existing DFGD unit at Coyote utilizes a calcium-based system (hydrated lime); therefore, using a calcium-based sorbent is the most logical. This removes the potential for new chemical (sodium) constituents into the system which may adversely affect the existing scrubber operations.

DSI is anticipated to provide approximately a 32% reduction in SO_2 emissions from the baseline scenario, lowering the expected performance rate from 0.85 to 0.58 lb SO_2 per MMBtu. Adding DSI to the existing DFGD unit is technically feasible and will be evaluated further.

4.1.2 Flue Gas Desulfurization (FGD) Improvements

FGD Improvements are grouped into two categories, operational improvements and equipment upgrades. The operational improvements evaluated consisted of increasing the lime quality, increasing the stoichiometric ratio of calcium to sulfur (Ca:S) by increasing lime quantity, and lowering the absorber outlet temperature closer to the saturation point. The equipment upgrades consisted of atomizer replacement, slaker replacement, adding an absorber module, and replacing the existing absorber module.

For each of the operational improvements and equipment upgrades evaluated, the only technically feasible options are increasing the stoichiometric ratio of Ca:S coupled with atomizer replacement and replacing the existing absorber module. Replacing the absorber module is evaluated independent in Section 4.1.4. For complete discussion of the options determined to be technical infeasible, see Appendix B.1.b, pages 5-4 through 5-12.

For Coyote, increasing the Ca:S stoichiometry is best accomplished by increasing the quantity of fresh lime introduced into the system. Engineering testing was conducted in October of 2018 to determine the impact this type of stoichiometry adjustment could have on lowering SO_2 emissions. During the testing, it was determined that increasing the Ca:S ratio could achieve a rate as low as 0.50 lb SO_2 per MMBtu. If an increased stoichiometric ratio were to be required on a permanent basis, the existing dry scrubber atomizer nozzles would also need to be replaced from an eight nozzle design to a twelve nozzle design to achieve a more optimal slurry spray and decrease the potential for operational issues which may cause unit downtime.

Ca:S stoichiometry adjustments coupled with the atomizer replacement is anticipated to provide approximately a 41% reduction in SO_2 emissions from the baseline scenario, lowering the expected performance rate from 0.85 to 0.50 lb SO_2 per MMBtu. Increasing the Ca:S stoichiometry coupled with the atomizer replacement at the existing DFGD unit is technically feasible and will be evaluated further.

4.1.3 FGD Improvements with DSI

The technologies evaluated in Section 4.1.1 (DSI) and Section 4.1.2 (FGD Improvements) could be implemented together, resulting in a more significant overall reduction of SO_2. Implementation of FGD Improvements with DSI is anticipated to provide a 61% reduction from the baseline scenario, lowering the performance rate from 0.85 to 0.33 lb SO_2 per MMBtu. Implementation of FGD Improvements and DSI is technically feasible and will be evaluated further. It should be noted that additional flow modeling and field testing would need to be performed to ensure this performance level could be achieved and maintained without adversely affecting plant operability.

4.1.4 Absorber Replacement

Replacing the existing absorber module is technically feasible and could provide a significant improvement in reducing SO_2 emissions. Coyote originally indicated there is a no physical space for installation of a new absorber, making it an infeasible option since an approximate 12-month downtime was estimated for the replacement to occur. This inherently made an absorber replacement a less attractive control option. Since the original information was provided, Coyote submitted an analysis on June 8, 2020 indicating they could implement an absorber replacement.[6]

The absorber module replacement is anticipated to provide a 89% reduction from the baseline scenario, lowering the performance rate from 0.85 to 0.09 lb SO_2 per MMBtu. Replacement of the absorber module is technically feasible and will be evaluated further.

4.1.5 New Dry FGD (DFGD) and Fabric Filter (FF)

Two types of new DFGD systems were evaluated at Coyote, a spray dryer absorber (SDA) and a circulating dry scrubber (CDS). Each of these systems is technically feasible, commercially available, and would require significant modifications to the facility. The engineering evaluation determined the CDS would outperform the SDA at Coyote.[7] A new SDA/FF is anticipated to be able to achieve a performance rate of 0.16 lb SO_2 per MMBtu. A new CDS/FF is anticipated to be able to achieve a performance rate of 0.09 lb SO_2 per MMBtu. Given the lower performance rate with the CDS/FF system, the Department will focus the remaining analysis on the CDS/FF system. Implementation of a CDS/FF system represents an 89% reduction from the baseline scenario. Replacing the existing DFGD unit with a new CDS/FF is technically feasible. However, this option will not be evaluated further since Coyote has submitted additional information indicating an absorber replacement could

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[6] Appendix B.1.b. PDF page 216

[7] Appendix B.1.b, p. 5-18. PDF page 52.

achieve the same performance rate of 0.09 lb SO_2 per MMBtu at less than half the cost of a new CDS/FF.[8]

4.1.6 Wet FGD (WFGD)

Replacing the DFGD with a WFGD system located downstream of the existing FF was the most effective and costly SO_2 control option evaluated. WFGD systems are well established in and are operated on many coal-fired power plants firing medium to high sulfur coal. All WFGD systems use an alkaline slurry that reacts with SO_2 to form calcium sulfite and calcium sulfate. A WFGD system designed for Coyote is anticipated to be able to achieve a performance rate of 0.06 lb SO_2 per MMBtu, or a 93% reduction from the baseline emissions scenario. Installation of a new WFGD system is technically feasible and will be evaluated further.

4.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost of compliance for the reasonable progress controls are listed in Table 9.

Table 9: SO_2 Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
DFGD/FF (Baseline)	0.85				
DSI + Existing FGD	0.58	4,118	12,371,000	3,004	
FGD Improvements	0.50	5,338	2,085,000	391	-8,431
DSI + FGD Improvements	0.33	7,930	14,456,000	1,823	4,772
Absorber Replacement	0.09	11,590	21,122,000	1,822	1,821
WFGD	0.06	12,048	49,094,000	4,075	61,139

A detailed breakdown of the costs listed in Table 9Table 6 can be found in Coyote's submitted four factors analysis.[9] The Department has reviewed these costs and believes them to be accurate.

There are many options available for Coyote to reduce SO_2 emissions. The control costs vary drastically in annualized cost and significantly in effectiveness. A summary of each option evaluated is provided in the following paragraphs.

Installation of DSI would provide a potential 32% reduction in emissions from the baseline scenario. This results in approximately 4,100 tons of SO_2 reduced at an annualized cost approximately $12.3 million, equating to $3,000 per ton of SO_2 reduced. The FGD Improvements discussed in the following paragraph provide for greater emissions reductions at a lower cost, therefore, stand-alone installation of DSI on the existing DFGD unit is not considered further for reasonable progress.

FGD Improvements, specifically the Ca:S stoichiometric adjustments, provide a potential 41% reduction in emissions from the baseline scenario. This results in approximately 5,300 tons of SO_2

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[8] Appendix B.1.b. PDF page 220.

[9] Appendix B.1.b. Appendix B. PDF page 94.

reduced at an annualized cost of approximately $2 million, equating to approximately $400 per ton of SO_2 reduced. A benefit to this controls option is the facility can take advantage of upgrading existing equipment at a low capital cost compared to replacement of equipment at high capital costs. Also, as stated in Section 4.3, FDG Improvements could be implemented very quickly providing for a more immediate reduction in SO_2 emissions from the facility.

FGD improvements coupled with installation of DSI would provide a 61% reduction in emissions from the baseline scenario. This results in roughly 7,900 tons of SO_2 reduced at an annualized cost of approximately $14.5 million, equating to $1,800 per ton of SO_2 reduced. Since upgrading the FGD is recommended prior to installation of DSI, the incremental effectiveness of each individual control was reviewed. Consistent with the FGD improvements discussed in above paragraph, roughly 5,300 tons of the 7,900 tons reduced are attributable to the FGD improvements at a cost of approximately $400 per ton. The remaining 2,600 tons reduction is attributable to the DSI installation at an incremental cost of $4,800 per ton. FGD improvements are expected to lower the SO_2 performance rate from 0.85 to 0.50 lb SO_2 per MMBtu and DSI would further lower this from 0.50 to 0.33 lb SO_2 per MMBtu. In other words, Coyote could reduce the baseline emission rate by 0.35 lb SO_2 per MMBtu at a cost of $400 per ton and further reduce the rate by 0.17 lb SO_2 per MMBtu at a cost of $4,800 per ton.

Replacing the existing absorber with a new absorber would provide an 89% reduction in emissions from the baseline scenario. This results in approximately 11,600 tons of SO_2 reduced at an annualized cost of $21.1 million, equating to roughly $1,800 per ton of SO_2 reduced. This control option provides for a major reduction in SO_2 at a capital cost and high annualized cost.

Replacing the existing DFGD unit with a new WFGD unit would provide for an 93% reduction in emissions from the baseline scenario. This results in approximately 12,000 tons of SO_2 reduced at an annualized cost of $49 million, equating to $4,000 per ton of SO_2 reduced. This control option provides for a major reduction in SO_2 at a capital cost and high annualized cost. To determine if the limited improvement from the absorber replacement to a WFGD unit was viable considering the increased annualized cost, the incremental cost effectiveness between the two options was calculated. This incremental cost effectiveness was determined to be approximately $61,100 per ton, meaning the addition 0.03 lb SO_2 per MMBtu improvement (0.09 – 0.06) comes at an expensive cost. Since the installation of a new WFGD unit would not significantly improve the SO_2 performance rate (over absorber module replacement), the WFGD will not be considered for reasonable progress.

Of the options evaluated, three options remain on the table as potentially reasonable controls based on cost. These include existing FGD improvements, existing FGD improvements coupled with DSI, and replacement of the existing absorber module.

4.3 Step 2 – Time Necessary for Compliance

A summary of the anticipated timelines for the installation of controls is provided in Table 10.

Table 10: Time Required for SO_2 Controls

Control Technology	**Total time after SIP approval (months)**
DSI + Existing FGD	18
FGD Improvements	0

Control Technology	**Total time after SIP approval (months)**
DSI + FGD Improvements	18
Absorber Replacement	32
WFGD	56

4.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

4.4.1 Energy

Small changes to onsite energy consumption are likely to be experienced with the implementation of any SO_2 control options.[10] The impacts are not significant enough to eliminate and SO_2 controls as viable control options.

4.4.2 Non-Air Quality Environmental Impacts

Similar to the energy impacts for SO_2 controls, any non-air quality environmental impacts are not significant enough to eliminate additional SO_2 controls as a viable option.[11]

4.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, Coyote is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

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[10] Appendix B.1.b, p. 8-2 – 8-4. PDF page 84-86.

[11] Appendix B.1.b, p. 8-2 – 8-4. PDF page 84-86.

A.2 – Basin AVS

1 Introduction and Representative Operations

Basin Electric Power Cooperative (Basin) – Antelope Valley Station (AVS) is a two-unit electrical generating utility (EGU). Each unit has the capacity to produce approximately 470 megawatts (MW) per hour of electricity. Unit 1 and Unit 2 are identical Combustion Engineering boilers firing pulverized lignite coal tangentially. Unit 1 and Unit 2 each have a heat input capacity of 6,275 MMBtu per hour. Unit 1 began commercial operation in 1984. Unit 2 began commercial operation in 1986. AVS is located in Mercer County about eight miles northwest of the town of Beulah, North Dakota and approximately six miles north of US Highway 200. AVS receives most of its lignite coal from the coal that is too fine-grained to be used by the Great Plains Synfuels Plant (GPSP). GPSP is located just south of AVS. The remaining coal is delivered from the nearby Freedom Mine, which is located approximately two miles north of AVS.

The average annual amount of North Dakota lignite coal combusted at AVS from 2009 through 2018 was approximately 5.3 million tons. See Table 1 for detailed information.

Table 1: Yearly Coal Combusted (tons)

Year	Unit 1 (tons)	Unit 2 (tons)
2009	2,908,708	2,876,852
2010	3,017,251	2,435,302
2011	1,899,776	2,642,530
2012	2,732,031	2,660,454
2013	2,804,599	2,369,861
2014	2,332,119	2,583,418
2015	2,736,138	2,833,973
2016	2,797,996	2,184,054
2017	2,442,876	2,826,520
2018	2,809,117	2,628,612
Average	**2,648,061**	**2,604,158**
Combined Average	**5,252,219**	

Over the same 10-year period (2009–2018), AVS operated at a 63% annual capacity factor (ACF), as determined on an actual heat input basis. Based on information provided to the North Dakota Department of Environmental Quality, Division of Air Quality (Department), future operations are expected to be consistent with this 10-year period and the 63% annual capacity factor was used when calculating the baseline and future projected emissions discussed in Section 2.

Table 2 displays the operational information from 2009–2018. The ACF is calculated by dividing the actual heat input by the maximum potential heat input of 55.0 x 10^6 MMBtu per year.

Table 2: Utilization and Annual Capacity Factor

Year	Unit 1 Heat Input (MMBtu/yr)	Unit 2 Heat Input (MMBtu/yr)	Unit 1 Annual Capacity Factor	Unit 2 Annual Capacity Factor
2009	38,437,954	37,867,178	0.70	0.69

Year	Unit 1 Heat Input (MMBtu/yr)	Unit 2 Heat Input (MMBtu/yr)	Unit 1 Annual Capacity Factor	Unit 2 Annual Capacity Factor
2010	39,571,458	31,668,162	0.72	0.58
2011	24,197,378	36,027,754	0.44	0.66
2012	35,197,379	35,877,026	0.64	0.65
2013	36,715,597	33,019,271	0.67	0.60
2014	31,118,421	36,431,873	0.57	0.66
2015	37,115,552	39,565,968	0.68	0.72
2016	37,148,044	29,420,896	0.68	0.54
2017	30,310,984	37,550,654	0.55	0.68
2018	34,370,105	35,494,838	0.63	0.65
Average	**34,418,287**	**35,292,362**	**0.63**	**0.64**
		Combined Average	**0.63**	

2 NO$_X$ and SO$_2$ Emissions Controls and History

AVS commenced operation in 1984 when Unit 1 was started up. As is stated above, Unit 2 was started up in 1986. AVS was not a BART eligible source since construction of the facility commenced after the August 7, 1977 end date for “facilities in existence”. AVS was, however, subject to the reasonable progress requirements during the first round of the regional haze program.

During the first round of the regional haze program, the Department determined that no NO$_x$ or SO$_2$ controls were required for AVS Unit 1 or AVS Unit 2.[1] However, the United States Environmental Protection Agency (EPA) disapproved the Department’s determination[2] and promulgated a Federal Implementation Plan (FIP)[3], which required that a separated overfire air and low-NO$_x$ concentric firing system (SOFA/LNCFS) be installed on AVS Unit 1 and Unit 2. The FIP also required that a new NO$_x$ emission limit of 0.17 lb/MMBtu (30-day rolling average) be established for AVS Unit 1 and Unit 2. The FIP required that the NO$_x$ control technologies be installed by July 31, 2018 on both Unit 1 and Unit 2.[4]

2.1 NO$_x$

2.1.1 NO$_X$ Emissions Controls

The overfire air pollution control system, which was operational during the decision-making process of the first round of the regional haze program, was retired from Unit 1 on May 27, 2014 and replaced with SOFA/LNCFS on May 28, 2014. The overfire air system was retired from Unit 2 on June 10, 2016 and replaced with SOFA/LNCFS on June 11, 2016. The current air pollution control system operating on both Unit 1 and Unit 2 includes SOFA/LNCFS.

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[1] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 177-188.

[2] https://www.federalregister.gov/d/2012-6586/p-124

[3] https://www.federalregister.gov/d/2012-6586/p-amd-6

[4] https://www.federalregister.gov/d/2012-6586/p-780

2.1.2 NO_X Emissions History

Since the NO_x control technologies were installed on Unit 1 and Unit 2 in different years, the baseline emissions rate was determined using different time frames for Unit 1 and Unit 2. The time period from January 2015 through December 2018 was used to determine the NO_x baseline emissions rate for Unit 1. The time period from January 2017 through December 2018 was used to determine the NO_x baseline emissions rate for Unit 2. This information is displayed in Table 3.

Table 3: NO_X emissions

	Unit 1 Emissions		Unit 2 Emissions		Difference Between Units	
Year	**lb NO_X/MMBtu**	**tons NO_X**	**lb NO_X/MMBtu**	**tons NO_X**	**lb NO_X/MMBtu**	**tons NO_X**
2014 [A]	0.20	3,196	0.32	6,052	0.12	2,856
2015	0.11	2,103	0.36	7,283	0.25	5,180
2016 [B]	0.13	2,358	0.19	2,683	0.06	325
2017	0.11	1,662	0.11	2,045	0.00	383
2018	0.10	1,783	0.10	1,806	0.00	23
Baseline	**0.11**	**1,723**	**0.11**	**1,926**	**0.01**	**203**

[A] SOFA/LNCFS began operation on Unit 1 in May 2014

[B] SOFA/LNCFS began operation on Unit 2 in July 2016

The average emissions rate of 0.11 lb NO_X per MMBtu is representative of future expected operations. This value is used as the starting point when determining the cost of compliance for the add-on controls evaluated in Section 3.2.

2.2 SO_2

2.2.1 SO_2 Emissions Controls

AVS is equipped with dry flue gas desulfurization (DFGD) and a fabric filter (FF) baghouse for SO_2 and particulate matter control. The DFGD and FF baghouse were installed during the construction of the facility and have not been significantly modified since. AVS was not required to install any additional SO_2 controls during the first round of the regional haze program.[5]

2.2.2 SO_2 Emissions History

The time period from January 2014 through December 2018 was used to determine the SO_2 baseline emissions rate from AVS. This information is displayed in Table 4.

Table 4: SO_2 emissions

	Unit 1 Emissions		Unit 2 Emissions		Difference Between Units	
Year	**lb SO_2/MMBtu**	**tons SO_2**	**lb SO_2/MMBtu**	**tons SO_2**	**lb SO_2/MMBtu**	**tons SO_2**
2014	0.38	5,809	0.38	6,975	0.00	1,166
2015	0.34	6,312	0.34	6,716	0.00	404
2016	0.39	7,254	0.34	5,089	0.05	2,165
2017	0.35	5,259	0.41	7,603	0.06	2,344
2018	0.35	5,911	0.35	6,126	0.00	215

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[5] https://www.federalregister.gov/d/2012-6586/p-127

Year	Unit 1 Emissions		Unit 2 Emissions		Difference Between Units	
	lb SO_2/MMBtu	tons SO_2	lb SO_2/MMBtu	tons SO_2	lb SO_2/MMBtu	tons SO_2
Baseline	**0.36**	**6,109**	**0.36**	**6,502**	**0.00**	**393**

The average emissions rate of 0.36 lb SO_2 per MMBtu is representative of future expected operations. This value is used as the starting point when determining the cost of compliance for the add-on controls evaluated in Section 4.2.

3 NO_X Analysis

3.1 NO_X Technologies

Rich reagent injection (RRI), gas reburn, and innovative technologies such as NO_XStar^{TM}, PerNO$_X$ide, LoTO$_X$, and water injection were evaluated in Basin's four-factors analysis but were determined to not be available or technically feasible.[6]

RRI is a technology created for cyclone boilers. Unit 1 and Unit 2 at AVS are tangentially fired coal boilers. Therefore, RRI is considered to not be technically feasible.

Gas reburn would require extensive testing at both Unit 1 and Unit 2. Therefore, gas reburn is considered to not be technically feasible.

NO_XStar^{TM} is currently an emerging technology and long-term full-scale demonstration testing would be required to demonstrate its effectiveness at AVS. PerNO$_X$ide has only been tested on a pilot-scale and has not yet been demonstrated on any coal-fired boilers. Although LoTO$_X$ has been successfully applied in refinery applications, there are not currently any full-scale installations on coal-fired boilers. The injection of atomized water spray to lower NO_X production has been well demonstrated for combustion turbine applications but has not been sufficiently demonstrated in coal-fired applications. Therefore, further testing is required for each of these innovative technologies to demonstrate that any of them could be installed effectively at AVS. They are considered to not be technically feasible at this time.

The reasonable progress controls evaluated by AVS and determined to be available and technically feasible are listed in Table 5. Note that the expected annual emissions in Table 5 were calculated using the performance rate, potential heat input, and the ACF (Table 2). Therefore, the tons of NO_X emissions are different than the tons of NO_X emissions displayed in Table 3 since Table 5 contains calculated emissions based on representative operations.

Table 5: Reasonable Progress NO_X Controls

Control Technology	Control Technology Abbreviation	Performance Rate (lb NO_X/MMBtu)	Emissions (tons/year)
Separated Overfire Air with Low-NO_x Concentric Firing System (baseline)	SOFA/LNCFS	0.11	1,917
Selective Non-Catalytic Reduction	SNCR	0.09	1,568
Selective Catalytic Reduction - Tail End Configuration	TE-SCR	0.05	871

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[6] Appendix B.2.b, p. 5-17. PDF page 312.

3.1.1 Selective Non-Catalytic Reduction (SNCR)

Installation of SNCR post combustion add-on control equipment has a limited impact on removing NO_X emissions from the flue gas. The limited removal is due to low NO_X concentrations in the flue gas stream affecting the reaction kinetics.[7] Sources that are well suited for SNCR typically have an uncontrolled NO_X concentration above 200 ppm.[8] AVS is generally around 60 ppm uncontrolled NO_X, making AVS not well suited for SNCR application. SNCR is anticipated to provide an approximately 18% reduction in NO_X emissions from the baseline scenario, lowering the expected performance rate from 0.11 to 0.09 lb NO_X per MMBtu. SNCR has a limited impact on reducing NOx, however, installation of SNCR on Unit 1 and Unit 2 at AVS is technically feasible and will be evaluated further.

3.1.2 Selective Catalytic Reduction (SCR)

SCR is post combustion add-on control equipment. SCR, when feasible, has a significant impact on removing NO_X emissions from a flue gas stream. SCR is traditionally installed in one of three configurations: high-dust, low-dust, or tail-end. During the first regional haze program planning period in North Dakota, the Department determined that installation of SCR, in any configuration, is not a technically feasible control technology since it has not been demonstrated in practice on North Dakota lignite coal.[9] However, the earlier determination focused on cyclone-fired boilers. Successful use of TE-SCR controls have since been demonstrated at existing bituminous- and subbituminous-fired units. Therefore, the current determination is deeming TE-SCR as being technically feasible. TE-SCR is anticipated to provide an approximately 55% reduction in NO_X emissions from the baseline scenario, lowering the expected performance rate from 0.11 to 0.05 lb NO_X per MMBtu. TE-SCR is assumed technically feasible for installation on Unit 1 and Unit 2 at AVS and will be evaluated further.

3.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost for the reasonable progress controls are listed in Table 6.

Table 6: NO_X Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
SOFA/LNCFS (Baseline)	0.11				
SNCR	0.09	349	3,285,412	9,426	
TE-SCR	0.05	1,046	36,344,908	34,758	47,424

A detailed breakdown of the costs listed in Table 6 can be found in Basin's submitted four factors analysis.[10] The Department has reviewed these costs and believes them to be accurate.

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[7] John Sorrels, EPA Cost control Manual, Section 4, Chapter 1, p 1-16.

[8] John Sorrels, EPA Cost control Manual, Section 4, Chapter 1, p 1-5.

[9] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, Appendix B.5.

[10] Appendix B.2.b. Appendix D. PDF page 356.

If SNCR is installed, a performance rate improvement of 0.02 lb NO_X per MMBtu could be achieved. This equates to a potential reduction of 349 tons NO_X per year from the baseline emissions. Fiscally, SNCR installation requires an estimated annualized cost of $3.3 million and a NO_X removal cost of $9,400 per ton.

If TE-SCR is installed, a performance rate improvement of 0.06 lb NO_X per MMBtu could be achieved. This equates to a potential reduction of 1,046 tons NO_X per year from the baseline emissions. Fiscally, TE-SCR installation requires an estimated annualized cost of $36.3 million and a NO_X removal cost of approximately $35,000 per ton.

3.3 Step 2 – Time Necessary for Compliance

A summary of the anticipated timelines for the installation of SNCR and TE-SCR is provided in Table 7.

Table 7: Time Required for NO_X Controls

Control Technology	Total time after SIP approval (months)
SNCR	22
TE-SCR	52

The anticipated timelines for the installation of SNCR and TE-SCR indicate either option could be installed prior to the end of the second planning period.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

3.4.1 Energy

The installation and operation of a TE-SCR would increase the pressure drop through the control systems, which would increase the auxiliary power requirements. This would adversely affect the net plant heat rate. This impact is significant but not significant enough to eliminate TE-SCR as a control option.

3.4.2 Non-Air Quality Environmental Impacts

The installation and operation of the TE-SCR could result in an increase in sulfur emissions due to the potential oxidation of SO_2 to SO_3 and the subsequent reaction with moisture in the stack to form H_2SO_4.

Both TE-SCR and SNCR use ammonia as a reagent. Ammonia slip emissions will result in the flue gas stream on the exhaust side of the control equipment due to the the operation of TE-SCR (~2 ppm) and SNCR (~10 ppm). The ammonia slip emissions from the operation of SNCR would likely combine with the dry FGD solids. The ammoniated dry FGD solids would require that further safety precautions are taken for AVS staff who perform maintenance on the ash handling system or staff who dispose of waste. Ammonia slip emissions from the operation of the TE-SCR would be emitted to the atmosphere. Subsequently, the ammonia could combine with SO_X and NO_X to form sulfates and nitrates, which will affect visibility.

The non-air quality environmental impacts for TE-SCR and SNCR are significant but not significant enough to eliminate either of them as a control option.

3.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, AVS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

4 SO_2 Analysis

4.1 SO_2 Technologies

Fuel switching was evaluated in Basin's four-factors analysis but was not determined to be available since AVS is a mine mouth generation facility.

The reasonable progress controls evaluated by AVS are listed in Table 8. Performance rate and expected annual emissions are included for each control technology that was determined to be technically feasible. Note that the expected annual emissions in Table 8 were calculated using the performance rate, potential heat input, and the ACF (Table 2). Therefore, the tons of SO_2 emissions are different than the tons of SO_2 emissions displayed in Table 4 since Table 8 contains calculated emissions based on representative operations.

Table 8: Reasonable Progress SO_2 Controls

Control Technology	**Control Technology Abbreviation**	**Performance Rate (lb SO_2/MMBtu)**	**Emissions (tons/year)**
Dry Flue Gas Desulfurization / Fabric Filter (baseline)	DFGD/FF	0.36	6,274
Existing DFGD Operational Improvement: Station Work Practice	Station Work Practice	0.35	6,100
Existing DFGD Operational Improvement: Increase Ca:S Stoichiometric Ratio [A]	Ca:S Stoichiometry	0.20	3,486
New Retrofit DFGD (Circulating Dry Scrubber / Fabric Filter)	DFGD (CDS/FF)	0.09	1,568
New Retrofit Wet Flue Gas Desulfurization	WFGD	0.07	1,220

[A] Dry sorbent injection was also considered but would not provide any additional SO_2 removal beyond what can be achieved by increasing the Ca:S stoichiometric ratio.

4.1.1 Flue Gas Desulfurization (FGD) Improvements

FGD Improvements are grouped into two categories: 1) equipment upgrades and 2) operational improvements. The proposed equipment upgrades consisted of atomizer replacement, lime-slaker replacement, adding an absorber module, and replacing the existing absorber module. The proposed operational improvements evaluated consisted of station work practices, increasing the lime quality, increasing the stoichiometric ratio of calcium to sulfur (Ca:S) by increasing lime quantity, and lowering the absorber outlet temperature closer to the saturation point.

None of the equipment upgrades are considered technically feasible.[11] It is not technically feasible to replace the atomizer in order to improve air pollution control because there has not been any significant moisture carry-over into the baghouse or wetting of the absorber walls that would indicate

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[11] Appendix B.2.b, p 4-20. PDF page 284.

that the atomizers are not operating properly. Since additional slaking capacity was installed in 2011, it is not technically feasible to replace the slakers in order to reduce emissions. In addition, an additional absorber module or the replacement of any existing absorber modules would not provide any significant improvements towards removing additional sulfur. Therefore, adding an absorber module or replacing any existing absorber modules are considered to not be technically feasible SO_2 control strategies.

When considering the potential operational improvements, increasing the lime quality and lowering the absorber outlet temperature closer to the saturation point are not considered technically feasible. The lime used at AVS is already of high quality for use in dry scrubbers. Therefore, it is not technically feasible to increase the quality of the lime to reduce SO_2 emissions. Similarly, it is not technically feasible to further lower the outlet temperature closer to the saturation point because the AVS dry scrubbers currently operate at a temperature near the adiabatic saturation temperature. Station work practices and increasing the stoichiometric ratio of Ca:S are both considered technically feasible.

The initiation of certain "station work practices" has the ability to decrease SO_2 emissions at AVS. Unit 1 and Unit 2 at AVS have a combined 3-hour rolling average SO_2 limit of 3,845 lb/hr in their Title V Permit to Operate (T5-F86003).[12] When either Unit 1 or Unit 2 is in an extended major outage, operators decrease the SO_2 removal on the other Unit, while maintaining compliance with the SO_2 permit limit. This typically occurs once every three years on each unit. Station work practices are anticipated to provide an approximately 3% reduction in SO_2 emissions from the baseline scenario, lowering the expected performance rate from 0.36 lb SO_2 per MMBtu to 0.35 lb SO_2 per MMBtu. A change to the current station work practices is considered a technically feasible SO_2 control option for AVS Unit 1 and Unit 2.

For AVS, increasing the Ca:S stoichiometric ratio is best accomplished by increasing the quantity of fresh lime introduced into the system. Basin contracted with Babcock and Wilcox (B&W), the original equipment manufacturer of AVS's DFGD system, to determine whether additional SO_2 could be removed if the amount of fresh lime added to the system was increased. Based on simulations conducted by B&W's proprietary software, AVS could achieve a performance rate of 0.16 lb SO_2 per MMBtu by increasing the amount of fresh lime added to the system. This equates to a 44% reduction in SO_2 emissions from the baseline scenario of 0.36 lb SO_2 per MMBtu. Increasing the Ca:S stoichiometric ratio is considered a technically feasible SO_2 control option for AVS Unit 1 and Unit 2.

4.1.2 New Dry FGD (DFGD) and Fabric Filter (FF)

Two types of new DFGD systems were evaluated at AVS: 1) a spray dryer absorber (SDA) and 2) a circulating dry scrubber (CDS). Each of these systems is technically feasible, commercially available, and would require significant modifications to the facility. The engineering evaluation determined that the CDS would outperform the SDA at AVS.[13] A new SDA/FF is anticipated to be able to achieve a performance rate of 0.15 lb SO_2 per MMBtu. A new CDS/FF is anticipated to be able to achieve a performance rate of 0.09 lb SO_2 per MMBtu. Given the better performance rate with the CDS/FF system, the Department will focus the remaining analysis on the CDS/FF system. Implementation of a CDS/FF system represents a 75% reduction from the baseline scenario of 0.36 lb SO_2 per MMBtu.

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[12] Appendix B.2.c. PDF page 373.

[13] Appendix B.2.b, p 4-17. PDF page 281.

Replacing the existing DFGD unit with a new CDS/FF is technically feasible and will be evaluated further.

4.1.3 Wet FGD (WFGD)

Replacing the DFGD with a WFGD system located downstream of the existing FF was the most effective and most costly SO_2 control option evaluated. WFGD systems are well established and are operated on many coal-fired power plants that fire medium- to high-sulfur coal. All WFGD systems use an alkaline slurry that reacts with SO_2 to form calcium sulfite and calcium sulfate. A WFGD system designed for AVS is anticipated to be able to achieve a performance rate of 0.07 lb SO_2 per MMBtu, or an 81% reduction from the baseline emissions scenario of 0.36 lb SO_2 per MMBtu. Installation of a new WFGD system is technically feasible and will be evaluated further.

4.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost of compliance for the reasonable progress controls are listed in Table 9.

Table 9: SO_2 Cost of Compliance and Incremental Cost of Compliance

Control Technology	**Performance Rate (lb SO_2/MMBtu)**	**Annual Emission Reduction (tpy)**	**Annualized Total Cost ($)**	**Cost of Compliance ($/ton)**	**Incremental Cost of Compliance ($/ton)**
DFGD/FF (Baseline)	0.36				
Station Work Practice	0.35	174	135,000	775	
Ca:S Stoichiometry	0.20	2,788	1,938,773	695	690
DFGD (CDS/FF)	0.09	4,705	35,603,658	7,566	17,561
WFGD	0.07	5,054	39,267,491	7,770	10,512

A detailed breakdown of the costs listed in Table 9 can be found in Basin's submitted four factors analysis.[14] The Department has reviewed these costs and believes them to be accurate.

There are many options available for AVS to reduce SO_2 emissions. The control costs vary drastically in annualized cost and significantly in effectiveness. A summary of each option evaluated is provided in the following paragraphs.

A change to the current station work practices would provide a potential 3% reduction in emissions from the baseline scenario. This would result in approximately 170 tons of SO_2 being reduced at an annualized cost of approximately $135,000, equating to $775 per ton of SO_2 reduced. As stated in Section 4.3, a change to the current station work practices can be implemented very quickly, which would provide for a quick reduction in SO_2 emissions from the facility.

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[14] Appendix B.2.b. Appendix C. PDF page 343.

FGD Improvements, specifically Ca:S stoichiometric adjustments, provide a potential 44% reduction in emissions from the baseline scenario. This would result in approximately 2,790 tons of SO_2 being reduced at an annualized cost of approximately $1.9 million, equating to approximately $700 per ton of SO_2 reduced. A benefit of this control option is that the facility can take advantage of upgrading existing equipment at a low capital cost when compared to replacement with new equipment at a high capital cost.

Replacing the existing DFGD unit and FF with a new CDS/FF unit would provide for a 75% reduction in emissions from the baseline scenario. This would result in approximately 4,700 tons of SO_2 being reduced at an annualized cost of $35.6 million, equating to approximately $7,600 per ton of SO_2 reduced.

Replacing the existing DFGD unit with a new WFGD unit would provide for an 81% reduction in emissions from the baseline scenario. This would result in approximately 5,050 tons of SO_2 reduced at an annualized cost of $39.3 million, equating to approximately $7,800 per ton of SO_2 reduced.

4.3 Step 2 – Time Necessary for Compliance

A summary of the anticipated timelines for the installation of the technically feasible control technologies is provided in Table 10.

Table 10: Time Required for SO_2 Controls

Control Technology	Total time after SIP approval (months)
Station Work Practice	3
Ca:S Stoichiometry	51
DFGD (CDS/FF)	56
WFGD	60

The anticipated timelines for the installation of each of the control technologies indicates all options could be installed prior to the end of the second planning period.

4.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

4.4.1 Energy

The replacement of the existing drying scrubbing system with a CDS/FF or WFGD would increase the pressure drop through the control systems, which will increase the auxiliary power requirements. This would adversely affect the net plant heat rate. This impact is significant but not significant enough to eliminate either CDS/FF or WFGD as a control option.

4.4.2 Non-Air Quality Environmental Impacts

The installation and operation of a WFGD control option would generate a liquid calcium sulfate by-product that would need to be dewatered prior to disposal. In addition, WFGD control systems generate wastewater streams that typically contain a saturated solution of calcium sulfate, calcium sulfite, sodium chloride, trace amounts of fly ash, and unreacted limestone. The wastewater stream would need to be treated prior to discharge. WFGD systems also require significantly more water than dry systems. The non-air quality environmental impacts for WFGD are significant but not significant enough to eliminate WFGD as a control option.

4.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, AVS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

A.3 – Basin LOS

1 Introduction and Representative Operations

Basin Electric Power Cooperative (Basin) – Leland Olds Station (LOS) is a two-unit electrical generating station. Unit 1 and Unit 2 both primarily fire lignite with a small amount of subbituminous coal combusted. Unit 1 began commercial operation in 1966 and is a Babcock & Wilcox opposed wall-fired boiler that has the capacity to produce approximately 216 Megawatts (MW) per hour of electricity. Unit 2 began commercial operation in 1975 and is a Babcock & Wilcox cyclone-fired boiler that has the capacity to produce approximately 440 MW per hour of electricity. LOS is located on the banks of the Missouri River in eastern Mercer county, approximately four miles southeast of the town of Stanton, North Dakota. LOS receives lignite from the Coteau Properties Freedom Mine, which is located approximately thirty miles west of LOS.

The average annual amount of coal combusted at LOS from 2009 through 2018 was approximately 1 million tons for Unit 1 and 2 million tons for Unit 2. See Table 1 for detailed information.

Table 1: Yearly Coal Combusted (tons)

Year	Unit 1	Unit 2
2009	1,287,756	2,125,157
2010	1,163,282	2,081,633
2011	877,802	1,821,590
2012	1,013,575	1,826,247
2013	1,114,170	2,373,552
2014	888,389	2,151,508
2015	1,172,715	1,872,825
2016	1,164,055	2,266,471
2017	944,117	2,270,661
2018	1,104,951	1,797,457
Average	**1,073,081**	**2,058,710**

Over the same 10-year period (2009–2018), LOS operated at a 62% annual capacity factor (ACF) for Unit 1 and 60% ACF for Unit 2, as determined on an actual heat input basis. Based on information provided to the North Dakota Department of Environmental Quality, Division of Air Quality (Department), future operations are expected to be consistent with this 10-year period. The 62% and 60% annual capacity factors were used when calculating the baseline and future projected emissions discussed in Section 2.

Table 2 and Table 3 display the operational information from 2009–2018 for LOS Unit 1 and Unit 2, respectively. The ACF is calculated by dividing the actual heat input by the maximum potential heat input of each unit. The maximum potential heat input of Unit 1 is 23.0 x 10^6 MMBtu per year and the maximum potential heat input of Unit 2 is 44.9 x 10^6 MMBtu per year.

Table 2: Unit 1 Utilization and Annual Capacity Factor

Year	Unit 1 Heat Input MMBtu/yr	Unit 1 Annual Capacity Factor
2009	17,175,940	0.75

Year	Unit 1 Heat Input MMBtu/yr	Unit 1 Annual Capacity Factor
2010	15,297,310	0.67
2011	11,653,716	0.51
2012	13,716,670	0.60
2013	14,639,199	0.64
2014	11,933,747	0.52
2015	15,787,030	0.69
2016	15,566,955	0.68
2017	12,515,725	0.54
2018	14,285,928	0.62
Average	**14,257,222**	**0.62**

Table 3: Unit 2 Utilization and Annual Capacity Factor

Year	Unit 2 Heat Input MMBtu/yr	Unit 2 Annual Capacity Factor
2009	27,865,279	0.62
2010	26,903,299	0.60
2011	23,660,990	0.53
2012	23,477,374	0.52
2013	30,526,164	0.68
2014	28,352,132	0.63
2015	24,730,648	0.55
2016	30,344,385	0.68
2017	29,914,155	0.67
2018	23,585,131	0.52
Average	**26,935,956**	**0.60**

2 NO_X and SO_2 Emissions Controls and History

LOS commenced operation in 1966 when Unit 1 was started up. As is stated above, Unit 2 was started up in 1975. LOS was a best available retrofit technology (BART) eligible source since construction of the facility commenced before the August 7, 1977 end date for “facilities in existence” and after August 7, 1962. The Department determined that BART for LOS Unit 1 and Unit 2 included new wet limestone flue gas desulfurization (WFGD) for SO_2 control and selective non-catalytic reduction (SNCR) and separated overfire (SOFA) air for NO_X control.[1]

LOS was also subject to the reasonable progress requirements during the first round of the Regional Haze program. The Department determined that no additional NO_x or SO_2 controls were required for LOS Unit 1 or Unit 2 within the reasonable progress requirements.[2]

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[1] North Dakota State Implementation Plan for Regional Haze, Appendix B.1.

[2] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 188.

The United States Environmental Protection Agency (EPA) proposed to partially approve and partially disapprove of North Dakota's State Implementation Plan for Regional Haze submitted on March 3, 2010. In regard to LOS, the EPA proposed to disapprove the NO_X BART determination and emissions limit for Unit 2.[3] The EPA proposed the promulgation of a Federal Implementation Plant (FIP), which proposed advanced separated overfire air (ASOFA) plus selective catalytic reduction (SCR) and an emission rate of 0.07 lb/MMBtu (30-day rolling average) as BART for NO_X control on LOS Unit 2.[4] Following the public notice and comment period, the EPA issued its Final Rule on April 6, 2012.[5] In the Final Rule, EPA reversed its position regarding the technical feasibility of SCR on LOS Unit 2 and approved North Dakota's BART determination for NO_X control on Unit 2.[6] Therefore, a FIP was not promulgated for NO_X BART on LOS Unit 2 and the Department's initial BART determination for both LOS Unit 1 and Unit 2 was approved.

2.1 NO_X

2.1.1 NO_X Emissions Controls

The NO_X air pollution control system upgrades including SOFA and SNCR for Unit 1 and Unit 2 were placed into service in stages over several years. The final stages included the startup of SNCR on Unit 1 and Unit 2 in August 2015. Optimization of the NO_X air pollution control system upgrades were needed through 2015. The SNCR on Unit 1 and Unit 2 were again optimized in 2017, lowering the NO_X emissions rate. The current NO_X air pollution control system operating on Unit 1 and Unit 2 includes SOFA and SNCR.

2.1.2 NO_X Emissions History

The baseline emissions rate for NO_X was determined using the time period of January 2017 through December 2018 for both Unit 1 and Unit 2. This information is displayed in Table 4 and Table 5.

Table 4: Unit 1 Annual NO_X Rate and Emissions

Year	Emissions Rate (lb/MMBtu)	NO_x Emissions (tons)
2014	0.22	1,373
2015 [A]	0.24	1,814
2016	0.25	1,856
2017 [B]	0.18	1,121
2018	0.15	1,065
Baseline	**0.16**	**1,093**

[A] SNCR began operation in August 2015

[B] SNCR was reoptimized in 2017

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[3] https://www.federalregister.gov/d/2011-23372/p-253.

[4] https://www.federalregister.gov/d/2011-23372/p-705.

[5] https://www.federalregister.gov/d/2012-6586/p-3.

[6] https://www.federalregister.gov/d/2012-6586/p-159.

Table 5: Unit 2 Annual NOX Rate and Emissions

Year	Emissions Rate (lb/MMBtu)	NO_x Emissions (tons)
2014	0.37	5,202
2015 [A]	0.37	4,557
2016	0.37	5,434
2017 [B]	0.29	4,418
2018	0.29	3,599
Baseline	**0.29**	**4,009**

[A] SNCR began operation in August 2015

[B] SNCR was reoptimized in 2017

Unit 1 and Unit 2 contain different boiler types and are not expected to operate in similar ways. Table 4 and Table 5 show that Unit 1 and Unit 2 are not comparable in terms of emissions rate or emissions. Therefore, each unit has its own value for baseline emissions rate. The average emissions rate of 0.16 lb NO_X per MMBtu is representative of future expected operations for Unit 1. The average emissions rate of 0.29 lb NO_X per MMBtu is representative of future expected operations for Unit 2. These values are used as the starting point when determining the cost of compliance for the add-on controls evaluated in Section 3.2.

2.2 SO_2

2.2.1 SO_2 Emissions Controls

The new WFGD for SO_2 control was started up on Unit 1 in June 2013 and on Unit 2 in October 2012. The current SO_2 air pollution control system operating on Unit 1 and Unit 2 consists of WFGD, as required by BART.

2.2.2 SO_2 Emissions History

The time period from January 2015 through December 2018 was used to determine the SO_2 baseline emissions rate from Unit 1 and Unit 2 at LOS. This information is displayed in Table 6 and Table 7.

Table 6: Unit 1 Annual SO_2 Rate and Emissions

Year	Emissions Rate (lb/MMBtu)	SO_2 Emissions (tons)
2014	0.06	412
2015	0.09	681
2016	0.09	711
2017	0.09	554
2018	0.09	652
Baseline	**0.09**	**650**

Table 7: Unit 2 Annual SO2 Rate and Emissions

Year	Emissions Rate (lb/MMBtu)	SO_2 Emissions (tons)
2014	0.07	1,025
2015	0.09	1,066
2016	0.08	1,217
2017	0.09	1,364
2018	0.08	1,052
Baseline	**0.08**	**1,175**

As displayed in Table 6 and Table 7, Unit 1 and Unit 2 are not comparable in terms of tons of SO_2 emitted since Unit 2 is approximately twice as large. However, the emission rates, in terms of lb SO_2 per MMBtu are comparable between Unit 1 and Unit 2, due to each unit operating a WFGD unit and firing similar coal.[7] The average emissions rate of 0.09 lb SO_2 per MMBtu for Unit 1 is representative of future expected operations. The average emissions rate of 0.08 lb SO_2 per MMBtu for Unit 2 is representative of future expected operations for Unit 2. These values are used as starting points when determining the cost of compliance for the add-on controls evaluated in Section 4.2.

3 NO_X Analysis

3.1 NO_X Technologies

Gas reburn and innovative technologies such as NO_XStar^{TM}, PerNO$_X$ide, LoTO$_X$, and water injection were evaluated in Basin's four-factors analysis but were determined to not be available or technically feasible.[8]

Gas reburn would require extensive testing at both Unit 1 and Unit 2. Therefore, gas reburn is considered to not be technically feasible.

NO_XStar^{TM} is currently an emerging technology and long-term full-scale demonstration testing would be required to demonstrate its effectiveness at LOS. PerNO$_X$ide has only been tested on a pilot-scale and has not yet been demonstrated on any coal-fired boilers. Although LoTO$_X$ has been successfully applied in refinery applications, there are not currently any full-scale installations on coal-fired boilers. The injection of atomized water spray to lower NO_X production has been well demonstrated for combustion turbine applications but has not been sufficiently demonstrated in coal-fired applications. Therefore, further testing is required for each of these innovative technologies to demonstrate that any of them could be installed effectively at LOS. They are considered to not be technically feasible at this time for either Unit 1 or Unit 2.

The reasonable progress controls evaluated by LOS determined to be available and technically feasible are listed in Table 8 (Unit 1) and Table 9 (Unit 2). Performance rate and expected annual emissions are included for each control technology determined to be technically feasible. Note that the expected annual emissions in Table 8 and Table 9 were calculated using the performance rate, potential heat input, and the ACF (Table 2 and Table 3). Therefore, the tons of NO_X emissions are

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[7] When rounded to three decimal places, Unit 1 average is 0.088 and Unit 2 average is 0.084.

[8] Appendix B.3.b, p. 5-18 – 5-20. PDF page 448-450.

different than the tons of NO_X emissions displayed in Table 4 and Table 5 since the tables below contain calculated emissions based on representative operations.

Table 8: Reasonable Progress NO_X Controls (Unit 1)

Control Technology	Control Technology Abbreviation	Performance Rate (lb NO_X/MMBtu)	Emissions (tons/year)
Low-NO_X Burner with Selective Non-Catalytic Reduction and Separated Overfire Air (baseline)	LNB/SNCR/SOFA	0.16	1,152
Selective Catalytic Reduction - Tail End Configuration	TE-SCR	0.05	356

Table 9: Reasonable Progress NO_X Controls (Unit 2)

Control Technology	Control Technology Abbreviation	Performance Rate (lb NO_X/MMBtu)	Emissions (tons/year)
Selective Non-Catalytic Reduction with Separated Overfire Air (baseline)	SNCR/SOFA	0.29	3,894
Optimized Selective Non-Catalytic Reduction	Optimized SNCR	0.27	3,636
Optimized Selective Non-Catalytic Reduction with Rich Reagent Injection	Optimized SNCR + RRI	0.22	2,963

3.1.1 Optimized Selective Non-Catalytic Reduction (SNCR)

SNCR is currently installed on Unit 1 and Unit 2 at LOS, as required by the first round of Regional Haze planning for North Dakota. Therefore, optimization of SNCR is being considered as an option to reduce NO_X emissions.

Based on computational fluid dynamics modeling conducted for Unit 1 at LOS, any additional urea injection could result in negative impacts with ammonia slip emissions. In addition, during installation of the SNCR control equipment on Unit 1, it was determined that it would not be possible to install any multi-nozzle lances in their optimal locations due to physical interferences. Therefore, the current SNCR system on Unit 1 is considered fully optimized.

Optimization of the SNCR control equipment on Unit 2 is considered technically feasible. The SNCR original equipment manufacturer proposed that the SNCR system on Unit 2 could be further optimized by relocating all cyclone vent ports to improve stoichiometry and relocating the current urea injection lances to better utilize the reagent. Optimization of the SNCR control equipment is anticipated to provide an approximately 7% reduction in NO_X emissions from the baseline scenario. This would lower the expected performance rate from 0.29 to 0.27 lb NO_X per MMBtu. Optimization of SNCR is assumed to be technically feasible for installation on Unit 2 at LOS and will be evaluated further.

3.1.2 Selective Catalytic Reduction (SCR)

SCR is post combustion add-on control equipment. SCR, when feasible, can have a significant impact on removing NO_X emissions from a flue gas stream. SCR is traditionally installed in one of three configurations: high-dust, low-dust, or tail-end. During the first regional haze program planning period in North Dakota, the Department determined that installation of SCR, in any configuration, is not a technically feasible control technology since it has not been demonstrated in practice on North Dakota lignite.[9]

The earlier determination focused on North Dakota lignite-fired cyclone boilers. Therefore, SCR is not considered technically feasible for Unit 2 at LOS.

Successful use of TE-SCR controls has since been demonstrated at existing bituminous- and subbituminous-fired units. Even though this has not been demonstrated on North Dakota lignite-fired boilers, the current determination is deeming TE-SCR as being technically feasible for Unit 1 at LOS, which is an opposed wall-fired boiler. TE-SCR is anticipated to provide an approximately 69% reduction in NO_X emissions from the baseline scenario on Unit 1. This would lower the expected performance rate from 0.16 to 0.05 lb NO_X per MMBtu for Unit 1. TE-SCR is assumed to be technically feasible for installation on Unit 1 at LOS and will be evaluated further.

3.1.3 Optimized Selective Non-Catalytic Reduction (SNCR) Plus Rich Reagent Injection (RRI)

Rich reagent injection (RRI) is a technology created for cyclone boilers. Therefore, RRI is not considered to be a technically feasible option for Unit 1.

RRI alone only provides a beneficial NO_X reduction at full load. However, if RRI is coupled with SNCR, NO_X reduction can be achieved through a wider range of operating loads on Unit 2. Optimized SNCR + RRI is anticipated to provide an approximately 24% reduction in NO_X emissions from the baseline scenario on Unit 2. This would lower the expected performance rate from 0.29 to 0.22 lb NO_X per MMBtu for Unit 2. Optimized SNCR + RRI is assumed to be technically feasible for installation on Unit 2 at LOS and will be evaluated further.

3.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost for the reasonable progress controls are listed in Table 10 (Unit 1) and Table 11 (Unit 2).

Table 10: NO_X Cost of Compliance and Incremental Cost of Compliance (Unit 1)

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
LNB/SNCR/SOFA (Baseline)	0.16			
TE-SCR	0.05	796	33,663,928	42,316

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[9] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, Appendix B.5.

Table 11: NO_X Cost of Compliance and Incremental Cost of Compliance (Unit 2)

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
SNCR/SOFA (Baseline)	0.29				
Optimized SNCR	0.27	258	924,151	3,582	
Optimized SNCR + RRI	0.22	931	5,402,503	5,801	6,650

A detailed breakdown of the costs listed in Table 10 and Table 11 can be found in Basin's submitted four factors analysis.[10] The Department has reviewed these costs and believes them to be accurate.

If TE-SCR is installed on Unit 1, a performance rate improvement of 0.09 lb NO_X per MMBtu could be achieved. This equates to a potential reduction of approximately 800 tons NO_X per year from the baseline emissions. Fiscally, TE-SCR installation requires an estimated annualized cost of $33.6 million and a NO_X removal cost of approximately $42,000 per ton.

If SNCR is optimized on Unit 2, a performance rate improvement of 0.02 lb NO_X per MMBtu could be achieved. This equates to a potential reduction of approximately 260 tons NO_X per year from the baseline emissions. Fiscally, SNCR optimization on Unit 2 requires an estimated annualized cost of approximately $924,000 and a NO_X removal cost of $3,600 per ton.

If SNCR is optimized with RRI on Unit 2, a performance rate improvement of 0.07 lb NO_X per MMBtu could be achieved. This equates to a potential reduction of approximately 930 tons NO_X per year from the baseline emissions. Fiscally, SNCR optimization with RRI requires an estimated annualized cost of $5.4 million and a NO_X removal cost of $5,800 per ton.

3.3 Step 2 – Time Necessary for Compliance

A summary of the anticipated timeline for the installation of TE-SCR on Unit 1 is provided in Table 12.

Table 12: Time Required for NO_X Controls (Unit 1)

Control Technology	Total time after SIP approval (months)
TE-SCR	52

The anticipated timeline for the installation of TE-SCR on Unit 1 indicates that TE-SCR could be installed prior to the end of the second planning period.

A summary of the anticipated timelines for the optimization of SNCR and the optimization of SNCR plus RRI for Unit 2 is provided in Table 13.

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[10] Appendix B.3.b. Appendix D. PDF page 493

Table 13: Time Required for NO_X Controls (Unit 2)

Control Technology	**Total time after SIP approval (months)**
Optimized SNCR	12
Optimized SNCR + RRI	16

The anticipated timelines for the optimization of SNCR and the optimization of SNCR plus RRI indicate either option could be installed prior to the end of the second planning period.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

3.4.1 Energy

The installation and operation of a TE-SCR on Unit 1 would increase the pressure drop through the control systems, which would increase the auxiliary power requirements. This would adversely affect the net plant heat rate. This impact is significant but not significant enough to eliminate TE-SCR as a control option.

Optimization of the SNCR and optimization of the SNCR plus RRI on Unit 2 will adversely affect the net plant heat rate due to the amount of water that will be injected with urea, which will negatively impact boiler efficiency. This impact is significant but not significant enough to eliminate optimization of the SNCR or optimization of the SNCR plus RRI as control options.

3.4.2 Non-Air Quality Environmental Impacts

The installation and operation of the TE-SCR on Unit 1 could result in an increase in sulfur emissions due to the potential oxidation of SO_2 to SO_3 and the subsequent reaction with moisture in the stack to form H_2SO_4. In addition, TE-SCR uses ammonia as a reagent. Ammonia slip emissions will result in the flue gas stream on the exhaust side of the control equipment due to the operation of TE-SCR (~2 ppm). Ammonia slip emissions from the operation of the TE-SCR would be emitted to the atmosphere. The non-air quality environmental impacts for TE-SCR are significant but not significant enough to eliminate either of them as a control option.

3.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, LOS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

4 SO_2 Analysis

4.1 SO_2 Technologies

As part of the first planning period for Regional Haze, LOS was required to install WFGD for SO_2 control on Unit 1 and Unit 2 at LOS. Therefore, improvements or upgrades to the existing WFGD systems are now considered for reasonable progress control options. The reasonable progress controls evaluated by LOS are listed in Table 14 (Unit 1) and Table 15 (Unit 2). Performance rate and expected annual emissions are included for each control technology that was determined to be technically feasible. Note that the expected annual emissions in Table 14 and Table 15 were calculated using the performance rate, potential heat input, and the ACF (Table 2 and Table 3). Therefore, the tons of SO_2 emissions are different than the tons of SO_2 emissions displayed in Table 6 and Table 7 since the tables below contain calculated emissions based on representative operations.

Table 14: Reasonable Progress SO_2 Controls (Unit 1)

Control Technology	Control Technology Abbreviation	Performance Rate (lb SO_2/MMBtu)	Emissions (tons/year)
Wet Limestone Flue Gas Desulfurization (baseline)	WFGD	0.088	630
Increase Ca:S Stoichiometric Ratio	Ca:S Stoichiometry	0.080	570
Incorporation of pH Buffer and Increasing Limestone Addition	pH Buffer Additive	0.055	392

Table 15: Reasonable Progress SO_2 Controls (Unit 2)

Control Technology	Control Technology Abbreviation	Performance Rate (lb SO_2/MMBtu)	Emissions (tons/year)
Wet Limestone Flue Gas Desulfurization (baseline)	WFGD	0.084	1138
Increase Ca:S Stoichiometric and Liquid-to-Gas Ratios	Ca:S Stoichiometry and L/G Ratio	0.075	1010
Incorporation of pH Buffer and Increasing Limestone Addition	pH Buffer Additive	0.050	673

Three decimal places are shown in Table 14 and Table 15 for the performance rate in order to properly illustrate the difference in performance rates between WFGD and Ca:S Stoichiometry.

4.1.1 Flue Gas Desulfurization (FGD) Improvements and Upgrades

FGD Improvements are grouped into two categories: 1) operational improvements and 2) design changes and equipment upgrades. The proposed operational improvements evaluated consisted of increasing the limestone quality, increasing the stoichiometric ratio of calcium to sulfur (Ca:S) by increasing limestone quantity, and improving the liquid-to-gas ratio. The proposed design changes and equipment upgrades consisted of adding an additional spray level, optimizing the spray level coverage, and the incorporation of a pH buffer.

When considering the potential operational improvements, increasing the quality of the limestone is not considered technically feasible for Unit 1 or Unit 2. The limestone used at LOS is already of high quality for use in wet scrubbers. Therefore, it is not technically feasible to increase the quality of the limestone to reduce SO_2 emissions.

Increasing the stoichiometric ratio of Ca:S is considered technically feasible. For LOS Unit 1 and Unit 2, increasing the Ca:S stoichiometric ratio is best accomplished by increasing the quantity of fresh limestone introduced into the system.

The limestone feed rate for Unit 1 is maintained near the maximum design stoichiometry based on the inlet SO_2 concentration. Therefore, increasing the fresh limestone addition rate slightly could provide minor additional SO_2 removal for Unit 1. Increasing the amount of fresh limestone added to the system would provide a performance rate improvement of 0.01 lb SO_2 per MMBtu. This equates to a 10% reduction in SO_2 emissions from the baseline scenario of 0.09 lb SO_2 per MMBtu. Increasing the Ca:S stoichiometric ratio is considered a technically feasible SO_2 control option for LOS Unit 1.

The recycle slurry flow rates for Unit 1 indicate that Unit 1 operating pumps typically operate at their maximum capacity. The recycle pumps are not adjusted for operating load or SO_2 loading. Therefore, changes to the liquid-to-gas (L/G) ratio at Unit 1 is not considering to be technically feasible.

As stated above, increasing the limestone feed rate for Unit 2 is technically feasible, but would need to be done in tandem with increasing the liquid-to-gas (L/G) ratio, since Unit 2 is not currently operating at its maximum design L/G ratio. Only three of the four recycle pumps have been operating at a time. Increasing the amount of fresh limestone added to the system in tandem with increasing the L/G ratio would provide a performance rate improvement of 0.01 lb SO_2 per MMBtu. This equates to an 11% reduction in SO_2 emissions from the baseline scenario of 0.08 lb SO_2 per MMBtu. Increasing the Ca:S stoichiometric ratio in tandem with increasing the L/G ratio is considered a technically feasible SO_2 control option for LOS Unit 2.

Regarding design changes, it is not technically feasible to add an additional spray level or to optimize the spray level coverage for Unit 1 or Unit 2. There is no room for an additional spray level on either unit. After reviewing the operations at LOS, the original equipment manufacturer of LOS's WFGD spray coverage concluded that no additional improvements could be made to the spray nozzle design that would reduce SO_2 emissions. Therefore, adding an additional spray level and optimizing the spray level coverage are not considered to be technically feasible SO_2 control strategies and will not be considered further.

The use of dibasic acid (DBA), a pH buffer additive, in conjunction with increasing the rate of injection of fresh limestone is expected to reduce SO_2 emissions at both Unit 1 and Unit 2.

Unit 1 could achieve a performance rate of 0.06 lb SO_2 per MMBtu using DBA in conjunction with increasing the fresh limestone injection rate. This equates to a 38% reduction in SO_2 emissions from the baseline scenario of 0.09 lb SO_2 per MMBtu. A pH buffer additive is considered a technically feasible SO_2 control option for LOS Unit 1.

Unit 2 could achieve a performance rate of 0.05 lb SO_2 per MMBtu using DBA in conjunction with increasing the fresh limestone injection rate. This equates to a 41% reduction in SO_2 emissions from the baseline scenario of 0.08 lb SO_2 per MMBtu. A pH buffer additive is considered a technically feasible SO_2 control option for LOS Unit 2.

4.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost of compliance for the reasonable progress controls are listed in Table 16 (Unit 1) and Table 17 (Unit 2).

Table 16: SO_2 Cost of Compliance and Incremental Cost of Compliance (Unit 1)

Control Technology	Performance Rate (lb SO_2/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
WFGD (Baseline)	0.09				
Ca:S Stoichiometry	0.08	59	752,000	12,698	
pH Buffer Additive	0.06	237	4,833,418	20,357	22,902

Table 17: SO_2 Cost of Compliance and Incremental Cost of Compliance (Unit 1)

Control Technology	Performance Rate (lb SO_2/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
WFGD (Baseline)	0.09				
Ca:S Stoichiometry and L/G Ratio	0.08	128	1,439,000	11,264	
pH Buffer Additive	0.05	464	8,287,368	17,843	20,340

A detailed breakdown of the costs listed in Table 16 and Table 17 can be found in Basin's submitted four factors analysis.[11] The Department has reviewed these costs and believes them to be accurate.

Ca:S stoichiometric adjustments on Unit 1 would provide a potential 10% reduction in emissions from the baseline scenario. This would result in approximately 60 tons of SO_2 being reduced at an annualized cost of approximately $752,000, equating to approximately $12,700 per ton of SO_2 reduced. This control option does not provide a significant reduction in emissions.

Ca:S stoichiometric adjustments in tandem with increasing the L/G ratio on Unit 2 would provide a potential 11% reduction in emissions from the baseline scenario. This would result in approximately 130 tons of SO_2 being removed at an annualized cost of approximately $1.4 million, equating to approximately $11,300 per ton of SO_2 reduced.

Incorporation of a pH buffer additive on Unit 1 would provide a potential 38% reduction in emissions from the baseline scenario. This would result in approximately 240 tons of SO_2 being reduced at an annualized cost of approximately $4.8 million, equating to approximately $20,400 per ton of SO_2 reduced.

Incorporation of a pH buffer additive on Unit 2 would provide a potential 41% reduction in emissions from the baseline scenario. This would result in approximately 460 tons of SO_2 being reduced at an annualized cost of approximately $8.3 million, equating to approximately $17,800 per ton of SO_2 reduced.

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[11] Appendix B.3.b. Appendix C. PDF page 482.

4.3 Step 2 – Time Necessary for Compliance

A summary of the anticipated timelines for the installation of the technically feasible control technologies for Unit 1 is provided in Table 18.

Table 18: Time Required for SO_2 Controls (Unit 1)

Control Technology	Total time after SIP approval (months)
Ca:S Stoichiometry	3
pH Buffer Additive	12

The anticipated timelines for the installation of each of the control technologies indicates all options could be installed prior to the end of the second planning period.

A summary of the anticipated timelines for the installation of the technically feasible control technologies for Unit 2 is provided in Table 19.

Table 19: Time Required for SO_2 Controls (Unit 2)

Control Technology	Total time after SIP approval (months)
Ca:S Stoichiometry and L/G Ratio	3
pH Buffer Additive	12

The anticipated timelines for the installation of each of the control technologies indicates all options could be installed prior to the end of the second planning period.

4.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

4.4.1 Energy

Adjustment of the Ca:S stoichiometric ratio would require an increased operation of the recycle pump, which will increase the auxiliary power requirements. This would adversely affect the net plant heat rate. This impact is significant but not significant enough to eliminate adjustment of the Ca:S stoichiometric ratio as a control option.

4.4.2 Non-Air Quality Environmental Impacts

There are no known significant non-air quality environmental impacts associated with any of the technically feasible SO_2 control technologies.

4.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, LOS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

A.4 – CCS

1 Introduction and Representative Operations

Coal Creek Station (CCS) is a two-unit electrical generating utility (EGU). Each unit has the capacity to produce approximately 605 megawatts (MW) of power on a gross basis. Unit 1 and Unit 2 are identical Combustion Engineering boilers firing pulverized lignite coal tangentially. Unit 1 has a heat input capacity of 6,015 MMBtu per hour; Unit 2 has a heat input capacity of 6,022 MMBtu per hour. Unit 1 began commercial operation in 1979. Unit 2 began commercial operation in 1980. CCS is located in south central McLean County about five miles south of the town of Underwood, North Dakota and approximately three miles west of US Highway 83. CCS receives its lignite coal from the Falkirk Mine that is operated by the Falkirk Mining Company, which is a subsidiary of the North American Coal Corporation.

The average annual amount of North Dakota lignite coal combusted at CCS from 2009 through 2018 was approximately 7.2 million tons. See Table 1 for detailed information.

Table 1: Yearly Coal Combusted (tons)

Year	Unit 1 (tons)	Unit 2 (tons)
2009	4,095,584	3,941,997
2010	3,835,877	3,284,752
2011	4,371,455	4,801,722
2012	3,645,837	3,579,986
2013	3,623,564	3,304,313
2014	3,407,090	3,528,472
2015	3,439,201	3,446,814
2016	3,355,393	2,862,056
2017	2,752,937	3,394,443
2018	3,750,337	3,667,824
Average	**3,627,728**	**3,581,238**
Combined Average	**7,208,966**	

Over the same 10-year period (2009–2018), CCS operated at an 87% annual capacity factor (ACF), as determined on an actual heat input basis. Based on information provided to the North Dakota Department of Environmental Quality, Division of Air Quality (Department), future operations are expected to be consistent with this 10-year period and the 87% annual capacity factor was used when calculating the baseline and future projected emissions discussed in Section 2.

Table 2 displays the operational information from 2009–2018. The ACF is calculated by dividing the actual heat input by the maximum potential heat input for Unit 1 (52.69×10^6 MMBtu/yr) and Unit 2 (52.75×10^6 MMBtu/yr).

Table 2: Utilization and Annual Capacity Factor

Year	Unit 1 Heat Input (MMBtu/yr)	Unit 2 Heat Input (MMBtu/yr)	Unit 1 Annual Capacity Factor	Unit 2 Annual Capacity Factor
2009	49,625,416	48,220,581	0.94	0.91

Year	Unit 1 Heat Input (MMBtu/yr)	Unit 2 Heat Input (MMBtu/yr)	Unit 1 Annual Capacity Factor	Unit 2 Annual Capacity Factor
2010	49,409,811	41,998,558	0.94	0.80
2011	43,014,802	46,942,626	0.82	0.89
2012	48,676,811	47,951,409	0.92	0.91
2013	48,686,810	43,924,548	0.92	0.83
2014	46,286,312	46,530,063	0.88	0.88
2015	47,059,790	46,053,317	0.89	0.87
2016	45,437,239	38,498,049	0.86	0.73
2017	37,327,033	44,826,636	0.71	0.85
2018	48,250,097	47,761,484	0.92	0.91
Average	**46,377,412**	**45,270,727**	**0.88**	**0.86**
		Combined Average	**0.87**	

2 SO_2 Emissions Controls and History

CCS commenced operation in 1979 when Unit 1 was started up. As is stated above, Unit 2 was started up in 1980. CCS was deemed BART eligible in round 1 of Regional Haze and an analysis determined that 0.15 lb/MMBtu of SO_2 as a 30-day rolling average met BART requirements. CCS currently operates four-module wet flue gas desulfurization scrubbers to comply with the 0.15 lb/MMBtu SO_2 limit.

2.1 SO_2

2.1.1 SO_2 Emissions Controls

CCS is equipped with wet flue gas desulfurization (WFGD) for SO_2 control on Unit 1 and Unit 2. CCS also utilizes DryFining^{TM}, a multi-pollutant control technology. DryFining^{TM} provides a heat input reduction that correspondingly decreases the amount of flue gas created in the combustion process. In 2017 a novel flue gas reheat system was installed. This allows for an additional proportion of gas to be routed to the wet scrubber instead of having to bypass, providing a decrease in the lb/MMBtu SO_2 emission rate.[1] Both exhaust stacks are equipped with a SO_2 continuous emissions monitoring system (CEMS).

2.1.2 SO_2 Emissions History

June 2017 through December 2018 was used to determine the SO_2 baseline emissions rate from CCS. This time period was chosen since it serves as the best representation of expected emissions and performance rate of the WFGD operations. This information is displayed in Table 3.

Table 3: SO_2 emissions

Year	Unit 1 Emissions		Unit 2 Emissions	
	lb SO_2/MMBtu	tons SO_2	lb SO_2/MMBtu	tons SO_2
2017	0.14	1,938	0.14	1,793
2018	0.14	3,458	0.14	3,400

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[1] Appendix B.4.b, p 5. PDF page 1051.

Year	Unit 1 Emissions		Unit 2 Emissions	
	lb SO_2/MMBtu	**tons SO_2**	**lb SO_2/MMBtu**	**tons SO_2**
Baseline	0.14	2,698	0.14	2,596

The average emissions rate of 0.14 lb SO_2 per MMBtu is representative of future expected operations. This value is used as the starting point when determining the cost of compliance for the add-on controls evaluated in Section 3.2.

3 SO_2 Analysis

3.1 SO_2 Technologies

The reasonable progress controls that were identified for analysis for CCS Unit 1 and Unit 2 are listed in Table 4, along with their approximate annual control efficiency. All controls were deemed technically feasible.

Table 4: SO_2 Controls Identified for Analysis

Control Technology	Approximate Annual Control Efficiency
Dry Sorbent Injection	50-70%
Spray Dry Absorption	70-90%
Natural Gas Reheat System	96%
New Wet Stack	96%

CCS currently utilizes a minor bypass in limited situations to maintain dry stack conditions. A natural gas reheat system or new wet stacks would theoretically remove the need for this bypass, maximizing the proportion of flue gas to the wet scrubber.[2] Both methods were analyzed as potential options and result in the same control efficiency. The existing WFGD system currently achieves an annual average removal efficiency of approximately 94% to 95%.[3] Dry sorbent injection and spray dry absorption would not provide improvement over CCS's existing SO_2 emissions control system and were not evaluated further.

3.1.1 New Wet Stack

One control option that was analyzed was the replacement of the current stacks on Unit 1 and Unit 2. CCS Unit 1 and Unit 2 are both dry stacks, despite using a wet scrubber. Converting the existing stacks to a wet stack design is not possible and instead new wet stacks would need to be constructed and the current stacks would be abandoned and demolished. For the evaluation of a new wet stack, Hamon Custodis, Inc. provided an initial high-level concept to effectively replace the two existing stacks with a rough budget price. CCS has added to this price a high-level and conservatively low set of cost estimates to convert the Custodis cost to an appropriate diameter and

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[2] Appendix B.4.b, pp 25-26. PDF pages 1071-1072.

[3] Appendix B.4.b, p 25. PDF page 1071.

to include foundations, duct work, and continuous emissions monitoring systems (CEMS).[4] A new wet stack would result in an approximate 1,377 ton per year reduction of SO_2.

3.1.2 Natural Gas Reheat System

CCS Units 1 and 2 currently utilize a novel flue gas reheat system that can maintain a dry stack under most operating situations, while maximizing the proportion of flue gas to the wet scrubber. During low load and cold weather operation, the existing reheat system does not provide enough thermal energy to reheat the stack gas to a dry state. The existing reheat system adds approximately 11 MMBtu/hr, and CCS estimates that approximately 31.5 MMBtu/hr of additional energy would be required to maintain a dry stack under all operating conditions. WBI Energy provided a cost estimate for a new gas line, with the cost split between both units. Barr Engineering provided an estimate for the natural gas-fired duct burner system, with additional consideration for site-specific installation factors. [5] The installation of a new natural gas reheat system would result in an approximate 1,377 ton per year reduction of SO_2.

3.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost of compliance for the reasonable progress controls are listed in Table 5.

Table 5: SO_2 Cost of Compliance and Incremental Cost of Compliance

Control Technology	**Performance Rate (lb SO_2/MMBtu)**	**Annual Emission Reduction (tpy)**	**Annualized Total Cost ($)**	**Cost of Compliance ($/ton)**
WFGD(Baseline)	0.14			
New Wet Stack	0.08	1,377	3,979,749	2,890
Natural Gas Reheat System	0.08	1,377	3,388,308	2,460

A detailed breakdown of the costs listed in Table 5 can be found in Great River Energy's submitted four factors analysis.[6] The Department has reviewed these costs and believes them to be accurate.

A new wet stack would result in a cost of compliance value of $2,890 per ton of SO_2 removed. A new natural gas reheat system would result in a cost of compliance value of $2,460 per ton of SO_2 removed.

3.3 Step 2 – Time Necessary for Compliance

Both the new wet stack and natural gas reheat system would require at least two to three years to engineer, permit, and install the equipment. Therefore, time necessary for compliance is not a limiting factor when determining additional reasonable controls. The anticipated timeline would allow for either option to be installed prior to the end of the second round of regional haze.

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[4] Appendix B.4.b, p 26. PDF page 1072.

[5] Appendix B.4.b, pp 26-27. PDF pages 1072-1073.

[6] Appendix B.4.b. Appendix A. PDF page 1078.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

The replacement wet stack would result in the demolition and disposal of a significant amount of materials with associated use of demolition equipment and portable engines to accommodate these activities.

The natural gas-fired reheat system would result in additional non-SO_2 pollutant emissions from the combustion of natural gas onsite. Potential NO_x emissions are estimated to be between 14 and 27 tons per year.[7]

The energy and non-air quality environmental impacts from the new wet stack or the natural gas reheat system are significant but do not significant enough to remove the control technology from consideration.

3.5 Step 4 – Remaining Useful Life

For the purposes of this analysis, a 20-year life was used for CCS to calculate emission reductions, amortized costs, and cost effectiveness. Therefore, remaining useful life does not need to be considered for the purposes of round 2 planning.

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[7] Appendix B.4.b, p 29. PDF page 1075.

A.5 – Minnkota MRY

1 Introduction and Representative Operations

Minnkota Power Cooperative, Inc. (Minnkota) – Milton R. Young Station (MRYS) is a two-unit electrical generating station. Unit 1 is a Babcock & Wilcox cyclone-fired boilers fired on lignite coal. Unit 1 commenced commercial operation in 1970. Unit 1 has a turbine-generator nameplate rating of 257 megawatts (MW) and a nominal rated heat input capacity of 3,200 MMBtu per hour. MRYS is located approximately five miles southeast of the town of Center, North Dakota. MRYS receives lignite from BNI Coal, Ltd's Center Mine, which is located adjacent to the facility.

The average annual amount of North Dakota lignite coal combusted at MRYS Unit 1 from 2009 through 2018 was 1.5 million tons. See Table 1 for detailed information.

Table 1: MRYS Unit 1 Coal Combusted

Year	Coal Combusted (tons)
2009	1,324,257
2010	1,582,806
2011	1,408,716
2012	1,610,825
2013	1,465,413
2014	1,545,188
2015	1,373,362
2016	1,683,786
2017	1,626,840
2018	1,320,317
Average	**1,494,151**

Over this same period (2009–2018), MRYS Unit 1 operated at a 70% annual capacity factor (ACF), as determined on an actual heat input basis. Future operations are expected to be consistent with this 10-year period and the 70% annual capacity factor was used when calculating the baseline and future projected emissions discussed in Section 2.

Table 2 displays the operational information from 2009-2018. The ACF is calculated by dividing the actual heat input by the maximum potential heat input of 28.0×10^6 MMBtu per year.

Table 2: Utilization and Annual Capacity Factor

Year	Actual Heat Input (MMBtu/yr)	Annual Capacity Factor
2009	17,449,077	0.62
2010	20,765,112	0.74
2011	18,534,017	0.66
2012	20,670,979	0.74
2013	18,864,309	0.67

Year	Actual Heat Input (MMBtu/yr)	Annual Capacity Factor
2014	19,129,722	0.68
2015	17,646,175	0.63
2016	23,097,486	0.82
2017	21,628,091	0.77
2018	17,453,674	0.62
Average	**19,523,864**	**0.70**

2 NO_X and SO_2 Emissions Controls and Representative History

MRYS Unit 1 commenced commercial operation in 1970. In April 2006, the Environmental Protection Agency, Department of Justice and the State of North Dakota, reached a Clean Air Act (CAA) major New Source Review Program settlement with Minnkota Power Cooperative and Square Butte Power Cooperative. Minnkota was required to spend approximately $100 million to install or upgrade state-of-the-art pollution controls between the time of the settlement and 2011. Minnkota was also required to reduce 23,561 tons per year (tpy) of SO_2 by 2012, 9,458 tpy of NO_x by 2010, and to comply with declining plant-wide caps for SO_2. The proposed Consent Decree requirements were incorporated into enforceable permits. The agreement resolved CAA violations that occurred at MRYS. MRYS was deemed BART-eligible in the first round of the regional haze program.

2.1 NOx

2.1.1 NO_X Emissions Controls

MRYS Unit 1 is equipped with Advanced Separated Over Fire Air (ASOFA) and selective non-catalytic reduction (SNCR) for NO_x control. These were the BART controls selected in the first round of the Regional Haze program.[1] Minnkota previously entered into a Consent Decree that required MRYS to install BACT for NO_x, which was determined to be SNCR with ASOFA.[2,3]

2.1.2 NO_X Emissions History

To determine the baseline emission rates, the time period of 2016-2018 was used. These results are shown in Table 3, along with the NO_x emissions for each year.

Table 3: Annual NOx Rate and Emissions

Year	Emissions Rate (lb/MMBtu)	NO_x Emissions (tons)
2016	0.33	3,841
2017	0.33	3,579
2018	0.33	2,924
Average	**0.33**	**3,448**

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[1] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 74.

[2] Available at: https://www.epa.gov/enforcement/minnkota-power-cooperative-and-square-butte-electric-cooperative-settlement (Last visited March 23, 2021)

[3] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, Appendix B.4, p.16-19.

The baseline was established in consultation with the NDDEQ. It is the most recent time period that includes two non-major outage years, and one major outage year. Outages on these units follow a three-year cycle, so the time period of 2016-2018 is the most representative of future expected emissions.[4] The average emissions rate of 0.33 lb NO_x per MMBtu is used as the starting point when determining the cost for the add-on controls evaluated in Section 3.2.

2.2 SO2

2.2.1 SO_2 Emissions Controls

MRYS Unit 1 is equipped with wet flue gas desulfurization (WFGD) for SO_2 control. This control technology was installed in 2011 as a result of the BART determination made in the first round of the Regional Haze program.[5] The WFGD system typically achieves an annual removal efficiency of approximately 97% and complies with a 30-day rolling average 95% SO_2 removal efficiency.[6]

2.2.2 SO_2 Emissions History

To determine the baseline emission rates, the time period of 2016-2018 was used. These results are shown in Table 4, along with the SO_2 emissions for each year.

Table 4: Annual SO2 Emissions Rate

Year	Emissions Rate (lb/MMBtu)	SO_2 Emissions (tons)
2016	0.08	909
2017	0.08	905
2018	0.06	518
Average	**0.07**	**777**

The average emission rate of 0.07 lb SO_2 per MMBtu is representative of future expected operations and is used as the starting point when determining the cost of compliance for the additional controls evaluated in Section 4.2. Note that the tons of SO_2 listed in Table 4 do not equal the calculated tons used for the baseline emissions (Table 8). The baseline emissions are calculated using the recent emissions rate with the average ACF over the last 10 years. This results in a difference of approximately 60 tons of SO_2.

3 NOx Analysis

3.1 NO_X Technologies

The reasonable progress controls evaluated by MRYS for Unit 1 are listed in Table 5. Performance rate and expected annual emissions are included for both control technologies that were determined to be technically feasible. MRYS evaluated optimizing their current SNCR control technologies as well as adding Rich Reagent Injection (RRI). Note that the expected annual emissions in Table 5 were calculated using the performance rate, potential heat input, and the ACF (Table 2).

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[4] Appendix B.5.b., p. 1-4. PDF page 1157.

[5] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 71.

[6] Appendix B.5.b., p. 3-3 – 3-4. PDF page 1179-1180.

Therefore, the tons of NO_X emissions are different than the tons of NO_X emissions displayed in Table 3 since the table below contains calculated emissions based on representative operations..

Table 5: Reasonable Progress NOx Controls

Control Technology	Performance Rate (lb/MMBtu)	Emissions (tons/year)
SNCR/ASOFA (baseline)	0.33	3,241
Optimized SNCR/ASOFA	0.33	3,221
RRI/SNCR/ASOFA	0.28	2,733

Selective catalytic reduction (SCR) was identified as a potential NO_x control technology but was deemed technically infeasible at MRYS in the previous BART and BACT analysis. No new information or experience has occurred since those analyses to change the conclusions that were made. SCR remains technically infeasible at MRYS.[7]

3.1.1 Optimization of Selective Non-Catalytic Reduction (SNCR)

Utilizing operating and vendor experience acquired since the original installation, enhancements to the existing system were identified to potentially reduce NO_x emission rates. Enhancements include changing the nozzles on existing lances, replacing the existing lances, adding lances in new locations and allowing for higher ammonia slip rates. Higher ammonia slip rates would allow for higher levels of urea injection, potentially reducing NO_x emission rates further. The ASOFA system would be operated in conjunction with the optimized SNCR system. These enhancements are projected to amount to minimal NO_x reductions per year. The optimization of SNCR was deemed technically feasible.

3.1.2 Rich Reagent Injection (RRI)

RRI is a NO_x emission control technology specifically intended for use on cyclone boilers. RRI adds dilute urea reagent to the hot boiler gases near the cyclones. This location must be devoid of free oxygen to avoid oxidation of the urea, which results in the formation of additional NO_x.[8]

The use of RRI control technology in conjunction with SNCR and ASOFA results in a 16% reduction in NO_x emissions from the baseline scenario. The expected performance rate would drop from 0.33 to 0.28 lb NO_x per MMBtu. The 0.28 lb per MMBtu performance rate was determined using MRYS unit-specific operations. Maximum NO_x reductions from both RRI and SNCR systems occur when the boiler is at or near full load, and in a steady-state condition. Emission rates stated by vendors are based on these conditions, and do not always account for site specific operating conditions. RRIs operational effectiveness depends on oxygen-deprived conditions. Both Unit 1 and Unit 2 at MRYS are designed to still be able to achieve full load even if one cyclone burner is out of service. This situation is not unusual during routine maintenance. When this occurs however, air can leak through

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[7] Appendix B.5.b., p. 2-3. PDF page 1163.

[8] Appendix B.5.b., p. 2-3. PDF page 1163.

the combustion air dampers of an out-of-service cyclone and will result in the increase of NO_x formation, due to the addition of oxygen in the fuel-rich zone of the in-service boiler.[9]

Another problem MRYS encounters with RRI and other control technologies, is that MRYS is a mine-mouth plant that utilizes run-of-mine fuel. This results in significant coal quality variability. These variations can lead to cyclones becoming fouled, meaning that insufficient temperature exists for the slag to flow properly from the cyclone. When this occurs, fuel oil is co-burned in the fouled cyclone which results in increased oxygen levels in the fuel-rich zone. This leads to additional formation of NO_x.[10] While these factors impact the performance rate for NO_x, the installation of RRI with SNCR and ASOFA was deemed technically feasible under limited conditions and will be evaluated further.

3.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost for the reasonable progress controls are listed in Table 6. Cost estimates are based on a vendor proposal and were calculated based on a 20-year project life.

Table 6: NOx Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
SNCR/ASOFA (Baseline)	0.33				
Optimized SNCR/ASOFA	0.33	20	1,996,685	102,269	
RRI/SNCR/ASOFA	0.28	508	5,996,594	11,813	8,195

A detailed breakdown of the costs listed in Table 6 can be found in Minnkota's submitted four factor analysis.[11] The Department has reviewed these costs and believes them to be accurate.

MRYS relied on a vendor proposal for cost estimates to account for certain site-specific costs that would be incurred implementing these NO_x control technologies. In the case of optimizing the SNCR, the detailed vendor evaluation identified new recommended SNCR injection locations, along with current nozzle and lance enhancements. The resulting annualized cost is approximately $2,000,000, with 83% of that being attributed to the cost of urea reagent. These changes would result in an annual reduction of approximately 20 tons of NO_x, and a cost of compliance value of approximately $102,000 per ton of NO_x reduced.

The implementation of RRI with the SNCR and ASOFA systems would result in an approximate annual reduction of 500 tons of NO_x. The annualized total cost is approximately $6,000,000, with a cost of compliance at $11,800 per ton of NO_x reduced. MRYS submitted its original four-factor analysis on January 31, 2019. NDDEQ questioned the excessive cost estimates for RRI at that time. In the revised four-factor analysis that was submitted on May 29, 2019, MRYS defended these

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[9] Appendix B.5.b, p. 2-5. PDF page 1165.

[10] Appendix B.5.b, p. 2-5. PDF page 1165.

[11] Appendix B.5.b. Appendix A. PDF page 1196 and 1211.

estimates. The cost estimates are site-specific and utilized computational fluid dynamic (CFD) modeling and boiler mapping along with vendor proposals.[12] The CFD modeling, boiler mapping, and RRI injection analysis determined that the necessary injection locations needed are not in easily accessible locations on either unit. This results in added cost for new platforms and stairs to access new injection locations, significant new piping for increased urea, cooling water, dilution water and atomization air, expansion of the microfiltration and reverse osmosis water system, and supply and installation of the boiler bent tube openings for the new RRI and SNCR injectors.[13] Minnkota firmly believes that these costs are accurate and represent the actual costs for installation and implementation of RRI with SNCR and ASOFA.

3.3 Step 2 – Time Necessary for Compliance

The time necessary for compliance is not a limiting factor when determining additional reasonable controls for MRYS Unit 1 NO_x emissions since SNCR optimization and/or RRI could be installed prior to the end of the second planning period.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

3.4.1 Energy

The primary energy impact of utilizing RRI with SNCR or optimizing existing SNCR system is reduced boiler efficiency due to evaporation of large amounts of dilute urea. This results in excess coal needing to be burned to evaporate the expected amount of dilute urea in the boiler. An incremental increase in energy will also result from providing more compressed air for reagent atomization. Auxiliary power requirements result in a 66 kW increase in an optimized SNCR, and a 132 kW increase with RRI and SNCR.[14] These energy impacts are only incrementally higher than the existing system, and do not remove either option from consideration.

3.4.2 Non-Air Quality Environmental Impacts

Non-air quality impacts of the control technologies are very similar to the impacts of the existing SNCR system. There may be an increase in ammonia slip, but a majority will be captured in the WFGD system. There will also be additional reverse osmosis/condensate waste due to the increase in demand from the systems and the need to dilute concentrated urea. This would result in millions of gallons of additional water treatment wastewaters being discharged from the MRYS facility on an annual basis. These impacts are considered acceptable and do not remove either option from consideration.

3.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, MRYS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

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[12] Appendix B.5.b., p. 2-4. PDF page 1164.

[13] Appendix B.5.b., p.2-7. PDF page 1167.

[14] Appendix B.5.b., p. 2-14. PDF page 1174.

4 SO_2 Analysis

4.1 SO_2 Technologies Evaluated

The reasonable progress controls that were identified for analysis for MRYS Unit 1 are listed in Table 7, along with their approximate annual control efficiency. A new WFGD was not evaluated for Unit 1, as the current system was installed in 2011. All controls were deemed technically feasible.

Table 7: SO_2 Controls Identified for Analysis

Control Technology	**Approximate Annual Control Efficiency**
ReACT Scrubber	92-98%
Modification of Existing WFGD	96-98%
Circulating Semi-Dry FGD	90-97%
Semi-Dry FGD	90-95%

As discussed in Section 2.2.1, the existing WFGD system currently achieves an annual average removal efficiency of approximately 97%. The approximate annual control efficiencies listed in Table 7 start from an estimate of uncontrolled SO_2 emissions based on inlet sulfur concentration.

4.1.1 Semi-Dry Flue Gas Desulfurization

Semi-dry FGD technology is an alternative to WFGD technology in SO_2 emission control. Spray Dryer Absorber (SDA) is the most common semi-dry FGD system. Circulating Dry Scrubber is another variation of the semi-dry process. SDA technology has never been clearly demonstrated to achieve the same SO_2 removal levels as WFGD technology.[15] The CDS system can achieve better control efficiency than the SDA process, but only achieves similar levels to those of the current WFGD system. Because the semi-dry FGD technologies achieve less or equal SO_2 removal to that of the current WFGD system, neither was evaluated further.

4.1.2 Regenerative Activated Coke Technology

Regenerative Activated Coke Technology (ReACT) is a multipollutant control system that utilizes activated coke to remove SO_2, NO_x and mercury. The ReACT process has been demonstrated to achieve 99% SO_2 removal on low sulfur coal units. However, the supplier of the ReACT process determined that MRYS is not a good candidate for the technology. MRYS factors that would impact the performance and cost of ReACT are that the inlet temperature is too high, higher oxidation of the activated coke would be expected, and the sulfuric acid production rates would be very high.[16] MRYS also utilizes high sulfur coal.[17] ReACT has only been applied on low sulfur fuel, and pilot tests on high sulfur coal have only shown 92-98% SO_2 removal rates. Because these levels could be achieved by the existing wet FGD system, ReACT was not evaluated further.

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[15] Appendix B.5.b., p. 3-5. PDF page 1181.

[16] Appendix B.5.b., p. 3-5. PDF page 1181.

[17] Appendix B.5.b., p. 3-5. PDF page 1181.

4.1.3 Modification of Existing Wet FGD (WFGD) System

The original equipment manufacturer for the existing WFGD system on Unit 1 evaluated potential modifications that could increase the SO_2 removal efficiency of the system. The upgrades that were evaluated include increasing the liquid-to-gas ratio, installation of new types of spray nozzles, running additional pumps, and adjusting the operating conditions of the scrubber. The evaluation determined that Unit 1 could achieve 97.4% SO_2 removal by increasing the Calcium/Sulfur stoichiometry to 1.025[18] and replacing three of four recirculation pump motors to increase the liquid to gas ratio in the scrubber.[19] This modification was deemed technically feasible and was evaluated further. The performance rate and SO_2 annual emissions are shown for this technology and the baseline in Table 8. Note that the expected annual emissions in Table 8 were calculated using the performance rate, potential heat input, and the ACF (Table 2). Therefore, the tons of SO_2 emissions are different than the tons of SO_2 emissions displayed in Table 4 since the table below contains calculated emissions based on representative operations..

Table 8: Reasonable Progress SO_2 Controls

Control Technology	Performance Rate (lb/MMBtu)	Emissions (tons/year)
WFGD (Baseline)	0.07	721
Modify WFGD	0.06	595

4.2 Step 1 – Cost of Compliance

The cost of compliance for modification of the existing WFGD is shown in Table 9.

Table 9: SO_2 Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
WFGD	0.074			
Modified WFGD	0.061	126	365,562	2,903

A detailed breakdown of the costs listed in Table 9 can be found in Minnkota's submitted four factor analysis.[20] The Department has reviewed these costs and believes them to be accurate.

The cost estimates for modifying the existing WFGD system were provided by the original equipment manufacturer. These costs were supplemented with engineering estimates for installation from Burns & McDonnell. The cost estimates are limited to these factors and assumes that all other existing systems, including the existing electrical system, are capable of supporting the modifications with no further upgrades.[21] It is also assumed that no change in operating staff will

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[18] Appendix B.5.b., p. 3-4. PDF page 1180.

[19] Appendix B.5.b., p.3-9. PDF page 1185.

[20] Appendix B.5.b., p.3-9 – 3-13. PDF page 1185-1189.

[21] Appendix B.5.b., p. 3-9. PDF page 1185.

occur from the modifications. These conservative estimates result in a cost of compliance value of \$2,900 per ton of SO_2 removed.

4.3 Step 2 – Time Necessary for Compliance

The process to bid, design, purchase, and install retrofits to an existing WFGD system can take two to three years.[22] The time necessary for compliance is not a limiting factor when determining additional reasonable controls for MRYS Unit 1 SO_2 emissions since the WFDG could be modified prior to the end of the second planning period.

4.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

4.4.1 Energy

Modifying the existing WFGD will result in an energy demand increase of 586 kW, a 0.3% increase in the percent of nominal generation. This increase is acceptable and does not remove WFGD modification as a control option.

4.4.2 Non-Air Quality Environmental Impacts

Modifying the existing WFGD system will have similar non-air quality environmental impacts to those of the existing system. However, there will be an incremental increase in the solids disposal rate as additional removal of SO_2 will result in increased byproduct. This is not a significant impact and does not remove the control technology from consideration.

4.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, MRYS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

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[22] Appendix B.5.b., p. 3-14. PDF page 1190

1 Introduction and Representative Operations

Minnkota Power Cooperative, Inc. (Minnkota) – Milton R. Young Station (MRYS) is a two-unit electrical generating station. Unit 2 is a Babcock & Wilcox cyclone-fired boilers fired on lignite coal. Unit 2 commenced commercial operation in 1977. Unit 2 has a turbine-generator nameplate rating of 477 MW and a nominal rated heat input capacity of 6,300 MMBtu per hour. MRYS is located approximately five miles southeast of the town of Center, North Dakota. MRYS receives lignite from BNI Coal, Ltd's Center Mine, which is located adjacent to the facility.

The average annual amount of North Dakota lignite coal combusted at MRYS Unit 2 from 2009 through 2018 was 2.6 million tons. See Table 1 for detailed information.

Table 1: MRYS Unit 2 Coal Combusted

Year	Coal Combusted (tons)
2009	2,690,168
2010	2,119,700
2011	2,949,190
2012	2,746,928
2013	2,102,746
2014	2,290,214
2015	2,845,985
2016	2,160,413
2017	3,010,361
2018	2,978,138
Average	**2,589,384**

Over this same period (2009–2018), MRYS Unit 2 operated at a 61% annual capacity factor (ACF), as determined on an actual heat input basis. Future operations are expected to be consistent with this 10-year period and the 61% annual capacity factor was used when calculating the baseline and future projected emissions discussed in Section 2.

Table 2 displays the operational information from 2009–2018 for Unit 2. The ACF is calculated by dividing the actual heat input by the maximum potential heat input of $55.1\text{x}10^6$ MMBtu per year.

Table 2: Utilization and Annual Capacity Factor

Year	Actual Heat Input (MMBtu/yr)	Annual Capacity Factor
2009	36,697,676	0.66
2010	29,507,936	0.53
2011	41,664,019	0.75
2012	34,923,781	0.63

Year	Actual Heat Input (MMBtu/yr)	Annual Capacity Factor
2013	26,539,099	0.48
2014	29,840,051	0.54
2015	36,389,744	0.66
2016	26,618,855	0.48
2017	38,455,791	0.70
2018	37,990,222	0.69
Average	**33,862,717**	**0.61**

2 NO_X and SO_2 Emissions Controls and Representative History

MRYS Unit 2 commenced commercial operation in 1977. In April 2006, the Environmental Protection Agency, Department of Justice and the State of North Dakota, reached a Clean Air Act (CAA) major New Source Review Program settlement with Minnkota Power Cooperative and Square Butte Power Cooperative. Minnkota was required to spend approximately $100 million to install or upgrade state-of-the-art pollution controls between the time of the settlement and 2011. Minnkota was also required to reduce 23,561 tons per year (tpy) of SO_2 by 2012, 9,458 tpy of NO_x by 2010, and to comply with declining plant-wide caps for SO_2. The proposed Consent Decree requirements were incorporated into enforceable permits. The agreement resolved CAA violations that occurred at MRYS. It was deemed BART-eligible in the first round of the regional haze program.

2.1 NOx

2.1.1 NO_X Emissions Controls

MRYS Unit 2 is equipped with Advanced Separated Over Fire Air (ASOFA) and selective non-catalytic reduction (SNCR) for NO_x control. These were the BART controls selected in the first round of the Regional Haze program.[1] Minnkota previously entered into a Consent Decree that required MRYS to install BACT for NO_x, which was determined to be SNCR with ASOFA.[2,3]

2.1.2 NO_X Emissions History

To determine the baseline emission rates, the time period of 2016-2018 was used. These results are shown in Table 3, along with the NO_x emissions for each year.

Table 3: Annual NOx Rate and Emissions

Year	Emissions Rate (lb/MMBtu)	NO_x Emissions (tons)
2016	0.33	4,466
2017	0.33	6,390
2018	0.33	6,351
Average	**0.33**	**5,736**

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[1] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 74.

[2] Available at: https://www.epa.gov/enforcement/minnkota-power-cooperative-and-square-butte-electric-cooperative-settlement (Last visited March 23, 2021)

[3] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, Appendix B.4, p.16-19.

The baseline was established in consultation with the NDDEQ. It is the most recent time period that includes two non-major outage years, and one major outage year. Outages on these units follow a three-year cycle, so the time period of 2016-2018 is the most representative of future expected emissions.[4] The average emissions rate of 0.33 lb NO_x per MMBtu is used as the starting point when determining the cost of compliance for the add-on controls evaluated in Section 3.2.

2.2 SO2

2.2.1 SO_2 Emissions Controls

MRYS Unit 2 is equipped with wet flue gas desulfurization (WFGD) for SO_2 control. This control technology was installed prior to the first round of the Regional Haze program. In the first round, the BART selected by the Department for Unit 2 was a 95% reduction efficiency or a limit of 0.15 lb/MMBtu on a 30-day rolling average, which could be achieved by modifying the existing scrubber. The Consent Decree for MRYS required a minimum of 90% reduction of SO_2 and was included in the BART permit.[5] The WFGD system typically achieves an annual removal efficiency of approximately 95% and complies with a 30-day rolling average 90% SO_2 removal efficiency and a 30-day rolling average 0.15 lb/MMBtu emission rate.

2.2.2 SO_2 Emissions History

To determine the baseline emission rates, the time period of 2016-2018 was used. These results are shown in Table 4, along with the SO_2 emissions for each year.

Table 4: Annual SO2 Emissions Rate

Year	**Emissions Rate (lb/MMBtu)**	**SO_2 Emissions (tons)**
2016	0.13	1,729
2017	0.13	2,507
2018	0.12	2,258
Average	**0.13**	**2,165**

The average emission rate of 0.13 lb SO_2 per MMBtu is representative of future expected operations and is used as the starting point when determining the cost of compliance for the additional controls evaluated in Section 4.2. Note that the tons of SO_2 listed in Table 4 do not equal the calculated tons used for the baseline emissions (Table 8). The baseline emissions are calculated using the recent emissions rate with the average ACF over the last 10 years. This results in a difference of approximately 30 tons of SO_2.

3 NOx Four-Factor Analysis

3.1 NO_X Technologies

The reasonable progress controls evaluated by MRYS for Unit 2 are listed in Table 5. Performance rate and expected annual emissions are included for both control technologies that were determined to be technically feasible. MRYS evaluated optimizing their current SNCR control technologies as well as adding Rich Reagent Injection (RRI). Note that the expected annual emissions

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[4] Appendix B.5.b., p. 1-4. PDF page 1157.

[5] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 71.

in Table 5 were calculated using the performance rate, potential heat input, and the ACF (Table 2). Therefore, the tons of NO_X emissions are different than the tons of NO_X emissions displayed in Table 3 since the table below contains calculated emissions based on representative operations.

Table 5: Reasonable Progress NOx Controls

Control Technology	Performance Rate (lb/MMBtu)	Emissions (tons/year)
SNCR/ASOFA (baseline)	0.33	5,655
Optimized SNCR/ASOFA	0.32	5,418
RRI/SNCR/ASOFA	0.26	4,402

Selective catalytic reduction (SCR) was identified as a potential NO_x control technology but was deemed technically infeasible at MRYS in the previous BART and BACT analysis. No new information or experience has occurred since those analyses to change the conclusions that were made. SCR remains technically infeasible at MRYS.[6]

3.1.1 Optimization of Selective Non-Catalytic Reduction (SNCR)

Utilizing operating and vendor experience acquired since the original installation, enhancements to the existing system were identified to potentially reduce NO_x emission rates. Enhancements include changing the nozzles on existing lances, replacing the existing lances, adding lances in new locations and allowing for higher ammonia slip rates. Higher ammonia slip rates would allow for higher levels of urea injection, potentially reducing NO_x emission rates further. The ASOFA system would be operated in conjunction with the optimized SNCR system. These enhancements are projected to amount to approximately 240 tons of NO_x reductions per year. The optimization of SNCR was deemed technically feasible for Unit 2.

3.1.2 Rich Reagent Injection (RRI)

RRI is a NO_x emission control technology specifically intended for use on cyclone boilers. RRI adds dilute urea reagent to the hot boiler gases near the cyclones. This location must be devoid of free oxygen to avoid oxidation of the urea, which results in the formation of additional NO_x.[7]

The use of RRI control technology in conjunction with SNCR and ASOFA results in a 22% reduction in NO_x emissions from the baseline scenario. The expected performance rate would drop from 0.33 to 0.26 lb NO_x per MMBtu. The 0.26 lb per MMBtu performance rate was determined using MRYS unit-specific operations. Maximum NO_x reductions from both RRI and SNCR systems occur when the boiler is at or near full load, and in a steady-state condition. Emission rates stated by vendors are based on these conditions, and do not always account for site specific operating conditions. RRIs operational effectiveness depends on oxygen-deprived conditions. Both Unit 1 and Unit 2 at MRYS are designed to still be able to achieve full load even if one cyclone burner is out of service. This situation is not unusual during routine maintenance. When this occurs however, air can leak through

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[6] Appendix B.5.b., p. 2-3. PDF page 1163.

[7] Appendix B.5.b., p. 2-3. PDF page 1163.

the combustion air dampers of an out-of-service cyclone and will result in the increase of NO_x formation, due to the addition of oxygen in the fuel-rich zone of the in-service boiler.[8]

Another problem MRYS encounters with RRI and other control technologies, is that MRYS is a mine-mouth plant that utilizes run-of-mine fuel. This results in significant coal quality variability. These variations can lead to cyclones becoming fouled, meaning that insufficient temperature exists for the slag to flow properly from the cyclone. When this occurs, fuel oil is co-burned in the fouled cyclone which results in increased oxygen levels in the fuel-rich zone. This leads to additional formation of NO_x.[9] While these factors impact the performance rate for NO_x, the installation of RRI with SNCR and ASOFA was deemed technically feasible under limited conditions and will be evaluated further.

3.2 Step 1 – Cost of Compliance

The cost of compliance and incremental cost of compliance for the reasonable progress controls are listed in Table 6. Cost estimates are based on a vendor proposal and were calculated based on a 20-year project life.

Table 6: NOx Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
SNCR/ASOFA (Baseline)	0.33				
Optimized SNCR/ASOFA	0.32	237	1,786,833	7,538	
RRI/SNCR/ASOFA	0.26	1,253	7,496,503	5,983	5,620

A detailed breakdown of the costs listed in Table 6 can be found in Minnkota's submitted four factor analysis.[10] The Department has reviewed these costs and believes them to be accurate.

MRYS relied on a vendor proposal for cost estimates to account for certain site-specific costs that would be incurred implementing these NO_x control technologies. In the case of optimizing the SNCR, the detailed vendor evaluation identified new recommended SNCR injection locations, along with current nozzle and lance enhancements. The resulting annualized cost for Unit 2 is approximately $1,800,000. These changes would result in an annual reduction of approximately 240 tons of NO_x, and a cost of compliance value of $7,500 per ton of NO_x reduced.

The implementation of RRI with the SNCR and ASOFA systems would result in an approximate annual reduction of 1,250 tons of NO_x. The annualized total cost is approximately $7,500,000, with a cost of compliance at $6,000 per ton of NO_x reduced. MRYS submitted its original four-factor analysis on January 31, 2019. NDDEQ questioned the excessive cost estimates for RRI at that time. In the revised four-factor analysis that was submitted on May 29, 2019, MRYS defended these estimates. The cost estimates are site-specific and utilized computational fluid dynamic (CFD)

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[8] Appendix B.5.b, p. 2-5. PDF page 1165.

[9] Appendix B.5.b, p. 2-5. PDF page 1165.

[10] Appendix B.5.b. Appendix A. PDF page 1196 and 1211.

modeling and boiler mapping along with vendor proposals.[11] The CFD modeling, boiler mapping, and RRI injection analysis determined that the necessary injection locations needed are not in easily accessible locations on either unit. This results in added cost for new platforms and stairs to access new injection locations, significant new piping for increased urea, cooling water, dilution water and atomization air, expansion of the microfiltration and reverse osmosis water system, and supply and installation of the boiler bent tube openings for the new RRI and SNCR injectors.[12] Minnkota firmly believes that these costs are accurate and represent the actual costs for installation and implementation of RRI with SNCR and ASOFA.

3.3 Step 2 – Time Necessary for Compliance

The time necessary for compliance is not a limiting factor when determining additional reasonable controls for MRYS Unit 2 NO_x emissions since SNCR optimization and/or RRI could be installed prior to the end of the second planning period.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

3.4.1 Energy

The primary energy impact of utilizing RRI with SNCR or optimizing existing SNCR system is reduced boiler efficiency due to evaporation of large amounts of dilute urea. This results in excess coal needing to be burned to evaporate the expected amount of dilute urea in the boiler. An incremental increase in energy will also result from providing more compressed air for reagent atomization. Auxiliary power requirements result in a 66 kW increase in an optimized SNCR, and a 132 kW increase with RRI and SNCR.[13] These energy impacts are only incrementally higher than the existing system, and do not remove either option from consideration.

3.4.2 Non-Air Quality Environmental Impacts

Non-air quality impacts of the control technologies are very similar to the impacts of the existing SNCR system. There may be an increase in ammonia slip, but a majority will be captured in the WFGD system. There will also be additional reverse osmosis/condensate waste due to the increase in demand from the systems and the need to dilute concentrated urea. This would result in millions of gallons of additional water treatment wastewaters being discharged from the MRYS facility on an annual basis. These impacts are considered acceptable and do not remove either option from consideration.

3.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, MRYS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

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[11] Appendix B.5.b., p. 2-4. PDF page 1164.

[12] Appendix B.5.b., p.2-7. PDF page 1167

[13] Appendix B.5.b., p. 2-14. PDF page 1174.

4 SO_2 Four-Factor Analysis

4.1 SO_2 Technologies Evaluated

The reasonable progress controls that were identified for analysis for MRYS Unit 2 are listed in Table 7, along with their approximate annual control efficiency. All controls were deemed technically feasible.

Table 7: SO_2 Controls Identified for Analysis

Control Technology	Approximate Annual Control Efficiency
ReACT Scrubber	92-98%
New WFGD	98%
Modification of Existing WFGD	96-98%
Circulating Semi-Dry FGD	90-97%
Semi-Dry FGD	90-95%

As discussed in Section 2.2.1, the existing WFGD system currently achieves an annual average removal efficiency of approximately 95%. The approximate annual control efficiencies listed in Table 7 start from an estimate of uncontrolled SO_2 emissions based on inlet sulfur concentration.

4.1.1 Semi-Dry Flue Gas Desulfurization

Semi-dry FGD technology is an alternative to WFGD technology in SO_2 emission control. Spray Dryer Absorber (SDA) is the most common semi-dry FGD system. Circulating Dry Scrubber is another variation of the semi-dry process. SDA technology has never been clearly demonstrated to achieve the same SO_2 removal levels as WFGD technology.[14] The CDS system can achieve better control efficiency than the SDA process, but only achieves similar levels to those of the current WFGD system. Because the semi-dry FGD technologies achieve less or equal SO_2 removal to that of the current WFGD system, neither was evaluated further.

4.1.2 Regenerative Activated Coke Technology

Regenerative Activated Coke Technology (ReACT) is a multipollutant control system that utilizes activated coke to remove SO_2, NO_x and mercury. The ReACT process has been demonstrated to achieve 99% SO_2 removal on low sulfur coal units. However, the supplier of the ReACT process determined that MRYS is not a good candidate for the technology. MRYS factors that would impact the performance and cost of ReACT are that the inlet temperature is too high, higher oxidation of the activated coke would be expected, and the sulfuric acid production rates would be very high.[15] MRYS also utilizes high sulfur coal.[16] ReACT has only been applied on low sulfur fuel, and pilot tests

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[14] Appendix B.5.b., p. 3-5. PDF page 1181.

[15] Appendix B.5.b., p. 3-5. PDF page 1181.

[16] Appendix B.5.b., p. 3-5. PDF page 1181.

on high sulfur coal have only shown 92-98% SO_2 removal rates. Because these levels could be achieved by the existing WFGD system, ReACT was not evaluated further.

4.1.3 Modification of Existing Wet FGD (WFGD) System

The original equipment manufacturer for the existing WFGD system on Unit 1 evaluated potential modifications that could increase the SO_2 removal efficiency of both systems. The upgrades that were evaluated include increasing the liquid-to-gas ratio, installation of new types of spray nozzles, running additional pumps, and adjusting the operating conditions of the scrubber. The evaluation determined that Unit 2 could achieve 97.6% SO_2 removal by increasing the Calcium/Sulfur stoichiometry to 1.020[17] and replacing all of the absorber spray nozzles with dual flow nozzles.[18] This modification was deemed technically feasible and was evaluated further.

4.1.4 New WFGD System

A new WFGD system was evaluated at a 98% SO_2 removal efficiency. While some new SO_2 control projects have achieved higher control efficiency, 98% was evaluated to account for upsets, fuel variability, and operation variability.[19] A new WFGD system was deemed technically feasible for MRYS Unit 2. The performance rate and SO_2 annual emissions are shown for this technology, along with a modified WFGD and the baseline, in Table 8. Note that the expected annual emissions in Table 8 were calculated using the performance rate, potential heat input, and the ACF (Table 2). Therefore, the tons of SO_2 emissions are different than the tons of SO_2 emissions displayed in Table 4 since the table below contains calculated emissions based on representative operations.

Table 8: Reasonable Progress SO_2 Controls

Control Technology	**Performance Rate (lb/MMBtu)**	**Emissions (tons/year)**
WFGD (Baseline)	0.13	2,133
Modify WFGD	0.06	965
New WFGD	0.05	804

4.2 Step 1 – Cost of Compliance

The cost of compliance for reasonable progress SO_2 controls are shown in Table 9.

Table 9: SO_2 Cost of Compliance

Control Technology	**Performance Rate (lb/MMBtu)**	**Annual Emission Reduction (tpy)**	**Annualized Total Cost ($)**	**Cost of Compliance ($/ton)**	**Incremental Cost ($/ton)**
WFGD (Baseline)	0.13				
Modify WFGD	0.06	1,168	839,319	718	
New WFGD	0.05	1,329	15,978,200	12,022	94,119

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[17] Appendix B.5.b., p. 3-4. PDF page 1180.

[18] Appendix B.5.b., p.3-9. PDF page 1185.

[19] Appendix B.5.b., p. 3-3. PDF page 1179.

A detailed breakdown of the costs listed in Table 9 can be found in Minnkota's submitted four factor analysis.[20] The Department has reviewed these costs and believes them to be accurate.

The cost estimates for modifying the existing WFGD system were provided by the original equipment manufacturer. These costs were supplemented with engineering estimates for installation from Burns & McDonnell. The cost estimates are limited to these factors and assumes that all other existing systems, including the existing electrical system, are capable of supporting the modifications with no further upgrades.[21] It is also assumed that no change in operating staff will occur from the modifications. These conservative estimates result in a cost of compliance value of \$700 per ton of SO_2 removed.

The cost estimates for a new WFGD system were determined using the 'IPM Model – Updates to Cost and Performance for APC Technologies Wet FGD Cost Development Methodology' available from the U.S. Environmental Protection Agency and supplemented with engineering estimates based upon Burns & McDonnell's in-house experience.[22] One option for the addition of a new WFGD would require new ductwork at the facility, modifications to the coal pile to create needed space, and electrical replacement/upgrades for the new scrubber. This option allows the new WFGD to be installed without an extended outage. The other option would require a significantly extended outage to allow for the existing WFGD system to be shut down while the new system was tied in, commissioned and started up.[23] A conservative approach was taken with the cost estimate of a new WFGD by assuming that all existing plant systems are capable of supporting the new system with no upgrades. The costs are representative of a typical furnish and erect contract by a WFGD system supplier. The resulting cost of compliance for a new WFGD system is approximately \$12,000, with an incremental cost of compliance of \$94,000.

4.3 Step 2 – Time Necessary for Compliance

The process to bid, design, purchase, and install retrofits to an existing WFGD system can take two to three years, with the installation of a new WFGD system taking significantly longer.[24] The time necessary for compliance is not a limiting factor when determining additional reasonable controls for MRYS Unit 2 since all reasonable cost effective SO_2 control technologies could be installed prior to the end of the second planning period.

4.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

4.4.1 Energy

Modifying the existing WFGD will result in an energy demand increase of 965 kW, a 0.2% increase in the percent of nominal generation. A new WFGD will result in an increase of 2,195 kW, a 0.5%

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[20] Appendix B.5.b., p.3-9 – 3-13. PDF page 1185-1189.
[21] Appendix B.5.b., p. 3-9. PDF page 1185.
[22] Appendix B.5.b., p. 3-7. PDF page 1183.
[23] Appendix B.5.b., p. 3-8. PDF page 1184.
[24] Appendix B.5.b., p. 3-14. PDF page 1190.

increase in the percent of nominal generation.[25] These increases are acceptable and do not remove these as control options.

4.4.2 Non-Air Quality Environmental Impacts

Modifying the existing WFGD system will have similar non-air quality environmental impacts to those of the existing system. However, there will be an incremental increase in the solids disposal rate as additional removal of SO_2 will result in increased byproduct. This is not a significant impact and does not remove the control technology from consideration.

4.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, MRYS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

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[25] Appendix B.5.b., p. 3-13. PDF page 1189.

A.6 – MDU Heskett

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February 16, 2021

Mr. Jay Skabo
Vice President – Electric Supply
Montana-Dakota Utilities Co.
400 N Fourth Street
Bismarck, ND 58501

Re: Air Pollution Control
Permit to Construct

Dear Mr. Skabo:

Pursuant to the Air Pollution Control Rules of the State of North Dakota, the Department of Environmental Quality (Department) has reviewed the application dated April 30, 2020 (updated January 11, 2021) to obtain a Permit to Construct for the removal of two existing coal-fired boilers and ancillary equipment as well as the installation of a new, 88 megawatt natural gas-fired simple cycle combustion turbine unit at the R.M. Heskett Station located in Morton County, ND.

Based on the results of the documents submitted on April 30, 2020 (updated January 11, 2021) the Department hereby issues the enclosed North Dakota Air Pollution Control Permit to Construct No. ACP-17983 v1.0.

Please advise the Department within 15 days after completing the project to allow for an inspection by the Department.

Note that the above-referenced permit addresses only air quality requirements applicable to your facility. Other divisions (Water Quality, Waste Management and Municipal Facilities) within the Department of Environmental Quality may have additional requirements. Contact information for the various divisions is listed at the bottom of this letter.

Please contact me at (701)328-5283 or at cristy.jones@nd.gov with any questions.

Sincerely,

Cristy Jones

Cristy Jones
Environmental Scientist
Division of Air Quality

CMJ:csc
Enc:
xc: Daniel Fagnant EPA/R8

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AIR POLLUTION CONTROL PERMIT TO CONSTRUCT

Pursuant to Chapter 23.1-06 of the North Dakota Century Code, and the Air Pollution Control Rules of the State of North Dakota (Article 33.1-15 of the North Dakota Administrative Code), and in reliance on statements and representations heretofore made by the owner designated below, a Permit to Construct is hereby issued authorizing such owner to construct and initially operate the source unit(s) at the location designated below. This Permit to Construct is subject to all applicable rules and orders now or hereafter in effect of the North Dakota Department of Environmental Quality (Department) and to any conditions specified below:

I. General Information:

A. **Permit to Construct Number**: ACP-17983 v1.0

B. **Source**:

1. Name: Montana-Dakota Utilities Co.
2. Location: R. M. Heskett Station
   2025-38th Street
   Mandan, ND 58554
   Morton County
3. Source Type: Electric Generating Unit; Simple Cycle Combustion Turbine
4. Existing Equipment at the Facility:

Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	Air Pollution Control Equipment
Coal-fired boiler with a rated heat input of 387.63 x 10^6 Btu/hr (Unit 1 boiler)	1	1	Electrostatic Precipitator (ESP)
Coal-fired boiler with a rated heat input of 916.5 x 10^6 Btu/hr (Unit 2 boiler)	2	2	Multiclone, ESP and Limestone addition to bed media (limestone addition operates on an as-needed basis)
Natural gas-fired IC engine rated at 134 bhp, 100 kW output, built 1963 (Emergency generator engine)	3	3	None

Emission Unit Description	**Emission Unit (EU)**	**Emission Point (EP)**	**Air Pollution Control Equipment**
Natural gas-fired sand dryer with a rated heat input of 3.0 x 10^6 Btu/hr (Sand dryer)	5	2	ESP (Emissions from EU 5 discharge into the inlet of the Unit 2 ESP)
Natural gas-fired combustion turbine nominally rated at 986 x 10^6 Btu/hr, built 2013 (Unit 3 turbine)	6	6	Dry Low NO_x (DLN) Combustion
Natural gas-fired in-line heater nominally rated at 2.75 x 10^6 Btu/hr (Unit 3 in-line heater)	7	7	None
Unit 1 coal storage silo	M1	M1	Fabric Filter
Unit 1 coal gallery	M2	M1	Fabric Filter
Three Unit 2 coal storage silos	2A, 2B & 2C	M3	Fabric Filters
Ash conveyor system	M4	M4	Fabric Filter
Unit 1 bottom ash silo	M5	M5	Fabric Filter
Sand storage silos	S2B	M6	Fabric Filter
Limestone hopper	S2A	M6	Fabric Filter
Fly ash silo	M7	M7	Fabric Filters
Gasoline storage tank, 1000 gal, built Dec. 2006	M8 [B]	M8	Submerged fill pipe
Limestone silo and limestone receiving	M9	M9	Fabric Filter
Limestone conveyor	M11	M11	Fabric Filters
Fugitive emissions	FUG	FUG	None

5. Equipment to be removed:

Emission Unit Description [A]	**Emission Unit (EU)**	**Emission Point (EP)**	**Air Pollution Control Equipment**
Coal-fired boiler with a rated heat input of 387.63 x 10^6 Btu/hr (Unit 1 boiler)	1	1	Electrostatic Precipitator (ESP)
Coal-fired boiler with a rated heat input of 916.5 x 10^6 Btu/hr (Unit 2 boiler)	2	2	Multiclone, ESP and Limestone addition to bed media
Natural gas-fired IC engine rated at 134 bhp, 100 kW output, built 1963 (Emergency generator engine)	3	3	None

Natural gas-fired sand dryer with a rated heat input of 3.0 x 10^6 Btu/hr (Sand dryer)	5	2	ESP
Unit 1 coal storage silo	M1	M1	Fabric Filter
Unit 1 coal gallery	M2	M1	Fabric Filter
Three Unit 2 coal storage silos	2A, 2B & 2C	M3	Fabric Filters
Ash conveyor system	M4	M4	Fabric Filter
Unit 1 bottom ash silo	M5	M5	Fabric Filter
Sand storage silos	S2B	M6	Fabric Filter
Limestone hopper	S2A	M6	Fabric Filter
Fly ash silo	M7	M7	Fabric Filters
Gasoline storage tank, 1000 gal, built Dec. 2006	M8	M8	Submerged fill pipe
Limestone silo and limestone receiving	M9	M9	Fabric Filter
Limestone conveyor	M11	M11	Fabric Filters

[A] Emission units must be removed or permanently decommissioned prior to the commencement of operation of the Unit 4 turbine (EU 12).

6. New equipment to be added to the facility:

Emission Unit Description	**Emission Unit (EU)**	**Emission Point (EP)**	**Air Pollution Control Equipment**
Natural gas-fired combustion turbine nominally rated at 986 x 10^6 Btu/hr (Unit 4 turbine) (KKKK) (TTTT)	12 [A]	12	Dry Low NO_x (DLN) Combustion
Natural gas-fired in-line heater nominally rated at 5 x 10^6 Btu/hr (Unit 4 in-line heater)	13	13	None
One (4SLB) natural gas-fired emergency generator rated at 5,364 bhp (2020 or newer) (JJJJ) (ZZZZ)	14 [A]	14	None

[A] The potential to emit for an emergency stationary reciprocating internal combustion engine (RICE) is based on operating no more hours per year than is allowed by the subparts (40 CFR 60, Subpart JJJJ and 40 CFR 63, Subpart ZZZZ) for other than emergency situations. For engines to be considered emergency stationary RICE under the RICE rules, engine operations must comply with the operating hour limits as specified in the applicable subparts. There is no time limit on the use of emergency stationary RICE in emergency situations.

C. **Owner/Operator (Permit Applicant)**:

1.	Name:	Montana-Dakota Utilities Co.
2.	Address:	400 N Fourth Street Bismarck, ND 58501
3.	Application Date:	April 30, 2020

II. **Conditions**: This Permit to Construct allows the construction and initial operation of the above-mentioned new or modified equipment at the source. The source may be operated under this Permit to Construct until a Permit to Operate is issued unless this permit is suspended or revoked. The source is subject to all applicable rules, regulations, and orders now or hereafter in effect of the North Dakota Department of Environmental Quality and to the conditions specified below.

A. **Emission Limits**: Emission limits from the operation of the source unit(s) identified in Item I.B of this Permit to Construct (hereafter referred to as "permit") are as follows. Source units not listed are subject to the applicable emission limits specified in the North Dakota Air Pollution Control Rules.

Emission Unit Description	EU	EP	Pollutant / Parameter	Emission Limit
Natural gas-fired combustion turbine nominally rated at 986 x 10^6 Btu/hr (Unit 4 turbine)	12	12	NOx: >50 MW (gross) & >0°F	15 ppmvd @ 15% O_2 or 54 ng/J (0.43 lb/MWh) [A, B, C, D]
			NO_x: ≤50 MW (gross) or <0°F	96 ppmvd @ 15% O_2 or 590 ng/J (4.7 lb/MWh) [A, B, C, D]
			NO_x	515.8 lb/hr [I]
			SO_2	110 ng/J (0.90 lb/MWh) (gross) or 0.060 lb/MMBtu (fuel use) [E]
			CO_2	50 kg CO_2/GJ heat input (120 lb CO_2/MMBtu) [F, G]
			Opacity	20% [H]

[A] CEMs installed in lieu of annual performance tests (40 CFR 60.4340(b)).

[B] CEMs installation, operation, and performance testing must meet the applicable standards of 40 CFR 60 Subpart KKKK.

[C] Based on a 4-hr rolling average.

[D] The higher NO_x limit emission limit applies for the entire hour if at any point in the hour the unit was subject to a higher limit.

[E] Sulfur content of the fuel must be determined using total sulfur methods per 40 CFR 60.4415 and 60.4370.

[F] Emissions standards must be met at all times; however, compliance must be determined only at the end of each applicable operating month.

[G] Emission limit is based on operations that supply less than or equal to its design efficiency (33.34%) or 50%, whichever is less, times its potential electric output as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts > 90% natural gas.

[H] 40% permissible for not more than one six-minute period per hour.

[I] Based on a 1-hr average.

B. **Fuel Restriction**:

The simple cycle combustion turbines, in-line heater, and emergency generator (EUs 12, 13, and 14) are restricted to combusting only natural gas containing no more than 2 grains of sulfur per 100 standard cubic feet.

C. **Emissions Testing**:

1. Initial Testing: Within 180 days after initial startup, the permittee shall conduct emissions tests at the emission units listed below using an independent testing firm, to determine the compliance status of the facility with respect to the emission limits specified in Condition II.A. Emissions testing shall be conducted for the pollutant(s) listed below in accordance with EPA Reference Methods listed in 40 CFR 60, Appendix A. Test methods other than those listed below may be used upon approval by the Department.

Emission Unit Description	**EU**	**Pollutant/ Parameter**	**Number of Runs**	**Length of Runs**	**EPA Ref. Method(s)**
Unit 4 turbine	12	NO_x CEMS Relative Accuracy Test Audit (RATA)	9	21 min	See 40 CFR 60.4405 for alternative method

[A] RATA must be conducted at a single load level, within plus or minus 25% of 100% of peak load and the ambient temperature must be greater than 0°F during the RATA runs.

A signed copy of the test results shall be furnished to the Department within 60 days of the test date. The basis for this condition is NDAC 33.1-15-01-12 which is hereby incorporated into this permit by reference. To facilitate preparing for and conducting such tests, and to facilitate reporting the test results to the Department, the owner/operator shall follow the procedures and formats in the Department's Emission Testing Guideline.

2. Notification: The permittee shall notify the Department using the form in the Emission Testing Guideline, or its equivalent, at least 30 calendar days in advance of any tests of emissions of air contaminants required by the Department. If the permittee is unable to conduct the performance test on the scheduled date, the permittee shall notify the Department at least five days prior to the scheduled test date and coordinate a new test date with the Department.

3. Sampling Ports/Access: Sampling ports shall be provided downstream of all emission control devices and in a flue, conduit, duct, stack or chimney arranged to conduct emissions to the ambient air.

   The ports shall be located to allow for reliable sampling and shall be adequate for test methods applicable to the facility. Safe sampling platforms and safe access to the platforms shall be provided. Plans and specifications showing the size and location of the ports, platform and utilities shall be submitted to the Department for review and approval.

4. Other Testing:

   a) The Department may require the permittee to have tests conducted to determine the emission of air contaminants from any source, whenever the Department has reason to believe that an emission of a contaminant not addressed by the permit applicant is occurring, or the emission of a contaminant in excess of that allowed by this permit is occurring. The Department may specify testing methods to be used in accordance with good professional practice. The Department may observe the testing. All tests shall be conducted by reputable, qualified personnel. A signed copy of the test results shall be furnished to the Department within 60 days of the test date.

      All tests shall be made and the results calculated in accordance with test procedures approved by the Department. All tests shall be made under the direction of persons qualified by training or experience in the field of air pollution control as approved by the Department.

   b) The Department may conduct tests of emissions of air contaminants from any source. Upon request of the Department, the permittee shall provide necessary holes in stacks or ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices, as may be necessary for proper determination of the emission of air contaminants.

D. **Stack Heights**: The stack height of the turbine shall be at least 56 feet.

E. **New Source Performance Standards (NSPS)**: The owner/operator shall comply with all applicable requirements of the following NSPS subparts as referenced in Chapter 33.1-15-12 of the North Dakota Air Pollution Control Rules and 40 CFR 60.

1. **40 CFR 60, Subpart KKKK**: The owner/operator shall comply with all applicable requirements of 40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines (EU 12).

2. **40 CFR 60, Subpart JJJJ**: The owner/operator shall comply with all applicable requirements of 40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (EU 14).

3. **40 CFR 60, Subpart TTTT**: The owner/operator shall comply with all applicable requirements of 40 CFR 60, Subpart TTTT - Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units (EU 12).

F. **Maximum Achievable Control Technology Standards (MACT)**: The permittee shall comply with all applicable requirements of the following MACT subparts as referenced in Chapter 33.1-15-22 of the North Dakota Air Pollution Control Rules and 40 CFR 63.

1. 40 CFR 63, Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (EU 1). The North Dakota Department of Environmental Quality has not adopted the area source provisions of this subpart. All required documentation must be submitted to EPA Region 8 at the following address:

U.S. EPA Region 8
1595 Wynkoop Street
Mail Code 8ENF – AT
Denver, CO 80202-1129

G. **Like-Kind Turbine Replacement**: This permit allows the permittee to replace the turbine with a like-kind turbine. Replacement is subject to the following conditions.

1. The Department must be notified within 10 days after change-out of the turbine.

2. The replacement turbine shall operate in the same manner, provide no increase in throughput and have equal or less emissions than the turbine it is replacing.

3. The date of manufacture of the replacement turbine must be included in the notification. The facility must comply with any applicable federal standards (e.g. NSPS, NESHAP, MACT) triggered by the replacement.

4. The replacement turbine is subject to the same state emission limits as the existing turbine in addition to any NSPS or MACT emission limit that is applicable. Testing shall be conducted to confirm compliance with the emission limits within 180 days after start-up of the new turbine.

H. **CEMS –Nitrogen Oxide (NO_x)**: The owner/operator shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, 0 percent excess air) of NO_x emissions into the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air. Monitoring of NO_x emissions must also meet all applicable requirements of 40 CFR 60, Subpart KKKK.

I. **Construction**: Construction of the above described facility shall be in accordance with information provided in the permit application as well as any plans, specifications and supporting data submitted to the Department. The Department shall be notified ten days in advance of any significant deviations from the specifications furnished. The issuance of this Permit to Construct may be suspended or revoked if the Department determines that a significant deviation from the plans and specifications furnished has been or is to be made.

Any violation of a condition issued as part of this permit to construct as well as any construction which proceeds in variance with any information submitted in the application, is regarded as a violation of construction authority and is subject to enforcement action.

J. **Startup Notice**: A notification of the actual date of initial startup shall be submitted to the Department within 15 days after the date of initial startup.

K. **Organic Compounds Emissions**: The permittee shall comply with all applicable requirements of NDAC 33.1-15-07 – Control of Organic Compounds Emissions.

L. **Title V Permit to Operate**: Within one year after startup of the units covered by this Permit to Construct, the owner/operator shall submit a permit application to modify the existing Title V Permit to Operate for the facility.

M. **Acid Rain Program**: The permittee shall comply with the applicable requirements of 40 CFR 72, 75 and 76. The permittee shall hold sulfur dioxide allowances, as of the allowance transfer deadline, in the unit's subaccount not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit.

N. **Permit Invalidation**: This permit shall become invalid if construction is not commenced within eighteen months after issuance of such permit, if construction is discontinued for a period of eighteen months or more; or if construction is not completed within a reasonable time.

O. **Fugitive Emissions**: The release of fugitive emissions shall comply with the applicable requirements in NDAC 33.1-15-17.

P. **Annual Emission Inventory/Annual Production Reports**: The owner/operator shall submit an annual emission inventory report and/or an annual production report upon Department request, on forms supplied or approved by the Department.

Q. **Source Operations**: Operations at the installation shall be in accordance with statements, representations, procedures and supporting data contained in the initial application, and any supplemental information or application(s) submitted thereafter. Any operations not listed in this permit are subject to all applicable North Dakota Air Pollution Control Rules.

R. **Alterations, Modifications or Changes**: Any alteration, repairing, expansion, or change in the method of operation of the source which results in the emission of an additional type or greater amount of air contaminants or which results in an increase in the ambient concentration of any air contaminant, must be reviewed and approved by the Department prior to the start of such alteration, repairing, expansion or change in the method of operation.

S. **Air Pollution from Internal Combustion Engines**: The permittee shall comply with all applicable requirements of NDAC 33.1-15-08-01 – Internal Combustion Engine Emissions Restricted.

T. **Recordkeeping**: The owner/operator shall maintain any compliance monitoring records required by this permit or applicable requirements. The owner/operator shall retain records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement, report or application. Support information may include all calibration and maintenance records and all original strip-chart recordings/computer printouts for continuous monitoring instrumentation, and copies of all reports required by the permit.

U. **Nuisance or Danger**: This permit shall in no way authorize the maintenance of a nuisance or a danger to public health or safety.

V. **Malfunction Notification**: The owner/operator shall notify the Department of any malfunction which can be expected to last longer than twenty-four hours and can cause the emission of air contaminants in violation of applicable rules and regulations.

W. **Operation of Air Pollution Control Equipment**: The owner/operator shall maintain and operate all air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.

X. **Transfer of Permit to Construct**: The holder of a permit to construct may not transfer such permit without prior approval from the Department.

Y. **Right of Entry**: Any duly authorized officer, employee or agent of the North Dakota Department of Environmental Quality may enter and inspect any property, premise or place at which the source listed in Item I.B of this permit is located at any time for the purpose of ascertaining the state of compliance with the North Dakota Air Pollution Control Rules. The Department may conduct tests and take samples of air contaminants, fuel, processing material, and other materials which affect or may affect emissions of air contaminants from any source. The Department shall have the right to access and copy any records required by the Department's rules and to inspect monitoring equipment located on the premises.

Z. **Other Regulations**: The owner/operator of the source unit(s) described in Item I.B of this permit shall comply with all State and Federal environmental laws and rules. In addition, the owner/operator shall comply with all local burning, fire, zoning, and other applicable ordinances, codes, rules and regulations.

AA. **Permit Issuance**: This permit is issued in reliance upon the accuracy and completeness of the information set forth in the application. Notwithstanding the tentative nature of this information, the conditions of this permit herein become, upon the effective date of this permit, enforceable by the Department pursuant to any remedies it now has, or may in the future have, under the North Dakota Air Pollution Control Law, NDCC Chapter 23.1-06.

BB. **Odor Restrictions**: The owner/operator shall not discharge into the ambient air any objectionable odorous air contaminant which is in excess of the limits established in NDAC 33.1-15-16.

The owner/operator shall not discharge into the ambient air hydrogen sulfide (H_2S) in concentrations that would be objectionable on land owned or leased by the complainant or in areas normally accessed by the general public. For the purpose of complaint resolution, two samples with concentrations greater than 0.05 parts per million (50 parts per billion) sampled at least 15 minutes apart within a two-hour period and measured in accordance with Section 33.1-15-16-04 constitute a violation.

CC. **Sampling and Testing**: The Department may require the owner/operator to conduct tests to determine the emission rate of air contaminants from the source. The Department may observe the testing and may specify testing methods to be used. A signed copy of the test results shall be furnished to the Department within 60 days of the test date. The basis for this condition is NDAC 33.1-15-01-12 which is hereby incorporated into this permit by reference. To facilitate preparing for and conducting such tests, and to facilitate reporting the test results to the Department, the owner/operator shall follow the procedures and formats in the Department's Emission Testing Guideline.

FOR THE NORTH DAKOTA DEPARTMENT
OF ENVIRONMENTAL QUALITY

Date 2/16/2021

By
James L. Semerad
Director
Division of Air Quality

NORTH
Dakota | Environmental Quality
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Air Quality Effects Analysis
For
Permit to Construct
ACP-17983 v1.0

I. **Date of Review**:
February 16, 2021 (FINAL)

II. **Applicant**:
Montana-Dakota Utilities Co.
400 N Fourth Street
Bismarck, ND 58501

III. **Source Location**:
R.M. Heskett Station
2025 - 38th Street
Mandan, ND 58554
Morton County
Sec. 10, T139N, R81W
Lat. 46.866808, Long.-100.883669

IV. **Introduction and Background**:

Montana-Dakota Utilities Co. (MDU) submitted a Permit to Construct (PTC) application on April 30, 2020, for the MDU R.M. Heskett Station. The PTC application proposes the removal of two existing coal-fired boilers (Unit 1 and Unit 2) and ancillary equipment as well as the installation of a new, 88 megawatt (MW) natural gas-fired simple cycle combustion turbine (SCCT), which will be used as a peaking (non-baseload) unit to provide sellable energy. There are no proposed operational or physical changes proposed to the existing simple cycle combustion turbine (Unit 3), or its ancillary equipment.

The MDU R.M. Heskett station will cease current operations as a coal-fired, steam energy generation facility, and will replace all gross energy generation operations with two natural gas-fired SCCTs, which will both act as peaking units. The coal-fired boilers and associated equipment will be removed prior to the commencement of operation of the additional SCCT.

Project proposed changes include the following:

- Removal of the coal-fired boiler rated at 387.63 x 10^6 Btu/hr (Unit 1 boiler),
- Removal of the coal-fired boiler rated at 916.5 x 10^6 Btu/hr (Unit 2 boiler),
- Removal of all ancillary equipment associated with the two coal-fired boilers,
- Installation of one 88 MW natural gas-fired SCCT (nominal output is based upon the proposed site elevation, 60% relative humidity, 43 degrees Fahrenheit, and 100% load),

- Installation of one 5,364 bhp natural gas-fired emergency generator, and
- Installation of one 5 x 10^6 Btu/hr fuel line heater.

The outcome of the project will comprise of an overall air emissions reduction for NO_x, CO, SO_2, PM and greenhouse gases; however, the MDU R. M. Heskett station will remain a major source of criteria pollutants.

In addition, air dispersion modeling of NO_x and air toxics was conducted as a part of the PTC application review process.

Table 1 - Equipment to be Removed

Emission Unit Description [A]	**Emission Unit (EU)**	**Emission Point (EP)**	**Air Pollution Control Equipment**
Coal-fired boiler with a rated heat input of 387.63 x 10^6 Btu/hr (Unit 1 boiler)	1	1	Electrostatic Precipitator (ESP)
Coal-fired boiler with a rated heat input of 916.5 x 10^6 Btu/hr (Unit 2 boiler)	2	2	Multiclone, ESP and Limestone addition to bed media
Natural gas-fired IC engine rated at 134 bhp, 100 kW output, built 1963 (Emergency generator engine)	3 [B, C]	3	None
Natural gas-fired sand dryer with a rated heat input of 3.0 x 10^6 Btu/hr (Sand dryer)	5	2	ESP
Unit 1 coal storage silo	M1	M1	Fabric Filter
Unit 1 coal gallery	M2	M1	Fabric Filter
Three Unit 2 coal storage silos	2A, 2B & 2C	M3	Fabric Filters
Ash conveyor system	M4	M4	Fabric Filter
Unit 1 bottom ash silo	M5	M5	Fabric Filter
Sand storage silos	S2B	M6	Fabric Filter
Limestone hopper	S2A	M6	Fabric Filter
Fly ash silo	M7	M7	Fabric Filters
Gasoline storage tank, 1000 gal, built Dec. 2006	M8	M8	Submerged fill pipe
Limestone silo and limestone receiving	M9	M9	Fabric Filter
Limestone conveyor	M11	M11	Fabric Filters

[A] Emission units must be removed or permanently decommissioned prior to the commencement of operation of the Unit 4 turbine (EU 12).

Table 2 - Remaining Equipment

Emission Unit Description	**Emission Unit (EU)**	**Emission Point (EP)**	**Air Pollution Control Equipment**
Natural gas-fired combustion turbine nominally rated at 986 x 10^6 Btu/hr, built 2013 (Unit 3 turbine) (2013) (KKKK)	6	6	Dry Low NO_x (DLN) Combustion
Natural gas-fired in-line heater nominally rated at 2.75 x 10^6 Btu/hr (Unit 3 in-line heater)	7	7	None
Fugitive emissions	FUG [A]	FUG	None

[A] Insignificant unit/activity or no specific emission limit.

Table 3 - New Equipment

Emission Unit Description	**Emission Unit (EU)**	**Emission Point (EP)**	**Air Pollution Control Equipment**
Natural gas-fired combustion turbine nominally rated at 986 x 10^6 Btu/hr (Unit 4 turbine) (KKKK) (TTTT)	12	12	Dry Low NO_x (DLN) Combustion
Natural gas-fired in-line heater nominally rated at 5 x 10^6 Btu/hr (Unit 4 in-line heater)	13	13	None
One (4SLB) natural gas-fired emergency generator rated at 5,364 bhp (2020 or newer) (JJJJ) (ZZZZ)	14 [A]	14	None

[A] The potential to emit for an emergency stationary reciprocating internal combustion engine (RICE) is based on operating no more hours per year than is allowed by the subparts (40 CFR 60, Subpart JJJJ and 40 CFR 63, Subpart ZZZZ) for other than emergency situations. For engines to be considered emergency stationary RICE under the RICE rules, engine operations must comply with the operating hour limits as specified in the applicable subparts. There is no time limit on the use of emergency stationary RICE in emergency situations.

V. **Potential to Emit (PTE) Emissions**:

Emissions from the facility are as follows:

Table 4 - Unit 4 SCCT Project PTE Calculations (in tons per year)[A]

PROJECT POTENTIAL TO EMIT POLLUTANTS (TONS/YEAR)							
Description of PTE Source	**PM/PM$_{10}$/PM$_{2.5}$ (tpy)**	**SO$_2$ (tpy)**	**NO$_x$ (tpy)**	**CO (tpy)**	**VOCs (tpy)**	**HAPs (tpy)[A, B]**	**H$_2$SO$_4$ (tpy)**
Unit 4 turbine	9.60/9.60/9.60	11.84	312.03	555.03	16.17	1.16	1.53
In-line heater	0.16/0.16/0.16	0.01	2.15	1.80	0.12	0.04	0.00
Emergency generator	0.02/0.02/0.02	0.01	1.18	2.37	0.59	0.11	0.00
Total PTE (without fugitives)	**9.78/9.78/9.78**	**11.86**	**315.36**	**559.20**	**16.88**	**1.31**	**1.53**
Total PTE (with fugitives)	**9.78/9.78/9.78**	**11.86**	**315.36**	**559.20**	**16.88**	**1.31**	**1.53**

[A] Pollutants are abbreviated as follows:
PM: particulate matter
PM$_{10}$: particulate matter under 10 microns (<10 μg), includes PM$_{2.5}$.
PM$_{2.5}$: particulate matter under 2.5 microns (<2.5 μg)
SO$_2$: sulfur dioxide
NO$_x$: nitrogen oxides
VOC: volatile organic compounds
CO: carbon monoxide

[B] HAPs: hazardous air pollutants as defined in Section 112(b) of the Clean Air Act Amendments of 1990

See application for more detailed emission calculations.

Table 5 - Emission Reduction After Coal-Fired Boiler Removal (Netting) (in tons per year)

NETTED POTENTIAL TO EMIT POLLUTANTS (TONS/YEAR)							
Time Period	**Description of PTE Source**	**PM/PM$_{10}$/PM$_{2.5}$ (tpy)**	**SO$_2$ (tpy)**	**NO$_x$ (tpy)**	**CO (tpy)**	**VOCs (tpy)**	**H$_2$SO$_4$ (tpy)**
Pre-Project [A]	Unit 1	-2.7/-3.1/-2.6	-953.6	-247.8	-203.3	-1.2	-146.0
	Unit 2	-8.5/-216.6/-215.0	-1,166.5	-945.1	-907.6	-5.5	-178.6
Post-Project	Unit 4	9.8/9.8/9.8	11.9	315.4	559.2	16.9	1.5
Netted Emissions [B]		**-1.4/-209.9/-207.8**	**-2,108.2**	**-877.5**	**-551.7**	**10.1**	**-323.0**

[A] Emissions based on the 24-month contemporaneous period from 2018 to 2019.

[B] Netted emissions are calculated by subtracting the pre-project emissions from the post-project emissions.

Table 6 - Total Post-Project Facility-Wide Emissions (in tons per year) [A]

TOTAL POST-PROJECT POTENTIAL TO EMIT POLLUTANTS (TONS/YEAR)							
Description of PTE Source	**PM/PM$_{10}$/PM$_{2.5}$ (tpy)**	**SO$_2$ (tpy)**	**NO$_x$ (tpy)**	**CO (tpy)**	**VOCs (tpy)**	**HAPs (tpy)**	**H$_2$SO$_4$ (tpy)**
Unit 3 [A]	24.4/24.4/24.4	18.4	159.7	263.3	9.7	1.9	NA
Unit 4	9.8/9.8/9.8	11.9	315.4	559.2	16.9	1.3	1.5
Total	**34.2/31.2/34.2**	**30.2**	**475.1**	**822.5**	**26.6**	**3.2**	**1.5**

[A] Emission values from PTC13016 application were used to estimate total emissions.

VI. Applicable Standards:

Table 7 - Applicable Standards

Emission Unit Description	**Emission Unit (EU)**	**Applicable Standards**
Unit 4 turbine	12	NDAC 33.1-15-02 NDAC 33.1-15-03 NDAC 33.1-15-05 NDAC 33.1-15-07 NDAC 33.1-15-21 NDAC 33.1-15-12, Subpart KKKK NDAC 33.1-15-12, Subpart TTTT
In-line heater	13	NDAC 33.1-15-02 NDAC 33.1-15-03 NDAC 33.1-15-05
Emergency generator	14	NDAC 33.1-15-03 NDAC 33.1-15-12, Subpart JJJJ 40 CFR 63, Subpart ZZZZ [EPA [A]]

[A] The Department has not adopted this subpart; all required documentation should be sent to EPA Region 8.

A. NDAC 33.1-15-02 – Ambient Air Quality Standards

The facility must comply with the Ambient Air Quality Standards (AAQS). Other requirements of this chapter include general prohibitions against harming health, causing damage to plants, animals, other property, and visible degradation. In addition to these standards, compliance with the Department's Air Toxics Policy is required.

Expected Compliance

In the *Criteria Pollutant Modeling Requirements for a Permit to Construct* Department memorandum dated October 6, 2014, dispersion modeling is required if the potential emissions exceed 100 tpy for NO_2 with some emissions vented from stack heights greater than 1.5 times the nearby building height. The facility's potential NO_2 emissions exceed 100 tons per year and emissions are vented from stack heights greater than 1.5 times nearby building height. Therefore, NO_2 1-hour and annual air dispersion modeling was conducted to demonstrate compliance with NAAQS. Modeling was also conducted for Class II increment consumption.

Table 8 below, as well as the accompanying Air Quality Impact Analysis demonstrate that the modeled 1-hour NO_2 design values of 149.86 $\mu g/m^3$, 150.51 $\mu g/m^3$ and 149.69 $\mu g/m^3$, are less than the NAAQS of 188 $\mu g/m^3$. The modeled annual NO_2 design values of 9.92 $\mu g/m^3$, 10.31 $\mu g/m^3$ and 10.18 $\mu g/m^3$, are less than the NAAQS of 100 $\mu g/m^3$. Therefore, compliance with this chapter is expected.

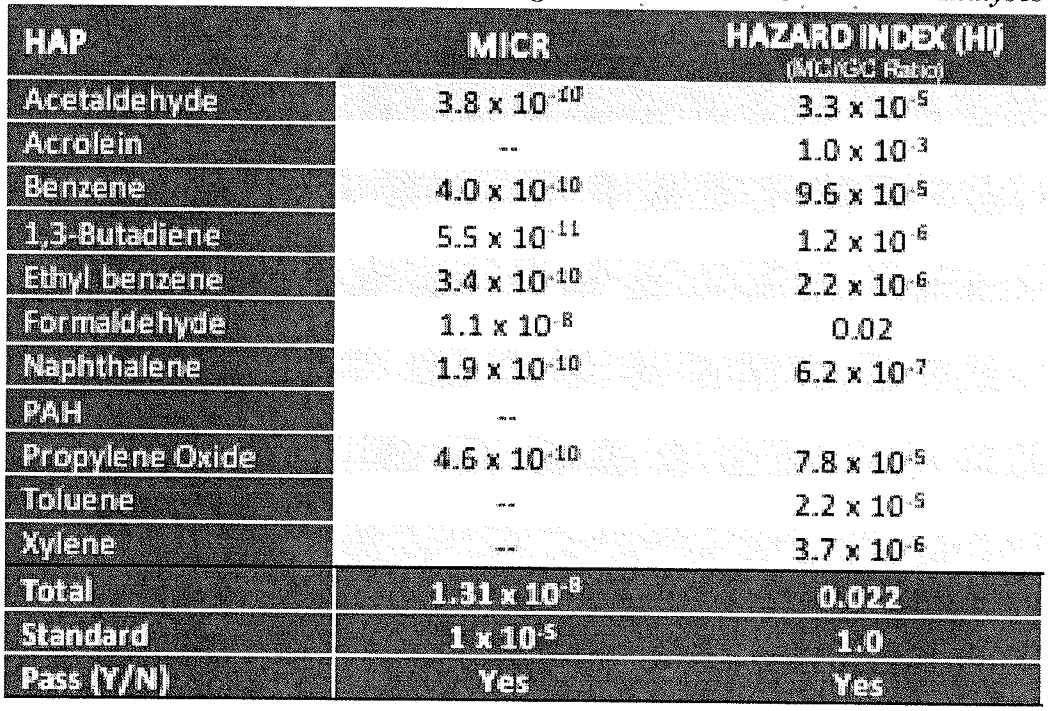
Table 8 - Cumulative – Ambient Air Quality Standards (AAQS) Results Summary

POLLUTANT	AVERAGING TIME	MODELED IMPACT ($\mu g/m^3$)	Class II/ AAQS SIL ($\mu g/m^3$)	BACKGROUND ($\mu g/m^3$)	TOTAL IMPACT ($\mu g/m^3$)	NAAQS/ NDAASQ ($\mu g/m^3$)	PASSED (Y/N)
PM_{10}	24-HR	--	5.0	30	--	150	--
$PM_{2.5}$	Annual	--	0.2	4.75	--	12	--
	24-HR	--	1.2	13.7	--	35	--
SO_2	Annual	--	0.2	3	--	80	--
	24-HR	--	5.0	9	--	365	--
	3-HR	--	25	11	--	1,309	--
	1-HR	--	7.8	13	--	196	--
NO_2 Baseload	Annual	4.92	1.0	5	**9.92**	100	Yes
	1-HR	114.69	7.5	35	**149.86**	188	Yes
NO_2 Worst Case	Annual	5.31	1.0	5	**10.31**	100	Yes
	1-HR	115.15	7.5	35	**150.15**	188	Yes
NO_2 Turndown	Annual	5.18	1.0	5	**10.18**	100	Yes
	1-HR	114.69	7.5	35	**149.69**	188	Yes
CO	8-HR	--	500	1,149	--	10,000	--
	1-HR	--	2,000	1,149	--	40,000	--

<u>Air Toxics Policy (*Policy for the Control of Hazardous Air Pollutant Emissions in North Dakota*) Expected Compliance</u>

The Air Toxics Policy (Policy) establishes guidelines to evaluate HAPs emitted into the ambient air (off-property). The evaluation includes a determination of both carcinogenic and non-carcinogenic risks due to the HAPs emissions. Individual HAP species, emission rates (gram/second), building downwash effects, and distances to nearby sources are modeled. The modeled HAP concentrations ($\mu g/m^3$) are used to calculate both a maximum individual carcinogenic risk (MICR) and a hazard index (HI). Modeled HAPs include those with potential to emit greater than 0.1 tpy. Tier 3 modeling (AERMOD v. 19191) is utilized to predict the following impacts:

Table 9 - Maximum Individual Carcinogenic Risk and Hazard Index Analyses



HAP	MICR	HAZARD INDEX (HI) (MIC/GC Ratio)
Acetaldehyde	3.8×10^{-10}	3.3×10^{-5}
Acrolein	--	1.0×10^{-3}
Benzene	4.0×10^{-10}	9.6×10^{-5}
1,3-Butadiene	5.5×10^{-11}	1.2×10^{-6}
Ethyl benzene	3.4×10^{-10}	2.2×10^{-6}
Formaldehyde	1.1×10^{-8}	0.02
Naphthalene	1.9×10^{-10}	6.2×10^{-7}
PAH	--	
Propylene Oxide	4.6×10^{-10}	7.8×10^{-5}
Toluene	--	2.2×10^{-5}
Xylene	--	3.7×10^{-6}
Total	**1.31×10^{-8}**	**0.022**
Standard	**1×10^{-5}**	**1.0**
Pass (Y/N)	**Yes**	**Yes**

The calculated MICR is the probability of an individual developing cancer after being exposed to the highest concentration of HAPs over a defined period of time. Only HAPs with known or possible carcinogenic risks are used to calculate the MICR. The MICR threshold stated in the Policy is 1 x 10^{-5}, which represents a probability of one person out of 100,000 people. The MICR calculated above at 1.31 x 10^{-8} is less than 1 x 10^{-5} and compliance with Air Toxics Policy is expected.

The HI calculation incorporates both carcinogenic and non-carcinogenic HAPs with acute and/or chronic health effects to determine both compliance with 1-hour and 8-hour guidelines concentrations. The HI is a sum of all modeled concentrations and guideline concentration ratios. A HI of less than 1 indicates that HAP modeled concentration are less than 1-hour and 8-hour guideline concentrations. The HI calculated above of 0.022 is less than 1.0 and compliance with the Air Toxics Policy is expected.

Total combined HAP emissions are low, with the MDU R.M. Heskett Station emissions at 3.2 tpy. Formaldehyde is the largest single HAP at 0.53 tpy, and compliance with applicable NSPS/MACT standards is expected. The facility is expected to comply with the ambient air quality standards and the *Air Toxics Policy*[1].

B. <u>NDAC 33.1-15-03 – Restriction of Emission of Visible Air Contaminants</u>

This chapter restricts the amount of visible air contaminants, primarily particulate matter, from incinerators and fuel-burning units.

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[1] August 25, 2010 NDDOH *Policy for the Control of Hazardous Air Pollutant (HAP) Emissions in ND (aka Air Toxics Policy)*, https://deq.nd.gov/publications/AQ/policy/Modeling/Air_Toxics_Policy.pdf

Expected Compliance

Based on the fuels used, visible air emissions are expected to be well below the 20% opacity limit established by this chapter.

Table 10 - Opacity Limits

Emission Unit Description	EU	Pollutant/ Parameter	Emission Limit
Unit 4 turbine	12	Opacity	20% [A]
In-line heater	13	Opacity	20% [A]
Emergency generator	14	Opacity	20% [A]

[A] 40% permissible for not more than one six-minute period per hour.

C. NDAC 33.1-15-05-Emissions of Particulate Matter Restricted

This chapter applies to any operation, process, or activity from which particulate matter is emitted except for the indirect heating in which the products of combustion do not come into direct contact with process materials.

Expected Compliance

Table 11 - Particulate Matter Limits

Emission Unit Description	EU	Pollutant/ Parameter	Emission Limit
Unit 4 turbine	12	PM	0.324 lb/MMBtu
In-line heater	13	PM	0.710 lb/MMBtu

Particulate matter emission limits are well below applicable standards when units are fueled by pipeline quality natural gas, therefore compliance with this chapter is expected.

D. NDAC 33.1-15-06-Emissions of Sulfur Compounds Restricted

This chapter applies to any installation in which fuel is burned in which the SO_2 emissions are substantially due to the sulfur content of the fuel burned and in which the fuel is burned primarily to produce heat. This chapter is not applicable to installations which are subject to a SO_2 emission limit under Chapter 33.1-15-12, Standards for Performance for New Stationary Sources, or installations which burn pipeline quality natural gas.

Expected Compliance

The facility is restricted to combusting only natural gas containing no more than 2 grains of sulfur per 100 standard cubic feet, therefore compliance with this chapter is expected.

D. NDAC 33.1-15-07 – Control of Organic Compounds Emissions

This chapter requires compressors handling volatile organic compounds must be equipped and operated with properly maintained seals.

Expected Compliance

Based on Department experience with similar sources, the facility is expected to comply with this chapter.

E. NDAC 33.1-15-12 - Standards of Performance for New Stationary Sources [40 Code of Federal Regulations Part 60 (40 CFR Part 60)]

This chapter adopts most of the Standards of Performance for New Stationary Sources (NSPS) under 40 CFR Part 60. The facility is subject to subparts listed under 40 CFR Part 60 which have been adopted by the North Dakota Department of Environmental Quality.

Table 12 - NSPS Requirements

Emission Unit Description	Emission Unit (EU)	Applicable Standards
Unit 4 turbine	12	NDAC 33.1-15-12, Subpart KKKK NDAC 33.1-15-12, Subpart TTTT
Emergency generator	14	NDAC 33.1-15-12, Subpart JJJJ

1. Subpart A-General Provisions

Subpart A contains the NSPS General Provisions, since the facility is subject to one or more NSPS (NDAC 33.1-15-12/40 CFR 60) it is subject to this subpart.

Expected Compliance

Compliance with the requirements of Subpart A is expected through compliance with each applicable NSPS subpart.

2. Subpart KKKK – Standards of Performance for Stationary Combustion Turbines, as incorporated by reference into NDAC 33.1-15-12

This subpart establishes emission standards and compliance schedules for the control of NO_x and SO_2 emissions from stationary combustion turbines that commenced construction, modification, or reconstruction after February 18, 2005.

Expected Compliance

The SCCT (EU 12) is subject to this subpart. As such it will have a dry low NO_x combustion control installed as well as a NO_x continuous emissions monitor (CEMs) per 40 CFR 60.4340(b) and 60.4345, which will assess excess emissions based on a 4-hour rolling average.

Table 13 - NO_x Emissions Per Operational Status

Operational Status	**NO_x Hourly Emissions (lb/hr)**	**Total Number of Hours**
Normal Operations	81.1	2,859
Start-up/Shutdown	4.6	450
Turn-down	515.0	691

Table 14 - SO_2 Emissions Per Operational Status

Operational Status	**NO_x Hourly Emissions (lb/hr)**	**Total Number of Hours**
Normal Operations	6.6	2,859
Start-up/Shutdown	0.41	450
Turn-down	6.6	691

Table 15 - Emission Limits

Emission Unit Description	**EU**	**EP**	**Pollutant / Parameter**	**Emission Limit**
Natural gas-fired combustion turbine nominally rated at 986 x 10^6 Btu/hr (Unit 4 turbine)	12	12	NO_x: >50 MW (gross) & >0°F	15 ppmvd @ 15% O_2 or 54 ng/J (0.43 lb/MWh) $^{A, B, C, D}$
			NO_x: ≤50 MW (gross) or <0°F	96 ppmvd @ 15% O_2 or 590 ng/J (4.7 lb/MWh) $^{A, B, C, D}$
			NO_x	515.8 lb/hr ^{H}
			SO_2	110 ng/J (0.90 lb/MWh) (gross) or 0.060 lb/MMBtu (fuel use) ^{E}
			CO_2	50 kg CO_2/GJ heat input (120 lb CO_2/MMBtu) $^{F, G}$

[A] CEMs installed in lieu of annual performance tests (40 CFR 60.4340(b)).

[B] CEMs installation, operation, and performance testing must meet the applicable standards of 40 CFR 60 Subpart KKKK.

[C] Based on a 4-hr rolling average.

[D] The higher NO_x limit emission limit applies for the entire hour if at any point in the hour the unit was subject to a higher limit.

[E] Sulfur content of the fuel must be determined using total sulfur methods per 40 CFR 60.4415 and 60.4370.

[F] Emissions standards must be met at all times; however, compliance must be determined only at the end of each applicable operating month.

[G] Emission limit is based on operations that supply less than or equal to its design efficiency (33.34%) or 50%, whichever is less, times its potential electric output as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts > 90% natural gas.

[H] Based on a 1-hr average.

NO_x concentration is dependent upon the combustion temperature; therefore, NO_x emission limits vary based on ambient temperatures.

For demonstrating compliance with SO_2 emission limits, the facility may conduct SO_2 performance tests per §60.4415(a) or monitor sulfur content of the fuel combusted in the turbine per §60.4360. A representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil, per 60.4415.

Compliance with this chapter is expected.

3. Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units, as incorporated by reference into NDAC 33.1-15-12

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a stationary combustion turbine that commences construction after January 8, 2014. An applicable unit shall be referred to as an affected electrical generating unit (EGU).

An affected EGU (per the definition in 40 CFR 60.5580), with a base load rating greater than 260 GJ/h (250 x 10^6 Btu/hr) of fossil fuel and capable of selling more than 25 MW to a power distribution system is subject to this subpart. Therefore, the Unit 4 turbine is considered an affected EGU per 40 CFR 60, Subpart TTTT and must comply with all applicable standards set forth in this rule.

Expected Compliance

Table 16 - Emission Limits

Emission Unit Description	EU	Pollutant/ Parameter	Emission Limit	Compliance Method
Unit 4 turbine	12	CO_2	50 kg CO_2/GJ heat input (120 lb CO_2/MMBtu) [A, B]	Notification and Recordkeeping

[A] Emissions standards must be met at all times; however, compliance must be determined only at the end of each applicable operating month.

B Emission limit is based on operations that supply less than or equal to its design efficiency (33.34%) or 50%, whichever is less, times its potential electric output as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts > 90% natural gas.

Within 30 days after the end of a compliance period, an initial compliance determination must be made with respect to the applicable emissions limits. Since MDU R.M. Heskett is subject to the Acid Rain Program, emissions reporting is required to begin under 40 CFR 60.5525(c).

Compliance with this chapter is expected.

4. **Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines, as incorporated by reference into NDAC 33.1-15-12**

This rule states that natural gas-fired emergency generators (spark-ignited) greater that 500 bhp manufactured after July 1, 2010 are subject to this subpart. The emergency generator (EU 14) is an affected unit according to this rule.

Expected Compliance

Table 17 - NSPS JJJJ Requirements

Emission Unit Description	**EU**	**Requirements**
Emergency generator	14	-The emergency engine may be operated for up to 50 hours or less per year (January through December) for non-emergency uses. -The emergency engine may be operated for a maximum total of 100 hours per year (January through December) for non-emergency uses such as maintenance and testing (50 hours of general non-emergency use must be counted toward the 100 total hours of use).

Table 18 - NSPS JJJJ Emission Limits

Emission Unit Description	EU	Pollutant / Parameter	Emission Limit
Emergency generator	14	NO_x	2.0 g/hp-hr or 160 ppmvd [A]
		CO	4.0 g/hp-hr or 540 ppmvd [A]
		VOC	1.0 g/hp-hr or 86 ppmvd [A]

[A] The emission limits in g/hp-hr and ppmvd (at 15% O_2) are from 40 CFR 60, Subpart JJJJ.

The emergency generator (EU 14) is subject to the requirements of this subpart. Compliance with this subpart is expected.

F. Chapter 33.1-15-14 – Designated Air Contaminant Sources, Permit to Construct, Minor Source Permit to Operate, Title V Permit to Operate

This chapter requires the facility to obtain a Permit to Construct prior to installation of sources of air pollution. This chapter also applies to Permit to Operate requirements for facilities that have sources of air pollution.

Expected Compliance

The company has submitted an application for a Permit to Construct and has met those requirements.

G. Chapter 33.1-15-15 – Prevention of Significant Deterioration of Air Quality

A Prevention of Significant Deterioration (PSD) review could potentially apply to this facility if it is classified as a "major stationary source" under Chapter 33.1-15-15.

This facility source category will have a PSD major source threshold of 250 tpy, not including fugitive emissions. Due to annual NO_x emissions greater than 250 tpy the facility is classified as a "major stationary source"; therefore, additional construction and modification projects may be subject to PSD review if the emissions increase due to the project exceeds the Significant Emission Rates (SERs) in Table 19 below.

Expected Compliance

Table 19 - Prevention of Significant Deterioration (PSD) Requirements

Pollutant	Project Emissions	Past Actual Emissions [A]	Net Emissions Increase	PSD Significant Emission Rate
NO_x	315.36	1,192.3	-877.49	40
PM_{10}	9.78	219.7	-209.9	15

Pollutant	Project Emissions	Past Actual Emissions [A]	Net Emissions Increase	PSD Significant Emission Rate
$PM_{2.5}$	9.78	217.6	-207.81	10
SO_2	11.86	2,120.1	-2,108.19	40
VOC	16.88	6.7	10.18	40
H_2SO_4	1.53	324.6	-323.04	7
CO_2e	267,276	669,155	-401,879	75,000

A Past actual emissions based on 24-month contemporaneous period from 2018 to 2019, which is within five years of construction.

Based on the table above, emissions from the new equipment proposed in ACP-17983 v1.0 are expected to be well below the PSD SERs; therefore, the new units are not subject to PSD review.

H. Chapter 33.1-15-16 – Restriction of Odorous Air Contaminants

The owner/operator shall not discharge into the ambient air any objectionable odorous air contaminant which is in excess of the limits established in NDAC 33.1-15-16.

Expected Compliance Status

Based on Department experience with similar sources, the facility is expected to comply with this chapter.

H. Chapter 33.1-15-21 – Acid Rain Program

The SCCT will be considered a utility under the requirements of Chapter 33.1-15-21. Therefore, the owner/operator must apply for, and obtain, an Acid Rain Permit in accordance with NDAC 33-15-21-08.1. In addition, the owner/operator must hold sulfur dioxide allowances, as of the allowance transfer deadline, in the unit's subaccount not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit. Monitoring of emissions must be accomplished in accordance with NDAC 33-15-21-09 (40 CFR 75).

Expected Compliance Status

The proposed Unit 4 turbine at MDU R.M. Heskett station must operate the unit in compliance with a complete Acid Rain permit application including any application for permit renewal or a superseding Acid Rain permit issued by the North Dakota Department of Environmental Quality, Division of Air Quality

MDU R.M. Heskett has submitted an Acid Rain Permit Application and compliance with this chapter is expected.

I. Chapter 33.1-15-22 – Emission Standards for Hazardous Air Pollutants for Source Categories

This chapter adopts most of the National Emission Standards for Hazardous Air Pollutants for Source Categories (MACT) under 40 CFR Part 63.

1. Subpart A-General Provisions

This chapter adopts the 40 CFR Part 63 regulations, also known as the Maximum Achievable Control Technology (MACT) standards, which regulates HAPs from regulated source categories. Typically, these standards apply to major sources of air pollution that are a regulated source category. In addition to the major source requirements, some of the regulations have "area source" standards (for non-major sources). Some of the area source standards have not been adopted by the Department and compliance will be determined by the United States Environmental Protection Agency (USEPA) (e.g. 40 CFR Part 63, Subpart ZZZZ area source provisions have not been adopted by the Department).

Expected Compliance

Subpart A contains the MACT General Provisions. Compliance with the requirements of Subpart A is expected through compliance with each applicable MACT subpart.

2. Subpart ZZZZ-National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The facility appears to have engines subject to the requirements under this subpart. The requirements of Subpart ZZZZ for the engines are met by complying with the requirements of NDAC 33.1-15-12, Subpart JJJJ for EU 14.

Expected Compliance

Table 20 - ZZZZ Requirements

Emission Unit Description	**Emission Unit (EU)**	**Applicable Standards**
One (4SLB) natural gas-fired emergency generator rated at 5,364 bhp	14	Comply with NDAC 33.1-15-12, Subpart JJJJ [A, B]

[A] The Department has not adopted the area source requirements of this subpart; EPA Region 8 is the implementing and enforcement authority for this subpart at minor sources of hazardous air pollutants.

[B] The requirements of Subpart ZZZZ for the engine is met by complying with the requirements of NDAC 33.1-15-12 [40 CFR 60], Subpart JJJJ.

Conclusions and Recommendations:

The facility is expected to comply with applicable federal and state rules. No comments were received during the 30-day public comment period. It is recommended that Permit to Construct No. ACP-17983 v1.0 be issued for the MDU R.M. Heskett Station.

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A.7 – Little Knife Gas Plant

1 Introduction and Representative Operations

Petro-Hunt, L.L.C. (Petro-Hunt) – Little Knife Gas Plant (LKGP) is comprised of numerous fuel gas combustion units, process equipment, tankage, flares, and a sulfur recovery process controlled by an incinerator. The major emissions source onsite is the 2-stage 2-bed Cold Bed Absorption (CBA) sulfur recovery unit (SRU) tail gas incinerator. The LKGP is located approximately 18 miles southwest of Killdeer, North Dakota in Billings County.

LKGP receives associated gas produced from North Dakota oilfields. Since the development of the Bakken shale formation, LKGP has continued to experience a decrease in sour gas received onsite. This is primarily due to the low concentrations of H_2S in Bakken shale gas paired with an increase in Bakken shale gas delivered to the facility. To determine representative operations for the facility, data from 2016–2018 was used. 2016–2018 was chosen since the SRU was converted from a four-stage unit to a two-stage Claus unit with cold bed absorption (CBA) in 2015. The SRU tail gas incinerator combusts the remaining unreacted H_2S after the gas passes through the SRU process. The SRU tail gas incinerator accounted for at least 85% of the total facility emissions since 2016, Table 1 displays the annual emissions reported in tons from 2016-2018.

Table 1: Facility Emissions in Tons

Year	$PM_{2.5}$	PM_{10}	SO_2	NO_x	CO	VOC	Total
2016	2	2	248	22	18	2	293
2017	1	1	389	19	16	2	428
2018	1	1	363	22	18	1	406

The SO_2 emissions displayed in Table 1 are primarily from the operation of the tail gas incinerator on the SRU. Due to the significant amount of emissions from the SRU compared to the rest of the facility, the Department focused the review of additional controls on the SRU process.

2 SO_2 Emissions Controls and Representative History

2.1 SO2

2.1.1 SO_2 Emissions Controls

The historical controls at Petro-Hunt LKGP consisted of two sulfur recovery units, a three-stage four-bed CBA unit and a standard 3-stage Claus unit. The units recovered approximately 98% of the sulfur from the acid gas and converted it to elemental sulfur. The remainder of the acid gas is converted from H_2S to SO_2 by the tail gas incinerator. SO_2 emissions from the incinerator are monitored by a continuous emission rate monitoring system (CERMS).

In September 2015 due to operational difficulty arising from the decrease in inlet H_2S gas to the facility, the sulfur recovery process was modified to handle the reduced H_2S. The three-stage Claus unit was removed from service and the four-bed CBA was converted to a two-stage Claus unit with CBA.

2.1.2 SO_2 Emissions History

Over the years 2016–2018, the SRU recovered approximately 94% of the sulfur entering the unit. The total sulfur recovered, the SO_2 emissions from the tail gas incinerator and the calculated sulfur mass emitted (SO_2 is twice as heavy as elemental sulfur) was used to calculate the SRU recovery efficiency. This information is displayed in Table 2.

Table 2: Sulfur Recovery Unit Efficiency

Year	Sulfur Recovered (tons)	SO2 Emissions from Incinerator (tons)	Sulfur Emissions (tons)	Sulfur Recovery (%)
2016	2975	242	121	96%
2017	2504	315	157	94%
2018	2284	363	181	93%
Average	**2588**	**307**	**153**	**94%**

The other potential significant source of SO_2 emissions from the facility occurs when a process malfunction occurs, and the facility needs to route H_2S inlet or process gas to the facility flare. This does not happen on a routine basis and there is no ability to reduce the emissions during these malfunction events. From 2016–2018 a combined total of 80 tons of SO_2 were emitted from the facility flare, with 74 tons SO_2 occurring in 2017.

3 SO_2 Analysis

3.1 SO_2 Technologies Evaluated

The reasonable progress controls evaluated by LKGP and determined to be technically feasible are listed in Table 3. Expected annual emissions were based on the three-year average SO_2 emissions from the SRU incinerator at LKGP (Table 2). LKGP expects no operational changes, therefore, these emissions are also repetitive of future expected emissions.

Table 3: Reasonable Progress SO_2 Controls

Control Technology	Control Technology Abbreviation	Emissions (tons/year)
Existing SRU (baseline)	--	307
Acid Gas Injection	AGI	0

LKGP also evaluated a catalyst replacement in the SRU reactors to increase the efficiency of unit. Catalyst replacement due to degradation and/or fouling happens on a regular basis and is not considered for reasonable progress controls.

3.1.1 Acid Gas Injection

Acid gas injection (AGI) is a process in which acid gases (H_2S and CO_2) are injected into deep underground wells to dispose of the acid gases produced during the sweeting process of natural gas at a gas processing facility. Installation of AGI eliminates the need for a facility to operate a SRU since the acid gases produced from the natural sweetening process are disposed of underground versus being processed in a SRU.

AGI eliminates all SO_2 emissions except for those emissions due to a malfunction of the injection equipment. When a malfunction occurs, the gas goes to a flare which will combust the H_2S to form SO_2.

3.2 Step 1 – Cost of Compliance

The cost of compliance for the reasonable progress controls are listed in Table 4.

Table 4: SO_2 Cost of Compliance

Control Technology	**Emissions (tons/year)**	**Annual Emission Reduction (tpy)**	**Annualized Total Cost ($)**	**Cost of Compliance ($/ton)**
Existing SRU (baseline)	307			
Acid Gas Injection	0	307	490,009	1,598
Acid Gas Injection[A]	0	307	628,523	2,050

[A] AGI includes redundant compressor and plumbing costs

A detailed breakdown of the costs listed in Table 4 can be found in LKGP's submitted four factors analysis.[1] The Department has reviewed these costs and believes them to be accurate.

If AGI is installed, all the routine SO_2 emissions from the current SRU process will be eliminated. This equates to a reduction of 307 tons SO_2 per year from the baseline emissions. Fiscally, AGI installation requires an estimated annualized cost of $490,000 and SO_2 removal cost of $1,600 per ton.

As mentioned in Table 4, if redundant AGI equipment is installed, the estimated annualized cost increases to $628,500 and SO_2 removal cost increases to roughly $2,100 per ton. Redundant AGI equipment would be utilized to dispose the acid gas in the event when a malfunction occurs. These malfunctions are generally unplanned, short duration-episodes (a few hours) with very high SO_2 emission rates that vary from year-to-year. Without redundancy, controlling emissions during malfunctions is not feasible and the acid gas is flared to prevent the release of high concentrations of H_2S.

3.3 Step 2 – Time Necessary for Compliance

Petro-Hunt indicated installation of AGI would require at least 72 months to complete.[2] The time necessary for compliance is not a limiting factor when determining additional reasonable controls for the LKGP since it could be installed prior to the end of the second planning period.

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[1] Appendix B.7.b. PDF page 1300-1311.

[2] Appendix B.7.b. PDF page 1298.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

3.4.1 Energy and Non-Air Quality Environmental Impacts

LKGP's submitted four factors analysis indicated various energy and non-air quality environmental impacts ranging from increased electrical demand to added fuel cost.[3] While these impacts can be significant, none of the impacts eliminate AGI as a potential add-on control option.

3.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, the Petro-Hunt LKGP is expected to operate beyond the life of the control equipment.[4] Therefore, remaining useful life was not considered.

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[3] Appendix B.7.b. PDF page 1299.

[4] Appendix B.7.b. PDF page 1299.

A.8 – Hess Tioga Gas Plant

1 Introduction and Representative Operations

Hess Tioga Gas Plant, LLC (Hess) – Hess Tioga Gas Plant (TGP) is comprised of numerous boilers, heaters, compressor engines, turbines, storage tanks, process equipment, flares, and a sulfur recovery process controlled by an incinerator. Most of the emissions are sourced from the compressor engines and the amine gas sweetening unit (the SRU tail gas incinerator). Tioga is located just to the east of Tioga, North Dakota in Williams County.

The average annual amount of inlet gas received, natural gas produced, and sulfur recovered from 2015 through 2018 is listed in Table 1. The time period of 2015–2018 was chosen as representative since Hess TGP completed a plant expansion in 2014, allowing the facility to process more inlet gas.

The process data does not directly correlate with the emissions from the facility but helps to show consistent operations over the recent years from the facility. With this consistent operation, emissions from this time period can be averaged to determine representative baseline emissions in order to evaluate additional feasible controls. See Table 1 for detailed information.

Table 1: Process Data from 2015-2018

Year	Gas Received (MMscf)	Gas Produced (MMscf)	Sulfur Produced (tons)
2015	70,800	36,200	8,970
2016	62,200	36,300	8,030
2017	63,900	39,200	8,170
2018	70,200	45,100	8,240

Hess TGP's future operations are expected to be in line with the 4-year average of 2014–2018.

2 NO_X and SO_2 Emissions Controls and Representative History

The emissions sources which contribute the largest to the overall emissions profile for Hess TGP are the Clark compressor engines and the sulfur recovery unit operations.

Over the years of 2014–2018, the Clark compressor engines accounted for 91% of the facilities total NO_X emissions. A breakdown of the NO_X emissions profile can be found in Section 2.1.2.

Over the years of 2014–2018, the sulfur recovery operation accounted for 94% of the facilities total SO_2 emissions, where 79% of the total was from the tail gas incinerator. A breakdown of the SO_2 emissions profile can be found in Section 2.2.2.

The sulfur recovery unit tail gas incinerator has a SO_2 continuous emissions rate monitor system (CERMS) installed. The Clark compressor engines are tested semi-annually to ensure they are operating in compliance with the total tons of NO_X restriction in the facility's Title V Permit to Operate.

During the first round of the regional haze program, the Department determined that no NO_X or SO_2 controls were required the Hess TGP.[1]

2.1 NOx

2.1.1 NO_X Emissions Controls

A summary of the existing NO_X controls for the applicable Hess TGP emissions units are discussed in Section 2.1.1.1 and 2.1.1.2.

2.1.1.1 Clark Compressor Engines

Hess TGP operates seven Clark compressor engines, identified as C1A through C1G. These engines are fueled by a portion of the natural gas produced by the facility and are used to boost the pressure of the inlet field gas received for processing. All the Clark engines are lean burn integral engines, meaning the engine and compressor structure are a single unit, making it both difficult and costly to replace the units. Two of the engines (C1D and C1F) required modification in 2004, which entailed adding turbocharging systems. The turbocharging system significantly reduced NO_X emissions from these engines compared to the other five engines. The other five engines (C1A, C1B, C1C, C1E, and C1G) have not been significantly modified since construction in the 1950's but have been kept in good working order.[2] Feasible add-on controls for the remaining five engines are evaluated in Section 3.1. A discussion on the breakdown of emissions from these engines can be found in Section 2.1.2.

2.1.1.2 Remaining NO_X Emissions Units

Hess TGP does not operate any other units which are significant contributors of NO_X emissions, therefore, no additional equipment is evaluated for additional controls with this analysis. Hess TGP included an evaluation of NO_X controls on the sulfur recovery unit tail gas incinerator and considered the feasibility of a flare management plan to reduce emissions from this activity. Neither of these evaluations yielded any feasible controls.[3]

2.1.2 NO_X Emissions History

No recent NO_X controls have been installed at the facility, therefore, the baseline emissions from the facility were determined based on the average emissions from 2015–2018. This information is displayed in Table 2.

Table 2: Annual NO_X Emissions (tons)

Year	Clark Engines	Remaining Units ^{A}	Total
2015	1,366	106	1,472
2016	1,133	76	1,209
2017	535	93	627
2018	614	92	706
Average	**912**	**92**	**1,004**

^{A} Accounts for all other onsite emissions units.

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[1] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 182-188.

[2] Appendix B.8.b., p. 11. PDF page 1386.

[3] Appendix B.8.b, p. 28. PDF page 1403.

Given the magnitude of emissions produced from the Clark engines (91% of the facility total NO_X), they are the focus of determining the need for NO_X controls under the reasonable progress requirements. The NO_X emissions from the Clark Engines (Table 2), have been further separated by individual engines in Table 3 to show the variation between each engine and the impact the modification of C1D and C1F had on the NO_X emissions rate.

Table 3: Annual NO_X Emissions from Clark Engines (tons)

Year	C1A	C1B	C1C	C1E	C1G	C1D^A	C1F^A
2015	238	293	209	353	207	30	35
2016	171	215	255	257	150	25	30
2017	18	99	127	81	155	26	29
2018	107	148	139	0	186	19	16
Average	**134**	**189**	**183**	**231**	**175**	**25**	**27**

^{A} C1D and C1F were modified in 2004

Since each engine does not have the same operating hours per year, looking only at total emissions does not directly help with determining the best sources for individual controls. Therefore, the Department used the annual emissions (Table 3) and the annual operating hours (Table 4) to calculate the average pounds per hour of NO_X emissions from each engine (Table 5).

Table 4: Clark Engine Operation (hours)

Year	C1A	C1B	C1C	C1E	C1G	C1D	C1F
2015	6,520	7,749	5,818	7,437	7,885	8,314	8,568
2016	3,720	6,417	6,965	6,600	5,217	7,045	7,962
2017	528	3,506	4,258	2,070	6,240	8,165	6,708
2018	3,228	4,438	4,648	0	5,325	5,133	3,668
Average	**3,499**	**5,528**	**5,422**	**5,369**	**6,167**	**7,164**	**6,727**

Table 5: Non-modified Clark Engine NO_X Emissions (lb/hr)

Year	C1A	C1B	C1C	C1E	C1G
2015	73	76	72	95	53
2016	92	67	73	78	57
2017	66	56	60	78	50
2018	66	67	60	0	70
Average	**75**	**66**	**66**	**84**	**57**

Averaging the pound per hour data across the five non-modified Clark engines from Table 5, and pairing this with the average operating hours for the non-modified Clark engines (Table 4), yields a baseline emissions value of 181 tons per year from each of the five non-modified Clark engines. By chance, this happens to compare to the simple average of the five non-modified Clark engines, which is 182 tons per year.

181 tons per year of NO_X is used as the baseline rate for each non-modified Clark engine when evaluating the cost of additional controls in Section 3.2.

2.2 SO2

2.2.1 SO_2 Emissions Controls

A summary of the existing SO_2 controls for the Hess TGP sulfur recovery process is discussed in Section 2.2.1.1.

2.2.1.1 Sulfur Recovery Process

The sulfur recovery process at Hess TGP consists of an amine gas sweeting unit and sulfur recovery unit (SRU). The SRU consists of a 2-stage Claus process followed by cold bed adsorption. Over the baseline years of 2015–2018 sulfur recovery has averaged 96%, see Table 6.

Table 6: Sulfur Recovery Process Data

Year	Sulfur Produced (Tons)	Sulfur from Tail Gas Incineration (Tons)	SRU Efficiency (%)
2015	8,968	307	96.7%
2016	8,029	241	97.1%
2017	8,167	359	95.8%
2018	8,243	497	94.3%
Average	**8,352**	**351**	**96.0%**

Remaining gas (tail gas) not converted to elemental sulfur during the reaction process is combusted in the tail gas incinerator. The tail gas incinerator accounted for an average of 79% of the facility SO_2 emissions (Table 7).

Another aspect of the sulfur recovery process produces SO_2 emissions is during acid gas flaring events. Acid gas produced by the amine sweeting unit feeds the sulfur recovery unit and acid gas flaring occurs when the sulfur recovery unit malfunctions and needs to be taken offline. Acid gas flaring is very intermittent, averaging 70 hours a year over the baseline years. This does, however, account for 15% of the facility SO_2 due to the high concentration of hydrogen sulfide in the acid gas. Since acid gas flaring is not a routine source of emissions, SO_2 reductions from this activity are not evaluated.

2.2.1.2 Remaining SO_2 Emissions Units

The only source of SO_2 emissions from the facility not associated with the sulfur recovery process come from the flaring of inlet (feedstock) gas. Hess TGP considered the feasibility of a flare management plan to reduce emissions from this activity.[4] Since flaring only occurs during emergency events and other malfunctions related occurrences and is highly intermittent, a flare management plan was deemed unnecessary. Flaring accounts for approximately 6% of the SO_2 emissions over the baseline years, see Table 7.

2.2.2 SO_2 Emissions History

No recent SO_2 controls have been installed at Hess TGP, therefore, the baseline emissions from the facility were determined based on the average emissions from 2015–2018. This information is displayed in Table 7.

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[4] Appendix B.8.b, p. 15 and 30. PDF pages 1390 and 1405.

Table 7: Annual SO_2 Emissions (tons)

Year	Tail Gas Incineration	Acid Gas Flaring	Inlet Gas Flaring	Total
2015	614	178	114	906
2016	481	308	77	866
2017	719	29	2	749
2018	994	20	26	1,040
Average	**702**	**134**	**55**	**890**

As shown in Table 7, most of the SO_2 emissions from Hess TGP come from the incineration of the tail gas produced by the sulfur recovery unit. During normal operations, this is the only significant source of SO_2 emissions. Tail gas incineration accounts for an average of 79% of the facility SO_2 emissions. Acid gas flaring (15%) and inlet gas flaring (6%) account for the remaining portion of SO_2 emissions where controls could theoretically be evaluated. However, as both inlet and acid gas flaring are intermittent and not intended operations, controls are not evaluated from these sources.

3 NOx Analysis

3.1 NO_X Technologies

The NO_X controls evaluated for the non-modified Clark engine are discussed in Sections 3.1.1 and 3.1.2.

3.1.1 Low-emission Controls (LEC)

LEC is s system of upgrades, modifications, and tuning on the Clark engines to achieve a lower emissions rate. LEC is anticipated to achieve 70-90% reduction in NO_X emissions and achieve a controlled emissions rate of 1 gram per brake horsepower hour, which is consistent with most new internal combustion engines.[5] LEC installation on non-modified Clark engines is technically feasible and will be further evaluated.

3.1.2 Selective Catalytic Reduction (SCR)

SCR is an exhaust control that could be applied to lean combustion engines which reduces NO_x emissions by reacting NO_x with ammonia or urea over a catalyst.[6] SCR is anticipated to achieve 70-90% reduction in NO_X emissions and achieve a controlled emissions rate of 1 gram per brake horsepower hour, the same rate which could be achieved through installation of LEC. Since LEC could achieve the emissions same rate as SCR with less impacts elsewhere, SCR will not be evaluated further. Additional impacts with SCR consist of multiple energy and non-environmental issues associated with installation and operation.[7] While technically feasible, SCR is rarely used in the natural gas transmission and related industries, giving further support to remove this from further evaluation.[8]

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[5] Appendix B.8.b, p. 12. PDF page 1387.

[6] Appendix B.8.b., p. 12. PDF page 1387.

[7] Appendix B.8.b., p. 12-13 and 24. PDF page 1387-1388.

[8] Appendix B.8.b., p. 13 and 29. PDF pages 1388 and 1404.

3.2 Step 1 – Cost of Compliance

The cost of compliance for the reasonable progress controls are listed in Table 8. These costs are for each individual non-modified Clark engines (C1A, C1B, C1C, C1E, and C1G). The costs have been determined on an average basis spread across each of the five engines due to the variability in each engines operation, as discussed in Section 2.1.2.

Table 8: NO_X Cost of Compliance for each non-modified Clark Engine

Control Technology	**Annual Emissions (tpy)**	**Annual Emissions Reduction (tpy)**	**Annualized Total Cost ($)**	**Cost of Compliance ($/ton)**
Baseline	181			
Low-Emissions Controls	36	145	1,271,977	8,784

A detailed breakdown of the costs listed in Table 8 can be found in Hess TGP's submitted four factors analysis.[9] The Department has reviewed these costs and believes them to be accurate.

As displayed in Table 8, installation of LEC would reduce emissions by approximately 145 tons NO_X on each of the five non-modified Clark engines. This amounts to a combined total of 724 tons of NO_X from each non-modified engine. Individually, this reduction comes at a cost of approximately $8,800 per ton of NO_X reduced at an annualized cost of approximately $1.3 million. Installing LEC on each of these five engines amounts to a total annualized cost of roughly $6.4 million.

3.3 Step 2 – Time Necessary for Compliance

Hess TGP indicated a timeline of five to seven years for installation of LEC on the non-modified Clark engines. This is due to the sequential order of installing controls to eliminate facility downtime.[10] The time necessary for compliance is not a limiting factor when determining additional reasonable controls for the Hess TGP since LEC controls could be installed prior to the end of the second planning period.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

There are no energy or non-air quality environmental impacts associated with the installation of LEC on the non-modified Clark engines.

3.5 Step 4 – Remaining Useful Life

Hess TGP is expected to operate beyond the useful life of additional controls, therefore, remaining useful life is not a factor for consideration.

4 SO_2 Analysis

4.1 SO_2 Technologies

The SO2 controls evaluated for the sulfur recovery process are discussed in Sections 4.1.1 through 4.1.3.

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[9] Appendix B.8.b., Appendix A. PDF page 1406

[10] Appendix B.8.b., p. 21. PDF page 1396

4.1.1 Tail Gas Treatment

Tail gas treatment or tail gas scrubbing treatment (TGST) adds an additional scrubbing system on the exhaust of the current sulfur recovery unit prior to the tail gas incineration. There are many types of tail gas treatment options available, each of which serves a specific purpose or industry.[11]

A TGST system reduces the amount of sulfur sent to the tail gas incinerator, thereby increasing the overall sulfur recovery efficiency by reducing the SO_2 emissions produced during tail gas incineration. LO-CAT® technology was chosen for evaluation as this technology is commonly associated with the natural gas industry.[12] The LO-CAT® removes H_2S from an acid gas (or SRU tail gas) stream and converts it to elemental sulfur, essentially supplementing the current sulfur production at the facility. LO-CAT® is expected to reduce an additional 90% sulfur beyond the existing sulfur recovery, increasing the overall sulfur recovery to greater than 99%. Additional tail gas scrubbing treatment is technically feasibility and will be evaluated further.

4.1.2 Flue Gas Desulfurization (FGD)

Flue gas desulfurization was briefly explored as an alternative control option for Hess TGP. There are multiple reasons why traditional flue gas desulfurization is not reasonable to implement for control of SO_2 emissions from a gas processing facility.[13] Tail gas treatment and acid gas disposal options are more effective and have less disadvantages associated with implementation, therefore, FGD will not be carried forward for further evaluation.

4.1.3 Acid Gas Disposal Injection Well

As an alternative to additional tail gas treatment discussed in Section 4.1.1, Hess TGP evaluated the feasibility of installing an acid gas disposal (AGD) injection well. In lieu of additional tail gas scrubbing, an AGD injection well can dispose of the tail gas produced by the SRU, eliminating the emissions associated with tail gas incineration. Infrastructure requirements and geological uncertainty both pose significant risk associated with implementation of an AGD injection well.[14] Nevertheless, AGD is technically feasible and will be evaluated further.

4.2 Step 1 – Cost of Compliance

The cost of compliance for the reasonable progress controls evaluated for the sulfur recovery process are listed in Table 9. These costs are for the SO_2 controls deemed technically feasible.

Table 9: SO_2 Cost of Compliance for the Sulfur Recovery Process

Control Technology	**Annual Emissions (tpy)**	**Annual Emission Reduction (tpy)**	**Annualized Total Cost ($)**	**Cost of Compliance ($/ton)**
Baseline (96% recovery)	702			
Tail Gas Treatment	70	632	7,151,657	11,321
Acid Gas Disposal Injection Well	7	695	2,256,837	3,248
Acid Gas Disposal Injection Well [A]	7	695	3,087,549	4,443

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[11] Appendix B.8.b., p. 6-8. PDF page 1381-1383

[12] Appendix B.8.b., p. 7. PDF page 1382

[13] Appendix B.8.b., p. 8-9 and 28. PDF pages 1383-1384 and 1403.

[14] Appendix B.8.b., p.10, 18-19, and 23. PDF pages 1385, 1393-1394, and 1398.

Control Technology	Annual Emissions (tpy)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)

[A] Includes redundant compressor and plumbing costs

A detailed breakdown of the costs listed in Table 9 can be found in Hess TGP's submitted four factors analysis.[15] The Department has reviewed these costs and believes them to be reasonably accurate. As indicated in the submitted report, the AGD injection well costs provided are expected to increase significantly if a further detailed evaluation is required.[16] The cost of compliance for AGD injection well can be thought of as the very minimum cost for implementing this technology.

If a tail gas treatment system is installed, such as the LO-CAT® technology, a 90% reduction from the current SO_2 emissions can be achieved. This equates to a reduction of 632 tons SO_2 per year from the baseline emissions. Fiscally, tail gas treatment system comes at an estimated annualized cost of approximately $7,152,000 and SO_2 removal cost of roughly $11,300 per ton.

If an AGD injection well is installed, 99% of the current SO_2 emissions from the current SRU process will be eliminated. This equates to a reduction of 695 tons SO_2 per year from the baseline emissions. Fiscally, AGD requires an estimated annualized cost of approximately $2,257,000 and SO_2 removal cost of roughly $3,250 per ton.

As mentioned in Table 9, if redundant AGD equipment is installed, the estimated annualized cost increases to approximately $3.1 million and SO_2 removal cost increases to roughly $4,400 per ton. Redundant AGD equipment would be utilized to dispose the acid gas in the event when a malfunction occurs. These malfunctions are generally unplanned, short duration-episodes (a few hours) with very high SO_2 emission rates that vary from year-to-year. Without redundancy, controlling emissions during malfunctions is not feasible and the acid gas is flared to prevent the release of high concentrations of H_2S, negating the benefit of injecting the gas underground.

4.3 Step 2 – Time Necessary for Compliance

Hess TGP indicated a timeline of four to five years for installation and operation of a LO-CAT® unit.[17] Construction and operation of an AGD injection well was estimated at a minimum of five years. This estimate is highly uncertain given all the variables associated with installation.[18] The variables, such as equipment procurement, land surveying and acquisition, permitting, sub-surface research, and pipeline construction, would also likely add significant unforeseen expenses. The time necessary for compliance is not a limiting factor when determining additional reasonable controls for the Hess TGP since the projects could likely be completed prior to the end of the second-round planning period or an agreed upon schedule could be negotiated between the Department and Hess TGP.

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[15] Appendix B.8.b., p. Appendix A. PDF page 1406

[16] Appendix B.8.b., p.18-19. PDF page 1939-1394.

[17] Appendix B.8.b., p. 21. PDF page 1396.

[18] Appendix B.8.b., p. 21-22. PDF page 1396-1397.

4.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

Hess TGP's submitted four factors analysis indicated various energy and non-air quality environmental impacts from the LO-CAT® unit ranging from increased electrical demand to spent catalyst disposal.[19] While these impacts can be significant, none of the impacts eliminate the LO-CAT® as a potential add-on control option.

Hess TGP's four factor analysis also indicated various energy and non-air quality environmental impacts from the AGD injection well. Risks associated with construction and operation of the AGD pipeline are potentially significant and AGD also generates a new waste stream from the compression and dehydration of the acid gas.[20] Additionally, a considerable amount of electricity is required for the operation of the AGD equipment. While these impacts can be significant, none of the impacts eliminate an AGD injection well as a potential add-on control option.

4.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, Hess TGP is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

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[19] Appendix B.8.b., p. 23. PDF page 1398.

[20] Appendix B.8.b., p. 23. PDF page 1398.

A.9 – Northern Border CS4

1 Introduction and Representative Operations

Northern Border Pipeline Company (NBPC) – Compressor Station No. 4 (CS4) is a compressor station with the majority of emissions being sourced from a 20,000 horsepower simple cycle natural gas-fired combustion turbine (Unit CE1), which drives a natural gas compressor. The turbine is a Cooper-Rolls Model Coberra 2648S Avon. CS4 is located approximately nine miles west of Watford City, North Dakota in McKenzie County.

Data from 2012–2018 was used to when determining representative operations for the facility. 2012–2018 was chosen since this seven-year timeframe captured two high utilization years, two low utilization years, and three moderate utilization years. The yearly data is displayed in Table 1. Utilization was calculated by taking the annual actual hours of operation divided by total hours in a year (8760 hours per year).

Table 1: Yearly Operational Data

Year	Operating Time (hrs)	Yearly Duty (MMBtu/yr)	Utilization
2012	8,494	1,262,480	97%
2013	8,346	1,328,516	95%
2014	4,116	594,188	47%
2015	3,713	499,517	42%
2016	7,161	1,052,922	82%
2017	6,822	1,048,291	78%
2018	6,909	983,570	79%
Average	**6,509**	**967,069**	**74%**

Based on the information provided to the Department by NBPC, CS4's recent averaged operational data, Table 1, is consistent with anticipated future operations.[1]

2 NO_X Emissions Controls and Representative History

During the first round of the regional haze program, the Department determined that NBPC – CS4 was eliminated from consideration of additional controls. This was due to the average 2006–2008 NO_X plus SO_2 emissions being 118 tons per year, resulting in a Q/d of 6.6 (118 tons/18 km = 6.6).[2] The focus of this determination is on NO_X emissions. CS4 combusts pipeline quality natural gas, therefore, SO_2 emissions were not considered when reviewing emissions control options.

2.1 NOx

2.1.1 NO_X Emissions Controls

There have been no upgrades or retrofits installed on CS4's 20,000 horsepower existing turbine. Additionally, there are no existing add-on NO_X controls installed on the turbine.

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[1] Appendix B.9.b., p.2. PDF page 1457.

[2] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 180.

2.1.2 NO_X Emissions History

Consistent with operational data displayed Table 1, 2012–2018 was the time period used to determine the NO_X baseline emissions for CS4. This information is displayed in Table 2.

Table 2: NO_X Emissions

Year	Representative Emissions Rate (lb/MMBtu)[A]	Emissions Rate (lb/hr)	Calculated NO_X Emissions (tpy)
2012	0.27	40.3	171
2013	0.27	43.1	180
2014	0.27	39.1	80
2015	0.27	36.5	68
2016	0.27	39.8	143
2017	0.27	41.6	142
2018	0.27	38.6	133
Average	**0.27**	**39.9**	**131**

[A] Average tested emission rate from testing completed from 2012-2018.

The representative emissions rate (lb/MMBtu) was calculated from an average of 11 tests over the 7 years. These tests are considered representative of typical operations and anticipated future operations. Load during testing ranged from 58% to 95%, with an average of 81%. Emissions rates varied from 0.21 to 0.33 lb/MMBtu, with an average of 0.27 lb/MMBtu.[3] The value of 0.27 lb/MMBtu is used as the stating point when determining the cost of compliance for add-on controls evaluated in 3.2.

3 NOx Four-Factor Analysis

3.1 NO_X Technologies Evaluated

The turbine manufacturer does not offer a burner retrofit option for lean premixed combustion, therefore, only add-on NOx controls were evaluated. Of the add-on control, selective catalytic reduction and water injections were reviewed.

Water injection is a control technology which has the potential to decrease NO_X emissions by decreasing the peak flame temperature in the turbine. Water injection is an older technology which has fallen out of favor since low emission combustion controls and/or SCRs have been refined and implemented. Factors which limit the feasibility of water injection are increased carbon monoxide emissions, heat rate penalty, and potential for flame blow-off or flame-out. The issues are significant enough to eliminate water injection as a potential NO_X control option.

The reasonable progress controls evaluated by NBPC and determined to be available and technically feasible are listed in Table 3. Performance rate and expected annual emissions are included for each control technology that was determined to be technically feasible. Expected annual emissions were calculated using the performance rate and the average yearly duty (Table 1).

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[3] Appendix B.9.c., PDF page 1471.

Table 3: Reasonable Progress NO_X Controls

Control Technology	Control Technology Abbreviation	Performance Rate (lb/MMBtu)	Emissions (tons/year)
Uncontrolled (baseline)	--	0.27	131
selective catalytic reduction	SCR	0.05	26

3.1.1 Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is an add-on control technology used to reduce NO_X emissions after formation during the combustion process. SCR is a well understood technology that has been implemented on many different combustion processes. SCR is anticipated to provide an approximately 80% reduction in NO_X emissions from the baseline scenario, lowering the expected performance from 0.27 to 0.05 lb NO_X per MMBtu. SCR is technically feasible and will be further evaluated.

3.2 Step 1 – Cost of Compliance

The cost of compliance for the reasonable progress controls are listed in Table 4.

Table 4: NO_X Cost of Compliance

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
Uncontrolled (baseline)	0.27			
selective catalytic reduction	0.05	105	1,374,201	13,040

A detailed breakdown of the costs listed in Table 4 can be found in NBPC's submitted four factors analysis.[4] The Department has reviewed these costs and believes them to be accurate.

If SCR is installed, a performance rate improvement of 0.22 lb NO_X per MMBtu could be achieved. This equates to a potential reduction of 105 tons NO_X per year from the baseline emissions. Fiscally, SCR installation requires an estimated annualized cost of $1.4 million and NO_X removal cost of $13,000 per ton.

3.3 Step 2 – Time Necessary for Compliance

Installation of SCR would require at least 36 months to complete.[5] The time necessary for compliance is not a limiting factor when determining additional reasonable controls for NBPC – CS4 since it could be installed prior to the end of the second planning period.

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[4] Appendix B.9.b., PDF page 1459.

[5] Appendix B.9.b., p.3. PDF page 1458.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

3.4.1 Energy and Non-Air Quality Environmental Impacts

NBPC's submitted four factors analysis indicated various energy and non-air quality environmental impacts ranging from increased electrical demand to ammonia slip emissions.[6] While these impacts can be significant, none of the impacts eliminate SCR as a potential add-on control option.

3.5 Step 4 – Remaining Useful Life

Based on the information provided to the Department, the turbine at CS4 is expected to operate beyond the life of the control equipment.[7] Therefore, remaining useful life was not considered.

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[6] Appendix B.9.b., p.3. PDF page 1458.

[7] Appendix B.9.b., p.4. PDF page 1459.

A.10 – Basin DGC

1 Introduction and Representative Operations

Dakota Gasification Company (DGC) – Great Plains Synfuels Plant (GPSP) is owned and operated by Bain Electric Power Cooperative (Basin). DGC is a for-profit subsidiary of Basin and produces synthetic natural gas, fertilizers, and other byproducts resulting from the gasification of lignite coal. GPSP also captures carbon dioxide, which is transported via pipeline to oil fields in Saskatchewan Canada. The GPSP is the only facility of its kind in the United States. The GPSP commenced operation in 1984. The GPSP consists of many emissions units and emissions points. The significant sources of NO_X and SO_2 emissions include:

- Three Riley boilers each rated at 763 MMBtu per hour
- Two superheaters each rated at 169 MMBtu per hour
- One package boiler rated at 318 MMbtu per hour
- The main flare and the start-up flare

The DGC GPSP is located approximately six miles northwest of the town of Beulah, North Dakota in Mercer County. The GPSP receives lignite coal from the Coteau Properties Freedom Mine located approximately two miles north of the GPSP. Coal which is too fine for gasification is sent back to the Antelope Valley Station (AVS) electrical generating utility (EGU).

The average annual amount of North Dakota lignite gasified from 2014 through 2018 was approximately 6.1 million tons. The amount of coal gasified at the GPSP does not directly correlate with the emissions from the facility but helps show consistent operations over the recent years from the facility. With this consistent operation, emissions from this time period can be averaged to determine representative baseline emissions in order to evaluate additional feasible controls. See Table 1 for detailed information.

Table 1: Annual Coal Consumed (tons)

Year	Gasifier Feed (tons)
2014	6,071,536
2015	6,207,012
2016	5,998,365
2017	6,047,430
2018	6,186,391
Average	**6,102,147**

Representative operations for the Riley boilers and Superheaters are based on the recent emissions from the units versus the amount of fuel consumed due to the variety of fuels these unit combust and varying heat content of the fuels. The Riley Boilers are designed to burn a combination of gasification products, including liquid and gaseous fuels consisting of waste gas, stink gas, tar oil, naphtha/phenol (N/P) blend, lock gas, medium BTU purge gas, and SNG. The Superheaters are designed to combust SGN and/or tar oil; typically firing 80-90% SNG. The Riley Boilers and the Superheaters share a common stack (Main Stack), where the Superheaters' flue gas is combined with the Riley Boilers' flue gas downstream of the Riley Boilers wet flue gas desulfurization (WFGD) system.

The Package Boiler was installed in 2017 to support the operation of the urea production facility and is fired strictly on natural gas. The Package Boiler flue gas is directed through the facility Bypass Stack. The Bypass Stack also handles the flue gas from the Main Stack (Riley Boilers and Superheaters) when the WFGD system is down.

The Main Flare is the primary control device and operates during upsets to control volatile process gases. The Start-up Flare is used during start-up, shutdowns, and gasifier malfunctions. Neither the Main Flare nor the Start-up Flare is indented to operate consistently; therefore, they will not be evaluated for additional controls.

2 NO_X and SO_2 Emissions Controls and Representative History

Both the Main Stack and the Bypass have NO_X and SO_2 continuous emissions monitor systems (CEMS) installed. The Main Stack CEMS monitors the routine emissions from the Riley Boilers and Superheaters. The Bypass Stack CEMS monitors the routine emissions from the Package Boiler and malfunction (bypass of WFGD) emissions from the Riley Boilers and Superheaters.

During the first round of the regional haze program, the Department determined that no NO_X or SO_2 controls were required the GPSP.[1]

2.1 NOx

2.1.1 NO_X Emissions Controls

A summary of the existing NO_X controls for the applicable GPSP emissions units are discussed in Section 2.1.1.1 through 2.1.1.4.

2.1.1.1 Riley Boilers

The existing NO_X controls on the Riley Boilers consists of Low-NO_X burners (LNB), Overfire Air, and combustion tuning. No add-on NO_X controls are installed on the Riley Boilers. Feasible add-on controls are evaluated in Section 3.1.

2.1.1.2 Superheaters

The existing NO_X controls on the Superheaters consist of LNB, partial flue gas recirculation (FGR), and combustion tuning. No add-on NO_X controls are installed on the Superheaters. Feasible add-on controls are evaluated in Section 3.1.

2.1.1.3 Package Boiler

The existing NO_X controls on the Package Boiler consist of Ultra LNB (ULNB). No add-on NO_X controls are installed on the Package Boiler. Add-on controls for the Package Boiler were not evaluated. Operation of ULNB is considered Best Available Control Technology (BACT) for units of similar size combusting natural gas. The Package Boiler currently achieves a NO_X rate of approximately 30 parts per million by volume dry (ppmvd) and is expected to continue to achieve this rate.[2]

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[1] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 182-188.

[2] Appendix B.10.b., p.7-1. PDF page 1527

2.1.1.4 Main Flare and Start-up Flare

The Main Flare and the Start-up Flare have no existing NO_X controls installed. The GPSP evaluated potential options for mitigating NO_X emissions from the flared process gases. No vendors were able to provide any viable solutions to reduce NO_X emissions from the either flare system, mainly due to the low baseline NO_X value, equivalent to approximately 0.06 lb NO_X per MMBtu.[3]

2.1.2 NO_X Emissions History

No recent NO_X controls have been installed at any facility, therefore, the baseline emissions from the facility were determined based on the average emissions from 2014–2018. This information, displayed by emissions point, is shown in Table 2.

Table 2: Annual NO_X Emissions

Year	Main Stack	Bypass Stack	Main Flare	Start-up Flare	Remaining Sources [A]	Total
2014	3,048	91	55	12	29	3,236
2015	2,777	49	105	12	40	2,982
2016	2,346	32	43	8	25	2,454
2017	2,373	120	54	10	23	2,580
2018	2,305	45	46	9	31	2,437
Average	**2,570**	**67**	**61**	**10**	**30**	**2,738**

[A] Accounts for all other onsite emissions units.

As shown in Table 2, most of the NO_X emissions from GPSP come from the Main Stack. During normal operations, the Main Stack receives flue gas from the Riley Boilers and the Superheaters. The Main Stack accounts for an average of 94% of the facility NO_X emissions. The Bypass stack accounts for the remaining portion of NO_X emissions where controls can be evaluated. The Bypass Stack only receives gas from the Package Boiler during normal operations and the Package Boiler has ULNB installed, therefore, evaluation of additional controls is focused on Riley Boilers and the Superheaters.

2.2 SO2

2.2.1 SO_2 Emissions Controls

A summary of the existing SO_2 controls for the applicable GPSP emissions units are discussed in Section 2.2.1.1 through 2.2.1.4.

2.2.1.1 Riley Boilers

The existing SO_2 controls on the Riley Boilers consists of a wet flue gas desulfurization (WFGD) system. The WFGD system is designed to treat 100% of the Riley Boiler flue gas during normal operations and often operates at a 97-98% SO_2 removal efficiency.[4] During the first-round planning period, the Department concluded that this system is comparable to BACT for this process and no additional controls were recommended.[5] There have been no significant improvements in available

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[3] Appendix B.10.b., p.8-2. PDF page 1529.

[4] Appendix B.10.b., p.5-1. PDF page 1509.

[5] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 183

SO_2 controls for the Riley Boilers WFGD system, therefore, further SO_2 reductions from this source cannot be evaluated.

2.2.1.2 Superheaters

The Superheaters have no existing SO_2 controls installed. The Superheaters typically fire between 80-90% SNG, with the balance being tar oil. SNG is an inherently low sulfur fuel. The SO_2 emissions from the Superheaters come from the firing of tar oil. Given most of the Superheaters heat input comes from firing of SNG, the only potentially viable way to reduce SO_2 from this source would be to eliminate firing of tar oil in the superheaters. Retaining the flexibility to fire tar oil in the Superheaters is essential to provide process relief during unexpectedly high tar oil production rates or high accumulation rates.[6] GPSP currently minimizes the SO_2 emissions attributable to the Superheaters by mainly firing SNG. As a result, no feasible control options exist to reduce SO_2 emissions resulting from the Superheaters.

2.2.1.3 Package Boiler

The Package Boiler fires SNG, an inherently low sulfur fuel. Therefore, no SO_2 control evaluated is warranted on this unit.[7]

2.2.1.4 Main Flare and Start-up Flare

The Main Flare and the Star-up Flare have no existing SO_2 controls installed. The GPSP evaluated flare gas scrubbing as a potential option for mitigating SO_2 emissions from the flared process gases. It was determined that, at a minimum, pilot scale testing would be needed to evaluate the effectiveness of the scrubbing.[8] This source also accounts for a small percentage (8%) of the facilities SO_2 emissions, therefore, this source will not be further evaluated.

2.2.2 SO_2 Emissions History

No recent SO_2 controls have been installed at any facility, therefore, the baseline emissions from the facility were determined based on the average emissions from 2014–2018. This information, displayed by emissions point, is shown in Table 3.

Table 3: Annual SO_2 Emissions

Year	Main Stack	Bypass Stack	Main Flare	Start-up Flare	Remaining Sources ^{A}	Total
2014	1,922	1,347	467	82	0	3,818
2015	2,211	794	212	74	2	3,294
2016	3,063	378	212	22	1	3,677
2017	2,742	2,152	284	24	0	5,203
2018	2,139	310	369	14	0	2,832
Average	**2,415**	**996**	**309**	**43**	**1**	**3,765**

^{A} Accounts for all other onsite emissions units.

As shown in Table 3, most of the SO_2 emissions from GPSP come from the Main Stack. During normal operations, the Main Stack receives flue gas from the Riley Boilers and the Superheaters. The Main

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[6] Appendix B.10.b., p.6-1. PDF page 1521

[7] Appendix B.10.b., p.7-1. PDF page 1527

[8] Appendix B.10.b., p.8-1 and 8-2. PDF page 1527-1528

Stack accounts for an average of 64% of the facility SO_2 emissions. The Bypass stack accounts for the remaining portion of SO_2 emissions where controls can be evaluated, as scrubbing of the flare gas was determined technically infeasible. During normal operations, the Bypass Stack only receives flue gas from the Package Boiler and the Package Boiler fires inherently low sulfur fuel (SNG). As displayed in Table 3, the majority of SO_2 emissions from the Bypass Stack occur when the Riley Boilers WFGD system malfunctions and the flue gas needs to be routed to the uncontrolled Bypass Stack.

As stated in Section 2.2.1.1, the Riley Boilers are controlled by a WFGD system operating at BACT levels.

3 NOx Analysis

3.1 NO_X Technologies

Additional NO_X controls have been evaluated for the Riley Boilers and the Superheaters at the GPSP.

3.1.1 Combustion Optimization

Combustion optimization was evaluated as a control option to reduce NO_X emissions though implementation of on-line combustion optimization concepts, such as neural networks. Combustion optimization on the Riley Boilers is technical infeasible due to the variety of fuels consumed in the Riley Boilers and the flexibility needed for steam production rates at pressures, flow rates, and qualities.[9] Combustion optimization on the Superheaters is technically feasible, but expected to only reduce 10 tons of NO_x on an annual average.[10] Combustion optimization will not be evaluated any further given the insignificant improvement on the Superheaters and technical infeasibility on the Riley Boilers.

3.1.2 Flue Gas Recirculation

Flue gas recirculation was evaluated as a potential control option to reduce NO_X emissions at the Riley Boilers. The Riley Boilers currently fire waste gas (as one of the fuels), which contains a significant percentage of inert compounds (CO_2). The high amount of inert compound results in similar combustion flame temperatures and oxygen content as traditional flue gas recirculation. Therefore, any additional flue gas recirculation is not technically feasible for implementation.[11]

3.1.3 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) was evaluated as a control option to reduce NO_X emissions from the Riley Boilers and Superheaters. Implementation of SNCR on the Riley Boilers was deemed technically infeasible during the first-round planning period and no new developments have occurred which changes this determination.[12] Similar to the Riley Boilers, installation of SNCR on the Superheaters is not technically feasible. This is due to the low reheat duct temperatures and the presence of sulfur in the fuel which will lead to the formation of ammonia salts which will foul the superheaters reducing their efficiency.

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[9] Appendix B.10.b, p.5-3. PDF page 1511.

[10] Appendix B.10.b, p.9-4. PDF page 1534.

[11] Appendix B.10.b, p.5-4. PDF page 1512.

[12] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 184.

3.1.4 Selective Catalytic Reduction

Selective catalytic reduction (SCR) was evaluated as a control option to reduce NO_X emissions from the Riley Boilers and Superheaters. Implementation of SCR on the Riley Boilers was deemed technically infeasible during the first-round planning period and no new developments have occurred which changes this determination.[13] Similar to the Riley Boilers, installation of SCR on the Superheaters is not technically feasible. This is due to the introduction of vapor phase alkali metals which degrade the SCR catalyst.[14]

3.2 Step 1 – Cost of Compliance

All NO_X controls evaluated are considered technically infeasible by the Department, therefore, no cost analysis is required to be completed. Since there was uncertainly in first-round planning period regarding the implantation of SCR on the Riley Boilers, GPSP performed a cost analysis on what tail-end SCR would cost and how much NO_X emissions would be reduced. GSPS estimated they could reduce approximately 1,800 tons of NO_X emissions from the Riley Boilers at a cost effectiveness of roughly $39,000 per tons of NO_x reduced. This comes at a total capital cost of approximately $180 million and an annualized cost of $70 million.

3.3 Step 2 – Time Necessary for Compliance

The time necessary for compliance is not considered since no feasible NO_X controls can be installed.

3.4 Step 3 – Energy and Non-Air Quality Environmental Impacts

The energy and non-air quality environmental impacts are not considered since no feasible NO_X controls can be installed.

3.5 Step 4 – Remaining Useful Life

The remaining useful life is not considered since no feasible NO_X controls can be installed.

4 SO_2 Analysis

There are no additional reasonable controls which could be installed at GPSP. As stated in Section 2.2.1.1, the Riley Boilers currently operate a WFGD comparable to BACT. As stated in Section 2.2.1.2, the Superheaters primarily fire inherently low natural gas and need to maintain the flexibility to combust tar oil to provide process relief during expected tar oil production rates or system build-up.

Since there are no feasible SO_2 controls being carried forward for evaluation, the cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life were not evaluated.

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[13] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 184.

[14] Appendix B.10.b, p.5-8 and 6-5. PDF pages 1516 and 1525.

Appendix B – Four-Factor Information

B.1 – Coyote Station

B.1.a – Department Request

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

FILE

May 2, 2018

Mr. Mark Thoma
OtterTail Power Company
P.O. Box 496
Fergus Falls, MN 56538-0496

Re: Regional Haze
Second Planning Period

Dear Mr. Thoma:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:
1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
Division of Municipal Facilities 701.328.5211
Division of Waste Management 701.328.5166
Division of Water Quality 701.328.5210

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair
Director
Division of Air Quality

TLO/TB:saj

B.1.b – Facility Response

215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpco.com

January 30, 2019

OTTER TAIL
POWER COMPANY

Mr. Terry L. O'Clair, P.E.
Director, Division of Air Quality
North Dakota Department of Health
Gold Seal Center, 918 East Divide Ave
Bismarck, ND 58501-1947

Dear Mr. O'Clair:

Re: Regional Haze Second Planning Period: Coyote Station Reasonable Progress Analysis

As requested by your letter dated May 2, 2018, enclosed is a Regional Haze reasonable progress analysis for Coyote Station. Sargent & Lundy, L.L.C. was retained to prepare this analysis of technically feasible sulfur dioxide and nitrogen oxide emission reduction measures using the four statutory factors provided in Section 169A(g)(1) of the Clean Air Act.

As noted in the report, this analysis is subject to several important caveats and limitations, including but not limited to:

- On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue new guidance on Regional Haze SIP Development by Spring 2019. Otter Tail reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by EPA.
- The emission rates that are presented for the technically feasible control options should not be construed to represent proposed permit limits. Corresponding permit limits would need to be evaluated on a control system-specific basis to account for operating margin.
- During the first planning period, the Department of Health determined that high-dust SCR and tail-end SCR were not available, and thus, not a technically feasible NOx control option for North Dakota lignite-fired boilers. Sargent & Lundy's evaluation continues to support the conclusion that high-dust SCR and tail-end SCR are not available NOx control technologies. Nevertheless, since tail-end SCR cost data was developed for Coyote Station in the first planning period, even though tail-end SCR is a technically infeasible technology, it was carried forward in the analysis to evaluate hypothetical cost-effectiveness.

We look forward to working with the Department throughout the second planning period. If you have any questions about this report, please contact me at (218) 739-8526.

Sincerely,

Mark Thoma

Mark Thoma
Manager, Environmental Services

Enclosure

An Equal Opportunity Employer

AN OTTERTAIL COMPANY

COYOTE STATION UNIT 1

NORTH DAKOTA REGIONAL HAZE SECOND PLANNING PERIOD FOUR-FACTOR ANALYSIS

SL-014745
Final

January 28, 2019
Project No. 12715-011

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000
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A. Coyote Unit 1 Baseline Emissions

B. SO_2 Control Cost Effectiveness Estimates

C. NO_X Control Cost Effectiveness Estimates

ABBREVIATIONS/ACRONYMS

Abbreviation/Acronym	Explanation
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BFP	boiler feed pump
Ca	calcium
CaO	calcium oxide
$Ca(OH)_2$	calcium hydroxide
$CaSO_3$	calcium sulfite
$CaSO_4$	calcium sulfate
CAA	Clean Air Act
CDS	circulating dry scrubber
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
DFGD	dry flue gas desulfurization
DSI	dry sorbent injection
ESP	electrostatic precipitator
EPA	Environmental Protection Agency
EGU	electric generating unit
FF	fabric filter
FGD	flue gas desulfurization
G&A	general and administration
GHG	greenhouse gas
H_2SO_4	sulfuric acid
LNB	Low-NO_X burner
LTS	Long-term strategy
MMBtu	million British thermal units
MNL	multi-nozzle lance
MRYS	Milton R. Young Station
MW	megawatt

MWg	megawatt gross
Na_2CO_3	sodium carbonate
ND	North Dakota
NDDH	North Dakota Department of Health
NH_3	ammonia
NO_X	nitrogen oxides
NSR	New Source Review
NSR	normalized stoichiometric ratio
OEM	Original equipment manufacturer
OFA	overfire air
O&M	operations and maintenance
OTP	Otter Tail Power Company
PM	particulate matter
PRB	Powder River Basin
RPG	Reasonable Progress Goals
RPO	Regional Planning Organization
RRI	rich reagent injection
S	sulfur
S&L	Sargent & Lundy, L.L.C.
SBC	sodium bicarbonate
SBS	sodium bisulfate
SCR	selective catalytic reduction
SDA	spray dryer absorber
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SOFA	separated overfire air
TE-SCR	tail-end SCR
URP	uniform rate of progress
WRAP	Western Region Air Partnership

EXECUTIVE SUMMARY

Coyote Station, located near Beulah, ND, commenced commercial operation in 1981. The facility is a single unit station with one 451 MWg (approximate) Babcock and Wilcox cyclone boiler (Coyote Unit 1). Coyote Unit 1 is designed to fire North Dakota lignite, and is equipped with separated overfire air (SOFA) for NO_X control, and dry flue gas desulfurization (DFGD or dry FGD) and fabric filter baghouse (FF) for SO_2 and particulate matter (PM) control. Lignite is delivered to the Station from the Coyote Creek Mine, whose primary operations are approximately 3-4 miles from the Coyote Station.

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the CAA, establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).[1] The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. The Regional Haze Rule established a schedule setting forth deadlines by which the States must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.[2] Second planning period Regional Haze SIPs must be submitted to EPA for review by July 31, 2021.

As part of North Dakota's SIP development for the second planning period, NDDH requested that Otter Tail prepare a "four factor" analysis for Coyote Unit 1. This evaluation reviews technically feasible SO_2 and NO_X emissions reduction measures for the following four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

Technically feasible SO_2 and NO_X control strategies for Coyote Unit 1 are included in Table ES-1 and Table ES-2. The tables also show baseline emission rates and estimated emission reductions for each control option.

---

[1] 64 FR 35713

[2] On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period SIPs (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

Table ES-1. SO_2 Control Options for Coyote Unit 1

Control Option	SO_2 Emission Rate tons/yr	% Reduction from Baseline Emission Rate
Baseline (existing DFGD/FF)	12,994	-
DSI + Existing FGD	8,863	32%
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	7,641	41%
DSI + FGD Operational Improvements	5,043	61%
FGD Upgrades - Replacing Existing Absorbers with New Absorber	4,432	66%
Dry FGD (CDS) + Existing FF	1,375	89%
Wet FGD	917	93%

Table ES-2. NO_X Control Options for Coyote Unit 1

Control Option	NO_X Emission Rate tons/yr	% Reduction from Baseline Emission Rate
Baseline (existing SOFA)	7,363	-
Combustion Optimization	6,775	8%
SNCR + Combustion Optimization	4,516	39%
SNCR + RRI + Combustion Optimization	3,226	56%
SCR – Tail-End Configuration(Note 1)	1,452	80%

Note 1. Tail-end SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of tail-end SCR on Coyote Unit 1. Nevertheless, during the initial planning period, tail-end SCR was included in the reasonable progress analysis for Coyote Unit 1, and evaluated the costs and cost-effectiveness of the control system. For consistency with the first planning period, tail-end SCR is carried forward to the Four Factor Analysis.

Costs of Compliance (Statutory Factor One)

Capital and O&M cost estimates were developed for each of the technically feasible SO_2 and NO_X control options. The Coyote Unit 1 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Unit 1 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on

Coyote Unit 1-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment.

Table ES-3 and Table ES-4 include estimated costs for SO_2 and NO_X control options for Coyote Unit 1. The tables provide the estimated annualized capital and operating and maintenance (O&M) costs, estimated emissions reductions, average annual cost effectiveness. The tables also include the incremental cost effectiveness that compares the costs and performance of a control option to those of the next most stringent option.

Table ES-3. SO_2 Emissions Control System Cost Effectiveness ($2018)

SO_2 Control Option	Total Annualized Cost $/yr	Expected Emission Reduction tons SO_2/yr	Average Annual Cost Effectiveness (Note 1) $/ton SO_2 removed	Incremental Annual Cost Effectiveness (Note 2, 3) $/ton SO_2 removed
Baseline (Existing DFGD/FF)	---	---	---	---
DSI + Existing FGD	$14,277,000	4,131	$3,456	
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	$2,492,000	5,354	$465	n/a
DSI + FGD Operational Improvements	$16,770,000	7,952	$2,109	$5,496
FGD Upgrades - Replacing Existing Absorbers with New Absorber	$22,197,000	8,563	$2,592	$8,879
Dry FGD (CDS) + Existing FF	$42,246,000	11,619	$3,636	$6,560
Wet FGD	$49,614,000	12,078	$4,108	$16,072

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.
Note 2. Incremental cost effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.
Note 3. "n/a" indicates that the next most effective control option is "inferior" (i.e., higher cost for less control)

Table ES-4. NO_X Emissions Control System Cost Effectiveness ($2018)

NO_X Control Option	Total Annualized Cost $/yr	Expected Emission Reduction tons NO_X/yr	Average Annual Cost Effectiveness (Note 1) $/ton NO_X removed	Incremental Annual Cost Effectiveness (Note 2) $/ton NO_X removed
Baseline (Existing SOFA)	---	---	---	---
Combustion Optimization	$0	589	$0	$0
SNCR + Combustion Optimization	$4,754,000	2,847	$1,670	$2,105
SNCR + RRI + Combustion Optimization	$8,617,000	4,137	$2,083	$2,994
SCR – Tail-End Configuration	$41,268,000	5,912	$6,981	$18,402

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.
Note 2. Incremental cost effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

Time Necessary for Compliance (Statutory Factor Two)

Table ES-5 and Table ES-6 provide estimated timeframes needed to implement each of the technically feasible control option. Notably, the estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve North Dakota's SIP.

Table ES-5. SO_2 Emissions Control System Implementation Schedule

SO_2 Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
DSI + Existing FGD	6	6	6	18
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0	0	0	0
DSI + FGD Operational Improvements	6	6	6	18
FGD Upgrades - Replacing Existing Absorbers with New Absorber	8	12	12	32
Dry FGD (CDS) + Existing FF	12	20	18	50
Wet FGD	12	22	22	56

Table ES-6. NO_X Emissions Control System Implementation Schedule

NO_X Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
Combustion Optimization	0	0	0	0
SNCR + Combustion Optimization	10	6	6	22
SNCR + RRI + Combustion Optimization	10	6	6	22
SCR – Tail-End Configuration	10	18	24	52

Energy and Non-Air Quality Environmental Impacts (Statutory Factor Three)

An evaluation of energy impacts indicates that certain control options (e.g., new FGD systems, TE-SCR) will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts include an increase in the solid waste generation with DSI. A summary of the environmental and energy impact analysis is provided in Table ES-7.

Table ES-7. Summary of Energy and Non-Air Quality Environmental Impacts

Control Option	Collateral Environmental & Energy Impacts
SO_2 Control Options	
Replace existing DFGD with New WFGD control system	➢ Increased water consumption ➢ Wet by-product that requires dewatering prior to disposal ➢ FGD wastewater treatment & discharge ➢ Increased auxiliary power requirements and heat rate penalty
Replace existing DFGD with New CDS/FF Control System	➢ Increased auxiliary power requirements and heat rate penalty ➢ Increased solid FGD by-product management and disposal
Replace existing dry scrubber modules with New DFGD modules while keeping existing FF	➢ Requires extended (approximately 12-month) outage of Coyote Unit 1 to demolish and replace the existing scrubber modules
Dry Sorbent Injection	➢ Increased solid FGD by-product management and disposal ➢ Increased auxiliary power requirements and heat rate penalty
NOx Control Options	
Selective Catalytic Reduction (SCR) - Tail End Configuration	➢ Increased auxiliary power requirements and heat rate penalty ➢ Increased ammonia slip emissions ➢ Potential increase in SO3 emissions
SNCR or SNCR + RRI	➢ Increased ammonia slip emissions ➢ Increased auxiliary power requirements and heat rate penalty

Remaining Useful Life (Statutory Factor Four)

The Coyote Station owners have not identified dates for the remaining useful life of the unit before the end of what would otherwise be the useful life of the control measures that were evaluated for Coyote Unit 1. Thus, the 20-year equipment life of the control measures was used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness.

1. INTRODUCTION

Sargent & Lundy, L.L.C. (S&L) was retained by Otter Tail Power Company (Otter Tail) to prepare a Reasonable Progress four-factor analysis for the control of sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions from Coyote Station Unit 1 (Coyote Unit 1).[3] The evaluation is in response to North Dakota Department of Health's (NDDH) request that Otter Tail prepare a four factor analysis for Coyote Unit 1.

The evaluation includes an assessment of potentially available emission reduction measures for the four statutory factors listed in 40 CFR 51.308(f)(2), and takes into consideration U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period* (the "Draft EPA Guidance").[4] Technically feasible SO_2 and NO_X emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliances
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

The Reasonable Progress four factor analysis for Coyote Unit 1 (the "Four Factor Analysis") is presented in the following sections:

Section 2:	**Facility Description** contains information describing the facility, site location, and existing equipment.
Section 3:	**Four-Factor Analysis Requirements** provides a brief description of the Regional Haze Program requirements set forth in 40 CFR 51.308.
Section 4:	**Baseline SO_2 and NO_X Emissions** establishes representative baseline SO_2 and NO_X emissions for the period 2013 to present.

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[3] Coyote Station is co-owned by Otter Tail Power Company (35%), Northern Municipal Power Agency (30%), Montana-Dakota Utilities Co. (25%), and NorthWestern Energy (10%).

[4] On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Otter Tail Power reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

Section 5: **SO_2 and NO_X Control Measures** identifies potentially available emission control technologies, and evaluates each control option for technical feasibility and effectiveness.

Section 6: **Costs of Compliance (Statutory Factor One)** evaluates the cost and cost-effectiveness of each technically feasible control option.

Section 7: **Time Necessary for Compliance (Statutory Factor Two)** provides typical timelines required to design, engineer, procure and install the technically feasible control options.

Section 8: **Energy and Non-Air Quality Environmental Impacts (Statutory Factor Three)** identifies the energy and non-air quality environmental impacts associated with each technically feasible control option**.**

Section 9: **Remaining Useful Life (Statutory Factor Four)** includes a discussion of the planned remaining useful life of Coyote Unit 1.

Section 10: **Summary and Conclusions**

Appendix A: Coyote Unit 1 Baseline Emissions

Appendix B: SO_2 Control Cost Effectiveness Estimates

Appendix C: NO_X Control Cost Effectiveness Estimates

2. FACILITY DESCRIPTION

Coyote Station, located near Beulah, ND, commenced commercial operation in 1981. The facility is a single unit station with one 451 MWg (approximate) Babcock and Wilcox cyclone boiler (Coyote Unit 1). Coyote Unit 1 is designed to fire North Dakota lignite, and is equipped with separated overfire air (SOFA) for NO_X control, and dry flue gas desulfurization (DFGD or dry FGD) and fabric filter baghouse (FF) for SO_2 and particulate matter (PM) control. Lignite is delivered to the Station from the Coyote Creek Mine, whose primary operations are approximately 3-4 miles from the Coyote Station.

Table 2-1 provides a summary of the process parameters used for the Coyote Unit 1 Four Factor Analysis. Process parameters listed in Table 2-1 were developed from information provided by OTP.[5]

Table 2-1. Process Parameters

Process Parameter	Coyote Unit 1
Boiler Type	Cyclone
Boiler Manufacturer	B&W
Full Load (MWg)	451
Full Load Boiler Heat Input (MMBtu/hr)	4,900
Full Load Coal Flow (lb/hr)	700,700
Boiler Excess Air (%)	14.0
Air Heater Leakage (%)	22.0
Bottom Ash/Fly Ash Ratio	65/35
Flue Gas Conditions at Air Heater Outlet	
Temperature (F)	330
Mass Flow Rate (lb/hr)	6,532,000
Volumetric Flow rate (acfm)	2,485,000
Annual Average Fuel Sulfur Content (%)	0.82 - 1.06
Annual Average Uncontrolled SO_2 Emissions (lb/MMBtu)	2.42 - 3.12

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[5] These process parameters are representative of typical average conditions. They should not be construed as maximum values or unit design values.

3. FOUR-FACTOR ANALYSIS REQUIREMENTS

3.1 REGIONAL HAZE RULE BACKGROUND

Section 169A of the 1977 Amendments to the Clean Air Act (CAA) sets forth a program for protecting visibility in Federal Class I areas which calls for the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Federal Class I areas which impairment results from manmade air pollution." Federal Class I areas include national parks, memorial parks, and wilderness areas over a certain size. Figure 3-1 shows the locations of the 156 federally mandated Class I areas. Federal Class I areas located within North Dakota include the Theodore Roosevelt National Park and the Lostwood National Wildlife Refuge.

Figure 3-1. Federal Class I Areas

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the CAA, establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).[6] The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a

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[6] 64 FR 35713

state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. In 2017, EPA issued a final rule revising portions of the 1999 Regional Haze Rule.[7] The 2017 Rule requires states to determine the baseline (2000 - 2004) visibility condition for the 20 percent most impaired days and requires that the long-term strategy and reasonable progress goals (RPGs) must provide for improvement in visibility for the most impaired days, relative to the baseline period. Specifically, states must determine the rate of improvement in visibility that would need to be maintained during each implementation period in order to reach natural conditions by 2064 for the 20 percent most impaired days, given the starting point of the baseline visibility condition.

To address the combined visibility effects of various pollution sources over a wide geographic region, EPA designated five Regional Planning Organizations (RPOs) to assist with the coordination and cooperation needed to address the visibility issue. The five RPOs are shown in Figure 3-2. North Dakota is a member of the Western Regional Air Partnership (WRAP), which serves as the RPO for visibility protection at 118 Class I areas in the 15 western states.

Figure 3-2. Regional Planning Organization Map

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[7] Final Rule: Protection of Visibility: Amendments to Requirements for State Plans, 82 FR 3078, January 10, 2017

3.1.1 First Implementation Period

The Regional Haze Rule established a schedule setting forth deadlines by which the States must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.[8]

Regional Haze SIP requirements for the first planning period required that states incorporate into their plans the core program requirements in 40 CFR 51.308(d), including: (1) establishing reasonable progress goals (RPGs) for each Class I area within the state that provide for measurable progress towards achieving natural visibility conditions; (2) developing a long-term strategy (LTS) including enforceable emissions limitations and compliance schedules to achieve the RPGs; and (3) developing plans to monitor and assess the effectiveness of the LTS to achieve the RPGs over the prior implementation period and affirmation of or revision to the RPGs.

The Regional Haze Rule requires that states determine the consistent rate of progress over time needed to attain natural visibility conditions on the 20 percent most anthropogenically impaired days by the year 2064. This "glidepath" is referred to as the uniform rate of progress (URP) line. States must consider the URP, and the emission reduction measures needed to achieve this level of improvement, when developing their RPGs and LTS. Regulations at 40 CFR 51.308(g) require each state to submit progress reports, in the form of SIP revisions, every 5 years following the submission of the initial SIP. These progress reports must evaluate the progress made towards the RPGs for Class I areas located within the state as well as those Class I areas located outside the state that may be affected by emissions from within the state.

3.1.1.1 Best Available Retrofit Technology

As a one-time requirement during the first implementation period, potential best available retrofit technology (BART) controls had to be evaluated for certain large stationary sources. States were required to conduct BART determinations for "BART-eligible" sources anticipated to cause or contribute to any visibility impairment in one or more Class I area. BART-eligible sources included coal-fired electric generating units (EGUs) that were in existence on August 7, 1977, but not in operation prior to August 7, 1962. In its determination of BART, states were required to take into consideration the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of

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[8] On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period SIPs (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[9] As an alternative to requiring source-specific BART controls, states also had the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provided greater reasonable progress towards improving visibility than BART.

3.1.1.2 Reasonable Progress Control Requirements for Coyote Station during First Planning Period

Coyote Unit 1 commenced operation in 1981, and was not classified as a BART-eligible source or subject to the BART requirements. Nevertheless, during the initial planning period, the North Dakota Department of Health (NDDH) evaluated emissions from the Coyote Station as a reasonable progress source. The reasonable progress analysis prepared by NDDH concluded that no additional controls would be required on Coyote Unit 1 during the initial planning period; however, NDDH and Otter Tail reached an agreement whereby Otter Tail committed to install SOFA equipment to reduce NO_X emissions. In the initial planning period SIP NDDH noted that additional SO_2 and NO_X controls for Coyote Unit 1 would be reevaluated during future planning periods to determine if additional emissions reductions would be required.

3.1.2 Second Implementation Period

Second planning period Regional Haze SIPs must be submitted to EPA for review by July 31, 2021. Among other requirements, second planning period SIPs are required to include an assessment of the state's RPGs and LTS. To support states in their efforts to develop the second planning period SIPs, in July 2016 EPA released a draft guidance document titled "*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*" ("Draft EPA Guidance").[10] The Draft EPA Guidance document describes key steps states should implement when developing their RPGs and LTS for the second implementation period. Key steps identified in the Draft EPA Guidance are listed in Table 3-1.

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[9] CAA Section 169A(g)(2).

[10] See, EPA-457/P-16-001. On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Otter Tail Power reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

Table 3-1. Key Steps in Developing Regional Haze SIPs for Second Planning Period

1.	*Ambient data analysis* – Quantify baseline, current and natural conditions and the uniform rate of progress that would achieve natures conditions in 2064 (40 CFR 51.308(f)(1))
2.	*Screening of sources* – Identify the pollutants and emission sources for which a full reasonable progress analysis will be completed and explain why it is appropriate to limit the full analysis to only these sources (40 CFR 51.308(f)(2))
3.	*Source and emission control measure analysis* – Identify potential emission control measures for sources selected in the screening step and develop data on the four statutory factors and visibility benefits if they will be considered (40 CFR 51.308(f)(2))
4.	*Decisions on the content of the LTS* – Consider applicable factors and decide on new emission controls for incorporation into the LTS (40 CFR 51.308(f)(2))
5.	*Regional scale modeling* – Model the emissions reductions that will result from implementation of the LTS and other enforceable measures that will reduce visibility impairment to set the RPGs for 2028 (40 CFR 51.308(f)(3))
6.	*Progress, degradation and glidepath checks* – Demonstrate that there will be an improvement on the 20 percent most impaired days. Demonstrate that there is no degradation on the 20 percent clearest days. Compare the 2028 RPG for the 20 percent most impaired days to the 2028 point on the URP line (the glidepath) and, if required, provide additional justification for the reasonableness of the RPG. Revise the LTS if additional measures are identified as necessary to make reasonable progress. (40 CFR 51.308(f)(3))
7.	*Additional requirements for SIPs* – Provide additional information necessary to ensure that other requirements of the Regional Haze rule are met.

The Draft EPA Guidance recommends that states evaluate all technically feasible emission control options for stationary sources and source categories identified as having the greatest potential to impact visibility at one or more Class I area. The Draft EPA Guidance recommends several options for states to consider when evaluating potential emission reductions, including work practices, replacement and retrofit controls, existing control upgrades, fuel switching year-round operation of controls, and operating restrictions.[11]

Emission control evaluations must consider the four statutory factors identified in 40 CFR 51.308(f)(2)(i) (discussed in Section 3.2). In addition, the Draft EPA Guidance notes that control technology assessment recommendations presented in the BART Guidelines continue to be relevant as recommendations for how a state

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[11] See, Draft EPA Guidance, pgs. 85-86.

should evaluate and select emission control measures for stationary sources.[12] Recommendations in the BART Guidelines that continue to be relevant to the Regional Progress Four Factor Analysis are listed in Appendix D of the Draft EPA Guidance, and include, in general, the recommended approach for evaluating the technical feasibility, effectiveness, costs, and cost-effectiveness of available emission control measures.[13]

3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS

Under 40 CFR 51.308(f)(2)(i), states must consider four statutory factors when evaluating and determining emissions reduction measures from stationary sources, or groups of sources, that are necessary to make reasonable progress towards achieving natural visibility conditions. The four statutory factors are:

5. The costs of compliance;
6. The time necessary for compliance;
7. The energy and non-air quality environmental impacts of compliance; and
8. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

A brief description of each of the four statutory factors, and EPA's recommendations for evaluating each of the four factors (from the Draft EPA Guidance) is provided below.

3.2.1 Costs of Compliance

Cost estimates should be developed for each technically feasible control option. Costs include the total capital costs to engineer, design, procure, and install the control technology, and annual operating and maintenance (O&M) costs. O&M costs include both fixed and variable O&M. Fixed O&M includes costs that are independent of control system operation and would be incurred even if the control system were shut down. Fixed O&M includes categories such as operating and maintenance labor, administrative charges, property taxes, and insurance. Variable O&M includes the cost of consumables, including reagent (e.g., lime or limestone, ammonia, urea, etc.), by-product management, water consumption, and auxiliary power requirements associated with operating the control system. For existing facilities, O&M cost estimates should represent the control option's incremental increase over current O&M costs.

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[12] Draft EPA Guidance, pg. 85. The BART Guidelines are published at 40 CFR Part 51 Appendix Y.
[13] Draft EPA Guidance, Appendix D, pgs. 186-196.

Capital costs include all costs required to engineer, design, procure, and install equipment needed for the control system. The Draft EPA Guideline recommends that states adhere to the accounting principles described in Chapter 2 Section 1 of EPA's Air Pollution Control Cost Manual (the "Control Cost Manual") when calculating control system costs for a four factor analysis.[14]

Section 2.3 of the Control Cost Manual (Section 1, Chapter 2) describes the cost categories generally used to calculate the total capital cost of a retrofit control technology. Cost categories include total capital investment (TCI), which is defined to "include all costs required to purchase equipment needed for the control systems (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also includes costs for land, working capital, and off-site facilities." Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (i.e., cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies.[15]

The total annual cost (TAC) of a control option includes the annualized capital recovery cost plus the total annual O&M costs. The Control Cost Manual recommends using an equivalent uniform annual cash flow method to annualize the total capital investment by multiplying the total capital investment by a capital recovery factor (CRF).[16] The product of the total capital investment and CRF gives a uniform end-of-year payment necessary to repay the initial capital investment in "n" years at an interest rate of "i". The CRF is calculated using the following equation:

$$\mathrm{CRF} = \frac{i * (1+i)^n}{(1+i)^n - 1}$$

Where:
i = interest rate; and
n = economic life of the emission control system

The Draft EPA Guidance suggests that states may use generic cost estimates or estimating algorithms for estimating

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[14] Draft EPA Guidance, pg.89.
[15] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, pg. 2-5.
[16] Id., at pg 2-21.

control system costs; however, source specific estimates prepared by knowledgeable engineering professionals provide more reliable information that generic cost estimates.[17] Source-specific cost estimate should be well documented for purposes of public comment and EPA review.[18]

The total annual cost of each control option ($/yr) is divided by the total annual emissions reduction (tpy) to determine the control option's average cost-effectiveness on a $/ton basis. Emissions reductions are calculated based on the difference between baseline annual emissions and post-control annual emissions. The Draft EPA Guidance generally recommends calculating baseline emissions based on projected 2028 emissions assuming source compliance with emission limits that have been adopted and are enforceable. As an alternative, baseline emissions may be based on representative past actual emissions, assuming there is no evident basis for using a different emissions rate.

3.2.2 Time Necessary for Compliance

For stationary sources, the provisions of the BART Guidelines regarding the time necessary for compliance are relevant to reasonable progress analyses. EPA recommends that prior experiences with the planning and installation of new emission controls is the best guide to how much time a particular source will reasonably need for compliance. However, source-specific factors should be considered when evaluating the time necessary to engineer, procure, and install an available and technically feasible control option. Source-specific factors that affect the time necessary to install new emission controls should be identified and documented in the four factor analysis.

3.2.3 Energy and Non-Air Quality Environmental Impacts

For stationary sources, the provisions of the BART Guidelines regarding energy impacts are relevant to reasonable progress analyses. Energy impacts of an emission control measure are a matter of engineering design and control system operation; thus, EPA recommends that prior experience at similar sources will be informative. Energy impacts may be considered in terms of kilowatt-hours or fuels used to operate the control system. The energy impact analysis should focus on direct energy consumption at the source rather than indirect energy inputs needed to produce raw materials for the construction and operation of control equipment.

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[17] Draft EPA Guidance, pg. 91.
[18] Id.

For stationary sources, the provisions of the BART Guidelines regarding non-air quality environmental impacts are relevant to reasonable progress analyses. Non-air quality impacts include solid or hazardous waste generation, increased water consumption, wastewater discharge, land use impacts, and impacts to threatened and endangered species or their natural habitat. Characterizing the non-air quality environmental impacts should be done on a source-specific basis. Other guidance intended for use in assessments under the National Environmental Policy Act may be relevant to this evaluation.

Even though states are not required to consider GHG emission impacts, the Draft EPA Guidance encourages states to consider GHG impacts when developing their Long-Term Strategy.[19] As an example, some measures that would reduce emissions that contribute to visibility impairment will also reduce GHG emissions, such as measures that reduce the use of energy produced from combusting fossil fuels with relatively high GHG emissions. Conversely, control measures that require significant energy to capture visibility impairing emissions could result in increased GHG emission. Where a measure necessary to make reasonable progress towards natural visibility conditions would increase GHG emissions, Draft EPA Guidance encourages states to work to harmonize visibility and climate change objectives.[20]

3.2.4 Remaining Useful Life

For stationary sources, the provisions of the BART Guidelines regarding remaining useful life are relevant to reasonable progress analyses. In general, the remaining useful life of the source itself will be longer than the useful life of the emission control measure under consideration unless there is an enforceable requirement for the source to cease operation sooner. Thus, the useful life of the control measure will normally be used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness. However, if there is an enforceable requirement for the source to cease operation by a date before the end of what would otherwise be the useful life of the control measure under consideration, then the enforceable shutdown date should be used to calculate remaining useful life and evaluate control technology cost-effectiveness.

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[19] Draft EPA Guidance, pg. 92.
[20] Id.

3.2.5 Four Factor Analysis Approach

S&L used the following approach to identify SO_2 and NO_X emission control options available to Coyote Unit 1 for inclusion in the Four Factor Analysis:

1. Establish representative baseline emissions achieved with existing controls.
2. Identify all potentially available control options.
3. Evaluate control options for technical feasibility (i.e., availability and applicability).
4. Eliminate control options that are not technically feasible or would have no practical application on Coyote Unit 1.
5. Determine the control effectiveness of each technically feasible control option.
6. Evaluate each technically feasible control option for the four statutory factors.

4. BASELINE SO_2 AND NO_X EMISSIONS

The first step in developing the Four Factor Analysis is to establish Coyote Unit 1 baseline SO_2 and NO_X emissions. To establish representative baseline emissions, S&L evaluated Coyote Unit 1 operating data for the period January 1, 2013 to June 30, 2018 to identify periods of normal operation (i.e., periods of operation when the boiler was not limited by infrequent or extraordinary operating restrictions). Based on review of fuels consumed, heat input to the boiler, boiler heat rates, power generation, and capacity factors, as well as input from OTP, it was determined that the operating periods of January 1, 2013 to December 31, 2014 and January 1, 2016 to June 30, 2018 were representative of normal operation. The year 2015 was not considered to be representative because Coyote Unit 1 was limited to approximately 50% load due to a boiler feed pump (BFP) overspeed event that damaged one of the unit's two 50% BFPs; thus, only one BFP was available throughout most of the year. Therefore, the periods January 1, 2013 to December 31, 2014, and January 1, 2016 to June 30, 2018 are representative of normal operation during the baseline period, and it was determined that SO_2 emissions during that period are also representative. In June 2016, Unit 1 SOFA upgrades were completed for the purpose of reducing NO_X emissions; thus, the representative baseline period for NO_X emissions was determined to be from July 1, 2016 to June 30, 2018.

Baseline annual SO_2 and NO_X emissions were determined based on data obtained from the Coyote Unit 1 continuous emissions monitoring system (CEMS) that was reported to EPA's Clean Air Markets. The annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons per year). Representative baseline emission factors (in terms of pounds per million British Thermal Units (lb/MMBtu)) were developed using baseline annual average emissions and the respective baseline heat inputs. Table 4-1 provides a summary of the Coyote Unit 1 SO_2 and NO_X representative baseline emissions; additional details are included in Appendix A.

Table 4-1. Coyote Unit 1 Baseline Emissions

Pollutant	Baseline Controls	Emissions		Heat Input	Notes
		lb/MMBtu	tons/yr	MMBtu/yr	
SO_2	DFGD/FF	0.85	12,994	30,562,287	SO_2 emissions based on annual average tpy for period January 2013-June 2018 (excluding 2015)
NO_X	SOFA	0.46	7,363	32,301,802	NOx emissions based on annual average tpy for period July 2016 to June 2018 (post-SOFA upgrades)

5. SO_2 AND NO_X CONTROL MEASURES

S&L used a top-down approach to identify and evaluate the technical feasibility and effectiveness of potentially available SO_2 and NO_X control measures. S&L followed Steps 1 thru 3 of the top-down approach described in the BART Guidelines to identify all available retrofit emission control measures, eliminate technically infeasible options, and evaluate the effectiveness of the technically feasible options.[21] A brief description of each step is provided below.

Step 1 - Identify All Available Control Options

Available control options are those air pollution control technologies with a practical potential for application to the emission unit and the regulated pollutant under evaluation. Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant, and include not only existing controls for the source category but also take into account technology transfer of controls that have been applied to similar source categories and gas streams. Technologies which have not been applied to (or permitted for) full scale operations need not be considered as available.[22]

In an effort to identify all potentially available emission control technologies, S&L searched a broad range of information sources including, but not necessarily limited to:

- EPA's RACT/BACT/LAER Clearinghouse;
- EPA’s New Source Review (NSR) and Clean Air Technology Center (CATC) Web sites;
- BART evaluations prepared during the initial Regional Haze planning period;
- Information from control technology vendors and engineering/environmental consultants;
- Federal and State NSR permits and Best Available Control Technology (BACT) determinations for similar sources; and
- Technical journals, reports, newsletters and air pollution control seminars.

Step 2 - Eliminate Technically Infeasible Control Options

In Step 2, S&L evaluated the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. Control technologies are technically feasible if either: (1) they have been

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[21] See, 40 CFR Part 51 Appendix Y, Section IV.D.
[22] Id., at IV.D.1.

installed and operated successfully for the type of source under review under similar conditions; or (2) the technology could be applied to the source under review. In order for a control option to be technically feasible, it must be "available" and "applicable" to the source under consideration. A technology is considered "available" if the source owner may obtain it through commercial channels. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.[23]

Control technologies that are technically infeasible (i.e., not available or not applicable to the source under consideration) are eliminated for further evaluation. A demonstration of technical infeasibility must be based on physical, chemical and engineering principals, and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/infeasibility.

Step 3 - Evaluate Technically Feasible Control Technologies for Effectiveness

Step 3 involves evaluating the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review. Control effectiveness should be expressed using a metric that ensures an "apples-to-apples" comparison of emissions performance levels among options, and is generally expressed as the rate that a pollutant is emitted after installation of the control measure. Control technology evaluations for existing sources should consider ways to improve the performance of existing control devices. Special circumstances pertinent to the specific unit under review should be identified and taken into consideration when assessing the capability of the control alternative and determining control effectiveness.

For this evaluation, S&L assessed the technically feasible SO_2 and NO_X control options for effectiveness on Coyote Unit 1. As discussed above, Coyote Unit 1 is an existing cyclone boiler designed to fire North Dakota lignite. The unit is equipped with SOFA for NO_X control, and dry FGD and FF for SO_2 and PM control.

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[23] A more detailed description of control technology "availability" and "applicability" is provided in 40 CFR Part 51 Appendix Y, Section IV.D.2.

5.1 SO_2 EMISSIONS CONTROLS

5.1.1 Identify Available SO_2 Control Options

Based on a review of available SO_2 control technologies, as well as operational practices and equipment upgrades implemented on existing control systems, potentially available options to control SO_2 emissions from Coyote Unit 1 are listed in Table 5-1.

Table 5-1. Available SO_2 Control Options

SO_2 Control Technologies
Fuel Switching
Existing DFGD Operational Improvements
Existing DFGD Equipment Upgrades
Existing DFGD + Dry Sorbent Injection (DSI)
Existing DFGD Operational Improvements + DSI
Retrofit New Dry FGD
Retrofit New Wet FGD

5.1.2 Technical Feasibility of Available SO_2 Control Options

Potentially available SO_2 control options identified in Table 5-1 were evaluated for technical feasibility (i.e., availability and applicability to Coyote Unit 1) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options determined to be technically infeasible, or options that have no practical application to Coyote Unit 1, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emissions performance level (i.e., control emissions rate) for each.

5.1.2.1 Fuel Switching

One potential strategy for reducing SO_2 emissions is to reduce the sulfur content of the coal. Limiting the amount of sulfur in the coal directly limits the amount released during the combustion process, and would reduce SO_2 loading to the dry scrubber. Coyote Unit 1 is a cyclone boiler designed to fire North Dakota lignite as the primary fuel. Lignite fired at the Coyote Station is mined and supplied to the station from the nearby Coyote Creek Mine. The mine, which is owned and operated by Coyote Creek Mining Company, has primary mining operations approximately 3-4 miles southwest of Coyote Station and can be considered a mine mouth plant. Previous regulatory and court decisions have concluded that requiring a mine mouth facility to evaluate low sulfur coal would require the facility to redefine its fundamental purpose and design; therefore, fuel switching can be rejected as an available control option.[24] Because the use of North Dakota lignite from the Coyote Creek Mine is an inherent aspect of Coyote operation, fuel switching will not be evaluated.

5.1.2.2 Existing DFGD Operational Improvements and Equipment Upgrades

Operational and other design changes/upgrades to the existing dry scrubber may provide an opportunity for additional SO_2 removal and allow the unit to achieve lower controlled SO_2 emissions. S&L, working with OTP personnel, identified a number of potentially feasible operational changes that may be available to increase SO_2 removal efficiency with the existing equipment. Potentially available operational and design changes to the existing control system are summarized in Table 5-2. A detailed discussion of each of these options is provided in the following sections.

Table 5-2. FGD Operational Improvements and Equipment Upgrades

FGD Operational Improvements
Lime Quality
Ca:S Stoichiometric Ratio
Approach to Saturation Temperature
FGD Design Changes and Equipment Upgrades
Atomizer Replacement
Slaker Replacement
Adding an Absorber Module
Replacing Existing Absorbers with New Absorber Modules

Lime Quality

The quantity of lime (CaO) available in a dry scrubbing system compared to the amount of SO_2 entering the system is called the stoichiometric ratio (generally referenced as the Ca:S stoichiometric ratio). Reagent quality directly

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[24] In re: Prairie State Generating Company, PSD Appeal No. 05-05, Slip. Op. at 36 (2006)

affects the Ca:S stoichiometric ratio in DFGD control systems. Using a high quality lime increases the availability of hydrated lime to support process chemistry, and reduces the lime slurry injection rate needed for SO_2 removal.

Lime quality is measured both by the CaO content and reactivity of the lime product. In a dry scrubber, CaO is combined with water to form hydrated lime or calcium hydroxide ($Ca(OH)_2$), which provides the calcium that is needed to react with SO_2 in the flue gas. With a higher quality lime, more calcium hydroxide is available to react with SO_2. Lime products with a CaO content of 90% or greater are generally considered high quality lime. Lower quality lime products have a lower CaO content and higher quantity of inert material. Reactivity of the lime is measured by the temperature rise when the lime is slaked (i.e., water addition). In general, porous lime products have higher reactivity which is demonstrated by achieving a temperature rise of approximately 40 °C within 3 minutes of adding water.

Based on a review of available lime analyses, and a review of operating data from the existing lime slaking system, Coyote Unit 1 currently procures a high quality lime for use in the dry scrubbers. The typical CaO content of the lime used at Coyote is 90% or greater, and when slaked can achieve a 39.4 °C temperature rise in 3 minutes of adding water. For these reasons, changing the lime quality is not considered a technically feasible operational change available to control SO_2 emissions from Coyote Unit, and will not be evaluated further.

Ca:S Stoichiometric Ratio

Other operational changes that may be available to increase the Ca:S stoichiometry in the existing dry scrubber include: (1) increasing the byproduct recycle rate; and/or (2) increasing the quantity of fresh hydrated lime introduced to the system. Due to the cost savings that may be realized with the first option, some facilities with existing DFGD controls have opted to increase solids recycle rates to as high as 40-50% solids to achieve an incremental increase in SO_2 reduction, if capacity was available in the byproducts handling system. If capacity is not available, increasing fresh lime addition to the system may also be a viable option to increase the Ca:S stoichiometric ratio.

Solids from a dry scrubber consist of fly ash, reaction byproduct, and residual unreacted hydrated lime. On Coyote Unit 1, solids collected in the fabric filter hoppers are conveyed to either a dry storage silo for disposal or to a recycle fly ash silo where it is used as make-up for the reactant slurry. The recycle system is designed to utilize a portion of the unreacted lime rather than disposing of all of the solids. Recycle solids are combined with the fresh lime addition to provide the makeup lime needed for SO_2 reduction. Increasing the recycle rate can increase the amount of hydrated lime added to the system (i.e., stoichiometric ratio) without increasing the quantity of fresh lime added to the system.

Based on information provided by the station, the DFGD system on Coyote Unit 1 currently operates the recycle system at approximately 24% solids. The Coyote Unit 1 recycle system is operating within the original design conditions and system capacity. The plant has tested higher recycle rates (up to 28-30% solids), but at these higher rates plant personnel reported significant problems with the atomizer wheels spilling over and pluggage of various strainers. Based on the adverse operational impacts observed during these tests, as well as the design limitations of the existing dry scrubber modules, increasing the recycle % solids is not considered a technically feasible SO_2 control option for Coyote Unit 1.

As an alternative to increasing the recycle rate, the Ca:S stoichiometric ratio in the system may be increased by increasing the quantity of fresh lime introduced to the system. Testing was completed in October 2018 on Coyote Unit 1 to determine the impact of increasing the amount of fresh lime slurry fed to the atomizer feed tanks while adjusting the amount of recycle slurry in order to maintain the design 24% solids to the absorber. During the test program Coyote Unit 1 was able to achieve an average controlled SO_2 emission rate of 0.50 lb/MMBtu without significant adverse operational impacts and represents an average emission rate that Coyote would be expected to achieve on an on-going long-term basis under normal operating conditions. The emission rate should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

Increasing the quantity of fresh lime introduced to the system will require the existing atomizer wheels to be upgraded from the eight (8) nozzle wheel to a twelve (12) nozzle wheel to mitigate for potential plugging and spill-over issues caused by the percent solid limitation of the existing atomizer wheels (see, Section 5.1.2.2 Atomizer Replacement), and to prevent the possibility of moisture carry-over that could occur with the increase in lime slurry flow. Although upgrades to the existing atomizer wheels and nozzles will be required, increasing the Ca:S stoichiometric ratio by adding additional fresh lime to the system is considered a technically feasible SO_2 control option for Coyote Unit 1, and will be included in the Four Factor Analysis.

Approach to Saturation Temperature

The reaction of SO_2 with $Ca(OH)_2$ in a dry scrubber is driven by the absorber temperature. Water surrounding the lime slurry droplet allows SO_2 to dissolve into the liquid and facilitates the reaction between lime and SO_2. The temperature differential between the inlet and the outlet of the DFGD is used as a driving force for SO_2 removal; however, outlet temperatures must be maintained above the saturation temperature to ensure byproducts exiting the absorber module are dry. Residence time within the absorber vessel, drying time, and exit temperature are all important design parameters for a dry scrubbing system.

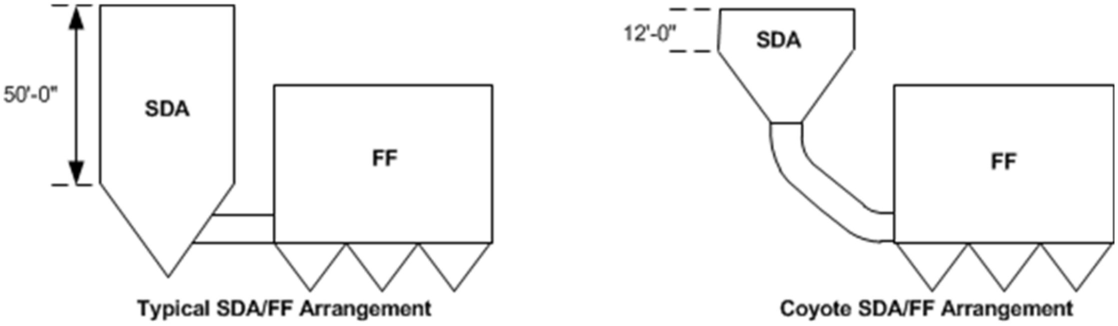
Inlet temperature to the dry scrubbing module is relatively constant; therefore, temperature differential across the module is a function of the outlet temperature. As a general rule-of-thumb, the closer the outlet temperature is to the adiabatic saturation temperature, the higher the SO_2 removal efficiency.

Operating a dry scrubbing system at outlet temperatures significantly above the adiabatic saturation temperature accelerates water evaporation from the reactant slurry, limits SO_2 absorption into the droplet, and limits the reaction between the lime and SO_2. Reducing the temperature in the absorber closer to the saturation point can provide additional SO_2 removal. On the other hand, the absorber module may not have sufficient residence time to dry all slurry droplets if the system is operated too close to adiabatic saturation, which would result in deposits in the absorber module, corrosion, and severe operational problems. Therefore, maintaining an absorber outlet temperature close to the point of saturation, while staying above it, is vital for optimal reaction kinetics.

The Coyote Unit 1 dry scrubbers currently operate at an outlet temperature of 190-210 °F, which is approximately 55-75 °F above the adiabatic saturation temperature and within original the OEM design steady state operating parameter of 190°F at the stack. More recent dry scrubbing systems have been designed to operate at 30 °F approach to adiabatic saturation. The station has attempted to lower the outlet temperatures to 165-170°F, however, this change caused significant corrosion of the absorber vessels and downstream equipment. Corrosion was likely due to the fact that the Coyote Unit 1 scrubbers were not able to completely dry the slurry droplets because the absorber vessels were designed with a residence time of approximately 1.0 second. More recent dry scrubbers are designed with approximately 10 seconds of residence time.

Figure 5-1 provides a simplified drawing of the Coyote Unit 1 scrubber compared to more recent DFGD designs, and depicts the arrangement limitation causing Coyote's shorter residence time. The low residence time limits the scrubbers ability to dry all slurry droplets when the system is operated too close to the approach to adiabatic saturation temperature. Due to the design limitations of the existing absorber vessels, reducing the outlet temperature is not considered a technically feasible SO_2 control option for Coyote Unit 1, and will not be evaluated further.

Figure 5-1. Comparison of Typical SDA/FF and Coyote Unit 1 SDA/FF Arrangement



Atomizer Replacement

Spray droplet size is an important parameter in the design and operation of a dry scrubber, and can improve lime utilization and SO_2 removal. Finer spray will increase the surface area of the slurry droplets exposed to the flue gas. Greater surface area increases the potential for SO_2 to absorb into the moisture of the slurry droplets. Droplet fineness also plays a role in particle drying time. Larger droplets can have a negative effect on the slurry drying time which can lead to moisture carryover to downstream equipment causing buildup and corrosion.

The Coyote Unit 1 dry scrubber, provided by Combustion Engineering, is designed with three (3) rotary atomizers, each with an eight (8) nozzle wheel in each absorber module to achieve a fine slurry spray. The design of the atomizer and speed at which the wheel rotates are controlling factors for the size and form of the droplets in the spray. The design and speed of atomizers is highly dependent on the spray pattern needed to mix with the hot flue gas in the scrubber module for optimum absorption of SO_2 while also preventing wetting of the absorber walls.

Based on S&L's assessment of the existing control system, previous testing completed by the station, and input from station operators, the existing DFGD system is limited in residence time, and the ability to increase the recycle ratio (solids content) to allow for more effective Ca:S contact in the scrubber vessels. The existing atomizers with eight (8) nozzle wheels would need to be upgraded to a twelve (12) nozzle wheel to mitigate for potential plugging and spill-over issues that could occur with the increased Ca:S stoichiometric ratio (discussed in Section 5.1.2.2). Based on engineering judgment, new 12 nozzle atomizers would improve spray atomization to produce slurry droplets that are smaller in size than the droplets produced by the existing nozzle design. Improved materials of construction would also allow for higher solids content in the slurry without detrimental equipment pluggage or spill-over.

Replacing the existing nozzles with a more recent 12 nozzle wheel design would provide better atomization of the slurry spray and allow for more effective Ca:S contact in the absorber vessels. However, nozzle replacement would not, on its own, be expected to provide a significant increase in SO_2 control. Nozzle upgrades coupled with operational changes designed to increase the Ca:S stoichiometric ratio is a technically feasible option that would be expected to provide additional SO_2 control (See, Section 5.1.2.2 Ca:S Stoichiometric Ratio).

Slaker Replacement

Lime slurry, the reagent used for SO_2 removal in a dry scrubber, is produced by mixing pebble lime with heated water in a slaker; this process is referred to as “slaking”. The slaker is operated at an optimum water-to-lime ratio (typically between 3:1 and 6:1) to produce lime slurry by metering the amount of water and the amount of lime added to the slaker. Slakers are typically designed to produce a lime slurry between 15-20% solids. The lime slurry is added to recycle slurry in a mix tank and then sent to the atomizer where it is sprayed into the scrubber for SO_2 removal.

Coyote Unit 1 still operates the original Dorr-Oliver detention slakers. The slakers operate at a 5:1 water-to-lime ratio and approximately 18% solids, which is in line with the design as well as industry practice. Therefore, replacing the slakers would not result in improved Ca:S contact in the absorber vessels or provide additional SO_2 removal. Replacing the lime slakers is not considered a technically feasible SO_2 control option for Coyote Unit 1, and will not be evaluated further.

Adding an Absorber Module

Another option for extending the residence time within the reactor modules and increasing Ca:S contact would be to add an additional absorber module. The existing system is designed with four absorber modules that share three fabric filter zones. The system is designed to operate with four modules at full load, three or four modules at 75% load and two modules at 50% load. At full load, the flue gas residence time in the reactor modules is approximately 1.0 second. More recent dry scrubbing systems have been designed with reaction vessel residence times of 10 seconds or more.

One potential option available to the Coyote Station to increase absorber module residence time would be to add an additional absorber module to the existing dry scrubbing system. The number of absorber modules used in a DFGD system is dependent on multiple operating parameters, including the flue gas flow rate and SO_2 concentrations. DFGD absorber modules are typically specified with minimum and maximum flue gas flow rates. If the absorber modules are oversized, flue gas velocities through the module can be too low, causing solids dropout inside the vessel. If the absorber modules are undersized, flue gas velocities can be too high, causing residence time to fall below recommended levels.

Dry scrubbing units that are operating at flue gas volumes significantly above the design flow rate can benefit from adding an extra module to the system. The module would be placed in parallel with the existing modules to achieve a similar pressure drop through each vessel and to ensure equal flue gas distribution to the vessels. Although adding an absorber module would likely allow additional residence time for the SO_2 removal reactions to occur, it would require extensive engineering and modifications to the existing system. More importantly, the Coyote Unit 1 absorber module design is no longer available from Combustion Engineering, and it would likely not be possible to procure a commercial offering from another technology vendor that would be compatible with the existing modules. Therefore, incorporating an additional absorber module into the existing system is not a commercially available or technically feasible SO_2 control strategy for Coyote, and will not be evaluated further.

Replacing Existing Absorbers with New Absorber Modules

Replacing the existing modules with new absorber modules would require significant engineering and facility modifications. Based on a preliminary review of the control system layout, the only practical location for this option would be to construct the new vessels in the same location as the existing modules. Locating the new modules adjacent to the existing absorber modules would require flue gas to be redirected from the air heater outlets to the new absorbers and back to the existing fabric filters, which would likely result in significant solids dropout and other operational issues. Therefore, locating the new absorber modules adjacent to the existing absorber modules is not considered a technically feasible option.

Installing the new absorber vessels in the same location as the existing dry scrubber modules would require Coyote Unit 1 to be taken off-line for an extended period of time. OTP could not operate the unit while the existing modules were dismantled and removed, or while the new absorber modules, duct work, and other system tie-ins were installed. Based on construction schedules for new DFGD systems, and taking into consideration decommissioning of the existing dry scrubber modules, this option would likely require an outage of at least 12-months and would require Coyote to purchase replacement power during this period. In comparison, a typical major outage at Coyote Station is only 6-8 weeks. Outage costs would add significantly to the cost of this control option.

Although replacing the existing dry scrubber modules with new DFGD reactor vessels would require a long outage, there is no technical basis for eliminating this option from the analysis. Replacing the exiting dry scrubber modules with new absorber modules would address the design and operational limits of the existing system. The new absorber modules could be designed to provide additional Ca:S contact and residence time between the exhaust gas and the slurry, and would likely allow OTP to reduce the approach to saturation temperature, design parameters which would increase overall SO_2 removal.

Coyote Unit 1 consistently achieves overall removal efficiencies in the range of approximately 65-73% with the existing dry scrubbing system. Based on engineering judgment and industry practice, it is expected that the fabric filter provides approximately 10-15% of the overall removal in the DFGD system. Assuming 10-15% removal in the fabric filter, approximately 60% of the SO_2 removal is achieved in the existing absorber modules based on the current coal sulfur content. Estimated SO_2 removal efficiencies across the existing DFGD system are shown in Table 5-3.

Table 5-3. Existing SO_2 Removal Efficiencies

Existing Scrubber Modules	Existing Fabric Filter	Overall
Inlet: 2.83 lb/MMBtu Outlet: 1.14 lb/MMBtu Efficiency: 60% of uncontrolled Contribution: 85% of overall removal	Inlet: 1.14lb/MMBtu Outlet: 0.85 lb/MMBtu Efficiency: 11% of uncontrolled Contribution: 15% of overall removal	Inlet: 2.83 lb/MMBtu Outlet: 0.85 lb/MMBtu Efficiency: 70%

Based on SO_2 removal efficiencies achieved in practice on existing units equipped with DFGD, it is anticipated that replacing the existing absorber modules with new scrubber modules could increase removal across the scrubber to approximately 80%, and increase overall removal efficiencies to approximately 91%. It should be noted that Coyote is expected to receive higher sulfur content coal in the future; therefore, the new scrubber vessel SO_2 removal analysis is based on this higher sulfur content coal. The removal efficiencies for this option are shown in Table 5-4.

Table 5-4. New Scrubber Vessel SO_2 Removal Efficiencies

New Scrubber Modules	Existing Fabric Filter	Overall
Inlet: 3.12 lb/MMBtu(Note 1) Outlet: 0.62 lb/MMBtu Efficiency: 80% of uncontrolled Contribution: 88% of overall removal	Inlet: 0.62 lb/MMBtu Outlet: 0.29 lb/MMBtu Efficiency: 11% of uncontrolled Contribution: 12% of overall removal	Inlet: 3.12 lb/MMBtu Outlet: 0.29 lb/MMBtu(Note 2) Efficiency: 91%

Note 1. Inlet SO_2 rate based on anticipated future fuel sulfur content.

Note 2. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

Replacing the existing dry scrubber modules with new absorber modules is a technically feasible control technology option that would provide an incremental increase in overall SO_2 removal efficiency. However, this option would require Coyote Unit 1 to be taken off-line for an extended period of time (approximately 12 months). Outage costs associated with the extended outage are included in the four-factor cost impact evaluation for this option. Given the constructability issues and extended outage requirements associated with replacing the existing dry scrubber modules, this may not be a practical option for Coyote; nevertheless, it will be included as a technically feasible SO_2 control option in the Four Factor Analysis.

5.1.2.3 Existing FGD + Dry Sorbent Injection

Alkali based sorbent injection is a proven technology for the removal of sulfur trioxide (SO_3) and other acid gases from coal-fired power plant flue gas, and can be used to provide SO_2 control. Sorbent is injected into the ductwork after the furnace and prior to the particulate collection device, where it reacts with SO_2 and other acid gases. Sorbent injection systems are relatively simple systems consisting of material storage, feeding mechanism, blower or transfer line, and an injection device. For SO_2 control on Coyote Unit 1, sorbent would be injected upstream of the dry scrubber to provide an incremental reduction in the concentration of SO_2 in the flue gas at the inlet to the dry scrubber.

Sorbents react with SO_2, and other acid gases, in the flue gas when injected at an appropriate rate and within the proper temperature range for that sorbent. The resulting particulate matter is removed from the flue gas by the particulate control system. The process works through neutralization of the acid gases with the alkaline sorbent. The neutralization reaction occurs as long as the sorbent remains in contact with the gas in the flue gas duct work within the required temperature range.

Dry sorbents that have been used for SO_2 control on coal-fired boilers include:

- Hydrated Lime ($Ca(OH)_2$)
- Trona or Sodium Bicarbonate (SBC)

The following wet sorbents have also been used for acid gas control at coal-fired power generating stations:

- Sodium Bisulfite (SBS)
- Soda Ash

Dry sorbents, including hydrated lime, Trona, and SBC would be injected pneumatically as a dry powder into the flue gas ductwork upstream of the Coyote Unit 1 dry scrubber. Trona and SBC are both sodium-based sorbents, which react with SO_2 to form sodium salts. Hydrated lime would react with SO_2 to form calcium sulfate salts. The hydrated lime reactions are the same reactions that are taking place in the existing dry scrubber.

Hydrated lime is less reactive than the sodium based dry sorbents; thus, higher injection rates and longer residence time would be required to achieve the same removal efficiency. However, hydrated lime has a lower unit cost compared to other sorbent options, offsetting the higher injection rates. It is also important to note that the hydrated lime chemistry involves the same reactions, and forms the same calcium salts, as those currently taking place in the dry scrubber reaction vessels. Therefore, using hydrated lime as the sorbent would not introduce any new constituents into the dry scrubbing system, and could potentially increase the Ca:S stoichiometry in the dry scrubber.

Because of the higher reactivity of sodium based sorbents, less reactant may be required to achieve the same removal efficiency; however, injecting a sodium-based sorbent into the flue gas upstream of the Coyote Unit 1 dry scrubber would introduce new chemical constituents into the scrubber and into the fly ash/scrubber byproduct material. This could prove problematic as sodium compounds are water soluble, and introducing sodium into the system could adversely affect the characteristics of the byproduct solids generated by the system. Detailed studies and demonstration tests would be needed to ensure that introducing relatively large amounts of sodium would not adversely affect scrubber operation or result in solids disposal issues.

SBS and soda ash (Na_2CO_3) injection are wet injection technologies typically used for SO_3 mitigation. SBS and soda ash can be injected into the flue gas upstream or downstream of the air heater as a 10% solution (by weight) using dual fluid atomizers. Both products will react with SO_2 and SO_3 to form sodium salts, which can be collected in the downstream particulate collection device. URS/Codan Associates own the patent for this SBS control process. Based on conversations with URS, their SBS technology is generally more economical using soda ash, and all recent projects have used soda ash. However, as with the dry sodium-based injection systems, these systems would introduce sodium into the Coyote Unit 1 DFGD control system.

Sorbent injection (dry or wet) upstream of the existing dry scrubber is a technically feasible and commercially available SO_2 control option for Coyote Unit 1. Taking into consideration the fact that Coyote is currently equipped with a calcium-based dry scrubbing system, hydrated lime dry sorbent injection would be the most practical, and potentially the most effective, sorbent injection control option. Sodium-based systems would require extensive testing to determine the potential impacts associated with introducing significant quantities of sodium into the existing system, and are not considered practical control options for Coyote Unit 1.

Based on engineering judgment, and assuming adequate residence time in the duct work upstream of the existing dry scrubber, hydrated lime injection could reduce SO_2 concentrations at the dry scrubber inlet by approximately 35%. Based on future design fuel characteristics, this would reduce SO_2 concentrations at the dry scrubber inlet from approximately 3.12 lb/MMBtu to approximately 2.03 lb/MMBtu. Applying the current scrubber SO_2 removal efficiency of 71% (dry scrubber plus fabric filter), would result in a controlled SO_2 emission rate of 0.58 lb/MMBtu. DSI upstream of the existing dry scrubbing system is considered a technically feasible SO_2 control technology; however, flow modeling and field testing at Coyote Unit 1 would be needed to ensure that adequate residence time is available for SO_2 control and to confirm the incremental reduction in SO_2 emissions achievable without creating unacceptable operational issues.

Table 5-5. DSI SO_2 Control Technology Estimated Emissions

	Unit 1
Uncontrolled SO_2 Emissions (lb/MMBtu)	3.12
SO_2 Emissions at DSI Outlet (lb/MMBtu)	2.03
SO_2 Emissions at FF Outlet (lb/MMBtu)	0.58[1]
Overall Removal (%)	**80.4**

Note 1. Emissions at the FF outlet were estimate by applying existing 71% SO_2 removal across the DFGD system ((2.03 lb/MMBtu x (1 – 0.71) = 0.58).

Note 2. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

5.1.2.4 FGD Operational Improvements + DSI

Some of the SO_2 control technologies which involve improvements to the FGD can potentially be applied in combination with dry sorbent injection to provide additional SO_2 removal. This option would be considered a layered technology of the technically feasible FGD operational improvements discussed in Section 5.1.2.2 with dry sorbent injection discussed in Section 5.1.2.3. Technically feasible FGD operational improvements include increasing the Ca:S stoichiometric ratio of the FGD by introducing additional fresh lime to the absorber modules. Based on engineering judgement, layering FGD operational improvements with DSI could reduce SO_2 emissions from the baseline SO_2 emission rate of 0.85 lb/MMBtu to approximately 0.33 lb/MMBtu at Coyote Unit 1 as shown in Table 5-6. However, as stated previously, flow modeling and field testing at Coyote Unit 1 would be needed to ensure that adequate residence time is available for SO_2 control and to confirm the incremental reduction in SO_2 emissions achievable without creating unacceptable operational issues.

Table 5-6. Layered (DSI + Ca:S) SO_2 Control Technology Estimated Emissions

	Unit 1
Uncontrolled SO_2 Emissions (lb/MMBtu)	3.12
SO_2 Emissions at DSI Outlet (lb/MMBtu)	2.03
SO_2 Emissions at FF Outlet (lb/MMBtu)	0.33[1]
Overall Removal (%)	**89.4**

Note 1. Emissions at the FF outlet were estimate by applying 84% SO_2 removal across the DFGD system with operational improvements ((2.03 lb/MMBtu x (1 - 0.84 lb/MMBtu) = 0.33 lb/MMBtu).
Note 2. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

5.1.2.5 Install New Dry FGD System

Replacing the existing dry scrubber and fabric filter with new control systems would require significant engineering and modifications to the facility. Based on a preliminary review of the facility layout, the new control systems could be located northeast of Coyote Unit 1's existing dry scrubber/FF. The new DFGD/FF and all auxiliary equipment could be constructed while the unit remains on-line. The control systems could be tied-in to the existing systems during a scheduled major outage.

Various DFGD systems have been designed for use with pulverized coal-fired boilers; including the spray dryer absorber (SDA) and circulating dry scrubber (CDS). Both systems are evaluated in more detail below.

Spray Dryer Absorber / Fabric Filter

SDA systems have been used in large coal-fired utility applications, and have demonstrated the ability to effectively reduce uncontrolled SO_2 emissions from pulverized coal units. Like other dry scrubbing systems, SDA control systems use a slurry of lime and water injected into the reaction modules to remove SO_2 from the combustion gases. The reaction modules are designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a dry by-product. Process equipment associated with an SDA control system includes an alkaline storage tank, mixing and feed tanks, atomizer assembly, spray chamber module, integrated fabric filter, and solids recycle system. The recycle system collects solid reaction byproducts and recycles them back to the spray dryer feed system to maximize reactant utilization.

Various process parameters affect the efficiency of the SDA process including: the type and quality of the additive used for the reactant, reactant-to-sulfur stoichiometric ratio, how close the SDA is operated to saturation conditions, and the amount of solids product recycled to the atomizer. SDA systems are typically designed to operate within approximately 30 ^{o}F adiabatic approach to saturation temperature. Operating closer to the adiabatic saturation temperature may allow for higher SO_2 control efficiencies; however, outlet temperatures too close to the saturation temperature will result in severe operating problems including reactant build-up in the absorber modules, blinding of the fabric filter bags, and corrosion in the fabric filter and ductwork.

SO_2 removal efficiencies in a SDA are also dependent upon good gas-to-liquid contact. Reactant spray nozzle designs are vendor-specific, and include both dual-fluid nozzles and rotary atomizers. The atomizing nozzle assembly is typically located in the SDA penthouse and flange mounted to the roof of the absorber vessel.

Replacing the existing dry scrubber/FF with a new SDA/FF control systems is a technically feasible and commercially available control option on Coyote Unit 1. SDA/FF control systems are generally installed on units that burn lower sulfur fuels (i.e., < 3 lb SO_2/MMBtu) because design limitations, including Ca:S stoichiometry, residence time, and approach to saturation typically limit total SO_2 removal to approximately 95%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system. On Coyote Unit 1, 95% removal would result in an average controlled SO_2 emission rate of approximately 0.16 lb/MMBtu.

Circulating Dry Scrubber / Fabric Filter

A second type of dry scrubbing system is the circulating dry scrubber (CDS). Similar to other dry flue gas desulfurization systems, the CDS system would be located after the air preheater, and byproducts from the system collected in an integrated fabric filter. Unlike the SDA systems, CDS systems use a circulating fluidized bed of hydrated lime reagent to remove SO_2 rather than an atomized lime slurry; however, similar chemical reaction kinetics are used in the SO_2 removal process.

In a CDS, flue gas is treated in an absorber vessel where the flue gas stream flows through a fluidized bed of hydrated lime and recycled byproduct. Water is injected into the absorber through a venturi located at the base of the absorber for temperature control. Flue gas velocity through the vessel is maintained to keep the fluidized bed of particles suspended in the absorber. Water sprayed into the absorber cools the flue gas from approximately 300 °F at the inlet to the scrubber to approximately 160 °F at the outlet of the fabric filter. The hydrated lime absorbs SO_2

from the gas and forms calcium sulfite and calcium sulfate solids. Desulfurized flue gas passes out of the absorber, along with the particulate matter (reaction products, unreacted hydrated lime, calcium carbonate, and the fly ash) to the fabric filter.

As with the SDA/FF option, replacing the existing dry scrubber/FF with a new CDS/FF control system would require significant engineering and modifications to the existing facility. For this evaluation it was assumed that the CDS/FF control systems could be located adjacent to the existing dry scrubber/FF, and that the control systems could be tied-in to the existing system during a scheduled major outage.

Replacing the existing dry scrubber and FF with a new CDS/FF control system is a technically feasible and commercially available control option for Coyote Unit 1. Based on engineering judgment, it is anticipated that the retrofit CDS/FF control option would achieve SO_2 removal efficiencies higher than those achieved with a SDA/FF due to the increased Ca:S contact in the fluidized bed absorber vessel. Based on recent CDS retrofit projects, and taking into consideration expected fuel characteristics, it is anticipated that the retrofit CDS/FF control system could achieve SO_2 removal efficiencies of approximately 97%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system. On Coyote Unit 1, 97% removal would result in an average controlled SO_2 emission rate of approximately 0.09 lb/MMBtu and represents an average emission rate that Coyote would be expected to achieve on an on-going long-term basis under normal operating conditions. The emission rate should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

5.1.2.6 Install New Wet FGD System

Another option available to the Coyote Station would be to replace the existing dry scrubbing system with a new wet FGD control system located downstream of the existing FF.

Wet FGD technology is an established SO_2 control technology. Wet scrubbing systems have been designed to utilize various alkaline scrubbing solutions including lime, limestone, and magnesium-enhanced lime. Wet scrubbing systems have also been designed with spray tower reactors and with reaction vessels (e.g., jet bubbling reactor). Although the flue gas/reactant contact systems may vary, the chemistry involved in all wet scrubbing systems is essentially identical. All wet scrubbing systems use an alkaline slurry that reacts with SO_2 in the flue gas to form insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts.

A large majority of the wet FGD systems designed to remove SO_2 from existing high-sulfur utility boilers have been designed as wet limestone scrubbers with spray towers and forced oxidation systems. Therefore, for this evaluation, it was assumed that the WFGD control system would be designed as a limestone spray tower scrubber with forced oxidation. Other potentially available wet scrubber designs are not included in this evaluation because the chemistry involved in all wet scrubbing systems are essentially identical, alternative designs would not provide any additional SO_2 control, and control system costs would be similar.

Wet Limestone Scrubbing

In a wet limestone scrubbing system, limestone ($CaCO_3$) is mixed with water to formulate the alkali scrubber slurry. Flue gas enters the absorber vessel and contacts the absorbent slurry in a countercurrent spray tower. SO_2 in the flue gas reacts with the limestone slurry to form insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) which is removed as a solid waste by-product. Spent absorbent is returned to the reaction tank where dissolved sulfur compounds are precipitated as calcium salts. Fresh limestone slurry is added to regenerate the spent absorbent.

The reaction tank is sized to provide sufficient time for precipitation of the sulfur compounds. From the reaction tank, regenerated absorbent slurry is recycled to the absorber. The slurry typically contains from 5 to 15% suspended solids consisting of fresh additive, absorption reaction products, and lesser amounts of fly ash. To regulate the accumulation of solids, a bleed stream from the reaction is routed to the solid/liquid separation equipment.

Forced oxidation of the scrubber slurry may be used with limestone WFGD systems to produce calcium sulfate solids (gypsum) instead of the calcium sulfite by-product. Air blown into the reaction tank provides oxygen to convert most of the calcium sulfite ($CaSO_3$) to a relatively pure gypsum. Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the spray tower. The gypsum by-product from this process must be dewatered, and may be salable if a local market for gypsum is available, reducing the quantity of solid waste that needs to be landfilled.

For this evaluation it was assumed that the existing Coyote Unit 1 dry scrubber reactor vessels would remain in place, and that the WFGD control system would be located downstream of the existing FFs and ID fans, most likely northeast of the unit's existing dry scrubber/FF. Dry scrubber reactor vessel internals would ultimately be removed to reduce pressure drop through the system. A single WFGD absorber tower would be sufficient for the Coyote

Unit 1 flue gas flow. In addition to the absorber tower and reaction vessel, the WFGD control system would require a limestone handling and preparation system and by-product dewatering systems. Because of the saturated nature of the flue gas exiting the WFGD, a new stack with a liner capable of wet flue gas operation would be required. New booster ID fans would also be required to account for the additional pressure drop through the WFGD control system.

Wet FGD technology is an established SO_2 control technology. Wet scrubbing systems have been installed on units that fire medium to high sulfur coals, and would be a technically feasible SO_2 control option for Coyote Unit 1. Based on engineering judgment and information from control system vendors, it is anticipated that a retrofit WFGD control system on a North Dakota lignite-fired unit would be designed to achieve and SO_2 removal efficiency of approximately 98%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system. On Coyote Unit 1, 98% removal would result in an average controlled SO_2 emission rate of approximately 0.06 lb/MMBtu and represents an average emission rate that Coyote would be expected to achieve on an on-going long-term basis under normal operating conditions. The emission rate should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

5.1.2.7 Technical Feasibility Summary

Table 5-7 summarizes the results of the feasibility evaluation of available control options for Coyote Unit 1.

Table 5-7. Technically Feasible SO_2 Control Options

SO_2 Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Fuel Switching	No	Fuel switching is not considered an available SO2 control option for Coyote Unit 1 since the use of North Dakota lignite coal is an inherent aspect of plant operations.
Existing DFGD Operational Improvements:		
Lime Quality	No	Changing lime quality in the existing DFGD control system is not a technically feasible operational change for Coyote Unit 1.
Ca:S Stoichiometric Ratio	Yes	Increasing the Ca:S stoichiometric ratio by increase the quantity of fresh lime to the system is considered a technically feasible option for Coyote Unit 1, assuming the operational change is coupled with atomizer replacement.

SO_2 Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Approach to Saturation Temperature	No	Due to design limitations, further reducing the absorber module outlet temperature on the existing DFGD control system is not a technically feasible option for Coyote Unit 1.
Existing DFGD Equipment Upgrades:		
Atomizer Replacement	Yes	Replacing the existing atomizers is a technically feasible option for Coyote Unit 1 and would provide additional SO2 control if coupled with increasing the Ca:S stoichiometric ratio.
Slaker Replacement	No	Slaker replacement would not be expected to provide additional SO_2 control, and is not a technically feasible equipment upgrade for Coyote Unit 1.
Adding an Absorber Module	No	Coyote Unit 1 DFGD absorber modules are no longer commercially available, thus, adding an absorber module to the existing system is not a technically feasible SO_2 control option.
Replacing Existing Absorbers with New Absorber Modules	Yes	Replacing the exiting absorber modules with new absorber modules is a technically feasible SO_2 control system upgrade for Coyote Unit 1 that would require an approximate 12-month outage.
Existing DFGD + DSI	Yes	Hydrated lime sorbent injection upstream of the existing Coyote Unit 1 absorber modules is a technically feasible SO_2 control option. Flow modeling and field testing would be needed to confirm that the incremental reduction in SO_2 emissions is achievable without creating unacceptable operational issues.
Existing DFGD Operational Improvements (Increase Ca:S Stoichiometric Ratio) + DSI	Yes	Combining operational improvements (i.e., increased Ca:S stoichiometric ratio) with hydrated lime sorbent injection is a technically feasible SO_2 control option for Coyote Unit 1. Flow modeling and field testing would be needed to confirm that the incremental reduction in SO_2 emissions is achievable without creating unacceptable operational issues.
New Retrofit DFGD (CDS/FF)	Yes	Replacing the existing DFGD control system with a new retrofit DFGD (i.e., CDS/FF) is a technically feasible SO_2 control option for Coyote Unit 1.
New Retrofit WFGD	Yes	Replacing the existing DFGD control system with a new retrofit WFGD is a technically feasible SO_2 control option for Coyote Unit 1.

5.1.3 Evaluate Technically Feasible SO_2 Control Options for Effectiveness

The technically feasible SO_2 control technologies are listed in Table 5-8 in descending order of control efficiency. Table 5-8 also provides control option-specific SO_2 emission rates in terms of lb/MMBtu. Emission rates shown in

Table 5-8 represent average emission rates that the control options would be expected to achieve during normal operations.

Table 5-8. Evaluate Technically Feasible SO_2 Control Options for Effectiveness

Control Option	SO_2 Emission Rate (Note 1) lb/MMBtu	% Reduction from Baseline Emission Rate
Baseline (existing DFGD/FF)	0.85	-
New Retrofit WFGD	0.06	92.9%
New Retrofit DFGD (CDS/FF)	0.09	89.4%
New Retrofit DFGD (SDA/FF)	0.16	81.1%
FGD Upgrades - Replacing Existing Absorbers with New Absorber	0.29	65.9%
DSI + FGD Operational Improvements	0.33	61.2%
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0.50	41.2%
DSI + Existing FGD	0.58	31.8%

Note 1. Emission rates shown in Table 5-8 represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

5.2 NO_X EMISSIONS CONTROLS

5.2.1 Identify Available NO_X Control Options

Based on a review of available NO_X control technologies installed on existing cyclone coal-fired boilers, as well as operational practices and equipment upgrades implemented on existing control systems, potentially available options to control NO_X emissions from Coyote Unit 1 are listed in Table 5-9.

Table 5-9. Available NO_X Control Options

NO_X Control Technologies
Combustion Optimization
Selective Non-Catalytic Reduction (SNCR)
Rich Reagent Injection (RRI)
SNCR + RRI
Gas Reburn
Innovative Technologies (i.e. NOxStar, Water Injection, LoTOX, PerNOxide, Water Injection)
Selective Catalytic Reduction - High Dust, Low Dust or Tail End Configuration (TE-SCR)

5.2.2 Technical Feasibility of Available NO_X Control Options

Potentially available NOx control options identified in Table 5-9 were evaluated for technical feasibility (i.e. availability and applicability to Coyote Unit 1) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options deemed to be technically infeasible, or options that have no practical application to Coyote Unit 1, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emission performance level (i.e., controlled emission rate) for each.

5.2.2.1 Combustion Optimization

Coyote Unit 1 is equipped with twelve (12) ten (10) foot cyclones, six (6) on the front wall and six (6) each on the rear wall, two levels of three on each wall. The lignite coal requires a pre-dry system, which conveys the coal through individual crushers and into a cyclone separator for moisture separation. The dried coal is discharged from the bottom of the separator through a rotary seal, while the transport air (with a small quantity of fines) is discharged out the top and into ports above the cyclones. The coal discharged through the bottom rotary seal is blown into the cyclone through a pipe referred to as the “lift line” or known as primary air on most other similar installations. The temperature of the pre-dry air/coal temperature is regulated along with the lift line air by injecting cold (tempering) air into the hot primary air stream to regulate the outlet temperatures.

In 2016, The Babcock and Wilcox Company (B&W) installed fourteen (14) separated overfire air (SOFA) ports (seven on the front and rear wall) and modified the cyclones with smaller re-entrant throats and a ⅓ – ⅔ split secondary air damper (each having its own damper) to reduce NOx emissions. For the SOFA process, the injection of air into the boiler is staged into two zones, in which approximately 5% to 20% of the total combustion air is diverted from the burners and injected through ports located above the top burner level. Staging of the combustion air reduces NOx formation by two mechanisms. First, staged combustion results in a cooler flame which will reduce the formation of thermal NO_X. Second the staged combustion results in less oxygen reacting with fuel molecules. The degree of staging is limited by operational problems since the staged combustion results in incomplete combustion conditions and a longer flame profile. The units normally operate with the ⅓rd damper closed or nearly closed to help recirculate the coal in the cyclone and allows for increased coal retention and improved combustion. Since the SOFA installation, Coyote Unit 1 has achieved average controlled NOx emissions of approximately 0.46 lb/MMBtu.

Tuning of the cyclone boiler to optimize the combustion process and minimize the generation of NOx was recently completed at Coyote Unit 1. Tuning was completed by lowering the stoichiometry (i.e., lower the air-to-fuel ratio) in the cyclone barrel and tracking the cyclone combustion stability, while staying within the OEM specifications for best combustion engineering practice. Based on the testing results, Coyote Unit 1 was able to achieve average NOx emissions of approximately 0.42 lb/MMBtu without obvious impacts to boiler performance and with minimal slagging. Based on the results of the combustion turning tests, combustion optimization is considered a technically feasible NOx control option.

5.2.2.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH_3) or urea ($CO(NH_2)_2$) at high flue gas temperatures (approximately 1,600ºF – 2,100ºF) in an oxidizing environment. The ammonia or urea reacts with NO_x in the flue gas to produce N_2 and water as shown below.

$$(NH_2)_2CO + 2NO + \frac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$
$$2NH_3 + 2NO + \frac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reagent injection can greatly affect NO_x removal efficiencies and the quantity of NH_3 or urea that will pass through the SNCR unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective in the range of 1,600ºF – 2,100ºF. At temperatures below the desired operating range, the NO_x reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NO_x resulting in low NO_x reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Furnace geometry, urea spray coverage, and droplet size must be considered when developing good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reagent and flue gas in that temperature window. As the boiler cycles in load, the optimum injection region may change; thus, most facilities require multiple injection zones which are placed in and out of service as the unit ramps in load. This can include modifying the zones of injectors that are operating at different loads and temperatures.

Retractable multinozzle lances (MNLs) are sometimes used to improve SNCR performance, especially if the furnace exit flue gas temperatures are too high. The retractable lances allow injection into the appropriate temperature zone more so than wall injectors, depending on the unit load and temperatures. The MNLs also help improve performance by refining the spray pattern for quicker vaporization of the conveying water. MNLs are often used in conjunction with wall injection to provide optimized coverage while reducing reagent cost.

In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to-NO_x ratio, and fuel sulfur content. Increasing the normalized stoichiometric ratio (NSR) can improve NOx removal.[25] This can be achieved by increasing urea solution flow through the injectors or changing the concentration of urea in the solution. However, too high of reagent injection rates will increase the ammonia slip beyond the recommended 10 ppmvd limit. Above this concentration, there are expected to be major impacts to the formation of ammonia salts on the boiler tube banks, reducing heat transfer efficiency, and air heater baskets, causing corrosion.

SNCR can be applied on cyclone boilers due to having reasonable temperature windows and residence time; however, the potential NOx reduction is boiler-specific. SNCR has been used as a retrofit NOx control system of on pulverized coal, fluidized bed boilers, and cyclone boilers. Furthermore, SNCR can be implemented on boilers

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[25] NSR defines the amount of reagent needed to achieve the targeted NOx reduction. Based on the reaction equations in 5.2.2.2, two moles of NOx can be removed with one mole of urea or two moles of ammonia. In practice, more than the theoretical amount of reagent needs to be injected into the boiler flue gas to obtain a specific level of NOx reduction. This is due to the complexity of the actual chemical reactions involving NOx and injected reagent and mixing limitations between reagent and flue gas. Factors that influence the NSR value: (1)percent NOx reduction; (2) uncontrolled NOx concentration in the flue gas; (3) temperature and residence time available for the NOx reduction reactions; (4) extent of mixing achievable in the boiler; and (5) allowable ammonia slip.

equipped with low-NOx burners, overfire air, or SOFA systems. Based on the boiler residence time, temperature profile, and stoichiometry, as well as input from SNCR OEMs, it is estimated that an SNCR system could achieve an average controlled NO_x emission rate of approximately 0.28 lb/MMBtu (approximately 39% below the baseline emission rate of 0.46 lb/MMBtu) at full load while limiting ammonia slip to 10 ppmvd. It should be noted that computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NOx emission is achievable without creating unacceptable operational issues.

5.2.2.3 Rich Reagent Injection

Similar to SNCR, the concept of rich reagent injection (RRI) is to use a nitrogen-containing additive (e.g., urea) injected into a reducing environment to promote NO_X removal. RRI is a commercial technology for cyclone boilers only. In contrast to SNCR, RRI typically is applied with only one injection level in the lower furnace near the cyclone barrels (temperature window of 2000°F-2600°F). The technology requires a sub-stoichiometric oxygen concentration near the barrels at less than approximately 0.95. This allows for a higher injection rate of reagent without oxidizing the nitrogen-containing reagent to NOx due to the sub-stoichiometry. Injection at this location also creates lower level of excess NH_3 emissions (NH_3 slip), while injecting at an NSR of 2.0-3.0.

Due to the changes of the lower furnace stoichiometry, RRI is often not a technically feasible option at low loads. Once the stoichiometric ratio increases to >1.0, the potential exists for NOx generation due to the reaction of NH_3 with oxygen, especially if the injection location and rate is not optimized. Based on these limitations, RRI is considered most effective at full load.

The RRI process is a commercially available process. Based on engineering judgment, RRI is expected to reduce NO_X emissions by approximately 20-40% at Coyote Unit 1 when operating at full load with minimal ammonia slip. However, due to the cyclone combustion temperature window, this technology only provides effective NOx reduction at or near full load. At low loads, RRI does not provide effective control; however, RRI can be combined with SNCR to provide NOx control across the full range of normal operating loads. RRI is a technically feasible NOx reduction option for North Dakota lignite-fired cyclone boilers. However, due to its limited operating conditions and ineffective NOx reduction at low loads, RRI alone is not considered an available NOx control option, and will only be evaluated in conjunction with SNCR.

5.2.2.4 SNCR + RRI

While RRI alone will provide beneficial NOx reduction at full load only, coupling RRI with SNCR can provide a balanced approach to NOx reduction through all load ranges. Since RRI and SNCR injectors are located at different elevations of the furnace and in different temperature windows, there are not concerns of spatial impacts. The combined system would utilize a relatively high urea injection rate, staged at multiple locations throughout the boiler. The main advantage of this combined system is that the SNCR can provide better NOx reduction at low load and at a lower NSR than RRI alone; thus, the combined system is expected to provide effective NOx control across all normal operating load ranges. Coupling RRI and SNCR is considered a technically feasible and commercially available NOx control technology option on Coyote Unit 1. Based on input from SNCR OEMs and engineering judgment, the control option is expected to achieve an average outlet NOx rate of approximately 0.20 lb/MMBtu with an ammonia slip of 10 ppmvd. It should be noted that computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NOx emission is achievable without creating unacceptable operational issues.

5.2.2.5 Gas Reburn

Gas reburn is a retrofit technique that has been used to control NO_X emissions from coal- and oil-fired boilers. Gas reburn involves combustion in three distinct zones within the boiler: (1) a primary combustion zone, where the primary fuel is fired using conventional burners; (2) a reburn zone, where secondary fuel, typically natural gas, is introduced into the boiler; and (3) an OFA burnout zone.

In the primary zone of coal-fired boilers, coal is fired through low-NOx burners (LNBs), at a rate corresponding to approximately 80% to 90% of the total heat input. Natural gas reburn fuel is then injected above the primary combustion zone under fuel-rich conditions at a rate corresponding to approximately 10% to 20% of the total heat input (on a Btu/hour basis). The fuel-rich reburn zone creates a reducing (substoichiometric) region within the boiler where the natural gas, principally methane (CH_4), breaks down to produce hydrocarbon radicals (CH and CH_2). The hydrocarbon radicals react with NO_X produced in the primary combustion zone to form nitrogen (N_2) and water vapor. Because the natural gas is not completely combusted in the reburn zone, gases exiting the reburn zone will contain considerable CO and unburned hydrocarbons; therefore, additional OFA is introduced above the reburn zone to complete the combustion process.

Critical design parameters that affect the feasibility and performance of a gas reburn retrofit system include: (1) baseline NO_X concentration; (2) reburn zone temperature, residence time, and stoichiometry: (3) OFA burnout zone temperature and residence time; and (4) mixing of the reburn fuel and overfire air with the bulk flue gas.

Gas reburn can have a positive impact on NOx emissions; however, in order to make a meaningful prediction of the NO_X removal capabilities at Coyote Unit 1, extensive testing would be required because gas reburn performance is significantly dependent upon boiler operating characteristics. More importantly, the lack of natural gas available at the Coyote Station precludes the ability to test and implement this control option on Coyote Unit 1. For these reasons, gas reburn is not considered an available or technically feasible NOx control technology at Coyote Unit 1.

5.2.2.6 Innovative Technologies

NO_XStar^{TM}

The NO_XStar™ process, also known as selective autocatalytic reduction (SACR), uses a continuous controlled amount of ammonia-based reagent with relatively small amounts of hydrocarbon to reduce NO_X emissions. The hydrocarbon is introduced into the flue gas at the convective pass of the boiler, at elevated temperatures. At the elevated temperatures, the hydrocarbon auto-ignites to form a plasma of free radicals that auto catalyzes the reaction of NH_3 and NO_X to form N_2 and H_2O. The hydrocarbon and ammonia are added through banks of nozzles in the superheat or reheat sections of the boiler. The injection location is determined by the location of the temperature windows for the "plasma creation zone" as well as the reaction zone for the ammonia.

To date, only one full-scale demonstration has been conducted to evaluate the technology on a utility-sized boiler. The process is an emerging NO_X control, and there is limited information available to evaluate its technical feasibility and long-term effectiveness on a large lignite-fired boiler. Potential NO_X removal efficiencies would be a function of NH_3-NO_X mixing, flue gas temperature, flue gas composition, and residence time downstream of the injection lances.

Because this is an emerging technology, extensive design engineering and long-term full scale demonstration testing would be required to evaluate the technical feasibility and effectiveness of the control system on Coyote Unit 1. Detailed design of the lances, mixing, optimization of the reagent supply across the boiler convective pass, flue gas temperatures, and flow distribution would have to be studied. Interference with the tube pendants in the convective pass may also make this more difficult to install. Installing a hydrocarbon distribution grid may present a problem with large boilers because of the span needed to uniformly distribute the reagent, interference with the tube pendants in the convective pass, and an additional booster fan may be needed. For these reasons, NO_XStar™ is not considered an available or technically feasible NOx control technology at Coyote Unit 1.

PerNO$_X$ide

PerNO$_X$ide utilizes hydrogen peroxide (H_2O_2) to reduce NO_X emissions. Hydrogen peroxide is injected into the ducts ahead of the air preheater and oxidizes the NO to NO_2, which is then captured in a downstream FGD system. To date, the technology has only been tested on a pilot-scale, and it has not been demonstrated on any coal-fired boilers. It is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system on Coyote Unit 1. For these reasons, PerNO$_X$ide is not considered an available or technically feasible NOx control technology at Coyote Unit 1.

LoTO$_X$®

The LoTO$_X$ system is a gas-phase, low-temperature oxidation system, wherein ozone is injected into the flue gas stream to oxidize NO and NO_2 to N_2O_5 before being removed in a wet scrubber. This highly oxidized species of NO_X is water-soluble and rapidly reacts with water to form nitric acid. The conversion of NO_X to nitric acid occurs as the N_2O_5 contacts liquid sprays in the scrubber. The nitric acid would react with the alkali compounds in the scrubber and would be eliminated via the scrubber waste and byproduct streams. The LoTO$_X$ system requires on-demand ozone generation from a liquid oxygen supply.

The LoTO$_X$ system has been successfully applied in refinery applications; however, there are no full scale installations on coal-fired boilers. According to the control system vendor, a demonstration test was performed on a 25-MW coal-fired boiler which showed effective NO_X removal. However, it is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system on Coyote Unit 1. As such, LoTO$_X$ is not considered an available or technically feasible NOx control technology at Coyote Unit 1.

Water Injection

The principle behind this technology is to inject an atomized water spray into the high-NO_X production zones of a cyclone burner or in the core of the flame for other furnaces. The water spray reduces the temperature and results in lower thermal NO_X production within this combustion zone. Developers claim that water injection through burners used in tangential-fired and wall-fired units will also reduce flame temperatures and lower thermal NO_X production. However, to date only bench-scale test results are available to evaluate this technology's effectiveness in coal-fired applications. Extensive design engineering, pilot-scale testing, and long-term full scale demonstration testing would be required to evaluate the technical feasibility and effectiveness of the control system on Coyote Unit 1.

Water injection has been used to control the formation of thermal NOx in combustion turbine applications. However, there is insufficient experience and demonstration data in coal-fired applications. As such, water injection is not considered an available or technically feasible NOx control technology at Coyote Unit 1.

5.2.2.7 Selective Catalytic Reduction

SCR is a process by which ammonia reacts with nitric oxide (NO) and nitrogen dioxide (NO_2), collectively NOx, in the presence of a catalyst to reduce the NO_X to nitrogen (N_2) and water. SCR technology has been applied to NO_X-bearing flue gases generated from power generating facilities burning various types of coal, including bituminous, subbituminous, and Texas lignite. The principal reactions resulting in NO_X reduction are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NO_2 + 8NH_3 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

Because these reactions proceed slowly at typical boiler exit gas temperatures of a coal-fired steam electric generating unit, a catalyst is used to increase the reaction rate between NO_X and ammonia. Depending on the specific constituents in the flue gas, a typical temperature range of 550°F to 780°F is necessary to achieve normal performance of the catalyst. For the typical coal-fired boiler, optimal performance will be in the range of approximately 650°F to 750°F.

In general, there are three candidate SCR configurations that can be employed on coal-fired steam electric generating units. The SCR configuration designations generally describe the location of the SCR reaction vessel in relation to other post-combustion air quality control systems. Candidate SCR configurations include:

- High-dust configuration
- Low-dust configuration
- Tail-end configuration

Each of these configurations is described below as they would be applied at Coyote Unit 1.

High-Dust Configuration

In a high-dust configuration, the SCR reactor is located in the flue gas stream between the economizer outlet and the air heater inlet. This configuration locates the SCR within the inherently optimal temperature range environment for NOx reduction (i.e., 650°F to 750°F); however, flue gas characteristics at the economizer outlet can also have detrimental effects on the SCR catalyst. As an example, the high-dust SCR configuration exposes the SCR catalyst to high levels of fly ash loading. High levels of fly ash can result in significant erosion of the catalyst, resulting in more frequent cleaning cycles and catalyst replacement. A second major concern with the high-dust configuration at Coyote Unit 1 is the presence of high levels of sodium (both in the vapor-phase and as submicron aerosols) in the North Dakota lignite-derived flue gas. Sodium is a known SCR catalyst poison, and also affects the adhesive and cohesive characteristics of the fly ash, which in turn, would have an adverse effect on the SCR catalyst and reactor vessel.

SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation) or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition). Loss of catalyst activity through thermal degradation or poisoning is permanent, and reactivity can only be restored by replacing the catalyst.

In a North Dakota lignite application, SCR catalyst poisoning is expected to result from the presence of trace elements and strong alkaline substances in flue gas, including sodium (Na), potassium (K), and calcium (Ca). Alkaline metals can chemically attach to active catalyst pore sites and cause deactivation. Sodium and potassium are of prime concern especially in their water-soluble forms, which are more mobile and can penetrate into the catalyst pores. Earth metals, especially calcium, can react with SO_3 absorbed within the catalyst to form $CaSO_4$ and blind the catalyst.

North Dakota lignite contains relatively high levels of organically associated alkali and alkaline-earth elements, including Na, Ca, K, and magnesium. Sodium levels in North Dakota lignite are typically 5 to 20 times higher than sodium levels in bituminous and subbituminous coals, and sodium compounds can represent between 5% and 11% of the ash generated from firing North Dakota lignite. These sodium levels, occurring in both the vapor phase and particulate phase, along with relatively high levels of potassium and calcium, significantly increase the potential for catalyst deactivation, plugging, and erosion. Based on the ash chemistry, a conventional high dust SCR arrangement would likely experience unacceptable catalyst deactivation rates.

To evaluate deactivation rates on a North Dakota lignite-fired boiler, EERC and several utilities and catalyst vendors conducted pilot scale testing at the Coyote Station in 2003-2004. The pilot scale test reactor SCR deployed at the Coyote Station became plugged and the catalyst pores deactivated after 2 months of operation (approximately 1,430 hours). This deactivation rate is significantly faster than the deactivation rate observed on bituminous and subbituminous coal-fired units, which can achieve catalyst life ranging between 10,000 and 30,000 operating hours. The EERC described the deactivation at the Coyote Station as extremely rapid and severe.[26]

NDDH prepared a comprehensive technical feasibility assessment of high dust SCR on lignite-fired boilers during the first planning period.[27] The Department concluded, based on the unique characteristics of North Dakota lignite-derived flue gas, that the high-dust SCR configuration was not a technically feasible or commercially available NOx control option for North Dakota lignite-fired boilers.[28] Reasons upon which NDDH based its conclusion that high-dust SCR was not a technically feasible option for North Dakota lignite-fired boilers included, but were not limit to:[29]

1) North Dakota lignite[30] has a higher organic matter content and contains a higher proportion of alkali metal constituents, especially sodium, than subbituminous coal. Approximately 75% of the total sodium in lignite is associated with the organic fraction of the lignite. During combustion, organic and water-soluble sodium vaporizes; consequently, combustion of the coal leads to higher flue-gas concentrations of alkali metals in vapor form.
2) The unburned or partially burned organic fraction of North Dakota lignite contains more sodium than other coals. Sodium can react with silicate particles causing a “stickiness” quality to the flue gas ash, resulting in increased ash deposition on heat transfer surfaces. Larger particles can fracture from heat-transfer surfaces (a.k.a. popcorn ash) and enter the flue gas stream. Consequently, deposition on surfaces of catalytic reactors occurs and rates of deposition are higher.
3) NOx reduction occurs on the flat surfaces of a catalyst and in pores within the flat surfaces. The pores are open to the flue gas passing through the catalyst reactor. Condensed vapors, alkali sulfates and alkaline-earth oxides and silicates are minute particles (less than 1 microns), which enter pores of the catalyst (a.k.a. plugging) and prevent catalytic reaction with NOx. Residual alkali vapors (Na, K, and Ca) displace hydrogen on fresh catalyst, which prevents catalytic reaction with NOx (a.k.a poisoning) and reacts with

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[26] See, Benson, Steven A., Energy and Environmental Research Center, Ash Impacts on SCR Catalyst Performance, University of North Dakota, Grand Forks, ND.
[27] See, North Dakota State Implementation Plan for Regional Haze, February 24, 2010, Appendix B.5, Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite, July 2009.
[28] Id. at pg. 19.
[29] Findings and conclusions are summarized from the North Dakota Regional Haze SIP, Appendix B.5, pgs. 15-19.
[30] Although the BART determination specifically references Fort Union lignite, the findings would apply to all North Dakota lignites.

sulfate to cause blinding of catalyst surfaces. Pore condensation of sodium also causes catalyst deactivation, which is a major deactivation mechanism. The rate of catalyst deactivation depends on the concentration and form of alkali in the flue gas; higher Na and K accelerate catalyst poisoning, blinding and plugging.

4) During the development of the initial planning period SIP, NDDH found that there were no SCR systems planned, constructed, or operating in the flue gas stream of boilers fired with North Dakota lignite. North Dakota lignite has certain coal characteristics that are uniquely different than Texas or Gulf Coast lignites, such as the larger proportion of organic matter and association of alkali, sodium specifically, with that organic matter.
5) Slipstream SCR reactors of the same design were installed at three power plants to test SCR for NOx emissions control. One of the plants was cyclone fired with North Dakota lignite and the others with subbituminous coal. Deposition on the reactor surface after two months using the lignite was significantly greater; the deposits were rich in sodium, calcium, and sulfur. The tests confirmed catalyst blinding and plugging, but did not provide rates for catalyst deactivation. Tests also indicated that the deposits causing blinding and plugging of pores contained more sodium compared to PRB coal.

Based on a review of SCR installations on coal-fired boilers and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) and the adhesive/cohesive characteristics and potential abrasive qualities of the North Dakota lignite-derived fly ash remain a concern for North Dakota lignite-fired boilers. SCR has not been installed and successfully operated on a North Dakota lignite-fired boiler, and the bench scale and pilot-scale studies needed to better understand ash behavior and catalyst blinding/erosion with North Dakota lignite-derived fly ash, and to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been required or completed. Pilot-scale studies are needed to evaluate these issues to inform the development of advanced catalyst formulations, and to support the engineering and design studies needed to mitigate for potential deactivation routes (e.g., removing soluble alkali compounds from the flue gas and SCR design considerations such as catalyst formulation, catalyst pitch, reactor velocity, and catalyst surface and volume). Pilot-scale tests and engineering/design studies have not advanced since the first planning period's exhaustive analysis.

These issues have not been resolved since the first planning period and remain a significant barrier to the design and successful operation of high dust SCR on North Dakota lignite-fired boilers. The BART Guidelines state that "[a] control technique is considered available…if it has reached the stage of licensing and commercial availability."[31] Commercial availability follows bench scale and laboratory testing and pilot scale testing. Consequently, the BART Guidelines state that "you would not consider technologies in the pilot scale testing stages

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[31] 40 CFR Part 51 Appendix Y, Section D.2.1.

of development as 'available' for purposes of BART review."[32] Furthermore, source owners/operators are not expected to conduct extended trials to learn how to apply a technique on a dissimilar source type.[33] These BART guidelines also apply as a recommendation for the development of the LTS in the second planning period and the four factor analysis.[34] Because there are unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not an available technically feasible NOx control technology for Coyote Unit 1.

Low-Dust Configuration

In the low-dust configuration, the SCR reactor vessel is located in the flue gas stream after the particulate collection device (i.e. ESP or FF). Employing this configuration would represent a relatively low level of exposure to fly ash (with the exception of submicron ash particles), but a potentially high level of vapor-phase alkalis, such as sodium. This configuration can be used on units equipped with particulate control only or units equipped with particulate control followed by a WFGD control system. The existing dry FGD/FF control configuration at Coyote Unit 1 for SO_2 and particulate control would preclude the application of a low-dust SCR configuration since, by definition, the SCR would have to be located downstream of both the dry FGD and FF. At that location the SCR would be more appropriately defined as a tail-end SCR configuration, which is described in more detail in the following section. Because Coyote Unit 1 is equipped with existing dry FGD/FF controls, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered a technically feasible NOx control option for Coyote Unit 1.

Tail-End Configuration

In the tail-end configuration, the SCR reaction vessel is located in the flue gas stream after the particulate and FGD control systems. The potential advantage of a tail-end SCR configuration at Coyote Unit 1 is that the flue gas will have passed through the dry FGD/FF system prior to the SCR catalyst. As such, there is the possibility that the mass transfer mechanism that results in the capture of SO_2 will also capture some of the vapor-phase sodium and the sodium-enriched submicron particles, reducing the risk of catalyst poisoning and/or deactivation.

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[32] Id.
[33] Id.
[34] See, Draft EPA Guidelines, pg. 183.

Successful operation of the tail-end configuration would also require a capital and operating cost-intensive gas-to-gas heat exchanger to reheat the flue gas from approximately 200 °F downstream of the existing FF to approximately 550°F to support the SCR NOx reactions. After the flue gas passes through the SCR (at approximately 550°F), it would pass through the hot side of the gas-to-gas heat exchanger to cool the flue gas to 150°F prior to the exhaust stack. Although this stack gas temperature would be lower than the current stack temperature (190-210°F), it is still higher than the adiabatic saturation temperature of the flue gas (i.e., approximately 135°F). As such, it is likely that the existing stack could be reused without any major modifications.

During the first planning period, NDDH initially concluded, based on preliminary information provided by SCR catalyst vendors, that the tail-end SCR configuration would be a technically feasible option for units firing North Dakota lignite that are subject to BART requirements.[35] However, as part of the Milton R. Young Station (MRYS) NOx BACT determination process, detailed information describing the expected ash characteristics and flue gas characteristics was provided to two SCR catalyst vendors (CERAM Environmental, Inc. (CERAM) and Haldor Topsoe, Inc.). Based on their review of the data, both vendors concluded that they would not be able to provide a catalyst life guarantee for either low-dust or tail-end SCR without pilot-scale testing.[36]

Both vendors also made statements bringing into question the technical feasibility of either low-dust or tail-end SCR. For example, CERAM stated that the high levels of sodium oxide (Na_2O) in the ash for North Dakota lignite are not commonly found in subbituminous and bituminous coals which are fired in boilers equipped with SCR systems, and that it was unaware of any SCR application experience in the industry with the level and form of sodium in the North Dakota lignite-derived MRYS ash.[37]

Based in part on this information provided by SCR design engineering firms and SCR catalyst vendors, NDDH concluded that the use of SCR technology, including low-dust and tail-end SCR, on the lignite-fired MRYS boilers would be technically infeasible. [38]

Based on a review of SCR installations on coal-fired boilers, and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) remain a concern for all North Dakota lignite-fired boilers. Tail-end SCR has not been demonstrated or installed on a North Dakota lignite-fired boiler, and there are still significant technical

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[35] See, North Dakota Regional Haze State Implementation Plan for Regional Haze, February 24, 2010, Appendix B.5, pg. 25.
[36] See, United States v. Minnkota, 831 F. Supp. 2d, at 1116- 1117.
[37] Id., at 1115-1116.
[38] Id., at 1118.

concerns associated with the availability of existing SCR catalysts on a North Dakota lignite-fired unit. Catalyst in a tail-end SCR will still be vulnerable to alkali poisoning, pore pluggage, and premature catalyst deactivation, and it is not known whether the comparatively high levels of soluble sodium and potassium in North Dakota lignite will be effectively removed by the upstream dry FGD/FF. Furthermore, the potential exists for fine particulate remaining in the flue gas to get into the catalyst pores reducing catalyst activity. Pilot-scale studies needed to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been completed.

In order to understand the effect of North Dakota lignite-derived flue gas on the tail-end SCR catalyst, identify potential design solutions, and evaluate the technical feasibility and effectiveness of tail-end SCR at Coyote Unit 1 with any degree of certainty, extended pilot scale testing of the control configuration would be needed. Additionally, because there are unresolved issues associated with catalyst poisoning, it’s unlikely that OTP could obtain a viable commercial offering for tail-end SCR on Coyote Unit 1. Therefore, tail-end SCR is not an available technically feasible NOx control technology.

SCR Summary

During the first planning period NDDH determined that high-dust SCR and tail-end SCR are not available, and thus, not a technically feasible NOx control option for North Dakota lignite-fired boilers. The administrative record developed during the first planning period, including the BART determinations and MRYS BACT analysis, supports the conclusion that high-dust SCR and tail-end SCR are not an available NOx control option for Coyote Unit 1. An evaluation of SCR installations and reported advances in SCR catalysts since the first planning period, coupled with the fact that high-dust SCR and tail-end SCR have not been demonstrated on a North Dakota lignite-fired boiler, and the likelihood that OTP could not obtain a viable commercial offering for tail-end SCR without extended pilot-scale testing, continues to support the conclusion that high-dust SCR and tail-end SCR are not available NOx control technologies. Nevertheless, since tail-end SCR cost data was developed by the NDDH for Coyote Unit 1 in the first planning period[39], even though tail-end SCR is a technically infeasible technology, it will be carried forward to the Four Factor Analysis to evaluate hypothetical cost-effectiveness. Based on controlled NOx emissions achieved in practice at existing bituminous- and subbituminous-fired unit, S&L assumed that the

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[39] See North Dakota State Implementation Plan for Regional Haze, February 24, 2010, Table 9.8. Notably, this cost data was developed prior to the final MRYS BACT determination in which the NDDH concluded tail-end SCR was technically infeasible.

hypothetical tail-end SCR control option could achieve an average controlled NOx emission rate of 0.09 lb/MMBtu.

5.2.2.8 Technical Feasibility Summary

Table 5-10 summarizes the results of the feasibility evaluation of available control options for Coyote Unit 1.

Table 5-10. Technically Feasible NOx Control Options

NOx Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Combustion Optimization	Yes	Tuning to optimize the existing combustion system, including lower the stoichiometry in the cyclone barrels, tracking cyclone combustion stability, and adjusting the SOFA system (while staying within original OEM specifications) is a technically feasible NOx control option.
Selective Non-Catalytic Reduction (SNCR)	Yes	SNCR is considered an available and technically feasible NOx control technology for Coyote Unit 1. Computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NOx emissions is achievable without creating unacceptable operational issues.
Rich Reagent Injection (RRI)	No	RRI is considered an available and technically feasible NOx control option cyclone burners at full load operation; however, at low load operation RRI does not provide effective NOx control. Therefore, RRI alone is not considered an available NOx control option, and will only be evaluated in conjunction with SNCR.
SNCR + RRI	Yes	Coupling RRI and SNCR is considered a technically feasible and commercially available NOx control technology option on Coyote Unit 1. Computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NOx emissions is achievable without creating unacceptable operational issues.
Gas Reburn	No	The lack of natural gas availability at the Coyote Station precludes the ability to test and implement this control option on Coyote Unit 1. Therefore, gas reburn is not considered an available or technically feasible NOx control technology at Coyote Unit 1.
Innovative Technologies: NOxStar™ PerNO$_X$ide LoTO$_X$ Water Injection	No	Innovative NOx control technologies are evaluated in Section 5.2.2.6. In all cases, the technologies have not been demonstrated on a large North Dakota lignite-fired boiler. Extensive testing and design engineering would be required to evaluate the technical feasibility and long-term effectiveness of each innovative control system on Coyote Unit 1. Therefore, the innovative NOx control technologies are not considered available control options and are not technically feasible NOx control options for Coyote Unit 1

NOx Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Selective Catalytic Reduction (SCR):		
High-dust configuration	No	Due to significant unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and based on the finding that engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not and available or technically feasible NOx control technology for Coyote Unit 1.
Low-dust configuration	No	Because Coyote Unit 1 is equipped with existing dry FGD/FF control systems, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered an available or technically feasible NOx control option for Coyote Unit 1.
Tail-end configuration	No	Based on the continued lack of demonstration testing and commercial guarantees, tail-end SCR is considered to be a technically infeasible control option for Coyote Unit 1. Nevertheless, it will be carried forward to the four factor analysis to present hypothetical costs since tail-end SCR was included in the reasonable progress analysis for Coyote Unit 1 during the first planning period.

5.2.3 Evaluate Technically Feasible NO_X Control Options for Effectiveness

The technically feasible NO_X control technologies are listed in Table 5-11 in descending order of control efficiency. Table 5-11 also provides control option-specific NOx emission rates in terms of lb/MMBtu. Emission rates shown in Table 5-11 represent average emission rates that the control options would be expected to achieve during normal operations.

Table 5-11. Evaluate Technically Feasible NO_X Control Options for Effectiveness

Control Technology	NO_X Emission Rate (Note 1) lb/MMBtu	% Reduction from Baseline Emission Rate
Baseline (existing SOFA)	0.46	-
SCR – Tail-End Configuration(Note 2)	0.09	80.3%
SNCR + RRI + Combustion Optimization	0.20	56.2%
SNCR + Combustion Optimization	0.28	38.7%
Combustion Optimization	0.42	8.0%

Note 1. Emission rates shown in Table 5-11 represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis; an additional margin would likely be needed to account for operating margin. Additionally, for control options that include SNCR or RRI, computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NOx emission is achievable without creating unacceptable operational issues.
Note 2. Tail-end SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of tail-end SCR on Coyote Unit 1. Nevertheless, during the initial planning period, tail-end SCR was included in the reasonable progress analysis for Coyote Unit 1, and evaluated the costs and cost-effectiveness of the control system. For consistency with the first planning period, tail-end SCR will be carried forward to the Four Factor Analysis.

6. COSTS OF COMPLIANCE (STATUTORY FACTOR ONE)

The economic analysis performed as part of the Four Factor analysis examines the cost-effectiveness of each technically feasible control technology, on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. For units with existing controls, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual operation and maintenance (O&M) costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of control equipment. Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25%[40] and equipment life of 20 years.[41] Cost effectiveness ($/ton) of a particular control option is simply the annual cost ($/yr) divided by the annual reduction in annual emissions (ton/yr). In addition to cost-effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the incremental cost effectiveness of the more stringent control.

Capital and O&M cost estimates were developed for each of the technically feasible SO_2 and NO_X control options. The Coyote Unit 1 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Unit 1 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on Coyote Unit 1-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the Coyote Unit 1 retrofit technologies as "concept screening" cost estimates generally based on parametric models, judgment, or analogy.

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[40] In an email to the North Dakota Department of Health dated December 18, 2018, EPA recommended use of a 5.25% interest rate. Otter Tail does not necessarily agree that this is an appropriate percentage to use and reserves the right to update and modify this percentage at a later date. Notably, on September 26, 2018 the North Dakota Public Service Commission approved a rate of return for Otter Tail of 7.64% (See https://psc.nd.gov/database/documents/17-0398/226-020.pdf). This ROR represents a total weighted average cost of capital. An interest rate of 5.25% is more representative of the long-term cost of debt, which is only one component of capital structure.

[41] The assumed 20-year equipment life is consistent with the control system equipment life used by NDDH in its evaluation of NO_X and SO_2 control technologies for BART-eligible sources. (see, e.g., ND Regional Haze Final SIP, Appendix C.1, "BART Determination Study for Leland Olds Station Units 1 & 2, Basin Electric Power Cooperative, August 2006, pgs. 64 (NOx controls) and 158 (SO2 controls). See also, ND Regional Haze Final SIP, Appendix C4, "NOx Best Available Control Technology Study for Milton R. Young Station Unit 1, Minnkota Power Cooperative, Inc., October 2006, pg. 3-22).

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, Contractor G&A expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements.[42] Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing dry scrubber and FF control systems.

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

The results of the SO_2 and NO_X control cost evaluations are included below in Sections 6.1 and 6.2.

6.1 ECONOMIC EVALUATION – SO_2 CONTROLS

Table 6-1 presents the capital costs and annual operating costs associated with installing and operating each technically feasible SO_2 control system for Unit 1. Table 6-2 shows the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix B.

Cost estimates were not prepared for the SDA/FF option since the capital and operating costs for the SDA/FF option would be similar to the costs for the CDS/FF option, and the CDS/FF option would likely provide the opportunity to achieve somewhat lower controlled SO_2 emissions (compared to SDA/FF). Therefore, of the two new DFGD system options, only the CDS/FF option was evaluated.

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[42] Variable O&M costs are based on the annual average uncontrolled SO_2 of 2.77 lb/MMBtu

Table 6-1. SO_2 Control Cost Summary ($2018)

SO_2 Control Option	Total Capital Investment $	Annualized Capital Cost $/yr	Annual Operating Cost $/yr	Total Annual Cost $/yr
DSI + Existing FGD	$23,765,000	$1,948,000	$12,329,000	$14,277,000
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	$526,000	$43,000	$2,449,000	$2,492,000
DSI + FGD Operational Improvements	$24,292,000	$1,991,000	$14,779,000	$16,770,000
FGD Upgrades - Replacing Existing Absorbers with New Absorber	$127,823,000	$10,475,000	$6,332,000	$22,197,000^(Note 1)
Dry FGD (CDS) + Existing FF	$242,647,000	$19,885,000	$22,361,000	$42,246,000
Wet FGD	$324,742,000	$26,613,000	$23,001,000	$49,614,000

Note 1. Total annual cost for “FGD Upgrades - Replacing Existing Absorbers with New Absorber” option includes annualized lost revenue due to extended outage and replacement power required for installation ($5,390,000).

Table 6-2. SO_2 Emissions Control System Cost Effectiveness ($2018)

SO_2 Control Option	Total Annual Cost $/yr	Expected Emission Reduction tons SO_2/yr	Average Annual Cost Effectiveness (Note 1) $/ton SO_2 removed	Incremental Annual Cost Effectiveness (Note 2, 3) $/ton SO_2 removed
Baseline (Existing DFGD/FF)	---	---	---	---
DSI + Existing FGD	$14,277,000	4,131	$3,456	
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	$2,492,000	5,354	$465	n/a
DSI + FGD Operational Improvements	$16,770,000	7,952	$2,109	$5,496
FGD Upgrades - Replacing Existing Absorbers with New Absorber	$22,197,000	8,563	$2,592	$8,879
Dry FGD (CDS) + Existing FF	$42,246,000	11,619	$3,636	$6,560
Wet FGD	$49,614,000	12,078	$4,108	$16,072

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.
Note 2. Incremental cost effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.
Note 3. "n/a" indicates that the next most effective control option is "inferior" (i.e., higher cost for less control)

Table 6-2 indicates that the average annual cost effectiveness of the technically feasible SO_2 control options for Unit 1 range from $465 per ton (FGD Operation Improvements) to $4,108 per ton (Wet FGD). Costs associated with equipment procurement and installation, and annual operating costs all have a significant impact on the cost of the SO_2 control systems.

Annual costs of the DSI system exceed the costs of the FGD Operational Improvements option, and the DSI system achieves lower SO_2 reductions. Therefore, the DSI system is an "inferior" control option.

The FGD Operational Improvements option would require the relatively low capital investment for upgrading the existing atomizer wheel and an increase in operating costs primarily due to increased reagent usage. This option will achieve approximately 41% SO_2 reduction from the baseline levels, resulting in a cost effectiveness of $465 per ton.

The option to incorporate FGD Operational Improvements and install a DSI system will achieve approximately 61% SO_2 reduction from the baseline. Capital costs are primarily attributed to the DSI equipment, and high operating costs are due to a significant increase in hydrated lime use. The cost effectiveness of the DSI + FGD Operational Improvements option is $2,109 per ton. Comparing this option to the next most effective control option, FGD Operational Improvements (without DSI), the incremental costs effectiveness is $5,496 per ton.

Replacing the existing absorber modules with new absorber modules will require Coyote Unit 1 to be taken off-line for approximately 12 months. In addition to capital and operating costs, the Coyote Station will incur costs associated with lost production and purchase of replacement power. The cost effectiveness of the FGD Upgrade - Replacing Existing Absorbers with New Absorber option is $2,592 per ton. Comparing this option to the next most effective control option, DSI + FGD Operational Improvements, the incremental cost effectiveness is $8,879 per ton.

The installation of new Dry FGD (CDS) or new Wet FGD systems are high capital and annual operating cost options. The cost effectiveness for these options are $3,636 per ton (Dry FGD) and $4,108 per ton (Wet FGD). The incremental cost of installing a Dry FGD system, compared to FGD Upgrades, is $6,560 per ton. The incremental cost of installing a Wet FGD system, compared to a Dry FGD system, is $16,072 per ton.

6.2 ECONOMIC EVALUATION – NO_X CONTROLS

Table 6-3 presents the capital costs and annual operating costs associated with building and operating each control system. Table 6-4 shows the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix C.

Table 6-3. NO_X Control Cost Summary ($2018)

NO_X Control Option	Total Capital Investment $	Annual Capital Cost $/yr	Annual Operating Cost $/yr	Total Annual Cost $/yr
Combustion Optimization	$0	$0	$0	$0
SNCR + Combustion Optimization	$19,840,000	$1,626,000	$3,128,000	$4,754,000
SNCR + RRI + Combustion Optimization	$25,895,000	$2,122,000	$6,495,000	$8,617,000
SCR – Tail-End Configuration	$254,128,160	$20,826,000	$20,442,000	$41,268,000

Table 6-4. NO_X Emissions Control System Cost Effectiveness ($2018)

NO_X Control Option	Total Annual Cost $/yr	Expected Emission Reduction tons NO_X/yr	Average Annual Cost Effectiveness (Note 1) $/ton NO_X removed	Incremental Annual Cost Effectiveness (Note 2) $/ton NO_X removed
Baseline (Existing SOFA)	---	---	---	---
Combustion Optimization	$0	589	$0	$0
SNCR + Combustion Optimization	$4,754,000	2,847	$1,670	$2,105
SNCR + RRI + Combustion Optimization	$8,617,000	4,137	$2,083	$2,994
SCR – Tail-End Configuration	$41,268,000	5,912	$6,981	$18,402

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.
Note 2. Incremental cost effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

Table 6-4 indicates that the average annual cost effectiveness of the technically feasible NO_X control options for Unit 1 range from $0 per ton (Combustion Optimization) to $6,981 per ton (TE-SCR) NO_X removed.

The Combustion Optimization option is expected to achieve 8% NO_X reduction from baseline levels without impact to boiler performance. This option can be implemented without additional capital or operating costs; therefore, the cost effectiveness is $0 per ton.

Installation of an SNCR system is expected to achieve approximately 39% NO_X reduction. The cost effectiveness of this option is $1,670 per ton. Compared the next most effective option, Combustion Optimization, the incremental cost effectiveness is $2,105 per ton.

The option to install an SNCR system combined with RRI would achieve approximately 56% NO_X reduction. Compared to installing SNCR alone, this option incurs additional capital costs for the RRI system and higher operating costs primarily due to increased urea consumption. The cost effectiveness of the SNCR + RRI option is $2,083 per ton, and the incremental cost compared to SNCR alone is $2,994 per ton.

Tail-end SCR system costs have been included to remain consistent with the reasonable progress analysis for Coyote Unit 1 during the initial planning period (i.e., evaluating the control system for costs and cost effectiveness). Based on preliminary cost estimates, the cost effectiveness of a tail-end SCR system is $6,981 per ton. Compared to the next most effective control option, SNCR + RRI, the incremental cost effectiveness is $18,402 per ton.

7. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO)

The time necessary for compliance is generally defined as the time needed for full implementation of the technically feasible control options. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. If reasonable progress measures are required at Coyote Station for the Reginal Haze second planning period, the anticipated compliance deadline would be July 1, 2028.[43] However, this compliance deadline must provide a reasonable amount of time for the source to implement the control measure.

Table 7-1 and Table 7-2 include estimated timeframes needed to implement each of the technically feasible control options. Notably, the estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve North Dakota's SIP.

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[43] For the first planning period, on March 14, 2011 the North Dakota Department of Health issued permit to construct number PTC10008 that required Coyote Station to meet the approved reasonable progress limitation by July 1, 2018.

Table 7-1. SO_2 Emissions Control System Implementation Schedule

SO_2 Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
DSI + Existing FGD	6	6	6	18
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0	0	0	0
DSI + FGD Operational Improvements	6	6	6	18
FGD Upgrades - Replacing Existing Absorbers with New Absorber	8	12	12	32
Dry FGD (CDS) + Existing FF	12	20	18	50
Wet FGD	12	22	22	56

Table 7-2. NO_X Emissions Control System Implementation Schedule

NO_X Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
Combustion Optimization	0	0	0	0
SNCR + Combustion Optimization	10	6	6	22
SNCR + RRI + Combustion Optimization	10	6	6	22
SCR – Tail-End Configuration	10	18	24	52

8. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE)

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal.

8.1 ENVIRONMENTAL IMPACTS

Coyote Unit 1 is currently equipped with SOFA for NOx control and dry scrubber technology for SO_2 control. The hydrated lime reactant used in a dry scrubbing system reacts with SO_2 in the flue gas to form calcium sulfate and calcium sulfite solids. The solids are captured in the existing FF particulate control system and either returned to the system for reuse or removed from the system as nonhazardous solid waste. The existing dry scrubbing system also requires water to hydrate the lime prior to injection into the reaction modules. Based on the design of the control system, Coyote Unit 1 currently uses approximately 465 gpm of water to hydrate the lime (at full load). Collateral environmental impacts associated with the existing Coyote Unit 1control systems include water consumption and increased solid waste generation. There were no collateral impacts associated with the SOFA system.

Based on a review of potential non-air quality environmental impacts, no significant collateral environmental impacts were identified for any of the SO_2 and NOx control options included in this evaluation, with the exception, potentially, of the WFGD, DSI, TE-SCR and SNCR/RRI options. No significant non-air quality environmental impacts were identified for the options that include replacing the existing scrubber modules with new scrubber modules, FGD operational improvements/upgrades or combustion optimization. Collateral environmental impact identified for the sorbent injection control option includes an increase in the solid waste generation. The sorbent injection system will increase the solid waste generated by approximately 50% (47,000 lb/hr to 70,000 lb/hr).

There are a number of potential non-air quality environmental impacts associated with the WFGD control option. Unlike dry scrubbing systems that generate a dry FGD byproduct, WFGD systems generate a liquid calcium sulfate by-product that must be dewatered prior to disposal. WFGD control systems can be designed with forced oxidation that results in a gypsum-grade by-product that can be sold into the local gypsum market. If an adequate gypsum market is not available, the gypsum by-product will require disposal. WFGD control systems also generate a wastewater stream that must be treated prior to discharge. WFGD wastewaters typically consist of a saturated solution of calcium sulfate, calcium sulfite, and sodium chloride, with trace amounts of fly ash and unreacted limestone. Traces of metal ions may also be present due to fly ash carryover from the flue gas to the WFGD scrubber liquor. WFGD wastewater treatment systems typically require calcium sulfate/sulfite desaturation, heavy metals precipitation, coagulation/precipitation, and sludge dewatering. Treated wastewater is typically discharged to surface water pursuant to an NPDES discharge permit, and solids are typically disposed of in a landfill.

WFGD systems also require significantly more water than the dry systems. Based on design criteria for wet and dry FGD control systems, WFGD systems typically require approximately 25-30% more water than a similarly sized DFGD control system. This would increase water consumption at Coyote Unit 1 on average approximately 130 gpm. Water consumption is an important factor when assessing potential non-air quality environmental impacts at facilities located in North Dakota, and could represent a significant non-air quality collateral environmental impact.

In addition, the TE-SCR, SNCR and SNCR/RRI control options have a number of collateral impacts. The TE-SCR catalyst oxidizes some of the SO_2 to SO_3 in addition to catalyzing the reaction between NOx and ammonia. There could be the potential for increased SO_3 emissions with the use of a TE-SCR. The SO_3 will react with the moisture in the stack to form H_2SO_4 emissions. In addition both the TE-SCR and SNCR, SNCR/RRI options utilize ammonia as the reagent for the reactions with NOx to occur. There will be some ammonia slip emission from a TE-SCR in the range of 2 ppm. However the ammonia slip emission from a SCR or SNCR/RRI control technology will be significantly higher at 10 ppm. Ammonia slip emissions from the SNCR/RRI options will likely end up in the dry FGD solids, however there is no means to capture the ammonia slip emissions from the TE-SCR since it is installed prior to the stack.

8.2 ENERGY IMPACTS

Options that include replacing the existing Unit 1 dry scrubbing system with a CDS/FF or WFGD system or adding a TE-SCR will increase pressure drop through the control systems, increase auxiliary power requirements, and adversely affect the unit' net plant heat rate (Btu heat input per MW_{Net} output).[44] Consequently, heat input to the

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[44] Heat rate represents the amount of heat input to the boiler (Btu) required to generate one megawatt (MW) net electric output and is reported as Btu/MW_{Net}.

boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease.

Although several of the control options have energy impacts, none of the impacts are considered significant enough as to disqualify any of the options from consideration in the four factor analysis. In order to account for potential energy impacts associated with each option, the auxiliary power cost associated with operating the control systems have been included as an annual operating cost in the economic impact assessment.

8.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY

A summary of the environmental and energy impact analysis is provided in Table 8-1.

Table 8-1. Summary of Energy and Non-Air Quality Environmental Impacts

Control Option	Collateral Environmental & Energy Impacts
Baseline	➢ Coyote Unit 1 is currently equipped with dry scrubbing / FF control systems. Existing collateral environmental and energy impacts include: ➢ Solid FGD by-product management and disposal ➢ Increased water consumption ➢ Increased auxiliary power requirements and heat rate penalty
<u>SO_2 Control Options</u>	
Replace existing DFGD with New WFGD control system	➢ Increased water consumption ➢ Wet by-product that requires dewatering prior to disposal ➢ FGD wastewater treatment & discharge ➢ Increased auxiliary power requirements and heat rate penalty
Replace existing DFGD with New CDS/FF Control System	➢ Increased auxiliary power requirements and heat rate penalty ➢ Increased solid FGD by-product management and disposal
Replace existing dry scrubber modules with New DFGD modules while keeping existing FF	➢ Requires extended (approximately 12-month) outage of Coyote Unit 1 to demolish and replace the existing scrubber modules
Dry Sorbent Injection	➢ Increased solid FGD by-product management and disposal ➢ Increased auxiliary power requirements and heat rate penalty
<u>NOx Control Options</u>	
Selective Catalytic Reduction (SCR) - Tail End Configuration	➢ Increased auxiliary power requirements and heat rate penalty ➢ Increased ammonia slip emissions ➢ Potential increase in SO3 emissions
SNCR or SNCR + RRI	➢ Increased ammonia slip emissions ➢ Increased auxiliary power requirements and heat rate penalty

9. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR)

The evaluation of technically feasible NO_X and SO_2 controls options should consider the source's "remaining useful life" in determining the costs of compliance. The remaining useful life is the difference between the date that controls would be put in place and the date that the facility permanently ceases operation. If the remaining useful life of the unit is shorter than the useful life of a particular control option, the remaining useful life should be used to annualize costs. If the remaining useful life exceeds the useful life of the control options, the remaining use life has no effect on the cost evaluation.

The cost of compliance for each control option (see Section 6) currently calculates the annual capital recovery cost by multiplying the total capital investment by a CRF from a formula based on a 20-year equipment lifetime. The Coyote Station owners have not identified dates for the remaining useful life of the unit before the end of what would otherwise be the useful life of the control measures that were evaluated for Coyote Unit 1. Thus, the 20-year equipment life of the control measures was used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness.

10. FOUR-FACTOR ANALYSIS SUMMARY

At the request of NDDH, a four factor analysis was prepared for Coyote Unit 1. The analysis identified technically feasible SO_2 and NO_X control options for Unit 1, and evaluated each of the control measures for the following four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

The cost of compliance evaluation prepared for SO_2 controls indicates that the average annual cost effectiveness ranges from $465 per ton (FGD Operation Improvements) to $4,108 per ton (Wet FGD). The evaluation prepared for NO_X controls options indicates that that the average annual cost effectiveness ranges from $0 per ton (Combustion Optimization) to $6,981 per ton (TE-SCR) NO_X removed.

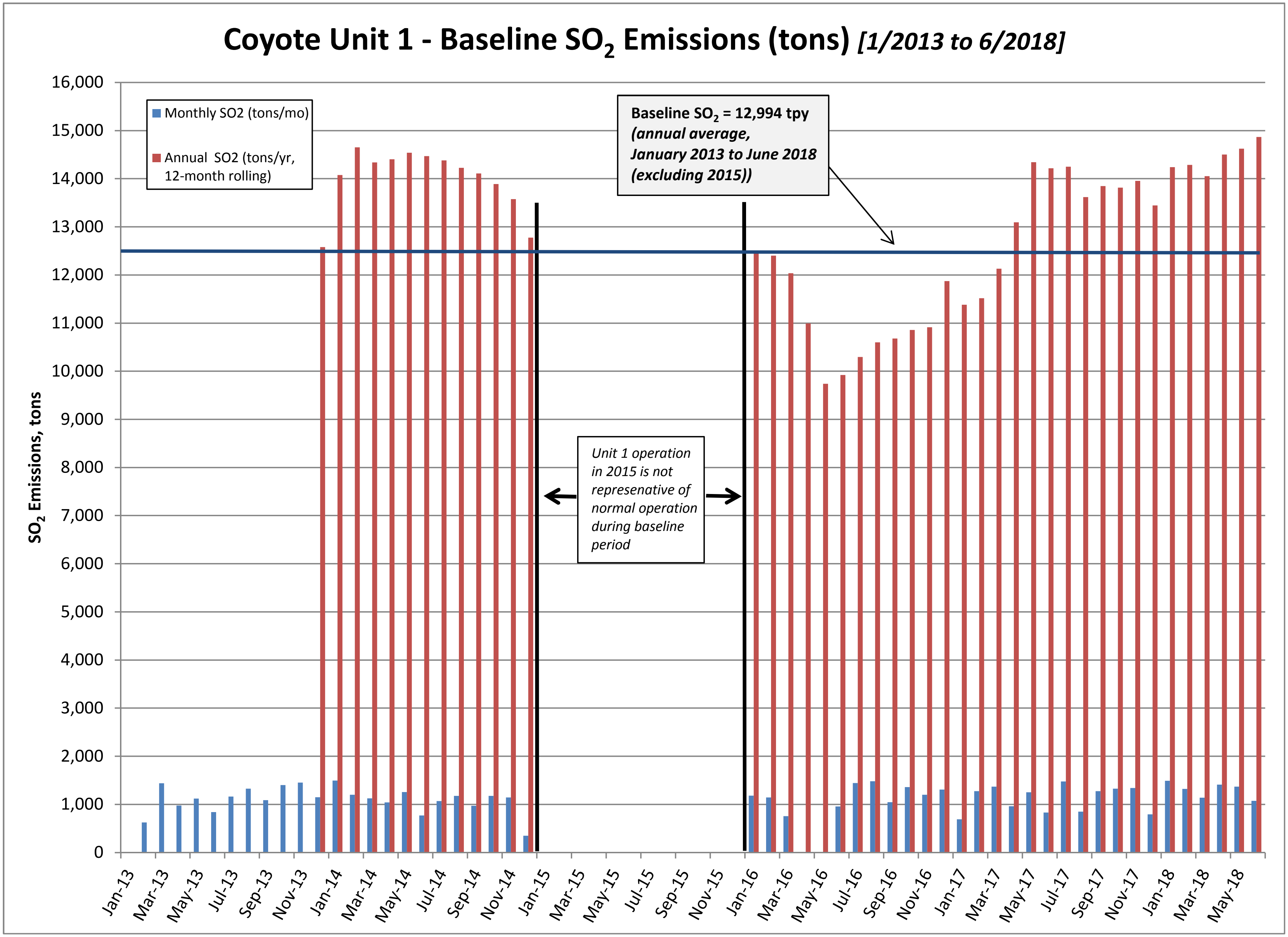
The time necessary for compliance for the SO_2 control options ranges from 0 months (FGD operational improvements) to 56 months (new wet FGD system). For NO_X control options, the time necessary for compliance ranges from 0 months (combustion optimization) to 46 months (tail-end SCR).

An evaluation of energy impacts indicates that certain control options (e.g., new FGD systems, TE-SCR) will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts include an increase in the solid waste generation with DSI, as well as potential incremental increase in fugitive dust emissions associated with sorbent deliveries to the facility.

Regarding remaining useful life, the Coyote Station owners have not identified dates for the remaining useful life of the unit before the end of what would otherwise be the 20-year useful life of the control measures that were evaluated for Coyote Unit 1. Therefore, the remaining useful life did not impact the annualized cost of control under the current regulatory framework.

APPENDIX A

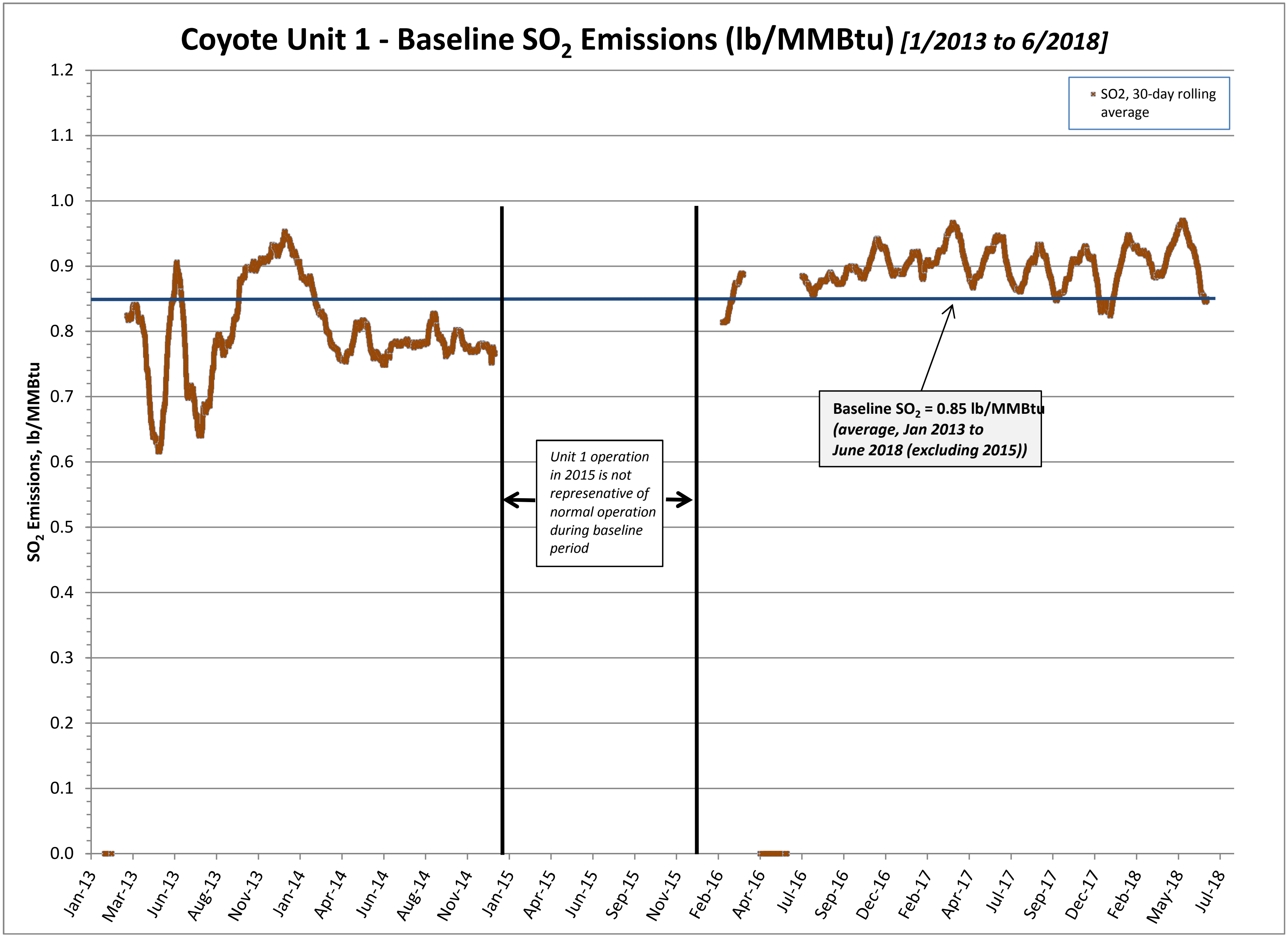
COYOTE UNIT 1 BASELINE EMISSIONS



Coyote Unit 1 - Baseline SO_2 Emissions (tons) *[1/2013 to 6/2018]*

Baseline SO_2 = 12,994 tpy
(annual average,
January 2013 to June 2018
(excluding 2015))

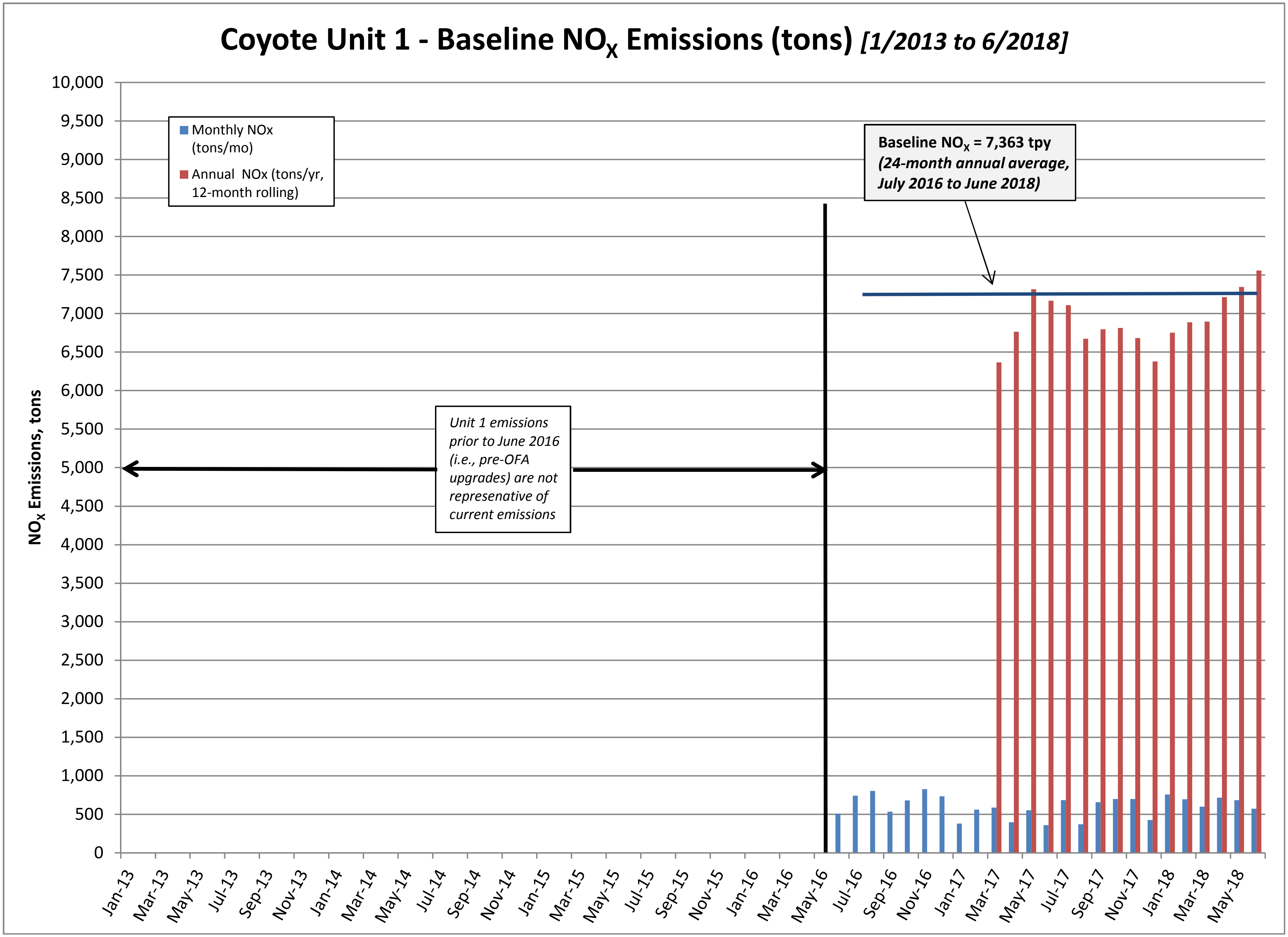
Unit 1 operation in 2015 is not represenative of normal operation during baseline period



Coyote Unit 1 - Baseline SO_2 Emissions (lb/MMBtu) ***[1/2013 to 6/2018]***

Unit 1 operation in 2015 is not represenative of normal operation during baseline period

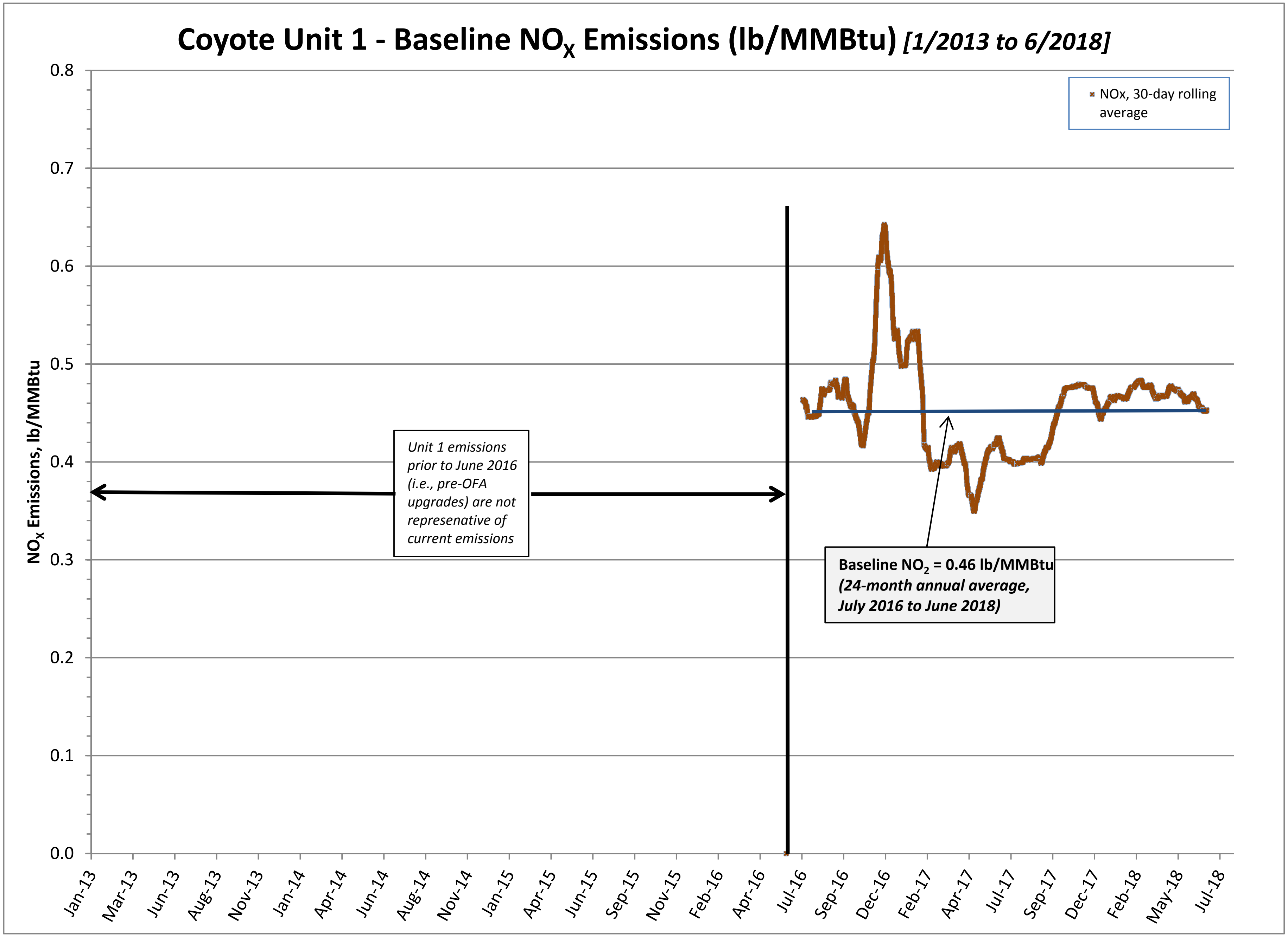
Baseline SO_2 = 0.85 lb/MMBtu
(average, Jan 2013 to June 2018 (excluding 2015))



Coyote Unit 1 - Baseline NO_X Emissions (tons) *[1/2013 to 6/2018]*

Baseline NO_X = 7,363 tpy
(24-month annual average, July 2016 to June 2018)

Unit 1 emissions prior to June 2016 (i.e., pre-OFA upgrades) are not represenative of current emissions



Coyote Unit 1 - Baseline NO_X Emissions (lb/MMBtu) *[1/2013 to 6/2018]*

Unit 1 emissions prior to June 2016 (i.e., pre-OFA upgrades) are not represenative of current emissions

Baseline NO_2 = 0.46 lb/MMBtu
(24-month annual average, July 2016 to June 2018)

APPENDIX B

SO_2 CONTROL COST EFFECTIVENESS ESTIMATES

Coyote Station Unit 1
SO_2 Control Summary

Table 1. Coyote Unit 1 Operating Parameters

Parameter		Unit	Notes
Power Output	427	MW-net	Nominal
Annual Heat Input	30,562,287	MMBtu/yr	24-month annual average for period July 2016 to June 2018.
Average Capacity Factor	72%	%	Based on annual average MW-h during the baseline period.

Table 2. Control Effectiveness

Control Technology	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)
Wet FGD	92.9%	917	0.06	12,078
Dry FGD (CDS) + FF	89.4%	1,375	0.09	11,619
FGD Upgrades - Replace Existing Absorbers with New Absorber	65.9%	4,432	0.29	8,563
DSI + FGD Operational Improvements	61.2%	5,043	0.33	7,952
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	41.2%	7,641	0.50	5,354
DSI + Existing FGD	31.8%	8,863	0.58	4,131
Baseline (DFGD/FF)		**12,994**	0.85	0

Table 3. Cost Effectiveness

Control Technology	Emissions (tpy)	Tons of SO_2 Removed (tpy)	Total Capital Requirement ($)	Annualized Capital Cost ($/year)	Annualized Outage Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline (DFGD/FF)	12,994	0	--	--		--	--		
DSI + Existing FGD	8,863	4,131	$23,765,000	$1,948,000	$0	$12,329,000	$14,277,000	**$3,456**	
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	7,641	5,354	$526,000	$43,000	$0	$2,449,000	$2,492,000	**$465**	
DSI + FGD Operational Improvements	5,043	7,952	$24,292,000	$1,991,000	$0	$14,779,000	$16,770,000	**$2,109**	$5,496
FGD Upgrades - Replace Existing Absorbers with New Absorber	4,432	8,563	$127,823,000	$10,475,000	$5,390,000	$6,332,000	$22,197,000	**$2,592**	$8,879
Dry FGD (CDS) + FF	1,375	11,619	$242,647,000	$19,885,000	$0	$22,361,000	$42,246,000	**$3,636**	$6,560
Wet FGD	917	12,078	$324,742,000	$26,613,000	$0	$23,001,000	$49,614,000	**$4,108**	$16,072

Coyote Station Unit 1
SO_2 Control Cost Evaluation
DSI + Existing FGD

SO_2 Control Option Description	**DSI + Existing FGD**
Baseline SO_2 Emissions, lb/MMBtu	0.85
Post Upgrade SO_2 Emissions, lb/MMBtu	0.58
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$10,884,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FG Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$544,000	5% of Equipment/Material Cost
Freight	$544,000	5% of Equipment/Material Cost
Total PEC	$11,972,000	
Direct Installation Costs		
Labor	$2,886,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$72,000	2.5% of Labor
Mobilization / Demobilization	$43,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$144,000	5% of Labor
Total Direct Installation Costs	$3,145,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$15,117,000**	
Indirect Costs		
Contractor's General and Administration Expense	$1,512,000	10% of Total Direct Costs
Contractor's Profit	$756,000	5% of Total Direct Costs
Dry FG Engineering, Procurement, & Project Services	$1,209,000	8% of Total Direct Costs
Construction Management/Field Engineering	$605,000	4% of Total Direct Costs
S-U / Commissioning	$227,000	1.5% of Total Direct Costs
Spare Parts	$76,000	0.5% of Total Direct Costs
Owner's Cost	$302,000	2% of Total Direct Costs
Total Indirect Costs	$4,687,000	
Contingency	**$3,961,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$23,765,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$1,948,000**	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Increased Waste Disposal Cost	$1,991,000	Based on disposal rate of $32.46 per ton.
Hydrated Lime Reagent Cost	$8,993,000	Based on hydrated lime reagent cost of $187 per ton.
Increased Auxiliary Power Cost	$115,000	Based on auxiliary power cost of $23 per MWh
Increased bag and cage replacement	$52,000	Based on bag and cage cost of $135 per bag
Total Variable O&M Costs	$11,151,000	
Fixed O&M Costs		
Additional Operators per shift	0	Assume no additional operators
Operating Labor	$0	N/A
Supervisor Labor	$0	N/A
Maintenance Materials	$227,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$227,000	
Indirect Operating Cost		
Property Taxes	$238,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$238,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$475,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$951,000	
Total Annual Operating Cost	**$12,329,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$1,948,000	
Annual Operating Cost	$12,329,000	
Total Annual Cost	**$14,277,000**	

Coyote Station Unit 1
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio**
Baseline SO_2 Emissions, lb/MMBtu	0.85
Post Upgrade SO_2 Emissions, lb/MMBtu	0.50
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$218,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FG Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$11,000	5% of Equipment/Material Cost
Freight	$11,000	5% of Equipment/Material Cost
Total PEC	$240,000	
Direct Installation Costs		
Labor	$87,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$2,000	2.5% of Labor
Mobilization / Demobilization	$1,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$4,000	5% of Labor
Total Direct Installation Costs	$94,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$334,000**	
Indirect Costs		
Contractor's General and Administration Expense	$33,000	10% of Total Direct Costs
Contractor's Profit	$17,000	5% of Total Direct Costs
Dry FG Engineering, Procurement, & Project Services	$27,000	8% of Total Direct Costs
Construction Management/Field Engineering	$13,000	4% of Total Direct Costs
S-U / Commissioning	$5,000	1% of Total Direct Costs
Spare Parts	$2,000	0.5% of Total Direct Costs
Owner's Cost	$7,000	2% of Total Direct Costs
Total Indirect Costs	**$104,000**	
Contingency	**$88,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$526,000**	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$43,000**	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Increased Waste Disposal Cost	$711,000	Based on disposal rate of $32.46 per ton.
Increased Lime Reagent Cost	$1,706,000	Based on lime reagent cost of $128 per ton.
Increased Auxiliary Power Cost	$4,000	Based on auxiliary power cost of $23 per MWh
Increased Water Cost	$2,000	Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs	$2,423,000	
Fixed O&M Costs		
Additional Operators per shift	0	Assume no additional operators
Operating Labor	$0	N/A
Supervisor Labor	$0	N/A
Maintenance Materials	$5,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$5,000	
Indirect Operating Cost		
Property Taxes	$5,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$5,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$11,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$21,000	
Total Annual Operating Cost	**$2,449,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$43,000	
Annual Operating Cost	$2,449,000	
Total Annual Cost	**$2,492,000**	

Coyote Station Unit 1
SO$_2$ Control Cost Evaluation
DSI + FGD Operational Improvements

SO$_2$ Control Option Description	**DSI + FGD Operational Improvements**
Baseline SO$_2$ Emissions, lb/MMBtu	0.85
Post Upgrade SO$_2$ Emissions, lb/MMBtu	0.33
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$11,102,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGI Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$555,000	5% of Equipment/Material Cost
Freight	$555,000	5% of Equipment/Material Cost
Total PEC	$12,212,000	
Direct Installation Costs		
Labor	$2,973,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$74,000	2.5% of Labor
Mobilization / Demobilization	$45,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$149,000	5% of Labor
Total Direct Installation Costs	$3,241,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$15,453,000**	
Indirect Costs		
Contractor's General and Administration Expense	$1,545,000	10% of Total Direct Costs
Contractor's Profit	$773,000	5% of Total Direct Costs
Dry FGI Engineering, Procurement, & Project Services	$1,236,000	8% of Total Direct Costs
Construction Management/Field Engineering	$618,000	4% of Total Direct Costs
S-U / Commissioning	$232,000	1.5% of Total Direct Costs
Spare Parts	$77,000	0.5% of Total Direct Costs
Owner's Cost	$309,000	2% of Total Direct Costs
Total Indirect Costs	**$4,790,000**	
Contingency	**$4,049,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$24,292,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$1,991,000**	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Increased Waste Disposal Cost	$2,702,000	Based on disposal rate of $32.46 per ton.
Increased Lime Reagent Cost	$1,706,400	Based on lime reagent cost of $128 per ton.
Hydrated Lime Reagent Cost	$8,993,000	Based on hydrated lime reagent cost of $187 per ton.
Increased Auxiliary Power Cost	$119,000	Based on auxiliary power cost of $23 per MWh
Increased bag and cage replacement	$52,000	Based on bag and cage cost of $135 per bag
Total Variable O&M Costs	$13,574,700	
Fixed O&M Costs		
Additional Operators per shift	0	Assume no additional operators
Operating Labor	$0	N/A
Supervisor Labor	$0	N/A
Maintenance Materials	$232,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$232,000	
Indirect Operating Cost		
Property Taxes	$243,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$243,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$486,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$972,000	
Total Annual Operating Cost	**$14,779,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$1,991,000	
Annual Operating Cost	$14,779,000	
Total Annual Cost	**$16,770,000**	

Coyote Station Unit 1
SO_2 Control Cost Evaluation
FGD Upgrades - Replace Existing Absorbers with New Absorber

SO_2 Control Option Description	**FGD Upgrades - Replace Existing Absorbers with New Absorber**
Baseline SO_2 Emissions, lb/MMBtu	0.85
Post Upgrade SO_2 Emissions, lb/MMBtu	0.29
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$42,282,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGD Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$2,114,000	5% of Equipment/Material Cost
Freight	$2,114,000	5% of Equipment/Material Cost
Total PEC	$46,510,000	
Direct Installation Costs		
Labor	$31,929,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$798,000	2.5% of Labor
Mobilization / Demobilization	$479,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$1,596,000	5% of Labor
Total Direct Installation Costs	$34,802,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$81,312,000**	
Indirect Costs		
Contractor's General and Administration Expense	$8,131,000	10% of Total Direct Costs
Contractor's Profit	$4,066,000	5% of Total Direct Costs
Dry FGD Engineering, Procurement, & Project Services	$6,505,000	8% of Total Direct Costs
Construction Management/Field Engineering	$3,252,000	4% of Total Direct Costs
S-U / Commissioning	$1,220,000	1.5% of Total Direct Costs
Spare Parts	$407,000	0.5% of Total Direct Costs
Owner's Cost	$1,626,000	2% of Total Direct Costs
Total Indirect Costs	**$25,207,000**	
Contingency	**$21,304,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$127,823,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$10,475,000**	
OUTAGE COSTS		
Outage Costs		
Standard Outage Duration (weeks/yr)	8	
Outage Duration due to Retrofit (weeks/yr)	52	
Lost Revenue due to Retrofit	**$51,979,000**	
Replacment Power Cost due to Retrofit	**$13,786,000**	Based on the difference in cost for Coyote to generate power at $23.00 per MWh and cost for Coyote to purchase replacement power.
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$	0.0820	20 year life of equipment (years) @ 7% interest.
Annualized Outage Costs (CRF x TCI)	**$5,390,000**	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Total Variable O&M Costs	$0	No incremental increases in variable O&M for absorber replacement
Fixed O&M Costs		
Additional Operators per shift	0	Assume no additional operators
Operating Labor	$0	N/A
Supervisor Labor	$0	N/A
Maintenance Materials	$1,220,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$1,220,000	
Indirect Operating Cost		
Property Taxes	$1,278,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,278,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$2,556,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$5,112,000	
Total Annual Operating Cost	**$6,332,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$10,475,000	
Annualized Outage Cost	$5,390,000	
Annual Operating Cost	$6,332,000	
Total Annual Cost	**$22,197,000**	

Coyote Station Unit 1
SO_2 Control Cost Evaluation
Dry FGD (CDS) + FF

SO_2 Control Option Description	**Dry FGD (CDS) + FF**
Baseline SO_2 Emissions, lb/MMBtu	0.85
Post Upgrade SO_2 Emissions, lb/MMBtu	0.09
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS	Cost (2018$)	Basis
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$61,993,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGD Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$3,100,000	5% of Equipment/Material Cost
Freight	$3,100,000	5% of Equipment/Material Cost
Total PEC	$68,193,000	
Direct Installation Costs		
Labor	$79,049,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,976,000	2.5% of Labor
Mobilization / Demobilization	$1,186,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$3,952,000	5% of Labor
Total Direct Installation Costs	$86,163,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$154,356,000**	
Indirect Costs		
Contractor's General and Administration Expense	$15,436,000	10% of Total Direct Costs
Contractor's Profit	$7,718,000	5% of Total Direct Costs
Dry FGD Engineering, Procurement, & Project Services	$12,348,000	8% of Total Direct Costs
Construction Management/Field Engineering	$6,174,000	4% of Total Direct Costs
S-U / Commissioning	$2,315,000	1.5% of Total Direct Costs
Spare Parts	$772,000	0.5% of Total Direct Costs
Owner's Cost	$3,087,000	2% of Total Direct Costs
Total Indirect Costs	**$47,850,000**	
Contingency	**$40,441,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$242,647,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$19,885,000**	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Increased Waste Disposal Cost	$2,743,000	Based on disposal rate of $32.46 per ton.
Increased Lime Reagent Cost	$6,998,000	Based on lime reagent cost of $128 per ton.
Increased Auxiliary Power Cost	$428,000	Based on auxiliary power cost of $23 per MWh
Increased Water Cost	$32,000	Based on water cost of $1.00 per 1000 gallons.
Increased bag and cage replacement	$140,000	Based on bag and cage cost of $135 per bag
Total Variable O&M Costs	$10,341,000	
Fixed O&M Costs		
Additional Operators per shift	0	Assume no additional operators
Operating Labor	$0	N/A
Supervisor Labor	$0	N/A
Maintenance Materials	$2,315,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,315,000	
Indirect Operating Cost		
Property Taxes	$2,426,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,426,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$4,853,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$9,705,000	
Total Annual Operating Cost	**$22,361,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$19,885,000	
Annual Operating Cost	$22,361,000	
Total Annual Cost	**$42,246,000**	

Coyote Station Unit 1
SO_2 Control Cost Evaluation
Wet FGD

SO_2 Control Option Description	**Wet FGD**
Baseline SO_2 Emissions, lb/MMBtu	0.85
Post Upgrade SO_2 Emissions, lb/MMBtu	0.06
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$112,208,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FG Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$5,610,000	5% of Equipment/Material Cost
Freight	$5,610,000	5% of Equipment/Material Cost
Total PEC	$123,428,000	
Direct Installation Costs		
Labor	$76,285,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,907,000	2.5% of Labor
Mobilization / Demobilization	$1,144,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$3,814,000	5% of Labor
Total Direct Installation Costs	$83,150,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$206,578,000**	
Indirect Costs		
Contractor's General and Administration Expense	$20,658,000	10% of Total Direct Costs
Contractor's Profit	$10,329,000	5% of Total Direct Costs
Dry FG Engineering, Procurement, & Project Services	$16,526,000	8% of Total Direct Costs
Construction Management/Field Engineering	$8,263,000	4% of Total Direct Costs
S-U / Commissioning	$3,099,000	1.5% of Total Direct Costs
Spare Parts	$1,033,000	0.5% of Total Direct Costs
Owner's Cost	$4,132,000	2% of Total Direct Costs
Total Indirect Costs	**$64,040,000**	
Contingency	**$54,124,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$324,742,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$26,613,000**	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Increased Waste Disposal Cost	$2,182,000	Based on disposal rate of $32.46 per ton.
Increased Lime Reagent Cost	-$3,679,000	Based on lime reagent cost of $128 per ton.
Limestone Reagent Cost	$4,895,000	Based on limestone reagent cost of $70 per ton.
Increased Auxiliary Power Cost	$949,000	Based on auxiliary power cost of $23 per MWh
Increased Water Cost	$68,000	Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs	$4,415,000	
Fixed O&M Costs		
Additional Operators per Shift	4	
Operating Labor	$2,172,000	Assume $62/hr for each additional operator
Supervisor Labor	$326,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$3,099,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$5,597,000	
Indirect Operating Cost		
Property Taxes	$3,247,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$3,247,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$6,495,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$12,989,000	
Total Annual Operating Cost	**$23,001,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$26,613,000	
Annual Operating Cost	$23,001,000	
Total Annual Cost	**$49,614,000**	

APPENDIX C

NO$_X$ CONTROL COST EFFECTIVENESS ESTIMATES

Coyote Station Unit 1
NO_X Control Summary

Table 1. Coyote Unit 1 Operating Parameters

Parameter		Unit	Notes
Power Output	427	MW-net	Nominal
Annual Average Heat Input	32,301,802	MMBtu/yr	24-month annual average for period July 2016 to June 2018 (post-SOFA upgrades)
Average Capcity Factor	79%	%	Based on annual average MW-h during the baseline period.

Table 2. Control Effectiveness

Control Technology	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)
Tail-End SCR	80.3%	1,452	0.09	5,912
SNCR + RRI	56.2%	3,226	0.20	4,137
SNCR	38.7%	4,516	0.28	2,847
Combustion Optimization	8.0%	6,775	0.42	589
Baseline (SOFA)		**7,363**	0.46	0

Table 3. Cost Effectiveness

Control Technology	Emissions (tpy)	Tons of NO_X Removed (tpy)	Total Capital Requirement ($)	Annualized Capital Cost ($/year)	Annualized Outage Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline (SOFA)	7,363	0	--	--	--	--	--		
Combustion Optimization	6,775	589	$0	$0	$0	$0	$0	**$0**	
SNCR	4,516	2,847	$19,840,000	$1,626,000	$0	$3,128,000	$4,754,000	**$1,670**	$2,105
SNCR + RRI	3,226	4,137	$25,895,000	$2,122,000	$0	$6,495,000	$8,617,000	**$2,083**	$2,994
Tail-End SCR	1,452	5,912	$254,128,000	$20,826,000	$0	$20,442,000	$41,268,000	**$6,981**	$18,402

Coyote Station Unit 1
NO_X Control Cost Evaluation
Combustion Optimization

NO_X Control Option Description	**Combustion Optimization**
Baseline NO_X Emissions, lb/MMBtu	0.46
Post Upgrade NO_X Emissions, lb/MMBtu	0.42
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$0	
Instrumentation	$0	
Sales Tax	$0	
Freight	$0	
Total PEC	$0	
Direct Installation Costs		
Labor	$0	
Scaffolding	$0	
Mobilization / Demobilization	$0	
Labor Cost Due To Overtime Ineffiency	$0	
Total Direct Installation Costs	$0	
Total Direct Costs (PEC + Direct Installation Costs)	**$0**	
Indirect Costs		
Contractor's General and Administration Expense	$0	
Contractor's Profit	$0	
Engineering, Procurement, & Project Services	$0	
Construction Management/Field Engineering	$0	
S-U / Commissioning	$0	
Spare Parts	$0	
Owner's Cost	$0	
Total Indirect Costs	**$0**	
Contingency	**$0**	
Total Capital Investment (TCI)	**$0**	
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$0**	
OPERATING COSTS		**Basis**
Operating & Maintenance Costs		
Variable O&M Costs		
Dry Urea Reagent Cost	$0	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$0	Based on ammonia reagent cost of $700 per ton.
RO Water Cost	$0	Based on water cost of $1.00 per 1,000 gallons.
Steam Cost	$0	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$0	Based on hydrated lime cost of $187 per ton.
Catalyst Replacement Cost	$0	Based on catalyst cost of $8,000 per m3 and catalyst replacement cost of $1,000 per m3.
Auxiliary Power Cost	$0	Based on auxiliary power cost of $23 per MWh
Total Variable O&M Costs	$0	
Fixed O&M Costs		
Additional Operators per shift	0	Assume no additional operators
Operating Labor	$0	N/A
Supervisor Labor	$0	N/A
Maintenance Materials	$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$0	
Indirect Operating Cost		
Property Taxes	$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$0	
Total Annual Operating Cost	**$0**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$0	
Annual Operating Cost	$0	
Total Annual Cost	**$0**	

Coyote Station Unit 1
NO_X Control Cost Evaluation
SNCR

NO_X Control Option Description	**SNCR**
Baseline NO_X Emissions, lb/MMBtu	0.46
Post Upgrade NO_X Emissions, lb/MMBtu	0.28
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$8,718,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$436,000	5% of Equipment/Material Cost
Freight	$436,000	5% of Equipment/Material Cost
Total PEC	$9,590,000	
Direct Installation Costs		
Labor	$2,780,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$70,000	2.5% of Labor
Mobilization / Demobilization	$42,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$139,000	5% of Labor
Total Direct Installation Costs	$3,031,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$12,621,000**	
Indirect Costs		
Contractor's General and Administration Expense	$1,262,000	10% of Total Direct Costs
Contractor's Profit	$631,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$1,010,000	8% of Total Direct Costs
Construction Management/Field Engineering	$505,000	4% of Total Direct Costs
S-U / Commissioning	$189,000	1.5% of Total Direct Costs
Spare Parts	$63,000	0.5% of Total Direct Costs
Owner's Cost	$252,000	2% of Total Direct Costs
Total Indirect Costs	**$3,912,000**	
Contingency	**$3,307,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$19,840,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$1,626,000**	
OPERATING COSTS		**Basis**
Operating & Maintenance Costs		
Variable O&M Costs		
Dry Urea Reagent Cost	$1,401,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$0	Based on ammonia reagent cost of $700 per ton.
Water Cost	$82,000	Based on water cost of $1.00 per 1,000 gallons.
Steam Cost	$32,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$0	Based on hydrated lime cost of $187 per ton.
Catalyst Replacement Cost	$0	Based on catalyst cost of $8,000 per m3 and catalyst replacement cost of $1,000 per m3.
Auxiliary Power Cost	$7,000	Based on auxiliary power cost of $23 per MWh
Total Variable O&M Costs	$1,522,000	
Fixed O&M Costs		
Additional Operators per shift	1	
Operating Labor	$543,000	Assume $62/hr for each additional operator
Supervisor Labor	$81,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$189,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$813,000	
Indirect Operating Cost		
Property Taxes	$198,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$198,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$397,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$793,000	
Total Annual Operating Cost	**$3,128,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$1,626,000	
Annual Operating Cost	$3,128,000	
Total Annual Cost	**$4,754,000**	

Coyote Station Unit 1
NO_X Control Cost Evaluation
SNCR + RRI

NO_X Control Option Description	**SNCR + RRI**
Baseline NO_X Emissions, lb/MMBtu	0.46
Post Upgrade NO_X Emissions, lb/MMBtu	0.20
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$11,179,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$559,000	5% of Equipment/Material Cost
Freight	$559,000	5% of Equipment/Material Cost
Total PEC	$12,297,000	
Direct Installation Costs		
Labor	$3,831,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$96,000	2.5% of Labor
Mobilization / Demobilization	$57,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$192,000	5% of Labor
Total Direct Installation Costs	$4,176,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$16,473,000**	
Indirect Costs		
Contractor's General and Administration Expense	$1,647,000	10% of Total Direct Costs
Contractor's Profit	$824,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$1,318,000	8% of Total Direct Costs
Construction Management/Field Engineering	$659,000	4% of Total Direct Costs
S-U / Commissioning	$247,000	1.5% of Total Direct Costs
Spare Parts	$82,000	0.5% of Total Direct Costs
Owner's Cost	$329,000	2% of Total Direct Costs
Total Indirect Costs	**$5,106,000**	
Contingency	**$4,316,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$25,895,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$2,122,000**	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Dry Urea Reagent Cost	$4,300,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$0	Based on ammonia reagent cost of $700 per ton.
RO Water Cost	$179,000	Based on water cost of $1.00 per 1,000 gallons.
Steam Cost	$99,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$0	Based on hydrated lime cost of $187 per ton.
Catalyst Replacement Cost	$0	Based on catalyst cost of $8,000 per m3 and catalyst replacement cost of $1,000 per m3.
Auxiliary Power Cost	$10,000	Based on auxiliary power cost of $23 per MWh
Total Variable O&M Costs	$4,588,000	
Fixed O&M Costs		
Additional Operators per shift	1	
Operating Labor	$543,000	Assume $62/hr for each additional operator
Supervisor Labor	$81,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$247,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$871,000	
Indirect Operating Cost		
Property Taxes	$259,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$259,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$518,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$1,036,000	
Total Annual Operating Cost	**$6,495,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$2,122,000	
Annual Operating Cost	$6,495,000	
Total Annual Cost	**$8,617,000**	

Coyote Station Unit 1
NO_X Control Cost Evaluation
Tail-End SCR

NO_X Control Option Description	**Tail-End SCR**
Baseline NO_X Emissions, lb/MMBtu	0.46
Post Upgrade NO_X Emissions, lb/MMBtu	0.09
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$85,566,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$4,278,000	5% of Equipment/Material Cost
Freight	$4,278,000	5% of Equipment/Material Cost
Total PEC	$94,122,000	
Direct Installation Costs		
Labor	$61,961,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,549,000	2.5% of Labor
Mobilization / Demobilization	$929,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$3,098,000	5% of Labor
Total Direct Installation Costs	$67,537,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$161,659,000**	
Indirect Costs		
Contractor's General and Administration Expense	$16,166,000	10% of Total Direct Costs
Contractor's Profit	$8,083,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$12,933,000	8% of Total Direct Costs
Construction Management/Field Engineering	$6,466,000	4% of Total Direct Costs
S-U / Commissioning	$2,425,000	1.5% of Total Direct Costs
Spare Parts	$808,000	0.5% of Total Direct Costs
Owner's Cost	$3,233,000	2% of Total Direct Costs
Total Indirect Costs	**$50,114,000**	
Contingency	**$42,355,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$254,128,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$20,826,000**	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Dry Urea Reagent Cost	$0	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$1,724,000	Based on ammonia reagent cost of $700 per ton.
RO Water Cost	$0	Based on water cost of $1.00 per 1,000 gallons.
Steam Cost	$0	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$298,000	Based on hydrated lime cost of $187 per ton.
Catalyst Replacement and Disposal Cost	$4,257,000	Based on catalyst cost of $8,000 per m3 and catalyst replacement cost of $1,000 per m3.
Auxiliary Power Cost	$1,074,000	Based on auxiliary power cost of $23 per MWh
Total Variable O&M Costs	$7,353,000	
Fixed O&M Costs		
Additional Operators per Shift	1	
Operating Labor	$434,000	Assume $49.5/hr for each additional operator
Supervisor Labor	$65,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$2,425,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,924,000	
Indirect Operating Cost		
Property Taxes	$2,541,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,541,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$5,083,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$10,165,000	
Total Annual Operating Cost	**$20,442,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$20,826,000	
Annual Operating Cost	$20,442,000	
Total Annual Cost	**$41,268,000**	

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OTTER TAIL
POWER COMPANY

MAY 2019
Received
Air Quality

May 10, 2019

Mr. Jim Semerad
Director, Division of Air Quality
North Dakota Department of Environmental Quality
Gold Seal Center, 918 East Divide Ave
Bismarck, ND 58501-1947

Dear Mr. Semerad:

Re: Four Factor Analysis - Coyote Station

Thank you for the North Dakota Department of Environmental Quality's (NDDEQ) review of the Coyote Station Regional Haze reasonable progress report (Four-Factor Analysis). Below are Otter Tail Power Company's (OTP) responses to the NDDEQ's March 20, 2019 comments. Additionally, two hardcopies of a revised report are enclosed.

1) Summary of NDDEQ Comment: "*...since you are anticipating a higher sulfur content in the future lignite combusted, past emissions do not represent a realistic estimate of anticipated emissions...The SO_2 analysis should be edited using a more appropriate baseline rate.*"

   OTP Response: The NDDEQ is correct that, as compared to recent years, Coyote Station is expecting an increase in future coal sulfur content. However, this future sulfur content is projected to be similar to the sulfur content of the lignite that was combusted from the years 2000-2008. On March 29, 2019 OTP provided a spreadsheet to the NDDEQ showing that Coyote Station has been able to maintain consistent SO_2 lb/mmbtu emission rates throughout the expected range of future coal sulfur content. For example, in year 2004, the average lignite sulfur content was 1.09%, and Coyote had an annual average emission rate of 0.85 lb/mmbtu. This emission rate is very similar to year 2018, in which Coyote had an average sulfur content of 0.83% and an annual average emission rate of 0.86 lb/mmbtu. Therefore, no adjustment is needed to the SO_2 baseline emission rate presented in the Four-Factor Analysis.

2) NDDEQ Comment: "*We also believe the inlet SO_2 rate to possible control options (3.12 lb/MBtu) is high. Using the AP-42 emission factor, we calculate an inlet emission rate of approximately 2.3 lb/MBtu for 1.06% sulfur in the lignite. We believe this will affect the Total Annual Cost and cost effectiveness of the various control options. The analysis should be changed based on a more realistic inlet SO_2 rate.*"

   OTP Response: We appreciate the NDDEQ's comment regarding calculation of the baseline SO_2 inlet rate. Sargent & Lundy (S&L) used projected future fuel analyses (sulfur and higher heating value) provided by OTP to calculate the baseline inlet SO_2 rate, assuming 100% conversion of fuel sulfur to SO_2 and without taking into account any inherent SO_2 conversion/capture. As pointed out by the NDDEQ, using the uncontrolled emission rate factor provided by AP-42[1] as the basis for inlet SO_2 would provide for a lower number of approximately 2.3 lb/mmbtu.

Regarding revising the cost estimate consistent with the recommendation for inlet SO2, the majority of the capital costs are a function of the flue gas flow rate and not the fuel sulfur content. Therefore, changing the inlet rate to 2.3 lb/MBtu would change the capital cost estimate slightly but not enough to affect the economic impact evaluation. The reagent prep and dewatering systems and byproduct handling systems are a very small portion of the overall cost of the retrofit FGD control system. For the DSI system, the main cost is attributable to the variable O&M cost of reagent which was based on 2.77 lb SO_2/MBtu as stated in Footnote 42 of the Four-Factor Analysis. The inlet SO_2 rate primarily impacts the variable O&M costs of the SO_2 control alternatives. Variable O&M costs that are impacted include reagent consumption (i.e., lime and limestone) and the byproduct or waste disposal. The difference between 2.3 lb SO_2/MBtu and 2.77 lb SO_2/MBtu will not have a significant impact on the FGD cost-effectiveness analysis because variable O&M costs are relatively small in relation to the capital cost portion of the SO_2 control alternatives. Nevertheless, S&L has revised the variable O&M costs to reflect a baseline SO_2 inlet rate of 2.3 lb SO_2/MBtu.

3) Summary of NDDEQ Comment: *"...high dust, low dust and tail-end SCR are not technically feasible for cyclone boilers combusting North Dakota lignite...Since tail-end SCR is not a technically feasible option, we suggest that it be removed from Tables 5-11, 6-3 and 6-4."*

   OTP Response: The Four-Factor Analysis has been revised to remove tail-end SCR from Tables 5-11, 6-3, and 6-4. Portions of the text were also updated to be consistent with this change.

4) NDDEQ Comment: *"Many cost estimates throughout the analysis are based on Sargent & Lundy's (S&L) conceptual cost estimating system with major equipment costs based on recently developed projects. When cost estimates are not based on EPA's Control Cost Manual, more documentation is required to substantiate costs. Please provide the documentation to support costs that are not based on the Control Cost Manual."*

   OTP Response: Please see the attached memorandum from Sargent & Lundy addressing this comment.

Thank you for the attention given to the Coyote Station Four-Factor Analysis. If you have any further questions on the revised report, please contact me at (218) 739-8526.

Sincerely,

Mark Thoma

Mark Thoma
Manager, Environmental Services

Enclosure

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[1] The AP-42 uncontrolled factor assumes that the alkali content of lignite has an effect on sulfur conversion and acts as a built-in sorbent for SO_x removal.

Sargent & Lundy LLC

TECHNIAL MEMORANDUM

From:	Wayshalee Patel	**Date:**	May 8, 2019
		Project No.:	A12715.011
Client:	Otter Tail Power		
Station:	Coyote Station		
Subject:	Agency Comments to Four Factor Analysis		

The purpose of this memorandum is to provide a response to the North Dakota Department of Enviornmental Quality (NDDEQ) comments on the Coyote Station Four Factor Analysis.

1. **NDDEQ Comment:** ***Many cost estimates throughout the analysis are based on Sargent & Lundy's (S&L) conceptual cost estimating system with major equipment costs based on recently developed projects. When cost estimates are not based on EPA's Control Cost Manual, more documentation is required to substantiate costs. Please provide the documentation to support costs that are not based on the Control Cost Manual.***

   S&L Response: S&L has considerable experience with the federal and state environmental regulations affecting power plant operations, as well as the specification, evaluation, selection, and implementation of emission control technologies for both gas- and coal-fueled utility power facilities, including extensive experience with air pollution control technologies. For example, since 2000, S&L has provided, or is currently providing, engineering services for the implementation of over 40 wet FGD projects, 30 dry FGD projects, 25 dry sorbent injection (DSI) projects, 60 selective catalytic reduction projects (SCR) and 30 selective non-catalytic reduction (SNCR) projects all of which are technologies that were analyzed as part of the Four-Factor Analysis.

   Cost estimates for the OTP Four-Factor Analysis were, to the extent practical, prepared in accordance with the methodology described in EPA's Control Cost Manual and represent study-level cost estimates. Capital costs for major equipment were developed using equipment costs for similar sized units (adjusted for actual equipment sizing), an approach allowed by the Control Cost Manual. Site-specific balance-of-plant (BOP) costs that Coyote Unit 1 would incur to retrofit the control system onto the existing unit were estimated based on site-specific general arrangements and project-specific indirect cost factors. Where possible, default factors from EPA's Control Cost Manual were used to calculate indirect costs. Specifically, cost estimates were prepared with the following general approach and site- specific information:

- Boiler operating parameters were reviewed and mass balances were prepared to calculate flue gas flows across the range of operating conditions and to size the air pollution control equipment.
- Fuel characteristics were evaluated and used to size the material handling, material storage, and piping systems.
- Plant design data were used to estimate absorber sizing, reagent storage and preparation systems, dewatering systems and byproduct handling systems for air pollution control equipment.
- Aerial views of the plant were used to identify the general vicinity in which major equipment would be located.

The capital cost estimates were prepared for the major control system components, equipment, material, labor, instrumentation, etc. Capital costs were annualized using the methodology described in the Control Cost Manual, and annual operating and maintenance (O&M) costs were added to the annualized cost of capital to generate a total annual cost. Detailed cost effectiveness worksheets were provided identifying the O&M costs including, variable O&M costs (i.e. reagent, waste disposal, auxiliary power and water), indirect operating costs (i.e. property taxes, insurance, and administrative services) and fixed O&M costs (i.e. operating personnel as well as maintenance material and labor) for all of the air pollution control options. Where possible, default factors from EPA's Control Cost Manual were used to calculate O&M costs. The approach used by S&L to generate capital cost estimates, O&M costs, and total annual costs is in general accordance with the methodology outlined in the Control Cost Manual.

OTTER TAIL
POWER COMPANY

COYOTE STATION UNIT 1

NORTH DAKOTA REGIONAL HAZE SECOND PLANNING PERIOD FOUR-FACTOR ANALYSIS

SL-014745
Final Rev 1

May 8, 2019
Project No. 12715-011

Sargent & Lundy

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CONTENTS

FIGURES/TABLES

APPENDIXES

A. Coyote Unit 1 Baseline Emissions

B. SO_2 Control Cost Effectiveness Estimates

C. NO_X Control Cost Effectiveness Estimates

ABBREVIATIONS/ACRONYMS

Abbreviation/Acronym	Explanation
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BFP	boiler feed pump
Ca	calcium
CaO	calcium oxide
$Ca(OH)_2$	calcium hydroxide
$CaSO_3$	calcium sulfite
$CaSO_4$	calcium sulfate
CAA	Clean Air Act
CDS	circulating dry scrubber
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
DFGD	dry flue gas desulfurization
DSI	dry sorbent injection
ESP	electrostatic precipitator
EPA	Environmental Protection Agency
EGU	electric generating unit
FF	fabric filter
FGD	flue gas desulfurization
G&A	general and administration
GHG	greenhouse gas
H_2SO_4	sulfuric acid
LNB	Low-NO_X burner
LTS	Long-term strategy
MMBtu	million British thermal units
MNL	multi-nozzle lance
MRYS	Milton R. Young Station
MW	megawatt

MWg	megawatt gross
Na_2CO_3	sodium carbonate
ND	North Dakota
NDDEQ	North Dakota Department of Environmental Quality
NH_3	ammonia
NO_X	nitrogen oxides
NSR	New Source Review
NSR	normalized stoichiometric ratio
OEM	Original equipment manufacturer
OFA	overfire air
O&M	operations and maintenance
OTP	Otter Tail Power Company
PM	particulate matter
PRB	Powder River Basin
RPG	Reasonable Progress Goals
RPO	Regional Planning Organization
RRI	rich reagent injection
S	sulfur
S&L	Sargent & Lundy, L.L.C.
SBC	sodium bicarbonate
SBS	sodium bisulfate
SCR	selective catalytic reduction
SDA	spray dryer absorber
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SOFA	separated overfire air
TE-SCR	tail-end SCR
URP	uniform rate of progress
WRAP	Western Region Air Partnership

EXECUTIVE SUMMARY

Coyote Station, located near Beulah, ND, commenced commercial operation in 1981. The facility is a single unit station with one 451 MWg (approximate) Babcock and Wilcox cyclone boiler (Coyote Unit 1). Coyote Unit 1 is designed to fire North Dakota lignite, and is equipped with separated overfire air (SOFA) for NO_X control, and dry flue gas desulfurization (DFGD or dry FGD) and fabric filter baghouse (FF) for SO_2 and particulate matter (PM) control. Lignite is delivered to the Station from the Coyote Creek Mine, whose primary operations are approximately 3-4 miles from the Coyote Station.

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the CAA, establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).[1] The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. The Regional Haze Rule established a schedule setting forth deadlines by which the States must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.[2] Second planning period Regional Haze SIPs must be submitted to EPA for review by July 31, 2021.

As part of North Dakota's SIP development for the second planning period, NDDEQ requested that Otter Tail prepare a "four factor" analysis for Coyote Unit 1. This evaluation reviews technically feasible SO_2 and NO_X emissions reduction measures for the following four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

Technically feasible SO_2 and NO_X control strategies for Coyote Unit 1 are included in Table ES-1 and Table ES-2. The tables also show baseline emission rates and estimated emission reductions for each control option.

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[1] 64 FR 35713

[2] On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period SIPs (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

Table ES-1. SO_2 Control Options for Coyote Unit 1

Control Option	SO_2 Emission Rate tons/yr	% Reduction from Baseline Emission Rate
Baseline (existing DFGD/FF)	12,994	-
DSI + Existing FGD	8,863	32%
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	7,641	41%
DSI + FGD Operational Improvements	5,043	61%
FGD Upgrades - Replacing Existing Absorbers with New Absorber	4,432	66%
Dry FGD (CDS) + Existing FF	1,375	89%
Wet FGD	917	93%

Table ES-2. NO_X Control Options for Coyote Unit 1

Control Option	NO_X Emission Rate tons/yr	% Reduction from Baseline Emission Rate
Baseline (existing SOFA)	7,363	-
Combustion Optimization	6,775	8%
SNCR + Combustion Optimization	4,516	39%
SNCR + RRI + Combustion Optimization	3,226	56%

Costs of Compliance (Statutory Factor One)

Capital and O&M cost estimates were developed for each of the technically feasible SO_2 and NO_X control options. The Coyote Unit 1 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Unit 1 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on Coyote Unit 1-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment.

Table ES-3 and Table ES-4 include estimated costs for SO_2 and NO_X control options for Coyote Unit 1. The tables provide the estimated annualized capital and operating and maintenance (O&M) costs, estimated emissions reductions, average annual cost effectiveness. The tables also include the incremental cost effectiveness that compares the costs and performance of a control option to those of the next most stringent option.

Table ES-3. SO_2 Emissions Control System Cost Effectiveness ($2018)

SO_2 Control Option	Total Annualized Cost $/yr	Expected Emission Reduction tons SO_2/yr	Average Annual Cost Effectiveness (Note 1) $/ton SO_2 removed	Incremental Annual Cost Effectiveness (Note 2, 3) $/ton SO_2 removed
Baseline (Existing DFGD/FF)	---	---	---	---
DSI + Existing FGD	$12,371,000	4,131	$2,994	
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	$2,085,000	5,354	$389	n/a
DSI + FGD Operational Improvements	$14,456,000	7,952	$1,818	$4,762
FGD Upgrades - Replacing Existing Absorbers with New Absorber	$22,197,000	8,563	$2,592	$12,664
Dry FGD (CDS) + Existing FF	$40,495,000	11,619	$3,485	$5,987
Wet FGD	$49,094,000	12,078	$4,065	$18,757

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.
Note 2. Incremental cost effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

Note 3. "n/a" indicates that the next most effective control option is "inferior" (i.e., higher cost for less control)

Table ES-4. NO_X Emissions Control System Cost Effectiveness ($2018)

NO_X Control Option	Total Annualized Cost $/yr	Expected Emission Reduction tons NO_X/yr	Average Annual Cost Effectiveness (Note 1) $/ton NO_X removed	Incremental Annual Cost Effectiveness (Note 2) $/ton NO_X removed
Baseline (Existing SOFA)	---	---	---	---
Combustion Optimization	$0	589	$0	$0
SNCR + Combustion Optimization	$4,754,000	2,847	$1,670	$2,105
SNCR + RRI + Combustion Optimization	$8,617,000	4,137	$2,083	$2,994

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.
Note 2. Incremental cost effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

Time Necessary for Compliance (Statutory Factor Two)

Table ES-5 and Table ES-6 provide estimated timeframes needed to implement each of the technically feasible control option. Notably, the estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve North Dakota's SIP.

Table ES-5. SO_2 Emissions Control System Implementation Schedule

SO_2 Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
DSI + Existing FGD	6	6	6	18
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0	0	0	0
DSI + FGD Operational Improvements	6	6	6	18
FGD Upgrades - Replacing Existing Absorbers with New Absorber	8	12	12	32
Dry FGD (CDS) + Existing FF	12	20	18	50
Wet FGD	12	22	22	56

Table ES-6. NO_X Emissions Control System Implementation Schedule

NO_X Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
Combustion Optimization	0	0	0	0
SNCR + Combustion Optimization	10	6	6	22
SNCR + RRI + Combustion Optimization	10	6	6	22

Energy and Non-Air Quality Environmental Impacts (Statutory Factor Three)

An evaluation of energy impacts indicates that certain control options (e.g., new FGD systems) will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts include an increase in the solid waste generation with DSI. A summary of the environmental and energy impact analysis is provided in Table ES-7.

Table ES-7. Summary of Energy and Non-Air Quality Environmental Impacts

Control Option	Collateral Environmental & Energy Impacts
SO$_2$ Control Options	
Replace existing DFGD with New WFGD control system	➢ Increased water consumption ➢ Wet by-product that requires dewatering prior to disposal ➢ FGD wastewater treatment & discharge ➢ Increased auxiliary power requirements and heat rate penalty
Replace existing DFGD with New CDS/FF Control System	➢ Increased auxiliary power requirements and heat rate penalty ➢ Increased solid FGD by-product management and disposal
Replace existing dry scrubber modules with New DFGD modules while keeping existing FF	➢ Requires extended (approximately 12-month) outage of Coyote Unit 1 to demolish and replace the existing scrubber modules
Dry Sorbent Injection	➢ Increased solid FGD by-product management and disposal ➢ Increased auxiliary power requirements and heat rate penalty
NOx Control Options	
SNCR or SNCR + RRI	➢ Increased ammonia slip emissions ➢ Increased auxiliary power requirements and heat rate penalty

Remaining Useful Life (Statutory Factor Four)

The Coyote Station owners have not identified dates for the remaining useful life of the unit before the end of what would otherwise be the useful life of the control measures that were evaluated for Coyote Unit 1. Thus, the 20-year equipment life of the control measures was used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness.

1. INTRODUCTION

Sargent & Lundy, L.L.C. (S&L) was retained by Otter Tail Power Company (Otter Tail) to prepare a Reasonable Progress four-factor analysis for the control of sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions from Coyote Station Unit 1 (Coyote Unit 1).[3] The evaluation is in response to North Dakota Department of Environmental Quality's (NDDEQ) request that Otter Tail prepare a four factor analysis for Coyote Unit 1.

The evaluation includes an assessment of potentially available emission reduction measures for the four statutory factors listed in 40 CFR 51.308(f)(2), and takes into consideration U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period* (the "Draft EPA Guidance").[4] Technically feasible SO_2 and NO_X emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliances
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

The Reasonable Progress four factor analysis for Coyote Unit 1 (the "Four Factor Analysis") is presented in the following sections:

Section 2: **Facility Description** contains information describing the facility, site location, and existing equipment.

Section 3: **Four-Factor Analysis Requirements** provides a brief description of the Regional Haze Program requirements set forth in 40 CFR 51.308.

Section 4: **Baseline SO_2 and NO_X Emissions** establishes representative baseline SO_2 and NO_X emissions for the period 2013 to present.

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[3] Coyote Station is co-owned by Otter Tail Power Company (35%), Northern Municipal Power Agency (30%), Montana-Dakota Utilities Co. (25%), and NorthWestern Energy (10%).

[4] On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Otter Tail Power reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

Section 5:	**SO_2 and NO_X Control Measures** identifies potentially available emission control technologies, and evaluates each control option for technical feasibility and effectiveness.
Section 6:	**Costs of Compliance (Statutory Factor One)** evaluates the cost and cost-effectiveness of each technically feasible control option.
Section 7:	**Time Necessary for Compliance (Statutory Factor Two)** provides typical timelines required to design, engineer, procure and install the technically feasible control options.
Section 8:	**Energy and Non-Air Quality Environmental Impacts (Statutory Factor Three)** identifies the energy and non-air quality environmental impacts associated with each technically feasible control option.
Section 9:	**Remaining Useful Life (Statutory Factor Four)** includes a discussion of the planned remaining useful life of Coyote Unit 1.
Section 10:	**Summary and Conclusions**

Appendix A: Coyote Unit 1 Baseline Emissions

Appendix B: SO_2 Control Cost Effectiveness Estimates

Appendix C: NO_X Control Cost Effectiveness Estimates

2. FACILITY DESCRIPTION

Coyote Station, located near Beulah, ND, commenced commercial operation in 1981. The facility is a single unit station with one 451 MWg (approximate) Babcock and Wilcox cyclone boiler (Coyote Unit 1). Coyote Unit 1 is designed to fire North Dakota lignite, and is equipped with separated overfire air (SOFA) for NO_X control, and dry flue gas desulfurization (DFGD or dry FGD) and fabric filter baghouse (FF) for SO_2 and particulate matter (PM) control. Lignite is delivered to the Station from the Coyote Creek Mine, whose primary operations are approximately 3-4 miles from the Coyote Station.

Table 2-1 provides a summary of the process parameters used for the Coyote Unit 1 Four Factor Analysis. Process parameters listed in Table 2-1 were developed from information provided by OTP.[5]

Table 2-1. Process Parameters

Process Parameter	Coyote Unit 1
Boiler Type	Cyclone
Boiler Manufacturer	B&W
Full Load (MWg)	451
Full Load Boiler Heat Input (MMBtu/hr)	4,900
Full Load Coal Flow (lb/hr)	700,700
Boiler Excess Air (%)	14.0
Air Heater Leakage (%)	22.0
Bottom Ash/Fly Ash Ratio	65/35
Flue Gas Conditions at Air Heater Outlet	
Temperature (F)	330
Mass Flow Rate (lb/hr)	6,532,000
Volumetric Flow rate (acfm)	2,485,000
Annual Average Fuel Sulfur Content (%)	0.82 - 1.06
Annual Average Uncontrolled SO_2 Emissions[6] (lb/MMBtu)	2.42 - 3.12

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[5] These process parameters are representative of typical average conditions. They should not be construed as maximum values or unit design values.

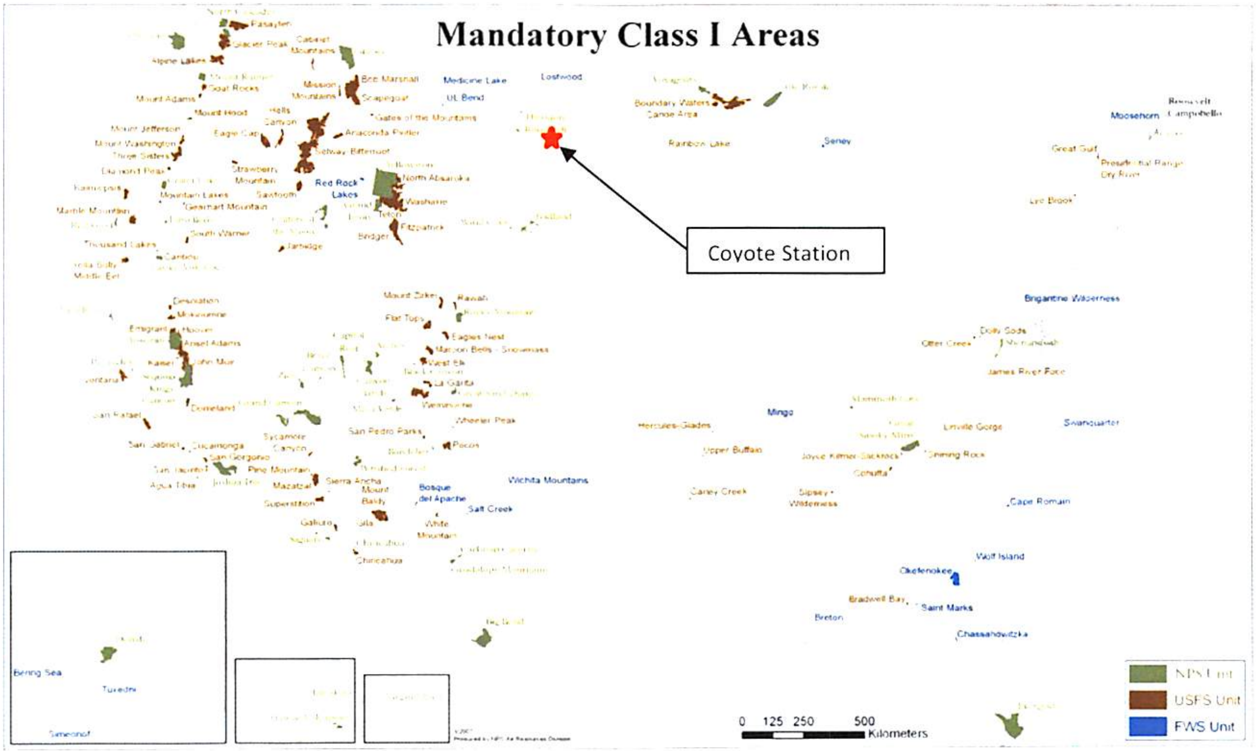
[6] Assuming 100% conversion of fuel sulfur to SO_2.

3. FOUR-FACTOR ANALYSIS REQUIREMENTS

3.1 REGIONAL HAZE RULE BACKGROUND

Section 169A of the 1977 Amendments to the Clean Air Act (CAA) sets forth a program for protecting visibility in Federal Class I areas which calls for the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Federal Class I areas which impairment results from manmade air pollution." Federal Class I areas include national parks, memorial parks, and wilderness areas over a certain size. Figure 3-1 shows the locations of the 156 federally mandated Class I areas. Federal Class I areas located within North Dakota include the Theodore Roosevelt National Park and the Lostwood National Wildlife Refuge.

Figure 3-1. Federal Class I Areas



On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the CAA, establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).[7] The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a

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[7] 64 FR 35713

state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. In 2017, EPA issued a final rule revising portions of the 1999 Regional Haze Rule.[8] The 2017 Rule requires states to determine the baseline (2000 - 2004) visibility condition for the 20 percent most impaired days and requires that the long-term strategy and reasonable progress goals (RPGs) must provide for improvement in visibility for the most impaired days, relative to the baseline period. Specifically, states must determine the rate of improvement in visibility that would need to be maintained during each implementation period in order to reach natural conditions by 2064 for the 20 percent most impaired days, given the starting point of the baseline visibility condition.

To address the combined visibility effects of various pollution sources over a wide geographic region, EPA designated five Regional Planning Organizations (RPOs) to assist with the coordination and cooperation needed to address the visibility issue. The five RPOs are shown in Figure 3-2. North Dakota is a member of the Western Regional Air Partnership (WRAP), which serves as the RPO for visibility protection at 118 Class I areas in the 15 western states.

Figure 3-2. Regional Planning Organization Map

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[8] Final Rule: Protection of Visibility: Amendments to Requirements for State Plans, 82 FR 3078, January 10, 2017

3.1.1 First Implementation Period

The Regional Haze Rule established a schedule setting forth deadlines by which the States must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.[9]

Regional Haze SIP requirements for the first planning period required that states incorporate into their plans the core program requirements in 40 CFR 51.308(d), including: (1) establishing reasonable progress goals (RPGs) for each Class I area within the state that provide for measurable progress towards achieving natural visibility conditions; (2) developing a long-term strategy (LTS) including enforceable emissions limitations and compliance schedules to achieve the RPGs; and (3) developing plans to monitor and assess the effectiveness of the LTS to achieve the RPGs over the prior implementation period and affirmation of or revision to the RPGs.

The Regional Haze Rule requires that states determine the consistent rate of progress over time needed to attain natural visibility conditions on the 20 percent most anthropogenically impaired days by the year 2064. This "glidepath" is referred to as the uniform rate of progress (URP) line. States must consider the URP, and the emission reduction measures needed to achieve this level of improvement, when developing their RPGs and LTS. Regulations at 40 CFR 51.308(g) require each state to submit progress reports, in the form of SIP revisions, every 5 years following the submission of the initial SIP. These progress reports must evaluate the progress made towards the RPGs for Class I areas located within the state as well as those Class I areas located outside the state that may be affected by emissions from within the state.

3.1.1.1 Best Available Retrofit Technology

As a one-time requirement during the first implementation period, potential best available retrofit technology (BART) controls had to be evaluated for certain large stationary sources. States were required to conduct BART determinations for "BART-eligible" sources anticipated to cause or contribute to any visibility impairment in one or more Class I area. BART-eligible sources included coal-fired electric generating units (EGUs) that were in existence on August 7, 1977, but not in operation prior to August 7, 1962. In its determination of BART, states were required to take into consideration the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of

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[9] On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period SIPs (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[10] As an alternative to requiring source-specific BART controls, states also had the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provided greater reasonable progress towards improving visibility than BART.

3.1.1.2 Reasonable Progress Control Requirements for Coyote Station during First Planning Period

Coyote Unit 1 commenced operation in 1981, and was not classified as a BART-eligible source or subject to the BART requirements. Nevertheless, during the initial planning period, the North Dakota Department of Environmental Quality (NDDEQ) evaluated emissions from the Coyote Station as a reasonable progress source. The reasonable progress analysis prepared by NDDEQ concluded that no additional controls would be required on Coyote Unit 1 during the initial planning period; however, NDDEQ and Otter Tail reached an agreement whereby Otter Tail committed to install SOFA equipment to reduce NO_X emissions. In the initial planning period SIP NDDEQ noted that additional SO_2 and NO_X controls for Coyote Unit 1 would be reevaluated during future planning periods to determine if additional emissions reductions would be required.

3.1.2 Second Implementation Period

Second planning period Regional Haze SIPs must be submitted to EPA for review by July 31, 2021. Among other requirements, second planning period SIPs are required to include an assessment of the state's RPGs and LTS. To support states in their efforts to develop the second planning period SIPs, in July 2016 EPA released a draft guidance document titled "*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*" ("Draft EPA Guidance").[11] The Draft EPA Guidance document describes key steps states should implement when developing their RPGs and LTS for the second implementation period. Key steps identified in the Draft EPA Guidance are listed in Table 3-1.

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[10] CAA Section 169A(g)(2).

[11] See, EPA-457/P-16-001. On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Otter Tail Power reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

Table 3-1. Key Steps in Developing Regional Haze SIPs for Second Planning Period

1. *Ambient data analysis* – Quantify baseline, current and natural conditions and the uniform rate of progress that would achieve natures conditions in 2064 (40 CFR 51.308(f)(1))
2. *Screening of sources* – Identify the pollutants and emission sources for which a full reasonable progress analysis will be completed and explain why it is appropriate to limit the full analysis to only these sources (40 CFR 51.308(f)(2))
3. *Source and emission control measure analysis* – Identify potential emission control measures for sources selected in the screening step and develop data on the four statutory factors and visibility benefits if they will be considered (40 CFR 51.308(f)(2))
4. *Decisions on the content of the LTS* – Consider applicable factors and decide on new emission controls for incorporation into the LTS (40 CFR 51.308(f)(2))
5. *Regional scale modeling* – Model the emissions reductions that will result from implementation of the LTS and other enforceable measures that will reduce visibility impairment to set the RPGs for 2028 (40 CFR 51.308(f)(3))
6. *Progress, degradation and glidepath checks* – Demonstrate that there will be an improvement on the 20 percent most impaired days. Demonstrate that there is no degradation on the 20 percent clearest days. Compare the 2028 RPG for the 20 percent most impaired days to the 2028 point on the URP line (the glidepath) and, if required, provide additional justification for the reasonableness of the RPG. Revise the LTS if additional measures are identified as necessary to make reasonable progress. (40 CFR 51.308(f)(3))
7. *Additional requirements for SIPs* – Provide additional information necessary to ensure that other requirements of the Regional Haze rule are met.

The Draft EPA Guidance recommends that states evaluate all technically feasible emission control options for stationary sources and source categories identified as having the greatest potential to impact visibility at one or more Class I area. The Draft EPA Guidance recommends several options for states to consider when evaluating potential emission reductions, including work practices, replacement and retrofit controls, existing control upgrades, fuel switching year-round operation of controls, and operating restrictions.[12]

Emission control evaluations must consider the four statutory factors identified in 40 CFR 51.308(f)(2)(i) (discussed in Section 3.2). In addition, the Draft EPA Guidance notes that control technology assessment recommendations presented in the BART Guidelines continue to be relevant as recommendations for how a state

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[12] See, Draft EPA Guidance, pgs. 85-86.

should evaluate and select emission control measures for stationary sources.[13] Recommendations in the BART Guidelines that continue to be relevant to the Regional Progress Four Factor Analysis are listed in Appendix D of the Draft EPA Guidance, and include, in general, the recommended approach for evaluating the technical feasibility, effectiveness, costs, and cost-effectiveness of available emission control measures.[14]

3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS

Under 40 CFR 51.308(f)(2)(i), states must consider four statutory factors when evaluating and determining emissions reduction measures from stationary sources, or groups of sources, that are necessary to make reasonable progress towards achieving natural visibility conditions. The four statutory factors are:

5. The costs of compliance;
6. The time necessary for compliance;
7. The energy and non-air quality environmental impacts of compliance; and
8. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

A brief description of each of the four statutory factors, and EPA's recommendations for evaluating each of the four factors (from the Draft EPA Guidance) is provided below.

3.2.1 Costs of Compliance

Cost estimates should be developed for each technically feasible control option. Costs include the total capital costs to engineer, design, procure, and install the control technology, and annual operating and maintenance (O&M) costs. O&M costs include both fixed and variable O&M. Fixed O&M includes costs that are independent of control system operation and would be incurred even if the control system were shut down. Fixed O&M includes categories such as operating and maintenance labor, administrative charges, property taxes, and insurance. Variable O&M includes the cost of consumables, including reagent (e.g., lime or limestone, ammonia, urea, etc.), by-product management, water consumption, and auxiliary power requirements associated with operating the control system. For existing facilities, O&M cost estimates should represent the control option's incremental increase over current O&M costs.

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[13] Draft EPA Guidance, pg. 85. The BART Guidelines are published at 40 CFR Part 51 Appendix Y.
[14] Draft EPA Guidance, Appendix D, pgs. 186-196.

Capital costs include all costs required to engineer, design, procure, and install equipment needed for the control system. The Draft EPA Guideline recommends that states adhere to the accounting principles described in Chapter 2 Section 1 of EPA's Air Pollution Control Cost Manual (the "Control Cost Manual") when calculating control system costs for a four factor analysis.[15]

Section 2.3 of the Control Cost Manual (Section 1, Chapter 2) describes the cost categories generally used to calculate the total capital cost of a retrofit control technology. Cost categories include total capital investment (TCI), which is defined to "include all costs required to purchase equipment needed for the control systems (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also includes costs for land, working capital, and off-site facilities." Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (i.e., cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies.[16]

The total annual cost (TAC) of a control option includes the annualized capital recovery cost plus the total annual O&M costs. The Control Cost Manual recommends using an equivalent uniform annual cash flow method to annualize the total capital investment by multiplying the total capital investment by a capital recovery factor (CRF).[17] The product of the total capital investment and CRF gives a uniform end-of-year payment necessary to repay the initial capital investment in "n" years at an interest rate of "i". The CRF is calculated using the following equation:

$$CRF = \frac{i * (1 + i)^n}{(1 + i)^n - 1}$$

Where:
i = interest rate; and
n = economic life of the emission control system

The Draft EPA Guidance suggests that states may use generic cost estimates or estimating algorithms for estimating

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[15] Draft EPA Guidance, pg.89.
[16] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, pg. 2-5.
[17] Id., at pg 2-21.

control system costs; however, source specific estimates prepared by knowledgeable engineering professionals provide more reliable information that generic cost estimates.[18] Source-specific cost estimate should be well documented for purposes of public comment and EPA review.[19]

The total annual cost of each control option ($/yr) is divided by the total annual emissions reduction (tpy) to determine the control option's average cost-effectiveness on a $/ton basis. Emissions reductions are calculated based on the difference between baseline annual emissions and post-control annual emissions. The Draft EPA Guidance generally recommends calculating baseline emissions based on projected 2028 emissions assuming source compliance with emission limits that have been adopted and are enforceable. As an alternative, baseline emissions may be based on representative past actual emissions, assuming there is no evident basis for using a different emissions rate.

3.2.2 Time Necessary for Compliance

For stationary sources, the provisions of the BART Guidelines regarding the time necessary for compliance are relevant to reasonable progress analyses. EPA recommends that prior experiences with the planning and installation of new emission controls is the best guide to how much time a particular source will reasonably need for compliance. However, source-specific factors should be considered when evaluating the time necessary to engineer, procure, and install an available and technically feasible control option. Source-specific factors that affect the time necessary to install new emission controls should be identified and documented in the four factor analysis.

3.2.3 Energy and Non-Air Quality Environmental Impacts

For stationary sources, the provisions of the BART Guidelines regarding energy impacts are relevant to reasonable progress analyses. Energy impacts of an emission control measure are a matter of engineering design and control system operation; thus, EPA recommends that prior experience at similar sources will be informative. Energy impacts may be considered in terms of kilowatt-hours or fuels used to operate the control system. The energy impact analysis should focus on direct energy consumption at the source rather than indirect energy inputs needed to produce raw materials for the construction and operation of control equipment.

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[18] Draft EPA Guidance, pg. 91.
[19] Id.

For stationary sources, the provisions of the BART Guidelines regarding non-air quality environmental impacts are relevant to reasonable progress analyses. Non-air quality impacts include solid or hazardous waste generation, increased water consumption, wastewater discharge, land use impacts, and impacts to threatened and endangered species or their natural habitat. Characterizing the non-air quality environmental impacts should be done on a source-specific basis. Other guidance intended for use in assessments under the National Environmental Policy Act may be relevant to this evaluation.

Even though states are not required to consider GHG emission impacts, the Draft EPA Guidance encourages states to consider GHG impacts when developing their Long-Term Strategy.[20] As an example, some measures that would reduce emissions that contribute to visibility impairment will also reduce GHG emissions, such as measures that reduce the use of energy produced from combusting fossil fuels with relatively high GHG emissions. Conversely, control measures that require significant energy to capture visibility impairing emissions could result in increased GHG emission. Where a measure necessary to make reasonable progress towards natural visibility conditions would increase GHG emissions, Draft EPA Guidance encourages states to work to harmonize visibility and climate change objectives.[21]

3.2.4 Remaining Useful Life

For stationary sources, the provisions of the BART Guidelines regarding remaining useful life are relevant to reasonable progress analyses. In general, the remaining useful life of the source itself will be longer than the useful life of the emission control measure under consideration unless there is an enforceable requirement for the source to cease operation sooner. Thus, the useful life of the control measure will normally be used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness. However, if there is an enforceable requirement for the source to cease operation by a date before the end of what would otherwise be the useful life of the control measure under consideration, then the enforceable shutdown date should be used to calculate remaining useful life and evaluate control technology cost-effectiveness.

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[20] Draft EPA Guidance, pg. 92.
[21] Id.

3.2.5 Four Factor Analysis Approach

S&L used the following approach to identify SO_2 and NO_X emission control options available to Coyote Unit 1 for inclusion in the Four Factor Analysis:

1. Establish representative baseline emissions achieved with existing controls.
2. Identify all potentially available control options.
3. Evaluate control options for technical feasibility (i.e., availability and applicability).
4. Eliminate control options that are not technically feasible or would have no practical application on Coyote Unit 1.
5. Determine the control effectiveness of each technically feasible control option.
6. Evaluate each technically feasible control option for the four statutory factors.

4. BASELINE SO_2 AND NO_X EMISSIONS

The first step in developing the Four Factor Analysis is to establish Coyote Unit 1 baseline SO_2 and NO_X emissions. To establish representative baseline emissions, S&L evaluated Coyote Unit 1 operating data for the period January 1, 2013 to June 30, 2018 to identify periods of normal operation (i.e., periods of operation when the boiler was not limited by infrequent or extraordinary operating restrictions). Based on review of fuels consumed, heat input to the boiler, boiler heat rates, power generation, and capacity factors, as well as input from OTP, it was determined that the operating periods of January 1, 2013 to December 31, 2014 and January 1, 2016 to June 30, 2018 were representative of normal operation. The year 2015 was not considered to be representative because Coyote Unit 1 was limited to approximately 50% load due to a boiler feed pump (BFP) overspeed event that damaged one of the unit's two 50% BFPs; thus, only one BFP was available throughout most of the year. Therefore, the periods January 1, 2013 to December 31, 2014, and January 1, 2016 to June 30, 2018 are representative of normal operation during the baseline period, and it was determined that SO_2 emissions during that period are also representative. In June 2016, Unit 1 SOFA upgrades were completed for the purpose of reducing NO_X emissions; thus, the representative baseline period for NO_X emissions was determined to be from July 1, 2016 to June 30, 2018.

Baseline annual SO_2 and NO_X emissions were determined based on data obtained from the Coyote Unit 1 continuous emissions monitoring system (CEMS) that was reported to EPA's Clean Air Markets. The annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons per year). Representative baseline emission factors (in terms of pounds per million British Thermal Units (lb/MMBtu)) were developed using baseline annual average emissions and the respective baseline heat inputs. Table 4-1 provides a summary of the Coyote Unit 1 SO_2 and NO_X representative baseline emissions; additional details are included in Appendix A.

Table 4-1. Coyote Unit 1 Baseline Emissions

Pollutant	Baseline Controls	Emissions		Heat Input	Notes
		lb/MMBtu	tons/yr	MMBtu/yr	
SO_2	DFGD/FF	0.85	12,994	30,562,287	SO_2 emissions based on annual average tpy for period January 2013-June 2018 (excluding 2015)
NO_X	SOFA	0.46	7,363	32,301,802	NOx emissions based on annual average tpy for period July 2016 to June 2018 (post-SOFA upgrades)

5. SO_2 AND NO_X CONTROL MEASURES

S&L used a top-down approach to identify and evaluate the technical feasibility and effectiveness of potentially available SO_2 and NO_X control measures. S&L followed Steps 1 thru 3 of the top-down approach described in the BART Guidelines to identify all available retrofit emission control measures, eliminate technically infeasible options, and evaluate the effectiveness of the technically feasible options.[22] A brief description of each step is provided below.

Step 1 - Identify All Available Control Options

Available control options are those air pollution control technologies with a practical potential for application to the emission unit and the regulated pollutant under evaluation. Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant, and include not only existing controls for the source category but also take into account technology transfer of controls that have been applied to similar source categories and gas streams. Technologies which have not been applied to (or permitted for) full scale operations need not be considered as available.[23]

In an effort to identify all potentially available emission control technologies, S&L searched a broad range of information sources including, but not necessarily limited to:

- EPA's RACT/BACT/LAER Clearinghouse;
- EPA's New Source Review (NSR) and Clean Air Technology Center (CATC) Web sites;
- BART evaluations prepared during the initial Regional Haze planning period;
- Information from control technology vendors and engineering/environmental consultants;
- Federal and State NSR permits and Best Available Control Technology (BACT) determinations for similar sources; and
- Technical journals, reports, newsletters and air pollution control seminars.

Step 2 - Eliminate Technically Infeasible Control Options

In Step 2, S&L evaluated the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. Control technologies are technically feasible if either: (1) they have been

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[22] See, 40 CFR Part 51 Appendix Y, Section IV.D.
[23] Id., at IV.D.1.

installed and operated successfully for the type of source under review under similar conditions; or (2) the technology could be applied to the source under review. In order for a control option to be technically feasible, it must be "available" and "applicable" to the source under consideration. A technology is considered "available" if the source owner may obtain it through commercial channels. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.[24]

Control technologies that are technically infeasible (i.e., not available or not applicable to the source under consideration) are eliminated for further evaluation. A demonstration of technical infeasibility must be based on physical, chemical and engineering principals, and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/infeasibility.

Step 3 - Evaluate Technically Feasible Control Technologies for Effectiveness

Step 3 involves evaluating the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review. Control effectiveness should be expressed using a metric that ensures an "apples-to-apples" comparison of emissions performance levels among options, and is generally expressed as the rate that a pollutant is emitted after installation of the control measure. Control technology evaluations for existing sources should consider ways to improve the performance of existing control devices. Special circumstances pertinent to the specific unit under review should be identified and taken into consideration when assessing the capability of the control alternative and determining control effectiveness.

For this evaluation, S&L assessed the technically feasible SO_2 and NO_X control options for effectiveness on Coyote Unit 1. As discussed above, Coyote Unit 1 is an existing cyclone boiler designed to fire North Dakota lignite. The unit is equipped with SOFA for NO_X control, and dry FGD and FF for SO_2 and PM control.

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[24] A more detailed description of control technology "availability" and "applicability" is provided in 40 CFR Part 51 Appendix Y, Section IV.D.2.

5.1 SO_2 EMISSIONS CONTROLS

5.1.1 Identify Available SO_2 Control Options

Based on a review of available SO_2 control technologies, as well as operational practices and equipment upgrades implemented on existing control systems, potentially available options to control SO_2 emissions from Coyote Unit 1 are listed in Table 5-1.

Table 5-1. Available SO_2 Control Options

SO_2 Control Technologies
Fuel Switching
Existing DFGD Operational Improvements
Existing DFGD Equipment Upgrades
Existing DFGD + Dry Sorbent Injection (DSI)
Existing DFGD Operational Improvements + DSI
Retrofit New Dry FGD
Retrofit New Wet FGD

5.1.2 Technical Feasibility of Available SO_2 Control Options

Potentially available SO_2 control options identified in Table 5-1 were evaluated for technical feasibility (i.e., availability and applicability to Coyote Unit 1) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options determined to be technically infeasible, or options that have no practical application to Coyote Unit 1, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emissions performance level (i.e., control emissions rate) for each.

5.1.2.1 Fuel Switching

One potential strategy for reducing SO_2 emissions is to reduce the sulfur content of the coal. Limiting the amount of sulfur in the coal directly limits the amount released during the combustion process, and would reduce SO_2 loading to the dry scrubber. Coyote Unit 1 is a cyclone boiler designed to fire North Dakota lignite as the primary fuel. Lignite fired at the Coyote Station is mined and supplied to the station from the nearby Coyote Creek Mine. The mine, which is owned and operated by Coyote Creek Mining Company, has primary mining operations approximately 3-4 miles southwest of Coyote Station and can be considered a mine mouth plant. Previous regulatory and court decisions have concluded that requiring a mine mouth facility to evaluate low sulfur coal would require the facility to redefine its fundamental purpose and design; therefore, fuel switching can be rejected as an available control option.[25] Because the use of North Dakota lignite from the Coyote Creek Mine is an inherent aspect of Coyote operation, fuel switching will not be evaluated.

5.1.2.2 Existing DFGD Operational Improvements and Equipment Upgrades

Operational and other design changes/upgrades to the existing dry scrubber may provide an opportunity for additional SO_2 removal and allow the unit to achieve lower controlled SO_2 emissions. S&L, working with OTP personnel, identified a number of potentially feasible operational changes that may be available to increase SO_2 removal efficiency with the existing equipment. Potentially available operational and design changes to the existing control system are summarized in Table 5-2. A detailed discussion of each of these options is provided in the following sections.

Table 5-2. FGD Operational Improvements and Equipment Upgrades

FGD Operational Improvements
Lime Quality
Ca:S Stoichiometric Ratio
Approach to Saturation Temperature
FGD Design Changes and Equipment Upgrades
Atomizer Replacement
Slaker Replacement
Adding an Absorber Module
Replacing Existing Absorbers with New Absorber Modules

Lime Quality

The quantity of lime (CaO) available in a dry scrubbing system compared to the amount of SO_2 entering the system is called the stoichiometric ratio (generally referenced as the Ca:S stoichiometric ratio). Reagent quality directly

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[25] In re: Prairie State Generating Company, PSD Appeal No. 05-05, Slip. Op. at 36 (2006)

affects the Ca:S stoichiometric ratio in DFGD control systems. Using a high quality lime increases the availability of hydrated lime to support process chemistry, and reduces the lime slurry injection rate needed for SO_2 removal.

Lime quality is measured both by the CaO content and reactivity of the lime product. In a dry scrubber, CaO is combined with water to form hydrated lime or calcium hydroxide ($Ca(OH)_2$), which provides the calcium that is needed to react with SO_2 in the flue gas. With a higher quality lime, more calcium hydroxide is available to react with SO_2. Lime products with a CaO content of 90% or greater are generally considered high quality lime. Lower quality lime products have a lower CaO content and higher quantity of inert material. Reactivity of the lime is measured by the temperature rise when the lime is slaked (i.e., water addition). In general, porous lime products have higher reactivity which is demonstrated by achieving a temperature rise of approximately 40 °C within 3 minutes of adding water.

Based on a review of available lime analyses, and a review of operating data from the existing lime slaking system, Coyote Unit 1 currently procures a high quality lime for use in the dry scrubbers. The typical CaO content of the lime used at Coyote is 90% or greater, and when slaked can achieve a 39.4 °C temperature rise in 3 minutes of adding water. For these reasons, changing the lime quality is not considered a technically feasible operational change available to control SO_2 emissions from Coyote Unit, and will not be evaluated further.

Ca:S Stoichiometric Ratio

Other operational changes that may be available to increase the Ca:S stoichiometry in the existing dry scrubber include: (1) increasing the byproduct recycle rate; and/or (2) increasing the quantity of fresh hydrated lime introduced to the system. Due to the cost savings that may be realized with the first option, some facilities with existing DFGD controls have opted to increase solids recycle rates to as high as 40-50% solids to achieve an incremental increase in SO_2 reduction, if capacity was available in the byproducts handling system. If capacity is not available, increasing fresh lime addition to the system may also be a viable option to increase the Ca:S stoichiometric ratio.

Solids from a dry scrubber consist of fly ash, reaction byproduct, and residual unreacted hydrated lime. On Coyote Unit 1, solids collected in the fabric filter hoppers are conveyed to either a dry storage silo for disposal or to a recycle fly ash silo where it is used as make-up for the reactant slurry. The recycle system is designed to utilize a portion of the unreacted lime rather than disposing of all of the solids. Recycle solids are combined with the fresh lime addition to provide the makeup lime needed for SO_2 reduction. Increasing the recycle rate can increase the amount of hydrated lime added to the system (i.e., stoichiometric ratio) without increasing the quantity of fresh lime added to the system.

Based on information provided by the station, the DFGD system on Coyote Unit 1 currently operates the recycle system at approximately 24% solids. The Coyote Unit 1 recycle system is operating within the original design conditions and system capacity. The plant has tested higher recycle rates (up to 28-30% solids), but at these higher rates plant personnel reported significant problems with the atomizer wheels spilling over and pluggage of various strainers. Based on the adverse operational impacts observed during these tests, as well as the design limitations of the existing dry scrubber modules, increasing the recycle % solids is not considered a technically feasible SO_2 control option for Coyote Unit 1.

As an alternative to increasing the recycle rate, the Ca:S stoichiometric ratio in the system may be increased by increasing the quantity of fresh lime introduced to the system. Testing was completed in October 2018 on Coyote Unit 1 to determine the impact of increasing the amount of fresh lime slurry fed to the atomizer feed tanks while adjusting the amount of recycle slurry in order to maintain the design 24% solids to the absorber. During the test program Coyote Unit 1 was able to achieve an average controlled SO_2 emission rate of 0.50 lb/MMBtu without significant adverse operational impacts and represents an average emission rate that Coyote would be expected to achieve on an on-going long-term basis under normal operating conditions. The emission rate should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

Increasing the quantity of fresh lime introduced to the system will require the existing atomizer wheels to be upgraded from the eight (8) nozzle wheel to a twelve (12) nozzle wheel to mitigate for potential plugging and spill-over issues caused by the percent solid limitation of the existing atomizer wheels (see, Section 5.1.2.2 Atomizer Replacement), and to prevent the possibility of moisture carry-over that could occur with the increase in lime slurry flow. Although upgrades to the existing atomizer wheels and nozzles will be required, increasing the Ca:S stoichiometric ratio by adding additional fresh lime to the system is considered a technically feasible SO_2 control option for Coyote Unit 1, and will be included in the Four Factor Analysis.

Approach to Saturation Temperature

The reaction of SO_2 with $Ca(OH)_2$ in a dry scrubber is driven by the absorber temperature. Water surrounding the lime slurry droplet allows SO_2 to dissolve into the liquid and facilitates the reaction between lime and SO_2. The temperature differential between the inlet and the outlet of the DFGD is used as a driving force for SO_2 removal; however, outlet temperatures must be maintained above the saturation temperature to ensure byproducts exiting the absorber module are dry. Residence time within the absorber vessel, drying time, and exit temperature are all important design parameters for a dry scrubbing system.

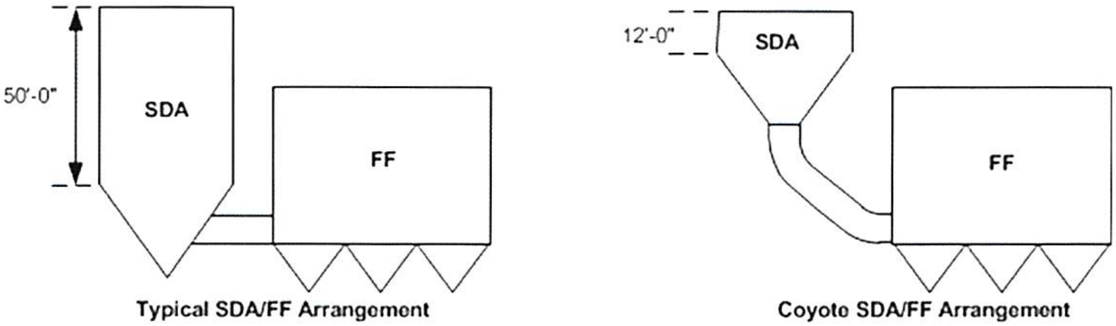
Inlet temperature to the dry scrubbing module is relatively constant; therefore, temperature differential across the module is a function of the outlet temperature. As a general rule-of-thumb, the closer the outlet temperature is to the adiabatic saturation temperature, the higher the SO_2 removal efficiency.

Operating a dry scrubbing system at outlet temperatures significantly above the adiabatic saturation temperature accelerates water evaporation from the reactant slurry, limits SO_2 absorption into the droplet, and limits the reaction between the lime and SO_2. Reducing the temperature in the absorber closer to the saturation point can provide additional SO_2 removal. On the other hand, the absorber module may not have sufficient residence time to dry all slurry droplets if the system is operated too close to adiabatic saturation, which would result in deposits in the absorber module, corrosion, and severe operational problems. Therefore, maintaining an absorber outlet temperature close to the point of saturation, while staying above it, is vital for optimal reaction kinetics.

The Coyote Unit 1 dry scrubbers currently operate at an outlet temperature of 190-210 °F, which is approximately 55-75 °F above the adiabatic saturation temperature and within original the OEM design steady state operating parameter of 190°F at the stack. More recent dry scrubbing systems have been designed to operate at 30 °F approach to adiabatic saturation. The station has attempted to lower the outlet temperatures to 165-170°F, however, this change caused significant corrosion of the absorber vessels and downstream equipment. Corrosion was likely due to the fact that the Coyote Unit 1 scrubbers were not able to completely dry the slurry droplets because the absorber vessels were designed with a residence time of approximately 1.0 second. More recent dry scrubbers are designed with approximately 10 seconds of residence time.

Figure 5-1 provides a simplified drawing of the Coyote Unit 1 scrubber compared to more recent DFGD designs, and depicts the arrangement limitation causing Coyote's shorter residence time. The low residence time limits the scrubbers ability to dry all slurry droplets when the system is operated too close to the approach to adiabatic saturation temperature. Due to the design limitations of the existing absorber vessels, reducing the outlet temperature is not considered a technically feasible SO_2 control option for Coyote Unit 1, and will not be evaluated further.

Figure 5-1. Comparison of Typical SDA/FF and Coyote Unit 1 SDA/FF Arrangement



Atomizer Replacement

Spray droplet size is an important parameter in the design and operation of a dry scrubber, and can improve lime utilization and SO_2 removal. Finer spray will increase the surface area of the slurry droplets exposed to the flue gas. Greater surface area increases the potential for SO_2 to absorb into the moisture of the slurry droplets. Droplet fineness also plays a role in particle drying time. Larger droplets can have a negative effect on the slurry drying time which can lead to moisture carryover to downstream equipment causing buildup and corrosion.

The Coyote Unit 1 dry scrubber, provided by Combustion Engineering, is designed with three (3) rotary atomizers, each with an eight (8) nozzle wheel in each absorber module to achieve a fine slurry spray. The design of the atomizer and speed at which the wheel rotates are controlling factors for the size and form of the droplets in the spray. The design and speed of atomizers is highly dependent on the spray pattern needed to mix with the hot flue gas in the scrubber module for optimum absorption of SO_2 while also preventing wetting of the absorber walls.

Based on S&L's assessment of the existing control system, previous testing completed by the station, and input from station operators, the existing DFGD system is limited in residence time, and the ability to increase the recycle ratio (solids content) to allow for more effective Ca:S contact in the scrubber vessels. The existing atomizers with eight (8) nozzle wheels would need to be upgraded to a twelve (12) nozzle wheel to mitigate for potential plugging and spill-over issues that could occur with the increased Ca:S stoichiometric ratio (discussed in Section 5.1.2.2). Based on engineering judgment, new 12 nozzle atomizers would improve spray atomization to produce slurry droplets that are smaller in size than the droplets produced by the existing nozzle design. Improved materials of construction would also allow for higher solids content in the slurry without detrimental equipment pluggage or spill-over.

Replacing the existing nozzles with a more recent 12 nozzle wheel design would provide better atomization of the slurry spray and allow for more effective Ca:S contact in the absorber vessels. However, nozzle replacement would not, on its own, be expected to provide a significant increase in SO_2 control. Nozzle upgrades coupled with operational changes designed to increase the Ca:S stoichiometric ratio is a technically feasible option that would be expected to provide additional SO_2 control (See, Section 5.1.2.2 Ca:S Stoichiometric Ratio).

Slaker Replacement

Lime slurry, the reagent used for SO_2 removal in a dry scrubber, is produced by mixing pebble lime with heated water in a slaker; this process is referred to as "slaking". The slaker is operated at an optimum water-to-lime ratio (typically between 3:1 and 6:1) to produce lime slurry by metering the amount of water and the amount of lime added to the slaker. Slakers are typically designed to produce a lime slurry between 15-20% solids. The lime slurry is added to recycle slurry in a mix tank and then sent to the atomizer where it is sprayed into the scrubber for SO_2 removal.

Coyote Unit 1 still operates the original Dorr-Oliver detention slakers. The slakers operate at a 5:1 water-to-lime ratio and approximately 18% solids, which is in line with the design as well as industry practice. Therefore, replacing the slakers would not result in improved Ca:S contact in the absorber vessels or provide additional SO_2 removal. Replacing the lime slakers is not considered a technically feasible SO_2 control option for Coyote Unit 1, and will not be evaluated further.

Adding an Absorber Module

Another option for extending the residence time within the reactor modules and increasing Ca:S contact would be to add an additional absorber module. The existing system is designed with four absorber modules that share three fabric filter zones. The system is designed to operate with four modules at full load, three or four modules at 75% load and two modules at 50% load. At full load, the flue gas residence time in the reactor modules is approximately 1.0 second. More recent dry scrubbing systems have been designed with reaction vessel residence times of 10 seconds or more.

One potential option available to the Coyote Station to increase absorber module residence time would be to add an additional absorber module to the existing dry scrubbing system. The number of absorber modules used in a DFGD system is dependent on multiple operating parameters, including the flue gas flow rate and SO_2 concentrations. DFGD absorber modules are typically specified with minimum and maximum flue gas flow rates. If the absorber modules are oversized, flue gas velocities through the module can be too low, causing solids dropout inside the vessel. If the absorber modules are undersized, flue gas velocities can be too high, causing residence time to fall below recommended levels.

Dry scrubbing units that are operating at flue gas volumes significantly above the design flow rate can benefit from adding an extra module to the system. The module would be placed in parallel with the existing modules to achieve a similar pressure drop through each vessel and to ensure equal flue gas distribution to the vessels. Although adding an absorber module would likely allow additional residence time for the SO_2 removal reactions to occur, it would require extensive engineering and modifications to the existing system. More importantly, the Coyote Unit 1 absorber module design is no longer available from Combustion Engineering, and it would likely not be possible to procure a commercial offering from another technology vendor that would be compatible with the existing modules. Therefore, incorporating an additional absorber module into the existing system is not a commercially available or technically feasible SO_2 control strategy for Coyote, and will not be evaluated further.

Replacing Existing Absorbers with New Absorber Modules

Replacing the existing modules with new absorber modules would require significant engineering and facility modifications. Based on a preliminary review of the control system layout, the only practical location for this option would be to construct the new vessels in the same location as the existing modules. Locating the new modules adjacent to the existing absorber modules would require flue gas to be redirected from the air heater outlets to the new absorbers and back to the existing fabric filters, which would likely result in significant solids dropout and other operational issues. Therefore, locating the new absorber modules adjacent to the existing absorber modules is not considered a technically feasible option.

Installing the new absorber vessels in the same location as the existing dry scrubber modules would require Coyote Unit 1 to be taken off-line for an extended period of time. OTP could not operate the unit while the existing modules were dismantled and removed, or while the new absorber modules, duct work, and other system tie-ins were installed. Based on construction schedules for new DFGD systems, and taking into consideration decommissioning of the existing dry scrubber modules, this option would likely require an outage of at least 12-months and would require Coyote to purchase replacement power during this period. In comparison, a typical major outage at Coyote Station is only 6-8 weeks. Outage costs would add significantly to the cost of this control option.

Although replacing the existing dry scrubber modules with new DFGD reactor vessels would require a long outage, there is no technical basis for eliminating this option from the analysis. Replacing the exiting dry scrubber modules with new absorber modules would address the design and operational limits of the existing system. The new absorber modules could be designed to provide additional Ca:S contact and residence time between the exhaust gas and the slurry, and would likely allow OTP to reduce the approach to saturation temperature, design parameters which would increase overall SO_2 removal.

Coyote Unit 1 consistently achieves overall removal efficiencies in the range of approximately 65-73% with the existing dry scrubbing system. Based on engineering judgment and industry practice, it is expected that the fabric filter provides approximately 10-15% of the overall removal in the DFGD system. Assuming 10-15% removal in the fabric filter, approximately 60% of the SO_2 removal is achieved in the existing absorber modules based on the current coal sulfur content. Estimated SO_2 removal efficiencies across the existing DFGD system are shown in Table 5-3.

Table 5-3. Existing SO_2 Removal Efficiencies

Existing Scrubber Modules	Existing Fabric Filter	Overall
Inlet: 2.83 lb/MMBtu Outlet: 1.14 lb/MMBtu Efficiency: 60% of uncontrolled Contribution: 85% of overall removal	Inlet: 1.14lb/MMBtu Outlet: 0.85 lb/MMBtu Efficiency: 11% of uncontrolled Contribution: 15% of overall removal	Inlet: 2.83 lb/MMBtu Outlet: 0.85 lb/MMBtu Efficiency: 70%

Based on SO_2 removal efficiencies achieved in practice on existing units equipped with DFGD, it is anticipated that replacing the existing absorber modules with new scrubber modules could increase removal across the scrubber to approximately 80%, and increase overall removal efficiencies to approximately 91%. It should be noted that Coyote is expected to receive higher sulfur content coal in the future; therefore, the new scrubber vessel SO_2 removal analysis is based on this higher sulfur content coal. The removal efficiencies for this option are shown in Table 5-4.

Table 5-4. New Scrubber Vessel SO_2 Removal Efficiencies

New Scrubber Modules	Existing Fabric Filter	Overall
Inlet: 3.12 lb/MMBtu$^{(Note\ 1)}$ Outlet: 0.62 lb/MMBtu Efficiency: 80% of uncontrolled Contribution: 88% of overall removal	Inlet: 0.62 lb/MMBtu Outlet: 0.29 lb/MMBtu Efficiency: 11% of uncontrolled Contribution: 12% of overall removal	Inlet: 3.12 lb/MMBtu Outlet: 0.29 lb/MMBtu$^{(Note\ 2)}$ Efficiency: 91%

Note 1. Inlet SO_2 rate based on anticipated future fuel sulfur content.

Note 2. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

Replacing the existing dry scrubber modules with new absorber modules is a technically feasible control technology option that would provide an incremental increase in overall SO_2 removal efficiency. However, this option would require Coyote Unit 1 to be taken off-line for an extended period of time (approximately 12 months). Outage costs associated with the extended outage are included in the four-factor cost impact evaluation for this option. Given the constructability issues and extended outage requirements associated with replacing the existing dry scrubber modules, this may not be a practical option for Coyote; nevertheless, it will be included as a technically feasible SO_2 control option in the Four Factor Analysis.

5.1.2.3 Existing FGD + Dry Sorbent Injection

Alkali based sorbent injection is a proven technology for the removal of sulfur trioxide (SO_3) and other acid gases from coal-fired power plant flue gas, and can be used to provide SO_2 control. Sorbent is injected into the ductwork after the furnace and prior to the particulate collection device, where it reacts with SO_2 and other acid gases. Sorbent injection systems are relatively simple systems consisting of material storage, feeding mechanism, blower or transfer line, and an injection device. For SO_2 control on Coyote Unit 1, sorbent would be injected upstream of the dry scrubber to provide an incremental reduction in the concentration of SO_2 in the flue gas at the inlet to the dry scrubber.

Sorbents react with SO_2, and other acid gases, in the flue gas when injected at an appropriate rate and within the proper temperature range for that sorbent. The resulting particulate matter is removed from the flue gas by the particulate control system. The process works through neutralization of the acid gases with the alkaline sorbent. The neutralization reaction occurs as long as the sorbent remains in contact with the gas in the flue gas duct work within the required temperature range.

Dry sorbents that have been used for SO_2 control on coal-fired boilers include:

- Hydrated Lime ($Ca(OH)_2$)
- Trona or Sodium Bicarbonate (SBC)

The following wet sorbents have also been used for acid gas control at coal-fired power generating stations:

- Sodium Bisulfite (SBS)
- Soda Ash

Dry sorbents, including hydrated lime, Trona, and SBC would be injected pneumatically as a dry powder into the flue gas ductwork upstream of the Coyote Unit 1 dry scrubber. Trona and SBC are both sodium-based sorbents, which react with SO_2 to form sodium salts. Hydrated lime would react with SO_2 to form calcium sulfate salts. The hydrated lime reactions are the same reactions that are taking place in the existing dry scrubber.

Hydrated lime is less reactive than the sodium based dry sorbents; thus, higher injection rates and longer residence time would be required to achieve the same removal efficiency. However, hydrated lime has a lower unit cost compared to other sorbent options, offsetting the higher injection rates. It is also important to note that the hydrated lime chemistry involves the same reactions, and forms the same calcium salts, as those currently taking place in the dry scrubber reaction vessels. Therefore, using hydrated lime as the sorbent would not introduce any new constituents into the dry scrubbing system, and could potentially increase the Ca:S stoichiometry in the dry scrubber.

Because of the higher reactivity of sodium based sorbents, less reactant may be required to achieve the same removal efficiency; however, injecting a sodium-based sorbent into the flue gas upstream of the Coyote Unit 1 dry scrubber would introduce new chemical constituents into the scrubber and into the fly ash/scrubber byproduct material. This could prove problematic as sodium compounds are water soluble, and introducing sodium into the system could adversely affect the characteristics of the byproduct solids generated by the system. Detailed studies and demonstration tests would be needed to ensure that introducing relatively large amounts of sodium would not adversely affect scrubber operation or result in solids disposal issues.

SBS and soda ash (Na_2CO_3) injection are wet injection technologies typically used for SO_3 mitigation. SBS and soda ash can be injected into the flue gas upstream or downstream of the air heater as a 10% solution (by weight) using dual fluid atomizers. Both products will react with SO_2 and SO_3 to form sodium salts, which can be collected in the downstream particulate collection device. URS/Codan Associates own the patent for this SBS control process. Based on conversations with URS, their SBS technology is generally more economical using soda ash, and all recent projects have used soda ash. However, as with the dry sodium-based injection systems, these systems would introduce sodium into the Coyote Unit 1 DFGD control system.

Sorbent injection (dry or wet) upstream of the existing dry scrubber is a technically feasible and commercially available SO_2 control option for Coyote Unit 1. Taking into consideration the fact that Coyote is currently equipped with a calcium-based dry scrubbing system, hydrated lime dry sorbent injection would be the most practical, and potentially the most effective, sorbent injection control option. Sodium-based systems would require extensive testing to determine the potential impacts associated with introducing significant quantities of sodium into the existing system, and are not considered practical control options for Coyote Unit 1.

Based on engineering judgment, and assuming adequate residence time in the duct work upstream of the existing dry scrubber, hydrated lime injection could reduce SO_2 concentrations at the dry scrubber inlet by approximately 35%. Based on future design fuel characteristics, this would reduce SO_2 concentrations at the dry scrubber inlet from approximately 3.12 lb/MMBtu to approximately 2.03 lb/MMBtu. Applying the current scrubber SO_2 removal efficiency of 71% (dry scrubber plus fabric filter), would result in a controlled SO_2 emission rate of 0.58 lb/MMBtu. DSI upstream of the existing dry scrubbing system is considered a technically feasible SO_2 control technology; however, flow modeling and field testing at Coyote Unit 1 would be needed to ensure that adequate residence time is available for SO_2 control and to confirm the incremental reduction in SO_2 emissions achievable without creating unacceptable operational issues.

Table 5-5. DSI SO_2 Control Technology Estimated Emissions

	Unit 1
Uncontrolled SO_2 Emissions (lb/MMBtu)	3.12
SO_2 Emissions at DSI Outlet (lb/MMBtu)	2.03
SO_2 Emissions at FF Outlet (lb/MMBtu)	0.58[1]
Overall Removal (%)	**80.4**

Note 1. Emissions at the FF outlet were estimate by applying existing 71% SO_2 removal across the DFGD system ((2.03 lb/MMBtu x (1 – 0.71) = 0.58).

Note 2. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

5.1.2.4 FGD Operational Improvements + DSI

Some of the SO_2 control technologies which involve improvements to the FGD can potentially be applied in combination with dry sorbent injection to provide additional SO_2 removal. This option would be considered a layered technology of the technically feasible FGD operational improvements discussed in Section 5.1.2.2 with dry sorbent injection discussed in Section 5.1.2.3. Technically feasible FGD operational improvements include increasing the Ca:S stoichiometric ratio of the FGD by introducing additional fresh lime to the absorber modules. Based on engineering judgement, layering FGD operational improvements with DSI could reduce SO_2 emissions from the baseline SO_2 emission rate of 0.85 lb/MMBtu to approximately 0.33 lb/MMBtu at Coyote Unit 1 as shown in Table 5-6. However, as stated previously, flow modeling and field testing at Coyote Unit 1 would be needed to ensure that adequate residence time is available for SO_2 control and to confirm the incremental reduction in SO_2 emissions achievable without creating unacceptable operational issues.

Table 5-6. Layered (DSI + Ca:S) SO_2 Control Technology Estimated Emissions

	Unit 1
Uncontrolled SO_2 Emissions (lb/MMBtu)	3.12
SO_2 Emissions at DSI Outlet (lb/MMBtu)	2.03
SO_2 Emissions at FF Outlet (lb/MMBtu)	0.33[1]
Overall Removal (%)	**89.4**

Note 1. Emissions at the FF outlet were estimate by applying 84% SO_2 removal across the DFGD system with operational improvements ((2.03 lb/MMBtu x (1 - 0.84 lb/MMBtu) = 0.33 lb/MMBtu).
Note 2. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

5.1.2.5 Install New Dry FGD System

Replacing the existing dry scrubber and fabric filter with new control systems would require significant engineering and modifications to the facility. Based on a preliminary review of the facility layout, the new control systems could be located northeast of Coyote Unit 1's existing dry scrubber/FF. The new DFGD/FF and all auxiliary equipment could be constructed while the unit remains on-line. The control systems could be tied-in to the existing systems during a scheduled major outage.

Various DFGD systems have been designed for use with pulverized coal-fired boilers; including the spray dryer absorber (SDA) and circulating dry scrubber (CDS). Both systems are evaluated in more detail below.

Spray Dryer Absorber / Fabric Filter

SDA systems have been used in large coal-fired utility applications, and have demonstrated the ability to effectively reduce uncontrolled SO_2 emissions from pulverized coal units. Like other dry scrubbing systems, SDA control systems use a slurry of lime and water injected into the reaction modules to remove SO_2 from the combustion gases. The reaction modules are designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a dry by-product. Process equipment associated with an SDA control system includes an alkaline storage tank, mixing and feed tanks, atomizer assembly, spray chamber module, integrated fabric filter, and solids recycle system. The recycle system collects solid reaction byproducts and recycles them back to the spray dryer feed system to maximize reactant utilization.

Various process parameters affect the efficiency of the SDA process including: the type and quality of the additive used for the reactant, reactant-to-sulfur stoichiometric ratio, how close the SDA is operated to saturation conditions, and the amount of solids product recycled to the atomizer. SDA systems are typically designed to operate within approximately 30 °F adiabatic approach to saturation temperature. Operating closer to the adiabatic saturation temperature may allow for higher SO_2 control efficiencies; however, outlet temperatures too close to the saturation temperature will result in severe operating problems including reactant build-up in the absorber modules, blinding of the fabric filter bags, and corrosion in the fabric filter and ductwork.

SO_2 removal efficiencies in a SDA are also dependent upon good gas-to-liquid contact. Reactant spray nozzle designs are vendor-specific, and include both dual-fluid nozzles and rotary atomizers. The atomizing nozzle assembly is typically located in the SDA penthouse and flange mounted to the roof of the absorber vessel.

Replacing the existing dry scrubber/FF with a new SDA/FF control systems is a technically feasible and commercially available control option on Coyote Unit 1. SDA/FF control systems are generally installed on units that burn lower sulfur fuels (i.e., < 3 lb SO_2/MMBtu) because design limitations, including Ca:S stoichiometry, residence time, and approach to saturation typically limit total SO_2 removal to approximately 95%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system. On Coyote Unit 1, 95% removal would result in an average controlled SO_2 emission rate of approximately 0.16 lb/MMBtu.

Circulating Dry Scrubber / Fabric Filter

A second type of dry scrubbing system is the circulating dry scrubber (CDS). Similar to other dry flue gas desulfurization systems, the CDS system would be located after the air preheater, and byproducts from the system collected in an integrated fabric filter. Unlike the SDA systems, CDS systems use a circulating fluidized bed of hydrated lime reagent to remove SO_2 rather than an atomized lime slurry; however, similar chemical reaction kinetics are used in the SO_2 removal process.

In a CDS, flue gas is treated in an absorber vessel where the flue gas stream flows through a fluidized bed of hydrated lime and recycled byproduct. Water is injected into the absorber through a venturi located at the base of the absorber for temperature control. Flue gas velocity through the vessel is maintained to keep the fluidized bed of particles suspended in the absorber. Water sprayed into the absorber cools the flue gas from approximately 300 °F at the inlet to the scrubber to approximately 160 °F at the outlet of the fabric filter. The hydrated lime absorbs SO_2

from the gas and forms calcium sulfite and calcium sulfate solids. Desulfurized flue gas passes out of the absorber, along with the particulate matter (reaction products, unreacted hydrated lime, calcium carbonate, and the fly ash) to the fabric filter.

As with the SDA/FF option, replacing the existing dry scrubber/FF with a new CDS/FF control system would require significant engineering and modifications to the existing facility. For this evaluation it was assumed that the CDS/FF control systems could be located adjacent to the existing dry scrubber/FF, and that the control systems could be tied-in to the existing system during a scheduled major outage.

Replacing the existing dry scrubber and FF with a new CDS/FF control system is a technically feasible and commercially available control option for Coyote Unit 1. Based on engineering judgment, it is anticipated that the retrofit CDS/FF control option would achieve SO_2 removal efficiencies higher than those achieved with a SDA/FF due to the increased Ca:S contact in the fluidized bed absorber vessel. Based on recent CDS retrofit projects, and taking into consideration expected fuel characteristics, it is anticipated that the retrofit CDS/FF control system could achieve SO_2 removal efficiencies of approximately 97%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system. On Coyote Unit 1, 97% removal would result in an average controlled SO_2 emission rate of approximately 0.09 lb/MMBtu and represents an average emission rate that Coyote would be expected to achieve on an on-going long-term basis under normal operating conditions. The emission rate should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

5.1.2.6 Install New Wet FGD System

Another option available to the Coyote Station would be to replace the existing dry scrubbing system with a new wet FGD control system located downstream of the existing FF.

Wet FGD technology is an established SO_2 control technology. Wet scrubbing systems have been designed to utilize various alkaline scrubbing solutions including lime, limestone, and magnesium-enhanced lime. Wet scrubbing systems have also been designed with spray tower reactors and with reaction vessels (e.g., jet bubbling reactor). Although the flue gas/reactant contact systems may vary, the chemistry involved in all wet scrubbing systems is essentially identical. All wet scrubbing systems use an alkaline slurry that reacts with SO_2 in the flue gas to form insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts.

A large majority of the wet FGD systems designed to remove SO_2 from existing high-sulfur utility boilers have been designed as wet limestone scrubbers with spray towers and forced oxidation systems. Therefore, for this evaluation, it was assumed that the WFGD control system would be designed as a limestone spray tower scrubber with forced oxidation. Other potentially available wet scrubber designs are not included in this evaluation because the chemistry involved in all wet scrubbing systems are essentially identical, alternative designs would not provide any additional SO_2 control, and control system costs would be similar.

Wet Limestone Scrubbing

In a wet limestone scrubbing system, limestone ($CaCO_3$) is mixed with water to formulate the alkali scrubber slurry. Flue gas enters the absorber vessel and contacts the absorbent slurry in a countercurrent spray tower. SO_2 in the flue gas reacts with the limestone slurry to form insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) which is removed as a solid waste by-product. Spent absorbent is returned to the reaction tank where dissolved sulfur compounds are precipitated as calcium salts. Fresh limestone slurry is added to regenerate the spent absorbent.

The reaction tank is sized to provide sufficient time for precipitation of the sulfur compounds. From the reaction tank, regenerated absorbent slurry is recycled to the absorber. The slurry typically contains from 5 to 15% suspended solids consisting of fresh additive, absorption reaction products, and lesser amounts of fly ash. To regulate the accumulation of solids, a bleed stream from the reaction is routed to the solid/liquid separation equipment.

Forced oxidation of the scrubber slurry may be used with limestone WFGD systems to produce calcium sulfate solids (gypsum) instead of the calcium sulfite by-product. Air blown into the reaction tank provides oxygen to convert most of the calcium sulfite ($CaSO_3$) to a relatively pure gypsum. Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the spray tower. The gypsum by-product from this process must be dewatered, and may be salable if a local market for gypsum is available, reducing the quantity of solid waste that needs to be landfilled.

For this evaluation it was assumed that the existing Coyote Unit 1 dry scrubber reactor vessels would remain in place, and that the WFGD control system would be located downstream of the existing FFs and ID fans, most likely northeast of the unit's existing dry scrubber/FF. Dry scrubber reactor vessel internals would ultimately be removed to reduce pressure drop through the system. A single WFGD absorber tower would be sufficient for the Coyote

Unit 1 flue gas flow. In addition to the absorber tower and reaction vessel, the WFGD control system would require a limestone handling and preparation system and by-product dewatering systems. Because of the saturated nature of the flue gas exiting the WFGD, a new stack with a liner capable of wet flue gas operation would be required. New booster ID fans would also be required to account for the additional pressure drop through the WFGD control system.

Wet FGD technology is an established SO_2 control technology. Wet scrubbing systems have been installed on units that fire medium to high sulfur coals, and would be a technically feasible SO_2 control option for Coyote Unit 1. Based on engineering judgment and information from control system vendors, it is anticipated that a retrofit WFGD control system on a North Dakota lignite-fired unit would be designed to achieve and SO_2 removal efficiency of approximately 98%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system. On Coyote Unit 1, 98% removal would result in an average controlled SO_2 emission rate of approximately 0.06 lb/MMBtu and represents an average emission rate that Coyote would be expected to achieve on an on-going long-term basis under normal operating conditions. The emission rate should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

5.1.2.7 Technical Feasibility Summary

Table 5-7 summarizes the results of the feasibility evaluation of available control options for Coyote Unit 1.

Table 5-7. Technically Feasible SO_2 Control Options

SO_2 Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Fuel Switching	No	Fuel switching is not considered an available SO2 control option for Coyote Unit 1 since the use of North Dakota lignite coal is an inherent aspect of plant operations.
Existing DFGD Operational Improvements:		
Lime Quality	No	Changing lime quality in the existing DFGD control system is not a technically feasible operational change for Coyote Unit 1.
Ca:S Stoichiometric Ratio	Yes	Increasing the Ca:S stoichiometric ratio by increase the quantity of fresh lime to the system is considered a technically feasible option for Coyote Unit 1, assuming the operational change is coupled with atomizer replacement.

SO_2 Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Approach to Saturation Temperature	No	Due to design limitations, further reducing the absorber module outlet temperature on the existing DFGD control system is not a technically feasible option for Coyote Unit 1.
Existing DFGD Equipment Upgrades:		
Atomizer Replacement	Yes	Replacing the existing atomizers is a technically feasible option for Coyote Unit 1 and would provide additional SO2 control if coupled with increasing the Ca:S stoichiometric ratio.
Slaker Replacement	No	Slaker replacement would not be expected to provide additional SO_2 control, and is not a technically feasible equipment upgrade for Coyote Unit 1.
Adding an Absorber Module	No	Coyote Unit 1 DFGD absorber modules are no longer commercially available, thus, adding an absorber module to the existing system is not a technically feasible SO_2 control option.
Replacing Existing Absorbers with New Absorber Modules	Yes	Replacing the exiting absorber modules with new absorber modules is a technically feasible SO_2 control system upgrade for Coyote Unit 1 that would require an approximate 12-month outage.
Existing DFGD + DSI	Yes	Hydrated lime sorbent injection upstream of the existing Coyote Unit 1 absorber modules is a technically feasible SO_2 control option. Flow modeling and field testing would be needed to confirm that the incremental reduction in SO_2 emissions is achievable without creating unacceptable operational issues.
Existing DFGD Operational Improvements (Increase Ca:S Stoichiometric Ratio) + DSI	Yes	Combining operational improvements (i.e., increased Ca:S stoichiometric ratio) with hydrated lime sorbent injection is a technically feasible SO_2 control option for Coyote Unit 1. Flow modeling and field testing would be needed to confirm that the incremental reduction in SO_2 emissions is achievable without creating unacceptable operational issues.
New Retrofit DFGD (CDS/FF)	Yes	Replacing the existing DFGD control system with a new retrofit DFGD (i.e., CDS/FF) is a technically feasible SO_2 control option for Coyote Unit 1.
New Retrofit WFGD	Yes	Replacing the existing DFGD control system with a new retrofit WFGD is a technically feasible SO_2 control option for Coyote Unit 1.

5.1.3 Evaluate Technically Feasible SO_2 Control Options for Effectiveness

The technically feasible SO_2 control technologies are listed in Table 5-8 in descending order of control efficiency. Table 5-8 also provides control option-specific SO_2 emission rates in terms of lb/MMBtu. Emission rates shown in

Table 5-8 represent average emission rates that the control options would be expected to achieve during normal operations.

Table 5-8. Evaluate Technically Feasible SO_2 Control Options for Effectiveness

Control Option	SO_2 Emission Rate (Note 1) lb/MMBtu	% Reduction from Baseline Emission Rate
Baseline (existing DFGD/FF)	0.85	-
New Retrofit WFGD	0.06	92.9%
New Retrofit DFGD (CDS/FF)	0.09	89.4%
New Retrofit DFGD (SDA/FF)	0.16	81.1%
FGD Upgrades - Replacing Existing Absorbers with New Absorber	0.29	65.9%
DSI + FGD Operational Improvements	0.33	61.2%
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0.50	41.2%
DSI + Existing FGD	0.58	31.8%

Note 1. Emission rates shown in Table 5-8 represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis; however, an additional 10-15% margin would likely be needed to account for operating margin.

5.2 NO_X EMISSIONS CONTROLS

5.2.1 Identify Available NO_X Control Options

Based on a review of available NO_X control technologies installed on existing cyclone coal-fired boilers, as well as operational practices and equipment upgrades implemented on existing control systems, potentially available options to control NO_X emissions from Coyote Unit 1 are listed in Table 5-9.

Table 5-9. Available NO_X Control Options

NO_X Control Technologies
Combustion Optimization
Selective Non-Catalytic Reduction (SNCR)
Rich Reagent Injection (RRI)
SNCR + RRI
Gas Reburn
Innovative Technologies (i.e. NOxStar, Water Injection, LoTOX, PerNOxide, Water Injection)
Selective Catalytic Reduction - High Dust, Low Dust or Tail End Configuration (TE-SCR)

5.2.2 Technical Feasibility of Available NO_X Control Options

Potentially available NOx control options identified in Table 5-9 were evaluated for technical feasibility (i.e. availability and applicability to Coyote Unit 1) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options deemed to be technically infeasible, or options that have no practical application to Coyote Unit 1, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emission performance level (i.e., controlled emission rate) for each.

5.2.2.1 Combustion Optimization

Coyote Unit 1 is equipped with twelve (12) ten (10) foot cyclones, six (6) on the front wall and six (6) each on the rear wall, two levels of three on each wall. The lignite coal requires a pre-dry system, which conveys the coal through individual crushers and into a cyclone separator for moisture separation. The dried coal is discharged from the bottom of the separator through a rotary seal, while the transport air (with a small quantity of fines) is discharged out the top and into ports above the cyclones. The coal discharged through the bottom rotary seal is blown into the cyclone through a pipe referred to as the "lift line" or known as primary air on most other similar installations. The temperature of the pre-dry air/coal temperature is regulated along with the lift line air by injecting cold (tempering) air into the hot primary air stream to regulate the outlet temperatures.

In 2016, The Babcock and Wilcox Company (B&W) installed fourteen (14) separated overfire air (SOFA) ports (seven on the front and rear wall) and modified the cyclones with smaller re-entrant throats and a ⅓ – ⅔ split secondary air damper (each having its own damper) to reduce NOx emissions. For the SOFA process, the injection of air into the boiler is staged into two zones, in which approximately 5% to 20% of the total combustion air is diverted from the burners and injected through ports located above the top burner level. Staging of the combustion air reduces NOx formation by two mechanisms. First, staged combustion results in a cooler flame which will reduce the formation of thermal NO_X. Second the staged combustion results in less oxygen reacting with fuel molecules. The degree of staging is limited by operational problems since the staged combustion results in incomplete combustion conditions and a longer flame profile. The units normally operate with the ⅓rd damper closed or nearly closed to help recirculate the coal in the cyclone and allows for increased coal retention and improved combustion. Since the SOFA installation, Coyote Unit 1 has achieved average controlled NOx emissions of approximately 0.46 lb/MMBtu.

Tuning of the cyclone boiler to optimize the combustion process and minimize the generation of NOx was recently completed at Coyote Unit 1. Tuning was completed by lowering the stoichiometry (i.e., lower the air-to-fuel ratio) in the cyclone barrel and tracking the cyclone combustion stability, while staying within the OEM specifications for best combustion engineering practice. Based on the testing results, Coyote Unit 1 was able to achieve average NOx emissions of approximately 0.42 lb/MMBtu without obvious impacts to boiler performance and with minimal slagging. Based on the results of the combustion turning tests, combustion optimization is considered a technically feasible NOx control option.

5.2.2.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH_3) or urea ($CO(NH_2)_2$) at high flue gas temperatures (approximately 1,600°F – 2,100°F) in an oxidizing environment. The ammonia or urea reacts with NO_x in the flue gas to produce N_2 and water as shown below.

$$(NH_2)_2CO + 2NO + \tfrac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$

$$2NH_3 + 2NO + \tfrac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reagent injection can greatly affect NO_x removal efficiencies and the quantity of NH_3 or urea that will pass through the SNCR unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective in the range of 1,600°F – 2,100°F. At temperatures below the desired operating range, the NO_x reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NO_x resulting in low NO_x reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Furnace geometry, urea spray coverage, and droplet size must be considered when developing good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reagent and flue gas in that temperature window. As the boiler cycles in load, the optimum injection region may change; thus, most facilities require multiple injection zones which are placed in and out of service as the unit ramps in load. This can include modifying the zones of injectors that are operating at different loads and temperatures.

Retractable multinozzle lances (MNLs) are sometimes used to improve SNCR performance, especially if the furnace exit flue gas temperatures are too high. The retractable lances allow injection into the appropriate temperature zone more so than wall injectors, depending on the unit load and temperatures. The MNLs also help improve performance by refining the spray pattern for quicker vaporization of the conveying water. MNLs are often used in conjunction with wall injection to provide optimized coverage while reducing reagent cost.

In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to-NO_x ratio, and fuel sulfur content. Increasing the normalized stoichiometric ratio (NSR) can improve NOx removal.[26] This can be achieved by increasing urea solution flow through the injectors or changing the concentration of urea in the solution. However, too high of reagent injection rates will increase the ammonia slip beyond the recommended 10 ppmvd limit. Above this concentration, there are expected to be major impacts to the formation of ammonia salts on the boiler tube banks, reducing heat transfer efficiency, and air heater baskets, causing corrosion.

SNCR can be applied on cyclone boilers due to having reasonable temperature windows and residence time; however, the potential NOx reduction is boiler-specific. SNCR has been used as a retrofit NOx control system of on pulverized coal, fluidized bed boilers, and cyclone boilers. Furthermore, SNCR can be implemented on boilers

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[26] NSR defines the amount of reagent needed to achieve the targeted NOx reduction. Based on the reaction equations in 5.2.2.2, two moles of NOx can be removed with one mole of urea or two moles of ammonia. In practice, more than the theoretical amount of reagent needs to be injected into the boiler flue gas to obtain a specific level of NOx reduction. This is due to the complexity of the actual chemical reactions involving NOx and injected reagent and mixing limitations between reagent and flue gas. Factors that influence the NSR value: (1)percent NOx reduction; (2) uncontrolled NOx concentration in the flue gas; (3) temperature and residence time available for the NOx reduction reactions; (4) extent of mixing achievable in the boiler; and (5) allowable ammonia slip.

equipped with low-NOx burners, overfire air, or SOFA systems. Based on the boiler residence time, temperature profile, and stoichiometry, as well as input from SNCR OEMs, it is estimated that an SNCR system could achieve an average controlled NO_x emission rate of approximately 0.28 lb/MMBtu (approximately 39% below the baseline emission rate of 0.46 lb/MMBtu) at full load while limiting ammonia slip to 10 ppmvd. It should be noted that computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NOx emission is achievable without creating unacceptable operational issues.

5.2.2.3 Rich Reagent Injection

Similar to SNCR, the concept of rich reagent injection (RRI) is to use a nitrogen-containing additive (e.g., urea) injected into a reducing environment to promote NO_X removal. RRI is a commercial technology for cyclone boilers only. In contrast to SNCR, RRI typically is applied with only one injection level in the lower furnace near the cyclone barrels (temperature window of 2000°F-2600°F). The technology requires a sub-stoichiometric oxygen concentration near the barrels at less than approximately 0.95. This allows for a higher injection rate of reagent without oxidizing the nitrogen-containing reagent to NOx due to the sub-stoichiometry. Injection at this location also creates lower level of excess NH_3 emissions (NH_3 slip), while injecting at an NSR of 2.0-3.0.

Due to the changes of the lower furnace stoichiometry, RRI is often not a technically feasible option at low loads. Once the stoichiometric ratio increases to >1.0, the potential exists for NOx generation due to the reaction of NH_3 with oxygen, especially if the injection location and rate is not optimized. Based on these limitations, RRI is considered most effective at full load.

The RRI process is a commercially available process. Based on engineering judgment, RRI is expected to reduce NO_X emissions by approximately 20-40% at Coyote Unit 1 when operating at full load with minimal ammonia slip. However, due to the cyclone combustion temperature window, this technology only provides effective NOx reduction at or near full load. At low loads, RRI does not provide effective control; however, RRI can be combined with SNCR to provide NOx control across the full range of normal operating loads. RRI is a technically feasible NOx reduction option for North Dakota lignite-fired cyclone boilers. However, due to its limited operating conditions and ineffective NOx reduction at low loads, RRI alone is not considered an available NOx control option, and will only be evaluated in conjunction with SNCR.

5.2.2.4 SNCR + RRI

While RRI alone will provide beneficial NOx reduction at full load only, coupling RRI with SNCR can provide a balanced approach to NOx reduction through all load ranges. Since RRI and SNCR injectors are located at different elevations of the furnace and in different temperature windows, there are not concerns of spatial impacts. The combined system would utilize a relatively high urea injection rate, staged at multiple locations throughout the boiler. The main advantage of this combined system is that the SNCR can provide better NOx reduction at low load and at a lower NSR than RRI alone; thus, the combined system is expected to provide effective NOx control across all normal operating load ranges. Coupling RRI and SNCR is considered a technically feasible and commercially available NOx control technology option on Coyote Unit 1. Based on input from SNCR OEMs and engineering judgment, the control option is expected to achieve an average outlet NOx rate of approximately 0.20 lb/MMBtu with an ammonia slip of 10 ppmvd. It should be noted that computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NOx emission is achievable without creating unacceptable operational issues.

5.2.2.5 Gas Reburn

Gas reburn is a retrofit technique that has been used to control NO_X emissions from coal- and oil-fired boilers. Gas reburn involves combustion in three distinct zones within the boiler: (1) a primary combustion zone, where the primary fuel is fired using conventional burners; (2) a reburn zone, where secondary fuel, typically natural gas, is introduced into the boiler; and (3) an OFA burnout zone.

In the primary zone of coal-fired boilers, coal is fired through low-NOx burners (LNBs), at a rate corresponding to approximately 80% to 90% of the total heat input. Natural gas reburn fuel is then injected above the primary combustion zone under fuel-rich conditions at a rate corresponding to approximately 10% to 20% of the total heat input (on a Btu/hour basis). The fuel-rich reburn zone creates a reducing (substoichiometric) region within the boiler where the natural gas, principally methane (CH_4), breaks down to produce hydrocarbon radicals (CH and CH_2). The hydrocarbon radicals react with NO_X produced in the primary combustion zone to form nitrogen (N_2) and water vapor. Because the natural gas is not completely combusted in the reburn zone, gases exiting the reburn zone will contain considerable CO and unburned hydrocarbons; therefore, additional OFA is introduced above the reburn zone to complete the combustion process.

Critical design parameters that affect the feasibility and performance of a gas reburn retrofit system include: (1) baseline NO_X concentration; (2) reburn zone temperature, residence time, and stoichiometry: (3) OFA burnout zone temperature and residence time; and (4) mixing of the reburn fuel and overfire air with the bulk flue gas.

Gas reburn can have a positive impact on NOx emissions; however, in order to make a meaningful prediction of the NO_X removal capabilities at Coyote Unit 1, extensive testing would be required because gas reburn performance is significantly dependent upon boiler operating characteristics. More importantly, the lack of natural gas available at the Coyote Station precludes the ability to test and implement this control option on Coyote Unit 1. For these reasons, gas reburn is not considered an available or technically feasible NOx control technology at Coyote Unit 1.

5.2.2.6 Innovative Technologies

NO_XStar™

The NO_XStar™ process, also known as selective autocatalytic reduction (SACR), uses a continuous controlled amount of ammonia-based reagent with relatively small amounts of hydrocarbon to reduce NO_X emissions. The hydrocarbon is introduced into the flue gas at the convective pass of the boiler, at elevated temperatures. At the elevated temperatures, the hydrocarbon auto-ignites to form a plasma of free radicals that auto catalyzes the reaction of NH_3 and NO_X to form N_2 and H_2O. The hydrocarbon and ammonia are added through banks of nozzles in the superheat or reheat sections of the boiler. The injection location is determined by the location of the temperature windows for the "plasma creation zone" as well as the reaction zone for the ammonia.

To date, only one full-scale demonstration has been conducted to evaluate the technology on a utility-sized boiler. The process is an emerging NO_X control, and there is limited information available to evaluate its technical feasibility and long-term effectiveness on a large lignite-fired boiler. Potential NO_X removal efficiencies would be a function of NH_3-NO_X mixing, flue gas temperature, flue gas composition, and residence time downstream of the injection lances.

Because this is an emerging technology, extensive design engineering and long-term full scale demonstration testing would be required to evaluate the technical feasibility and effectiveness of the control system on Coyote Unit 1. Detailed design of the lances, mixing, optimization of the reagent supply across the boiler convective pass, flue gas temperatures, and flow distribution would have to be studied. Interference with the tube pendants in the convective pass may also make this more difficult to install. Installing a hydrocarbon distribution grid may present a problem with large boilers because of the span needed to uniformly distribute the reagent, interference with the tube pendants in the convective pass, and an additional booster fan may be needed. For these reasons, NO_XStar™ is not considered an available or technically feasible NOx control technology at Coyote Unit 1.

PerNO$_X$ide

PerNO$_X$ide utilizes hydrogen peroxide (H_2O_2) to reduce NO_X emissions. Hydrogen peroxide is injected into the ducts ahead of the air preheater and oxidizes the NO to NO_2, which is then captured in a downstream FGD system. To date, the technology has only been tested on a pilot-scale, and it has not been demonstrated on any coal-fired boilers. It is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system on Coyote Unit 1. For these reasons, PerNO$_X$ide is not considered an available or technically feasible NOx control technology at Coyote Unit 1.

LoTO$_X$®

The LoTO$_X$ system is a gas-phase, low-temperature oxidation system, wherein ozone is injected into the flue gas stream to oxidize NO and NO_2 to N_2O_5 before being removed in a wet scrubber. This highly oxidized species of NO_X is water-soluble and rapidly reacts with water to form nitric acid. The conversion of NO_X to nitric acid occurs as the N_2O_5 contacts liquid sprays in the scrubber. The nitric acid would react with the alkali compounds in the scrubber and would be eliminated via the scrubber waste and byproduct streams. The LoTO$_X$ system requires on-demand ozone generation from a liquid oxygen supply.

The LoTO$_X$ system has been successfully applied in refinery applications; however, there are no full scale installations on coal-fired boilers. According to the control system vendor, a demonstration test was performed on a 25-MW coal-fired boiler which showed effective NO_X removal. However, it is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system on Coyote Unit 1. As such, LoTO$_X$ is not considered an available or technically feasible NOx control technology at Coyote Unit 1.

Water Injection

The principle behind this technology is to inject an atomized water spray into the high-NO_X production zones of a cyclone burner or in the core of the flame for other furnaces. The water spray reduces the temperature and results in lower thermal NO_X production within this combustion zone. Developers claim that water injection through burners used in tangential-fired and wall-fired units will also reduce flame temperatures and lower thermal NO_X production. However, to date only bench-scale test results are available to evaluate this technology's effectiveness in coal-fired applications. Extensive design engineering, pilot-scale testing, and long-term full scale demonstration testing would be required to evaluate the technical feasibility and effectiveness of the control system on Coyote Unit 1.

Water injection has been used to control the formation of thermal NOx in combustion turbine applications. However, there is insufficient experience and demonstration data in coal-fired applications. As such, water injection is not considered an available or technically feasible NOx control technology at Coyote Unit 1.

5.2.2.7 Selective Catalytic Reduction

SCR is a process by which ammonia reacts with nitric oxide (NO) and nitrogen dioxide (NO_2), collectively NOx, in the presence of a catalyst to reduce the NO_X to nitrogen (N_2) and water. SCR technology has been applied to NO_X-bearing flue gases generated from power generating facilities burning various types of coal, including bituminous, subbituminous, and Texas lignite. The principal reactions resulting in NO_X reduction are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NO_2 + 8NH_3 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

Because these reactions proceed slowly at typical boiler exit gas temperatures of a coal-fired steam electric generating unit, a catalyst is used to increase the reaction rate between NO_X and ammonia. Depending on the specific constituents in the flue gas, a typical temperature range of 550°F to 780°F is necessary to achieve normal performance of the catalyst. For the typical coal-fired boiler, optimal performance will be in the range of approximately 650°F to 750°F.

In general, there are three candidate SCR configurations that can be employed on coal-fired steam electric generating units. The SCR configuration designations generally describe the location of the SCR reaction vessel in relation to other post-combustion air quality control systems. Candidate SCR configurations include:

- High-dust configuration
- Low-dust configuration
- Tail-end configuration

Each of these configurations is described below as they would be applied at Coyote Unit 1.

High-Dust Configuration

In a high-dust configuration, the SCR reactor is located in the flue gas stream between the economizer outlet and the air heater inlet. This configuration locates the SCR within the inherently optimal temperature range environment for NOx reduction (i.e., 650°F to 750°F); however, flue gas characteristics at the economizer outlet can also have detrimental effects on the SCR catalyst. As an example, the high-dust SCR configuration exposes the SCR catalyst to high levels of fly ash loading. High levels of fly ash can result in significant erosion of the catalyst, resulting in more frequent cleaning cycles and catalyst replacement. A second major concern with the high-dust configuration at Coyote Unit 1 is the presence of high levels of sodium (both in the vapor-phase and as submicron aerosols) in the North Dakota lignite-derived flue gas. Sodium is a known SCR catalyst poison, and also affects the adhesive and cohesive characteristics of the fly ash, which in turn, would have an adverse effect on the SCR catalyst and reactor vessel.

SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation) or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition). Loss of catalyst activity through thermal degradation or poisoning is permanent, and reactivity can only be restored by replacing the catalyst.

In a North Dakota lignite application, SCR catalyst poisoning is expected to result from the presence of trace elements and strong alkaline substances in flue gas, including sodium (Na), potassium (K), and calcium (Ca). Alkaline metals can chemically attach to active catalyst pore sites and cause deactivation. Sodium and potassium are of prime concern especially in their water-soluble forms, which are more mobile and can penetrate into the catalyst pores. Earth metals, especially calcium, can react with SO_3 absorbed within the catalyst to form $CaSO_4$ and blind the catalyst.

North Dakota lignite contains relatively high levels of organically associated alkali and alkaline-earth elements, including Na, Ca, K, and magnesium. Sodium levels in North Dakota lignite are typically 5 to 20 times higher than sodium levels in bituminous and subbituminous coals, and sodium compounds can represent between 5% and 11% of the ash generated from firing North Dakota lignite. These sodium levels, occurring in both the vapor phase and particulate phase, along with relatively high levels of potassium and calcium, significantly increase the potential for catalyst deactivation, plugging, and erosion. Based on the ash chemistry, a conventional high dust SCR arrangement would likely experience unacceptable catalyst deactivation rates.

To evaluate deactivation rates on a North Dakota lignite-fired boiler, EERC and several utilities and catalyst vendors conducted pilot scale testing at the Coyote Station in 2003-2004. The pilot scale test reactor SCR deployed at the Coyote Station became plugged and the catalyst pores deactivated after 2 months of operation (approximately 1,430 hours). This deactivation rate is significantly faster than the deactivation rate observed on bituminous and subbituminous coal-fired units, which can achieve catalyst life ranging between 10,000 and 30,000 operating hours. The EERC described the deactivation at the Coyote Station as extremely rapid and severe.[27]

NDDEQ prepared a comprehensive technical feasibility assessment of high dust SCR on lignite-fired boilers during the first planning period.[28] The Department concluded, based on the unique characteristics of North Dakota lignite-derived flue gas, that the high-dust SCR configuration was not a technically feasible or commercially available NOx control option for North Dakota lignite-fired boilers.[29] Reasons upon which NDDEQ based its conclusion that high-dust SCR was not a technically feasible option for North Dakota lignite-fired boilers included, but were not limit to:[30]

1) North Dakota lignite[31] has a higher organic matter content and contains a higher proportion of alkali metal constituents, especially sodium, than subbituminous coal. Approximately 75% of the total sodium in lignite is associated with the organic fraction of the lignite. During combustion, organic and water-soluble sodium vaporizes; consequently, combustion of the coal leads to higher flue-gas concentrations of alkali metals in vapor form.
2) The unburned or partially burned organic fraction of North Dakota lignite contains more sodium than other coals. Sodium can react with silicate particles causing a "stickiness" quality to the flue gas ash, resulting in increased ash deposition on heat transfer surfaces. Larger particles can fracture from heat-transfer surfaces (a.k.a. popcorn ash) and enter the flue gas stream. Consequently, deposition on surfaces of catalytic reactors occurs and rates of deposition are higher.
3) NOx reduction occurs on the flat surfaces of a catalyst and in pores within the flat surfaces. The pores are open to the flue gas passing through the catalyst reactor. Condensed vapors, alkali sulfates and alkaline-earth oxides and silicates are minute particles (less than 1 microns), which enter pores of the catalyst (a.k.a. plugging) and prevent catalytic reaction with NOx. Residual alkali vapors (Na, K, and Ca) displace hydrogen on fresh catalyst, which prevents catalytic reaction with NOx (a.k.a poisoning) and reacts with

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[27] See, Benson, Steven A., Energy and Environmental Research Center, Ash Impacts on SCR Catalyst Performance, University of North Dakota, Grand Forks, ND.
[28] See, North Dakota State Implementation Plan for Regional Haze, February 24, 2010, Appendix B.5, Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite, July 2009.
[29] Id. at pg. 19.
[30] Findings and conclusions are summarized from the North Dakota Regional Haze SIP, Appendix B.5, pgs. 15-19.
[31] Although the BART determination specifically references Fort Union lignite, the findings would apply to all North Dakota lignites.

sulfate to cause blinding of catalyst surfaces. Pore condensation of sodium also causes catalyst deactivation, which is a major deactivation mechanism. The rate of catalyst deactivation depends on the concentration and form of alkali in the flue gas; higher Na and K accelerate catalyst poisoning, blinding and plugging.

4) During the development of the initial planning period SIP, NDDEQ found that there were no SCR systems planned, constructed, or operating in the flue gas stream of boilers fired with North Dakota lignite. North Dakota lignite has certain coal characteristics that are uniquely different than Texas or Gulf Coast lignites, such as the larger proportion of organic matter and association of alkali, sodium specifically, with that organic matter.

5) Slipstream SCR reactors of the same design were installed at three power plants to test SCR for NOx emissions control. One of the plants was cyclone fired with North Dakota lignite and the others with subbituminous coal. Deposition on the reactor surface after two months using the lignite was significantly greater; the deposits were rich in sodium, calcium, and sulfur. The tests confirmed catalyst blinding and plugging, but did not provide rates for catalyst deactivation. Tests also indicated that the deposits causing blinding and plugging of pores contained more sodium compared to PRB coal.

Based on a review of SCR installations on coal-fired boilers and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) and the adhesive/cohesive characteristics and potential abrasive qualities of the North Dakota lignite-derived fly ash remain a concern for North Dakota lignite-fired boilers. SCR has not been installed and successfully operated on a North Dakota lignite-fired boiler, and the bench scale and pilot-scale studies needed to better understand ash behavior and catalyst blinding/erosion with North Dakota lignite-derived fly ash, and to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been required or completed. Pilot-scale studies are needed to evaluate these issues to inform the development of advanced catalyst formulations, and to support the engineering and design studies needed to mitigate for potential deactivation routes (e.g., removing soluble alkali compounds from the flue gas and SCR design considerations such as catalyst formulation, catalyst pitch, reactor velocity, and catalyst surface and volume). Pilot-scale tests and engineering/design studies have not advanced since the first planning period's exhaustive analysis.

These issues have not been resolved since the first planning period and remain a significant barrier to the design and successful operation of high dust SCR on North Dakota lignite-fired boilers. The BART Guidelines state that "[a] control technique is considered available…if it has reached the stage of licensing and commercial availability."[32] Commercial availability follows bench scale and laboratory testing and pilot scale testing. Consequently, the BART Guidelines state that "you would not consider technologies in the pilot scale testing stages

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[32] 40 CFR Part 51 Appendix Y, Section D.2.1.

of development as 'available' for purposes of BART review."[33] Furthermore, source owners/operators are not expected to conduct extended trials to learn how to apply a technique on a dissimilar source type.[34] These BART guidelines also apply as a recommendation for the development of the LTS in the second planning period and the four factor analysis.[35] Because there are unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not an available technically feasible NOx control technology for Coyote Unit 1.

Low-Dust Configuration

In the low-dust configuration, the SCR reactor vessel is located in the flue gas stream after the particulate collection device (i.e. ESP or FF). Employing this configuration would represent a relatively low level of exposure to fly ash (with the exception of submicron ash particles), but a potentially high level of vapor-phase alkalis, such as sodium. This configuration can be used on units equipped with particulate control only or units equipped with particulate control followed by a WFGD control system. The existing dry FGD/FF control configuration at Coyote Unit 1 for SO_2 and particulate control would preclude the application of a low-dust SCR configuration since, by definition, the SCR would have to be located downstream of both the dry FGD and FF. At that location the SCR would be more appropriately defined as a tail-end SCR configuration, which is described in more detail in the following section. Because Coyote Unit 1 is equipped with existing dry FGD/FF controls, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered a technically feasible NOx control option for Coyote Unit 1.

Tail-End Configuration

In the tail-end configuration, the SCR reaction vessel is located in the flue gas stream after the particulate and FGD control systems. The potential advantage of a tail-end SCR configuration at Coyote Unit 1 is that the flue gas will have passed through the dry FGD/FF system prior to the SCR catalyst. As such, there is the possibility that the mass transfer mechanism that results in the capture of SO_2 will also capture some of the vapor-phase sodium and the sodium-enriched submicron particles, reducing the risk of catalyst poisoning and/or deactivation.

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[33] Id.
[34] Id.
[35] See, Draft EPA Guidelines, pg. 183.

Successful operation of the tail-end configuration would also require a capital and operating cost-intensive gas-to-gas heat exchanger to reheat the flue gas from approximately 200 °F downstream of the existing FF to approximately 550°F to support the SCR NOx reactions. After the flue gas passes through the SCR (at approximately 550°F), it would pass through the hot side of the gas-to-gas heat exchanger to cool the flue gas to 150°F prior to the exhaust stack. Although this stack gas temperature would be lower than the current stack temperature (190-210°F), it is still higher than the adiabatic saturation temperature of the flue gas (i.e., approximately 135°F). As such, it is likely that the existing stack could be reused without any major modifications.

During the first planning period, NDDEQ initially concluded, based on preliminary information provided by SCR catalyst vendors, that the tail-end SCR configuration would be a technically feasible option for units firing North Dakota lignite that are subject to BART requirements.[36] However, as part of the Milton R. Young Station (MRYS) NOx BACT determination process, detailed information describing the expected ash characteristics and flue gas characteristics was provided to two SCR catalyst vendors (CERAM Environmental, Inc. (CERAM) and Haldor Topsoe, Inc.). Based on their review of the data, both vendors concluded that they would not be able to provide a catalyst life guarantee for either low-dust or tail-end SCR without pilot-scale testing.[37]

Both vendors also made statements bringing into question the technical feasibility of either low-dust or tail-end SCR. For example, CERAM stated that the high levels of sodium oxide (Na_2O) in the ash for North Dakota lignite are not commonly found in subbituminous and bituminous coals which are fired in boilers equipped with SCR systems, and that it was unaware of any SCR application experience in the industry with the level and form of sodium in the North Dakota lignite-derived MRYS ash.[38]

Based in part on this information provided by SCR design engineering firms and SCR catalyst vendors, NDDEQ concluded that the use of SCR technology, including low-dust and tail-end SCR, on the lignite-fired MRYS boilers would be technically infeasible.[39]

Based on a review of SCR installations on coal-fired boilers, and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) remain a concern for all North Dakota lignite-fired boilers. Tail-end SCR has not been demonstrated or installed on a North Dakota lignite-fired boiler, and there are still significant technical

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[36] See, North Dakota Regional Haze State Implementation Plan for Regional Haze, February 24, 2010, Appendix B.5, pg. 25.
[37] See, United States v. Minnkota, 831 F. Supp. 2d, at 1116- 1117.
[38] Id., at 1115-1116.
[39] Id., at 1118.

concerns associated with the availability of existing SCR catalysts on a North Dakota lignite-fired unit. Catalyst in a tail-end SCR will still be vulnerable to alkali poisoning, pore pluggage, and premature catalyst deactivation, and it is not known whether the comparatively high levels of soluble sodium and potassium in North Dakota lignite will be effectively removed by the upstream dry FGD/FF. Furthermore, the potential exists for fine particulate remaining in the flue gas to get into the catalyst pores reducing catalyst activity. Pilot-scale studies needed to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been completed.

In order to understand the effect of North Dakota lignite-derived flue gas on the tail-end SCR catalyst, identify potential design solutions, and evaluate the technical feasibility and effectiveness of tail-end SCR at Coyote Unit 1 with any degree of certainty, extended pilot scale testing of the control configuration would be needed. Additionally, because there are unresolved issues associated with catalyst poisoning, it's unlikely that OTP could obtain a viable commercial offering for tail-end SCR on Coyote Unit 1. Therefore, tail-end SCR is not an available technically feasible NOx control technology.

SCR Summary

During the first planning period NDDEQ determined that high-dust SCR and tail-end SCR are not available, and thus, not a technically feasible NOx control option for North Dakota lignite-fired boilers. The administrative record developed during the first planning period, including the BART determinations and MRYS BACT analysis, supports the conclusion that high-dust SCR and tail-end SCR are not an available NOx control option for Coyote Unit 1. An evaluation of SCR installations and reported advances in SCR catalysts since the first planning period, coupled with the fact that high-dust SCR and tail-end SCR have not been demonstrated on a North Dakota lignite-fired boiler, and the likelihood that OTP could not obtain a viable commercial offering for tail-end SCR without extended pilot-scale testing, continues to support the conclusion that high-dust SCR and tail-end SCR are not available NOx control technologies.

5.2.2.8 Technical Feasibility Summary

Table 5-10 summarizes the results of the feasibility evaluation of available control options for Coyote Unit 1.

Table 5-10. Technically Feasible NOx Control Options

NOx Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Combustion Optimization	Yes	Tuning to optimize the existing combustion system, including lower the stoichiometry in the cyclone barrels, tracking cyclone combustion stability, and adjusting the SOFA system (while staying within original OEM specifications) is a technically feasible NOx control option.
Selective Non-Catalytic Reduction (SNCR)	Yes	SNCR is considered an available and technically feasible NOx control technology for Coyote Unit 1. Computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NOx emissions is achievable without creating unacceptable operational issues.
Rich Reagent Injection (RRI)	No	RRI is considered an available and technically feasible NOx control option cyclone burners at full load operation; however, at low load operation RRI does not provide effective NOx control. Therefore, RRI alone is not considered an available NOx control option, and will only be evaluated in conjunction with SNCR.
SNCR + RRI	Yes	Coupling RRI and SNCR is considered a technically feasible and commercially available NOx control technology option on Coyote Unit 1. Computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NOx emissions is achievable without creating unacceptable operational issues.
Gas Reburn	No	The lack of natural gas availability at the Coyote Station precludes the ability to test and implement this control option on Coyote Unit 1. Therefore, gas reburn is not considered an available or technically feasible NOx control technology at Coyote Unit 1.
Innovative Technologies: NOxStar™ PerNO$_X$ide LoTO$_X$ Water Injection	No	Innovative NOx control technologies are evaluated in Section 5.2.2.6. In all cases, the technologies have not been demonstrated on a large North Dakota lignite-fired boiler. Extensive testing and design engineering would be required to evaluate the technical feasibility and long-term effectiveness of each innovative control system on Coyote Unit 1. Therefore, the innovative NOx control technologies are not considered available control options and are not technically feasible NOx control options for Coyote Unit 1
Selective Catalytic Reduction (SCR):		
High-dust configuration	No	Due to significant unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and based on the finding that engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not and available or technically feasible NOx control technology for Coyote Unit 1.
Low-dust configuration	No	Because Coyote Unit 1 is equipped with existing dry FGD/FF

NOx Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
		control systems, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered an available or technically feasible NOx control option for Coyote Unit 1.
Tail-end configuration	No	Based on the continued lack of demonstration testing and commercial guarantees, tail-end SCR is not considered to be a technically feasible control option for Coyote Unit 1.

5.2.3 Evaluate Technically Feasible NO_X Control Options for Effectiveness

The technically feasible NO_X control technologies are listed in Table 5-11 in descending order of control efficiency. Table 5-11 also provides control option-specific NOx emission rates in terms of lb/MMBtu. Emission rates shown in Table 5-11 represent average emission rates that the control options would be expected to achieve during normal operations.

Table 5-11. Evaluate Technically Feasible NO_X Control Options for Effectiveness

Control Technology	NO_X Emission Rate (Note 1) lb/MMBtu	% Reduction from Baseline Emission Rate
Baseline (existing SOFA)	0.46	-
SNCR + RRI + Combustion Optimization	0.20	56.2%
SNCR + Combustion Optimization	0.28	38.7%
Combustion Optimization	0.42	8.0%

Note 1. Emission rates shown in Table 5-11 represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for Coyote Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis; an additional margin would likely be needed to account for operating margin. Additionally, for control options that include SNCR or RRI, computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NOx emission is achievable without creating unacceptable operational issues.

6. COSTS OF COMPLIANCE (STATUTORY FACTOR ONE)

The economic analysis performed as part of the Four Factor analysis examines the cost-effectiveness of each technically feasible control technology, on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. For units with existing controls, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual operation and maintenance (O&M) costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of control equipment. Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25%[41] and equipment life of 20 years.[42] Cost effectiveness ($/ton) of a particular control option is simply the annual cost ($/yr) divided by the annual reduction in annual emissions (ton/yr). In addition to cost-effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the incremental cost effectiveness of the more stringent control.

Capital and O&M cost estimates were developed for each of the technically feasible SO_2 and NO_X control options. The Coyote Unit 1 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Unit 1 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on Coyote Unit 1-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the Coyote Unit 1 retrofit technologies as "concept screening" cost estimates generally based on parametric models, judgment, or analogy.

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[41] In an email to the North Dakota Department of Health dated December 18, 2018, EPA recommended use of a 5.25% interest rate. Otter Tail does not necessarily agree that this is an appropriate percentage to use and reserves the right to update and modify this percentage at a later date. Notably, on September 26, 2018 the North Dakota Public Service Commission approved a rate of return for Otter Tail of 7.64% (See https://psc.nd.gov/database/documents/17-0398/226-020.pdf). This ROR represents a total weighted average cost of capital. An interest rate of 5.25% is more representative of the long-term cost of debt, which is only one component of capital structure.

[42] The assumed 20-year equipment life is consistent with the control system equipment life used by NDDEQ in its evaluation of NO_X and SO_2 control technologies for BART-eligible sources. (see, e.g., ND Regional Haze Final SIP, Appendix C.1, "BART Determination Study for Leland Olds Station Units 1 & 2, Basin Electric Power Cooperative, August 2006, pgs. 64 (NOx controls) and 158 (SO2 controls). See also, ND Regional Haze Final SIP, Appendix C4, "NOx Best Available Control Technology Study for Milton R. Young Station Unit 1, Minnkota Power Cooperative, Inc., October 2006, pg. 3-22).

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, Contractor G&A expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements.[43] Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing dry scrubber and FF control systems.

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

The results of the SO_2 and NO_X control cost evaluations are included below in Sections 6.1 and 6.2.

6.1 ECONOMIC EVALUATION – SO_2 CONTROLS

Table 6-1 presents the capital costs and annual operating costs associated with installing and operating each technically feasible SO_2 control system for Unit 1. Table 6-2 shows the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix B.

Cost estimates were not prepared for the SDA/FF option since the capital and operating costs for the SDA/FF option would be similar to the costs for the CDS/FF option, and the CDS/FF option would likely provide the opportunity to achieve somewhat lower controlled SO_2 emissions (compared to SDA/FF). Therefore, of the two new DFGD system options, only the CDS/FF option was evaluated.

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[43] Variable O&M costs are based on an uncontrolled SO_2 of 2.3 lb/MMBtu as recommended by the NDDEQ.

Table 6-1. SO_2 Control Cost Summary (\$2018)

SO_2 Control Option	Total Capital Investment \$	Annualized Capital Cost \$/yr	Annual Operating Cost \$/yr	Total Annual Cost \$/yr
DSI + Existing FGD	\$23,765,000	\$1,948,000	\$10,423,000	\$12,371,000
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	\$526,000	\$43,000	\$2,042,000	\$2,085,000
DSI + FGD Operational Improvements	\$24,292,000	\$1,991,000	\$12,465,000	\$14,456,000
FGD Upgrades - Replacing Existing Absorbers with New Absorber	\$127,823,000	\$10,475,000	\$6,332,000	\$22,197,000(Note 1)
Dry FGD (CDS) + Existing FF	\$242,647,000	\$19,885,000	\$20,610,000	\$40,495,000
Wet FGD	\$324,742,000	\$26,613,000	\$22,481,000	\$49,094,000

Note 1. Total annual cost for "FGD Upgrades - Replacing Existing Absorbers with New Absorber" option includes annualized lost revenue due to extended outage and replacement power required for installation (\$5,390,000).

Table 6-2. SO$_2$ Emissions Control System Cost Effectiveness ($2018)

SO$_2$ Control Option	Total Annual Cost $/yr	Expected Emission Reduction tons SO$_2$/yr	Average Annual Cost Effectiveness (Note 1) $/ton SO$_2$ removed	Incremental Annual Cost Effectiveness (Note 2, 3) $/ton SO$_2$ removed
Baseline (Existing DFGD/FF)	---	---	---	---
DSI + Existing FGD	$12,371,000	4,131	$2,994	
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	$2,085,000	5,354	$389	n/a
DSI + FGD Operational Improvements	$14,456,000	7,952	$1,818	$4,762
FGD Upgrades - Replacing Existing Absorbers with New Absorber	$22,197,000	8,563	$2,592	$12,664
Dry FGD (CDS) + Existing FF	$40,495,000	11,619	$3,485	$5,987
Wet FGD	$49,094,000	12,078	$4,065	$18,757

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.
Note 2. Incremental cost effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.
Note 3. "n/a" indicates that the next most effective control option is "inferior" (i.e., higher cost for less control)

Table 6-2 indicates that the average annual cost effectiveness of the technically feasible SO$_2$ control options for Unit 1 range from $389 per ton (FGD Operation Improvements) to $4,065 per ton (Wet FGD). Costs associated with equipment procurement and installation, and annual operating costs all have a significant impact on the cost of the SO$_2$ control systems.

Annual costs of the DSI system exceed the costs of the FGD Operational Improvements option, and the DSI system achieves lower SO$_2$ reductions. Therefore, the DSI system is an "inferior" control option.

The FGD Operational Improvements option would require the relatively low capital investment for upgrading the existing atomizer wheel and an increase in operating costs primarily due to increased reagent usage. This option will achieve approximately 41% SO$_2$ reduction from the baseline levels, resulting in a cost effectiveness of $465 per ton.

The option to incorporate FGD Operational Improvements and install a DSI system will achieve approximately 61% SO_2 reduction from the baseline. Capital costs are primarily attributed to the DSI equipment, and high operating costs are due to a significant increase in hydrated lime use. The cost effectiveness of the DSI + FGD Operational Improvements option is $1,818 per ton. Comparing this option to the next most effective control option, FGD Operational Improvements (without DSI), the incremental costs effectiveness is $4,762 per ton.

Replacing the existing absorber modules with new absorber modules will require Coyote Unit 1 to be taken off-line for approximately 12 months. In addition to capital and operating costs, the Coyote Station will incur costs associated with lost production and purchase of replacement power. The cost effectiveness of the FGD Upgrade - Replacing Existing Absorbers with New Absorber option is $2,592 per ton. Comparing this option to the next most effective control option, DSI + FGD Operational Improvements, the incremental cost effectiveness is $12,664 per ton.

The installation of new Dry FGD (CDS) or new Wet FGD systems are high capital and annual operating cost options. The cost effectiveness for these options are $3,485 per ton (Dry FGD) and $4,065 per ton (Wet FGD). The incremental cost of installing a Dry FGD system, compared to FGD Upgrades, is $5,987 per ton. The incremental cost of installing a Wet FGD system, compared to a Dry FGD system, is $18,757 per ton.

6.2 ECONOMIC EVALUATION – NO_X CONTROLS

Table 6-3 presents the capital costs and annual operating costs associated with building and operating each control system. Table 6-4 shows the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix C.

Table 6-3. NO_X Control Cost Summary ($2018)

NO_X Control Option	Total Capital Investment $	Annual Capital Cost $/yr	Annual Operating Cost $/yr	Total Annual Cost $/yr
Combustion Optimization	$0	$0	$0	$0
SNCR + Combustion Optimization	$19,840,000	$1,626,000	$3,128,000	$4,754,000
SNCR + RRI + Combustion Optimization	$25,895,000	$2,122,000	$6,495,000	$8,617,000

Table 6-4. NO_X Emissions Control System Cost Effectiveness ($2018)

NO_X Control Option	Total Annual Cost $/yr	Expected Emission Reduction tons NO_X/yr	Average Annual Cost Effectiveness (Note 1) $/ton NO_X removed	Incremental Annual Cost Effectiveness (Note 2) $/ton NO_X removed
Baseline (Existing SOFA)	---	---	---	---
Combustion Optimization	$0	589	$0	$0
SNCR + Combustion Optimization	$4,754,000	2,847	$1,670	$2,105
SNCR + RRI + Combustion Optimization	$8,617,000	4,137	$2,083	$2,994

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.
Note 2. Incremental cost effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

Table 6-4 indicates that the average annual cost effectiveness of the technically feasible NO_X control options for Unit 1 range from $0 per ton (Combustion Optimization) to $2,083 per ton (SNCR + RRI) NO_X removed.

The Combustion Optimization option is expected to achieve 8% NO_X reduction from baseline levels without impact to boiler performance. This option can be implemented without additional capital or operating costs; therefore, the cost effectiveness is $0 per ton.

Installation of an SNCR system is expected to achieve approximately 39% NO_X reduction. The cost effectiveness of this option is $1,670 per ton. Compared the next most effective option, Combustion Optimization, the incremental cost effectiveness is $2,105 per ton.

The option to install an SNCR system combined with RRI would achieve approximately 56% NO_X reduction. Compared to installing SNCR alone, this option incurs additional capital costs for the RRI system and higher operating costs primarily due to increased urea consumption. The cost effectiveness of the SNCR + RRI option is $2,083 per ton, and the incremental cost compared to SNCR alone is $2,994 per ton.

7. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO)

The time necessary for compliance is generally defined as the time needed for full implementation of the technically feasible control options. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. If reasonable progress measures are required at Coyote Station for the Reginal Haze second planning period, the anticipated compliance deadline would be July 1, 2028.[44] However, this compliance deadline must provide a reasonable amount of time for the source to implement the control measure.

Table 7-1 and Table 7-2 include estimated timeframes needed to implement each of the technically feasible control options. Notably, the estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve North Dakota's SIP.

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[44] For the first planning period, on March 14, 2011 the North Dakota Department of Health issued permit to construct number PTC10008 that required Coyote Station to meet the approved reasonable progress limitation by July 1, 2018.

Table 7-1. SO_2 Emissions Control System Implementation Schedule

SO_2 Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
DSI + Existing FGD	6	6	6	18
FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0	0	0	0
DSI + FGD Operational Improvements	6	6	6	18
FGD Upgrades - Replacing Existing Absorbers with New Absorber	8	12	12	32
Dry FGD (CDS) + Existing FF	12	20	18	50
Wet FGD	12	22	22	56

Table 7-2. NO_X Emissions Control System Implementation Schedule

NO_X Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
Combustion Optimization	0	0	0	0
SNCR + Combustion Optimization	10	6	6	22
SNCR + RRI + Combustion Optimization	10	6	6	22

8. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE)

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal.

8.1 ENVIRONMENTAL IMPACTS

Coyote Unit 1 is currently equipped with SOFA for NOx control and dry scrubber technology for SO_2 control. The hydrated lime reactant used in a dry scrubbing system reacts with SO_2 in the flue gas to form calcium sulfate and calcium sulfite solids. The solids are captured in the existing FF particulate control system and either returned to the system for reuse or removed from the system as nonhazardous solid waste. The existing dry scrubbing system also requires water to hydrate the lime prior to injection into the reaction modules. Based on the design of the control system, Coyote Unit 1 currently uses approximately 465 gpm of water to hydrate the lime (at full load). Collateral environmental impacts associated with the existing Coyote Unit 1control systems include water consumption and increased solid waste generation. There were no collateral impacts associated with the SOFA system.

Based on a review of potential non-air quality environmental impacts, no significant collateral environmental impacts were identified for any of the SO_2 and NOx control options included in this evaluation, with the exception, potentially, of the WFGD, DSI, and SNCR/RRI options. No significant non-air quality environmental impacts were identified for the options that include replacing the existing scrubber modules with new scrubber modules, FGD operational improvements/upgrades or combustion optimization. Collateral environmental impact identified for the sorbent injection control option includes an increase in the solid waste generation. The sorbent injection system will increase the solid waste generated by approximately 50% (47,000 lb/hr to 70,000 lb/hr).

There are a number of potential non-air quality environmental impacts associated with the WFGD control option. Unlike dry scrubbing systems that generate a dry FGD byproduct, WFGD systems generate a liquid calcium sulfate by-product that must be dewatered prior to disposal. WFGD control systems can be designed with forced oxidation that results in a gypsum-grade by-product that can be sold into the local gypsum market. If an adequate gypsum market is not available, the gypsum by-product will require disposal. WFGD control systems also generate a wastewater stream that must be treated prior to discharge. WFGD wastewaters typically consist of a saturated solution of calcium sulfate, calcium sulfite, and sodium chloride, with trace amounts of fly ash and unreacted limestone. Traces of metal ions may also be present due to fly ash carryover from the flue gas to the WFGD scrubber liquor. WFGD wastewater treatment systems typically require calcium sulfate/sulfite desaturation, heavy metals precipitation, coagulation/precipitation, and sludge dewatering. Treated wastewater is typically discharged to surface water pursuant to an NPDES discharge permit, and solids are typically disposed of in a landfill.

WFGD systems also require significantly more water than the dry systems. Based on design criteria for wet and dry FGD control systems, WFGD systems typically require approximately 25-30% more water than a similarly sized DFGD control system. This would increase water consumption at Coyote Unit 1 on average approximately 130 gpm. Water consumption is an important factor when assessing potential non-air quality environmental impacts at facilities located in North Dakota, and could represent a significant non-air quality collateral environmental impact.

In addition, the SNCR and SNCR/RRI control options have the collateral impact of ammonia slip emissions at 10 ppm since these options utilize ammonia as the reagent for the reactions with NOx to occur. Ammonia slip emissions from the SNCR/RRI options will likely end up in the dry FGD solids.

8.2 ENERGY IMPACTS

Options that include replacing the existing Unit 1 dry scrubbing system with a CDS/FF or WFGD system will increase pressure drop through the control systems, increase auxiliary power requirements, and adversely affect the unit' net plant heat rate (Btu heat input per MW_{Net} output).[45] Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease.

Although several of the control options have energy impacts, none of the impacts are considered significant enough as to disqualify any of the options from consideration in the four factor analysis. In order to account for potential energy impacts associated with each option, the auxiliary power cost associated with operating the control systems have been included as an annual operating cost in the economic impact assessment.

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[45] Heat rate represents the amount of heat input to the boiler (Btu) required to generate one megawatt (MW) net electric output and is reported as Btu/MW_{Net}.

8.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY

A summary of the environmental and energy impact analysis is provided in Table 8-1.

Table 8-1. Summary of Energy and Non-Air Quality Environmental Impacts

Control Option	Collateral Environmental & Energy Impacts
Baseline	➢ Coyote Unit 1 is currently equipped with dry scrubbing / FF control systems. Existing collateral environmental and energy impacts include: ➢ Solid FGD by-product management and disposal ➢ Increased water consumption ➢ Increased auxiliary power requirements and heat rate penalty
<u>SO_2 Control Options</u>	
Replace existing DFGD with New WFGD control system	➢ Increased water consumption ➢ Wet by-product that requires dewatering prior to disposal ➢ FGD wastewater treatment & discharge ➢ Increased auxiliary power requirements and heat rate penalty
Replace existing DFGD with New CDS/FF Control System	➢ Increased auxiliary power requirements and heat rate penalty ➢ Increased solid FGD by-product management and disposal
Replace existing dry scrubber modules with New DFGD modules while keeping existing FF	➢ Requires extended (approximately 12-month) outage of Coyote Unit 1 to demolish and replace the existing scrubber modules
Dry Sorbent Injection	➢ Increased solid FGD by-product management and disposal ➢ Increased auxiliary power requirements and heat rate penalty
<u>NOx Control Options</u>	
SNCR or SNCR + RRI	➢ Increased ammonia slip emissions ➢ Increased auxiliary power requirements and heat rate penalty

9. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR)

The evaluation of technically feasible NO_X and SO_2 controls options should consider the source's "remaining useful life" in determining the costs of compliance. The remaining useful life is the difference between the date that controls would be put in place and the date that the facility permanently ceases operation. If the remaining useful life of the unit is shorter than the useful life of a particular control option, the remaining useful life should be used to annualize costs. If the remaining useful life exceeds the useful life of the control options, the remaining use life has no effect on the cost evaluation.

The cost of compliance for each control option (see Section 6) currently calculates the annual capital recovery cost by multiplying the total capital investment by a CRF from a formula based on a 20-year equipment lifetime. The Coyote Station owners have not identified dates for the remaining useful life of the unit before the end of what would otherwise be the useful life of the control measures that were evaluated for Coyote Unit 1. Thus, the 20-year equipment life of the control measures was used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness.

10. FOUR-FACTOR ANALYSIS SUMMARY

At the request of NDDEQ, a four factor analysis was prepared for Coyote Unit 1. The analysis identified technically feasible SO_2 and NO_X control options for Unit 1, and evaluated each of the control measures for the following four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

The cost of compliance evaluation prepared for SO_2 controls indicates that the average annual cost effectiveness ranges from $389 per ton (FGD Operation Improvements) to $4,065 per ton (Wet FGD). The evaluation prepared for NO_X controls options indicates that that the average annual cost effectiveness ranges from $0 per ton (Combustion Optimization) to $2,083 per ton (SNCR + RRI) NO_X removed.

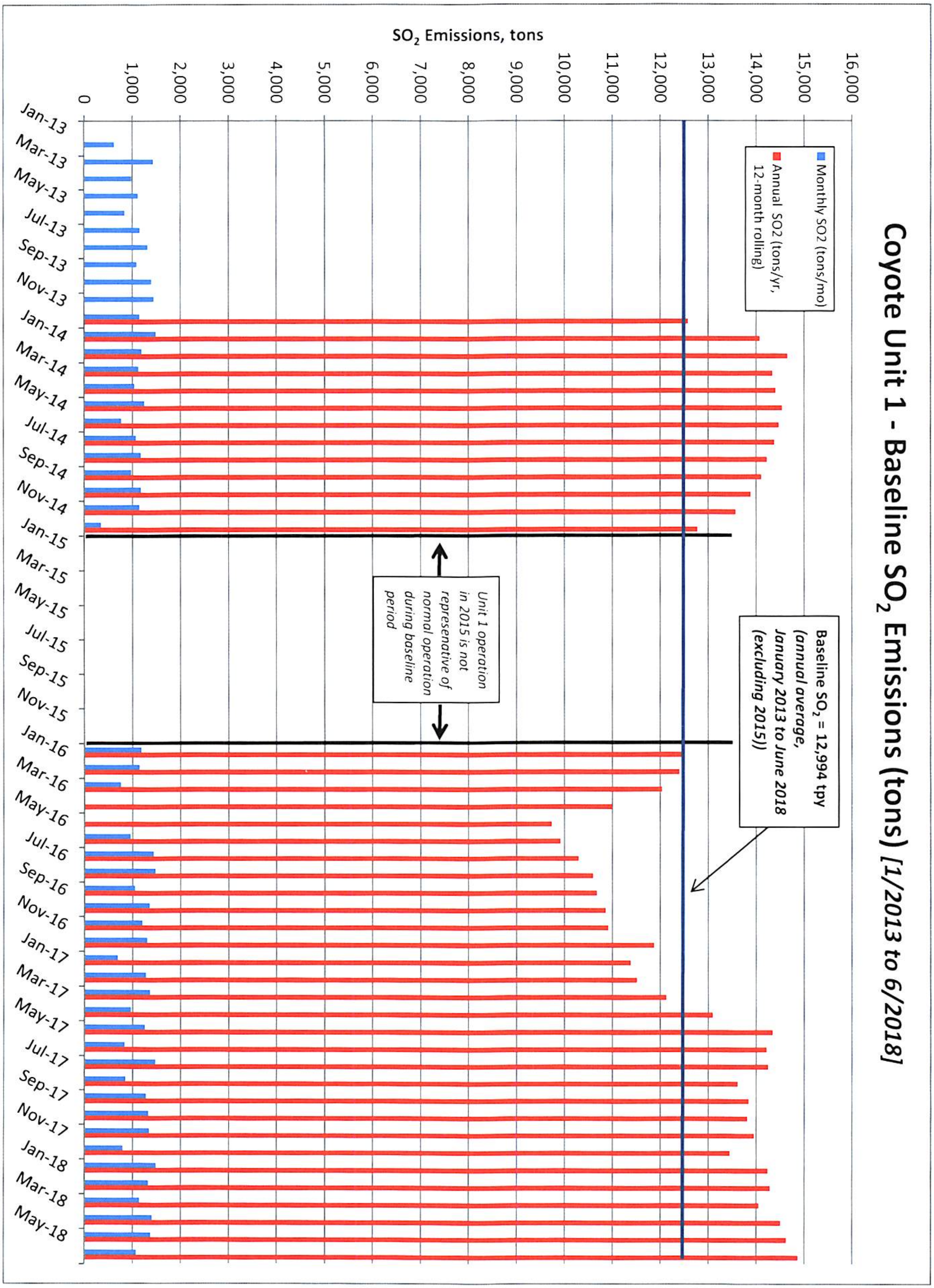
The time necessary for compliance for the SO_2 control options ranges from 0 months (FGD operational improvements) to 56 months (new wet FGD system). For NO_X control options, the time necessary for compliance ranges from 0 months (combustion optimization) to 22 months (SNCR + RRI).

An evaluation of energy impacts indicates that certain control options (e.g., new FGD systems) will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts include an increase in the solid waste generation with DSI, as well as potential incremental increase in fugitive dust emissions associated with sorbent deliveries to the facility.

Regarding remaining useful life, the Coyote Station owners have not identified dates for the remaining useful life of the unit before the end of what would otherwise be the 20-year useful life of the control measures that were evaluated for Coyote Unit 1. Therefore, the remaining useful life did not impact the annualized cost of control under the current regulatory framework.

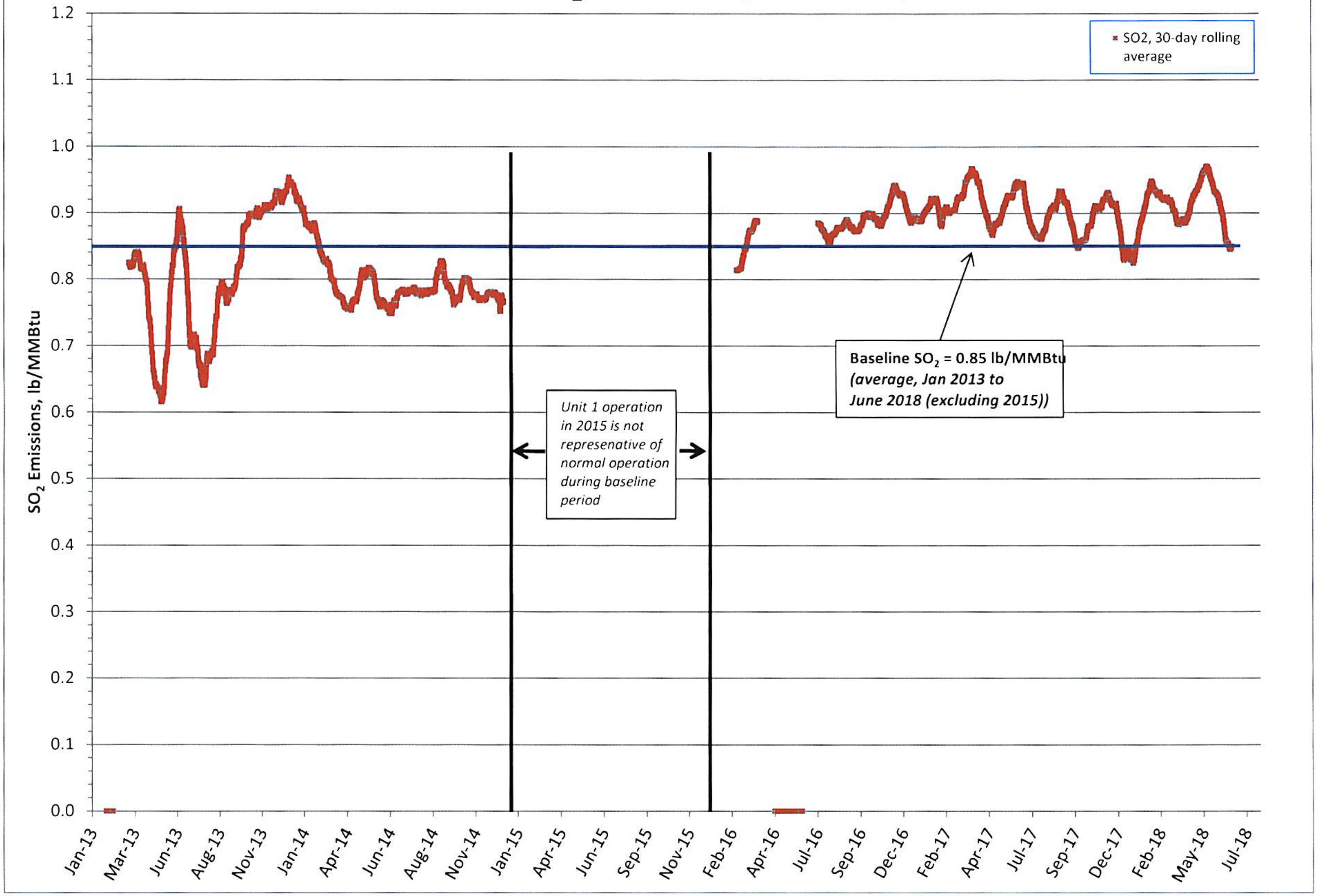
APPENDIX A

COYOTE UNIT 1 BASELINE EMISSIONS



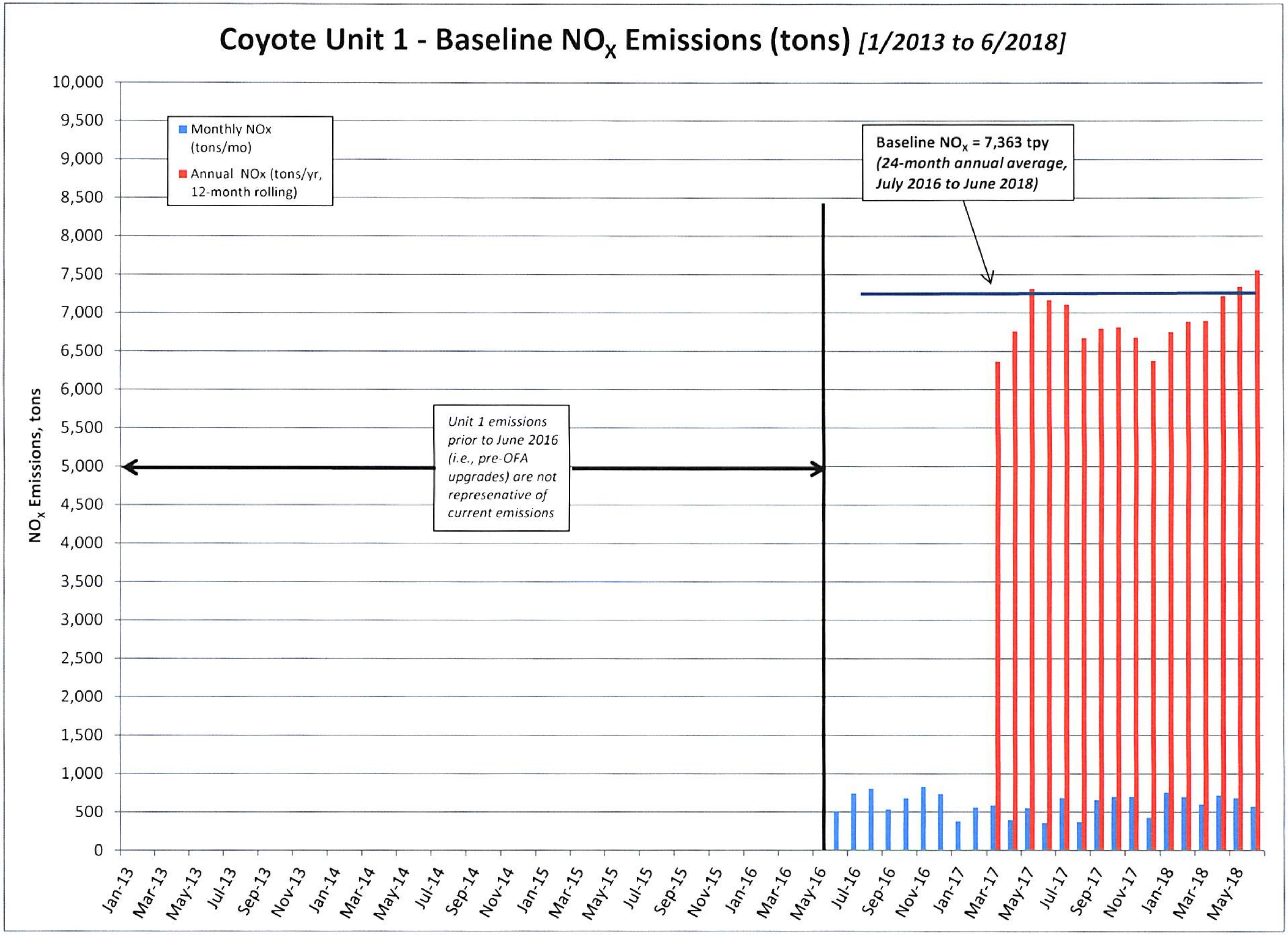
Coyote Unit 1 - Baseline SO_2 Emissions (tons) *[1/2013 to 6/2018]*

Coyote Unit 1 - Baseline SO_2 Emissions (lb/MMBtu) *[1/2013 to 6/2018]*



Unit 1 operation in 2015 is not represenative of normal operation during baseline period

Baseline SO_2 = 0.85 lb/MMBtu *(average, Jan 2013 to June 2018 (excluding 2015))*

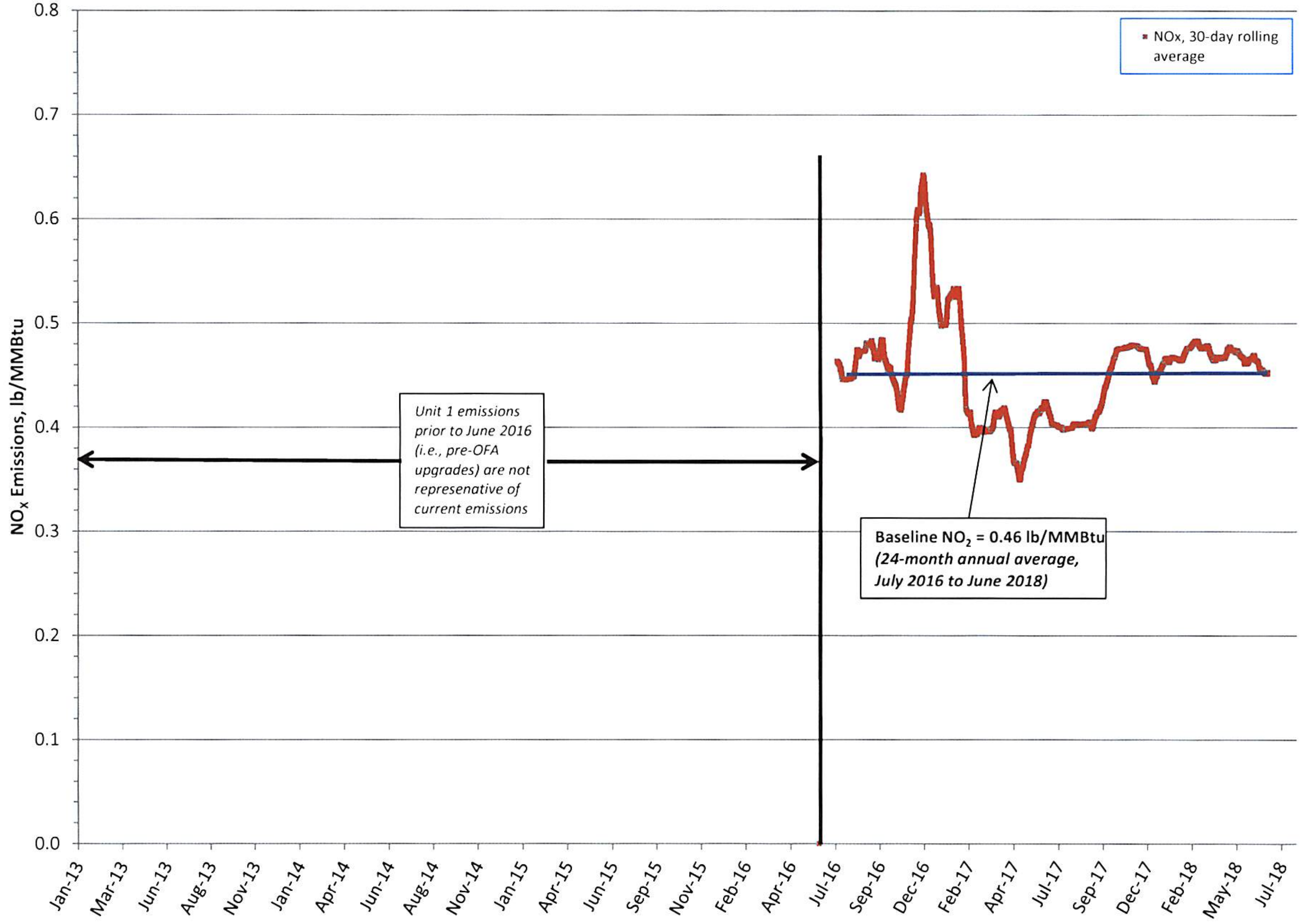


Coyote Unit 1 - Baseline NO_X Emissions (tons) *[1/2013 to 6/2018]*

Baseline NO_X = 7,363 tpy *(24-month annual average, July 2016 to June 2018)*

Unit 1 emissions prior to June 2016 (i.e., pre-OFA upgrades) are not represenative of current emissions

Coyote Unit 1 - Baseline NO$_X$ Emissions (lb/MMBtu) *[1/2013 to 6/2018]*



Unit 1 emissions prior to June 2016 (i.e., pre-OFA upgrades) are not represenative of current emissions

Baseline NO$_2$ = 0.46 lb/MMBtu *(24-month annual average, July 2016 to June 2018)*

APPENDIX B

SO_2 CONTROL COST EFFECTIVENESS ESTIMATES

Coyote Station Unit 1
SO_2 Control Summary

Table 1. Coyote Unit 1 Operating Parameters

Parameter		Unit	Notes
Power Output	427	MW-net	Nominal
Annual Heat Input	30,562,287	MMBtu/yr	24-month annual average for period July 2016 to June 2018.
Average Capacity Factor	72%	%	Based on annual average MW-h during the baseline period.

Table 2. Control Effectiveness

Control Technology	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)
Wet FGD	92.9%	917	0.06	12,078
Dry FGD (CDS) + FF	89.4%	1,375	0.09	11,619
FGD Upgrades - Replace Existing Absorbers with New Absorber	65.9%	4,432	0.29	8,563
DSI + FGD Operational Improvements	61.2%	5,043	0.33	7,952
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	41.2%	7,641	0.50	5,354
DSI + Existing FGD	31.8%	8,863	0.58	4,131
Baseline (DFGD/FF)		**12,994**	0.85	0

Table 3. Cost Effectiveness

Control Technology	Emissions (tpy)	Tons of SO_2 Removed (tpy)	Total Capital Requirement ($)	Annualized Capital Cost ($/year)	Annualized Outage Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline (DFGD/FF)	12,994	0	--	--		--	--		
DSI + Existing FGD	8,863	4,131	$23,765,000	$1,948,000	$0	$10,423,000	$12,371,000	**$2,994**	
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	7,641	5,354	$526,000	$43,000	$0	$2,042,000	$2,085,000	**$389**	
DSI + FGD Operational Improvements	5,043	7,952	$24,292,000	$1,991,000	$0	$12,465,000	$14,456,000	**$1,818**	$4,762
FGD Upgrades - Replace Existing Absorbers with New Absorber	4,432	8,563	$127,823,000	$10,475,000	$5,390,000	$6,332,000	$22,197,000	**$2,592**	$12,664
Dry FGD (CDS) + FF	1,375	11,619	$242,647,000	$19,885,000	$0	$20,610,000	$40,495,000	**$3,485**	$5,987
Wet FGD	917	12,078	$324,742,000	$26,613,000	$0	$22,481,000	$49,094,000	**$4,065**	$18,757

Coyote Station Unit 1
SO_2 Control Cost Evaluation
DSI + Existing FGD

SO_2 Control Option Description	DSI + Existing FGD
Baseline SO_2 Emissions, lb/MMBtu	0.85
Post Upgrade SO_2 Emissions, lb/MMBtu	0.58
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS	Cost (2018$)	Basis
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$10,884,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGD Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$544,000	5% of Equipment/Material Cost
Freight	$544,000	5% of Equipment/Material Cost
Total PEC	$11,972,000	
Direct Installation Costs		
Labor	$2,886,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$72,000	2.5% of Labor
Mobilization / Demobilization	$43,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$144,000	5% of Labor
Total Direct Installation Costs	$3,145,000	
Total Direct Costs (PEC + Direct Installation Costs)	$15,117,000	
Indirect Costs		
Contractor's General and Administration Expense	$1,512,000	10% of Total Direct Costs
Contractor's Profit	$756,000	5% of Total Direct Costs
Dry FGD Engineering, Procurement, & Project Services	$1,209,000	8% of Total Direct Costs
Construction Management/Field Engineering	$605,000	4% of Total Direct Costs
S-U / Commissioning	$227,000	1.5% of Total Direct Costs
Spare Parts	$76,000	0.5% of Total Direct Costs
Owner's Cost	$302,000	2% of Total Direct Costs
Total Indirect Costs	$4,687,000	
Contingency	**$3,961,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$23,765,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = i(1+ i)^ / (1 + i)^ - 1	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$1,948,000**	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Increased Waste Disposal Cost	$1,652,000	Based on disposal rate of $32.46 per ton.
Hydrated Lime Reagent Cost	$7,426,000	Based on hydrated lime reagent cost of $187 per ton.
Increased Auxiliary Power Cost	$115,000	Based on auxiliary power cost of $23 per MWh
Increased bag and cage replacement	$52,000	Based on bag and cage cost of $135 per bag
Total Variable O&M Costs	$9,245,000	
Fixed O&M Costs		
Additional Operators per shift	0	Assume no additional operators
Operating Labor	$0	N/A
Supervisor Labor	$0	N/A
Maintenance Materials	$227,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$227,000	
Indirect Operating Cost		
Property Taxes	$238,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$238,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$475,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$951,000	
Total Annual Operating Cost	**$10,423,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$1,948,000	
Annual Operating Cost	$10,423,000	
Total Annual Cost	**$12,371,000**	

Coyote Station Unit 1
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio**
Baseline SO_2 Emissions, lb/MMBtu	0.85
Post Upgrade SO_2 Emissions, lb/MMBtu	0.50
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$218,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGI Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$11,000	5% of Equipment/Material Cost
Freight	$11,000	5% of Equipment/Material Cost
Total PEC	$240,000	
Direct Installation Costs		
Labor	$87,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$2,000	2.5% of Labor
Mobilization / Demobilization	$1,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$4,000	5% of Labor
Total Direct Installation Costs	$94,000	
Total Direct Costs (PEC + Direct Installation Costs)	$334,000	
Indirect Costs		
Contractor's General and Administration Expense	$33,000	10% of Total Direct Costs
Contractor's Profit	$17,000	5% of Total Direct Costs
Dry FGI Engineering, Procurement, & Project Services	$27,000	8% of Total Direct Costs
Construction Management/Field Engineering	$13,000	4% of Total Direct Costs
S-U / Commissioning	$5,000	1% of Total Direct Costs
Spare Parts	$2,000	0.5% of Total Direct Costs
Owner's Cost	$7,000	2% of Total Direct Costs
Total Indirect Costs	$104,000	
Contingency	$88,000	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	$526,000	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	$43,000	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Increased Waste Disposal Cost	$591,000	Based on disposal rate of $32.46 per ton.
Increased Lime Reagent Cost	$1,418,000	Based on lime reagent cost of $128 per ton.
Increased Auxiliary Power Cost	$4,000	Based on auxiliary power cost of $23 per MWh
Increased Water Cost	$3,000	Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs	$2,016,000	
Fixed O&M Costs		
Additional Operators per shift	0	Assume no additional operators
Operating Labor	$0	N/A
Supervisor Labor	$0	N/A
Maintenance Materials	$5,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$5,000	
Indirect Operating Cost		
Property Taxes	$5,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$5,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$11,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$21,000	
Total Annual Operating Cost	$2,042,000	
TOTAL ANNUAL COST		
Annualized Capital Cost	$43,000	
Annual Operating Cost	$2,042,000	
Total Annual Cost	$2,085,000	

Coyote Station Unit 1
SO_2 Control Cost Evaluation
DSI + FGD Operational Improvements

SO_2 Control Option Description	**DSI + FGD Operational Improvements**
Baseline SO_2 Emissions, lb/MMBtu	0.85
Post Upgrade SO_2 Emissions, lb/MMBtu	0.33
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$11,102,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGI Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$555,000	5% of Equipment/Material Cost
Freight	$555,000	5% of Equipment/Material Cost
Total PEC	$12,212,000	
Direct Installation Costs		
Labor	$2,973,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$74,000	2.5% of Labor
Mobilization / Demobilization	$45,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$149,000	5% of Labor
Total Direct Installation Costs	$3,241,000	
Total Direct Costs (PEC + Direct Installation Costs)	$15,453,000	
Indirect Costs		
Contractor's General and Administration Expense	$1,545,000	10% of Total Direct Costs
Contractor's Profit	$773,000	5% of Total Direct Costs
Dry FGI Engineering, Procurement, & Project Services	$1,236,000	8% of Total Direct Costs
Construction Management/Field Engineering	$618,000	4% of Total Direct Costs
S-U / Commissioning	$232,000	1.5% of Total Direct Costs
Spare Parts	$77,000	0.5% of Total Direct Costs
Owner's Cost	$309,000	2% of Total Direct Costs
Total Indirect Costs	$4,790,000	
Contingency	$4,049,000	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	$24,292,000	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	$1,991,000	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Increased Waste Disposal Cost	$2,243,000	Based on disposal rate of $32.46 per ton.
Increased Lime Reagent Cost	$1,417,600	Based on lime reagent cost of $128 per ton.
Hydrated Lime Reagent Cost	$7,426,000	Based on hydrated lime reagent cost of $187 per ton.
Increased Auxiliary Power Cost	$119,000	Based on auxiliary power cost of $23 per MWh
Increased bag and cage replacement	$52,000	Based on bag and cage cost of $135 per bag
Total Variable O&M Costs	$11,260,600	
Fixed O&M Costs		
Additional Operators per shift	0	Assume no additional operators
Operating Labor	$0	N/A
Supervisor Labor	$0	N/A
Maintenance Materials	$232,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$232,000	
Indirect Operating Cost		
Property Taxes	$243,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$243,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34
Administration	$486,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34
Total Indirect Operating Cost	$972,000	
Total Annual Operating Cost	$12,465,000	
TOTAL ANNUAL COST		
Annualized Capital Cost	$1,991,000	
Annual Operating Cost	$12,465,000	
Total Annual Cost	$14,456,000	

Coyote Station Unit 1
SO_2 Control Cost Evaluation
FGD Upgrades - Replace Existing Absorbers with New Absorber

SO_2 Control Option Description	**FGD Upgrades - Replace Existing Absorbers with New Absorber**
Baseline SO_2 Emissions, lb/MMBtu	0.85
Post Upgrade SO_2 Emissions, lb/MMBtu	0.29
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$42,282,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGE Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$2,114,000	5% of Equipment/Material Cost
Freight	$2,114,000	5% of Equipment/Material Cost
Total PEC	$46,510,000	
Direct Installation Costs		
Labor	$31,929,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$798,000	2.5% of Labor
Mobilization / Demobilization	$479,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$1,596,000	5% of Labor
Total Direct Installation Costs	$34,802,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$81,312,000**	
Indirect Costs		
Contractor's General and Administration Expense	$8,131,000	10% of Total Direct Costs
Contractor's Profit	$4,066,000	5% of Total Direct Costs
Dry FGE Engineering, Procurement, & Project Services	$6,505,000	8% of Total Direct Costs
Construction Management/Field Engineering	$3,252,000	4% of Total Direct Costs
S-U / Commissioning	$1,220,000	1.5% of Total Direct Costs
Spare Parts	$407,000	0.5% of Total Direct Costs
Owner's Cost	$1,626,000	2% of Total Direct Costs
Total Indirect Costs	**$25,207,000**	
Contingency	**$21,304,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$127,823,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$10,475,000**	
OUTAGE COSTS		
Outage Costs		
Standard Outage Duration (weeks/yr)	8	
Outage Duration due to Retrofit (weeks/yr)	52	
Lost Revenue due to Retrofit	**$51,979,000**	
Replacment Power Cost due to Retrofit	**$13,786,000**	Based on the difference in cost for Coyote to generate power at $23.00 per MWh and cost for Coyote to purchase replacement power.
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 7% interest.
Annualized Outage Costs (CRF x TCI)	**$5,390,000**	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Total Variable O&M Costs	$0	No incremental increases in variable O&M for absorber replacement
Fixed O&M Costs		
Additional Operators per shift	0	Assume no additional operators
Operating Labor	$0	N/A
Supervisor Labor	$0	N/A
Maintenance Materials	$1,220,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$1,220,000	
Indirect Operating Cost		
Property Taxes	$1,278,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,278,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$2,556,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$5,112,000	
Total Annual Operating Cost	**$6,332,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$10,475,000	
Annualized Outage Cost	$5,390,000	
Annual Operating Cost	$6,332,000	
Total Annual Cost	**$22,197,000**	

Coyote Station Unit 1
SO_2 Control Cost Evaluation
Dry FGD (CDS) + FF

SO_2 Control Option Description	Dry FGD (CDS) + FF
Baseline SO_2 Emissions, lb/MMBtu	0.85
Post Upgrade SO_2 Emissions, lb/MMBtu	0.09
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS	Cost (2018$)	Basis
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$61,993,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGC Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$3,100,000	5% of Equipment/Material Cost
Freight	$3,100,000	5% of Equipment/Material Cost
Total PEC	$68,193,000	
Direct Installation Costs		
Labor	$79,049,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,976,000	2.5% of Labor
Mobilization / Demobilization	$1,186,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$3,952,000	5% of Labor
Total Direct Installation Costs	$86,163,000	
Total Direct Costs (PEC + Direct Installation Costs)	$154,356,000	
Indirect Costs		
Contractor's General and Administration Expense	$15,436,000	10% of Total Direct Costs
Contractor's Profit	$7,718,000	5% of Total Direct Costs
Dry FGC Engineering, Procurement, & Project Services	$12,348,000	8% of Total Direct Costs
Construction Management/Field Engineering	$6,174,000	4% of Total Direct Costs
S-U / Commissioning	$2,315,000	1.5% of Total Direct Costs
Spare Parts	$772,000	0.5% of Total Direct Costs
Owner's Cost	$3,087,000	2% of Total Direct Costs
Total Indirect Costs	$47,850,000	
Contingency	$40,441,000	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	$242,647,000	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = i(1+ i)^ / (1 + i)^ - 1	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	$19,885,000	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Increased Waste Disposal Cost	$2,175,000	Based on disposal rate of $32.46 per ton.
Increased Lime Reagent Cost	$5,815,000	Based on lime reagent cost of $128 per ton.
Increased Auxiliary Power Cost	$428,000	Based on auxiliary power cost of $23 per MWh
Increased Water Cost	$32,000	Based on water cost of $1.00 per 1000 gallons.
Increased bag and cage replacement	$140,000	Based on bag and cage cost of $135 per bag
Total Variable O&M Costs	$8,590,000	
Fixed O&M Costs		
Additional Operators per shift	0	Assume no additional operators
Operating Labor	$0	N/A
Supervisor Labor	$0	N/A
Maintenance Materials	$2,315,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,315,000	
Indirect Operating Cost		
Property Taxes	$2,426,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,426,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$4,853,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$9,705,000	
Total Annual Operating Cost	$20,610,000	
TOTAL ANNUAL COST		
Annualized Capital Cost	$19,885,000	
Annual Operating Cost	$20,610,000	
Total Annual Cost	$40,495,000	

Coyote Station Unit 1
SO_2 Control Cost Evaluation
Wet FGD

SO_2 Control Option Description	Wet FGD
Baseline SO_2 Emissions, lb/MMBtu	0.85
Post Upgrade SO_2 Emissions, lb/MMBtu	0.06
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$112,208,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Dry FGC Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$5,610,000	5% of Equipment/Material Cost
Freight	$5,610,000	5% of Equipment/Material Cost
Total PEC	$123,428,000	
Direct Installation Costs		
Labor	$76,285,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,907,000	2.5% of Labor
Mobilization / Demobilization	$1,144,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$3,814,000	5% of Labor
Total Direct Installation Costs	$83,150,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$206,578,000**	
Indirect Costs		
Contractor's General and Administration Expense	$20,658,000	10% of Total Direct Costs
Contractor's Profit	$10,329,000	5% of Total Direct Costs
Dry FGC Engineering, Procurement, & Project Services	$16,526,000	8% of Total Direct Costs
Construction Management/Field Engineering	$8,263,000	4% of Total Direct Costs
S-U / Commissioning	$3,099,000	1.5% of Total Direct Costs
Spare Parts	$1,033,000	0.5% of Total Direct Costs
Owner's Cost	$4,132,000	2% of Total Direct Costs
Total Indirect Costs	**$64,040,000**	
Contingency	**$54,124,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$324,742,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$26,613,000**	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Increased Waste Disposal Cost	$1,895,000	Based on disposal rate of $32.46 per ton.
Increased Lime Reagent Cost	-$3,057,000	Based on lime reagent cost of $128 per ton.
Limestone Reagent Cost	$4,042,000	Based on limestone reagent cost of $70 per ton.
Increased Auxiliary Power Cost	$949,000	Based on auxiliary power cost of $23 per MWh
Increased Water Cost	$66,000	Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs	$3,895,000	
Fixed O&M Costs		
Additional Operators per Shift	4	
Operating Labor	$2,172,000	Assume $62/hr for each additional operator
Supervisor Labor	$326,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$3,099,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$5,597,000	
Indirect Operating Cost		
Property Taxes	$3,247,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$3,247,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$6,495,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$12,989,000	
Total Annual Operating Cost	**$22,481,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$26,613,000	
Annual Operating Cost	$22,481,000	
Total Annual Cost	**$49,094,000**	

APPENDIX C

NO_X CONTROL COST EFFECTIVENESS ESTIMATES

Coyote Station Unit 1
NO_X Control Summary

Table 1. Coyote Unit 1 Operating Parameters

Parameter		**Unit**	**Notes**
Power Output	427	MW-net	Nominal
Annual Average Heat Input	32,301,802	MMBtu/yr	24-month annual average for period July 2016 to June 2018 (post-SOFA upgrades)
Average Capcity Factor	79%	%	Based on annual average MW-h during the baseline period.

Table 2. Control Effectiveness

Control Technology	**Control Efficiency (%)**	**Expected Emissions (ton/year)**	**Emission Rate (lb/MMBtu)**	**Expected Emissions Reduction (ton/year)**
SNCR + RRI	56.2%	3,226	0.20	4,137
SNCR	38.7%	4,516	0.28	2,847
Combustion Optimization	8.0%	6,775	0.42	589
Baseline (SOFA)		**7,363**	0.46	0

Table 3. Cost Effectiveness

Control Technology	**Emissions (tpy)**	**Tons of NO_X Removed (tpy)**	**Total Capital Requirement ($)**	**Annualized Capital Cost ($/year)**	**Annualized Outage Cost ($/year)**	**Total Annual Operating Costs ($/year)**	**Total Annual Costs ($)**	**Average Cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**
Baseline (SOFA)	7,363	0	--	--	--	--	--		
Combustion Optimization	6,775	589	$0	$0	$0	$0	$0	$0	
SNCR	4,516	2,847	$19,840,000	$1,626,000	$0	$3,128,000	$4,754,000	$1,670	$2,105
SNCR + RRI	3,226	4,137	$25,895,000	$2,122,000	$0	$6,495,000	$8,617,000	$2,083	$2,994

Coyote Station Unit 1
NO_x Control Cost Evaluation
Combustion Optimization

NO_x Control Option Description	Combustion Optimization
Baseline NO_x Emissions, lb/MMBtu	0.46
Post Upgrade NO_x Emissions, lb/MMBtu	0.42
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS	Cost (2018$)	Basis
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$0	
Instrumentation	$0	
Sales Tax	$0	
Freight	$0	
Total PEC	$0	
Direct Installation Costs		
Labor	$0	
Scaffolding	$0	
Mobilization / Demobilization	$0	
Labor Cost Due To Overtime Ineffiency	$0	
Total Direct Installation Costs	$0	
Total Direct Costs (PEC + Direct Installation Costs)	$0	
Indirect Costs		
Contractor's General and Administration Expense	$0	
Contractor's Profit	$0	
Engineering, Procurement, & Project Services	$0	
Construction Management/Field Engineering	$0	
S-U / Commissioning	$0	
Spare Parts	$0	
Owner's Cost	$0	
Total Indirect Costs	$0	
Contingency	$0	
Total Capital Investment (TCI)	$0	
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	$0	
OPERATING COSTS		**Basis**
Operating & Maintenance Costs		
Variable O&M Costs		
Dry Urea Reagent Cost	$0	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$0	Based on ammonia reagent cost of $700 per ton.
RO Water Cost	$0	Based on water cost of $1.00 per 1,000 gallons.
Steam Cost	$0	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$0	Based on hydrated lime cost of $187 per ton.
Catalyst Replacement Cost	$0	Based on catalyst cost of $8,000 per m3 and catalyst replacement cost of $1,000 per m3.
Auxiliary Power Cost	$0	Based on auxiliary power cost of $23 per MWh
Total Variable O&M Costs	$0	
Fixed O&M Costs		
Additional Operators per shift	0	Assume no additional operators
Operating Labor	$0	N/A
Supervisor Labor	$0	N/A
Maintenance Materials	$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$0	
Indirect Operating Cost		
Property Taxes	$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34
Administration	$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$0	
Total Annual Operating Cost	$0	
TOTAL ANNUAL COST		
Annualized Capital Cost	$0	
Annual Operating Cost	$0	
Total Annual Cost	$0	

Coyote Station Unit 1
NO_x Control Cost Evaluation
SNCR

NO_x Control Option Description	SNCR
Baseline NO_x Emissions, lb/MMBtu	0.46
Post Upgrade NO_x Emissions, lb/MMBtu	0.28
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$8,718,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$436,000	5% of Equipment/Material Cost
Freight	$436,000	5% of Equipment/Material Cost
Total PEC	$9,590,000	
Direct Installation Costs		
Labor	$2,780,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$70,000	2.5% of Labor
Mobilization / Demobilization	$42,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$139,000	5% of Labor
Total Direct Installation Costs	$3,031,000	
Total Direct Costs (PEC + Direct Installation Costs)	$12,621,000	
Indirect Costs		
Contractor's General and Administration Expense	$1,262,000	10% of Total Direct Costs
Contractor's Profit	$631,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$1,010,000	8% of Total Direct Costs
Construction Management/Field Engineering	$505,000	4% of Total Direct Costs
S-U / Commissioning	$189,000	1.5% of Total Direct Costs
Spare Parts	$63,000	0.5% of Total Direct Costs
Owner's Cost	$252,000	2% of Total Direct Costs
Total Indirect Costs	$3,912,000	
Contingency	$3,307,000	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	$19,840,000	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	$1,626,000	
OPERATING COSTS		**Basis**
Operating & Maintenance Costs		
Variable O&M Costs		
Dry Urea Reagent Cost	$1,401,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$0	Based on ammonia reagent cost of $700 per ton.
Water Cost	$82,000	Based on water cost of $1.00 per 1,000 gallons.
Steam Cost	$32,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$0	Based on hydrated lime cost of $187 per ton.
Catalyst Replacement Cost	$0	Based on catalyst cost of $8,000 per m3 and catalyst replacement cost of $1,000 per m3.
Auxiliary Power Cost	$7,000	Based on auxiliary power cost of $23 per MWh
Total Variable O&M Costs	$1,522,000	
Fixed O&M Costs		
Additional Operators per shift	1	
Operating Labor	$543,000	Assume $62/hr for each additional operator
Supervisor Labor	$81,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$189,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$813,000	
Indirect Operating Cost		
Property Taxes	$198,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$198,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$397,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$793,000	
Total Annual Operating Cost	$3,128,000	
TOTAL ANNUAL COST		
Annualized Capital Cost	$1,626,000	
Annual Operating Cost	$3,128,000	
Total Annual Cost	$4,754,000	

Coyote Station Unit 1
NO_x Control Cost Evaluation
SNCR + RRI

NO_x Control Option Description	SNCR + RRI
Baseline NO_x Emissions, lb/MMBtu	0.46
Post Upgrade NO_x Emissions, lb/MMBtu	0.20
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS	Cost (2018$)	Basis
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$11,179,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$559,000	5% of Equipment/Material Cost
Freight	$559,000	5% of Equipment/Material Cost
Total PEC	$12,297,000	
Direct Installation Costs		
Labor	$3,831,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$96,000	2.5% of Labor
Mobilization / Demobilization	$57,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$192,000	5% of Labor
Total Direct Installation Costs	$4,176,000	
Total Direct Costs (PEC + Direct Installation Costs)	$16,473,000	
Indirect Costs		
Contractor's General and Administration Expense	$1,647,000	10% of Total Direct Costs
Contractor's Profit	$824,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$1,318,000	8% of Total Direct Costs
Construction Management/Field Engineering	$659,000	4% of Total Direct Costs
S-U / Commissioning	$247,000	1.5% of Total Direct Costs
Spare Parts	$82,000	0.5% of Total Direct Costs
Owner's Cost	$329,000	2% of Total Direct Costs
Total Indirect Costs	$5,106,000	
Contingency	$4,316,000	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	$25,895,000	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	$2,122,000	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Dry Urea Reagent Cost	$4,300,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$0	Based on ammonia reagent cost of $700 per ton.
RO Water Cost	$179,000	Based on water cost of $1.00 per 1,000 gallons.
Steam Cost	$99,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$0	Based on hydrated lime cost of $187 per ton.
Catalyst Replacement Cost	$0	Based on catalyst cost of $8,000 per m3 and catalyst replacement cost of $1,000 per m3.
Auxiliary Power Cost	$10,000	Based on auxiliary power cost of $23 per MWh
Total Variable O&M Costs	$4,588,000	
Fixed O&M Costs		
Additional Operators per shift	1	
Operating Labor	$543,000	Assume $62/hr for each additional operator
Supervisor Labor	$81,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$247,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$871,000	
Indirect Operating Cost		
Property Taxes	$259,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$259,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$518,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$1,036,000	
Total Annual Operating Cost	$6,495,000	
TOTAL ANNUAL COST		
Annualized Capital Cost	$2,122,000	
Annual Operating Cost	$6,495,000	
Total Annual Cost	$8,617,000	

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OTTER TAIL
POWER COMPANY

2020
Received
Air Quality

January 6, 2020

Mr. Jim Semerad
Director, Division of Air Quality
North Dakota Department of Health
Gold Seal Center, 918 East Divide Ave
Bismarck, ND 58501-1947

Dear Mr. Semerad:

Re: Updates to Regional Haze Four Factor Analysis - Coyote Station

The purpose of this submittal is to provide the North Dakota Department of Environmental Quality (DEQ) with updated information related to the NOx technology options presented in the Coyote Station Regional Haze reasonable progress report (Four-Factor Analysis).

As you recall, Revision 1 of the Four-Factor Analysis, dated May 8, 2019, determined that there were two technically feasible post-combustion NOx technologies applicable to Coyote Station: Selective non-catalytic reduction (SNCR) and Rich Reagent Injection (RRI). The Four-Factor Analysis presented the predicted emission reductions and costs associated with those technologies; however, in both cases the report noted that computational fluid dynamic (CFD) modeling would be needed to confirm that the incremental reduction in NOx emission is achievable without creating unacceptable operational issues.[1]

Subsequent to the Four-Factor Analysis, Otter Tail Power Company proceeded with the CFD modeling, and retained Sargent & Lundy, L.L.C. (S&L) to prepare the attached technical memorandum to summarize the modeling results and determine the associated impacts to the Four-Factor Analysis.

As described in the S&L memorandum, it has been determined that in order to achieve the level of NOx reductions with RRI originally predicted by the Four-Factor Analysis, Coyote Station would need to relocate both the existing furnace vent ports and separated overfire air ports. Therefore, the costs of the RRI option need to be revised upward to account for these port relocations.

We look forward to working with the DEQ throughout the second planning period. If you have any questions about this updated information, please contact me at (218) 739-8526.

Sincerely,

Mark Thoma

Mark Thoma
Manager, Environmental Services

Enclosure

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[1] See Pages 5-26 and 5-27 of the Coyote Station May 8, 2019 Four-Factor Analysis

Sargent & Lundy LLC

TECHNICAL MEMORANDUM

From:	Wayshalee Patel	**Date:**	January 6, 2020
		Project No.:	A12715.011
Client:	Otter Tail Power Company		
Station:	Coyote Station Unit 1		
Subject:	Update to Four Factor Analysis		

The purpose of this technical memorandum is to provide the North Dakota Department of Environmental Quality (NDDEQ) a summary of computational fluid dynamic (CFD) modeling recently completed by Otter Tail Power Company (OTP) since the submittal of the Coyote Station Unit 1 Four-Factor Analysis dated May 8, 2019. For nitrogen oxides (NOx), the CFD modeling was conducted for the selective non-catalytic reduction (SNCR) and rich reagent injection (RRI) technology options.

NOx CFD Modeling Summary

OTP engaged Reaction Engineering International (REI) to complete CFD modeling of OTP's Coyote Station Unit 1 to further evaluate and potentially refine the emission removal capabilities and equipment modifications necessary for SNCR and RRI for NOx emissions.

NOx Emissions Modeling:

REI developed a CFD model of the Coyote Unit 1 cyclone barrels and boiler furnace in order to evaluate the impact of various technologies on Unit 1 furnace NOx reduction. The modeling effort assessed performance of combustion modifications, SNCR, and RRI systems and generally evaluated the following:

- SNCR with sensitivity to injector locations, urea solution droplet sizes, and normalized stoichiometric ratio (NSR)
- RRI exploring injector locations and performance when combined with existing and alternative OFA and vent designs

The results of the NOx CFD modeling effort predict that the average NOx emission rate achievable with SNCR is 0.28 lb/MMBtu[1], which is the value that was estimated in the Four-Factor Analysis. As such, the achievable emission reduction and associated costs and cost effectiveness for SNCR provided in the Four-Factor Analysis is reasonable and updates are not necessary. For the RRI option, the CFD modeling

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[1] Modeling scenarios that resulted in a predicted ammonia slip of greater than 10 ppm were not included in determining this average in order to avoid formation of ammonia salts on the boiler tube banks.

indicated that the 12 existing furnace vents and the 14 existing separated overfire air (SOFA) vents would need to be relocated at an elevation higher in the furnace in order to create sub-stoichiometric oxygen concentrations in the lower furnace, thereby promoting NOx reduction. The Four-Factor Analysis did not include the costs associated with relocating theses SOFA and vent ports which, based on the CFD modeling, is necessary to obtain the estimated NOx reductions indicated in the Four-Factor Analysis. As such, the cost effectiveness table provided in the Four-Factor Analysis has been updated and is provided in Table 1 below. In summary, the cost effectiveness for the option that included RRI increased from $2,083/ton to $3,067/ton. Detailed cost effectiveness tables are included in Appendix A of this memorandum.

Table 1. NO_X Emissions Control System Cost Effectiveness ($2018)

	Total Annualized Cost	Expected Emission Reduction	Average Annual Cost Effectiveness (Note 1)	Incremental Annual Cost Effectiveness (Note 2)
NO_X Control Option	**$/yr**	**tons NO_X/yr**	**$/ton NO_X removed**	**$/ton NO_X removed**
Baseline (Existing SOFA)	---	---	---	---
Combustion Optimization	$0	589	$0	$0
SNCR + Combustion Optimization	$4,754,000	2,847	$1,670	$2,105
SNCR + RRI + Combustion Optimization + SOFA/Vent Port	$12,690,000	4,137	$3,067	$6,150

Note 1. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.
Note 2. Incremental cost effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

Appendix A

Revised NOx Cost Effectiveness Tables

Coyote Station Unit 1
NO_X Control Summary

Table 1. Coyote Unit 1 Operating Parameters

Parameter		Unit	Notes
Power Output	427	MW-net	Nominal
Annual Average Heat Input	32,301,802	MMBtu/yr	24-month annual average for period July 2016 to June 2018 (post-SOFA upgrades)
Average Capcity Factor	79%	%	Based on annual average MW-h during the baseline period.

Table 2. Control Effectiveness

Control Technology	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)
SNCR + RRI	56.2%	3,226	0.20	4,137
SNCR	38.7%	4,516	0.28	2,847
Combustion Optimization	8.0%	6,775	0.42	589
Baseline (SOFA)		**7,363**	0.46	0

Table 3. Cost Effectiveness

Control Technology	Emissions (tpy)	Tons of NO_X Removed (tpy)	Total Capital Requirement ($)	Annualized Capital Cost ($/year)	Annualized Outage Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline (SOFA)	7,363	0	--	--	--	--	--		
Combustion Optimization	6,775	589	$0	$0	$0	$0	$0	**$0**	
SNCR	4,516	2,847	$19,840,000	$1,626,000	$0	$3,128,000	$4,754,000	**$1,670**	$2,105
SNCR + RRI	3,226	4,137	$56,864,000	$4,660,000	$0	$8,030,000	$12,690,000	**$3,067**	$6,150

Coyote Station Unit 1
NO_x Control Cost Evaluation
SNCR + RRI

NO_x Control Option Description	SNCR + RRI
Baseline NO_x Emissions, lb/MMBtu	0.46
Post Upgrade NO_x Emissions, lb/MMBtu	0.20
Capacity Factor used of Cost Estimates (%)	79%

CAPITAL COSTS	Cost (2018$)	Basis
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$19,179,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$959,000	5% of Equipment/Material Cost
Freight	$959,000	5% of Equipment/Material Cost
Total PEC	$21,097,000	
Direct Installation Costs		
Labor	$13,831,000	Based on Sargent & Lundy's conceptual cost estimating system
Scaffolding	$346,000	2.5% of Labor
Mobilization / Demobilization	$207,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$692,000	5% of Labor
Total Direct Installation Costs	$15,076,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$36,173,000**	
Indirect Costs		
Contractor's General and Administration Expense	$3,617,000	10% of Total Direct Costs
Contractor's Profit	$1,809,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$2,894,000	8% of Total Direct Costs
Construction Management/Field Engineering	$1,447,000	4% of Total Direct Costs
S-U / Commissioning	$543,000	1.5% of Total Direct Costs
Spare Parts	$181,000	0.5% of Total Direct Costs
Owner's Cost	$723,000	2% of Total Direct Costs
Total Indirect Costs	**$11,214,000**	
Contingency	**$9,477,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$56,864,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) $= i(1+i)^n / (1+i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$4,660,000**	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Dry Urea Reagent Cost	$4,300,000	Based on dry urea reagent cost of $354 per ton
Ammonia Reagent Cost	$0	Based on ammonia reagent cost of $700 per ton.
RO Water Cost	$179,000	Based on water cost of $1.00 per 1,000 gallons
Steam Cost	$99,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$0	Based on hydrated lime cost of $187 per ton
Catalyst Replacement Cost	$0	Based on catalyst cost of $8,000 per m3 and catalyst replacement cost of $1,000 per m3.
Auxiliary Power Cost	$10,000	Based on auxiliary power cost of $23 per MWh
Total Variable O&M Costs	$4,588,000	
Fixed O&M Costs		
Additional Operators per shift	1	
Operating Labor	$543,000	Assume $62/hr for each additional operator
Supervisor Labor	$81,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31
Maintenance Materials	$543,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$1,167,000	
Indirect Operating Cost		
Property Taxes	$569,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$569,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34
Administration	$1,137,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34
Total Indirect Operating Cost	$2,275,000	
Total Annual Operating Cost	**$8,030,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$4,660,000	
Annual Operating Cost	$8,030,000	
Total Annual Cost	**$12,690,000**	

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OTTERTAIL POWER COMPANY

June 8, 2020

Mr. James L. Semerad
Director, Division of Air Quality
North Dakota Department of Health
Gold Seal Center, 918 East Divide Ave
Bismarck, ND 58501-1947

Dear Mr. Semerad:

Re: Update to Regional Haze Four Factor Analysis - Coyote Station

The purpose of this submittal is to provide the North Dakota Department of Environmental Quality (DEQ) with updated information related to the sulfur dioxide (SO_2) technology options presented in the Coyote Station Regional Haze Four-Factor Analysis.

As you may recall, Revision 1 of the Four-Factor Analysis, dated May 8, 2019, determined that there were six technically feasible SO_2 technologies applicable to Coyote Station. One of these options involved retrofitting the existing dry flue gas desulfurization (DFGD) system with a new absorber module(s). This option was specifically limited to dismantling Coyote Station Unit 1's existing absorber modules and installing a new reactor absorber(s) in the same location. The same location was used for the retrofit absorbers as the existing DFGD because, at the time of the initial Four-Factor Analysis, it was predicted that redirecting flue gas to a different location would likely result in significant solids dropout and other operational issues.[1]

Subsequent to the Four-Factor Analysis, Otter Tail Power Company (OTP) became aware of a recent successful project by Babcock and Wilcox (B&W) that involved redirecting flue gas to a new SDA module located adjacent to an existing fabric filter. Therefore, OTP engaged B&W and Sargent & Lundy, L.L.C. (S&L) to perform a supplemental evaluation of this option for Coyote Station Unit 1. The attached technical memorandum from S&L summarizes the results of that evaluation and associated impacts to the Four-Factor Analysis.

We look forward to working with the DEQ throughout the second planning period. If you have any questions about this updated information, please contact me at (218) 739-8526.

Sincerely,

Mark Thoma

Mark Thoma
Manager, Environmental Services

Enclosure

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[1] See *Coyote Station Unit 1: North Dakota Regional Haze Second Planning Period Four-Factor Analysis* pg. 5-10. May 8, 2019.

Sargent & Lundy LLC

TECHNICAL MEMORANDUM

From:	Wayshalee Patel	**Date:**	June 4, 2020
		Project No.:	A12715.011
Client:	Otter Tail Power Company		
Station:	Coyote Station Unit 1		
Subject:	Update to Four Factor Analysis		

The purpose of this technical memorandum is to provide the North Dakota Department of Environmental Quality (NDDEQ) a summary of an additional evaluation regarding replacement of the existing spray dry absorber (SDA) modules with new absorber module(s) on the Otter Tail Power Company (OTP) Coyote Station Unit 1.

SDA Module Replacement Option

One of the technically feasible sulfur dioxide control technologies presented to the NDDEQ in the initial Four-Factor Analysis for Coyote Station Unit 1 involved retrofitting the existing dry flue gas desulfurization (DFGD) system with a new absorber modules.[1] This option was specifically limited to dismantling Coyote Station Unit 1's existing absorber modules and installing new reactor absorbers in the same location. The same location was used for the retrofit absorbers as the existing DFGD because, at the time of the initial Four-Factor Analysis, it was predicted that redirecting flue gas to a different location would likely result in significant solids dropout and other operational issues.

Since submittal of the Four-Factor Analysis, OTP became aware of a recent successful project by Babcock and Wilcox (B&W) that involved redirecting flue gas to a new SDA module located adjacent to an existing fabric filter.[2] Therefore, OTP engaged B&W and Sargent & Lundy to perform a supplemental evaluation of this option for Coyote Station Unit 1.

B&W evaluated single module and two-module equipment arrangements for Coyote Station Unit 1. Given B&W's extensive project experience and Coyote Station's operating conditions, B&W's evaluation focused on the two-module design in order to confidently treat 100% of the Coyote Station Unit 1 flue gas. B&W's evaluation determined that Coyote Station's flue gas could in fact be re-directed through two new 62 ft. diameter modules[3] located adjacent to the existing Coyote Station Unit 1 DFGD, and then following the new SDA modules, the flue gas could be routed back to the existing Reverse Air Fabric Filter (RAFF). The

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[1] See *Coyote Station Unit 1: North Dakota Regional Haze Second Planning Period Four-Factor Analysis*. May 8, 2019.

[2] In 2017, B&W installed a new SDA adjacent to an existing fabric filter at the Colorado Springs Utilities Nixon Plant.

[3] These exact modules have been installed by B&W at several sites, and most recently at Alliant Columbia Power Station (start-up 2015).

expected performance of this arrangement is an average controlled SO_2 emission rate of approximately 0.09 lb/MMBtu at Coyote Station Unit 1.

Balance of Plant Impacts

The following balance of plant systems were evaluated by Sargent & Lundy to determine what other modifications to the existing systems would be required as part of the overall retrofit cost for the B&W two absorber module option.

Pebble Lime Reagent Preparation & Fresh Lime Slurry System:

- The storage duration of the existing lime silo (63,000 ft^3 or 1,733 tons) will be reduced from over 15.75 days of storage to 5.89 days assuming the unit is operated at full load, 100% capacity. This would result in an increased number of pebble lime deliveries; however no modifications will be required for the storage silos.
- The existing detention slakers and the rest of the slaking equipment will be reused; no modifications required. However, a new slaker water flow control valve (FCV) will be added to increase the controllable flow up to 375 gpm.
- The existing reagent mix tank reagent feed pumps (150 gpm) are undersized and will be replaced with new 2 x 100% lime slurry transfer pumps (500 gpm).
- The two (2) existing atomizer feed tanks (11,800 gal) will be repurposed as the lime slurry feed tanks, new 2 x 100% lime slurry feed pumps will transfer slurry to new 2 x 50% atomizer head tanks located in the new SDA penthouse. The lime slurry will be fed to the atomizer head tank in a continuous loop returning to the lime slurry storage tank. Flow from the continuous loop will be metered into the atomizer head tank based on unit load, inlet SO_2, the SO_2 emission setpoint and trimmed by the SO_2 feedback measured at the stack.

Recycle Slurry System:

- Solids from the existing RAFF are collected and transported (via the ash handling system) to the existing recycle silo (38,000 ft^3). No modifications required.
- A new rotary feeder will be added at the outlet of the recycle silo to meter recycle solids into the recycle mixer where water will be added to achieve an increased recycle slurry solids content of 45% solids.
- New 2 x 100% fly ash slurry transfer pumps will forward slurry to the existing reagent storage tanks that will be repurposed as recycle slurry storage tanks.
- The recycle mix chamber agitator, recycle fly ash wetting tank agitator and the repurposed recycle slurry tank agitators will be upgraded and/or replaced to handle the increase in torque caused by the higher recycle slurry solids content.
- The existing 2 x 100% recycle slurry feed pumps will be upgraded to be capable of transferring the new slurry demand. Similar to the new lime slurry feed pumps, the recycle slurry will be fed in a continuous loop to the new atomizer head tanks to maintain a tank level setpoint.

Byproduct/Waste Ash Conveying System:

- Sargent & Lundy evaluated the original design of the existing waste ash conveying system and determined that the existing system is sufficiently sized to operate with the higher byproduct generation.

Waste Ash Silo:

- When operating to achieve an outlet SO_2 emission of 0.09 lb/MMBtu, the produced waste ash will have a higher concentration of FGD byproducts and unreacted lime, and therefore a decreased concentration of fly ash which will decrease volumetric density of the waste ash.
    - Based on the original waste ash silo design information available, Sargent & Lundy estimated approximately six days (147 hours) of storage, assuming the unit is operated at full load, 100% capacity.
    - With the higher concentration of FGD byproducts and unreacted lime, the waste ash density was estimated to be reduced to approximately 34 lb/ft^3 (reduced fly ash concentration ~29%), reducing the storage duration to a little over three days (85 hours), assuming the unit is operated at full load, 100% capacity.
    - As 3 days of storage is typically recommended as the minimum storage time to cover operation over long weekends without silo unloading activities, it is assumed that the plant should still be able to manage loadout activities accordingly, and therefore no modifications or new equipment is required.
- The unloader from the silo is sufficiently rated and should not require any modifications.
- The waste ash is conditioned with water in pug mills for truck unloading. The plant has made recent upgrades to the water spray headers to the pug mills and have adequate water to condition the increased amount of waste ash loadout activities.
- To help facilitate the increased activity at the waste ash silo, costs have been included to enclose the three (3) open sides of the silo skirt.

Reverse Air Fabric Filter (RAFF):

- The existing Wheelabrator baghouse has 38 compartments, but at any given time, the baghouse normally has 36 compartments operating with 2 compartments offline for cleaning. The existing cleaning system can clean all 38 compartments in 30 minutes (i.e. can complete two cleaning cycles per hour).
- The existing Wheelabrator baghouse was designed for 1,582,000 ACFM at 185°F. Each compartment has 204 bags (12 rows of 17), for a total of 7,752 bags. The total cloth area of 709,308 ft^2 results in an air to cloth (A/C) ratio of 2.33:1 when normally operating 36 compartments.
- The new outlet conditions from the 2 SDA modules are estimated to be approximately 2,011,000 ACFM at 174°F. B&W confirmed that the new resulting A/C ratio (approximate 2.8:1) is within their recommended RAFF guidelines and continued operation should not require modifications. However, since the proposed outlet temperature of the 2 SDA modules will be closer to the water saturation temperature, it will be important to prevent moisture from condensing in the baghouse that may potentially cause corrosion.

- The solids loading to the baghouse will be increasing by approximately 70%. Assuming the current pressure drop across the baghouse will be maintained in the new configuration by increased the frequency of cleaning cycles will cause an increased wear on the bags, shortening the bag life to approximately 3-4 years from the current 6 years.

ID Fans:

- The two (2) variable pitch, axial flow induced draft (ID) fans are each rated for 1,279,000 ACFM, 46.71 in. w.c. and 210°F. The incremental increase in pressure for the new configuration is within the capacity of the existing fans. As the fans and motors are in good condition, no modifications are required.

Based on this additional evaluation by Sargent & Lundy and B&W, re-directing Coyote Station's Unit 1 flue gas to two new absorber modules adjacent to the existing fabric filter is considered a technically feasible option.

Revised SO_2 Cost Effectiveness Summary

Budgetary costs estimates were prepared by B&W and reviewed by Sargent & Lundy for the design, procurement, supply, and installation of the new SDA modules and associated balance of plant equipment.

The Four-Factor Analysis cost effectiveness table has been updated to include the associated costs and cost effectiveness for the replacement of the existing DFGD with two new SDA modules and is provided in Table 1 below. Note that since this new option is similar in annualized costs and achieves greater emissions reductions as compared to the prior Four-Factor Analysis option for an in-place absorber, the prior option was removed from the cost effectiveness table. Similarly, since the new two SDA module option is substantially lower in annualized costs and achieves the same emissions reductions as compared to the prior Four-Factor Analysis option for a new Dry FGD, the new Dry FGD option was removed from the cost effectiveness table.

Detailed cost effectiveness tables are included in Appendix A of this memorandum.

Table 1. SO_2 Emissions Control System Cost Effectiveness ($2018)

SO_2 Control Option	Total Annualized Cost (Note 1) $/yr	Expected Emission Reduction tons SO_2/yr	Average Annual Cost Effectiveness (Note 2) $/ton SO_2 removed	Incremental Annual Cost Effectiveness (Note 3) $/ton SO_2 removed
Baseline (existing DFGD/FF)	---	---	---	---
DSI + Existing FGD	$12,371,000	4,131	$2,994	
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	$2,082,000	5,354	$389	
DSI + FGD Operational Improvements	$14,453,000	7,952	$1,818	$4,762
FGD Upgrades - Replace Existing Absorbers with New Absorber (In-Place)	(Removed from Four Factor Analysis)			
FGD Upgrades – Replace Existing Absorbers with Two (2) New Absorbers (Adjacent to Existing FF + Increased Lime Injection)	$21,122,000	11,619	$1,818	$1,819
Dry FGD (CDS) + FF	(Removed from Four Factor Analysis)			
Wet FGD	$49,035,000	12,078	$4,060	$60,813

Note 1. Total annualized costs for all options presented reflect more recent Coyote Station water consumption pricing.
Note 2. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.
Note 3. Incremental cost effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual emissions reductions (tpy) between a control option and the next most effective option.

Sargent & Lundy LLC

TECHNICAL MEMORANDUM

Appendix A

Revised SO_2 Cost Effectiveness Tables

Coyote Station Unit 1
SO_2 Control Summary

Table 1. Coyote Unit 1 Operating Parameters

Parameter		Unit	Notes
Power Output	427	MW-net	Nominal
Annual Heat Input	30,562,287	MMBtu/yr	24-month annual average for period July 2016 to June 2018.
Average Capacity Factor	72%	%	Based on annual average MW-h during the baseline period.

Table 2. Control Effectiveness

Control Technology	Control Efficiency (%)	Expected Emissions (ton/year)	Emission Rate (lb/MMBtu)	Expected Emissions Reduction (ton/year)
Wet FGD	92.9%	917	0.06	12,078
Dry FGD (CDS) + FF	(Removed from Four Factor Analysis)			
FGD Upgrades - Replace Existing Absorbers with 2 New Absorbers (Adjacent to Existing FF + Increased Lime Injection)	89.4%	1,375	0.09	11,619
FGD Upgrades - Replace Existing Absorbers with New Absorber (In-Place)	(Removed from Four Factor Analysis)			
DSI + FGD Operational Improvements	61.2%	5,043	0.33	7,952
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	41.2%	7,641	0.50	5,354
DSI + Existing FGD	31.8%	8,863	0.58	4,131
Baseline (DFGD/FF)		**12,994**	0.85	0

Table 3. Cost Effectiveness

Control Technology	Emissions (tpy)	Tons of SO_2 Removed (tpy)	Total Capital Requirement ($)	Annualized Capital Cost ($/year)	Annualized Outage Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Baseline (DFGD/FF)	12,994	0	--	--		--	--		
DSI + Existing FGD	8,863	4,131	$23,765,000	$1,948,000	$0	$10,423,000	$12,371,000	**$2,994**	
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	7,641	5,354	$526,000	$43,000	$0	$2,039,000	$2,082,000	**$389**	
DSI + FGD Operational Improvements	5,043	7,952	$24,292,000	$1,991,000	$0	$12,462,000	$14,453,000	**$1,818**	$4,762
FGD Upgrades - Replace Existing Absorbers with New Absorber (In-Place)	(Removed from Four Factor Analysis)								
FGD Upgrades - Replace Existing Absorbers with 2 New Absorbers (Adjacent to Existing FF + Increased Lime Injection)	1,375	11,619	$110,120,000	$9,025,000	$0	$12,097,000	$21,122,000	**$1,818**	$1,819
Dry FGD (CDS) + FF	(Removed from Four Factor Analysis)								
Wet FGD	917	12,078	$324,742,000	$26,613,000	$0	$22,422,000	$49,035,000	**$4,060**	$60,813

Coyote Station Unit 1
SO$_2$ Control Cost Evaluation
FGD Upgrades - Replace Existing Absorbers with 2 New Absorbers (Adjacent to Existing FF + Increased Lime Injection)

SO$_2$ Control Option Description	**FGD Upgrades - Replace Existing Absorbers with 2 New Absorbers (Adjacent to Existing FF + Increased Lime Injection)**
Baseline SO$_2$ Emissions, lb/MMBtu	0.85
Post Upgrade SO$_2$ Emissions, lb/MMBtu	0.09
Capacity Factor used of Cost Estimates (%)	72%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$47,564,000	Based on budgetary quote received from B&W and Sargent & Lundy's conceptual cost estimating system. Costs include equipment and material.
Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$2,378,000	5% of Equipment/Material Cost
Freight	$2,378,000	5% of Equipment/Material Cost
Total PEC	$52,320,000	
Direct Installation Costs		
Labor	$35,917,000	Based on budgetary quote received from B&W and Sargent & Lundy's conceptual cost estimating system.
Scaffolding	included	
Mobilization / Demobilization	included	
Labor Cost Due To Overtime Ineffiency	included	
Total Direct Installation Costs	$35,917,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$88,237,000**	
Indirect Costs		
Contractor's General and Administration Expense	included	
Contractor's Profit	included	
Engineering, Procurement, & Project Services	included	
Construction Management/Field Engineering	included	
S-U / Commissioning	$1,324,000	1.5% of Total Direct Costs
Spare Parts	$441,000	0.5% of Total Direct Costs
Owner's Cost	$1,765,000	2% of Total Direct Costs
Total Indirect Costs	**$3,530,000**	
Contingency	**$18,353,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$110,120,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$9,025,000**	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Increased Waste Disposal Cost	$2,564,000	Based on disposal rate of $32.46 per ton.
Increased Lime Reagent Cost	$3,573,000	Based on lime reagent cost of $128 per ton.
Increased Auxiliary Power Cost	$229,000	Based on auxiliary power cost of $23 per MWh
Increased Water Cost	$3,000	Based on water cost of $0.11 per 1000 gallons.
Increased bag and cage replacement	$52,000	Based on bag cost of $135 per bag
Total Variable O&M Costs	$6,369,000	
Fixed O&M Costs		
Additional Operators per shift	0	Assume no additional operators
Operating Labor	$0	N/A
Supervisor Labor	$0	N/A
Maintenance Materials	$1,324,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$1,324,000	
Indirect Operating Cost		
Property Taxes	$1,101,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,101,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$2,202,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$4,404,000	
Total Annual Operating Cost	**$12,097,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$9,025,000	
Annual Operating Cost	$12,097,000	
Total Annual Cost	**$21,122,000**	

B.1.c – Communications

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

March 20, 2019

FILE

Mr. Mark Thoma
Manager, Environmental Services
OtterTail Power Cooperative
P.O. Box 496
Fergus Falls, MN 56538-0496

Re: Four Factors Analysis - Coyote Station

Dear Mr. Thoma:

We have reviewed the Four-Factors Analysis for the Coyote Station and have only a few significant comments.

1) The baseline emission rates should represent a realistic depiction of anticipated (future) annual emissions for a source (BART Guideline, 4. Step 4). Table 2-1 indicates an expected sulfur content of the lignite combusted in the range of 0.82 – 1.06%. Footnote 1 to Table 5-4 indicates that the inlet SO_2 rate of 3.12 lb/MMBtu to the various scrubbing options is based on a future sulfur content. Normally, a look back at past emissions would be acceptable for determining the baseline emissions. However, since you are anticipating a higher sulfur content in the future lignite combusted, past emissions do not represent a realistic estimate of anticipated emissions. We believe the baseline SO_2 emission rate (12,994 tons/yr) is underestimated in the analysis. The North Dakota Department of Health (Department) has calculated the average SO_2 removal efficiency of the current FGD system from 2013, 2014, 2016, 2017 and 2018 using the AP-42 emission factor of 30(S). Using this average FGD removal efficiency (49%), an average sulfur content of 0.94% (average of 0.82% and 1.06%), and the average coal consumption for the same period (2,204,420 tons/yr), we calculate a baseline emission rate of 15,852 tons/yr. This rate compares very favorably to the 2018 actual emissions (14,913 tons) when adjusting the 2018 sulfur content of 0.89% to 0.94%. The Annual Emissions Inventory Reports for 2016, 2017 and 2018 indicate an increasing sulfur content. The SO_2 analysis should be edited using a more appropriate baseline emission rate.

2) We also believe the inlet SO_2 rate to possible control options (3.12 lb/MMBtu) is high. Using the AP-42 emission factor, we calculate an inlet emission rate of approximately 2.3 lb/MMBtu for 1.06% sulfur in the lignite. We believe this will affect the Total Annual Cost and cost effectiveness of the various control options. The analysis should be changed based on a more realistic inlet SO_2 rate.

3) The Department included tail-end selective catalytic reduction (SCR) as a technically feasible option in the first Regional Haze planning period. However, as you noted in your analysis, the Department ultimately determined that high dust, low dust and tail-end SCR are not technically feasible for cyclone boilers combusting North Dakota lignite (see *United States of America and the State of North Dakota versus Minnkota Power Cooperative and Square Butte Power Cooperative).* Table 5-10 lists tail-end SCR as a technically infeasible option. Since tail-end SCR is not a technically feasible option, we suggest that it be removed from Tables 5-11, 6-3 and 6-4.

4) Many cost estimates throughout the analysis are based on Sargent & Lundy's (S&L) conceptual cost estimating system with major equipment costs based on recently developed projects. When cost estimates are not based on EPA's Control Cost Manual, more documentation is required to substantiate the costs. Please provide the documentation to support costs that are not based on the Control Cost Manual.

If you have any questions, please feel free to contact Tom Bachman of my staff at (701) 328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:csc

B.2 – Basin AVS

B.2.a – Department Request

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
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www.ndhealth.gov

FILE

May 2, 2018

Mr. Mike Paul
Basin Electric Power Coop.
1717 E Interstate Avenue
Bismarck, ND 58503-0564

Re: Regional Haze
Second Planning Period

Dear Mr. Paul:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

Environmental Health
Section Chief's Office
701.328.5150

Division of
Air Quality
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Division of
Municipal Facilities
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Division of
Waste Management
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Division of
Water Quality
701.328.5210

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair
Director
Division of Air Quality

TLO/TB:saj
xc: Cris Miller, Basin Electric Power Coop.

B.2.b – Facility Response

BASIN ELECTRIC
POWER COOPERATIVE
A Touchstone Energy® Cooperative

Received
Air Quality
JAN 2019

January 31, 2019

Mr. Terry O'Clair
North Dakota Department of Health
918 East Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Mr. O'Clair:

RE: Four Factor Analysis Submittal for Antelope Valley Station and Leland Olds Station

Enclosed, you will find one CD and three hard copies of Basin Electric Power Cooperative's (**Basin Electric**) Round II Regional Haze Determination Four Factor Analysis for the Antelope Valley and Leland Olds Stations. This analysis was performed as outlined in the North Dakota Department of Health's (**NDDH**) May 2, 2018, request. Basin Electric is aware that the four factor analysis is one component contributing to the NDDH's Round II Regional Haze State Implementation Plan's Determination for each of these emission sources.

North Dakota is relying on the Western Regional Air Partnership (**WRAP**) to develop the visibility modeling platform needed to evaluate visibility at the Class I areas and subsequently for the individual states to develop and assess compliance strategies that will be formalized within the Round II Regional Haze State Implementation Plan.

Basin Electric requests that the NDDH withhold its Round II Regional Haze Determination until a comparative evaluation of visibility from the various control alternatives have been performed. The timing of the visibility analysis is subject to model availability. Basin Electric will continue to monitor WRAP's model development and will coordinate closely with the NDDH prior to initiating visibility impact analysis.

Should you have any questions concerning this submittal, please do not hesitate to contact Erin Dukart, Environmental Compliance Administrator at edukart@bepc.com or 701.557.5557.

Sincerely,

Mike Paul

Mike Paul
Chief Technical Advisor

/efd/sw
Enclosures

cc: Erin Fox Dukart
Keri Schiferl
Casey Mutzenberger

1717 East Interstate Avenue | Bismarck, ND 58503 | 701.223.0441 | Fax 701.557.5336 | basinelectric.com
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BASIN ELECTRIC
POWER COOPERATIVE
A Touchstone Energy® Cooperative

NORTH DAKOTA ROUND II REGIONAL HAZE STATE IMPLEMENTATION PLAN DETERMINATION'S FOUR-FACTOR ANALYSIS FOR ANTELOPE VALLEY STATION UNITS 1 AND 2

SL-014754
Final
January 30, 2019
Project No. 13772-001

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603-5780 USA • 312-269-2000
www.sargentlundy.com

CONTENTS

FIGURES/TABLES

APPENDICES

ABBREVIATIONS/ACRONYMS

Abbreviation/Acronym	Explanation
ASOFA	advanced separated overfire air
AVS	Antelope Valley Station
B&W	Babcock & Wilcox
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Basin Electric	Basin Electric Power Cooperative
Ca	calcium
CAA	Clean Air Act
CATC	Clean Air Technology Center
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CRF	capital recovery factor
DFGD	dry lime flue gas desulfurization
DSI	dry DSI
dv	deciview
ESP	electrostatic precipitator
EPA	Environmental Protection Agency
EGU	electric generating unit
FGD	flue gas desulfurization
FIP	Federal Implementation Plan
G&A	general and administrative
GHG	greenhouse gas
GPSP	Great Plains Synfuels Plant
HHV	Higher Heating Value
H_2O	water
H_2SO_4	sulfuric acid
K	potassium
LNB	Low-NO_X burner
LTS	long-term strategy
Mg	magnesium

MMBtu	million British thermal units
MNL	multi-nozzle lance
MRYS	Milton R. Young Station
MW	megawatt
MWg	megawatt gross
N_2	nitrogen
Na	sodium
ND	North Dakota
NDDH	North Dakota Department of Health
NH_3	ammonia
NO	nitric oxide
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSR	New Source Review
OEM	original equipment manufacturer
OFA	overfire air
O&M	operations and maintenance
PC	pulverized coal
PM	particulate matter
PRB	Powder River Basin
RBLC	RACT/BACT/LAER Clearinghouse
Round II Determination	Round II Regional Haze Sate Implementation Plan Determination
RPG	Reasonable Progress Goals
RPO	Regional Planning Organization
RRI	rich reagent injection
S	sulfur
S&L	Sargent & Lundy, L.L.C.
SACR	selective autocatalytic reduction
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide

SOFA	separated overfire air
TAC	total annual cost
TCI	total capital investment
TE-SCR	tail-end SCR
URP	uniform rate of progress
WRAP	Western Region Air Partnership

EXECUTIVE SUMMARY

The Antelope Valley Station (AVS), located near Beulah, North Dakota, has two generating units (Units 1 and 2) each rated at 470 megawatts gross (MWg). AVS Unit 1 went on line in 1984 and Unit 2 went on line in 1986. AVS Units 1 and 2 are Combustion Engineering (CE) pulverized coal (PC), tangential fired units firing North Dakota lignite. Each unit is equipped with an over-fire air (OFA) system, low-NO_X concentric firing system (LNCFS), and Omnivise Combustion Optimizer for NO_X control, a dry lime flue gas desulfurization (DFGD) system, and fabric filter baghouse (FF) control system for SO_2 and particulate matter (PM) control. AVS receives a majority of its lignite fuel from the fine coal rejected by the adjacent Great Plains Syngas Plant (GPSP) coal screening process, with the balance of fuel requirements being delivered directly to AVS from the Freedom Mine, which is located adjacent to the AVS/GPSP Complex.

On July 1, 1999, the U.S. EPA published regulations implementing Section 169A of the Clean Air Act (CAA), establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).[1] The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. The Regional Haze Rule established a schedule setting forth deadlines by which the states must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.[2]

During the initial planning period, North Dakota Department of Health's (NDDH) reasonable progress determination found that no NO_X or SO_2 controls were warranted for Basin Electric Power Cooperative's (Basin Electric) AVS Units 1 & 2. U.S. EPA disapproved NDDH's determination for AVS Units 1 & 2, and promulgated a Federal Implementation Plan (FIP) that included a reasonable progress determination that low NO_X burners and separated overfire air (LNB+SOFA) and a NO_X emission limit of 0.17 lb/MMBtu (30-day rolling average) was required for NO_X control for AVS Units 1 and 2. The FIP required Basin Electric to install the NO_X control technologies on AVS Units 1 & 2 by July 31, 2018. In accordance with the FIP requirements, Basin Electric

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[1] 64 FR 35713

[2] On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

installed a low-NO_X concentric firing system (LNCFS) on AVS Units 1 and 2 in 2014 and 2016, respectively, coinciding with the scheduled tri-annual maintenance outages.

As part of the Round II Regional Haze State Implementation Plan (Round II Determination), NDDH requested that Basin Electric prepare a four-factor analysis of sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions control options for AVS Units 1 and 2. The analysis evaluates technically feasible SO_2 and NO_X emission reduction measures for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliance
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

Sargent & Lundy LLC (S&L) and Basin Electric evaluated potentially available SO_2 and NO_X emissions reduction options for AVS Units 1 and 2 to identify technically feasible control options for inclusion in the four factor analysis. The SO_2 and NO_X control options included in this four factor analysis are identified in Table ES-1 and Table ES-2.

Table ES-1. Technically Feasible SO_2 Control Options for AVS Units 1 and 2

Alt. No.	SO_2 Control Technology
E	New Retrofit WFGD
D	New Retrofit DFGD (CDS/FF)
C	New Retrofit DFGD (SDA/FF)
B	FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio
A	FGD Operational Improvements – Station Work Practice
--	Baseline (existing DFGD/FF)

Table ES-2. Technically Feasible NO_X Control Options for AVS Units 1 and 2

Alt. No.	NO_X Control Technology
B	SCR – tail-end configuration (Note 1)
A	SNCR
--	Baseline (existing OFA/LNCFS)

Note 1. Tail-end SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of tail-end SCR on AVS Unit 1. Nevertheless, during the initial planning period, NDDH concluded that tail-end SCR was a technically feasible NO_X control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. For consistency with NDDH's conclusion from the first planning period, tail-end SCR will be carried forward to the four factor analysis

The cost of compliance evaluation (Statutory Factor 1) prepared for SO_2 controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible SO_2 control options for Unit 1 ranges from \$340 per ton (Alternative A) to \$6,992 per ton SO_2 removed (Alternative E), and for Unit 2 ranges from \$284 per ton (Alternative A) to \$6,861 per ton SO_2 removed (Alternative E). When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible SO_2 control options for Unit 1 ranges from \$623 per ton (Alternative A) to \$6,677 per ton SO_2 removed (Alternative D), and for Unit 2 ranges from \$526 per ton (Alternative A) to \$6,584 per ton SO_2 removed (Alternative D).

The cost of compliance evaluation prepared for NO_X controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible NO_X control options for Unit 1 ranges from \$19,893 per ton (Alternative A) to \$39,035 per ton NO_X removed (Alternative B), and for Unit 2 ranges from \$18,179 per ton (Alternative A) to \$36,792 per ton NO_X removed (Alternative B). When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible NO_X control options for Unit 1 ranges from \$16,667 per ton (Alternative A) to \$31,977 per ton NO_X removed (Alternative B), and for Unit 2 ranges from \$15,910 per ton (Alternative A) to \$31,589 per ton NO_X removed (Alternative B).

The time necessary for compliance (Statutory Factor 2) for the SO_2 control options ranges from 3 months (Alternative A) to 60 months (Alternative E). For NO_X control options, the time necessary for compliance ranges from 22 months (Alternative A) to 52 months (Alternative B).

An evaluation of energy impacts and non-air environmental impacts (Statutory Factor 3) indicates that certain control options will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts include increases in water consumption, FGD wastewater treatment and discharge, solid waste generation, and sulfuric acid mist and ammonia emissions.

Regarding remaining useful life (Statutory Factor 4), under the current Basin Electric resource plan, the remaining useful life of AVS Units 1 and 2 are considered to be greater than 20 years. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework.

Based on the results of the four factor analysis prepared for AVS, Basis Electric is aware that reducing SO_2 emissions by implementing FGD Operational Improvements (Alternative B) on Units 1 and 2 may be determined to be cost effective by the NDDH.

Within the Round II Determination process, the NDDH will evaluate visibility improvements relying on Western Region Area Partnership's (WRAP) cumulative modeling of the North Dakota based facilities for the various control options being evaluated. Basin Electric requests that the NDDH withhold their Round II Regional Haze SIP Determination for the AVS until the cumulative modeling platform is made available to the public and visibility improvement assessments can be conducted. Basin Electric will then perform a comparative visibility improvement analysis and submit the results to the NDDH for consideration. This effort will be coordinated with the NDDH for consistency of modeling protocols and model inputs.

In addition, Basin Electric requests, that in the event that SO_2 reductions will be required, any future 30-day rolling average permit limit will be based on an equivalent mass based combined plant (lb SO_2/hr) 30-day rolling average basis. Since AVS began operation, the current combined plant total permit limit of 3,845 lb SO_2/hr, 3-hour average, has been the benchmark for all operations guidance and procedures and is imbedded in the DFGD process control logic. To alter the basis of the operational control to a mass emission rate (lb SO_2/MMBtu) will be extremely disruptive from an operational perspective when consideration is given to the complexity and variability of DFGD operations.

The four factor analysis prepared for AVS NO_X reductions indicates that SNCR and tail-end SCR control options are cost prohibitive. The control cost evaluation indicates that the average cost effectiveness levels exceed $15,000 per ton NO_X removed. Basin Electric is proposing that the existing OFA / LNCFS systems on Units 1 and 2 represent appropriate controls for the Round II Determination, therefore no change to the current Title V Operating Permit is proposed for NO_X emissions at AVS. Table ES-3 includes a summary of the proposed Round II

Determination's control strategy for SO_2, assessed SO_2 emissions on a 30-day rolling average basis and a proposed combined plant average emission rate for AVS. The proposed emissions include compliance margin to account for items such as variability in fuel heating value and sulfur content, and operating load profile.

Table ES-3. Proposed Round II Determination's SO_2 Emission Rate

AVS Unit No.	Pollutant	Proposed Round II Determination's Emission Rate lb/MMBtu (30-day rolling average)	Proposed Round II Determination's Combined Plant Emission Rate (Note 1) (lb/hr)	Control Technology
Unit 1	SO_2	0.30	2,958	FGD Operational Improvements
Unit 2	SO_2	0.30	2,958	FGD Operational Improvements

Note 1. The proposed Round II Determination's combined plant emission rate is a 23% reduction from the current combined plant permit limit of 3,845 lb SO_2/hr, 3-hour avg.

1. INTRODUCTION

Sargent & Lundy, L.L.C. (S&L) was retained by Basin Electric Power Cooperative (Basin Electric) to prepare a Round II Regional Haze State Implementation Plan Determination's (Round II Determination) four-factor analysis for the control of sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions from Basin Electric's Antelope Valley Station (AVS) Units 1 and 2. The evaluation is in response to the North Dakota Department of Health's formal letter dated May 2, 2018, attached in Appendix A. The evaluation includes an assessment of potentially available emission reduction measures for the four statutory factors listed in 40 CFR 51.308(f)(2), and takes into consideration U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period* (the "Draft EPA Guidance").[3] Technically feasible SO_2 and NO_X emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliance
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

The Round II Determination's four factor analysis for AVS Units 1 and 2 is presented in the following sections:

Section 2: **Facility Description** contains information describing the facility, site location, and existing equipment.

Section 3: **Four-Factor Analysis Requirements** provides a brief description of the Regional Haze Program requirements set forth in 40 CFR 51.308.

Section 4: **SO_2 Control Evaluation** establishes representative baseline SO_2 emissions, identifies potentially available emission control technologies, evaluates each control option for technical feasibility and evaluates cost effectiveness of technically feasible control options.

Section 5: **NO_X Control Evaluation** establishes representative baseline NO_X emissions, identifies potentially available emission control technologies, evaluates each control option for

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[3] On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Basin Electric reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

technical feasibility and evaluates cost effectiveness of technically feasible control options.

Section 6: **Time Necessary for Compliance** provides typical timelines required to design, engineer, procure and install the technically feasible control options.

Section 7: **Energy and Non-Air Quality Environmental Impacts** identifies the energy and non-air quality environmental impacts associated with each technically feasible control option**.**

Section 8: **Remaining Useful Life** includes a discussion of the planned remaining useful life of AVS Units 1 and 2, including an evaluation of how remaining useful life affects the cost-effectiveness of each technically feasible control option.

Section 9: **Summary and Conclusions**

Appendix A: North Dakota Department of Health Letter

Appendix B: Antelope Valley Station Units 1 and 2 Baseline Emissions

Appendix C: SO_2 Control Cost Effectiveness Estimates

Appendix D: NO_X Control Cost Effectiveness Estimates

2. FACILITY DESCRIPTION

The Antelope Valley Station (AVS), located near Beulah, North Dakota, has two generating units (Units 1 and 2) each rated at 470 megawatts gross (MWg). AVS Unit 1 went on line in 1984 and Unit 2 went on line in 1986. AVS Units 1 and 2 are Combustion Engineering (CE) pulverized coal (PC), tangential fired units firing North Dakota lignite. Each unit is equipped with an over-fire air (OFA), low-NO_X concentric firing system (LNCFS), and Omnivise Combustion Optimizer for NO_X control, a dry lime flue gas desulfurization (DFGD) system, and fabric filter baghouse (FF) control system for SO_2 and PM control. AVS receives a majority of its lignite fuel from the fine coal rejected by the adjacent Great Plains Syngas Plant (GPSP) coal screening process, with the balance of fuel requirements being delivered directly to AVS from the Freedom Mine, which is located adjacent to the AVS/GPSP Complex.

Table 2-1 provides a summary of the design parameters used for the AVS Units 1 and 2 four factor analysis. The four factor analysis design parameters listed in Table 2-1 were developed from information provided by Basin Electric. The parameters are for each AVS unit.

Table 2-1. Four Factor Analysis Design Basis Parameters

Parameter	AVS Unit 1	AVS Unit 2
Boiler type	PC tangential fired	PC tangential fired
Boiler manufacturer	Combustion Engineering	Combustion Engineering
Generating Capacity (MWg)	470	470
Design Heat Input (MBtu/hr)	4,930	4,930
Average Hourly Heat Input for Baseline SO_2 period (MBtu/hr)	4,459	4,499
Capacity Factor for Baseline SO_2 period (%)	86	87
Average Hourly Heat Input for Baseline NO_X period (MBtu/hr)	4,126	4,480
Capacity Factor for Baseline NO_X period (%)	81	85

Parameter	AVS Unit 1	AVS Unit 2
DFGD Design Parameters		
SO_2 Content lb/MMbtu	3.56	3.56
Design Removal Efficiency (%)	89	89
Baseline Fuel Parameters(1)		
Higher Heating Value (Btu/lb)	6,755	6,755
Fuel sulfur content (%)	0.98	0.98
SO_2 content (lb/MMBtu)	2.90	2.90
Projected Future Fuel Parameters(2)		
Higher Heating Value (Btu/lb)	6,434	6,434
Fuel sulfur content (%)	1.09	1.09
SO_2 content (lb/MMBtu)	3.39	3.39

Note 1. Baseline fuel parameters are based on the actual annual average fuel sulfur content from 2013-2018 provided by Basin Electric.
Note 2. Projected future fuel parameters are based on anticipated annual average coal projections provided by Basin Electric from 2019-2045. Projected future sulfur and SO_2 content includes margin based on the actual deviation in annual average sulfur content from current coal data. Additional detail on coal sulfur provided in Section 4.2.

3. FOUR-FACTOR ANALYSIS REQUIREMENTS

3.1 REGIONAL HAZE RULE BACKGROUND

Section 169A of the 1977 Amendments to the Clean Air Act (CAA) sets forth a program for protecting visibility in Federal Class I areas which calls for " the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Federal Class I areas which impairment results from manmade air pollution." Federal Class I areas include national parks, memorial parks, and wilderness areas over a certain size. Figure 3-1 shows the locations of the 156 federally mandated Class I areas. Federal Class I areas located within ND include the Theodore Roosevelt National Park and the Lostwood National Wildlife Refuge.

Figure 3-1. Federal Class I Areas

On July 1, 1999, the U.S. EPA published regulations implementing Section 169A of the CAA, establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).[4] The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. Regional Haze SIPs must contain such emission limits, schedules of compliance, and other measures as may be necessary to make reasonable progress toward meeting the national visibility goal of achieving visibility in Class 1 areas which reflects natural conditions by 2064.

To address the combined visibility effects of various pollution sources over a wide geographic region, EPA designated five Regional Planning Organizations (RPOs) to assist with the coordination and cooperation needed to address the visibility issue. The five RPOs are shown in Figure 3-2. North Dakota is a member of the Western Regional Air Partnership (WRAP), which serves as the RPO for visibility protection at 118 Class I areas in 15 western states.

Figure 3-2. Regional Planning Organization Map

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[4] 64 FR 35713

3.1.1 First Implementation Period

The Regional Haze Rule established a schedule setting forth deadlines by which the states must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.[5]

Regional Haze SIP requirements for the first planning period required that states incorporate into their plans the core program requirements in 40 CFR 51.308(d), including: (1) establishing reasonable progress goals (RPGs) for each Class I area within the state that provide for measurable progress towards achieving natural visibility conditions; (2) developing a long-term strategy (LTS) including enforceable emissions limitations and compliance schedules to achieve the RPGs; and (3) developing plans to monitor and assess the effectiveness of the LTS to achieve the RPGs over the prior implementation period and affirmation of or revision to the RPGs.

The Regional Haze Rule requires that states determine the consistent rate of progress over time needed to attain natural visibility conditions on the 20 percent most impaired days by the year 2064. This "glidepath" is referred to as the uniform rate of progress (URP) line. States must consider the URP, and the emission reduction measures needed to achieve this level of improvement, when developing their RPGs and LTS. Regulations at 40 CFR 51.308(g) require each state to submit progress reports, in the form of SIP revisions, every 5 years following the submission of the initial SIP. These progress reports must evaluate the progress made towards the RPGs for Class I areas located within the state as well as those Class I areas located outside the state that may be affected by emissions from within the state.

3.1.1.1 Best Available Retrofit Technology

As a one-time requirement during the first implementation period, potential best available retrofit technology (BART) controls had to be evaluated for certain large stationary sources. States were required to conduct BART determinations for "BART-eligible" sources anticipated to cause or contribute to any visibility impairment in one or more Class I area. BART-eligible sources included coal-fired electric generating units (EGUs) that were in existence on August 7, 1977, but not in operation prior to August 7, 1962. In its determination of BART, states were required to take into consideration the costs of compliance, the energy and non-air quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of

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[5] On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[6] As an alternative to requiring source-specific BART controls, states also had the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provided greater reasonable progress towards improving visibility than BART.

3.1.1.2 North Dakota's Initial Planning Period SIP Summary

The State of North Dakota submitted its regional haze SIP addressing the requirements of 40 CFR 51.308 to EPA for review on March 3, 2010 (the "Regional Haze SIP").[7] The Regional Haze SIP was prepared by the North Dakota Department of Health, Air Quality Division (NDDH). The SIP included BART determinations for seven steam EGU's identified as being subject to the BART requirements of 40 CFR 51.208(e) and a reasonable progress evaluation for six additional non-BART sources identified as having the potential to affect visibility in a Class I area.

Basin Electric's Leland Olds Station (LOS) Units 1 & 2 were evaluated by NDDH as subject-to-BART sources.[8] Based on its evaluation of available control technologies, NDDH concluded that BART for both LOS units included new wet flue gas desulfurization (WFGD) for SO_2 control and separated overfire air (SOFA) with selective non-catalytic reduction (SNCR) for NO_X control. NDDH determined that selective catalytic reduction (SCR), a higher performing NO_X control option, was not an available, and thus not a technically feasible, NO_X control option.[9]

Basin Electric's AVS Units 1 & 2 were evaluated by NDDH under the further reasonable progress requirements. Based on an evaluation of the four reasonable progress statutory factors (i.e., costs of compliance, time necessary

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[6] CAA Section 169A(g)(2).

[7] North Dakota State Implementation Plan for Regional Haze – A Plan for Implementing the Regional Haze Program Requirements of Section 308 of 40 CFR Part 51, Subpart P – Protection of Visibility, North Dakota Department of Health, February 24, 2010. In addition to the initial SIP submittal, the State submitted a SIP Supplement No. 1 on July 27, 1010, and a SIP Amendment No. 1 on July 28, 2011 (collectively the "Regional Haze SIP").

[8] In addition to LOS Units 1 & 2, NDDH evaluated Great River Energy's Coal Creek Station Units 1 & 2; Great River Energy's Stanton Station Unit 1; and Minnkota Power Cooperative's Milton R. Young Station Units 1 & 2 as subject-to-BART sources.

[9] Regional Haze SIP, pg. 73. The State's evaluation of SCR for North Dakota lignite was included as Appendix B.5 to the Regional Haze SIP (Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite, July 2009). NDDH eliminated SCR from consideration as BART based on a finding that SCR was not technically feasible to control emissions from North Dakota lignite coal. In particular, NDDH noted that no SCR has ever been employed on an electric generating unit (EGU) burning North Dakota lignite, that North Dakota lignite has unique properties that have the potential to quickly degrade the SCR catalyst, and that no catalyst vendor would provide a guarantee of catalyst life without first conducting slipstream or pilot testing.

for compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of the units) plus an evaluation of incremental visibility improvement, NDDH concluded that requiring additional controls (beyond those required for the BART-eligible sources) would not substantially improve visibility in the Class I areas, and that for all reasonable progress sources evaluated individually and cumulatively, control technology costs (evaluated on a dollar per deciview improvement ($/dv) basis) was excessive. Therefore, the initial Regional Haze SIP did not include additional control for AVS Units 1 & 2.[10]

On September 21, 2011, EPA published a Proposed Rule proposing to partially approve and partially disapprove specific aspects the Regional Haze SIP.[11] Among other things, EPA proposed to disapprove the State's determination of BART for LOS Unit 2 as well as the reasonable progress determination for AVS Units 1 & 2. EPA proposed to approve the remaining aspects of North Dakota's Regional Haze SIP, including that State's BART determination for SO_2 control at LOS (i.e., new WFGD) and the NO_X BART determination for LOS Unit 1 (i.e., SOFA+SNCR).[12] Along with the proposed partial disapproval of North Dakota's SIP, EPA proposed the promulgation of a Federal Implementation Plan (FIP). The proposed FIP included, among other items: (1) a NO_X BART determination and emission limits for LOS Unit 2; and (2) a reasonable progress determination and NO_X emission limits for AVS Units 1 & 2. EPA proposed advanced SOFA (ASOFA) plus SCR and an emission rate of 0.07 lb/MMBtu (30-day rolling average) as BART for NO_X control on LOS Unit 2. EPA also proposed low-NO_X burners (LNB) plus SOFA and an emission limit of 0.17 lb/MMBtu (30-day rolling average) as representing reasonable progress NO_X control on AVS Units 1 & 2.[13]

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[10] *Id.* at pg. 188.

[11] 76 Fed. Reg. 58570, September 21, 2011 (the "Proposed FIP"). In addition to the proposed disapproval of the State's BART determination for Leland Olds Station Unit 2, EPA proposed disapproving the BART determinations for the Coal Creek Station and Milton R. Young Station (MRYS) Units 1 & 2.

[12] *Id.* at pg. 58619. Note that for LOS Unit 1 EPA stated that it did not agree with the State's cost analysis for SCR, but nonetheless found the elimination of SCR for LOS Unit 1 to be acceptable because LOS Unit 1 is relatively small (216 MW) compared to LOS Unit 2 (440 MW) and MRYS Units 1 & 2, and LOS Unit 1 had lower baseline NOx emission. (76 FR 58596, Table 22).

[13] *Id.* at pg. 58632. EPA eliminated higher performing NOx control options for AVS Units 1 & 2, including LNB + SNCR; SCR; and LNB + SCR, because their cost effectiveness values were significantly higher and/or the emission reductions were not that much higher than LNB. Considering the statutory factors, EPA found that it was not reasonable to insist on these higher control levels in the first; however, EPA noted that expected North Dakota to consider such controls in the next planning period.

Following the public notice and comment period EPA issued its Final Rule on April 6, 2012.[14] The Final Rule differed from the Proposed Rule in that EPA reversed its position regarding the technical feasibility of SCR on LOS Unit 2 and decided to approve the State's BART determination for NO_X control on LOS Unit 2.[15] Conversely, EPA finalized its determination that LNB+SOFA was required by reasonable progress for AVS Units 1 & 2.

EPA's decision to accept the BART determinations for LOS Unit 2 (and Milton R. Young Station (MRYS) Units 1 & 2) was based primarily on the decision in United States v. Minnkota Power Cooperative, Inc.[16] which concluded that the State's best available control technology (BACT) analysis for NO_X control on MRYS Units 1 & 2 was not unreasonable, a conclusion that was contrary to EPA's position at the time of the Proposed FIP.[17] In explaining its decision to reverse its position that SCR was a technically feasible NO_X control option for LOS Unit 2, EPA noted that the technical feasibility determination under the BACT and BART analyses was substantially the same, and that the BART Guidelines permit a state to rely upon a BACT determination for purposes of selecting BART unless new technologies have become available or best control levels for recent retrofits have become more stringent.[18] Noting that the District Court upheld North Dakota's BACT determination for MRYS Units 1 & 2, EPA concluded that it would be inappropriate to proceed with its proposed disapproval of SNCR as BART, and approved the State's determination that ASOFA+SNCR and an emission rate of 0.35 lb/MMBtu (30-day rolling average) was BART for NO_X control on LOS Unit 2.

With respect to NO_X control on AVS Units 1 & 2, EPA finalized its proposed determination that LNB+SOFA and a NO_X emission rate of 0.17 lb/MMBtu (30-day rolling average) was required for reasonable progress. North Dakota challenged EPA's disapproval of its reasonable progress determination for AVS Units 1 & 2, and EPA's subsequent promulgation of the FIP. The District Court found that EPA's determination on this matter was entitled to judicial

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[14] 77 Fed. Reg. 20894.

[15] *Id.* at pg. 20897-98. EPA also reversed its position and decided to approve the State's BART determination for NOx control on MRYS Units 1 & 2.

[16] United States v. Minnkota Power Cooperative, Inc., 831 F. Supp. 2d 1109, 1127-30 (D.ND. 2011).

[17] Contemporaneous with the Regional Haze SIP/FIP process, NDDH was also determining BACT for MRYS Units 1 & 2 pursuant to a Consent Decree entered into between the owner of the station (Minnkota), the State, and EPA under the CAA's Prevention of Significant Deterioration program. In its BACT analysis, NDDH concluded that SCR was technically infeasible on a lignite-fired cyclone boiler, and selected SNCR as BACT. EPA challenged the State's BACT determination in district court, contending that SCR was a technically feasible emission control option and should have been selected as BACT. On December 21, 2011, the District Court issued its decision on EPA's challenge of the State's BACT determination, finding that the State's conclusion that SCR was not technically feasible was not unreasonable. See, U.S. v. Minnkota, 831 F. Supp. 2d at 1127-30.

[18] 77 Fed. Reg. 20897.

deference, and could not conclude that EPA acted in a manner that was arbitrary or capricious; therefore, the State's petition for review was denied and EPA's reasonable progress determination for AVS Units 1 & 2 was upheld.

Emission controls required by the Regional Haze SIP for the Basin Electric's LOS and AVS stations are summarized in Table 3-1.

Table 3-1. Initial Planning Period SIP Summary

Source & Unit	Pollutant	Control Device / Emission Limit
LOS Unit 1 (BART)	NO_X	Basic SOFA + SNCR with an emission limit of 0.19 lb/MMBtu (30-day rolling average)
	SO_2	New wet FGD operating at 95% efficiency or below an emission limit of 0.15 lb/MMBtu (30-day rolling average
LOS Unit 2 (BART)	NO_X	Advanced SOFA + SNCR with an emission limit of 0.35 lb/MMBtu (30-day rolling average)
	SO_2	New wet FGD operating at 95% efficiency or below an emission limit of 0.15 lb/MMBtu (30-day rolling average
AVS Unit 1 (reasonable progress)	NO_X	LNB+SOFA with an emission limit of 0.17 lb/MMBtu (30-day rolling average)
	SO_2	No additional control beyond the existing dry FGD / baghouse
AVS Unit 2 (reasonable progress)	NO_X	LNB+SOFA with an emission limit of 0.17 lb/MMBtu (30-day rolling average)
	SO_2	No additional control beyond the existing dry FGD / baghouse

3.1.1.3 Reasonable Progress Control Requirements for AVS Units 1 and 2 during First Planning Period

AVS Units 1 & 2 were not subject to the Regional Haze BART requirements of 40 CFR 51.208(e). Nevertheless, during the initial planning period NDDH evaluated emissions reductions from AVS as a reasonable progress source. Based on an evaluation of control technology costs and the resulting incremental improvement in visibility, NDDH found that no additional NO_X controls were warranted during the initial planning period. As discussed in Section 3.1.1.2, EPA disapproved the State's reasonable progress determination for AVS Units 1 & 2, and promulgated a FIP that included a reasonable progress determination that LNB+SOFA and a NO_X emission limit of 0.17 lb/MMBtu (30-day rolling average) was required for NO_X control for AVS Units 1 and 2. The FIP required Basin Electric to install the NO_X control technologies on AVS Units 1 & 2 by July 31, 2018. In accordance with the FIP requirements, Basin Electric installed a low-NO_X concentric firing system (LNCFS) on AVS Units 1 and 2 in 2014 and 2016, respectively, coinciding with the scheduled tri-annual maintenance outages.

3.1.2 Round II Regional Haze SIP Determination

The Round II Determination must be submitted to EPA for review by July 31, 2021. Among other requirements, the Round II Determination is required to include an assessment of the state's RPGs and LTS. To support states in their efforts to develop the Round II Determination, in July 2016 EPA released a draft guidance document titled "*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*" ("Draft EPA Guidance").[19] The Draft EPA Guidance document describes key steps states should implement when developing their RPGs and LTS for the Round II Determination. Key steps identified in the Draft EPA Guidance are listed in Table 3-2.

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[19] See, EPA-457/P-16-001. On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Basin Electric reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

Table 3-2. Key Steps in Developing the Round II Determination

1. *Ambient data analysis* – Quantify baseline, current and natural conditions and the uniform rate of progress that would achieve natural conditions by 2064 (40 CFR 51.308(f)(1))
2. *Screening of sources* – Identify the pollutants and emission sources for which a full reasonable progress analysis will be completed and explain why it is appropriate to limit the full analysis to only these sources (40 CFR 51.308(f)(2))
3. *Source and emission control measure analysis* – Identify potential emission control measures for sources selected in the screening step and develop data on the four statutory factors and visibility benefits if they will be considered (40 CFR 51.308(f)(2))
4. *Decisions on the content of the LTS* – Consider applicable factors and decide on new emission controls for incorporation into the LTS (40 CFR 51.308(f)(2))
5. *Regional scale modeling* – Model the emissions reductions that will result from implementation of the LTS and other enforceable measures that will reduce visibility impairment to set the RPGs for 2028 (40 CFR 51.308(f)(3))
6. *Progress, degradation and glidepath checks* – Demonstrate that there will be an improvement on the 20 percent most impaired days. Demonstrate that there is no degradation on the 20 percent clearest days. Compare the 2028 RPG for the 20 percent most impaired days to the 2028 point on the URP line (the glidepath) and, if required, provide additional justification for the reasonableness of the RPG. Revise the LTS if additional measures are identified as necessary to make reasonable progress. (40 CFR 51.308(f)(3))
7. *Additional requirements for SIPs* – Provide additional information necessary to ensure that other requirements of the Regional Haze rule are met.

The Draft EPA Guidance recommends that states evaluate all technically feasible emission control options for stationary sources and source categories identified as having the greatest potential to impact visibility at one or more Class I area. The Draft EPA Guidance recommends several options for states to consider when evaluating potential emission reductions, including work practices, replacement and retrofit controls, existing control upgrades, fuel switching, year-round operation of controls, and operating restrictions.[20]

Emission control evaluations must consider the four statutory factors identified in 40 CFR 51.308(f)(2)(i) (discussed in Section 3.2). In addition, the Draft EPA Guidance notes that control technology assessment recommendations presented in the BART Guidelines continue to be relevant as recommendations for how a state should evaluate and select emission control measures for stationary sources.[21] Recommendations in the BART

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[20] See, Draft EPA Guidance, pgs. 85-86.

[21] Draft EPA Guidance, pg. 85. The BART Guidelines are published at 40 CFR Part 51 Appendix Y.

Guidelines that continue to be relevant to the Round II Determination's four factor analysis are listed in the Appendix of the Draft EPA Guidance, and include, in general, the recommended approach for evaluating the technical feasibility, effectiveness, costs, and cost-effectiveness of available emission control measures.[22]

3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS

Under 40 CFR 51.308(f)(2)(i), states must consider four statutory factors when evaluating and determining emissions reduction measures from stationary sources, or groups of sources, that are necessary to make reasonable progress towards achieving natural visibility conditions. The four statutory factors are:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

A brief description of each of the four statutory factors, and EPA's recommendations for evaluating each of the four factors (from the Draft EPA Guidance) is provided below.

3.2.1 Costs of Compliance

Cost estimates should be developed for each technically feasible control option. Costs include the total capital costs to engineer, design, procure, and install the control technology, and annual operating and maintenance (O&M) costs. O&M costs include both fixed and variable O&M. Fixed O&M includes costs that are independent of control system operation and would be incurred even if the control system were shut down. Fixed O&M includes categories such as operating and maintenance labor, administrative charges, property taxes, and insurance. Variable O&M includes the cost of consumables, including reagent (e.g., lime or limestone, ammonia, urea, etc.), by-product management, water consumption, and auxiliary power requirements associated with operating the control system. For existing facilities, O&M cost estimates should represent the control option's incremental increase over current O&M costs.

Capital costs include all costs required to engineer, design, procure, and install equipment needed for the control system. The Draft EPA Guideline recommends that states adhere to the accounting principles described in Chapter

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[22] Draft EPA Guidance, Appendix D, pgs. 186-196.

2 Section 1 of EPA's Air Pollution Control Cost Manual (the "Control Cost Manual") when calculating control system costs for a four factor analysis.[23]

Section 2.3 of the Control Cost Manual (Section 1, Chapter 2) describes the cost categories generally used to calculate the total capital cost of a retrofit control technology. Cost categories include total capital investment (TCI), which is defined to "include all costs required to purchase equipment needed for the control systems (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also includes costs for land, working capital, and off-site facilities." Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (i.e., cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies.[24]

The total annual cost (TAC) of a control option includes the annualized capital recovery cost plus the total annual O&M costs. The Control Cost Manual recommends using an equivalent uniform annual cash flow method to annualize the total capital investment by multiplying the total capital investment by a capital recovery factor (CRF).[25] The product of the total capital investment and CRF gives a uniform end-of-year payment necessary to repay the initial capital investment in "n" years at an interest rate of "i". The CRF is calculated using the following equation:

$$\mathrm{CRF} = \frac{\mathrm{i} * (1+\mathrm{i})^{\mathrm{n}}}{(1+\mathrm{i})^{\mathrm{n}} - 1}$$

Where:
i = interest rate; and
n = economic life of the emission control system

The Draft EPA Guidance suggests that states may use generic cost estimates or estimating algorithms for estimating control system costs; however, source specific estimates prepared by knowledgeable engineering professionals

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[23] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002.
[24] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, pg. 2-5.
[25] Id., at pg 2-21.

provide more reliable information than generic cost estimates.[26] Source-specific cost estimate should be well documented for purposes of public comment and EPA review.[27]

The total annual cost of each control option ($/yr) is divided by the total annual emissions reduction (tpy) to determine the control option's average cost-effectiveness on a $/ton basis. Emissions reductions are calculated based on the difference between baseline annual emissions and post-control annual emissions. The Draft EPA Guidance generally recommends calculating baseline emissions based on projected 2028 emissions assuming source compliance with emission limits that have been adopted and are enforceable. As an alternative, baseline emissions may be based on representative past actual emissions, assuming there is no evident basis for using a different emissions rate.

3.2.2 Time Necessary for Compliance

For stationary sources, the provisions of the BART Guidelines regarding the time necessary for compliance are relevant to the Round II Determination's analyses. EPA recommends that prior experiences with the planning and installation of new emission controls is the best guide to how much time a particular source will reasonably need for compliance. However, source-specific factors should be considered when evaluating the time necessary to engineer, procure, and install an available and technically feasible control option. Source-specific factors that affect the time necessary to install new emission controls should be identified and documented in the four factor analysis.

3.2.3 Energy and Non-Air Quality Environmental Impacts

For stationary sources, the provisions of the BART Guidelines regarding energy impacts are relevant to the Round II Determination's analyses. Energy impacts of an emission control measure are a matter of engineering design and control system operation; thus, EPA recommends that prior experience at similar sources will be informative. Energy impacts may be considered in terms of kilowatt-hours or fuels used to operate the control system. The energy impact analysis should focus on direct energy consumption at the source rather than indirect energy inputs needed to produce raw materials for the construction and operation of control equipment.

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[26] Draft EPA Guidance, pg. 91.
[27] *Id.*

For stationary sources, the provisions of the BART Guidelines regarding non-air quality environmental impacts are relevant to the Round II Determination's analyses. Non-air quality impacts include solid or hazardous waste generation, increased water consumption, wastewater discharge, land use impacts, and impacts to threatened and endangered species or their natural habitat. Characterizing the non-air quality environmental impacts should be done on a source-specific basis. Other guidance intended for use in assessments under the National Environmental Policy Act may be relevant to this evaluation.

Even though states are not required to consider GHG emission impacts, the Draft EPA Guidance encourages states to consider GHG impacts when developing their LTS.[28] As an example, some measures that would reduce emissions that contribute to visibility impairment will also reduce GHG emissions, such as measures that reduce the use of energy produced from combusting fossil fuels with relatively high GHG emissions. Conversely, control measures that require significant energy to capture visibility impairing emissions could result in increased GHG emission. Where a measure necessary to make reasonable progress towards natural visibility conditions would increase GHG emissions, Draft EPA Guidance encourages states to work to harmonize visibility and climate change objectives.[29]

3.2.4 Remaining Useful Life

For stationary sources, the provisions of the BART Guidelines regarding remaining useful life are relevant to the Round II Determination's analyses. In general, the remaining useful life of the source itself will be longer than the useful life of the emission control measure under consideration unless there is an enforceable requirement for the source to cease operation sooner. Thus, the useful life of the control measure will normally be used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness. However, if there is an enforceable requirement for the source to cease operation by a date before the end of what would otherwise be the useful life of the control measure under consideration, then the enforceable shutdown date should be used to calculate remaining useful life and evaluate control technology cost-effectiveness.

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[28] Draft EPA Guidance, pg. 92.
[29] *Id.*

3.2.5 Approach for Evaluating Control Measures

S&L used a top-down approach to identify and evaluate the technical feasibility and effectiveness of potentially available SO_2 and NO_X control measures. S&L followed Steps 1 thru 3 of the top-down approach described in the BART Guidelines to identify all available retrofit emission control measures, eliminate technically infeasible options, and evaluate the effectiveness of the technically feasible options.[30] A brief description of each step is provided below.

Step 1 - Identify All Available Control Options

Available control options are those air pollution control technologies with a practical potential for application to the emission unit and the regulated pollutant under evaluation. Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant, and include not only existing controls for the source category but also take into account technology transfer of controls that have been applied to similar source categories and gas streams. Technologies which have not been applied to (or permitted for) full scale operations need not be considered as available.[31]

In an effort to identify all potentially available emission control technologies, S&L searched a broad range of information sources including, but not necessarily limited to:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC);
- EPA's New Source Review (NSR) and Clean Air Technology Center (CATC) Web sites;
- BART evaluations prepared during the initial Regional Haze planning period;
- Information from control technology vendors and engineering/environmental consultants;
- Federal and State NSR permits and BACT determinations for similar sources; and
- Technical journals, reports, newsletters and air pollution control seminars.

Step 2 - Eliminate Technically Infeasible Control Options

In Step 2, S&L evaluated the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. Control technologies are technically feasible if either: (1) they have been installed and operated successfully for the type of source under review under similar conditions; or (2) the technology could be applied to the source under review. In order for a control option to be technically feasible, it

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[30] See, 40 CFR Part 51 Appendix Y, Section IV.D.
[31] *Id.*, at IV.D.1.

must be "available" and "applicable" to the source under consideration. A technology is considered "available" if the source owner may obtain it through commercial channels. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.[32]

Control technologies that are technically infeasible (i.e., not available or not applicable to the source under consideration) are eliminated for further evaluation. A demonstration of technical infeasibility must be based on physical, chemical and engineering principals, and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/infeasibility.

Step 3 - Evaluate Technically Feasible Control Technologies for Effectiveness

Step 3 involves evaluating the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review. Control effectiveness should be expressed using a metric that ensures an "apples-to-apples" comparison of emissions performance levels among options, and is generally expressed as the rate that a pollutant is emitted after installation of the control measure. Control technology evaluations for existing sources should consider ways to improve the performance of existing control devices. Special circumstances pertinent to the specific source under review should be identified and taken into consideration when assessing the capability of the control alternative and determining control effectiveness.

For this evaluation, S&L assessed the technically feasible SO_2 and NO_X control options for effectiveness on AVS Units 1 and 2. As discussed above, AVS Units 1 and 2 are PC tangential-fired boilers designed to fire North Dakota lignite. The units are equipped with SOFA, LNCFS and an Omnivise Combustion Optimizer for NO_X control, DFGD and FF for SO_2 and PM control.

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[32] A more detailed description of control technology "availability" and "applicability" is provided in 40 CFR Part 51 Appendix Y, Section IV.D.2.

4. SO_2 CONTROL EVALUATION

4.1 BASELINE SO_2 EMISSIONS

The first step in developing the four factor analysis is to establish AVS Units 1 and 2 baseline SO_2 emissions. To establish representative baseline emissions, S&L evaluated AVS Units 1 and 2 operating data for the five year period January 1, 2013 to June 30, 2018 to identify periods of normal operation (i.e., periods of operation when the boiler was not limited by infrequent or extraordinary operating restrictions). Based on review of fuels consumed, heat input to the boiler, boiler heat rates, power generation, and capacity factors, as well as input from Basin Electric, it was determined that the operating periods of January 1, 2013 to June 30, 2018 were representative of normal boiler operation for SO_2 emissions. The representative baseline periods for the AVS Units are shown in Table 4-1.

Table 4-1. Representative Baseline Periods for SO_2 Emissions

Pollutant	Representative Baseline Periods	
	AVS Unit 1	AVS Unit 2
SO_2 Emissions	1/1/2013 to 6/30/2018	1/1/2013 to 6/30/2018

Baseline annual SO_2 emissions were determined based on data obtained from the Units 1 and 2 continuous emissions monitoring system (CEMS) that was reported to EPA's Clean Air Markets. The maximum 24-consecutive month annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons per year). Representative baseline emission factors (in terms of pounds per million British Thermal Units (lb/MMBtu)) were developed using baseline annual emissions and the respective annual heat inputs. Table 4-2 provides a summary of the AVS Units 1 and 2 SO_2 representative baseline emissions; additional details are included in Appendix B. Table 4-3 provides a summary of the AVS Units 1 and 2 SO_2 projected future maximum emissions based on the future projected coal sulfur content, boiler design heat input and 100% capacity factor.

Table 4-2. Baseline Actual SO_2 Emissions

AVS Unit	Baseline Controls	SO_2 Emission (Notes 1 and 2)			Capacity Factor During Baseline Period	Current SO_2 Control Percentage (Note 3)	Current Permit Limits (3-hr rolling average)
		lb/hr	lb/MMBtu	tons/yr			
Unit 1	DFGD/FF	1,656	0.37	6,921	86%	86-88	1.2 lb/MMBtu 3,845 lb/hr (plant total)
Unit 2	DFGD/FF	1,685	0.37	7,016	87%	86-88	1.2 lb/MMBtu 3,845 lb/hr (plant total)

Note 1. Unit 1 SO_2 emissions based on 24-month annual average for period September 2014 to August 2016.
Note 2. Unit 2 SO_2 emissions based on 24-month annual average for period July 2016 to June 2018.
Note 3. Control percentage calculated based on the range of baseline annual coal SO_2 content (2.72 – 3.15 lb/MMBtu) between 2013-2018.

Table 4-3. Projected Future Maximum SO_2 Emissions

AVS Unit	Baseline Controls	SO_2 Emission (Note 1)			Capacity Factor for Future Maximum Emissions	Assumed SO_2 Control Percentage (Note 2)	Current Permit Limits (3-hr rolling average)
		lb/hr	lb/MMBtu	tons/yr			
Unit 1	DFGD/FF	1,831	0.37	8,018	100%	89.1	1.2 lb/MMBtu 3,845 lb/hr (plant total)
Unit 2	DFGD/FF	1,847	0.37	8,089	100%	89.1	1.2 lb/MMBtu 3,845 lb/hr (plant total)

Note 1. Projected future maximum SO_2 emissions based on forecast future maximum coal SO_2 content of 3.39 lb/MBtu, boiler design heat input of 4,930 MBtu/hr and assumes 100% capacity factor.
Note 2. Control percentage calculated based on the baseline SO_2 emission rate of 0.37 lb/MMBtu and the baseline average uncontrolled emission rate of 3.39 lb/MMBtu.

4.2 COAL SULFUR CONTENT

The generation of SO_2 is directly related to the sulfur content and heating value (HHV) of the fuel burned. AVS currently burns North Dakota Lignite fuel from the Freedom Mine. North Dakota lignite is characterized by a low heating value and relatively low sulfur content. Typical HHV and coal sulfur content provided by Basin Electric are listed in Table 4-4. The coal quality is based on actual annual fuel data provided by the facility between 2013 and 2018, which is the same time period as the baseline emission rates.

Table 4-4. Baseline AVS Coal Quality (Annual)

Parameter	Minimum	Average	Maximum
HHV (Btu/lb)	6556	6755	7169
As-Received Sulfur (%)	0.89	0.98	1.13
Uncontrolled SO_2 (lb/MMBtu)	2.72	2.90	3.15

As shown in Table 4-4, the deviation between the average coal sulfur content and the maximum coal sulfur content is 0.15%.

In addition, Basin Electric provided anticipated future annual average coal quality projections for the facility between 2019 and 2045. The future range in coal quality is provided in Table 4-5.

Table 4-5. Future AVS Coal Quality (Annual)

Parameter	Minimum	Average	Maximum
HHV (Btu/lb)	6,434	6,506	6,587
As-Received Sulfur (%)	0.72	0.84	0.94

The future projected coal quality listed in Table 4-5 are based on an annual average values and do not take into account potential deviations in the coal quality that could be seen on a short term basis. As such, S&L and Basin Electric applied the actual coal sulfur content deviation (0.15%) from the baseline coal quality, stated above, to the maximum annual sulfur coal in Table 4-5. The results are shown in Table 4-6.

Table 4-6. Design Basis for Future Projected AVS Coal Quality (Annual)

Parameter	Value
HHV (Btu/lb)	6,434
As-Received Sulfur (%)	1.09
Uncontrolled SO_2 (lb/MMBtu)	3.39
Uncontrolled SO_2 per Unit(lb/hr) (Note 1)	16,704
Uncontrolled SO_2 per Unit (ton/yr) (Note 1)	73,164

Note 1. Uncontrolled SO_2 emissions calculated at the design heat input (4,930 MBtu/hr) of each Unit.

Based on the evaluation above, S&L and Basin Electric have concluded that using a 3.39 lb SO_2/MMBtu as the design basis for evaluating the SO_2 control technologies presented in this report is reasonable.

4.3 SO_2 EMISSIONS CONTROLS

4.3.1 Identify Available SO_2 Control Options

Based on a review of available SO_2 control technologies, as well as operational practices and equipment upgrades implemented on existing control systems, potentially available options to control SO_2 emissions from AVS Units 1 and 2 are listed in Table 4-7.

Table 4-7. Available SO_2 Control Options

SO_2 Control Technologies
Fuel Switching
Existing DFGD Operational Improvements
Existing DFGD Upgrades
Existing DFGD + Dry DSI (DSI)
Retrofit New Dry FGD
Retrofit New Wet FGD

4.3.2 Technical Feasibility of Available SO_2 Control Options

Potentially available SO_2 control options identified in Table 4-7 are those control technologies and operational improvements with a practical potential for application to AVS Units 1 and 2. The technologies were evaluated for technical feasibility (i.e. availability and applicability to AVS Units 1 and 2) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options determined to be technically infeasible, or options that have no practical application to AVS, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emissions performance level (i.e., control emissions rate) for each.

4.3.2.1 Fuel Switching

One potential strategy for reducing SO_2 emissions is to reduce the sulfur content of the coal. Limiting the amount of sulfur in the coal directly limits the amount released during the combustion process, and would reduce SO_2 loading to the dry scrubber.

AVS is a mine mouth generation facility. AVS was designed and developed to burn North Dakota lignite coal received from the adjacent Freedom Mine for the purpose of generating electricity. Previous regulatory and court decisions have concluded that requiring a mine mouth facility to evaluate low sulfur coal would require the facility to redefine its fundamental purpose and design; therefore, fuel switching can be rejected as an available control option.[33] Because the use of North Dakota lignite from the adjacent Freedom Mine is an inherent aspect of AVS operation, fuel switching will not be evaluated.

4.3.2.2 Existing FGD Operational Improvements and Equipment Upgrades

Operational and other design changes/upgrades to the existing dry scrubber may provide an opportunity for additional SO_2 removal and allow the units to achieve lower controlled SO_2 emissions. S&L, working with Basin Electric personnel, identified a number of potentially feasible operational changes that may be available to increase SO_2 removal efficiency with the existing equipment. Potentially available operational and design changes to the existing control system are summarized in Table 4-8. A detailed discussion of each of these options is provided in the following sections.

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[33] In re: Prairie State Generating Company, PSD Appeal No. 05-05, Slip. Op. at 36 (2006)

Table 4-8. FGD Operational Improvements and Equipment Upgrades

Existing FGD Operational Improvements
Station Work Practices
Lime Quality
Ca:S Stoichiometric Ratio
Lower Approach to Saturation Temperature
Existing FGD Design Changes and Equipment Upgrades
Atomizer Replacement
Slaker Replacement
Adding an Absorber Module
Replacing Existing Absorbers with New Absorber Modules

Station Work Practices

AVS Units 1 and 2 have a 3-hour SO_2 plantwide applicability limit (PAL) of 3,845 lb/hr in their Title V Air Permit that allows the station to adjust operation of each unit's FGD system as long as they achieve the overall plantwide limit. Historically, when one unit would be in extended major outage the station would adjust operation (i.e., decrease SO_2 removal) on the other Unit to be in compliance with the PAL. AVS schedules major maintenance outages on a tri-annual(three-year) basis. As such, the opportunity for additional reductions is available one out of every 3 years on each unit. S&L reviewed the operating practices of the two units over the period June 2015–June 2018 to determine the increase in SO_2 emissions for the unit that was not in outage.

Table 4-9 and Table 4-10 below show the increase in SO_2 emissions for both Units 1 and 2.

Table 4-9. Increased SO_2 Emissions on AVS Unit 1 (June 2015-June 2018)

Parameter	AVS Unit 1	AVS Unit 2
Average annual hours in outage on Unit 2	--	981
Average SO_2 emissions on Unit 1 during Unit 2 outage (lb/hr)	2,394	--
Average SO_2 emissions on Unit 1 during normal operation (lb/hr)	1,432	--
Average excess SO_2 emissions on Unit 1 during Unit 2 outage (lb/hr)	962	--
Average excess SO_2 emissions on Unit 1 during Unit 2 outage (ton/yr)	**472**	**--**

Table 4-10. Increased SO_2 Emissions on AVS Unit 2 (June 2015-June 2018)

Parameter	AVS Unit 1	AVS Unit 2
Average annual hours in outage on Unit 1	769	--
Average SO_2 emissions on Unit 2 during Unit 1 outage (lb/hr)	--	2,573
Average SO_2 emissions on Unit 2 during normal operation (lb/hr)	--	1,542
Average excess SO_2 emissions on Unit 2 during Unit 1 outage (lb/hr)	--	1,031
Average excess SO_2 emissions on Unit 2 during Unit 1 outage (ton/yr)	**--**	**396**

As shown in the tables above, the excess emission on Units 1 and 2 were 472 tons and 396 tons, respectively on an annual basis. Using the annual baseline SO_2 emissions and annual average heat input, provided in Section 4, eliminating these emissions would reduce the outlet SO_2 emission rate from 0.37 lb/MMBtu to a controlled emission rate of 0.35 lb/MMBtu on each Unit. However, it should be noted that under the current outage schedule, the emission reductions shown above would only be achieved every 3rd year for a single unit since outages occur on a tri-annual basis. Based on this analysis, a change to the current station work practice is considered a technically feasible SO_2 control option for AVS Units 1 and 2.

Lime Quality

The quantity of lime (CaO) available in a dry scrubbing system compared to the amount of SO_2 entering the system is called the stoichiometric ratio (generally referenced as the Ca:S stoichiometric ratio). Reagent quality directly affects the Ca:S stoichiometric ratio in DFGD control systems. Using a high quality lime increases the availability of hydrated lime to support process chemistry, and reduces the lime slurry injection rate needed for SO_2 removal.

Lime quality is measured both by the CaO content and reactivity of the lime product. In a dry scrubber system, CaO is combined with water in a slaker to form hydrated lime or calcium hydroxide ($Ca(OH)_2$), which provides the calcium that is needed to react with SO_2 in the flue gas. With a higher quality lime, more calcium hydroxide is available to react with SO_2. Lime products with a CaO content of 90% or greater are generally considered high quality lime. Reactivity of the lime is measured by the temperature rise when the lime is slaked (i.e. water addition). In general, porous lime products have higher reactivity which is demonstrated by achieving a temperature rise 40°C within three minutes of adding water.

Based on a review of lime analyses and a review of operating data from the existing lime slaking system, AVS currently procures a high quality lime for use in the dry scrubbers. The typical CaO content of the lime used at AVS is 90% or greater, and the slaking process achieves a 40°C temperature rise within three minutes of adding water. For these reasons, changing the lime quality is not considered a technically feasible operational change available to control SO_2 emissions from AVS, and will not be evaluated further.

Ca:S Stoichiometric Ratio

Other operational changes that may be available to increase the Ca:S stoichiometry in the existing dry scrubber include: (1) increasing the byproduct recycle ash rate; and/or (2) increasing the quantity of fresh hydrated lime introduced to the system. Due to the cost savings that may be realized with the first option, some facilities with existing DFGD controls have opted to increase solids recycle rates to as high as 40-50% solids to achieve an incremental increase in SO_2 reduction, if capacity was available in the byproducts handling system. If capacity is not available, increasing fresh lime addition to the system may also be a viable option to increase the Ca:S stoichiometric ratio.

Within each AVS DFGD, there are two parallel slurry preparation trains that prepare and supply the lime slurry feed to each of the five scrubber modules. The slurry preparation trains consist of recycle ash silos, ash mix tanks, slurry feed tanks and associated slurry and atomizer feed pumps, piping and controls and instrumentation. Solids from a dry scrubber consist of fly ash, reaction byproduct, and residual unreacted hydrated lime. On AVS Units 1 and 2, solids collected in the fabric filter hoppers are conveyed to either a dry storage silo for disposal or to a recycle ash silo where it is used as reactant slurry. The recycle system is designed to utilize a portion of the unreacted lime in the solids rather than disposing of all of the solids. Recycle solids are combined with the fresh lime addition to provide the makeup lime needed for SO_2 reduction. Increasing the recycle rate can increase the amount of available Ca added to the system (i.e., stoichiometric ratio) without increasing the quantity of fresh lime added to the system.

The DFGD systems on the AVS Units currently operate the recycle system at approximately 45% solids. The AVS recycle system is operating within the original design conditions and system capacity which is in line with industry practice. The plant has tested higher recycle rates, but at these higher rates plant personnel reported significant problems with recycle slurry pumping and pluggage of the recycle tanks and negative impacts to the FF due to the increase in ash loading. Based on the adverse operational impacts observed during these tests, increasing the recycle percent solids is not considered a technically feasible SO_2 control option for the AVS Units, and will not be evaluated further.

As an alternative to increasing the recycle rate, the Ca:S stoichiometric ratio in the system may be increased by increasing the quantity of fresh lime introduced to the system. Basin Electric contracted with B&W, the original equipment manufacturer (OEM) of the AVS DFGD system, to determine if additional SO_2 removal could be achieved by increasing the amount of fresh lime added to the system while maintaining approximate 40-45% solids slurry to the atomizer. B&W ran their proprietary software which estimates the AVS DFGD performance. The results of the model indicated that AVS could potentially achieve 93% SO_2 removal of normal DFGD operation at 1% sulfur coal by increasing the fresh lime to the DFGD. Due to the uncertainties with the model, additional analysis is required to fully understand plant operational and performance impacts associated with an increased Ca:S stoichiometric ratio. There would be percent solids capacity limitation with the existing recycle slurry system and risks of increased scaling and build-up within tanks and piping with the increased lime solids. As such, this system will require modifications including new mix tanks, pumps and piping to minimize slurry preparation train outages. When a slurry preparation train fails, it requires the standby slurry preparation train to come on-line that could result in an increase in short term emissions until the slurry preparation train is placed into service. The 93% removal represents an average percent control that each AVS unit would be expected to achieve on an on-going long-term basis under normal operating conditions with the equipment upgrades installed. The emission rate should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Approach to Saturation Temperature

The reaction of SO_2 with $Ca(OH)_2$ in a dry scrubber is driven by the absorber temperature. Water surrounding the lime slurry droplet allows SO_2 to dissolve into the liquid and facilitates the reaction between lime and SO_2. The temperature differential between the inlet and the outlet of the DFGD is used as a driving force for SO_2 removal; however, outlet temperatures must be maintained above the saturation temperature to ensure byproducts exiting the absorber module are dry and remain dry as they pass through the FF, ductwork and stack. Residence time within the absorber vessel, drying time, and exit temperature are all important design parameters for a dry scrubbing system.

Inlet temperature to the dry scrubbing module is relatively constant; however there can be short term temperature swings of +/- 10°F that occur due to coal quality, boiler sootblowing, convection pass and air heater cleanliness; therefore, temperature differential across the module is a function of the outlet temperature. As a general rule-of-thumb, the closer the outlet temperature is to the adiabatic saturation temperature, the higher the SO_2 removal efficiency.

Operating a dry scrubbing system at outlet temperatures significantly above the adiabatic saturation temperature accelerates water evaporation from the reactant slurry, limits SO_2 absorption into the droplet, and limits the reaction between the lime and SO_2. Reducing the temperature in the absorber closer to the saturation point can provide additional SO_2 removal. On the other hand, the absorber module may not have sufficient residence time to dry all slurry droplets if the system is operated too close to adiabatic saturation, which would result in deposits in the absorber module, corrosion, and severe operational problems. Therefore, maintaining an absorber outlet temperature close to the point of saturation, while staying above it, is vital for optimal reaction kinetics.

The AVS dry scrubbers currently operate with at an outlet temperature near 165-170°F, which is approximately 30°F above the adiabatic saturation temperature and within the OEM design. This is in line with new spray dryer absorbers which are typically designed to operate at 30°F approach to saturation. Therefore, the current approach to saturation temperature achieved on the AVS scrubbers are aligned with standard industry practices. Lowering the outlet temperature further has significant potential to cause detrimental corrosion of the vessel or downstream equipment and other significant operating issues. Therefore, further reducing the absorber module outlet temperature is not considered a technically feasible SO_2 control option for AVS, and will not be evaluated further.

Atomizer Replacement

Spray droplet size is an important parameter in the design and operation of a dry scrubber, and can improve lime utilization and SO_2 removal. Finer spray will increase the surface area of the slurry droplets exposed to the flue gas. Greater surface area increases the potential for SO_2 to absorb into the moisture of the slurry droplets. Droplet fineness also plays a role in particle drying time. Larger droplets can have a negative effect on the slurry drying time which can lead to moisture carryover to downstream equipment causing buildup and corrosion.

AVS Units 1 and 2 dry scrubbers were provided by B&W's predecessor Joy Niro, and were designed with five absorber modules each with a single rotary atomizer with a 12 nozzle wheel to achieve a fine slurry spray. The design of the atomizer and speed at which the wheel rotates are controlling factors for the size and form of the droplets in the spray. Each atomizer wheel in AVS Unit 1 absorber module is powered by a 700 hp motor and Unit 2 absorber modules are designed with a 800 hp motor. In addition, the design of the atomizers is highly dependent on the spray pattern needed to mix with the hot flue gas in the scrubber module for optimum absorption of SO_2 while also preventing wetting of the absorber walls. Based on S&L's analysis and input from the station, there has not been any significant moisture carry-over into the baghouse or wetting of the absorber walls that would indicate that the atomizers are not achieving an optimum droplet size or spray pattern. In addition, both AVS dry scrubbers are operating at a consistent 30°F approach to saturation temperature, in-line with industry practice, concluding that the droplets are drying efficiently. Therefore, replacing the atomizer motor or atomizer wheel is not considered a technically feasible SO_2 control option for the AVS scrubbers, and will not be evaluated further.

Slaker Replacement

Lime slurry, the reagent used for SO_2 removal in a dry scrubber, is produced by mixing pebble lime with heated water in a slaker; this process is referred to as "slaking". The slaker is operated at an optimum water-to-lime ratio (typically between 3:1 and 6:1) to produce lime slurry by metering the amount of water and the amount of lime added to the slaker. Slakers are typically designed to produce a lime slurry between 15-20% solids. The lime slurry is added to the recycle slurry in a mix tank and then sent to the atomizer where it is sprayed into the scrubber for SO_2 removal.

In 2011, additional slaking capacity was installed at a cost pf approximately $15 million, in the form of two Vert-Mill lime slakers, lime storage and conveying systems in preparation of higher sulfur fuel deliveries. The slakers operate at a 5:1 water to lime ratio and approximately 18% solids which is in line with the design as well as industry practice. Therefore, replacing the already upgraded slaking systems is not considered a technically feasible SO_2 control option for the AVS scrubbers, and will not be evaluated further.

Adding an Absorber Module

Another option for extending the residence time within the reactor modules and increasing Ca:S contact would be to add an additional reactor module to each AVS unit. The existing system is designed with five absorber modules per unit. The system was originally designed to operate with four modules carrying full load gas flow with a standby spare available for routine maintenance. Subsequently, operation was changed so that all five modules are operated for full load gas flow. This change increased flue gas residence time in the reaction vessels from 5.0 seconds (at full load) to 6.5 seconds. More recent dry scrubbing systems have been designed with reaction vessel residence times of 10 seconds or more.

One potential option available to AVS to further increase reaction vessel residence time would be to add an additional absorber module to the existing dry scrubbing system on each unit. The number of absorber modules used in a DFGD system is dependent on multiple operating parameters, including the flue gas flow rate and SO_2 concentrations. DFGD modules are typically specified with minimum and maximum flue gas flow rates. If the absorber modules are oversized, flue gas velocities through the module can be too low, causing solids dropout inside the vessel. If the absorber modules are undersized, flue gas velocities can be too high, causing residence time to fall below recommended levels.

Dry scrubbing units that are operating at flue gas volumes significantly above the design flow rate can benefit from adding an extra module to the system. The module would be placed in parallel with the existing modules to achieve a similar pressure drop through each vessel and to ensure equal flue gas distribution to the modules. In 2006, Basin Electric hired B&W's Allen-Sherman Hoff to develop a computer model of the existing five scrubber modules to determine the impact of adding a 6th absorber module to each of the AVS units in response to potentially higher-sulfur fuels in the future. The modeling showed the five existing absorbers have adequate residence time for the expected higher sulfur in the coal and operate at an approach to saturation of 30°F which is consistent with industry practice. Installation of a sixth absorber would not provide any significant improvement towards removing additional sulfur. The primary benefit of a sixth SDA chamber would be to provide redundancy. While this would be beneficial towards maintaining unit loads without having to restrict generating capacity for chamber maintenance items, inspections and chamber cleaning, it would not provide any additional improvement to reducing SO_2. Therefore, incorporating an additional absorber module into the existing system is not a technically feasible SO_2 control strategy for AVS, and will not be evaluated further.

Replacing Existing Absorbers with New Absorber Modules

Replacing the existing modules with new absorber modules would require significant engineering and facility modifications. Based on a preliminary review of the control system layout, the only practical location for this option would be to construct the new vessels in the same location as the existing modules. Locating the DFGD modules adjacent to the existing dry scrubber would require flue gas to be redirected from the air heater outlet to the new absorbers and back to the existing fabric filter, which would likely result in significant solids dropout and other operational issues. Therefore, locating the new absorber modules adjacent to the existing absorber modules is not considered a technically feasible option.

DFGD control systems use a hydrated lime slurry to remove SO_2 from the combustion gases. Various operating parameters will affect the efficiency of the DFGD process including the residence time and how close the system operates to saturation. These are the same operating parameters that affect the efficiency of the existing AVS Units 1 and 2 dry scrubbers. The AVS Units 1 and 2 dry scrubbers already operate at an approach to saturation temperature of 30°F which is consistent with industry practice as well as have adequate residence time. Therefore, replacing the existing absorber modules with new absorber modules would not provide any additional benefit and will not be evaluated further.

4.3.2.3 Existing FGD + Dry DSI

Alkali based DSI is a proven technology for the removal of sulfur trioxide (SO_3) and other acid gases from coal-fired power plant flue gas, and can be used to provide SO_2 control. Sorbent is injected into the ductwork after the furnace and prior to the particulate collection device, where it reacts with SO_2 and other acid gases. DSI systems are relatively simple systems consisting of material storage, feeding mechanism, blower or transfer line, and an injection device. For SO_2 control on AVS Units 1 and 2, sorbent would be injected upstream of the dry scrubber to provide an incremental reduction in the concentration of SO_2 in the flue gas at the inlet to the dry scrubber.

Sorbents react with SO_2, and other acid gases, in the flue gas when injected at an appropriate rate and within the proper temperature range for that sorbent. The resulting particulate matter is removed from the flue gas by the particulate control system. The process works through neutralization of the acid gases with the alkaline sorbent. The neutralization reaction occurs as long as the sorbent remains in contact with the gas in the flue gas duct work within the required temperature range.

Dry sorbents that have been used for SO_2 control on coal-fired boilers include:

- Hydrated Lime ($Ca(OH)_2$)
- Trona or Sodium Bicarbonate (SBC)

The following wet sorbents have also been used for acid gas control at coal-fired power generating stations:

- Sodium Bisulfite (SBS)
- Soda Ash

Dry sorbents, including hydrated lime, Trona, and SBC would be injected pneumatically as a dry powder into the flue gas ductwork upstream of the AVS Units 1 and 2 DFGD. Trona and SBC are both sodium-based sorbents, which react with SO_2 to form sodium salts. Hydrated lime would react with SO_2 to form calcium sulfate salts. The hydrated lime reactions are the same reactions that are taking place in the existing dry scrubber.

Hydrated lime is less reactive than the sodium based dry sorbents; thus, higher injection rates and longer residence time would be required to achieve the same removal efficiency. However, hydrated lime has a lower unit cost compared to other sorbent options, offsetting the higher injection rates. It is also important to note that the hydrated lime chemistry involves the same reactions, and forms the same calcium salts, as those currently taking place in the dry scrubber reaction vessels. Therefore, using hydrated lime as the sorbent would not introduce any new constituents into the dry scrubbing system, and could potentially increase the Ca:S stoichiometry in the dry scrubber.

Because of the higher reactivity of sodium based sorbents, less reactant may be required to achieve the same removal efficiency; however, injecting a sodium-based sorbent into the flue gas upstream of the AVS Units 1 and 2 DFGD would introduce new chemical constituents into the scrubber and into the fly ash/scrubber byproduct material. This could prove problematic as sodium compounds are water soluble, and introducing sodium into the system could adversely affect the characteristics of the byproduct solids generated by the system and introduce additional corrosion related issues within the SDA and FF systems. Detailed studies and demonstration tests would be needed to ensure that introducing relatively large amounts of sodium would not adversely affect scrubber operation or result in solids disposal issues.

SBS and soda ash (Na_2CO_3) injection are wet injection technologies typically used for SO_3 mitigation. SBS and soda ash can be injected into the flue gas upstream or downstream of the air heater as a 10% solution (by weight) using dual fluid atomizers. Both products will react with SO_2 and SO_3 to form sodium salts, which can be collected in the downstream particulate collection device. URS/Codan Associates own the patent for this SBS control process. Based on conversations with URS, their SBS technology is generally more economical using soda ash, and all recent projects have used soda ash. However, as with the dry sodium-based injection systems, these systems would introduce sodium into the AVS Units 1 and 2 DFGD control system.

DSI upstream of the existing dry scrubber is a technically feasible and commercially available SO_2 control option for AVS Units 1 and 2. Taking into consideration the fact that AVS is currently equipped with a calcium-based dry scrubbing system, hydrated lime dry DSI would be the most practical, and potentially the most effective, DSI control option. Sodium-based systems would require extensive testing to determine the potential impacts associated with introducing significant quantities of sodium into the existing system, and are not considered practical control options for AVS Units 1 and 2. However, although DSI is a technically feasible control option, it should be noted that DSI upstream of the existing DFGD control system at AVS would not provide any additional SO_2 removal than what could already be achieved by increasing the fresh lime or calcium content through the existing upgraded lime slaking system as discussed in Section 4.3.2.2 Ca:S Stoichiometric Ratio. The existing upgraded lime slaking system at AVS has sufficient capacity to provide the increase in calcium content. Therefore, DSI will not be evaluated further.

4.3.2.4 Retrofit New Dry FGD System

Replacing the existing dry scrubber/FF with new control systems would require significant engineering and modifications to the facility. Based on a preliminary review of the facility layout, the new control systems could be located south of Unit 1 and north of the Unit 2 existing dry scrubber/FF. The new DFGD/FF and all auxiliary equipment could be constructed while the units remain on line. The control systems could be tied-in to the existing systems during a scheduled major outage.

Various DFGD systems have been designed for use with pulverized coal-fired boilers; including the SDA and circulating dry scrubber (CDS). Both systems are evaluated in more detail below.

Spray Dryer Absorber / Fabric Filter

SDA systems have been used in large coal-fired utility applications, and have demonstrated the ability to effectively reduce uncontrolled SO_2 emissions from pulverized coal units. Like other dry scrubbing systems, SDA control systems use a slurry of lime and water injected into the reaction modules to remove SO_2 from the combustion gases. The reaction modules are designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a dry by-product. Process equipment associated with an SDA control system includes an alkaline storage tank, mixing and feed tanks, atomizer assembly, spray chamber module, integrated fabric filter, and solids recycle system. The recycle system collects solid reaction byproducts and recycles them back to the spray dryer feed system to maximize reactant utilization.

Various process parameters affect the efficiency of the SDA process including: the type and quality of the additive used for the reactant, reactant-to-sulfur stoichiometric ratio, how close the SDA is operated to saturation conditions, and the amount of solids product recycled to the atomizer. SDA systems are typically designed to operate within approximately 30 ^{o}F adiabatic approach to saturation temperature. Operating closer to the adiabatic saturation temperature may allow for higher SO_2 control efficiencies; however, outlet temperatures too close to the saturation temperature will result in severe operating problems including reactant build-up in the absorber modules, blinding of the fabric filter bags, and corrosion in the fabric filter and ductwork.

SO_2 removal efficiencies in a SDA are also dependent upon good gas-to-liquid contact. Reactant spray nozzle designs are vendor-specific, and include both dual-fluid nozzles and rotary atomizers. The atomizing nozzle assembly is typically located in the SDA penthouse and flange mounted to the roof of the absorber vessel.

Replacing the existing dry scrubber/FF with a new SDA/FF control systems is a technically feasible and commercially available control option on the AVS Units. SDA/FF control systems are generally limited to an SO_2 removal of approximately 95%. This removal represents what the control system vendor would be willing to guarantee upon initial operation of the control system.

Circulating Dry Scrubber / Fabric Filter

A second type of dry scrubbing system is the circulating dry scrubber (CDS). Similar to other DFGD systems, the CDS system would be located after the air preheater, and byproducts from the system collected in an integrated fabric filter. Unlike the SDA systems, CDS systems use a circulating fluidized bed of hydrated lime reagent to remove SO_2 rather than an atomized lime slurry; however, similar chemical reaction kinetics are used in the SO_2 removal process.

In a CDS, flue gas is treated in an absorber vessel where the flue gas stream flows through a fluidized bed of hydrated lime and recycled byproduct. Water is injected into the absorber through a venturi located at the base of the absorber for temperature control. Flue gas velocity through the vessel is maintained to keep the fluidized bed of particles suspended in the absorber. Water sprayed into the absorber cools the flue gas from approximately 300 °F at the inlet to the scrubber to approximately 160 °F at the outlet of the fabric filter. The hydrated lime absorbs SO_2 from the gas and forms calcium sulfite and calcium sulfate solids. Desulfurized flue gas passes out of the absorber, along with the particulate matter (reaction products, unreacted hydrated lime, calcium carbonate, and the fly ash) to the fabric filter.

As with the SDA/FF option, replacing the existing DFGD with a new CDS/FF control system would require significant engineering and modifications to the existing facility. For this evaluation it was assumed that the CDS/FF control systems could be located adjacent to the existing dry scrubber/FF, and that the control systems could be tied-in to the existing system during a scheduled major outage.

Replacing the existing dry scrubber and FF with a new CDS/FF control system is a technically feasible and commercially available control option for the AVS units. Based on engineering judgment, it is anticipated that the retrofit CDS/FF control option would achieve controlled SO_2 emission rates higher than those achieved with a SDA/FF due to the increased Ca:S in the fluidized bed absorber vessel. Based on recent CDS retrofit projects, and taking into consideration expected future design coal characteristics, it is anticipated that the retrofit CDS/FF control system could achieve SO_2 removal efficiencies of approximately 97%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system and on an on-going long-term basis under normal operating conditions.

4.3.2.5 Retrofit New Wet FGD System

Another option available to AVS would be to replace the existing dry scrubbing system with a new wet FGD control system located downstream of the existing FF.

Wet FGD technology is an established SO_2 control technology. Wet scrubbing systems have been designed to utilize various alkaline scrubbing solutions including lime, limestone, and magnesium-enhanced lime. Wet scrubbing systems have also been designed with spray tower reactors and with reaction vessels (e.g., jet bubbling reactor). Although the flue gas/reactant contact systems may vary, the chemistry involved in all wet scrubbing systems is essentially identical. All wet scrubbing systems use an alkaline slurry that reacts with SO_2 in the flue gas to form insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts.

A large majority of the wet FGD systems designed to remove SO_2 from existing high-sulfur utility boilers have been designed as wet limestone scrubbers with spray towers and forced oxidation systems. Therefore, for this evaluation, it was assumed that the WFGD control system would be designed as a limestone spray tower scrubber with forced oxidation. Other potentially available wet scrubber designs are not included in this evaluation because the chemistry involved in all wet scrubbing systems are essentially identical, alternative designs would not provide any additional SO_2 control, and control system costs would be similar.

Wet Limestone Scrubbing

In a wet limestone scrubbing system, limestone ($CaCO_3$) is mixed with water to formulate the alkali scrubber slurry. Flue gas enters the absorber vessel and contacts the absorbent slurry in a countercurrent spray tower. SO_2 in the flue gas reacts with the limestone slurry to form insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) which is removed as a solid waste by-product. Spent absorbent is returned to the reaction tank where dissolved sulfur compounds are precipitated as calcium salts. Fresh limestone slurry is added to regenerate the spent absorbent.

The reaction tank is sized to provide sufficient time for precipitation of the sulfur compounds. From the reaction tank, regenerated absorbent slurry is recycled to the absorber. The slurry typically contains from 5 to 15% suspended solids consisting of fresh additive, absorption reaction products, and lesser amounts of fly ash. To regulate the accumulation of solids, a bleed stream from the reaction is routed to the solid/liquid separation equipment.

Forced oxidation of the scrubber slurry may be used with limestone WFGD systems to produce calcium sulfate solids (gypsum) instead of the calcium sulfite by-product. Air blown into the reaction tank provides oxygen to convert most of the calcium sulfite ($CaSO_3$) to relatively pure gypsum. Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the spray tower. The gypsum by-product from this process must be dewatered, and may be salable if a local market for gypsum is available, reducing the quantity of solid waste that needs to be landfilled.

For this evaluation it was assumed that the existing AVS dry scrubber reactor vessel would remain in place, and that the WFGD control system would be located downstream of the existing FFs and ID fans most likely south of Unit 1 and north of the Unit 2 existing dry scrubber/FF. Dry scrubber reactor vessel internals would ultimately be removed to reduce pressure drop through the system. A single absorber tower for each Unit would be sufficient for the flue gas flow. In addition to the absorber tower and reaction vessel, the WFGD control system would require a limestone handling and preparation system and by-product dewatering systems. Because of the saturated nature of the flue gas exiting the WFGD and the velocity requirements with wet stack operation, a new stack with a liner capable of wet flue gas operation would be required. New booster ID fans would also be required to account for the additional pressure drop through the WFGD control system.

Wet FGD technology is an established SO_2 control technology. Wet scrubbing systems have been installed on units that fire medium to high sulfur coals, and would be a technically feasible SO_2 control option for AVS Units 1 and 2. Based on engineering judgment and information from control system vendors, it is anticipated that a retrofit WFGD control system on a North Dakota lignite-fired unit would be designed to achieve and SO_2 removal efficiency of approximately 98%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system and on an on-going long-term basis under normal operating conditions.

4.3.2.6 Technical Feasibility Summary

Table 4-11 summarizes the results of the feasibility evaluation of available control options for AVS Units 1 and 2.

Table 4-11. Technically Feasible SO_2 Control Options

SO_2 Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Fuel Switching	No	0%	Fuel switching is not considered an available SO_2 control option for AVS Units 1 and 2 since the units are mine mouth to the existing source of lignite coal.
Existing DFGD Operational Improvements:			
Station Work Practice	Yes	5%	Adjusting operation on the non-outage unit to maintain the same SO_2 removal efficiency achieved prior to the other Unit taking an outage is considered a technically feasible option for AVS Units 1 and 2. However, the opportunity to achieve these reductions is one out of every three years on each unit
Lime Quality	No	0%	Changing lime quality in the existing DFGD control system is not a technically feasible operational change for AVS Units 1 and 2.
Ca:S Stoichiometric Ratio	Yes	93%	Increasing the Ca:S stoichiometric ratio by increase the quantity of fresh lime to the system is considered a technically feasible option for AVS Units 1 and 2.
Approach to Saturation Temperature	No	0%	Further reducing the absorber module outlet temperature on the existing DFGD control system is not a technically feasible option for AVS Units 1 and 2.
Existing DFGD Equipment Upgrades:			
Atomizer Replacement	No	0%	Replacing the existing atomizers is not a technically feasible option for AVS Units 1 and 2.
Slaker Replacement	No	0%	Slaker replacement would not be expected to provide additional SO_2 control, and is not a technically feasible equipment upgrade for AVS Units 1 and 2.
Adding an Absorber Module	No	0%	Adding an absorber module to AVS Units 1 and 2 is not a technically feasible SO_2 control option.
Replace Existing Absorbers with New Absorber Modules	No	0%	Replacing the exiting absorber modules with new absorber modules is not a feasible SO_2 control system upgrade for AVS Units 1 and 2 since it would require at least a 12-month outage and replacement power, existing today, is not available.
Existing DFGD + DSI	Yes	0%	Hydrated lime DSI upstream of the existing AVS Units 1 and 2 absorber modules is a technically feasible SO_2 control option, however would not be expected to provide any additional SO_2 control beyond what could be achieved with increasing the Ca:S stoichiometric ratio through the existing lime slaking system.
New Retrofit DFGD (CDS/FF)	Yes	97%	Replacing the existing DFGD control system with a new retrofit DFGD (i.e., CDS/FF) is a technically feasible SO_2 control option for AVS Units 1 and 2.

SO_2 Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
New Retrofit WFGD	Yes	98%	Replacing the existing DFGD control system with a new retrofit WFGD is a technically feasible SO_2 control option for AVS Units 1 and 2.

Note 1. Control percentage calculated using the baseline SO_2 coal quality of 2.90 lb/MBtu and the achievable SO_2 emission rate for each technically feasible control option.

4.3.3 Evaluate Technically Feasible SO_2 Control Options for Effectiveness

The technically feasible SO_2 control technologies for Units 1 and 2 are listed in Table 4-12 and Table 4-13 in increasing order of control efficiency. Table 4-12 and Table 4-13 also provide control option-specific SO_2 emission rates in terms of lb/MMBtu. Emission rates shown represent baseline average emission rates that the control options would be expected to achieve during normal operations.

Table 4-12. Evaluate Technically Feasible SO_2 Control Options by Effectiveness for AVS Unit 1 (Baseline Average Emissions)

Alt. No.	Control Technology	SO_2 Emission Rate (Note 1) lb/MMBtu	% Reduction from Baseline SO_2 Coal Quality (Note 2)	SO_2 Emission Rate (Note 1) lb/hr	SO_2 Emission Rate (Note 1) tons/yr
E	New Retrofit WFGD	0.07	98%	312	1,305
D	New Retrofit DFGD (CDS/FF)	0.09	97%	401	1,678
C	New Retrofit DFGD (SDA/FF)	0.15	95%	669	2,796
B	FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0.20	93%	892	3,728
A	FGD Operational Improvements – Station Work Practice (Note 3)	0.35	88%	1,561	6,524
--	Baseline (existing DFGD/FF)	0.37	87%	1,656	6,921
--	Permit Limit (assumes 50/50 split for each unit)	1.2 (3-hour)		1,923 (3-hour)	

Note 1: Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for AVS Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis.
Note 2: Baseline SO_2 coal quality is 2.90 lb/MMBtu. See Section 4.2 for additional details on coal sulfur.
Note 3: Emission reductions achievable, under the current outage schedule, would only be achieved once every three years on each Unit.

Table 4-13. Evaluate Technically Feasible SO_2 Control Options by Effectiveness for AVS Unit 2 (Baseline Average Emissions)

Alt. No.	Control Technology	SO_2 Emission Rate (Note 1) lb/MMBtu	% Reduction from Baseline SO_2 Coal Quality (Note 2)	SO_2 Emission Rate (Note 1) lb/hr	SO_2 Emission Rate (Note 1) tons/yr
E	New Retrofit WFGD	0.07	98%	315	1,311
D	New Retrofit DFGD (CDS/FF)	0.09	97%	405	1,686
C	New Retrofit DFGD (SDA/FF)	0.15	95%	675	2,810
B	FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0.20	93%	900	3,746
A	FGD Operational Improvements – Station Work Practice (Note 3)	0.35	88%	1,575	6,555
--	Baseline (existing DFGD/FF)	0.37	87%	1,685	7,016
--	Permit Limit (assumes 50/50 split for each unit)	1.2 (3-hour)		1,923 (3-hour)	

Note 1: Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for AVS Unit 2. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis.
Note 2: Baseline SO_2 coal quality is 2.90 lb/MMBtu. See Section 4.2 for additional details on coal sulfur.
Note 3: Emission reductions achievable, under the current outage schedule, would only be achieved once every three years on each Unit.

Table 4-14 provides control option-specific SO_2 emission rates in terms of lb/MMBtu based on the projected future maximum emission rates. Emission rates shown represent the projected future maximum emission rates that the control options would be expected to achieve during normal operations.

Table 4-14. Evaluate Technically Feasible SO_2 Control Options by Effectiveness – AVS Unit 1 or 2 (Projected Future Maximum Emissions)

Alt. No.	Control Technology	SO_2 Emission Rate (Note 4) lb/MMBtu	% Reduction from Future SO_2 Coal Quality (Note 1)	SO_2 Emission Rate (Note 1) lb/hr	SO_2 Emission Rate (Note 2) tons/yr
E	New Retrofit WFGD	0.07	98%	334	1,463
D	New Retrofit DFGD (CDS/FF)	0.10	97%	501	2,195
C	New Retrofit DFGD (SDA/FF)	0.17	95%	838	3,671
B	FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	0.24	93%	1,169	5,121
A	FGD Operational Improvements – Station Work Practice (Note 3)	0.34	90%	1,670	7,316
--	Baseline Unit 1 (existing DFGD/FF)	0.37	89%	1,831	8,018
--	Baseline Unit 2 (existing DFGD/FF)	0.37	89%	1,847	8,089
--	Permit Limit (assumes 50/50 split for each unit)	1.2 (3-hour)		1,923 (3-hour)	

Note 1. Future SO_2 coal quality is 3.39 lb/MMBtu. See Section 4.2 for additional details on coal sulfur.
Note 2. Annual SO_2 emissions based on 8,760 hours per year operation.
Note 3: Emission reductions achievable, under the current outage schedule, would only be achieved once every three years on each Unit.
Note 4. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

4.4 SO_2 COST OF COMPLIANCE (STATUTORY FACTOR ONE)

The economic analysis performed as part of the four factor analysis examines the cost-effectiveness of each technically feasible control technology, on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. For units with existing controls, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual O&M costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of control equipment. Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25% and equipment life of 20 years.[34] Cost effectiveness ($/ton) of a particular

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[34] The assumed 20-year equipment life is consistent with the control system equipment life used by NDDH in its evaluation of NOX and SO_2 control technologies for BART-eligible sources. (see, e.g., ND Regional Haze Final SIP, Appendix C.1, "BART Determination Study for Leland Olds Station Units 1 & 2, Basin Electric Power Cooperative, August 2006, pgs. 64 (NOx controls) and 158 (SO_2 controls). See also, ND

control option is simply the annual cost ($/yr) divided by the annual reduction in annual emissions (ton/yr). In addition to cost-effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the incremental cost effectiveness of the more stringent control.

Capital and O&M cost estimates were developed for each of the technically feasible SO_2 control options. The AVS Units 1 and 2 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Units 1 and 2 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on AVS-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the AVS Units 1 and 2 retrofit technologies as "concept screening" cost estimates generally based on parametric models, judgment, or analogy.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, Contractor G&A expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing dry scrubber and FF control systems.

Regional Haze Final SIP, Appendix C4, "NOx Best Available Control Technology Study for Milton R. Young Station Unit 1, Minnkota Power Cooperative, Inc., October 2006, pg. 3-22).

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

4.4.1 SO_2 Average Annual Economic Evaluation

Table 4-15 presents the capital costs and annual operating costs associated with installing and operating each technically feasible SO_2 control system for AVS Units 1 and 2.

Table 4-16 shows the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix C.

Cost estimates were not prepared for the SDA/FF option since the capital and operating costs for the SDA/FF option would be similar to the costs for the CDS/FF option, and the CDS/FF option would likely provide the opportunity to achieve somewhat lower controlled SO_2 emissions (compared to SDA/FF). Therefore, of the two new DFGD system options, only the CDS/FF option was evaluated.

Table 4-15. SO_2 Control Cost Summary (Average Annual)

AVS Unit No.	Alt. No.	SO_2 Control Option	Total Capital Investment $	Annual Capital Recovery Cost $/yr	Annual Operating Cost $/yr (Note 1)	Total Annual Cost $/yr
Unit 1	E	Retrofit New Wet FGD	$272,384,000	$22,322,000	$16,945,000	$39,267,000
	D	Retrofit New Dry FGD (CDS + FF)	$230,447,000	$18,886,000	$16,718,000	$35,604,000
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	$9,698,000	$795,000	$1,144,000	$1,939,000
	A	Existing FGD Operational Improvements – Station Work Practice	$0	$0	$135,000	$135,000
Unit 2	E	Retrofit New Wet FGD	$272,384,000	$22,322,000	$16,819,000	$39,141,000
	D	Retrofit New Dry FGD (CDS + FF)	$230,447,000	$18,886,000	$16,678,000	$35,564,000
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	$9,698,000	$795,000	$1,142,000	$1,937,000
	A	Existing FGD Operational Improvements – Station Work Practice	$0	$0	$131,000	$131,000

Note 1. Annual operating costs based on baseline SO_2 coal quality (2.90 lb/MBtu) and capacity factor during baseline SO_2 period for each AVS Unit.

Table 4-16. SO_2 Emissions Control System Cost Effectiveness (Average Annual)

AVS Unit No.	Alt. No.	SO_2 Control Option	Total Annual Cost $	Expected Emission Reduction (Note 2) tons SO_2/yr	Average Annual Cost-Effectiveness (Note 2) \$/ton SO_2 removed	Incremental Annual Cost-Effectiveness (Note 1) \$/ton SO_2 removed
Unit 1	E	Retrofit New Wet FGD	$39,267,000	5,616	$6,992	$9,826
	D	Retrofit New Dry FGD (CDS + FF)	$35,604,000	5,243	$6,790	$16,420
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	$1,939,000	3,193	$607	$645
	A	Existing FGD Operational Improvements – Station Work Practice	$135,000	397	$340	--
Unit 2	E	Retrofit New Wet FGD	$39,141,000	5,705	$6,861	$9,549
	D	Retrofit New Dry FGD (CDS + FF)	$35,564,000	5,330	$6,672	$16,322
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	$1,937,000	3,270	$592	$643
	A	Existing FGD Operational Improvements – Station Work Practice	$131,000	461	$284	--

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual SO_2 emissions reductions (tpy) between a control option and the next most effective option. For the option "Existing FGD operational improvements – Increase Ca:S Stoichiometric Ratio," incremental cost compares to the option "Existing FGD operational improvements – Station Work Practice."

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline SO_2 coal quality (2.90 lb/MBtu) and capacity factor during baseline SO_2 period for each AVS Unit.

Table 4-16 indicates that the average annual cost effectiveness of the technically feasible SO_2 control options for Unit 1 range from $340 per ton (Existing FGD Operational Improvements – Station Work Practice) to $6,992 per ton (Retrofit New Wet FGD) SO_2 removed; and for Unit 2 ranges from $284 per ton to $6,861 per ton SO_2 removed.

The "Existing FGD operational improvements – Station Work Practice" control option is expected to achieve approximately 5% reduction from the current baseline SO_2 emissions. This option can be implemented without additional capital costs and with minimal increases in operating costs associated with increased lime use during outage periods only. The cost effectiveness of "Existing FGD Operational Improvements – Station Work Practice" control option is approximately $300 per ton, respectively.

The "Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio" option would require relatively low capital investment for new tanks, pumps and piping in the slurry preparation systems since the lime slaking system had been recently upgraded, and an increase in operating costs primarily due to increased reagent usage. This option will achieve approximately 93% SO_2 reduction, resulting in a cost effectiveness of approximately $600 per ton. It should be noted that the recent slaking upgrade project incurred a cost of $15 million which allows the increased Ca:S stoichiometric ratio option to be viable in this analysis. Without the slaking upgrade project, the Ca:S stoichiometric ratio option would have to bear this additional cost.

The installation of new Dry FGD (CDS) or new Wet FGD systems are high capital and annual operating cost options. The cost effectiveness for these options is approximately $6,700 per ton (Dry FGD) and $6,900 per ton (Wet FGD). The incremental cost of installing a Dry FGD system, compared to "Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio," is approximately $16,000 per ton. The incremental cost of installing a Wet FGD system, compared to a Dry FGD system, is approximately $10,000 per ton.

4.4.2 SO_2 Projected Future Maximum Annual Economic Evaluation

Table 4-17 presents the capital costs and annual operating costs associated with building and operating each control system; annual operating costs are based on the unit's operating at 100% capacity factor and projected future coal quality considering potential variability.

Table 4-17. SO_2 Control Cost Summary (Projected Future Maximum)

AVS Unit No.	Alt. No.	SO_2 Control Option	Total Capital Investment $	Annual Capital Recovery Cost $/yr	Annual Operating Cost (Note 1) $/yr	Total Annual Cost $/yr
Unit 1	E	Retrofit New Wet FGD	$272,384,000	$22,322,000	$18,361,000	$40,683,000
	D	Retrofit New Dry FGD (CDS + FF)	$230,447,000	$18,886,000	$19,993,000	$38,879,000
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	$9,698,000	$795,000	$2,937,000	$3,732,000
	A	Existing FGD Operational Improvements – Station Work Practice	$0	$0	$437,000	$437,000
Unit 2	E	Retrofit New Wet FGD	$272,384,000	$22,322,000	$18,210,000	$40,532,000
	D	Retrofit New Dry FGD (CDS + FF)	$230,447,000	$18,886,000	$19,919,000	$38,805,000
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	$9,698,000	$795,000	$2,932,000	$3,727,000
	A	Existing FGD Operational Improvements – Station Work Practice	$0	$0	$406,000	$406,000

Note 1. Annual operating costs based on projected future maximum SO_2 coal quality (3.39 lb/MBtu) and 100% capacity factor for each AVS Unit.

Table 4-18 shows the average annual and incremental cost effectiveness for each control system with emissions reductions and cost effectiveness values based on 100% capacity factors and projected future maximum emission rates. Additional cost details are provided in Appendix C.

Table 4-18. SO_2 Emissions Control System Cost Effectiveness (Projected Future Maximum)

AVS Unit No.	Alt. No.	SO_2 Control Option	Total Annual Cost $	Expected Emission Reduction (Note 2) tons SO_2/yr	Average Annual Cost-Effectiveness (Note 2) $/ton SO_2 removed	Incremental Annual Cost-Effectiveness (Note 1) $/ton SO_2 removed
Unit 1	E	Retrofit New Wet FGD	$40,683,000	6,555	$6,207	$2,466
	D	Retrofit New Dry FGD (CDS + FF)	$38,879,000	5,823	$6,677	$12,010
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	$3,732,000	2,896	$1,288	$1,501
	A	Existing FGD Operational Improvements – Station Work Practice	$437,000	702	$623	--
Unit 2	E	Retrofit New Wet FGD	$40,532,000	6,625	$6,118	$2,360
	D	Retrofit New Dry FGD (CDS + FF)	$38,805,000	5,894	$6,584	$11,986
	B	Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio	$3,727,000	2,967	$1,256	$1,513
	A	Existing FGD Operational Improvements – Station Work Practice	$406,000	772	$526	--

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual SO_2 emissions reductions (tpy) between a control option and the next most effective option. For the option "Existing FGD operational improvements – Increase Ca:S Stoichiometric Ratio," incremental cost compares to the option "Existing FGD operational improvements – Station Work Practice."

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline SO_2 coal quality (3.39 lb/MBtu) and 100% capacity factor for each AVS Unit.

Table 4-18 indicates that the average annual cost effectiveness of the technically feasible SO_2 control options for Unit 1 range from \$623 per ton (Existing FGD operational improvements – Station Work Practice) to \$6,677 per ton (Retrofit New Dry FGD) SO_2 removed; and for Unit 2 ranges from \$526 per ton to \$6,584 per ton SO_2 removed.

The "Existing FGD Operational Improvements – Station Work Practice" control option is expected to achieve approximately 5% reduction from the current baseline SO_2 emissions once every three years on each Unit based on the current maintenance schedule. This option can be implemented without additional capital costs and with minimal increases in operating costs associated with increased lime use. The cost effectiveness of "Existing FGD operational improvements – Station Work Practice" control option is approximately \$600 per ton.

The "Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio" option would require the relatively low capital investment for new tanks, pumps and piping, in the slurry preparation systems since the lime slaking system had been recently upgraded, and an increase in operating costs primarily due to increased reagent usage. This option will achieve approximately 93% SO_2 removal from the projected future maximum levels, resulting in a cost effectiveness of approximately \$1,200 per ton. It should be noted that the slaking upgrade project incurred a cost of \$15 million which allows the increased Ca:S stoichiometric ratio option to be viable in this analysis. Without the slaking upgrade, the Ca:S stoichiometric ratio option would have to bear this additional cost.

The installation of new Dry FGD (CDS) or new Wet FGD systems are high capital and annual operating cost options. The cost effectiveness for these options is approximately \$6,600 per ton (Dry FGD) and \$6,200 per ton (Wet FGD). The incremental cost of installing a Dry FGD system, compared to "Existing FGD Operational Improvements – Increase Ca:S Stoichiometric Ratio," is approximately \$12,000 per ton. The incremental cost of installing a Wet FGD system, compared to a Dry FGD system, is approximately \$2,400 per ton.

5. NO_X CONTROL EVALUATION

5.1 BASELINE NO_X EMISSIONS

The first step in developing the four factor analysis is to establish AVS Units 1 and 2 baseline NO_X emissions. To establish representative baseline emissions, S&L evaluated Units 1 and 2 operating data for the period January 1, 2013 to June 30, 2018 to identify periods of normal operation (i.e., periods of operation when the boiler was not limited by infrequent or extraordinary operating restrictions). Based on review of fuels consumed, heat input to the boiler, boiler heat rates, power generation, and capacity factors, as well as input from Basin Electric, it was determined that the operating periods of January 1, 2013 to June 30, 2018 were representative of normal plant operation. However, during the baseline period, the OFA and LNB on Units 1 and 2 were upgraded in order to comply with the First Regional Haze Planning Period. The upgraded NO_X control systems were in service and additional optimization was achieved on June 2017 (Unit 1) and July 2017 (Unit 2), by installing an Omnivise Combustion Optimizer. Thus, representative baseline periods for the AVS Units are shown in Table 5-1.

Table 5-1. Representative Baseline Periods for NO_X Emissions

Pollutant	Representative Baseline Periods	
	AVS Unit 1	AVS Unit 2
NO_X Emissions	6/1/2017 to 6/30/2018	7/1/2017 to 6/30/2018

Baseline annual NO_X emissions were determined based on data obtained from the Units 1 and 2 continuous emissions monitoring system (CEMS) that was reported to EPA's Clean Air Markets. The maximum 12-month annual average emission rates were used to establish the baseline NO_X emissions. Representative baseline emission factors (in terms of lb/MMBtu) were developed using baseline annual emissions and the respective annual heat inputs. Table 5-2 provides a summary of the AVS Units 1 and 2 NO_X representative baseline emissions; additional details are included in Appendix B. Table 5-3 provides a summary of the AVS Units 1 and 2 NO_X projected future maximum emissions based on the boiler design heat input and 100% capacity factor.

Table 5-2. Baseline Actual NO_X Emissions

AVS Unit	Baseline Controls	NO_X Emission(Note 1)			Capacity Factor During Baseline Period	Current Permit Limits
		lb/hr	lb/MMBtu	tons/yr		
Unit 1	OFA / LNCFS	427	0.10	1,802	81%	0.17 lb/MMBtu (30-day average) 4,930 lb/hr (3-hr average, plant total) 0.50 lb/MMBtu (3-hr average)
Unit 2	OFA / LNCFS	466	0.10	1,904	85%	0.17 lb/MMBtu (30-day average) 4,930 lb/hr (3-hr average, plant total) 0.50 lb/MMBtu (3-hr average)

Note 1. Units 1 and 2 NO_X emissions based on annual average for period July 2017 to June 2018.

Table 5-3. Baseline Projected Future Maximum NO_X Emissions

AVS Unit	Baseline Controls	NO_X Emission(Note 1)			Capacity Factor During Baseline Period	Current Permit Limits
		lb/hr	lb/MMBtu	tons/yr		
Unit 1	OFA / LNCFS	510	0.10	2,235	100%	0.17 lb/MMBtu (30-day average) 4,930 lb/hr (3-hr average, plant total) 0.50 lb/MMBtu (3-hr average)
Unit 2	OFA / LNCFS	512	0.10	2,244	100%	0.17 lb/MMBtu (30-day average) 4,930 lb/hr (3-hr average, plant total) 0.50 lb/MMBtu (3-hr average)

Note 1. Projected future maximum NO_X emissions based on the boiler design heat input of 4,930 MBtu/hr and assumes 100% capacity factor.

5.2 NO$_X$ EMISSIONS CONTROLS

5.2.1 Identify Available NO$_X$ Control Options

Based on a review of available NO$_X$ control technologies installed on existing tangential-fired pulverized coal boilers designed to fire lignite coal, NO$_X$ control techniques can be divided into pre-combustion strategies and post-combustion controls. NO$_X$ control options identified for potential application to AVS Units 1 and 2 are listed in Table 5-4.

Table 5-4. Available NO$_X$ Control Options

NO$_X$ Control Technologies
Selective Catalytic Reduction - High Dust, Low Dust or Tail End Configuration (TE-SCR)
Selective Non-Catalytic Reduction (SNCR)
Gas Reburn
Innovative Technologies (i.e. NO$_X$Star, Water Injection, LoTOX, PerNO$_X$ide, Water Injection)

5.2.2 Technical Feasibility of Available NO$_X$ Control Options

Potentially available NO$_X$ control options identified in Table 5-4 were evaluated for technical feasibility (i.e. availability and applicability to AVS Units 1 and 2) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options deemed to be technically infeasible, or options that have no practical application to AVS Units 1 and 2, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emission performance level (i.e., controlled emission rate) for each.

5.2.2.1 Selective Catalytic Reduction

SCR is a process by which ammonia (NH_3) reacts with nitric oxide (NO) and nitrogen dioxide (NO_2), collectively NO$_X$, in the presence of a catalyst to reduce the NO$_X$ to nitrogen (N_2) and water (H_2O). SCR technology has been applied to NO$_X$-bearing flue gases generated from power generating facilities burning various types of coal, including bituminous, subbituminous, and Texas lignite). The principal reactions resulting in NO$_X$ reduction are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NO_2 + 8NH_3 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

Because these reactions proceed slowly at typical boiler exit gas temperatures of a coal-fired steam electric generating unit, a catalyst is used to increase the reaction rate between NO_X and NH_3. Depending on the specific constituents in the flue gas, a typical temperature range of 550°F to 780°F is necessary to achieve normal performance of the catalyst. For the typical coal-fired boiler, optimal performance will be in the range of approximately 650°F to 750°F.

In general, there are three candidate SCR configurations that can be employed on coal-fired steam electric generating units. The SCR configuration designations generally describe the location of the SCR reaction vessel in relation to other post-combustion air quality control systems. Candidate SCR configurations include:

- High-dust configuration
- Low-dust configuration
- Tail-end configuration

Each of these configurations is described below as they may be applied at AVS Units 1 and 2.

High-Dust Configuration

In a high-dust configuration, the SCR reactor is located in the flue gas stream between the economizer outlet and the air heater inlet. This configuration locates the SCR within the inherently optimal temperature range environment for NO_X reduction (i.e., 650°F to 750°F); however, flue gas characteristics at the economizer outlet can also have detrimental effects on the SCR catalyst. As an example, the high-dust SCR configuration exposes the SCR catalyst to high levels of fly ash loading. High levels of fly ash can result in significant erosion of the catalyst, resulting in more frequent cleaning cycles and catalyst replacement. A second major concern with the high-dust configuration at AVS Units 1 and 2 is the presence of high levels of sodium (both in the vapor-phase and as submicron aerosols) in the North Dakota lignite-derived flue gas. Sodium is a known SCR catalyst poison, and also affects the adhesive and cohesive characteristics of the fly ash, which in turn, would have an adverse effect on the SCR catalyst and reactor vessel.

SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation) or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition). Loss of catalyst activity through thermal degradation or poisoning is permanent, and reactivity can only be restored by replacing the catalyst.

In a North Dakota lignite application, SCR catalyst poisoning is expected to result from the presence of trace elements and strong alkaline substances in flue gas, including sodium (Na), potassium (K), and calcium (Ca). Alkaline metals can chemically attach to active catalyst pore sites and cause deactivation. Sodium and potassium are of prime concern especially in their water-soluble forms, which are more mobile and can penetrate into the catalyst pores. Earth metals, especially calcium, can react with SO_3 absorbed within the catalyst to form $CaSO_4$ and blind the catalyst.

North Dakota lignite contains relatively high levels of organically associated alkali and alkaline-earth elements, including Na, Ca, K, and Mg. Sodium levels in North Dakota lignite are typically 5 to 20 times higher than sodium levels in bituminous and subbituminous coals, and sodium compounds can represent between 5% and 11% of the ash generated from firing North Dakota lignite. These sodium levels, occurring in both the vapor phase and particulate phase, along with relatively high levels of potassium and calcium, significantly increase the potential for catalyst deactivation, plugging, and erosion. Based on the ash chemistry, a conventional high dust SCR arrangement would likely experience unacceptable catalyst deactivation rates.

As noted in section 3.1.1.2, during the first Regional Haze planning period, NDDH prepared a comprehensive technical feasibility assessment of high dust SCR on lignite-fired boilers (North Dakota Regional Haze SIP, Appendix B-5).[35] The NDDH concluded, based on the unique characteristics of North Dakota lignite-derived flue gas, that the high-dust SCR configuration was not a technically feasible or commercially available NO_X control option for North Dakota lignite-fired boilers such as AVS Units 1 and 2.[36] This determination was consistent with the NDDH's NO_X BACT determination for MRYS Units 1 & 2.[37] Reasons upon which NDDH based its

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[35] See, North Dakota State Implementation Plan for Regional Haze, February 24, 2010, Appendix B.5, Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite, July 2009.

[36] *Id*. at pg. 19.

[37] As noted in section 3.1.1.2, contemporaneous with the Regional Haze SIP/FIP process, NDDH also prepared a BACT analysis for MRYS Units 1 & 2. In its BACT analysis, NDDH concluded that SCR was technically infeasible on a lignite-fired cyclone boiler, and selected SNCR as BACT. On December 21, 2011, the District Court issued a decision finding that the State's conclusion that SCR was not technically feasible was not unreasonable. See, U.S. v. Minnkota, 831 F. Supp. 2d at 1127-30

conclusion that high-dust SCR was not a technically feasible option for North Dakota lignite-fired boilers included, but were not limit to:[38]

1) North Dakota lignite[39] has a higher organic matter content and contains a higher proportion of alkali metal constituents, especially sodium, than subbituminous coal. Approximately 75% of the total sodium in lignite is associated with the organic fraction of the lignite. During combustion, organic and water-soluble sodium vaporizes; consequently, combustion of the coal leads to higher flue-gas concentrations of alkali metals in vapor form.
2) The unburned or partially burned organic fraction of North Dakota lignite contains more sodium than other coals. Sodium can react with silicate particles causing a "stickiness" quality to the flue gas ash, resulting in increased ash deposition on heat transfer surfaces. Larger particles can fracture from heat-transfer surfaces (a.k.a. popcorn ash) and enter the flue gas stream. Consequently, deposition on surfaces of catalytic reactors occurs and rates of deposition are higher.
3) NO_X reduction occurs on the flat surfaces of a catalyst and in pores within the flat surfaces. The pores are open to the flue gas passing through the catalyst reactor. Condensed vapors, alkali sulfates and alkaline-earth oxides and silicates are minute particles (less than 1 microns), which enter pores of the catalyst (a.k.a. plugging) and prevent catalytic reaction with NO_X. Residual alkali vapors (Na, K, and Ca) displace hydrogen on fresh catalyst, which prevents catalytic reaction with NO_X (a.k.a poisoning) and reacts with sulfate to cause blinding of catalyst surfaces. Pore condensation of sodium also causes catalyst deactivation, which is a major deactivation mechanism. The rate of catalyst deactivation depends on the concentration and form of alkali in the flue gas; higher Na and K accelerate catalyst poisoning, blinding and plugging.
4) During the development of the initial planning period SIP, NDDH found that there were no SCR systems planned, constructed, or operating in the flue gas stream of boilers fired with North Dakota lignite. North Dakota lignite has certain coal characteristics that are uniquely different than Texas or Gulf Coast lignites, such as the larger proportion of organic matter and association of alkali, sodium specifically, with that organic matter.
5) Slipstream SCR reactors of the same design were installed at three power plants to test SCR for NO_X emissions control. One of the plants was cyclone fired with North Dakota lignite and the others with subbituminous coal. Deposition on the reactor surface after two months using the lignite was significantly greater; the deposits were rich in sodium, calcium, and sulfur. The tests confirmed catalyst blinding and plugging, but did not provide rates for catalyst deactivation. Tests also indicated that the deposits causing blinding and plugging of pores contained more sodium compared to Powder River Basin (PRB) coal.

Based on these findings, NDDH concluded that additional pilot scale testing would be required to assess issues specifically associated with the North Dakota lignite-generated flue gas characteristics, including potential impacts associated with:

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[38] Findings and conclusions are summarized from the North Dakota Regional Haze SIP, Appendix B.5, pgs. 15-19.

[39] Although the BART determination specifically references Fort Union lignite, the findings would apply to all North Dakota lignites.

- the high level of soluble alkali in North Dakota lignite;
- the potential abrasive qualities of North Dakota lignite ash; and
- particle size and sticky nature of high alkaline North Dakota lignite ash.

The NDDH concluded that without pilot scale testing the long term NO_X reduction efficiency, the volume of the reactor, the catalyst pitch and life of catalyst, could not be predicted with a high degree of confidence. Noting that the BART Guidelines do not require source owners/operators to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type, and that technologies in the pilot scale testing stages of development are not considered as "available" for purposes of BART, NDDH determined that high dust SCR was not available, and thus, not technically feasible for units combusting North Dakota lignite.[40]

Although the first planning period BART determinations, focused on North Dakota lignite-fired cyclone boilers (i.e., LOS Unit 2 and MRYS Units 1 & 2), technical issues regarding the high level of soluble alkali in North Dakota lignite, the particle size and sticky nature of high alkaline fly ash, and the potential abrasive qualities of North Dakota lignite ash would apply equally to wall-fired and tangentially fired boilers. Technical issues identified by NDDH during the first planning period would also apply to AVS Units 1 & 2; therefore, findings and conclusions from the first planning period BART determinations (Regional Haze SIP, Appendix B.5) and the MRYS Units 1 & 2 BACT analysis, are incorporated by reference into this reasonable progress four-factor analysis.

Based on a review of SCR installations on coal-fired boilers and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) and the adhesive/cohesive characteristics and potential abrasive qualities of the North Dakota lignite-derived fly ash still remain a concern for North Dakota lignite-fired boilers. SCR has not been installed and successfully operated on a North Dakota lignite-fired boiler, and the bench scale and pilot-scale studies needed to better understand ash behavior and catalyst blinding/erosion with North Dakota lignite-derived fly ash, and to better understand catalyst deactivation mechanisms associated with high soluble alkali compound

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[40] *Id.* at pg. 19. NDDH reached a similar conclusion in its BACT determination for NOx control on MRYS Units 1 & 2, finding that high-dust SCR had not been deployed on the same or a similar source, and that the flue gas characteristics of North Dakota lignite are significantly different from other sources that have applied high-dust SCR. The NDDH found that these unique characteristics present significant challenges to the successful application of high-dust SCR for NOx control, and that pilot testing would be needed to evaluate applicability of the control technology. Thus, NDDH concluded that because high-dust SCR is neither "available" nor "applicable" to the MRYS units, the control technology was technically infeasible and excluded from consideration as BACT. (See, Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2, April 2010).

concentrations in the flue gas have not been required or completed. Pilot-scale studies are needed to evaluate these issues to inform the development of advanced catalyst formulations, and to support the engineering and design studies needed to mitigate for potential deactivation routes (e.g., removing soluble alkali compounds from the flue gas and SCR design considerations such as catalyst formulation, catalyst pitch, reactor velocity, and catalyst surface and volume). Pilot-scale tests and engineering/design studies have not advanced since the first planning period's exhaustive analysis. These issues have not been resolved since the first planning period and still remain a significant barrier to the design and successful operation of high dust SCR on North Dakota lignite-fired boilers.

The BART Guidelines state that "[a] control technique is considered available…if it has reached the stage of licensing and commercial availability."[41] Commercial availability follows bench scale and laboratory testing and pilot scale testing. Consequently, the guidelines state that "you would not consider technologies in the pilot scale testing stages of development as 'available' for purposes of BART review."[42] Furthermore, source owners/operators are not expected to conduct extended trials to learn how to apply a technique on a dissimilar source type.[43] These BART guidelines also apply as a recommendation for the development of the LTS in the second planning period and the four factor analysis.[44] Because there are still unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and engineering solutions have not yet been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is still not available, and thus, not a technically feasible NO_X control technology for AVS Units 1 and 2.

Low-Dust Configuration

In the low-dust configuration, the SCR reactor vessel is located in the flue gas stream after the particulate collection device (i.e. ESP or FF). Employing this configuration would represent a relatively low level of exposure to fly ash (with the exception of submicron ash particles), but a potentially high level of vapor-phase alkalis, such as sodium. This configuration can be used on units equipped with particulate control only or units equipped with particulate control followed by a WFGD control system. The existing dry FGD/FF control configuration at AVS Units 1 and 2 for SO_2 and particulate control would preclude the application of a low-dust SCR configuration since, by definition, the SCR would have to be located downstream of both the dry FGD and FF. At that location the SCR would be more appropriately defined as a tail-end SCR configuration, which is described in more detail in the following

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[41] 40 CFR Part 51 Appendix Y, Section D.2.1.
[42] *Id.*
[43] *Id.*
[44] See, Draft EPA Guidelines, pg. 183.

section. Because AVS Units 1 and 2 are equipped with existing dry FGD/FF controls, low-dust SCR has no practical application on these units, and low-dust SCR is not considered a technically feasible NO_X control option for AVS Units 1 and 2.

Tail-End Configuration

In the tail-end configuration, the SCR reaction vessel is located in the flue gas stream after the particulate and FGD control systems. The potential advantage of a tail-end SCR configuration at AVS is that the flue gas will have passed through the dry FGD/FF system prior to the SCR catalyst. As such, there is the possibility that the mass transfer mechanism that results in the capture of SO_2 will also capture some of the vapor-phase sodium and the sodium-enriched submicron particles, reducing the risk of catalyst poisoning and/or deactivation.

Successful operation of the tail-end configuration would also require a capital and operating cost-intensive gas-to-gas heat exchanger to reheat the flue gas from approximately 170 ^{o}F downstream of the existing FF to approximately 550°F to support the SCR NO_X reactions. After the flue gas passes through the SCR (at approximately 550°F), it would pass through the hot side of the gas-to-gas heat exchanger to cool the flue gas to 150°F prior to the exhaust stack. Although this stack gas temperature would be lower than the current stack temperature (165-170°F), it is still higher than the adiabatic saturation temperature of the flue gas (i.e., approximately 135°F). As such, it is likely that the existing stack could be reused with minor modifications.

During the first planning period, NDDH initially concluded, based on preliminary information provided by SCR catalyst vendors, that the tail-end SCR configuration would be a technically feasible option for units firing North Dakota lignite.[45] However, as part of the MRYS NO_X BACT determination process, detailed information describing the expected ash characteristics and flue gas characteristics was provided to two SCR catalyst vendors (CERAM Environmental, Inc. (CERAM) and Haldor Topsoe, Inc.). Based on their review of the data, both vendors concluded that they would not be able to provide a catalyst life guarantee for either low-dust or tail-end SCR without pilot-scale testing.[46]

During the BACT review process, both companies made statements bringing into question the technical feasibility of either low-dust or tail-end SCR. For example, CERAM stated that the high levels of sodium oxide (Na_2O) in the ash for North Dakota lignite are not commonly found in subbituminous and bituminous coals which are fired in

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[45] See, North Dakota Regional Haze SIP, Appendix B.5, pg. 25.
[46] See, United States v. Minnkota, 831 F. Supp. 2d, at 1117.

boilers equipped with SCR systems, and that it was unaware of any SCR application experience in the industry with the level and form of sodium in the North Dakota lignite-derived ash. CERAM stated further that small aerosol particles can penetrate and neutralize active catalyst sites even in dry conditions, and that catalyst installed even in low dust and tail-end locations can be poisoned from exposure to the high levels of phosphorous, sodium, and potassium found in the mineral analyses provided for the MRYS BACT analysis.[47] Similarly, Haldor Topsoe stated that the potential exists that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a non-viable option for controlling NO_X emissions.

Based on information provided by SCR design engineering firms and SCR catalyst vendors, NDDH made the following findings and conclusions with respect to the technical feasibility of low-dust and tail-end SCR on a North Dakota lignite-fired boiler:[48]

1) There has never been a full scale SCR of any type installed on a facility that burns North Dakota lignite.
2) To determine technical feasibility of tail-end SCR, one must compare the flue gas characteristics generated from firing North Dakota lignite to the flue gas characteristics of other source types to which these control technologies have been applied previously.
3) Flue gas characteristics of boilers firing North Dakota lignite are significantly different from other boilers where SCR has been applied.
4) North Dakota lignite contains high quantities of soluble sodium and potassium which can cause catalyst reaction site poisoning, blinding, and plugging of catalyst pores and channels, and that the soluble sodium and potassium can also form sulfates that can blind and plug the catalyst pores and plug the catalyst channels.
5) Both CERAM and Haldor Topsoe indicated that they would not provide a guarantee for the catalyst life without successful pilot scale testing being done.

Technologies in the pilot scale testing phase of development need not be considered as available control technologies. Based on the fact that SCR had not been installed nor effectively operated on an North Dakota lignite-fired unit, the lack of a commercially viable vendor guarantee, and the need to conduct pilot-scale testing to evaluate potentially significant operational and design issues, NDDH concluded that the use of SCR technology, including low-dust and tail-end SCR, on the lignite-fired MRYS boilers would be technically infeasible.[49]

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[47] *Id.*

[48] Findings and conclusions are summarized from <u>United States v. Minnkota</u>, pgs 1115-1116.

[49] Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2, April, 2010, pg. 21.

Although the MRYS BACT determination, and the initial planning period BART determinations, focused on North Dakota lignite-fired cyclone boilers (i.e., LOS Unit 2 and MRYS Units 1 & 2), technical issues regarding the high level of soluble alkali in North Dakota lignite-derived flue gas would also apply to AVS Units 1 & 2. Therefore, findings and conclusions included in the MRYS Units 1 & 2 BACT analysis and the initial planning period BART determinations (Regional Haze SIP, Appendix B.5) are incorporated by reference into this four-factor analysis.

Based on a current review of SCR installations on coal-fired boilers, and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) still remain a concern for North Dakota lignite-fired boilers. Tail-end SCR has not been demonstrated on a North Dakota lignite-fired boiler, and there are still significant technical concerns associated with the availability of existing SCR catalysts on a lignite-fired unit. Catalyst in a tail-end SCR will still be vulnerable to alkali poisoning, pore pluggage, and premature catalyst deactivation, and it is not known whether the comparatively high levels of soluble sodium and potassium in North Dakota lignite will be effectively removed by the upstream dry FGD/FF. Furthermore, the potential exists for fine particulate remaining in the flue gas to get into the catalyst pores reducing catalyst activity. Pilot-scale studies are needed to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been completed.

In order to understand the effect of North Dakota lignite-derived flue gas on tail-end SCR catalyst, identify potential design solutions, and evaluate the technical feasibility and effectiveness of tail-end SCR at AVS Units 1 and 2 with any degree of certainty, pilot scale testing of the control configuration would be needed. Because there are still unresolved issues associated with catalyst poisoning, it's very unlikely that Basin Electric could obtain a viable commercial offering for tail-end SCR on AVS Units 1 and 2 without extended pilot-scale tests.

During the first planning period NDDH determined that tail-end SCR was not available, and thus, not a technically feasible NO_X control option for North Dakota lignite-fired boilers. Although the NDDH's control technology evaluation during the first planning period specifically focused on North Dakota lignite-fired cyclone boilers, technical issues regarding catalyst deactivation mechanisms associated with the high level of soluble alkali in North Dakota lignite would apply equally to wall-fired and tangentially-fired boilers. The administrative record developed during the first planning period, including the BART determinations and MRYS BACT analysis, supports the conclusion that tail-end SCR is not an available NO_X control option for AVS Units 1 & 2. An evaluation of SCR installations and reported advances in SCR catalysts since the first planning period, coupled with the fact that tail-end SCR has not been demonstrated on a North Dakota lignite-fired boiler, and the likelihood that Basin Electric could not obtain a viable commercial offering for tail-end SCR without extended pilot-scale testing, continues to support the conclusion that tail-end SCR is not an available NO_X control technology. Nevertheless, because the first planning period BART analysis (and the MRYS BACT analysis) focused on cyclone boilers, Basin Electric has elected to include tail-end SCR as a potentially feasible control option and carry it forward to the cost impact evaluation (Section 5.2.2.1). Based on controlled NO_X emissions achieved in practice at existing bituminous- and subbituminous-fired units, S&L assumed that the tail-end SCR control option could achieve an average controlled NO_X emission rate of 0.05 lb/MMBtu.

5.2.2.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia or urea ($CO(NH_2)_2$) at high flue gas temperatures (approximately 1,600ºF – 2,100ºF) in an oxidizing environment. The ammonia or urea reacts with NO_X in the flue gas to produce N_2 and water as shown below.

$$(NH_2)_2CO + 2NO + \frac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$

$$2NH_3 + 2NO + \frac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reagent injection can greatly affect NO_X removal efficiencies and the quantity of NH_3 or urea that will pass through the SNCR unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective in the range of 1,600ºF – 2,100ºF. At temperatures below the desired operating range, the NO_X reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NO_X resulting in low NO_X reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Furnace geometry, urea spray coverage, and droplet size must be considered when developing good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reagent and flue gas in that temperature window. As the boiler cycles in load, the optimum injection region may change. Thus most facilities require multiple injection zones which are placed in and out of service as the unit ramps in load. This can include modifying the zones of injectors that are operating and different loads and temperatures.

Retractable multinozzle lances (MNLs) are sometimes used to improve SNCR performance, especially if the furnace exit flue gas temperatures are too high. The retractable lances allow injection into the appropriate temperature zone more so than wall injectors, depending on the unit load and temperatures. The MNLs also help improve performance by refining the spray pattern for quicker vaporization of the conveying water. MNLs are often used in conjunction with wall injection to provide optimized coverage while reducing reagent cost.

In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to-NO_X ratio, and fuel sulfur content. Increasing the normalized stoichiometric ratio can improve NO_X removal. This is completed by increasing urea solution flow through the injectors or changing the concentration of urea in the solution. However, too high of reagent injection rates will increase the ammonia slip beyond the recommended 10 ppmvd limit. Above this concentration, there are expected to be major impacts to the formation of ammonia salts on the boiler tube banks, reducing heat transfer efficiency, and air heater baskets, causing corrosion.

SNCR can be applied on pulverized coal boiler due to having reasonable temperature windows and residence time, however the potential NO_X reduction is boiler-specific. SNCR has been used as a retrofit NO_X control system on pulverized coal, fluidized bed boilers, and cyclone boilers. Furthermore, SNCR can be implemented on boilers equipped with LNB, overfire air, or SOFA systems. Based on the boiler residence time, temperature profile, and stoichiometry, as well as input from SNCR OEMs, it is estimated that an SNCR system could achieve an average controlled NO_X emission rate of approximately 0.09 lb/MMBtu (approximately 10% below the baseline emission rate of 0.10 lb/MMBtu) while limiting ammonia slip to 10 ppmvd. It should be noted that computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO_X emission is achievable without creating unacceptable operational issues.

5.2.2.3 Rich Reagent Injection

Similar to SNCR, the concept of rich reagent injection (RRI) is to use a nitrogen-containing additive (urea) injected into a reducing environment to promote peak NO_X reduction efficiency. RRI is a commercial technology for cyclone boilers only. Since the AVS units are pulverized coal boilers, this technology is not considered a technically feasible NO_X control technology at AVS.

5.2.2.4 Gas Reburn

Gas reburn is a retrofit technique that has been used to control NO_X emissions from coal- and oil-fired boilers. Gas reburn involves combustion in three distinct zones within the boiler: (1) a primary combustion zone, where the primary fuel is fired using conventional burners; (2) a reburn zone, where secondary fuel, typically natural gas, is introduced into the boiler; and (3) an OFA burnout zone.

In the primary zone of coal-fired boilers, coal is fired through LNCFS, at a rate corresponding to approximately 80% to 90% of the total heat input. Natural gas reburn fuel is then injected above the primary combustion zone under fuel-rich conditions at a rate corresponding to approximately 10% to 20% of the total heat input (on a Btu/hour basis). The fuel-rich reburn zone creates a reducing (sub-stoichiometric) region within the boiler where the natural gas, principally methane (CH_4), breaks down to produce hydrocarbon radicals (CH and CH_2). The hydrocarbon radicals react with NO_X produced in the primary combustion zone to form nitrogen (N_2) and water vapor. Because the natural gas is not completely combusted in the reburn zone, gases exiting the reburn zone will contain considerable CO and unburned hydrocarbons; therefore, additional OFA is introduced above the reburn zone to complete the combustion process.

Critical design parameters that affect the feasibility and performance of a gas reburn retrofit system include: (1) baseline NO_X concentration; (2) reburn zone temperature, residence time, and stoichiometry: (3) OFA burnout zone temperature and residence time; and (4) mixing of the reburn fuel and overfire air with the bulk flue gas.

Gas reburn can have a positive impact on emissions of NO_X; however, in order to make a meaningful prediction of the NO_X removal capabilities at AVS, extensive testing at each unit would be required because the performance is significantly dependent upon boiler operating characteristics. As such, gas reburn is not considered a technically feasible NO_X control technology at AVS.

5.2.2.5 Innovative Technologies

NO_XStar™

The NO_XStar™ process, also known as selective autocatalytic reduction (SACR), uses a continuous controlled amount of ammonia-based reagent with relatively small amounts of hydrocarbon to reduce NO_X emissions. The hydrocarbon is introduced into the flue gas at the convective pass of the boiler, with elevated temperatures. At the elevated temperatures, the hydrocarbon auto-ignites to form a plasma of free radicals that auto catalyzes the reaction of NH_3 and NO_X to form N_2 and H_2O. The hydrocarbon and ammonia are added through banks of nozzles in the superheat or reheat sections of the boiler. The injection location is determined by the location of the temperature windows for the "plasma creation zone" as well as the reaction zone for the ammonia.

To date, only one full-scale demonstration has been conducted to evaluate the technology on utility-sized boilers similar to AVS. The process is an emerging NO_X control, and there is limited information available to evaluate its technical feasibility and long-term effectiveness on a large lignite-fired boiler. Potential NO_X removal efficiencies would be a function of NH_3-NO_X mixing, flue gas temperature, flue gas composition, and residence time downstream of the injection lances.

Because this is an emerging technology, long-term full-scale demonstration testing is required to demonstrate its effectiveness at AVS. It is likely that extensive design engineering and testing would be required to evaluate the technical feasibility and long-term effectiveness of the control system. Detailed design of the lances, mixing, optimization of the reagent supply across the boiler convective pass, flue gas temperatures, and flow distribution would have to be studied. Interference with the tube pendants in the convective pass may also make this more difficult to install. Installing a hydrocarbon distribution grid may present a problem with large boilers because of the span needed to uniformly distribute the reagent, interference with the tube pendants in the convective pass, and an additional booster fan may be needed. As such, NO_XStar™ is not considered a technically feasible NO_X control technology at AVS.

PerNO$_X$ide

PerNO$_X$ide utilizes hydrogen peroxide (H_2O_2) to reduce NO_X emissions. Hydrogen peroxide is injected into the ducts ahead of the air preheater and oxidizes the NO to NO_2, which is then captured in a downstream FGD system. To date, the technology has only been tested on a pilot-scale, and it has not been demonstrated on any coal-fired boilers. It is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system on AVS. As such, PerNO$_X$ide is not considered a technically feasible NO_X control technology at AVS.

LoTOX®

The LoTO$_X$ system is a gas-phase, low-temperature oxidation system, wherein ozone is injected into the flue gas stream to oxidize NO and NO_2 to N_2O_5 before being removed in a wet scrubber. This highly oxidized species of NO_X is water-soluble and rapidly reacts with water to form nitric acid. The conversion of NO_X to nitric acid occurs as the N_2O_5 contacts liquid sprays in the scrubber. The nitric acid would react with the alkali compounds in the scrubber and would be eliminated via the scrubber waste and byproduct streams. The LoTO$_X$ system requires on demand ozone generation from a liquid oxygen supply.

The LoTO$_X$ system has been successfully applied in refinery applications however; there are no full-scale installations on coal-fired boilers. According to vendors, one coal-fired boiler demonstration on a 25-MW boiler was performed which showed 90% NO$_X$ removal. It is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system at AVS. As such, LoTO$_X$ is not considered a technically feasible NO$_X$ control technology at AVS.

Water Injection

The principle behind this technology is to inject an atomized water spray into the high-NO$_X$ production zones of a cyclone burner or in the core of the flame for other furnaces. The water spray reduces the temperature and results in lower NO$_X$ production within this zone. Developers claim that water injection through burners used in tangential-fired and wall-fired units will also lower the flame temperature and, hence, lower NO$_X$ production. However, only laboratory results are available to demonstrate this technology's effectiveness in coal-fired applications.

Water injection is well demonstrated for combustion turbine applications for NO$_X$ reduction. However, there is insufficient experience and demonstration data in coal-fired applications. As such, water injection is not considered a technically feasible NO$_X$ control technology at AVS.

5.2.2.6 Technical Feasibility Summary

Table 5-5 summarizes the results of the feasibility evaluation of available NO$_X$ control options for AVS Units 1 and 2.

Table 5-5. Technically Feasible NO_X Control Options

NO_X Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Selective Non-Catalytic Reduction (SNCR)	Yes	10%	SNCR is considered an available and technically feasible NO_X control technology for AVS Units 1 and 2. Computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO_X emissions is achievable without creating unacceptable operational issues.
Rich Reagent Injection	No	0%	RRI is not considered an available or technically feasible NO_X control option at AVS.
Gas Reburn	No	0%	Gas reburn is not considered an available or technically feasible NO_X control technology at AVS Units 1 and 2.
Innovative Technologies: NO_XStar™ PerNO$_X$ide LoTO$_X$ Water Injection	No	0%	Innovative NO_X control technologies are evaluated in Section 5.2.2.5. In all cases, the technologies have not been demonstrated on a large North Dakota lignite-fired boiler. Extensive testing and design engineering would be required to evaluate the technical feasibility and long-term effectiveness of each innovative control system on AVS Units 1 and 2. Therefore, the innovative NO_X control technologies are not considered available control options and are not technically feasible NO_X control options for AVS Units 1 and 2.
Selective Catalytic Reduction:			
High-dust configuration	No	0%	Due to significant unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and based on the finding that engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not an available or technically feasible NO_X control technology for AVS Units 1 and 2.
Low-dust configuration	No	0%	Because AVS Units 1 and 2 is equipped with existing dry FGD/FF control systems, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered an available or technically feasible NO_X control option for AVS Units 1 and 2.

NO_X Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Tail-end configuration	Yes	50%	Tail-end SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of tail-end SCR on AVS Units 1 and 2. Because there are unresolved issues associated with catalyst poisoning, it's unlikely that Basin Electric could obtain a viable commercial offering for tail-end SCR on AVS Units 1 and 2. Nevertheless, during the initial planning period, NDDH concluded that tail-end SCR was a technically feasible NO_X control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. Based on the approach NDDH used during the initial planning period (i.e., assuming technical feasibility and evaluating the control system for costs and cost-effectiveness), tail-end SCR will be carried forward to the four factor analysis.

Note 1. Control percentage calculated using the baseline NO_X emission rate and the achievable NO_X emission rate for each technically feasible control option.

5.2.3 Evaluate Technically Feasible NO_X Control Options for Effectiveness

The technically feasible NO_X control technologies for Units 1 and 2 are listed in Table 5-6 and Table 5-7 in descending order of control efficiency. Table 5-6 and Table 5-7 also provide control option-specific NO_X emission rates in terms of lb/MMBtu. Emission rates shown represent average emission rates that the control options would be expected to achieve during normal operations.

Table 5-6. Evaluate Technically Feasible NO_X Control Options by Effectiveness for AVS Unit 1 (Baseline Average Emissions)

Alt. No.	Control Technology	NO_X Emission Rate (Note 1) lb/MMBtu	% Reduction from Baseline (Note 2)	NO_X Emission Rate (Note 1) lb/hr	NO_X Emission Rate (Note 1) tons/yr
B	SCR – tail-end configuration (Note 2)	0.05	52%	206	870
A	SNCR	0.09	10%	388	1,636
--	Baseline (existing OFA/LNCFS)	0.10		427	1,802
--	Permit Limit (assume 50/50 split for each unit)	0.17 (30-day) 0.50 (3-hour)	--	2,465 lb/hr (3-hr average)	

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for AVS Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2. Tail-end SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of tail-end SCR on AVS Unit 1. Nevertheless, during the initial planning period, NDDH concluded that tail-end SCR was a technically feasible NO_X control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. For consistency with NDDH's conclusion from the first planning period, tail-end SCR will be carried forward to the four factor analysis.

Table 5-7. Evaluate Technically Feasible NO_X Control Options by Effectiveness for AVS Unit 2 (Baseline Average Emissions)

Alt. No.	Control Technology	NO_X Emission Rate(Note 1) lb/MMBtu	% Reduction from Baseline	NO_X Emission Rate(Note 1) lb/hr	NO_X Emission Rate(Note 1) tons/yr
B	SCR – tail-end configuration (Note 2)	0.05	52%	224	916
A	SNCR	0.09	10%	421	1,722
--	Baseline (existing OFA/LNCFS)	0.10		466	1,904
--	Permit Limit (assume 50/50 split for each unit)	0.17 (30-day) 0.50 (3-hour)	--	2,465 lb/hr (3-hr average)	

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for AVS Unit 2. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2. Tail-end SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of tail-end SCR on AVS Unit 2. Nevertheless, during the initial planning period, NDDH concluded that tail-end SCR was a technically feasible NO_X control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. For consistency with NDDH's conclusion from the first planning period, tail-end SCR will be carried forward to the four factor analysis.

Table 5-8 provides control option-specific NO_X emission rates in terms of lb/MMBtu based on the projected future maximum emission rates. Emission rates shown represent the projected future maximum emission rates that the control options would be expected to achieve during normal operations.

Table 5-8. Evaluate Technically Feasible NO_X Control Options by Effectiveness – AVS Unit 1 or 2 (Projected Future Maximum Emissions)

Alt. No.	Control Technology	NO_X Emission Rate$^{(Note\ 1)}$ lb/MMBtu	% Reduction from Baseline	NO_X Emission Rate$^{(Note\ 1)}$ lb/hr	NO_X Emission Rate$^{(Note\ 1)}$ tons/yr
B	SCR – tail-end configuration $^{(Note\ 2)}$	0.05	52%	247	1,080
A	SNCR	0.09	10%	463	2,030
--	Baseline Unit 1 (existing OFA/LNCFS)	0.10	--	510	2,235
--	Baseline Unit 2 (existing OFA/LNCFS)	0.10	--	512	2,244
--	Permit Limit (assume 50/50 split for each unit)	0.17 (30-day) 0.50 (3-hour)	--	2,465 lb/hr (3-hr average)	

Note 1. Emission rates shown represent projected future maximum emission rates that the control options would be expected to achieve on an on-going long-term basis under 100% capacity factor operation for AVS Unit 1 or 2. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2. Tail-end SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of tail-end SCR on AVS Units 1 and 2. Nevertheless, during the initial planning period, NDDH concluded that tail-end SCR was a technically feasible NO_X control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. For consistency with NDDH's conclusion from the first planning period, tail-end SCR will be carried forward to the four factor analysis.

5.3 NO_X COST OF COMPLIANCE (STATUTORY FACTOR ONE)

The economic analysis performed as part of the four factor analysis examines the cost-effectiveness of each technically feasible control technology, on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. For units with existing controls, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual O&M costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of control equipment. Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25% and equipment life of 20 years.[50] Cost effectiveness ($/ton) of a particular control option is simply the annual cost ($/yr) divided by the annual reduction in annual emissions (ton/yr). In addition to cost-effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the incremental cost effectiveness of the more stringent control.

Capital and O&M cost estimates were developed for each of the technically feasible NO_X control options. The AVS Units 1 and 2 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Units 1 and 2 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on AVS-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the AVS Units 1 and 2 retrofit technologies as "concept screening" cost estimates generally based on parametric models, judgment, or analogy.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, Contractor G&A expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing control systems.

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[50] The assumed 20-year equipment life is consistent with the control system equipment life used by NDDH in its evaluation of NOX and SO_2 control technologies for BART-eligible sources. (see, e.g., ND Regional Haze Final SIP, Appendix C.1, "BART Determination Study for Leland Olds Station Units 1 & 2, Basin Electric Power Cooperative, August 2006, pgs. 64 (NO_X controls) and 158 (SO_2 controls). See also, ND Regional Haze Final SIP, Appendix C4, "NO_X Best Available Control Technology Study for Milton R. Young Station Unit 1, Minnkota Power Cooperative, Inc., October 2006, pg. 3-22).

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

5.3.1 NO_X Average Annual Economic Evaluation

Table 5-9 presents the capital costs and annual operating costs associated with building and operating each control system. Table 5-9 shows the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix D.

Table 5-9. NO_X Control Cost Summary (Average Annual)

AVS Unit No.	Alt. No.	NO_X Control Option	Total Capital Investment $	Annual Capital Recovery Cost $/yr	Annual Operating Cost $/yr	Total Annual Cost $/yr
Unit 1	B	SCR – tail-end configuration	$221,396,000	$18,144,000	$18,201,000	$36,345,000
	A	SNCR	$16,356,000	$1,340,000	$1,945,000	$3,285,000
Unit 2	B	SCR – tail-end configuration	$221,396,000	$18,144,000	$18,207,000	$36,351,000
	A	SNCR	$16,356,000	$1,340,000	$1,970,000	$3,310,000

Table 5-10. NO_X Emissions Control System Cost Effectiveness (Average Annual)

AVS Unit No.	Alt. No.	NO_X Control Option	Total Annual Cost $	Expected Emission Reduction (Note 2) tons NO_X/yr	Average Annual Cost-Effectiveness (Note 2) $/ton NO_X removed	Incremental Annual Cost-Effectiveness (Note 1) $/ton NO_X removed
Unit 1	B	SCR – tail-end configuration	$36,345,000	931	$39,035	$43,161
	A	SNCR	$3,285,000	165	$19,893	
Unit 2	B	SCR – tail-end configuration	$36,351,000	988	$36,792	$40,997
	A	SNCR	$3,310,000	182	$18,179	

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual NO_X emissions reductions (tpy) between a control option and the next most effective option. For the option "SCR ," incremental cost compares to the option "SNCR."

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline NO_X emission rate and capacity factor during baseline NO_X period for each AVS Unit.

Table 5-10 indicates that the average annual cost effectiveness of the technically feasible NO_X control options for Unit 1 range from $19,893 per ton (SNCR) to $39,035 per ton (SCR – Tail end configuration) NO_X removed; and for Unit 2 ranges from $18,179 per ton to $36,792 per ton NO_X removed.

Installation of an SNCR system is expected to achieve approximately 10% NO_X reduction. The cost effectiveness of this option is approximately $19,000 per ton.

Tail-end SCR system costs have been included to remain consistent with the approach used by NDDH during the initial planning period. Based on preliminary cost estimates, the cost effectiveness of a tail-end SCR system is approximately $39,000 per ton. Compared to the SNCR control option, the incremental cost effectiveness is approximately $43,000 per ton.

5.3.2 NO_X Projected Future Maximum Economic Evaluation

Table 5-11 presents the capital costs and annual operating costs associated with building and operating each control system; annual operating costs are based on the units operating at 100% capacity factor. Table 5-12 shows the average annual and incremental cost effectiveness for each control system with emissions reductions and cost effectiveness values based on 100% capacity factors and projected future maximum emission rates. Additional cost details are provided in Appendix D.

Table 5-11. NO_X Control Cost Summary (Projected Future Maximum)

AVS Unit No.	Alt. No.	NO_X Control Option	Total Capital Investment $	Annual Capital Recovery Cost $/yr	Annual Operating Cost $/yr	Total Annual Cost $/yr
Unit 1	B	SCR – tail-end configuration	$221,396,000	$18,144,000	$18,788,000	$36,932,000
	A	SNCR	$16,356,000	$1,340,000	$2,074,000	$3,414,000
Unit 2	B	SCR – tail-end configuration	$221,396,000	$18,144,000	$18,649,000	$36,793,000
	A	SNCR	$16,356,000	$1,340,000	$2,075,000	$3,415,000

Note 1. Annual operating costs based on baseline NO_X emissions and 100% capacity factor for each AVS

Table 5-12. NO_X Emissions Control System Cost Effectiveness (Based on Projected Future Maximum Emissions)

AVS Unit No.	Alt. No.	NO_X Control Option	Total Annual Cost $	Expected Emission Reduction tons NO_X/yr	Average Annual Cost-Effectiveness \$/ton NO_X removed	Incremental Annual Cost-Effectiveness (Note 1) \$/ton NO_X removed
Unit 1	B	SCR – tail-end configuration	$36,932,000	1,155	$31,977	$35,278
	A	SNCR	$3,414,000	205	$16,667	
Unit 2	B	SCR – tail-end configuration	$36,793,000	1,165	$31,589	$35,131
	A	SNCR	$3,415,000	215	$15,910	

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual NO_X emissions reductions (tpy) between a control option and the next most effective option. For the option "SCR ," incremental cost compares to the option "SNCR."

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline NO_X emissions and 100% capacity factor for each AVS Unit.

Table 5-12 indicates that the average annual cost effectiveness based on projected future maximum of the technically feasible NO_X control options for Unit 1 from $16,667 per ton (SNCR) to $31,977 per ton (SCR – Tail end configuration) NO_X removed; and for Unit 2 ranges from $15,910 per ton to $31,589 per ton NO_X removed.

Installation of an SNCR system is expected to achieve approximately 10% NO_X reduction from the projected future maximum emissions. The cost effectiveness of this option is approximately $16,000 per ton.

Tail-end SCR system costs have been included to remain consistent with the approach used by NDDH during the initial planning period. Based on preliminary cost estimates, the cost effectiveness of a tail-end SCR system is approximately $31,000 per ton. Compared to the SNCR control option, the incremental cost effectiveness is approximately $35,000 per ton.

6. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO)

The time necessary for compliance is generally defined as the time needed for full implementation of the technically feasible control options. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. Therefore, compliance deadlines must consider the time necessary for compliance by setting a compliance deadline that provides a reasonable amount of time for the source to implement the control measure.

Table 6-1 and Table 6-2 include estimated timeframes needed to implement each of the technically feasible control. The estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; therefore, the scheduled activities identified below commence immediately after SIP approval and are subject to the maintenance outage schedules of the individual unit.

Table 6-1. SO_2 Emissions Control System Implementation Schedule

SO_2 Control Option	Alt. No.	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup / Tuning (months)	Compliance Date (months after SIP approval)
FGD operational improvements – Station Work Practice (Note 1)	A	0	0	3	3
FGD operational improvements – Increase Ca:S Stoichiometric Ratio	B	12	15	24^(Note 2)	No later than 60 months
Dry FGD (CDS) + Existing FF	D	12	20	24	No later than 60 months
Wet FGD	E	12	22	26	No later than 60 months

Note 1. Although this option would not require design/fabrication and construction months, Basin Electric would need 2-3 months to update O&M manuals and personnel training for the change to the work practice of the existing DFGD systems.

Note 2. Requires coordination with normal tri-annual outage shedules.

Table 6-2. NO_X Emissions Control System Implementation Schedule

NO_X Control Option	Alt. No.	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Compliance Date (months after SIP approval)
SNCR	A	10	6	6	No later than 60 months
SCR – Tail-End Configuration	B	10	18	24	No later than 60 months

7. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE)

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal.

7.1 ENVIRONMENTAL IMPACTS

AVS Units 1 and 2 are currently equipped with LNCFS/OFA for NO_X control and dry scrubber technology for SO_2 control. The hydrated lime reactant used in a dry scrubbing system reacts with SO_2 in the flue gas to form calcium sulfate and calcium sulfite solids. The solids are captured in the existing FF particulate control system and either returned to the system for reuse or removed from the system as nonhazardous solid waste. The existing dry scrubbing system also requires water to hydrate the lime prior to injection into the reaction modules. Based on the design of the control system, the DFGD at AVS currently use approximately 690 gpm of water. Collateral environmental impacts associated with the existing Units 1 and 2 control systems include water consumption and increased solid waste generation. There were no collateral impacts associated with the LNCF/OFA system.

Based on a review of potential non-air quality environmental impacts, no significant collateral environmental impacts were identified for any of the SO_2 and NO_X control options included in this evaluation, with the exception, potentially, of the WFGD, TE-SCR and SNCR options. No significant non-air quality environmental impacts were identified for the options that include replacing the existing scrubber modules with new scrubber modules or FGD operational improvements/upgrades.

There are a number of potential non-air quality environmental impacts associated with the WFGD control option. Unlike dry scrubbing systems that generate a dry FGD byproduct, WFGD systems generate a liquid calcium sulfate by-product that must be dewatered prior to disposal. WFGD control systems can be designed with forced oxidation that results in a gypsum-grade by-product that can be sold into the local gypsum market. If an adequate gypsum market is not available, the gypsum by-product will require disposal. WFGD control systems also generate a wastewater stream that must be treated prior to discharge. WFGD wastewaters typically consist of a saturated solution of calcium sulfate, calcium sulfite, and sodium chloride, with trace amounts of fly ash and unreacted limestone. Traces of metal ions may also be present due to fly ash carryover from the flue gas to the WFGD scrubber liquor. WFGD wastewater treatment systems typically require calcium sulfate/sulfite desaturation, heavy metals precipitation, coagulation/precipitation, and sludge dewatering. Treated wastewater is typically discharged to surface water pursuant to a National Pollutant Discharge Elimination System (NPDES) discharge permit, and solids are typically disposed of in a landfill. However, AVS is a zero discharge facility where only non-contact stormwater is currently discharged. With the implementation of a WFGD, the facility would need to remain a zero discharge facility.

WFGD systems also require significantly more water than the dry systems. Based on design criteria for wet and dry FGD control systems, WFGD systems typically require approximately 25-30% more water than a similarly sized DFGD control system. This would increase water consumption at each AVS Unit on average approximately 115 gpm. Water consumption is an important factor when assessing potential non-air quality environmental impacts at facilities located in North Dakota, and could represent a significant non-air quality collateral environmental impact.

In addition, the TE-SCR and SNCR control options have a number of collateral impacts. The TE-SCR catalyst oxidizes some of the SO_2 to SO_3 in addition to catalyzing the reaction between NO_X and ammonia. There could be the potential for increased SO_3 emissions with the use of a TE-SCR. The SO_3 will react with the moisture in the stack to form H_2SO_4 emissions. In addition both the TE-SCR and SNCR options utilize ammonia as the reagent for the reactions with NO_X to occur. There will be some ammonia slip emission from a TE-SCR in the range of 2 ppm. However the ammonia slip emission from a SNCR control technology will be significantly higher at 10 ppm. Ammonia slip emissions from the SNCR option will likely end up in the dry FGD solids, however there is no means to capture the ammonia slip emissions from the TE-SCR since it is installed prior to the stack. The ammoniated dry FGD solids would create a more difficult work environment for the AVS staff that would be performing maintenance on the ash handling system and performing waste disposal activities.

7.2 ENERGY IMPACTS

Options that include replacing the existing Unit 1 dry scrubbing system with a CDS/FF or WFGD system or adding a TE-SCR will increase pressure drop through the control systems, increase auxiliary power requirements, and adversely affect the unit' net plant heat rate (Btu heat input per MW_{Net} output).[51] Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease.

Although several of the control options have energy impacts, none of the impacts are considered significant enough as to disqualify any of the options from consideration in the four factor analysis. In order to account for potential energy impacts associated with each option, the auxiliary power cost associated with operating the control systems have been included as an annual operating cost in the economic impact assessment.

7.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY

A summary of the Statutory Factor 3 environmental and energy impact analysis is provided in Table 7-1.

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[51] Heat rate represents the amount of heat input to the boiler (Btu) required to generate one megawatt (MW) net electric output and is reported as Btu/MW_{Net}.

Table 7-1. Summary of Energy and Non-Air Quality Environmental Impacts

Control Option	Collateral Environmental & Energy Impacts
Baseline	➢ AVS Units 1 and 2 are currently equipped with dry scrubbing / FF control systems. Existing collateral environmental and energy impacts include: ➢ Solid FGD by-product management and disposal ➢ Increased water consumption ➢ Increased auxiliary power requirements and heat rate penalty
<u>SO_2 Control Options</u>	
Replace existing DFGD with New WFGD control system	➢ Increased water consumption ➢ Wet by-product that requires dewatering prior to disposal ➢ FGD wastewater treatment & discharge ➢ Increased auxiliary power requirements and heat rate penalty
Replace existing DFGD with New CDS/FF Control System	➢ Increased auxiliary power requirements and heat rate penalty ➢ Increased solid FGD by-product management and disposal
<u>NO_X Control Options</u>	
Selective Catalytic Reduction (SCR) - Tail End Configuration	➢ Increased auxiliary power requirements and heat rate penalty ➢ Increased ammonia slip emissions ➢ Potential increase in SO_3 emissions
SNCR	➢ Increased ammonia slip emissions ➢ Increased auxiliary power requirements and heat rate penalty ➢ Increased water consumption ➢ Increased health and safety precautions required with ammoniated dry FGD solids O&M activities.

8. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR)

The evaluation of technically feasible NO_X and SO_2 controls options should consider the source's "remaining useful life" in determining the costs of compliance. The remaining useful life is the difference between the data that controls would be put in place and the date that the facility permanently ceases operation. If the remaining useful life of the unit is shorter than the useful life of a particular control option, the remaining useful life should be used annualizing costs. If the remaining useful life exceeds the useful life of the control options, the remaining use life has no effect on the cost evaluation.

Under the current Basin Electric resource plan, the remaining useful life of AVS Units 1 and 2 are considered to be greater than 20 years. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework.

9. CONCLUSIONS

At the request of NDDH, a four factor analysis was prepared for AVS Units 1 and 2 for use in their Round II Determination. The analysis identified technically feasible SO_2 and NO_X control options for the units, and evaluated each of the control measures for the following four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

The cost of compliance evaluation (Statutory Factor 1) prepared for SO_2 controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible SO_2 control options for Unit 1 ranges from $340 per ton (Alternative A) to $6,992 per ton SO_2 removed (Alternative E), and for Unit 2 ranges from $284 per ton (Alternative A) to $6,861 per ton SO_2 removed (Alternative E). When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible SO_2 control options for Unit 1 ranges from $623 per ton (Alternative A) to $6,677 per ton SO_2 removed (Alternative D), and for Unit 2 ranges from $526 per ton (Alternative A) to $6,584 per ton SO_2 removed (Alternative D).

The cost of compliance evaluation prepared for NO_X controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible NO_X control options for Unit 1 ranges from $19,893 per ton (Alternative A) to $39,035 per ton NO_X removed (Alternative B), and for Unit 2 ranges from $18,179 per ton (Alternative A) to $36,792 per ton NO_X removed (Alternative B) from historical baselines. When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible NO_X control options for Unit 1 ranges from $16,667 per ton (Alternative A) to $31,977 per ton NO_X removed (Alternative B), and for Unit 2 ranges from $15,910 per ton (Alternative A) to $31,589 per ton NO_X removed (Alternative B).

The time necessary for compliance (Statutory Factor 2) for the SO_2 control options ranges from 3 months (Alternative A) to 60 months (Alternative E). For NO_X control options, the time necessary for compliance ranges from 22 months (Alternative A) to 52 months (Alternative B).

An evaluation of energy impacts and non-air environmental impacts (Statutory Factor 3) indicates that certain control options will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts include increases in water consumption, FGD wastewater treatment and discharge, and solid waste generation.

Regarding remaining useful life (Statutory Factor 4), under the current Basin Electric resource plan, the remaining useful life of AVS Units 1 and 2 are considered to be greater than 20 years. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework.

Based on the results of the four factor analysis prepared for AVS, Basis Electric is aware that reducing SO_2 emissions by implementing FGD Operational Improvements (Alternative B) on Units 1 and 2 may be determined to be cost effective by the NDDH.

Within the Round II Determination process, the NDDH will evaluate visibility improvements relying on Western Region Area Partnership's (WRAP) cumulative modeling of the North Dakota based facilities for the various control options being evaluated. Basin Electric requests that the NDDH withhold their Round II Regional Haze SIP Determination for the AVS until the cumulative modeling platform is made available to the public and visibility improvement assessments can be conducted. Basin Electric will then perform a comparative visibility improvement analysis and submit the results to the NDDH for consideration. This effort will be coordinated with the NDDH for consistency of modeling protocols and model inputs.

In addition, Basin Electric requests, that in the event that SO_2 reductions will be required, any future 30-day rolling average permit limit will be based on an equivalent mass based combined plant (lb SO_2/hr) 30-day rolling average basis. Since AVS began operation, the current combined plant total permit limit of 3,845 lb SO_2/hr, 3-hour average, has been the benchmark for all operations guidance and procedures and is imbedded in the DFGD process control logic. To alter the basis of the operational control to a mass emission rate (lb SO_2/MMBtu) will be extremely disruptive from an operational perspective when consideration is given to the complexity and variability of DFGD operations.

The four factor analysis prepared for AVS NO_X reductions indicates that SNCR and tail-end SCR control options are cost prohibitive. The control cost evaluation indicates that the average cost effectiveness levels exceed $15,000 per ton NO_X removed. Basin Electric is proposing that the existing OFA / LNCFS systems on Units 1 and 2 represent appropriate controls for the Round II Determination, therefore no change to the current Title V Operating Permit is proposed for NO_X emissions at AVS. Table ES-3 includes a summary of the proposed Round II Determination's control strategy for SO_2, assessed SO_2 emissions on a 30-day rolling average basis and a proposed combined plant average emission rate for AVS. The proposed emissions include compliance margin to account for items such as variability in fuel heating value and sulfur content, and operating load profile.

Table ES-1. Proposed Round II Determination's SO_2 Emission Rate

AVS Unit No.	Pollutant	Proposed Round II Determination's Emission Rate lb/MMBtu (30-day rolling average)	Proposed Round II Determination's Combined Plant Emission Rate (Note 1) (lb/hr)	Control Technology
Unit 1	SO_2	0.30	2,958	FGD Operational Improvements
Unit 2	SO_2	0.30	2,958	FGD Operational Improvements

Note 1. The proposed Round II Determination's combined plant emission rate is a 23% reduction from the current combined plant permit limit of 3,845 lb SO_2/hr, 3-hour avg.

APPENDIX A

NORTH DAKOTA DEPARTMENT OF HEALTH LETTER

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

May 2, 2018

RECEIVED MAY 04 2018

Mr. Mike Paul
Basin Electric Power Coop.
1717 E Interstate Avenue
Bismarck, ND 58503-0564

Re: Regional Haze
Second Planning Period

Dear Mr. Paul:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:
1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
Division of Municipal Facilities 701.328.5211
Division of Waste Management 701.328.5166
Division of Water Quality 701.328.5210

Printed on recycled paper.

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

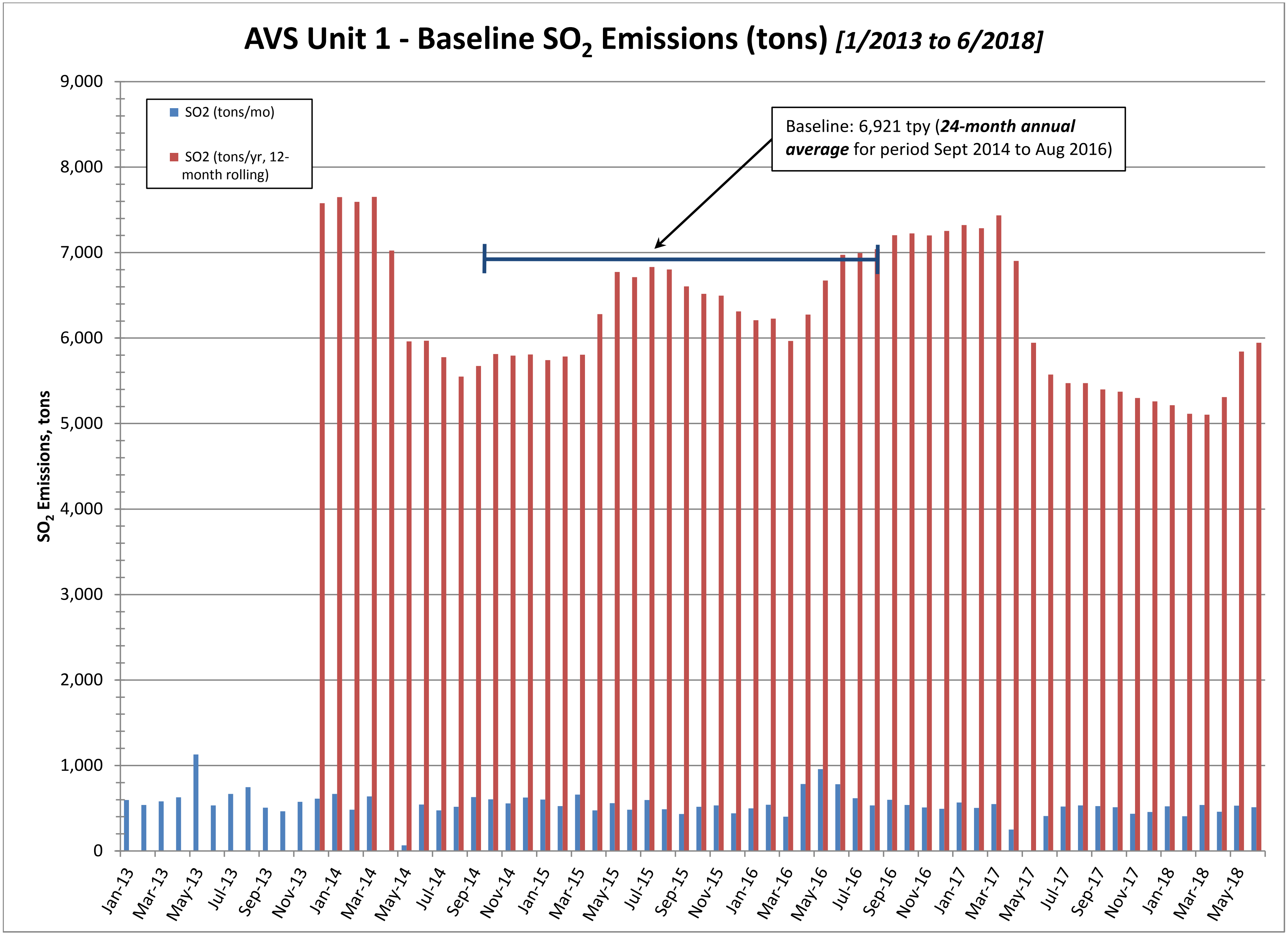
Terry O'Clair

Terry L. O'Clair
Director
Division of Air Quality

TLO/TB:saj
xc: Cris Miller, Basin Electric Power Coop.

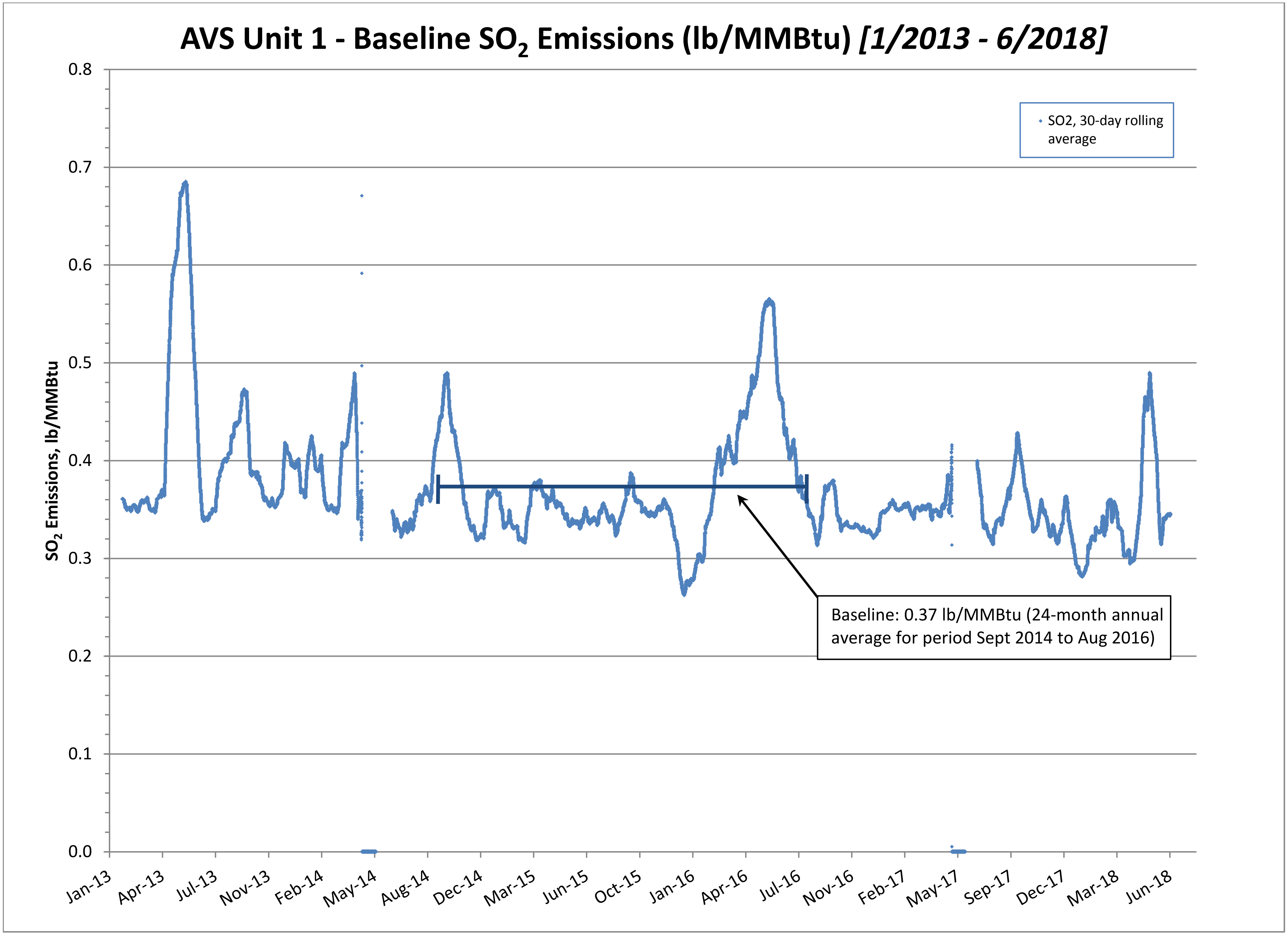
APPENDIX B

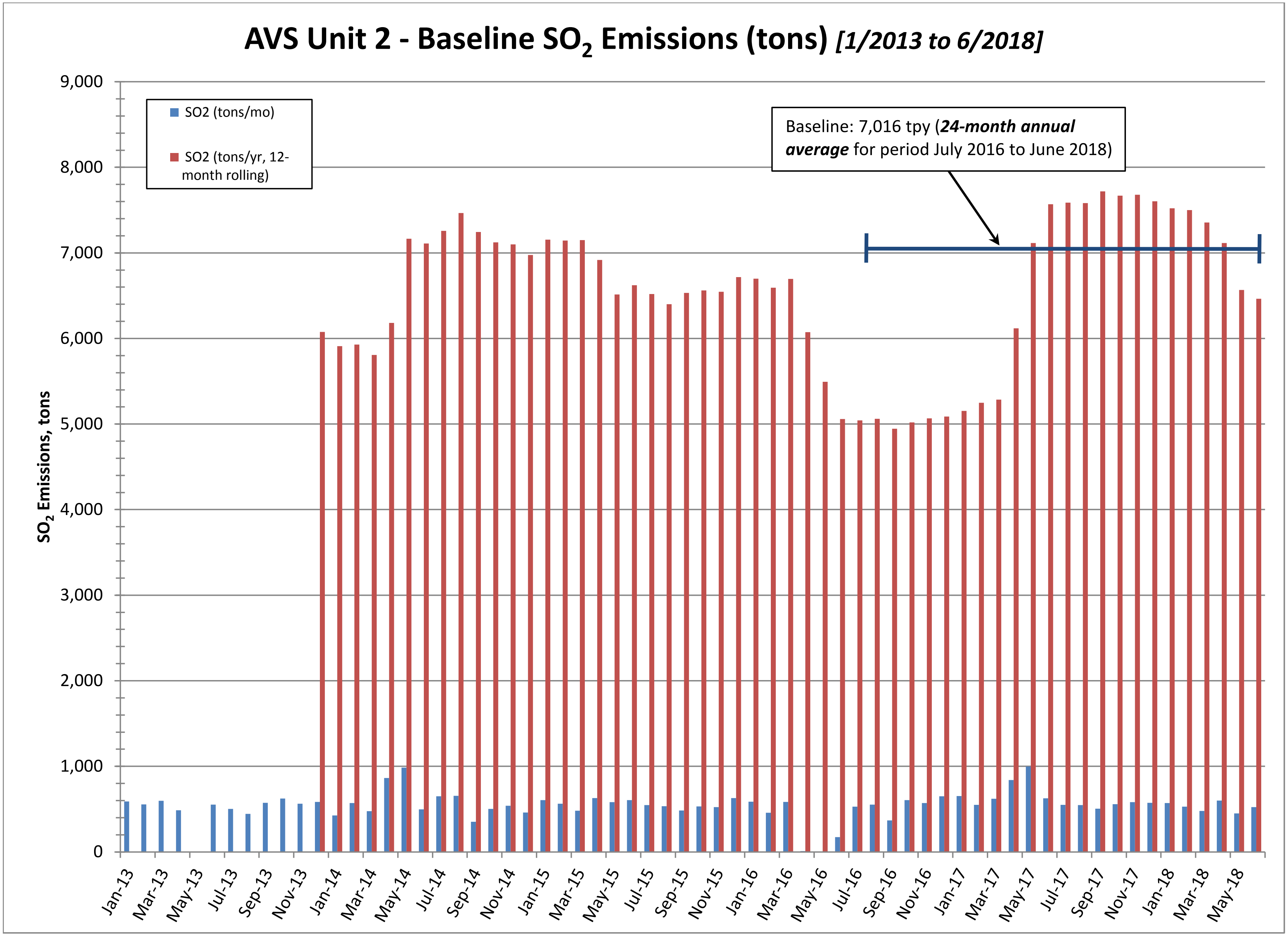
ANTELOPE VALLEY UNITS 1 AND 2 BASELINE EMISSIONS



AVS Unit 1 - Baseline SO_2 Emissions (tons) *[1/2013 to 6/2018]*

Baseline: 6,921 tpy (***24-month annual average*** for period Sept 2014 to Aug 2016)


AVS Unit 1 - Baseline SO2 Emissions (lb/MMBtu) [1/2013 - 6/2018]
SO2 Emissions, lb/MMBtu
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
Jan-13
Apr-13
Jul-13
Nov-13
Feb-14
May-14
Aug-14
Dec-14
Mar-15
Jun-15
Oct-15
Jan-16
Apr-16
Jul-16
Nov-16
Feb-17
May-17
Sep-17
Dec-17
Mar-18
Jun-18
SO2, 30-day rolling average
Baseline: 0.37 lb/MMBtu (24-month annual average for period Sept 2014 to Aug 2016)


AVS Unit 2 - Baseline SO$_2$ Emissions (tons) *[1/2013 to 6/2018]*
SO2 (tons/mo)
SO2 (tons/yr, 12-month rolling)
Baseline: 7,016 tpy (***24-month annual average*** for period July 2016 to June 2018)
SO$_2$ Emissions, tons
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
Jan-16
Mar-16
May-16
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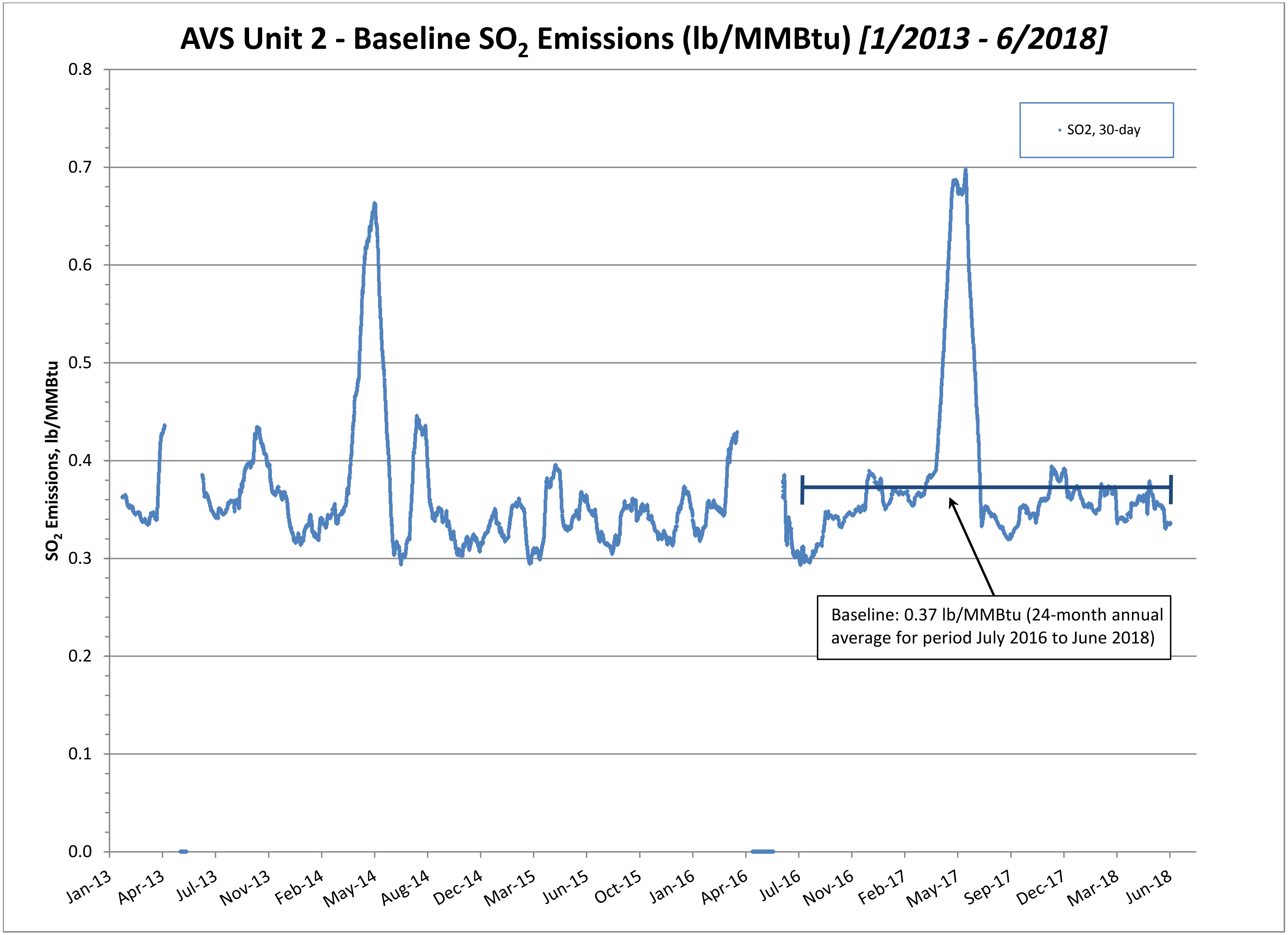
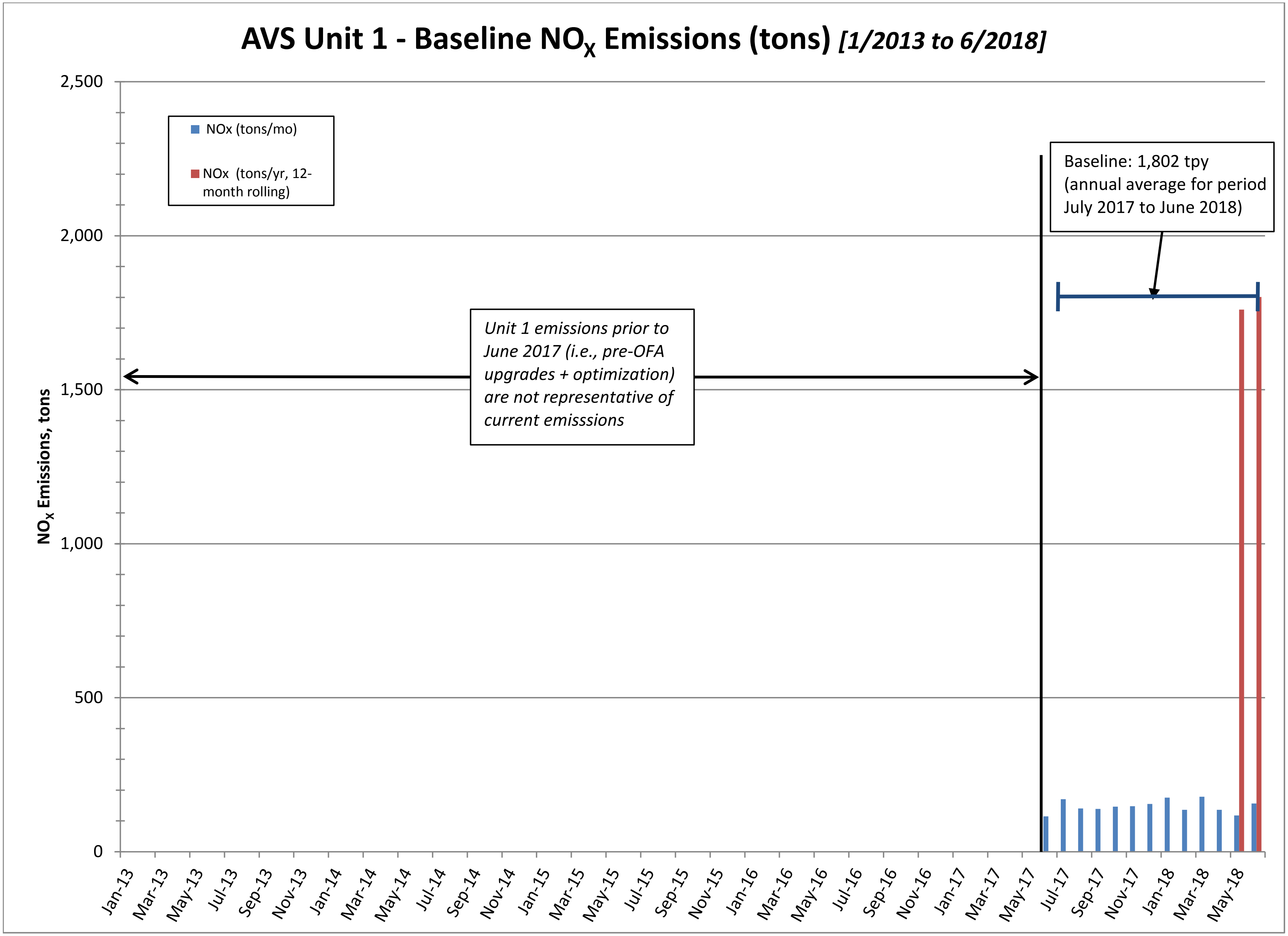
Nov-17
Jan-18
Mar-18
May-18

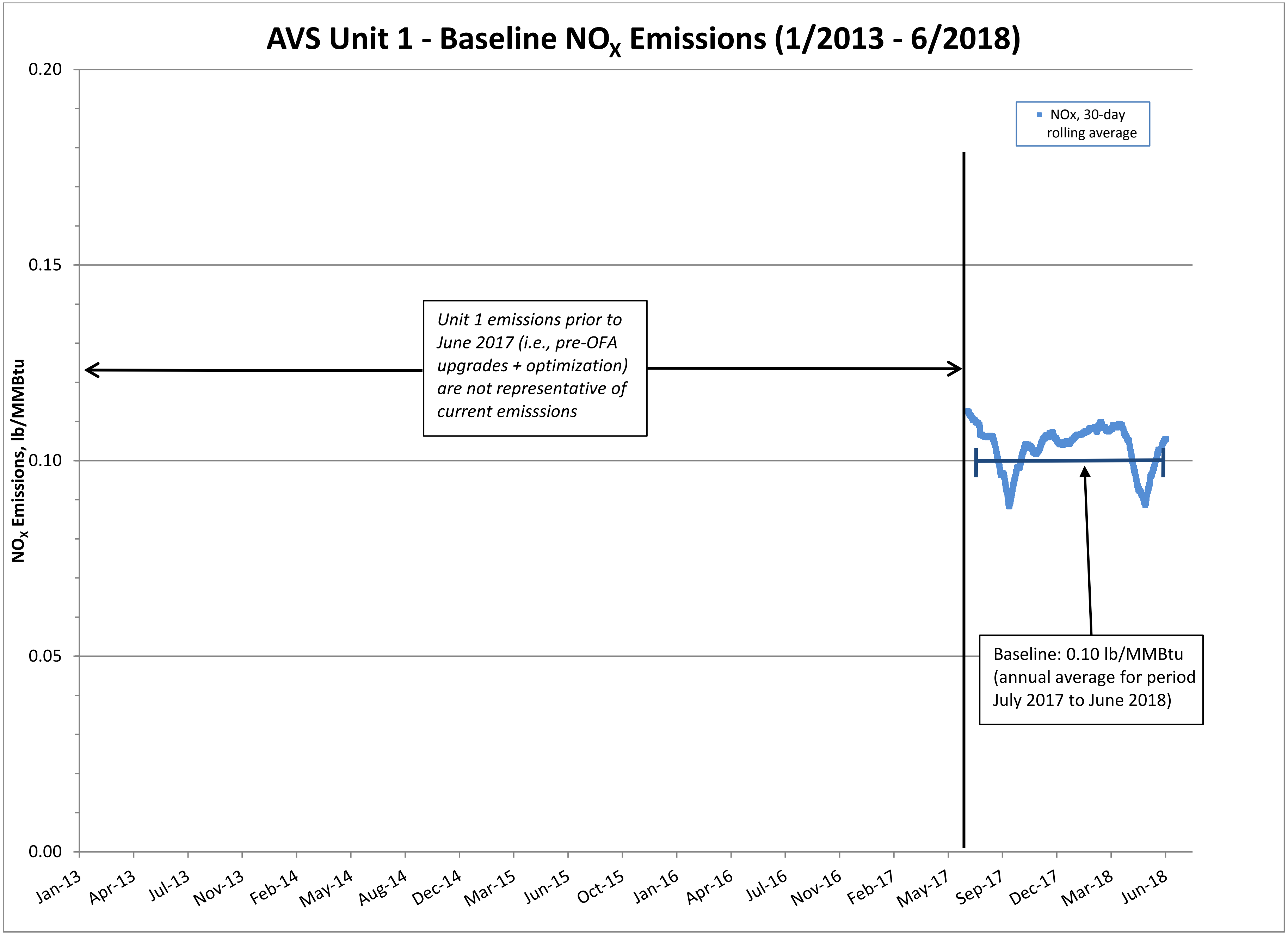

AVS Unit 2 - Baseline SO_2 Emissions (lb/MMBtu) *[1/2013 - 6/2018]*

Baseline: 0.37 lb/MMBtu (24-month annual average for period July 2016 to June 2018)



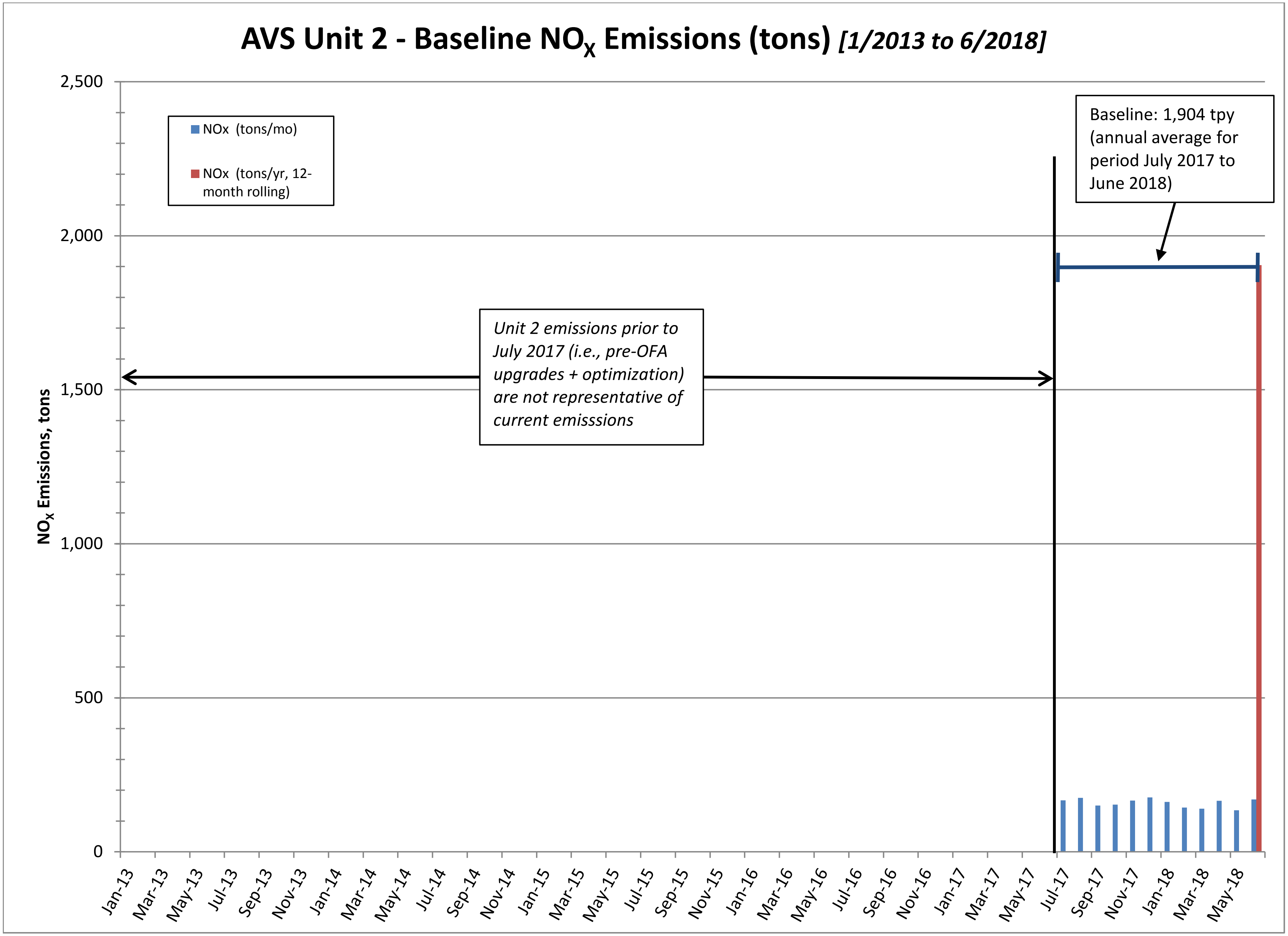
Unit 1 emissions prior to June 2017 (i.e., pre-OFA upgrades + optimization) are not representative of current emisssions

Baseline: 1,802 tpy (annual average for period July 2017 to June 2018)



Unit 1 emissions prior to June 2017 (i.e., pre-OFA upgrades + optimization) are not representative of current emisssions

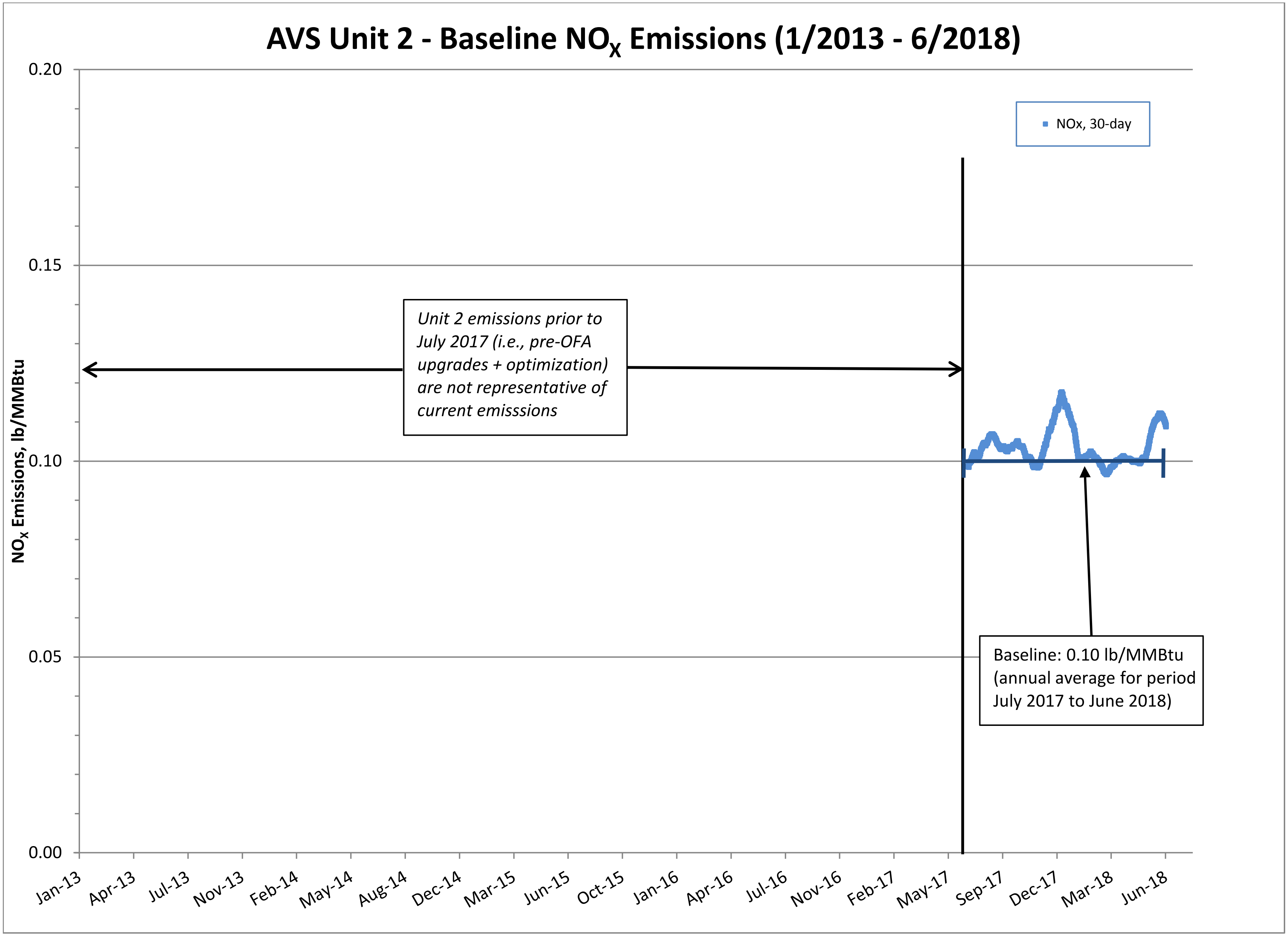
Baseline: 0.10 lb/MMBtu (annual average for period July 2017 to June 2018)



AVS Unit 2 - Baseline NO_X Emissions (tons) *[1/2013 to 6/2018]*

Baseline: 1,904 tpy (annual average for period July 2017 to June 2018)

Unit 2 emissions prior to July 2017 (i.e., pre-OFA upgrades + optimization) are not representative of current emisssions


AVS Unit 2 - Baseline NO$_X$ Emissions (1/2013 - 6/2018)
NO$_X$ Emissions, lb/MMBtu
0.20
0.15
0.10
0.05
0.00
Jan-13
Apr-13
Jul-13
Nov-13
Feb-14
May-14
Aug-14
Dec-14
Mar-15
Jun-15
Oct-15
Jan-16
Apr-16
Jul-16
Nov-16
Feb-17
May-17
Sep-17
Dec-17
Mar-18
Jun-18
NOx, 30-day
Unit 2 emissions prior to July 2017 (i.e., pre-OFA upgrades + optimization) are not representative of current emisssions
Baseline: 0.10 lb/MMBtu (annual average for period July 2017 to June 2018)

APPENDIX C

SO_2 CONTROL COST EFFECTIVENESS ESTIMATES

SO_2 CONTROL COST EFFECTIVENESS ESTIMATES

BASELINE CAPACITY FACTORS/EMISSIONS AND PROJECTED ACTUAL EMISSION RATES

Antelope Valley Station Units 1 & 2
SO$_2$ Control Summary

Table 1. AVS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW gross	470	470	
Annual Heat Input	MMBtu/yr	37,278,202	37,459,113	24-month annual average for periods Sept 2014 to Aug 2016 (Unit 1) and July 2016 to June 2018 (Unit 2).
Annual Capacity Factor	%	86%	87%	Capacity factor based on Design Hourly Heat Input (MBtu/hr) and Annual Baseline Heat Input (MBtu/yr)
Average Baseline Hourly Heat Input	MMBtu/hr	4,459	4,499	Average hourly heat input for periods Sept 2014 to Aug 2016 (Unit 1) and July 2016 to June 2018 (Unit 2). Emission rates in lb/hr based on Average baseline hourly heat input.
Design Hourly Heat Input	MMBtu/hr	4,930	4,930	AVS Boiler Design Data Sheet @ 100% MCR

Table 2. SO$_2$ Control Effectiveness

	Unit 1					Unit 2				
Control Technology	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
Wet FGD	98%	1,305	312	0.07	5,616	98%	1,311	315	0.07	5,705
Dry FGD (CDS + FF)	97%	1,678	401	0.09	5,243	97%	1,686	405	0.09	5,330
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	93%	3,728	892	0.20	3,193	93%	3,746	900	0.20	3,270
FGD Operational Improvements - Station Work Practice	88%	6,524	1,561	0.35	397	88%	6,555	1,575	0.35	461
Baseline (DFGD/FF)	87%	6,921	1,656	0.37		87%	7,016	1,685	0.37	
Uncontrolled SO$_2$		54,082	12,939	2.90			54,345	13,053	2.90	

Table 3. SO$_2$ Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of SO$_2$ Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)	($/ton)
Wet FGD	1,305	5,616	$272,384,000	$22,322,000		$16,945,000	$39,267,000	**$6,992**	$9,826
Dry FGD (CDS + FF)	1,678	5,243	$230,447,000	$18,886,000		$16,718,000	$35,604,000	**$6,790**	$16,420
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	3,728	3,193	$9,698,000	$795,000		$1,144,000	$1,939,000	**$607**	$645
FGD Operational Improvements - Station Work Practice	6,524	397	$0	$0		$135,000	$135,000	**$340**	
Baseline (DFGD/FF)	6,921								

Table 4. SO$_2$ Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of SO$_2$ Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)	($/ton)
Wet FGD	1,311	5,705	$272,384,000	$22,322,000		$16,819,000	$39,141,000	**$6,861**	$9,549
Dry FGD (CDS + FF)	1,686	5,330	$230,447,000	$18,886,000		$16,678,000	$35,564,000	**$6,672**	$16,322
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	3,746	3,270	$9,698,000	$795,000		$1,142,000	$1,937,000	**$592**	$643
FGD Operational Improvements - Station Work Practice	6,555	461	$0	$0		$131,000	$131,000	**$284**	
Baseline (DFGD/FF)	7,016								

AVS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Station Work Practice

SO_2 Control Option Description	**FGD Operational Improvements - Station Work Practice**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO_2 Emissions, lb/MMBtu	0.35	0.35
Capacity Factor used of Cost Estimates (%)	86%	87%

CAPITAL COSTS	**Cost (2018$)**		**Basis**
	Unit 1	**Unit 2**	
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$0	$0	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$0	$0	5% of Equipment/Material Cost
Freight	$0	$0	5% of Equipment/Material Cost
Total PEC	$0	$0	
Direct Installation Costs			
Labor	$0	$0	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$0	$0	2.5% of Labor
Mobilization / Demobilization	$0	$0	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$0	$0	5% of Labor
Total Direct Installation Costs	$0	$0	
Total Direct Costs (PEC + Direct Installation Costs)	**$0**	**$0**	
Indirect Costs			
Contractor's General and Administration Expense	$0	$0	10% of Total Direct Costs
Contractor's Profit	$0	$0	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$0	$0	8% of Total Direct Costs
Construction Management/Field Engineering	$0	$0	4% of Total Direct Costs
S-U / Commissioning	$0	$0	1% of Total Direct Costs
Spare Parts	$0	$0	0.5% of Total Direct Costs
Owner's Cost	$0	$0	2% of Total Direct Costs
Total Indirect Costs	**$0**	**$0**	
Contingency	**$0**	**$0**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$0**	**$0**	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$0**	**$0**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$69,000	$75,000	Based on disposal rate of $6.53 per ton.
Increased Lime Reagent Cost	$61,000	$51,000	Based on lime reagent cost of $97 per ton.
Hydrated Lime Reagent Cost	$0	$0	Based on hydrated lime cost of $189 per ton.
Limestone Reagent Cost	$0	$0	Based on limestone reagent cost of $57 per ton.
Increased Auxiliary Power Cost	$0	$0	Based on auxiliary power cost of $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Increased Water Cost	$5,000	$5,000	Based on water cost of $0.60 per 1,000 gallons.
Increased bag and cage replacement	$0	$0	Based on bag and cage cost of $141 per bag
Total Variable O&M Costs	$135,000	$131,000	
Fixed O&M Costs			
Additional Operators per shift	0	0	Assume no additional operators
Operating Labor	$0	$0	N/A
Supervisor Labor	$0	$0	N/A
Maintenance Materials	$0	$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$0	$0	
Indirect Operating Cost			
Property Taxes	$0	$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$0	$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0	$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$0	$0	
Total Annual Operating Cost	**$135,000**	**$131,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$0	$0	
Annual Operating Cost	$135,000	$131,000	
Total Annual Cost	**$135,000**	**$131,000**	

AVS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO_2 Emissions, lb/MMBtu	0.20	0.20
Capacity Factor used of Cost Estimates (%)	86%	87%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$4,016,000	$4,016,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$201,000	$201,000	5% of Equipment/Material Cost
Freight	$201,000	$201,000	5% of Equipment/Material Cost
Total PEC	$4,418,000	$4,418,000	
Direct Installation Costs			
Labor	$1,607,000	$1,607,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$40,000	$40,000	2.5% of Labor
Mobilization / Demobilization	$24,000	$24,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$80,000	$80,000	5% of Labor
Total Direct Installation Costs	$1,751,000	$1,751,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$6,169,000**	**$6,169,000**	
Indirect Costs			
Contractor's General and Administration Expense	$617,000	$617,000	10% of Total Direct Costs
Contractor's Profit	$308,000	$308,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$494,000	$494,000	8% of Total Direct Costs
Construction Management/Field Engineering	$247,000	$247,000	4% of Total Direct Costs
S-U / Commissioning	$93,000	$93,000	1% of Total Direct Costs
Spare Parts	$31,000	$31,000	0.5% of Total Direct Costs
Owner's Cost	$123,000	$123,000	2% of Total Direct Costs
Total Indirect Costs	**$1,913,000**	**$1,913,000**	
Contingency	**$1,616,000**	**$1,616,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$9,698,000**	**$9,698,000**	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$795,000**	**$795,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$76,000	$76,000	Based on disposal rate of $6.53 per ton.
Increased Lime Reagent Cost	$510,000	$512,000	Based on lime reagent cost of $97 per ton.
Hydrated Lime Reagent Cost	$0	$0	Based on hydrated lime cost of $189 per ton.
Limestone Reagent Cost	$0	$0	Based on limestone reagent cost of $57 per ton.
Increased Auxiliary Power Cost	$72,000	$68,000	Based on auxiliary power cost of $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Increased Water Cost	$5,000	$5,000	Based on water cost of $0.60 per 1,000 gallons.
Increased bag and cage replacement	$0	$0	Based on bag and cage cost of $141 per bag
Total Variable O&M Costs	$663,000	$661,000	
Fixed O&M Costs			
Additional Operators per shift	0	0	Assume no additional operators
Operating Labor	$0	$0	N/A
Supervisor Labor	$0	$0	N/A
Maintenance Materials	$93,000	$93,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$93,000	$93,000	
Indirect Operating Cost			
Property Taxes	$97,000	$97,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$97,000	$97,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$194,000	$194,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$388,000	$388,000	
Total Annual Operating Cost	**$1,144,000**	**$1,142,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$795,000	$795,000	
Annual Operating Cost	$1,144,000	$1,142,000	
Total Annual Cost	**$1,939,000**	**$1,937,000**	

AVS Units 1 and 2
SO_2 Control Cost Evaluation
Dry FGD (CDS + FF)

SO_2 Control Option Description	**Dry FGD (CDS + FF)**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO_2 Emissions, lb/MMBtu	0.09	0.09
Capacity Factor used of Cost Estimates (%)	86%	87%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$66,686,000	$66,686,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$3,334,000	$3,334,000	5% of Equipment/Material Cost
Freight	$3,334,000	$3,334,000	5% of Equipment/Material Cost
Total PEC	$73,354,000	$73,354,000	
Direct Installation Costs			
Labor	$67,192,000	$67,192,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,680,000	$1,680,000	2.5% of Labor
Mobilization / Demobilization	$1,008,000	$1,008,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$3,360,000	$3,360,000	5% of Labor
Total Direct Installation Costs	$73,240,000	$73,240,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$146,594,000**	**$146,594,000**	
Indirect Costs			
Contractor's General and Administration Expense	$14,659,000	$14,659,000	10% of Total Direct Costs
Contractor's Profit	$7,330,000	$7,330,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$11,728,000	$11,728,000	8% of Total Direct Costs
Construction Management/Field Engineering	$5,864,000	$5,864,000	4% of Total Direct Costs
S-U / Commissioning	$2,199,000	$2,199,000	1.5% of Total Direct Costs
Spare Parts	$733,000	$733,000	0.5% of Total Direct Costs
Owner's Cost	$2,932,000	$2,932,000	2% of Total Direct Costs
Total Indirect Costs	**$45,445,000**	**$45,445,000**	
Contingency	**$38,408,000**	**$38,408,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$230,447,000**	**$230,447,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$18,886,000**	**$18,886,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$393,000	$395,000	Based on disposal rate of $6.53 per ton.
Increased Lime Reagent Cost	$3,711,000	$3,728,000	Based on lime reagent cost of $97 per ton.
Hydrated Lime Reagent Cost	$0	$0	Based on hydrated lime cost of $189 per ton.
Limestone Reagent Cost	$0	$0	Based on limestone reagent cost of $57 per ton.
Increased Auxiliary Power Cost	$1,033,000	$974,000	Based on auxiliary power cost of $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Increased Water Cost	$13,000	$13,000	Based on water cost of $0.60 per 1,000 gallons.
Increased bag and cage replacement	$152,000	$152,000	Based on bag and cage cost of $141 per bag
Total Variable O&M Costs	$5,302,000	$5,262,000	
Fixed O&M Costs			
Additional Operators per shift	0	0	Assume no additional operators
Operating Labor	$0	$0	N/A
Supervisor Labor	$0	$0	N/A
Maintenance Materials	$2,199,000	$2,199,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,199,000	$2,199,000	
Indirect Operating Cost			
Property Taxes	$2,304,000	$2,304,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,304,000	$2,304,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$4,609,000	$4,609,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$9,217,000	$9,217,000	
Total Annual Operating Cost	**$16,718,000**	**$16,678,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$18,886,000	$18,886,000	
Annualized Lost Revenue due to Outage	$0	$0	
Annual Operating Cost	$16,718,000	$16,678,000	
Total Annual Cost	**$35,604,000**	**$35,564,000**	

AVS Units 1 and 2
SO_2 Control Cost Evaluation
Wet FGD

SO_2 Control Option Description	**Wet FGD**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO_2 Emissions, lb/MMBtu	0.07	0.07
Capacity Factor used of Cost Estimates (%)	86%	87%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$97,161,000	$97,161,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$4,858,000	$4,858,000	5% of Equipment/Material Cost
Freight	$4,858,000	$4,858,000	5% of Equipment/Material Cost
Total PEC	$106,877,000	$106,877,000	
Direct Installation Costs			
Labor	$60,913,000	$60,913,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,523,000	$1,523,000	2.5% of Labor
Mobilization / Demobilization	$914,000	$914,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$3,046,000	$3,046,000	5% of Labor
Total Direct Installation Costs	$66,396,000	$66,396,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$173,273,000**	**$173,273,000**	
Indirect Costs			
Contractor's General and Administration Expense	$17,327,000	$17,327,000	10% of Total Direct Costs
Contractor's Profit	$8,664,000	$8,664,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$13,862,000	$13,862,000	8% of Total Direct Costs
Construction Management/Field Engineering	$6,931,000	$6,931,000	4% of Total Direct Costs
S-U / Commissioning	$2,599,000	$2,599,000	1.5% of Total Direct Costs
Spare Parts	$866,000	$866,000	0.5% of Total Direct Costs
Owner's Cost	$3,465,000	$3,465,000	2% of Total Direct Costs
Total Indirect Costs	**$53,714,000**	**$53,714,000**	
Contingency	**$45,397,000**	**$45,397,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$272,384,000**	**$272,384,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$22,322,000**	**$22,322,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$121,000	$122,000	Based on disposal rate of $6.53 per ton.
Increased Lime Reagent Cost	-$6,629,000	-$6,660,000	Based on lime reagent cost of $97 per ton.
Hydrated Lime Reagent Cost	$0	$0	Based on hydrated lime cost of $189 per ton.
Limestone Reagent Cost	$5,408,000	$5,433,000	Based on limestone reagent cost of $57 per ton.
Increased Auxiliary Power Cost	$2,116,000	$1,995,000	Based on auxiliary power cost of $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Increased Water Cost	$17,000	$17,000	Based on water cost of $0.60 per 1,000 gallons.
Increased bag and cage replacement	$0	$0	Based on bag and cage cost of $141 per bag
Total Variable O&M Costs	$1,033,000	$907,000	
Fixed O&M Costs			
Additional Operators per Shift	4	4	
Operating Labor	$2,102,000	$2,102,000	Assume $60/hr for each additional operator
Supervisor Labor	$315,000	$315,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$2,599,000	$2,599,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$5,016,000	$5,016,000	
Indirect Operating Cost			
Property Taxes	$2,724,000	$2,724,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,724,000	$2,724,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$5,448,000	$5,448,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$10,896,000	$10,896,000	
Total Annual Operating Cost	**$16,945,000**	**$16,819,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$22,322,000	$22,322,000	
Annual Operating Cost	$16,945,000	$16,819,000	
Total Annual Cost	**$39,267,000**	**$39,141,000**	

SO_2 CONTROL COST EFFECTIVENESS ESTIMATES

100% CAPACITY FACTOR AND PROJECTED FUTURE MAXIMUM EMISSION RATES

Antelope Valley Station Units 1 & 2
SO_2 Control Summary

Table 1. AVS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW gross	470	470	
Annual Heat Input	MMBtu/yr	43,186,800	43,186,800	Based on hourly heat input (per Permit No. T5-F86003) and 100% capacity factor
Annual Capacity Factor	%	100%	100%	
Hourly Heat Input	MMBtu/hr	4,930	4,930	AVS Boiler Design Data Sheet @ 100% MCR

Table 2. SO_2 Control Effectiveness

	Unit 1					Unit 2				
Control Technology	**Control Efficiency (%)**	**Expected Emissions (ton/year)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/MMBtu)**	**Expected Emissions Reduction (ton/year)**	**Control Efficiency (%)**	**Expected Emissions (ton/year)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/MMBtu)**	**Expected Emissions Reduction (ton/year)**
Wet FGD	98%	1,463	334	0.07	6,555	98%	1,463	334	0.07	6,625
Dry FGD (CDS + FF)	97%	2,195	501	0.10	5,823	97%	2,195	501	0.10	5,894
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	93%	5,121	1,169	0.24	2,896	93%	5,121	1,169	0.24	2,967
FGD Operational Improvements - Station Work Practice	90%	7,316	1,670	0.34	702	90%	7,316	1,670	0.34	772
Baseline (DFGD/FF)	89%	**8,018**	1,831	0.37		89%	**8,089**	1,847	0.37	
Uncontrolled SO_2		73,164	16,704	3.39			73,164	16,704	3.39	

Table 3. SO_2 Control Cost Effectiveness - Unit 1

Control Technology	Emissions (tpy)	Tons of SO_2 Removed (tpy)	Total Capital Requirement ($)	Annualized Capital Cost ($/year)	Annualized Outage Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Wet FGD	1,463	6,555	$272,384,000	$22,322,000		$18,361,000	$40,683,000	**$6,207**	$2,466
Dry FGD (CDS + FF)	2,195	5,823	$230,447,000	$18,886,000		$19,993,000	$38,879,000	**$6,677**	$12,010
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	5,121	2,896	$9,698,000	$795,000		$2,937,000	$3,732,000	**$1,288**	$1,501
FGD Operational Improvements - Station Work Practice	7,316	702	$0	$0		$437,000	$437,000	**$623**	
Baseline (DFGD/FF)	8,018								

Table 4. SO_2 Control Cost Effectiveness - Unit 2

Control Technology	Emissions (tpy)	Tons of SO_2 Removed (tpy)	Total Capital Requirement ($)	Annualized Capital Cost ($/year)	Annualized Outage Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Wet FGD	1,463	6,625	$272,384,000	$22,322,000		$18,210,000	$40,532,000	**$6,118**	$2,360
Dry FGD (CDS + FF)	2,195	5,894	$230,447,000	$18,886,000		$19,919,000	$38,805,000	**$6,584**	$11,986
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	5,121	2,967	$9,698,000	$795,000		$2,932,000	$3,727,000	**$1,256**	$1,513
FGD Operational Improvements - Station Work Practice	7,316	772	$0	$0		$406,000	$406,000	**$526**	
Baseline (DFGD/FF)	8,089								

AVS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Station Work Practice

SO_2 Control Option Description	**FGD Operational Improvements - Station Work Practice**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO_2 Emissions, lb/MMBtu	0.34	0.34
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$0	$0	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$0	$0	5% of Equipment/Material Cost
Freight	$0	$0	5% of Equipment/Material Cost
Total PEC	$0	$0	
Direct Installation Costs			
Labor	$0	$0	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$0	$0	2.5% of Labor
Mobilization / Demobilization	$0	$0	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$0	$0	5% of Labor
Total Direct Installation Costs	$0	$0	
Total Direct Costs (PEC + Direct Installation Costs)	**$0**	**$0**	
Indirect Costs			
Contractor's General and Administration Expense	$0	$0	10% of Total Direct Costs
Contractor's Profit	$0	$0	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$0	$0	8% of Total Direct Costs
Construction Management/Field Engineering	$0	$0	4% of Total Direct Costs
S-U / Commissioning	$0	$0	1% of Total Direct Costs
Spare Parts	$0	$0	0.5% of Total Direct Costs
Owner's Cost	$0	$0	2% of Total Direct Costs
Total Indirect Costs	**$0**	**$0**	
Contingency	**$0**	**$0**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$0**	**$0**	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$0**	**$0**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$280,000	$280,000	Based on disposal rate of $6.53 per ton.
Increased Lime Reagent Cost	$144,000	$113,000	Based on lime reagent cost of $97 per ton.
Hydrated Lime Reagent Cost	$0	$0	Based on hydrated lime cost of $189 per ton.
Limestone Reagent Cost	$0	$0	Based on limestone reagent cost of $57 per ton.
Increased Auxiliary Power Cost	$0	$0	Based on auxiliary power cost of $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Increased Water Cost	$13,000	$13,000	Based on water cost of $0.60 per 1,000 gallons.
Increased bag and cage replacement	$0	$0	Based on bag and cage cost of $141 per bag
Total Variable O&M Costs	$437,000	$406,000	
Fixed O&M Costs			
Additional Operators per shift	0	0	Assume no additional operators
Operating Labor	$0	$0	N/A
Supervisor Labor	$0	$0	N/A
Maintenance Materials	$0	$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$0	$0	
Indirect Operating Cost			
Property Taxes	$0	$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$0	$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0	$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$0	$0	
Total Annual Operating Cost	**$437,000**	**$406,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$0	$0	
Annual Operating Cost	$437,000	$406,000	
Total Annual Cost	**$437,000**	**$406,000**	

AVS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO_2 Emissions, lb/MMBtu	0.24	0.24
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$4,016,000	$4,016,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$201,000	$201,000	5% of Equipment/Material Cost
Freight	$201,000	$201,000	5% of Equipment/Material Cost
Total PEC	$4,418,000	$4,418,000	
Direct Installation Costs			
Labor	$1,607,000	$1,607,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$40,000	$40,000	2.5% of Labor
Mobilization / Demobilization	$24,000	$24,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$80,000	$80,000	5% of Labor
Total Direct Installation Costs	$1,751,000	$1,751,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$6,169,000**	**$6,169,000**	
Indirect Costs			
Contractor's General and Administration Expense	$617,000	$617,000	10% of Total Direct Costs
Contractor's Profit	$308,000	$308,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$494,000	$494,000	8% of Total Direct Costs
Construction Management/Field Engineering	$247,000	$247,000	4% of Total Direct Costs
S-U / Commissioning	$93,000	$93,000	1% of Total Direct Costs
Spare Parts	$31,000	$31,000	0.5% of Total Direct Costs
Owner's Cost	$123,000	$123,000	2% of Total Direct Costs
Total Indirect Costs	**$1,913,000**	**$1,913,000**	
Contingency	**$1,616,000**	**$1,616,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$9,698,000**	**$9,698,000**	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$795,000**	**$795,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$382,000	$382,000	Based on disposal rate of $6.53 per ton.
Increased Lime Reagent Cost	$1,978,000	$1,978,000	Based on lime reagent cost of $97 per ton.
Hydrated Lime Reagent Cost	$0	$0	Based on hydrated lime cost of $189 per ton.
Limestone Reagent Cost	$0	$0	Based on limestone reagent cost of $57 per ton.
Increased Auxiliary Power Cost	$83,000	$78,000	Based on auxiliary power cost of $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Increased Water Cost	$13,000	$13,000	Based on water cost of $0.60 per 1,000 gallons.
Increased bag and cage replacement	$0	$0	Based on bag and cage cost of $141 per bag
Total Variable O&M Costs	$2,456,000	$2,451,000	
Fixed O&M Costs			
Additional Operators per shift	0	0	Assume no additional operators
Operating Labor	$0	$0	N/A
Supervisor Labor	$0	$0	N/A
Maintenance Materials	$93,000	$93,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$93,000	$93,000	
Indirect Operating Cost			
Property Taxes	$97,000	$97,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$97,000	$97,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$194,000	$194,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$388,000	$388,000	
Total Annual Operating Cost	**$2,937,000**	**$2,932,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$795,000	$795,000	
Annual Operating Cost	$2,937,000	$2,932,000	
Total Annual Cost	**$3,732,000**	**$3,727,000**	

AVS Units 1 and 2
SO_2 Control Cost Evaluation
Dry FGD (CDS + FF)

SO_2 Control Option Description	**Dry FGD (CDS + FF)**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO_2 Emissions, lb/MMBtu	0.10	0.10
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS	**Cost (2018$)**		**Basis**
	Unit 1	**Unit 2**	
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$66,686,000	$66,686,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$3,334,000	$3,334,000	5% of Equipment/Material Cost
Freight	$3,334,000	$3,334,000	5% of Equipment/Material Cost
Total PEC	$73,354,000	$73,354,000	
Direct Installation Costs			
Labor	$67,192,000	$67,192,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,680,000	$1,680,000	2.5% of Labor
Mobilization / Demobilization	$1,008,000	$1,008,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$3,360,000	$3,360,000	5% of Labor
Total Direct Installation Costs	$73,240,000	$73,240,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$146,594,000**	**$146,594,000**	
Indirect Costs			
Contractor's General and Administration Expense	$14,659,000	$14,659,000	10% of Total Direct Costs
Contractor's Profit	$7,330,000	$7,330,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$11,728,000	$11,728,000	8% of Total Direct Costs
Construction Management/Field Engineering	$5,864,000	$5,864,000	4% of Total Direct Costs
S-U / Commissioning	$2,199,000	$2,199,000	1.5% of Total Direct Costs
Spare Parts	$733,000	$733,000	0.5% of Total Direct Costs
Owner's Cost	$2,932,000	$2,932,000	2% of Total Direct Costs
Total Indirect Costs	**$45,445,000**	**$45,445,000**	
Contingency	**$38,408,000**	**$38,408,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$230,447,000**	**$230,447,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$18,886,000**	**$18,886,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$917,000	$917,000	Based on disposal rate of $6.53 per ton.
Increased Lime Reagent Cost	$6,282,000	$6,282,000	Based on lime reagent cost of $97 per ton.
Hydrated Lime Reagent Cost	$0	$0	Based on hydrated lime cost of $189 per ton.
Limestone Reagent Cost	$0	$0	Based on limestone reagent cost of $57 per ton.
Increased Auxiliary Power Cost	$1,197,000	$1,123,000	Based on auxiliary power cost of $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Increased Water Cost	$29,000	$29,000	Based on water cost of $0.60 per 1,000 gallons.
Increased bag and cage replacement	$152,000	$152,000	Based on bag and cage cost of $141 per bag
Total Variable O&M Costs	$8,577,000	$8,503,000	
Fixed O&M Costs			
Additional Operators per shift	0	0	Assume no additional operators
Operating Labor	$0	$0	N/A
Supervisor Labor	$0	$0	N/A
Maintenance Materials	$2,199,000	$2,199,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,199,000	$2,199,000	
Indirect Operating Cost			
Property Taxes	$2,304,000	$2,304,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,304,000	$2,304,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$4,609,000	$4,609,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$9,217,000	$9,217,000	
Total Annual Operating Cost	**$19,993,000**	**$19,919,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$18,886,000	$18,886,000	
Annualized Lost Revenue due to Outage	$0	$0	
Annual Operating Cost	$19,993,000	$19,919,000	
Total Annual Cost	**$38,879,000**	**$38,805,000**	

AVS Units 1 and 2
SO_2 Control Cost Evaluation
Wet FGD

SO_2 Control Option Description	**Wet FGD**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.37	0.37
Post Upgrade SO_2 Emissions, lb/MMBtu	0.07	0.07
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$97,161,000	$97,161,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$4,858,000	$4,858,000	5% of Equipment/Material Cost
Freight	$4,858,000	$4,858,000	5% of Equipment/Material Cost
Total PEC	$106,877,000	$106,877,000	
Direct Installation Costs			
Labor	$60,913,000	$60,913,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,523,000	$1,523,000	2.5% of Labor
Mobilization / Demobilization	$914,000	$914,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$3,046,000	$3,046,000	5% of Labor
Total Direct Installation Costs	$66,396,000	$66,396,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$173,273,000**	**$173,273,000**	
Indirect Costs			
Contractor's General and Administration Expense	$17,327,000	$17,327,000	10% of Total Direct Costs
Contractor's Profit	$8,664,000	$8,664,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$13,862,000	$13,862,000	8% of Total Direct Costs
Construction Management/Field Engineering	$6,931,000	$6,931,000	4% of Total Direct Costs
S-U / Commissioning	$2,599,000	$2,599,000	1.5% of Total Direct Costs
Spare Parts	$866,000	$866,000	0.5% of Total Direct Costs
Owner's Cost	$3,465,000	$3,465,000	2% of Total Direct Costs
Total Indirect Costs	**$53,714,000**	**$53,714,000**	
Contingency	**$45,397,000**	**$45,397,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$272,384,000**	**$272,384,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = i(1+ i)^n / (1 + i)^n - 1	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$22,322,000**	**$22,322,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$280,000	$280,000	Based on disposal rate of $6.53 per ton.
Increased Lime Reagent Cost	-$7,681,000	-$7,681,000	Based on lime reagent cost of $97 per ton.
Hydrated Lime Reagent Cost	$0	$0	Based on hydrated lime cost of $189 per ton.
Limestone Reagent Cost	$7,365,000	$7,365,000	Based on limestone reagent cost of $57 per ton.
Increased Auxiliary Power Cost	$2,452,000	$2,301,000	Based on auxiliary power cost of $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Increased Water Cost	$33,000	$33,000	Based on water cost of $0.60 per 1,000 gallons.
Increased bag and cage replacement	$0	$0	Based on bag and cage cost of $141 per bag
Total Variable O&M Costs	$2,449,000	$2,298,000	
Fixed O&M Costs			
Additional Operators per Shift	4	4	
Operating Labor	$2,102,000	$2,102,000	Assume $60/hr for each additional operator
Supervisor Labor	$315,000	$315,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$2,599,000	$2,599,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$5,016,000	$5,016,000	
Indirect Operating Cost			
Property Taxes	$2,724,000	$2,724,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,724,000	$2,724,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$5,448,000	$5,448,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$10,896,000	$10,896,000	
Total Annual Operating Cost	**$18,361,000**	**$18,210,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$22,322,000	$22,322,000	
Annual Operating Cost	$18,361,000	$18,210,000	
Total Annual Cost	**$40,683,000**	**$40,532,000**	

APPENDIX D

NO$_X$ CONTROL COST EFFECTIVENESS ESTIMATES

NO_X CONTROL COST EFFECTIVENESS ESTIMATES

BASELINE CAPACITY FACTORS/EMISSIONS AND PROJECTED ACTUAL EMISSION RATES

Antelope Valley Station Units 1 & 2
NO$_X$ Control Summary

Table 1. AVS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW gross	470	470	
Annual Heat Input	MMBtu/yr	34,816,500	36,633,799	Annual heat inputs and capacity factors for period July 2017 to June 2018.
Annual Capacity Factor	%	81%	85%	Capacity factor based on Design Hourly Heat Input (MBtu/hr) and Annual Baseline Heat Input (MBtu/yr)
Average Baseline Hourly Heat Input	MMBtu/hr	4,126	4,480	Average hourly heat input for periods July 2017 to June 2018. Emission rates in lb/hr based on Average baseline hourly heat input.
Hourly Heat Input	MMBtu/hr	4,930	4,930	AVS Boiler Design Data Sheet @ 100% MCR

Table 2. NO$_X$ Control Effectiveness

	Unit 1					Unit 2				
Control Technology	**Control Efficiency**	**Expected Emissions**	**Emission Rate**	**Emission Rate**	**Expected Emissions Reduction**	**Control Efficiency**	**Expected Emissions**	**Emission Rate**	**Emission Rate**	**Expected Emissions Reduction**
	(%)	**(ton/year)**	**(lb/hr)**	**(lb/MMBtu)**	**(ton/year)**	**(%)**	**(ton/year)**	**(lb/hr)**	**(lb/MMBtu)**	**(ton/year)**
SCR - Tail-End Configuration	52%	870	206	0.05	931	52%	916	224	0.05	988
SNCR	9%	1,636	388	0.09	165	10%	1,722	421	0.09	182
Baseline (OFA/LNCFS)		**1,802**	427	0.10			**1,904**	466	0.10	

Table 3. NO$_X$ Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of NOx Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	**(tpy)**	**($)**	**($/year)**	**($/year)**	**($/year)**	**($)**	**($/ton)**	**($/ton)**
SCR - Tail-End Configuration	870	931	$221,396,000	$18,144,000		$18,201,000	$36,345,000	**$39,035**	$43,161
SNCR	1,636	165	$16,356,000	$1,340,000		$1,945,000	$3,285,000	**$19,893**	
Baseline (OFA/LNCFS)	1,802								

Table 4. NO$_X$ Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of NOx Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	**(tpy)**	**($)**	**($/year)**	**($/year)**	**($/year)**	**($)**	**($/ton)**	**($/ton)**
SCR - Tail-End Configuration	916	988	$221,396,000	$18,144,000		$18,207,000	$36,351,000	**$36,792**	$40,997
SNCR	1,722	182	$16,356,000	$1,340,000		$1,970,000	$3,310,000	**$18,179**	
Baseline (OFA/LNCFS)	1,904								

AVS Units 1 and 2
NO$_X$ Control Cost Evaluation
SNCR

NO$_X$ Control Option Description	SNCR	
	Unit 1	**Unit 2**
Baseline NO$_X$ Emissions, lb/MMBtu	0.10	0.10
Post Upgrade NO$_X$ Emissions, lb/MMBtu	0.09	0.09
Capacity Factor used of Cost Estimates (%)	81%	85%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$7,411,000	$7,411,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$371,000	$371,000	5% of Equipment/Material Cost
Freight	$371,000	$371,000	5% of Equipment/Material Cost
Total PEC	$8,153,000	$8,153,000	
Direct Installation Costs			
Labor	$2,066,000	$2,066,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$52,000	$52,000	2.5% of Labor
Mobilization / Demobilization	$31,000	$31,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$103,000	$103,000	5% of Labor
Total Direct Installation Costs	$2,252,000	$2,252,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$10,405,000**	**$10,405,000**	
Indirect Costs			
Contractor's General and Administration Expense	$1,041,000	$1,041,000	10% of Total Direct Costs
Contractor's Profit	$520,000	$520,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$832,000	$832,000	8% of Total Direct Costs
Construction Management/Field Engineering	$416,000	$416,000	4% of Total Direct Costs
S-U / Commissioning	$156,000	$156,000	1.5% of Total Direct Costs
Spare Parts	$52,000	$52,000	0.5% of Total Direct Costs
Owner's Cost	$208,000	$208,000	2% of Total Direct Costs
Total Indirect Costs	**$3,225,000**	**$3,225,000**	
Contingency	**$2,726,000**	**$2,726,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$16,356,000**	**$16,356,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$1,340,000**	**$1,340,000**	
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost	$461,000	$485,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$0	$0	Based on ammonia reagent cost of $700 per ton.
Water Cost	$38,000	$39,000	Based on water cost of $0.60 per 1,000 gallons.
Steam Cost	$12,000	$12,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$0	$0	Based on hydrated lime cost of $189 per ton.
Catalyst Replacement Cost	$0	$0	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost	$19,000	$19,000	Based on auxiliary power cost of $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Total Variable O&M Costs	$530,000	$555,000	
Fixed O&M Costs			
Additional Operators per shift	1	1	
Operating Labor	$525,600	$525,600	Assume $60/hr for each additional operator
Supervisor Labor	$79,000	$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$156,100	$156,100	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$760,700	$760,700	
Indirect Operating Cost			
Property Taxes	$163,600	$163,600	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$163,600	$163,600	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$327,100	$327,100	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$654,300	$654,300	
Total Annual Operating Cost	**$1,945,000**	**$1,970,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$1,340,000	$1,340,000	
Annual Operating Cost	$1,945,000	$1,970,000	
Total Annual Cost	**$3,285,000**	**$3,310,000**	

AVS Units 1 and 2
NO_X Control Cost Evaluation
SCR - Tail-End Configuration

NO_X Control Option Description	**SCR - Tail-End Configuration**	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu	0.10	0.10
Post Upgrade NO_X Emissions, lb/MMBtu	0.05	0.05
Capacity Factor used of Cost Estimates (%)	81%	85%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$74,544,000	$74,544,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$3,727,000	$3,727,000	5% of Equipment/Material Cost
Freight	$3,727,000	$3,727,000	5% of Equipment/Material Cost
Total PEC	$81,998,000	$81,998,000	
Direct Installation Costs			
Labor	$53,980,000	$53,980,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,350,000	$1,350,000	2.5% of Labor
Mobilization / Demobilization	$810,000	$810,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$2,699,000	$2,699,000	5% of Labor
Total Direct Installation Costs	$58,839,000	$58,839,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$140,837,000**	**$140,837,000**	
Indirect Costs			
Contractor's General and Administration Expense	$14,084,000	$14,084,000	10% of Total Direct Costs
Contractor's Profit	$7,042,000	$7,042,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$11,267,000	$11,267,000	8% of Total Direct Costs
Construction Management/Field Engineering	$5,633,000	$5,633,000	4% of Total Direct Costs
S-U / Commissioning	$2,113,000	$2,113,000	1.5% of Total Direct Costs
Spare Parts	$704,000	$704,000	0.5% of Total Direct Costs
Owner's Cost	$2,817,000	$2,817,000	2% of Total Direct Costs
Total Indirect Costs	**$43,660,000**	**$43,660,000**	
Contingency	**$36,899,000**	**$36,899,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$221,396,000**	**$221,396,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$18,144,000**	**$18,144,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost	$0	$0	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$262,000	$276,000	Based on ammonia reagent cost of $700 per ton.
RO Water Cost	$0	$0	Based on water cost of $0.60 per 1,000 gallons.
Steam Cost	$0	$0	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$294,000	$309,000	Based on hydrated lime cost of $189 per ton.
Catalyst Replacement and Disposal Cost	$4,257,000	$4,257,000	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost	$1,814,000	$1,791,000	Based on auxiliary power cost of $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Total Variable O&M Costs	$6,627,000	$6,633,000	
Fixed O&M Costs			
Additional Operators per Shift	1	1	
Operating Labor	$526,000	$526,000	Assume $60/hr for each additional operator
Supervisor Labor	$79,000	$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$2,113,000	$2,113,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,718,000	$2,718,000	
Indirect Operating Cost			
Property Taxes	$2,214,000	$2,214,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,214,000	$2,214,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$4,428,000	$4,428,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$8,856,000	$8,856,000	
Total Annual Operating Cost	**$18,201,000**	**$18,207,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$18,144,000	$18,144,000	
Annual Operating Cost	$18,201,000	$18,207,000	
Total Annual Cost	**$36,345,000**	**$36,351,000**	

NO_X CONTROL COST EFFECTIVENESS ESTIMATES

100% CAPACITY FACTOR AND PROJECTED FUTURE MAXIMUM EMISSION RATES

Antelope Valley Station Units 1 & 2
NO$_X$ Control Summary

Table 1. AVS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW gross	450	450	
Annual Heat Input	MMBtu/yr	43,186,800	43,186,800	Based on hourly heat input (per Permit No. T5-F86003) and 100% capacity factor
Annual Capacity Factor	%	100%	100%	
Hourly Heat Input	MMBtu/hr	4,930	4,930	AVS Boiler Design Data Sheet @ 100% MCR

Table 2. NO$_X$ Control Effectiveness

	Unit 1					Unit 2				
Control Technology	**Control Efficiency**	**Expected Emissions**	**Emission Rate**	**Emission Rate**	**Expected Emissions Reduction**	**Control Efficiency**	**Expected Emissions**	**Emission Rate**	**Emission Rate**	**Expected Emissions Reduction**
	(%)	**(ton/year)**	**(lb/hr)**	**(lb/MMBtu)**	**(ton/year)**	**(%)**	**(ton/year)**	**(lb/hr)**	**(lb/MMBtu)**	**(ton/year)**
SCR - Tail-End Configuration	52%	1,080	247	0.05	1,155	52%	1,080	247	0.05	1,165
SNCR	9%	2,030	463	0.09	205	10%	2,030	463	0.09	215
Baseline (OFA/LNCFS)		**2,235**	510	0.10			**2,244**	512	0.10	

Table 3. NO$_X$ Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of NOx Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	**(tpy)**	**($)**	**($/year)**	**($/year)**	**($/year)**	**($)**	**($/ton)**	**($/ton)**
SCR - Tail-End Configuration	1,080	1,155	$221,396,000	$18,144,000		$18,788,000	$36,932,000	**$31,977**	$35,278
SNCR	2,030	205	$16,356,000	$1,340,000		$2,074,000	$3,414,000	**$16,667**	
Baseline (OFA/LNCFS)	2,235								

Table 4. NO$_X$ Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of NOx Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	**(tpy)**	**($)**	**($/year)**	**($/year)**	**($/year)**	**($)**	**($/ton)**	**($/ton)**
SCR - Tail-End Configuration	1,080	1,165	$221,396,000	$18,144,000		$18,649,000	$36,793,000	**$31,589**	$35,131
SNCR	2,030	215	$16,356,000	$1,340,000		$2,075,000	$3,415,000	**$15,910**	
Baseline (OFA/LNCFS)	2,244								

AVS Units 1 and 2
NO_X Control Cost Evaluation
SNCR

NO_X Control Option Description	SNCR	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu	0.10	0.10
Post Upgrade NO_X Emissions, lb/MMBtu	0.09	0.09
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$7,411,000	$7,411,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$371,000	$371,000	5% of Equipment/Material Cost
Freight	$371,000	$371,000	5% of Equipment/Material Cost
Total PEC	$8,153,000	$8,153,000	
Direct Installation Costs			
Labor	$2,066,000	$2,066,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$52,000	$52,000	2.5% of Labor
Mobilization / Demobilization	$31,000	$31,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$103,000	$103,000	5% of Labor
Total Direct Installation Costs	$2,252,000	$2,252,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$10,405,000**	**$10,405,000**	
Indirect Costs			
Contractor's General and Administration Expense	$1,041,000	$1,041,000	10% of Total Direct Costs
Contractor's Profit	$520,000	$520,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$832,000	$832,000	8% of Total Direct Costs
Construction Management/Field Engineering	$416,000	$416,000	4% of Total Direct Costs
S-U / Commissioning	$156,000	$156,000	1.5% of Total Direct Costs
Spare Parts	$52,000	$52,000	0.5% of Total Direct Costs
Owner's Cost	$208,000	$208,000	2% of Total Direct Costs
Total Indirect Costs	**$3,225,000**	**$3,225,000**	
Contingency	**$2,726,000**	**$2,726,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$16,356,000**	**$16,356,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$1,340,000**	**$1,340,000**	
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost	$572,000	$572,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$0	$0	Based on ammonia reagent cost of $700 per ton.
Water Cost	$47,000	$47,000	Based on water cost of $0.60 per 1,000 gallons.
Steam Cost	$16,000	$18,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$0	$0	Based on hydrated lime cost of $189 per ton.
Catalyst Replacement Cost	$0	$0	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost	$24,000	$23,000	Based on auxiliary power cost of $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Total Variable O&M Costs	$659,000	$660,000	
Fixed O&M Costs			
Additional Operators per shift	1	1	
Operating Labor	$525,600	$525,600	Assume $60/hr for each additional operator
Supervisor Labor	$79,000	$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$156,100	$156,100	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$760,700	$760,700	
Indirect Operating Cost			
Property Taxes	$163,600	$163,600	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$163,600	$163,600	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$327,100	$327,100	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$654,300	$654,300	
Total Annual Operating Cost	**$2,074,000**	**$2,075,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$1,340,000	$1,340,000	
Annual Operating Cost	$2,074,000	$2,075,000	
Total Annual Cost	**$3,414,000**	**$3,415,000**	

AVS Units 1 and 2
NO_X Control Cost Evaluation
SCR - Tail-End Configuration

NO_X Control Option Description	SCR - Tail-End Configuration	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu	0.10	0.10
Post Upgrade NO_X Emissions, lb/MMBtu	0.05	0.05
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$74,544,000	$74,544,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$3,727,000	$3,727,000	5% of Equipment/Material Cost
Freight	$3,727,000	$3,727,000	5% of Equipment/Material Cost
Total PEC	$81,998,000	$81,998,000	
Direct Installation Costs			
Labor	$53,980,000	$53,980,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,350,000	$1,350,000	2.5% of Labor
Mobilization / Demobilization	$810,000	$810,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$2,699,000	$2,699,000	5% of Labor
Total Direct Installation Costs	$58,839,000	$58,839,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$140,837,000**	**$140,837,000**	
Indirect Costs			
Contractor's General and Administration Expense	$14,084,000	$14,084,000	10% of Total Direct Costs
Contractor's Profit	$7,042,000	$7,042,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$11,267,000	$11,267,000	8% of Total Direct Costs
Construction Management/Field Engineering	$5,633,000	$5,633,000	4% of Total Direct Costs
S-U / Commissioning	$2,113,000	$2,113,000	1.5% of Total Direct Costs
Spare Parts	$704,000	$704,000	0.5% of Total Direct Costs
Owner's Cost	$2,817,000	$2,817,000	2% of Total Direct Costs
Total Indirect Costs	**$43,660,000**	**$43,660,000**	
Contingency	**$36,899,000**	**$36,899,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$221,396,000**	**$221,396,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$18,144,000**	**$18,144,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost	$0	$0	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$325,000	$325,000	Based on ammonia reagent cost of $700 per ton.
RO Water Cost	$0	$0	Based on water cost of $0.60 per 1,000 gallons.
Steam Cost	$0	$0	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$381,000	$381,000	Based on hydrated lime cost of $189 per ton.
Catalyst Replacement and Disposal Cost	$4,257,000	$4,257,000	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost	$2,251,000	$2,112,000	Based on auxiliary power cost of $38.07 per MWh (Unit 1) and $35.72 (Unit 2).
Total Variable O&M Costs	$7,214,000	$7,075,000	
Fixed O&M Costs			
Additional Operators per Shift	1	1	
Operating Labor	$526,000	$526,000	Assume $60/hr for each additional operator
Supervisor Labor	$79,000	$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$2,113,000	$2,113,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,718,000	$2,718,000	
Indirect Operating Cost			
Property Taxes	$2,214,000	$2,214,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,214,000	$2,214,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$4,428,000	$4,428,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$8,856,000	$8,856,000	
Total Annual Operating Cost	**$18,788,000**	**$18,649,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$18,144,000	$18,144,000	
Annual Operating Cost	$18,788,000	$18,649,000	
Total Annual Cost	**$36,932,000**	**$36,793,000**	

B.2.c – Communications

June 20, 2019 : 9:16 AM

To: *Erin Dukart*

From: *Bachman, Tom A.*
CC: *Stroh, David E.; Seligman, Angela N.*
Subject: *AVS Four Factors Analysis*
Attachments: *Scubber Efficiency.pdf; image002.png;*

Erin:

I have reviewed the four factors analysis and have only a few comments:

1. On p.2-2 and Table 4-6, the design is based on all of the sulfur in the coal exiting the boiler. AP-42 indicates 25% of the sulfur in lignite is retained in the ash. This indicates the design emission rate is higher than it should be. This may effect the overall design of any new equipment (including the cost) and annual operating costs. The design sulfur emission rate should be reevaluated and appropriate revision to the analysis made.
2. On p. 4-6, it is indicated the AVS has a Plantwide Applicability Limit (PAL). AVS does not have a PAL as described in the PSD rules. The cap on three-hour SO2 emissions is different from a PAL (annual limit). The section should be revised.
3. In Tables 4-12 and 4-13, we believe the baseline reduction of SO2 (87%) is high. Using the AP-42 emission factor of 30(S), we believe it is around 82 - 83% (see attachment).

If you have any questions, please feel free to contact me.

Tom Bachman
Senior Env. Engr.
Division of Air Quality

701.328.5188 • 701.328.5185 (fax) • tbachman@nd.gov• deq.nd.gov •
918 East Divide Ave., Bismarck, ND 58501-1947

ANTELOPE VALLEY STATION
SO_2 SCRUBBER
REMOVAL EFFICIENCY

Year	**PLANT**	**COAL BURNED (TONS)**	**AVG. SULFUR CONTENT (%)**	**BOILER EXIT SO_2 EMISSIONS (TONS)**	**ACTUAL SO_2 EMISSIONS (TONS)**	**SCRUBBER REMOVAL (%)**	**COAL-TO-STACK REMOVAL (%)**
2000	AVS 1	2859172	0.71	30,450	6,640	78.2	83.6
2000	AVS 2	2,992,950	0.69	30,977	6,407	79.3	84.5
2001	AVS1	2,997,691	0.70	31,476	6,843	78.3	83.7
2001	AVS 2	2,283,892	0.70	23,981	5,226	78.2	83.7
2002	AVS 1	2,514,487	0.67	25,271	7,283	71.2	78.4
2002	AVS 2	2,833,115	0.67	28,473	6,580	76.9	82.7
2003	AVS 1	2,896,392	0.59	25,633	7,374	71.2	78.4
2003	AVS 2	3,009,046	0.59	26,630	7,654	71.3	78.4
2004	AVS 1	2,946,565	0.63	27,845	8,858	68.2	76.1
2004	AVS 2	2,502,053	0.64	24,020	5,276	78.0	83.5
2005	AVS 1	2,455,107	0.65	23,937	5,911	75.3	81.5
2005	AVS 2	2,932,021	0.63	27,708	7,163	74.1	80.6
2006	AVS 1	3,082,307	0.67	30,977	7,092	77.1	82.8

ANTELOPE VALLEY STATION
SO_2 SCRUBBER
REMOVAL EFFICIENCY

2006	AVS 2	2,899,414	0.65	28,269	7,433	73.7	80.3
2007	AVS 1	2,976,707	0.76	33,934	7,054	79.2	84.4
2007	AVS 2	2,519,337	0.74	27,965	6,618	76.3	82.3
2008	AVS 1	2,549,265	0.78	29,826	6,504	78.2	83.6
2008	AVS 2	2,791,136	0.77	32,238	7,790	75.8	81.9
2009	AVS 1	2,908,708	0.75	32,723	7,039	78.5	83.9
2009	AVS 2	2,876,852	0.8	34,522	7,359	78.7	84.0
2010	AVS 1	3,017,251	0.93	42,091	8,479	79.9	84.9
2010	AVS 2	2,435,302	0.93	33,972	6,413	81.1	85.8
2011	AVS 1	1,899,776	0.96	27,357	5,176	81.1	85.8
2011	AVS 2	2,642,530	0.93	36,863	8,730	76.3	82.2
2012	AVS 1	2,732,031	0.98	40,161	6,871	82.9	87.2
2012	AVS 2	2,660,454	0.96	38,311	7,035	81.6	86.2
2013	AVS 1	2,804,599	0.95	39,966	7,578	81.0	85.8
2013	AVS 2	2,369,861	0.91	32,349	6,076	81.2	85.9
2014	AVS 1	2,332,119	1.02	35,681	5,509	84.6	88.4

ANTELOPE VALLEY STATION
SO$_2$ SCRUBBER
REMOVAL EFFICIENCY

2014	AVS 2	2,583,418	0.99	38,364	6,975	81.8	86.4
2015	AVS 1	2,736,138	0.99	40,632	6,312	84.5	88.3
2015	AVS 2	2,833,973	0.98	41,659	6,717	83.9	87.9
2016	AVS 1	2,797,996	1.01	42,390	7,254	82.9	87.2
2016	AVS 2	2,184,054	0.97	31,778	5,089	84.0	88.0
2017	AVS 1	2,442,876	0.91	33,345	5,259	84.2	88.2
2017	AVS 2	2,826,520	0.93	39,430	7,603	80.7	85.5
2018	AVS 1	2,809,117	0.82	34,552	5,911	82.9	87.2
2018	AVS 2	2,628,612	0.86	33,909	6,126	81.9	86.5
AVG.	***AVS 1***					***78.9***	
AVG.	***AVS 2***					***78.7***	
AVG.	***AVS 1 & 2***					***78.8***	
AVG.	***AVS 1 & 2***					***82.8***	
2013-2018 Avg.	**AVS 1**			***37,761***	***6,304***	***83.3***	
2013-2018 Avg.	AVS 2			**36,248**	**6,431**	***82.3***	

BASIN ELECTRIC POWER COOPERATIVE
A Touchstone Energy® Cooperative

NORTH DAKOTA ROUND II REGIONAL HAZE STATE IMPLEMENTATION PLAN DETERMINATION'S FOUR-FACTOR ANALYSIS FOR ANTELOPE VALLEY STATION

RESPONSE TO AGENCY COMMENTS

July 12, 2019
Project No. 13772-001

Sargent & Lundy

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000
www.sargentlundy.com

Introduction

In January 2019, Sargent & Lundy LLC (S&L) prepared a Round II Regional Haze Four-Factor Analysis for the Antelope Valley Station (AVS) on behalf of Basin Electric Power Cooperative (Basin). The analysis was prepared in response to a request made by the North Dakota Department of Environmental Quality (NDDEQ) and included an assessment of potentially available sulfur dioxide (SO_2) and nitrogen oxide (NOx) emission reduction technologies that could be applied to AVS Unit 1 and 2.

NDDEQ tendered comments to Basin on June 20, 2019, regarding the AVS Four-Factor Analysis. The purpose of this document is to provide responses to the June 20 comments from NDDEQ.

NDDEQ Comment 1

> On p.2-2 and Table 4-6, the design is based on all of the sulfur in the coal exiting the boiler. AP-42 indicates 25% of the sulfur in lignite is retained in the ash. This indicates the design emission rate is higher than it should be. This may effect the overall design of any new equipment (including the cost) and annual operating costs. The design sulfur emission rate should be reevaluated and appropriate revision to the analysis made.

S&L/Basin Response

> We appreciate the agency's comment regarding calculation of the design SO_2 inlet rate; however, adjusting the design inlet rate to account for sulfur that may be retained in the ash would not have a significant impact on either capital or O&M costs presented in the Four-Factor Analysis. S&L used projected future fuel analyses (sulfur and HHV) provided by Basin to calculate a design inlet SO_2 rate. Projections were based on the annual average fuel sulfur content and average heating value of the fuel for each year over the next 20 years, taking into account historical deviations seen in the coal quality. Coal data were provided to Basin by the Freedom Mine. The design SO_2 rate of 3.39 lb/MBtu show in Table 4-6 of the report represents the highest annual average SO_2 emission rate assuming 100% conversion of fuel sulfur to SO_2 without taking into account any inherent SO_2 retention in the ash.

It appears that NDDEQ used the Fourth Edition Compilation of Air Pollutant Emissions Factors (AP-42) from 1985 to support its comment that S&L's design SO_2 emission rate (calculated assuming 100% conversion of fuel sulfur to SO_2) is higher than it should be. That edition of AP-42 includes an assumption for lignite fuels that, on average, 75% of the fuel sulfur will be converted to SO_2 (i.e. 3.39 lb SO_2/MBtu * 0.75 = 2.54 lb SO_2/MBtu). A more recent edition recommends using an emission factor of 30S (lb/ton) for lignite-fired pulverized coal (PC) boilers, where S = weight % sulfur content of the lignite on a wet basis (see, Fifth Edition Compilation of Air Pollutant Emissions Factors AP-42, Volume 1: Stationary Point and Area Sources, Chapter 1, Table 1.7-1). A conversion factor of 0.077 is used to convert from lb/ton to lb/MBtu assuming an average lignite heating value of 6,500 Btu/lb. Using this approach, the inlet SO_2 rate would be calculated as: (30)*(1.09)*(0.077) = 2.52 lb SO_2/MBtu.

Although S&L used an uncontrolled SO_2 rate of 3.39 lb/MBtu as the design basis for the Four-Factor Analysis, that value was only used for the Projected Future Maximum Case. Uncontrolled SO_2 rates of 2.90 lb SO_2/MBtu for Units 1 and 2 (see Table 4-4 of the Four Factor Analysis) were used for the Actual Average Case.

When reviewing the technically feasible SO_2 alternatives for the AVS station, costs associated with the DFGD upgrades are primarily O&M driven. Variable O&M costs for DFGD operational changes are predominantly a function of the lime consumption rate. Lime consumption rates were based on an uncontrolled SO_2 rate of 2.90 lb SO_2/MBtu for the Actual Average Case. Revising the uncontrolled emission rate to 2.54 lb SO_2/MBtu would reduce the lime consumption rate by approximately 15%; however, they would be a corresponding reduction in the quantity of SO_2 removed such that the change would not have an impact on the cost-effectiveness analysis.

For the capital driven SO_2 alternatives (i.e., new DFGD or new WFGD), capital costs are predominantly driven by the absorber size which is based on the flue gas volumetric flow rate rather than inlet SO_2 concentration. As such, the difference between designing new equipment for 2.54 lb SO_2/MBtu and 2.90 lb SO_2/MBtu will not have a significant impact on the cost-effectiveness analysis because the capital costs would essentially be the same.

NDDEQ Comment 2

On p. 4-6, it is indicated the AVS has a Plantwide Applicability Limit (PAL). AVS does not have a PAL as described in the PSD rules. The cap on three-hour SO_2 emissions is different from a PAL (annual limit). The section should be revised.

S&L/Basin Response

We will revise the section accordingly. Previous terminology that was used will be adjusted as follows: "AVS Units 1 and 2 have a combined 3-hour SO_2 ~~plantwide applicability~~ limit ~~(PAL)~~ of 3,845 lb/hr in their Title V Air Permit that allows the station to adjust operation of each unit's FGD system as long as they achieve the combined ~~overall plantwide~~ limit."

NDDEQ Comment 3

In Tables 4-12 and 4-13, we believe the baseline reduction of SO_2 (87%) is high. Using the AP-42 emission factor of 30(S), we believe it is around 82 - 83% (see attachment).

S&L/Basin Response

We agree that the existing DFGD alone may provide a removal efficiency of approximately 82-83%, while the coal-to-stack removal efficiency is closer to 87%. Removal efficiencies listed in Table 4-12 and 4-13 were calculated based on the controlled SO_2 emission rate achieved with each technology and assuming an inlet SO_2 rate of 2.90 lb/MBtu (see response to Comment 1). Removal efficiencies in Table 4-12 and 4-13 represent overall SO_2 removal and are provided for comparative purposes. However, it is important to note that the baseline SO_2 emission rates (in tpy) were not calculated using an uncontrolled emission rate of 2.90 lb SO_2/MBtu; instead it was calculated based on the historic annual heat input and stack emission rate. Therefore, reducing the uncontrolled SO_2 rate, or adjusting the removal efficiencies, would not have an impact on the tons of SO_2 removed or the cost-effectiveness analysis.

B.3 – Basin LOS

B.3.a – Department Request

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

FILE

May 2, 2018

Mr. Mike Paul
Basin Electric Power Coop.
1717 E Interstate Avenue
Bismarck, ND 58503-0564

Re: Regional Haze
Second Planning Period

Dear Mr. Paul:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:
1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO$_2$) and nitrogen oxides (NO$_X$).

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
Division of Municipal Facilities 701.328.5211
Division of Waste Management 701.328.5166
Division of Water Quality 701.328.5210

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Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair
Director
Division of Air Quality

TLO/TB:saj
xc: Cris Miller, Basin Electric Power Coop.

B.3.b – Facility Response

BASIN ELECTRIC
POWER COOPERATIVE
A Touchstone Energy® Cooperative

Received
Air Quality
JAN 2019

January 31, 2019

Mr. Terry O'Clair
North Dakota Department of Health
918 East Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Mr. O'Clair:

RE: Four Factor Analysis Submittal for Antelope Valley Station and Leland Olds Station

Enclosed, you will find one CD and three hard copies of Basin Electric Power Cooperative's (**Basin Electric**) Round II Regional Haze Determination Four Factor Analysis for the Antelope Valley and Leland Olds Stations. This analysis was performed as outlined in the North Dakota Department of Health's (**NDDH**) May 2, 2018, request. Basin Electric is aware that the four factor analysis is one component contributing to the NDDH's Round II Regional Haze State Implementation Plan's Determination for each of these emission sources.

North Dakota is relying on the Western Regional Air Partnership (**WRAP**) to develop the visibility modeling platform needed to evaluate visibility at the Class I areas and subsequently for the individual states to develop and assess compliance strategies that will be formalized within the Round II Regional Haze State Implementation Plan.

Basin Electric requests that the NDDH withhold its Round II Regional Haze Determination until a comparative evaluation of visibility from the various control alternatives have been performed. The timing of the visibility analysis is subject to model availability. Basin Electric will continue to monitor WRAP's model development and will coordinate closely with the NDDH prior to initiating visibility impact analysis.

Should you have any questions concerning this submittal, please do not hesitate to contact Erin Dukart, Environmental Compliance Administrator at edukart@bepc.com or 701.557.5557.

Sincerely,

Mike Paul

Mike Paul
Chief Technical Advisor

/efd/sw
Enclosures

cc: Erin Fox Dukart
Keri Schiferl
Casey Mutzenberger

`

BASIN ELECTRIC POWER COOPERATIVE
A Touchstone Energy® Cooperative

NORTH DAKOTA ROUND II REGIONAL HAZE STATE IMPLEMENTATION PLAN DETERMINATION'S FOUR-FACTOR ANALYSIS FOR LELAND OLDS STATION UNITS 1 AND 2

SL-014752
Final
January 30, 2019
Project No. 13772-002

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603-5780 USA • 312-269-2000
www.sargentlundy.com

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B. Leland Olds Station Units 1 and 2 Baseline Emissions
C. SO_2 Control Cost Effectiveness Estimates
D. NO_X Control Cost Effectiveness Estimates

ABBREVIATIONS/ACRONYMS

Abbreviation/Acronym	Explanation
ABS	ammonium bisulfate
acfm	actual cubic feet per minute
ASOFA	advanced separated overfire air
B&W	Babcock & Wilcox
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Basin Electric	Basin Electric Power Cooperative
Ca	calcium
CAA	Clean Air Act
$CaCO_3$	limestone
CATC	Clean Air Technology Center
CEMS	continuous emissions monitoring system
CFD	computational fluid dynamics
CFR	Code of Federal Regulations
CRF	capital recovery factor
DBA	dibasic acid
DSI	dry sorbent injection
dv	deciview
ESP	electrostatic precipitator
EPA	Environmental Protection Agency
EGU	electric generating unit
FGD	flue gas desulfurization
FIP	Federal Implementation Plan
G&A	general and administration
GHG	greenhouse gas
H_2O	water
HHV	higher heating value
K	potassium
L/G	liquid-to-gas

LNB	Low-NO_X burner
LOS	Leland Olds Station
LTS	long-term strategy
Mg	magnesium
MMBtu	million British thermal units
MNL	multi-nozzle lance
MRYS	Milton R. Young Station
MW	megawatt
MWg	megawatt gross
N_2	nitrogen
Na	sodium
ND	North Dakota
NDDH	North Dakota Department of Health
NH_3	ammonia
NO	nitric oxide
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSR	New Source Review
NSR	normalized stoichiometric ratio
OEM	original equipment manufacturer
OFA	overfire air
ORP	oxidation-reduction potential
O&M	operations and maintenance
PM	particulate matter
PRB	Powder River Basin
RBLC	RACT/BACT/LAER Clearinghouse
Round II Determination	Round II Regional Haze State Implementation Plan Determination
RPG	reasonable progress goals
RPO	Regional Planning Organization
RRI	rich reagent injection
S	sulfur
S&L	Sargent & Lundy, L.L.C.
SACR	selective autocatalytic reduction

SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SOFA	separated overfire air
TAC	total annual cost
TCI	total capital investment
TE-SCR	tail-end SCR
URP	uniform rate of progress
WRAP	Western Region Air Partnership

EXECUTIVE SUMMARY

The Leland Olds Station (LOS), located near Stanton, ND, has two generating units (Units 1 and 2) rated at 220 MW and 440 MW, respectively. Both units are designed to fire North Dakota lignite coal. LOS Unit 1 is a B&W opposed wall-fired unit that went online in 1966. LOS Unit 1 is equipped with an Emerson combustion optimizers, low-NO_X burners (LNB), advanced separated overfire air (SOFA) and selective non-catalytic reduction (SNCR) for nitrogen oxide (NO_X) control, wet limestone flue gas desulfurization (WFGD) system for sulfur dioxide (SO_2) control, and electrostatic precipitators (ESP) for particulate matter (PM) control. LOS Unit 2 is a B&W cyclone-fired unit that went online in 1975. LOS Unit 2 is equipped with an Emerson combustion optimizer, SOFA, and SNCR for NO_X control, WFGD for SO_2 control, and ESP for PM control.

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the Clean Air Act (CAA), establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).[1] The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. The Regional Haze Rule established a schedule setting forth deadlines by which the states must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.[2]

During the initial planning period, the North Dakota Department of Health (NDDH) concluded that best available retrofit technology (BART) for both of Basin Electric Cooperative's (Basin Electric) LOS units included new WFGDs for SO_2 control and SOFA with SNCR for NO_X control. U.S. EPA initially disapproved NDDH's determination for LOS Unit 2 NO_X emissions, and issued a proposed a Federal Implementation Plan (FIP) that included advanced SOFA plus selective catalytic reduction (SCR). Following the public notice and comment period for the proposed FIP, EPA reversed its position regarding the technical feasibility of SCR on LOS Unit 2 and decided to approve the State's BART determination for NO_X control on LOS Unit 2.

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[1] 64 FR 35713

[2] On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

As part of the Round II Regional Haze State Implementation Plan Determination (Round II Determination), NDDH requested that Basin Electric prepare a four-factor analysis of SO_2 and NO_X emissions control options for LOS Units 1 and 2. The analysis evaluates technically feasible SO_2 and NO_X emission reduction measures for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliance
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

Sargent & Lundy LLC (S&L) and Basin Electric evaluated potentially available SO_2 and NO_X emissions reduction options for LOS Units 1 and 2 to identify technically feasible control options for inclusion in the four factor analysis. The SO_2 and NO_X control options included in this four factor analysis are identified in Table ES-1 and Table ES-2.

Table ES-1. Technically Feasible SO_2 Control Options

LOS Unit 1		LOS Unit 2	
Alt. No.	**SO_2 Control Technology**	**Alt. No.**	**SO_2 Control Technology**
B	FGD Upgrades – pH Buffer Addition	B	FGD Upgrades – pH Buffer Addition
A	FGD Operational Improvements – Ca:S Stoichiometry	A	FGD Operational Improvements – Ca:S Stoichiometry and Liquid-to-Gas Ratio
--	Baseline (existing WFGD)	--	Baseline (existing WFGD)

Table ES-2. Technically Feasible NO_X Control Options

LOS Unit 1		LOS Unit 2	
Alt. No.	**NO_X Control Technology**	**Alt. No.**	**NO_X Control Technology**
		B	Optimized SNCR + rich reagent injection (RRI)
A	SCR – tail-end configuration (Note 1)	A	Optimized SNCR
--	Baseline (existing LNB / SOFA / SNCR)	--	Baseline (existing LNB / SOFA / SNCR)

Note 1. Tail-end SCR (TE-SCR) has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of TE-SCR on LOS Unit 1. Nevertheless, during the initial planning period, NDDH concluded that TE-SCR was a technically feasible NO_X control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. For consistency with NDDH's conclusion from the first planning period, TE-SCR will be carried forward to the Four Factor Analysis.

The cost of compliance evaluation (Statutory Factor 1) prepared for SO_2 controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible SO_2 control options for Unit 1 ranges from $10,021 per ton (Alternative A) to $17,948 per ton SO_2 removed (Alternative B), and for Unit 2 ranges from $6,906 per ton (Alternative A) to $13,946 per ton SO_2 removed (Alternative B). When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible SO_2 control options for Unit 1 ranges from $18,200 per ton (Alternative A) to $18,948 per ton SO_2 removed (Alternative B), and for Unit 2 ranges from $13,444 per ton (Alternative A) to $15,462 per ton SO_2 removed (Alternative B).

The cost of compliance evaluation prepared for NO_X controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible NO_X control options for Unit 1 is $54,605 per ton NO_X removed (Alternative A), and for Unit 2 ranges from $1,896 per ton (Alternative A) to $3,630 per ton NO_X removed (Alternative B). When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible NO_X control options for Unit 1 is $28,528 per ton NO_X removed (Alternative A), and for Unit 2 ranges from $1,588 per ton (Alternative A) to $3,186 per ton NO_X removed (Alternative B). For Unit 2, Alternatives A and B will also affect the units' net plant heat rate since the amount of water that will be injected with the urea will negatively impact boiler efficiency. Both alternatives do not include additional costs that would be incurred due to the loss in net generation.

The time necessary for compliance (Statutory Factor 2) for the SO_2 control options ranges from 3 months (Alternative A) to 12 months (Alternative B). For NO_X control options, the time necessary for compliance ranges from 12 months (Alternatives A and B – Unit 2) to 52 months (Alternative A – Unit 1).

An evaluation of energy impacts and non-air environmental impacts (Statutory Factor 3) indicates that certain control options will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts potential include increases in water consumption, solid waste generation, sulfuric acid mist emissions, and ammonia emissions.

Regarding remaining useful life (Statutory Factor 4), under the current Basin Electric resource plan, the remaining useful life of LOS Unit 1 and 2 are considered to be greater than 20 years. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework.

Based on the results of the four factor analysis prepared for LOS SO_2 emissions reductions, WFGD Operational Improvements and WFGD Upgrades are cost prohibitive. The control cost evaluation indicates that the average cost effectiveness levels exceed $6,900 per ton SO_2 removed. Therefore, Basin Electric is proposing that the existing WFGD systems on Units 1 and 2 represent appropriate controls for the Round II Determination.

The four factor analysis prepared for LOS Units 1 indicates that additional NO_X controls are cost prohibitive. The cost effectiveness of installing a TE-SCR system on Unit 1 is over $28,000 per ton NO_X removed. Therefore, Basin Electric is proposing that the existing LNB / SOFA / SNCR system on Unit 1 represents appropriate controls for the Round II Determination. For Unit 2, the analysis indicates a cost effectiveness of $1,600 ton for the optimized SNCR alternative. The implementation of the optimized SNCR decreases the actual hourly mass emission rate by approximately 100 lb per hr (from historical baseline emissions). However, it can increase ammonia emissions, and that effect would result in additional haze formation. As such, a 5th factor analysis (visibility improvement using modeling) is recommended for this option to determine whether there is any or only a trivial amount of visibility improvement. Basin Electric requests that the NDDH withhold their Round II Determination until the Western Region Area Partnership's cumulative modeling platform are available so that a visibility improvement assessment can be conducted. Basin Electric will then perform a comparative visibility improvement analysis between the two control alternatives and submit the results to the NDDH for consideration.

It is generally understood from previous visibility modeling efforts that increased ammonia injection has the opportunity of providing additional ammonia to the atmosphere. This increased ammonia availability within the emitted plume itself is known to contribute to increased visibility impairment due to more direct formation of ammonium sulfate and ammonium nitrate, especially in the winter months where fine particulate formation is ammonia limited. In fact, it is during the winter months that the NO_X emissions have a visibility effect; the observed (and modeled) nitrate haze during the warmer months with more park visitation is negligible. As a result of the future modeling analysis, the actual visibility benefit of the optimized SNCR alternative may be considered minimal if not de-minimis.

For the Round II Determination, no change to the current Title V Operating Permit is proposed for SO_2 emissions on either LOS Unit 1 or 2 and no proposed change to the NO_X emissions on LOS Unit 1. Table ES-3 includes a summary of the proposed Round II Determination's strategy for NO_X, assessed NO_X emissions on a 30-day rolling average basis and a proposed Round II Determination's emission rate on a 30-day rolling average basis for LOS

Unit 2. The proposed emissions limits include compliance margin to account for items such as variability in the operating load profile.

Table ES-3. Proposed Round II Determination's NO_X Emission Rate

LOS Unit No.	Pollutant	Assessed Emission Rate lb/MMBtu(Note 2) (30-day rolling average)	Proposed Round II Determination's Emission Rate lb/MMBtu(Note 1) (30-day rolling average)	Control Technology
Unit 2	NO_X	0.27	0.30	Optimized SNCR System

Note 1. The proposed Round II Determination's emission rate is a 14% reduction from the current permit limit of 0.35 lb NO_X/MMBtu, 30-day rolling avg.

Note 2. The assessed emission rate represents the average emission rate that LOS Unit 2 would be expected to achieve on an on-going long-term basis under normal operating conditions.

1. INTRODUCTION

Sargent & Lundy, L.L.C. (S&L) was retained by Basin Electric Power Cooperative (Basin Electric) to prepare a Round II Regional Haze State Implementation Plan Determination's (Round II Determination) four-factor analysis for the control of sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions from Basin Electric's Leland Olds Station (LOS) Units 1 and 2. This evaluation is in response to the North Dakota Department of Health's formal letter dated May 2, 2018, attached in Appendix A. The evaluation includes an assessment of potentially available emission reduction measures for the four statutory factors listed in 40 CFR 51.308(f)(2), and takes into consideration U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period* (the "Draft EPA Guidance").[3] Technically feasible SO_2 and NO_X emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliance
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

The Round II Determination's four factor analysis for LOS Units 1 and 2 is presented in the following sections:

Section 2: **Facility Description** contains information describing the facility, site location, and existing equipment.

Section 3: **Four-Factor Analysis Requirements** provides a brief description of the Regional Haze Program requirements set forth in 40 CFR 51.308.

Section 4: **SO_2 Control Evaluation** establishes representative baseline SO_2 emissions, identifies potentially available emission control technologies, evaluates each control option for technical feasibility and evaluates cost effectiveness of technically feasible control options.

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[3] On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Basin Electric reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

Section 5: **NO_X Control Evaluation** establishes representative baseline NO_X emissions, identifies potentially available emission control technologies, evaluates each control option for technical feasibility and evaluates cost effectiveness of technically feasible control options.

Section 6: **Time Necessary for Compliance (Statutory Factor Two)** provides typical timelines required to design, engineer, procure and install the technically feasible control options.

Section 7: **Energy and Non-Air Quality Environmental Impacts (Statutory Factor Three)** identifies the energy and non-air quality environmental impacts associated with each technically feasible control option**.**

Section 8: **Remaining Useful Life (Statutory Factor Four)** includes a discussion of the planned remaining useful life of LOS Units 1 and 2, including an evaluation of how remaining useful life affects the cost-effectiveness of each technically feasible control option.

Section 9: **Summary and Conclusions**

Appendix A: North Dakota Department of Health Letter

Appendix B: Leland Olds Station Units 1 and 2 Baseline Emissions

Appendix C: SO_2 Control Cost Effectiveness Estimates

Appendix D: NO_X Control Cost Effectiveness Estimates

2. FACILITY DESCRIPTION

The Leland Olds Station (LOS), located near Stanton, ND, has two generating units (Units 1 and 2) rated at 220 MW and 440 MW, respectively. Both units are designed to fire North Dakota lignite coal. LOS Unit 1 is a Babcock and Wilcox (B&W) opposed wall-fired unit that went online in 1966. LOS Unit 1 is equipped with an Emerson combustion optimizer, low-NO_X burners (LNB), advanced separated overfire air (SOFA) and selective non-catalytic reduction (SNCR) for NO_X control, wet limestone flue gas desulfurization (WFGD) system for SO_2 control, and electrostatic precipitators (ESP) for particulate matter (PM) control. LOS Unit 2 is a B&W cyclone-fired unit that went online in 1975. LOS Unit 2 is equipped with an Emerson combustion optimizer, SOFA, and SNCR for NO_X control, WFGD for SO_2 control, and ESP for PM control

Table 2-1 provides a summary of the design parameters used for the LOS Units 1 and 2 four factor analysis. The four factor analysis design parameters listed in Table 2-1 were developed from information provided by Basin Electric.

Table 2-1. Four Factor Analysis Design Basis Parameters

Parameter	LOS Unit 1	LOS Unit 2
Boiler type	PC opposed wall-fired	Cyclone-fired
Boiler manufacturer	B&W	B&W
Generating Capacity (MWg)	220	440
Design heat input (MMBtu/hr)	2,622	5,130
Average Hourly Heat Input for Baseline SO_2 period (MMBtu/hr)	1,851	3,779
Capacity Factor for Baseline SO_2 period (%)	68	69
Average Hourly Heat Input for Baseline NO_X period (MMBtu/hr)	1,646	3,692
Capacity Factor for Baseline NO_X period (%)	51	68
Full load flue gas conditions at WFGD Outlet		
Temperature (°F)	145	144

Parameter	LOS Unit 1	LOS Unit 2
Mass flow rate (lb/hr)	3,028,000	6,396,000
Volumetric flow rate (acfm)	816,500	1,722,500
Baseline Fuel Parameters(1)		
Higher Heating Value (Btu/lb)	6,793	6,818
Fuel sulfur content (%)	1.06	1.04
SO_2 content (lb/MMBtu)	3.12	3.05
Projected Future Fuel Parameters(2)		
Higher Heating Value (Btu/lb)	6,595	
Fuel sulfur content (%)	1.23	
SO_2 content (lb/MMBtu)	3.73	

Note 1. Current fuel parameters are based on the actual annual average fuel sulfur content from 2014-2018 provided by Basin Electric.
Note 2. Projected future fuel parameters are based on anticipated annual average coal projections provided by Basin Electric from 2019-2040. Projected future sulfur and SO_2 content includes margin based on the actual deviation in annual average sulfur content from current coal data. Additional detail on coal sulfur provided in Section 4.2.

3. FOUR-FACTOR ANALYSIS REQUIREMENTS

3.1 REGIONAL HAZE RULE BACKGROUND

Section 169A of the 1977 Amendments to the Clean Air Act (CAA) sets forth a program for protecting visibility in Federal Class I areas which calls for "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Federal Class I areas which impairment results from manmade air pollution." Federal Class I areas include national parks, memorial parks, and wilderness areas over a certain size. Figure 3-1 shows the locations of the 156 federally mandated Class I areas. Federal Class I areas located within North Dakota include the Theodore Roosevelt National Park and the Lostwood National Wildlife Refuge.

Figure 3-1. Federal Class I Areas

On July 1, 1999, the U.S. EPA published regulations implementing Section 169A of the CAA, establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).[4] The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. Regional Haze SIPs must contain such emission limits, schedules of compliance, and other measures as may be necessary to make reasonable progress toward meeting the national visibility goal of achieving visibility in Class 1 areas which reflects natural conditions by 2064.

To address the combined visibility effects of various pollution sources over a wide geographic region, EPA designated five Regional Planning Organizations (RPOs) to assist with the coordination and cooperation needed to address the visibility issue. The five RPOs are shown in Figure 3-2. North Dakota is a member of the Western Regional Air Partnership (WRAP), which serves as the RPO for visibility protection at 118 Class I areas in 15 western states.

Figure 3-2. Regional Planning Organization Map

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[4] 64 FR 35713

3.1.1 First Implementation Period

The Regional Haze Rule established a schedule setting forth deadlines by which the states must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.[5]

Regional Haze SIP requirements for the first planning period required that states incorporate into their plans the core program requirements in 40 CFR 51.308(d), including: (1) establishing reasonable progress goals (RPGs) for each Class I area within the state that provide for measurable progress towards achieving natural visibility conditions; (2) developing a long-term strategy (LTS) including enforceable emissions limitations and compliance schedules to achieve the RPGs; and (3) developing plans to monitor and assess the effectiveness of the LTS to achieve the RPGs over the prior implementation period and affirmation of or revision to the RPGs.

The Regional Haze Rule requires that states determine the consistent rate of progress over time needed to attain natural visibility conditions on the 20 percent most impaired days by the year 2064. This "glidepath" is referred to as the uniform rate of progress (URP) line. States must consider the URP, and the emission reduction measures needed to achieve this level of improvement, when developing their RPGs and LTS. Regulations at 40 CFR 51.308(g) require each state to submit progress reports, in the form of SIP revisions, every 5 years following the submission of the initial SIP. These progress reports must evaluate the progress made towards the RPGs for Class I areas located within the state as well as those Class I areas located outside the state that may be affected by emissions from within the state.

3.1.1.1 Best Available Retrofit Technology

As a one-time requirement during the first implementation period, potential best available retrofit technology (BART) controls had to be evaluated for certain large stationary sources. States were required to conduct BART determinations for "BART-eligible" sources anticipated to cause or contribute to any visibility impairment in one or more Class I area. BART-eligible sources included coal-fired electric generating units (EGUs) that were in existence on August 7, 1977, but not in operation prior to August 7, 1962. As an alternative to requiring source-

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[5] On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

specific BART controls, states also had the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provided greater reasonable progress towards improving visibility than BART.

3.1.1.2 North Dakota's Initial Planning Period SIP

The State of North Dakota submitted its regional haze SIP addressing the requirements of 40 CFR 51.308 to EPA for review on March 3, 2010 (the "Regional Haze SIP").[6] The Regional Haze SIP was prepared by the North Dakota Department of Health, Air Quality Division (NDDH). The SIP included BART determinations for seven steam EGUs identified as being subject to the BART requirements of 40 CFR 51.208(e) and a reasonable progress evaluation for six additional non-BART sources identified as having the potential to affect visibility in a Class I area.

Basin Electric's LOS Units 1 & 2 were evaluated by NDDH as subject-to-BART sources.[7] Based on its evaluation of available control technologies, NDDH concluded that BART for both LOS units included new WFGD for SO_2 control and SOFA with SNCR for NO_X control. NDDH determined that selective catalytic reduction (SCR), a higher performing NO_X control option, was not an available, and thus not a technically feasible, NO_X control option.[8]

Basin Electric's AVS Units 1 & 2 were evaluated by NDDH under the reasonable progress requirements. Based on an evaluation of the four reasonable progress statutory factors (i.e., costs of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of the units) plus an evaluation of incremental visibility improvement, NDDH concluded that requiring additional controls (beyond those required for the BART-eligible sources) would not substantially improve visibility in the Class I

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[6] North Dakota State Implementation Plan for Regional Haze – A Plan for Implementing the Regional Haze Program Requirements of Section 308 of 40 CFR Part 51, Subpart P – Protection of Visibility, North Dakota Department of Health, February 24, 2010. In addition to the initial SIP submittal, the State submitted a SIP Supplement No. 1 on July 27, 1010, and a SIP Amendment No. 1 on July 28, 2011 (collectively the "Regional Haze SIP").

[7] In addition to LOS Units 1 & 2, NDDH evaluated Great River Energy's Coal Creek Station Units 1 & 2; Great River Energy's Stanton Station Unit 1; and Minnkota Power Cooperative's Milton R. Young Station Units 1 & 2 as subject-to-BART sources.

[8] Regional Haze SIP, pg. 73. The State's evaluation of SCR for North Dakota lignite was included as Appendix B.5 to the Regional Haze SIP (Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite, July 2009). NDDH eliminated SCR from consideration as BART based on a finding that SCR was not technically feasible to control emissions from North Dakota lignite coal. In particular, NDDH noted that no SCR has ever been employed on an EGU burning North Dakota lignite, that North Dakota lignite has unique properties that have the potential to quickly degrade the SCR catalyst, and that no catalyst vendor would provide a guarantee of catalyst life without first conducting slipstream or pilot testing.

areas, and that for all reasonable progress sources evaluated individually and cumulatively, control technology costs (evaluated on a dollar per deciview improvement ($/dv) basis) was excessive. Therefore, the Regional Haze SIP did not include additional control for AVS Units 1 & 2.[9]

On September 21, 2011, EPA published a Proposed Rule proposing to partially approve and partially disapprove specific aspects the Regional Haze SIP.[10] Among other things, EPA proposed to disapprove the State's determination of BART for LOS Unit 2 as well as the reasonable progress determination for AVS Units 1 & 2. EPA proposed to approve the remaining aspects of North Dakota's Regional Haze SIP, including that State's BART determination for SO_2 control at LOS (i.e., new WFGD) and the NO_X BART determination for LOS Unit 1 (i.e., SOFA+SNCR).[11] Along with the proposed partial disapproval of North Dakota's SIP, EPA proposed the promulgation of a Federal Implementation Plan (FIP). The proposed FIP included, among other items: (1) a NO_X BART determination and emission limits for LOS Unit 2; and (2) a reasonable progress determination and NO_X emission limits for AVS Units 1 & 2. EPA proposed advanced SOFA (ASOFA) plus SCR and an emission rate of 0.07 lb/MMBtu (30-day rolling average) as BART for NO_X control on LOS Unit 2. EPA also proposed LNB plus SOFA and an emission limit of 0.17 lb/MMBtu (30-day rolling average) as representing reasonable progress NO_X control on AVS Units 1 & 2.[12]

Following the public notice and comment period EPA issued its Final Rule on April 6, 2012.[13] The Final Rule differed from the Proposed Rule in that EPA reversed its position regarding the technical feasibility of SCR on LOS

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[9] *Id.* at pg. 188.

[10] 76 Fed. Reg. 58570, September 21, 2011 (the "Proposed FIP"). In addition to the proposed disapproval of the State's BART determination for Leland Olds Station Unit 2, EPA proposed disapproving the BART determinations for the Coal Creek Station and Milton R. Young Station (MRYS) Units 1 & 2.

[11] *Id.* at pg. 58619. Note that for LOS Unit 1 EPA stated that it did not agree with the State's cost analysis for SCR, but nonetheless found the elimination of SCR for LOS Unit 1 to be acceptable because LOS Unit 1 is relatively small (216 MW) compared to LOS Unit 2 (440 MW) and MRYS Units 1 & 2, and LOS Unit 1 had lower baseline NOx emission. (76 FR 58596, Table 22).

[12] *Id.* at pg. 58632. EPA eliminated higher performing NOx control options for AVS Units 1 & 2, including LNB + SNCR; SCR; and LNB + SCR, because their cost effectiveness values were significantly higher and/or the emission reductions were not that much higher than LNB. Considering the statutory factors, EPA found that it was not reasonable to insist on these higher control levels in the first; however, EPA noted that expected North Dakota to consider such controls in the next planning period.

[13] 77 Fed. Reg. 20894.

Unit 2 and decided to approve the State's BART determination for NO_X control on LOS Unit 2.[14] Conversely, EPA finalized its determination that LNB+SOFA was required by reasonable progress for AVS Units 1 & 2.

EPA's decision to accept the BART determinations for LOS Unit 2 (and Minnkota Power Cooperative Inc.'s Milton R. Young Station (MRYS) Units 1 & 2) was based primarily on the decision in United States v. Minnkota Power Cooperative, Inc.[15] which concluded that the State's best available control technology (BACT) analysis for NO_X control on MRYS Units 1 & 2 was not unreasonable, a conclusion that was contrary to EPA's position at the time of the Proposed FIP.[16] In explaining its decision to reverse its position that SCR was a technically feasible NO_X control option for LOS Unit 2, EPA noted that the technical feasibility determination under the BACT and BART analyses was substantially the same, and that the BART Guidelines permit a state to rely upon a BACT determination for purposes of selecting BART unless new technologies have become available or best control levels for recent retrofits have become more stringent.[17] Noting that the District Court upheld North Dakota's BACT determination for MRYS Units 1 & 2, EPA concluded that it would be inappropriate to proceed with its proposed disapproval of SNCR as BART, and approved the State's determination that ASOFA+SNCR and an emission rate of 0.35 lb/MMBtu (30-day rolling average) was BART for NO_X control on LOS Unit 2.

Emission controls required by the Regional Haze SIP for the Basin Electric's LOS and AVS stations are summarized in Table 3-1.

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[14] *Id.* at pg. 20897-98. EPA also reversed its position and decided to approve the State's BART determination for NOx control on MRYS Units 1 & 2.

[15] United States v. Minnkota Power Cooperative, Inc., 831 F. Supp. 2d 1109, 1127-30 (D.ND. 2011).

[16] Contemporaneous with the Regional Haze SIP/FIP process, NDDH was also determining BACT for MRYS Units 1 & 2 pursuant to a Consent Decree entered into between the owner of the station (Minnkota), the State, and EPA under the CAA's Prevention of Significant Deterioration program. In its BACT analysis, NDDH concluded that SCR was technically infeasible on a lignite-fired cyclone boiler, and selected SNCR as BACT. EPA challenged the State's BACT determination in district court, contending that SCR was a technically feasible emission control option and should have been selected as BACT. On December 21, 2011, the District Court issued its decision on EPA's challenge of the State's BACT determination, finding that the State's conclusion that SCR was not technically feasible was not unreasonable. See, U.S. v. Minnkota, 831 F. Supp. 2d at 1127-30.

[17] 77 Fed. Reg. 20897.

Table 3-1. Initial Planning Period SIP Summary

Source & Unit	Pollutant	Control Device / Emission Limit
LOS Unit 1 (BART)	NO_X	Basic SOFA + SNCR with an emission limit of 0.19 lb/MMBtu (30-day rolling average)
	SO_2	New WFGD operating at 95% efficiency or below an emission limit of 0.15 lb/MMBtu (30-day rolling average)
LOS Unit 2 (BART)	NO_X	Advanced SOFA + SNCR with an emission limit of 0.35 lb/MMBtu (30-day rolling average)
	SO_2	New WFGD operating at 95% efficiency or below an emission limit of 0.15 lb/MMBtu (30-day rolling average)
AVS Unit 1 (reasonable progress)	NO_X	LNB + SOFA with an emission limit of 0.17 lb/MMBtu (30-day rolling average)
	SO_2	No additional control beyond the existing dry FGD / baghouse
AVS Unit 2 (reasonable progress)	NO_X	LNB + SOFA with an emission limit of 0.17 lb/MMBtu (30-day rolling average)
	SO_2	No additional control beyond the existing dry FGD / baghouse

3.1.1.3 BART Requirements for Leland Olds Station during First Planning Period

LOS Unit 1 and 2 commenced operation in 1966 and 1975, respectively; thus, both units were subject to BART requirements during the first planning period. The BART selected by NDDH for LOS Unit 1 and Unit 2 was WFGD for SO_2 control and SOFA and SNCR for NO_X control with a compliance date of April 4, 2017.

A 0.15 lb SO_2/MMBtu or 95% SO_2 removal on a 30-day rolling average limit was placed on each LOS Unit, which corresponds with the Presumptive BART SO_2 control level proposed by EPA for a WFGD. A NO_X limit of 0.19 lb/MMBtu and 0.35 lb/MMBtu on a 30-day rolling average was placed on LOS Unit 1 and 2, respectively.

The WFGD systems for Units 1 and 2 were placed in early operation in 2012 (LOS Unit 2) and 2013 (LOS Unit 1), due to the increasing sulfur content of the fuel supply. The layered NO_X control systems were placed in service in stages over several years with the systems fully in service and optimized in 2016 for both units.

3.1.2 Round II Regional Haze SIP Determination

The Round II Determination must be submitted to EPA for review by July 31, 2021. Among other requirements, the Round II Determination is required to include an assessment of the state's RPGs and LTS. To support states in their efforts to develop the Round II Determination, in July 2016 EPA released a draft guidance document titled "*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*" ("Draft EPA Guidance").[18] The Draft EPA Guidance document describes key steps states should implement when developing their RPGs and LTS for the Round II Determination. Key steps identified in the Draft EPA Guidance are listed in Table 3-2.

Table 3-2. Key Steps in Developing the Round II Determination

1.	*Ambient data analysis* – Quantify baseline, current and natural conditions and the URP that would achieve natural conditions by 2064 (40 CFR 51.308(f)(1))
2.	*Screening of sources* – Identify the pollutants and emission sources for which a full reasonable progress analysis will be completed and explain why it is appropriate to limit the full analysis to only these sources (40 CFR 51.308(f)(2))
3.	*Source and emission control measure analysis* – Identify potential emission control measures for sources selected in the screening step and develop data on the four statutory factors and visibility benefits if they will be considered (40 CFR 51.308(f)(2))
4.	*Decisions on the content of the LTS* – Consider applicable factors and decide on new emission controls for incorporation into the LTS (40 CFR 51.308(f)(2))
5.	*Regional scale modeling* – Model the emissions reductions that will result from implementation of the LTS and other enforceable measures that will reduce visibility impairment to set the RPGs for 2028 (40 CFR 51.308(f)(3))
6.	*Progress, degradation and glidepath checks* – Demonstrate that there will be an improvement on the 20 percent most impaired days. Demonstrate that there is no degradation on the 20 percent clearest days. Compare the 2028 RPG for the 20 percent most impaired days to the 2028 point on the URP line (the glidepath) and, if required, provide additional justification for the reasonableness of the RPG. Revise the LTS if additional measures are identified as necessary to make reasonable progress. (40 CFR 51.308(f)(3))
7.	*Additional requirements for SIPs* – Provide additional information necessary to ensure that other requirements of the Regional Haze rule are met.

The Draft EPA Guidance recommends that states evaluate all technically feasible emission control options for

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[18] See, EPA-457/P-16-001. On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Basin Electric reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

stationary sources and source categories identified as having the greatest potential to impact visibility at one or more Class I area. The Draft EPA Guidance recommends several options for states to consider when evaluating potential emission reductions, including work practices, replacement and retrofit controls, existing control upgrades, fuel switching, year-round operation of controls, and operating restrictions.[19]

Emission control evaluations must consider the four statutory factors identified in 40 CFR 51.308(f)(2)(i) (discussed in Section 3.2). In addition, the Draft EPA Guidance notes that control technology assessment recommendations presented in the BART Guidelines continue to be relevant as recommendations for how a state should evaluate and select emission control measures for stationary sources.[20] Recommendations in the BART Guidelines that continue to be relevant to the Round II Determination's four factor analysis are listed in the Appendix D of the Draft EPA Guidance, and include, in general, the recommended approach for evaluating the technical feasibility, effectiveness, costs, and cost-effectiveness of available emission control measures.[21]

3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS

Under 40 CFR 51.308(f)(2)(i), states must consider four statutory factors when evaluating and determining emissions reduction measures from stationary sources, or groups of sources, that are necessary to make reasonable progress towards achieving natural visibility conditions. The four statutory factors are:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

A brief description of each of the four statutory factors, and EPA's recommendations for evaluating each of the four factors (from the Draft EPA Guidance) is provided below.

3.2.1 Costs of Compliance

Cost estimates should be developed for each technically feasible control option. Costs include the total capital costs to engineer, design, procure, and install the control technology, and annual operations and maintenance

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[19] See, Draft EPA Guidance, pgs. 85-86.
[20] Draft EPA Guidance, pg. 85. The BART Guidelines are published at 40 CFR Part 51 Appendix Y.
[21] Draft EPA Guidance, Appendix D, pgs. 186-196.

(O&M) costs. O&M costs include both fixed and variable O&M. Fixed O&M includes costs that are independent of control system operation and would be incurred even if the control system were shut down. Fixed O&M includes categories such as O&M labor, administrative charges, property taxes, and insurance. Variable O&M includes the cost of consumables, including reagent (e.g., lime or limestone, ammonia, urea, etc.), by-product management, water consumption, and auxiliary power requirements associated with operating the control system. For existing facilities, O&M cost estimates should represent the control option's incremental increase over current O&M costs.

Capital costs include all costs required to engineer, design, procure, and install equipment needed for the control system. The Draft EPA Guideline recommends that states adhere to the accounting principles described in Chapter 2 Section 1 of EPA's Air Pollution Control Cost Manual (the "Control Cost Manual") when calculating control system costs for a four factor analysis.[22]

Section 2.3 of the Control Cost Manual (Section 1, Chapter 2) describes the cost categories generally used to calculate the total capital cost of a retrofit control technology. Cost categories include total capital investment (TCI), which is defined to "include all costs required to purchase equipment needed for the control systems (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also includes costs for land, working capital, and off-site facilities." Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (i.e., cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies.[23]

The total annual cost (TAC) of a control option includes the annualized capital recovery cost plus the total annual O&M costs. The Control Cost Manual recommends using an equivalent uniform annual cash flow method to annualize the total capital investment by multiplying the total capital investment by a capital recovery factor

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[22] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002.
[23] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, pg. 2-5.

(CRF).[24] The product of the total capital investment and CRF gives a uniform end-of-year payment necessary to repay the initial capital investment in "n" years at an interest rate of "i". The CRF is calculated using the following equation:

$$\mathrm{CRF} = \frac{i * (1+i)^n}{(1+i)^n - 1}$$

Where:
i = interest rate; and
n = economic life of the emission control system

The Draft EPA Guidance suggests that states may use generic cost estimates or estimating algorithms for estimating control system costs; however, source specific estimates prepared by knowledgeable engineering professionals provide more reliable information than generic cost estimates.[25] Source-specific cost estimate should be well documented for purposes of public comment and EPA review.[26]

The total annual cost of each control option ($/yr) is divided by the total annual emissions reduction (tons/yr) to determine the control option's average cost-effectiveness on a $/ton basis. Emissions reductions are calculated based on the difference between baseline annual emissions and post-control annual emissions. The Draft EPA Guidance generally recommends calculating baseline emissions based on projected 2028 emissions assuming source compliance with emission limits that have been adopted and are enforceable. As an alternative, baseline emissions may be based on representative data of past actual emissions, assuming there is no evident basis for using a different emissions rate. As such, the cost of compliance is based on historical baseline as well as future projected capacity factors and fuels.

3.2.2 Time Necessary for Compliance

For stationary sources, the provisions of the BART Guidelines regarding the time necessary for compliance are relevant to the Round II Determination's analyses. EPA recommends that prior experiences with the planning and installation of new emission controls is the best guide to how much time a particular source will reasonably need for compliance. However, source-specific factors should be considered when evaluating the time necessary to

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[24] Id., at pg 2-21.
[25] Draft EPA Guidance, pg. 91.
[26] *Id*.

engineer, procure, and install an available and technically feasible control option. Source-specific factors that affect the time necessary to install new emission controls should be identified and documented in the four factor analysis.

3.2.3 Energy and Non-Air Quality Environmental Impacts

For stationary sources, the provisions of the BART Guidelines regarding energy impacts are relevant to Round II Determination's analyses. Energy impacts of an emission control measure are a matter of engineering design and control system operation; thus, EPA recommends that prior experience at similar sources will be informative. Energy impacts may be considered in terms of kilowatt-hours or fuels used to operate the control system. The energy impact analysis should focus on direct energy consumption at the source rather than indirect energy inputs needed to produce raw materials for the construction and operation of control equipment.

For stationary sources, the provisions of the BART Guidelines regarding non-air quality environmental impacts are relevant to the Round II Determination's analyses. Non-air quality impacts include solid or hazardous waste generation, increased water consumption, wastewater discharge, land use impacts, and impacts to threatened and endangered species or their natural habitat. Characterizing the non-air quality environmental impacts should be done on a source-specific basis. Other guidance intended for use in assessments under the National Environmental Policy Act may be relevant to this evaluation.

Even though states are not required to consider greenhouse gas (GHG) emission impacts, the Draft EPA Guidance encourages states to consider GHG impacts when developing their LTS.[27] As an example, some measures that would reduce emissions that contribute to visibility impairment will also reduce GHG emissions, such as measures that reduce the use of energy produced from combusting fossil fuels with relatively high GHG emissions. Conversely, control measures that require significant energy to capture visibility impairing emissions could result in increased GHG emission. Where a measure necessary to make reasonable progress towards natural visibility conditions would increase GHG emissions, Draft EPA Guidance encourages states to work to harmonize visibility and climate change objectives.[28]

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[27] Draft EPA Guidance, pg. 92.
[28] *Id.*

3.2.4 Remaining Useful Life

For stationary sources, the provisions of the BART Guidelines regarding remaining useful life are relevant to the Round II Determination's analyses. In general, the remaining useful life of the source itself will be longer than the useful life of the emission control measure under consideration unless there is an enforceable requirement for the source to cease operation sooner. Thus, the useful life of the control measure will normally be used in the four factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness. However, if there is an enforceable requirement for the source to cease operation by a date before the end of what would otherwise be the useful life of the control measure under consideration, then the enforceable shutdown date should be used to calculate remaining useful life and evaluate control technology cost-effectiveness.

3.2.5 Four Factor Analysis Approach

S&L used a top-down approach to identify and evaluate the technical feasibility and effectiveness of potentially available SO_2 and NO_X control measures. S&L followed Steps 1 thru 3 of the top-down approach described in the BART Guidelines to identify all available retrofit emission control measures, eliminate technically infeasible options, and evaluate the effectiveness of the technically feasible options.[29] A brief description of each step is provided below.

Step 1 - Identify All Available Control Options

Available control options are those air pollution control technologies with a practical potential for application to the emission unit and the regulated pollutant under evaluation. Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant, and include not only existing controls for the source category but also take into account technology transfer of controls that have been applied to similar source categories and gas streams. Technologies which have not been applied to (or permitted for) full scale operations need not be considered as available.[30]

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[29] See, 40 CFR Part 51 Appendix Y, Section IV.D.
[30] *Id.*, at IV.D.1.

In an effort to identify all potentially available emission control technologies, S&L searched a broad range of information sources including, but not necessarily limited to:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC);
- EPA's New Source Review (NSR) and Clean Air Technology Center (CATC) Web sites;
- BART evaluations prepared during the initial Regional Haze planning period;
- Information from control technology vendors and engineering/environmental consultants;
- Federal and State NSR permits and BACT determinations for similar sources; and
- Technical journals, reports, newsletters and air pollution control seminars.

Step 2 - Eliminate Technically Infeasible Control Options

In Step 2, S&L evaluated the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. Control technologies are technically feasible if either: (1) they have been installed and operated successfully for the type of source under review under similar conditions; or (2) the technology could be applied to the source under review. In order for a control option to be technically feasible, it must be "available" and "applicable" to the source under consideration. A technology is considered "available" if the source owner may obtain it through commercial channels. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.[31]

Control technologies that are technically infeasible (i.e., not available or not applicable to the source under consideration) are eliminated for further evaluation. A demonstration of technical infeasibility must be based on physical, chemical and engineering principals, and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/infeasibility.

Step 3 - Evaluate Technically Feasible Control Technologies for Effectiveness

Step 3 involves evaluating the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review. Control effectiveness should be expressed using a metric that ensures an "apples-to-apples" comparison of emissions performance levels among options, and is generally

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[31] A more detailed description of control technology "availability" and "applicability" is provided in 40 CFR Part 51 Appendix Y, Section IV.D.2.

expressed as the rate that a pollutant is emitted after installation of the control measure. Control technology evaluations for existing sources should consider ways to improve the performance of existing control devices. Special circumstances pertinent to the specific control technology under review should be identified and taken into consideration when assessing the capability of the control alternative and determining control effectiveness.

For this evaluation, S&L assessed the technically feasible SO_2 and NO_X control options for effectiveness on LOS Unit 1, which is equipped with SOFA/LNB/SNCR/Emerson Combustion Optimizer for NO_X control and WFGD for SO_2 control. In addition, control options were assessed for technical feasibility and effectiveness for LOS Unit 2. LOS Unit 2 is equipped with SOFA/SNCR/Emerson Combustion Optimizer for NO_X control, and WFGD for SO_2 control.

4. SO_2 CONTROL EVALUATION

4.1 BASELINE SO_2 EMISSIONS

The first step in developing the four factor analysis is to establish LOS Units 1 and 2 baseline SO_2 emissions. To establish representative baseline emissions, S&L evaluated Units 1 and 2 operating data for the five year period between January 1, 2013 to September 30, 2018 to identify periods of normal operation (i.e., periods of operation when the boiler was not limited by infrequent or extraordinary operating restrictions). Based on review of fuels consumed, heat input to the boiler, boiler heat rates, power generation, and capacity factors, as well as input from Basin Electric, it was determined that the operating periods of January 1, 2013 to September 30, 2018 were representative of normal boiler operation. The Unit 2 WFGD system for SO_2 control was installed prior to the baseline period (October 2012); however, the Unit 1 WFGD system for SO_2 control was not placed in service until June 2013. Thus, the representative baseline periods for SO_2 emissions for the LOS Units are:

Table 4-1. Representative Baseline Periods for SO_2 Emissions

Pollutant	Representative Baseline Periods	
	LOS Unit 1	LOS Unit 2
SO_2 Emissions	6/1/2013 to 9/30/2018	1/1/2013 to 9/30/2018

Baseline annual SO_2 emissions were determined based on data obtained from the Units 1 and 2 continuous emissions monitoring system (CEMS) that was reported to EPA's Clean Air Markets. The maximum 24-consecutive month annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons per year). Representative baseline emission factors (in terms of pounds per million British Thermal Units (lb/MMBtu)) were developed using baseline annual emissions and the respective annual heat inputs. Table 4-2 provides a summary of the LOS Units 1 and 2 baseline SO_2 emissions. Additional details are included in Appendix B.

Table 4-2: Baseline Actual SO_2 Emissions

LOS Unit	Baseline Controls	SO_2 Emission (Notes 1 and 2)			Capacity Factor During Baseline Period	Current SO_2 Control Percentage (Note 3)	Current Permit Limits (30-day rolling average)
		lb/hr	lb/MMBtu	tons/yr			
Unit 1	WFGD	166	0.09	697	68%	97.1%	0.15 lb/MMBtu or 95% SO_2 removal
Unit 2	WFGD	334	0.09	1,366	69%	97.1%	0.15 lb/MMBtu or 95% SO_2 removal

Note 1. Unit 1 SO_2 emissions based on 24-month annual average for period February 2015 to January 2017.
Note 2. Unit 2 SO_2 emissions based on 24-month annual average for period April 2016 to March 2018.
Note 3. Control percentage calculated based on the range of current annual coal SO_2 content (3.12 lb/MMBtu on Unit 1 and 3.05 lb/MMBtu on Unit 2) between 2014-2018.

Table 4-3: Projected Future Maximum SO_2 Emissions

LOS Unit	Baseline Controls	SO_2 Emission (Note 1)			Capacity Factor for Future Maximum Emissions	Assumed SO_2 Control Percentage (Note 1)	Current Permit Limits (30-day rolling average)
		lb/hr	lb/MMBtu	tons/yr			
Unit 1	WFGD	235	0.09	1,030	100%	97.6	0.15 lb/MMBtu or 95% SO_2 removal
Unit 2	WFGD	454	0.09	1,989	100%	97.6	0.15 lb/MMBtu or 95% SO_2 removal

Note 1. Baseline future maximum SO_2 emission based on a forecast future maximum coal SO_2 content of 3.73 lb/MMBtu, boiler design heat inputs of 2,622 MMBtu/hr (Unit 1) and 5,130 MMBtu/hr (Unit 2), current typical SO_2 removal of 96%, and assumes 100% capacity factor.

4.2 COAL SULFUR CONTENT

The generation of SO_2 is directly related to the sulfur content and heating value (HHV) of the fuel burned. LOS currently burns North Dakota Lignite fuel from the Freedom Mine. North Dakota lignite is characterized by a low heating value and relatively low sulfur content. Typical HHV and coal sulfur content provided by Basin Electric are listed in Table 4-4. The coal quality is based on actual annual fuel data provided by the facility between 2014 and 2018, which is a similar time period as the baseline emission rates.

Table 4-4. Baseline LOS Coal Quality (Annual)

	LOS Unit 1			LOS Unit 2		
Parameter	**Minimum**	**Average**	**Maximum**	**Minimum**	**Average**	**Maximum**
HHV (Btu/lb)	5,387	6,793	7,545	6,124	6,818	7,597
As-Received Sulfur (%)	0.56	1.06	1.90	0.61	1.04	1.78
Uncontrolled SO_2 (lb/MMBtu)	2.08	3.12	5.04	1.99	3.05	4.67
WFGD Design (lb/MMBtu)	--	--	3.9	--	--	3.9

When reviewing the as received coal data, the standard deviation of the coal sulfur content is 0.16% for both units.

In addition, Basin Electric provided anticipated future annual average coal quality projections for the facility between 2019 and 2040. The future range in coal quality is provided in Table 4-5.

Table 4-5. Future LOS Coal Quality (Annual)

Parameter	Minimum	Average	Maximum
HHV (Btu/lb)	6,595	6,650	6,722
As-Received Sulfur (%)	0.70	0.89	1.07
Uncontrolled SO_2 (lb/MMBtu)	2.10	2.67	3.22

The future anticipated coal quality listed in Table 4-5 are based on an annual average values and do not take into account potential deviations in the coal quality that could be seen on a short term basis. As such, the actual coal sulfur content standard deviation (0.16%) from the current coal quality was applied, as stated above, to the maximum annual sulfur coal in Table 4-5. The results are shown in Table 4-6.

Table 4-6. Design Basis for Future Projected LOS Coal Quality (Annual)

Parameter	Unit 1	Unit 2
HHV (Btu/lb)	6,595	6,595
As-Received Sulfur (%)	1.23	1.23
Uncontrolled SO_2 (lb/MMBtu)	3.73	3.73
Uncontrolled SO_2 per Unit (lb/hr) (Note 1)	9,780	19,135
Uncontrolled SO_2 per Unit (tons/yr) (Note 1)	42,837	83,811

Note 1. Uncontrolled SO_2 emissions calculated at the design heat inputs of each Unit (2,622 MMBtu/hr for Unit and 5,130 MMBtu/hr for Unit 2).

Based on the evaluation above, 3.73 lb SO_2/MMBtu is used as the design basis for evaluating the SO_2 control technologies presented in this report is reasonable.

4.3 SO_2 EMISSIONS CONTROLS

4.3.1 Identify Available SO_2 Control Options

The first step in this SO_2 emissions control analysis is to identify, for the emission unit in question, all available SO_2 control options. Available control options are those air pollution control technologies and operational measures with a practical potential for application to the emission unit and the regulated pollutant under evaluation. As part of the first planning period for Regional Haze, the NDDH concluded that WFGD for SO_2 control was BART for LOS Units 1 and 2. As such, the facility is already equipped with modern high-efficiency post-combustion SO_2 control. For the Round II Determination's four factor analysis presented in this report, the NDDH requested Basin Electric to evaluate improvements or upgrades to the existing WFGD systems that could be made to reduce SO_2 emissions further. As such, S&L identified additional SO_2 control options for potential application to Unit 1 and 2 which are listed in Table 4-7.

Table 4-7. Available SO_2 Control Options

SO_2 Control Technologies
Existing FGD Operational Improvements
Existing FGD Design Changes and Equipment Upgrades

4.3.2 Technical Feasibility of Available SO_2 Control Options

Potentially available SO_2 control options identified in Table 4-7 were evaluated for technical feasibility (i.e., availability and applicability to LOS Unit 1 and 2) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options determined to be technically infeasible, or options that have no practical application to LOS Unit 1 and 2, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emissions performance level (i.e., control emissions rate) for each.

4.3.2.1 Operational Improvements and Equipment Upgrades on Existing WFGD

Operational and other design changes/upgrades to the existing WFGD may provide an opportunity for additional SO_2 removal and allow the units to achieve lower controlled SO_2 emissions. S&L, working with Basin Electric personnel, identified a number of potentially feasible operational changes that may be available to increase SO_2 removal efficiency with the existing equipment. Potentially available operational and design changes to the existing control system are summarized in Table 4-8. A detailed discussion of each of these options is provided in the sections below.

Table 4-8. Potential WFGD Operational Improvements and Equipment Upgrades

Existing FGD Operational Improvements
Limestone Quality
Ca:S Stoichiometric Ratio
Liquid-to-Gas (L/G) Ratio
Existing FGD Design Changes and Equipment Upgrades
Additional Spray Level
Optimized Spray Level Coverage
pH Buffer Additive

Limestone Quality

The quantity of limestone ($CaCO_3$) available in a wet scrubbing system compared to the amount of SO_2 entering the system is called the stoichiometric ratio (generally referenced as the Ca:S stoichiometric ratio). Reagent quality directly affects the Ca:S stoichiometric ratio in WFGD control systems. Using a high quality limestone increases the availability of reagent to support process chemistry, and reduces the limestone slurry injection rate needed for SO_2 removal. Better limestone quality allows for a potential increased SO_2 reduction efficiency with fresh limestone slurry injection rates similar to existing rates.

Limestone quality typically ranges from 85-95% for use in WFGD systems. The higher quality limestone is often used in facilities that generate commercial grade saleable gypsum; this limestone would consist of a $CaCO_3$ content of 95% or greater with minimal magnesium (<2.5%). For facilities that do not need to make a salable high quality WFGD byproduct, lower grade limestone quality is adequate. The quality required for disposable byproduct is typically between 85-90% $CaCO_3$. Since the limestone quality is lower, it will result in higher consumption rates when compared to high quality limestone (i.e.>95%).

The LOS WFGD byproduct is currently disposed, as such using a lower quality limestone is acceptable. The facility on average receives 90% or greater $CaCO_3$ content, which is on the high end of quality for generating WFGD byproduct for disposal. Procuring a higher $CaCO_3$ content limestone would not provide any valuable improvement in WFGD performance. Thus, for these reasons, changing the limestone quality is not a technically feasible SO_2 control option for LOS, and will not be evaluated further.

Ca:S Stoichiometric Ratio

Potential operational changes may be available to increase Ca:S stoichiometry in the WFGD by increasing the fresh limestone injected into the Unit 1 or 2 WFGD system. In a WFGD system, flue gas containing SO_2 is brought into contact with limestone slurry droplets and the SO_2 is absorbed into the water droplet. Within the droplet, the SO_2 and calcium form calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4 \cdot 2H_2O$) byproduct. As the slurry falls through the flue gas, it eventually falls into the reaction tank, where it is stored for a few minutes before being recirculated back into the flue gas stream through the recycle spray headers.

As sulfur continues to react with the available $CaCO_3$, fresh limestone makeup to the system is required to maintain the necessary concentration and pH for the reactions and SO_2 removal. More frequent fresh limestone addition will ensure that there is a higher concentration of available reagent in the recycle slurry.

S&L reviewed limestone addition data provided by LOS for Units 1 and 2. At LOS Unit 1, limestone feed rate is maintained relatively close to the maximum design stoichiometry based on the inlet SO_2 concentration. Increasing the fresh limestone addition rate to operate closer to the maximum design stoichiometry could provide nominal additional SO_2 removal. Further increases to limestone consumption beyond the design rate are not recommended, due to potential harmful effects of changes of slurry pH, which can lead to scaling concerns and oxidation-reduction potential (ORP) issues. LOS has already had issues with pH control and limestone addition beyond the design rate may drive the pH too high. As such, an increase in Ca:S stoichiometry to the design is considered to be a technically feasible SO_2 control option for LOS Unit 1. This adjustment to station work practices would require a slight increase in limestone addition to achieve an11% reduction from the baseline SO_2 hourly rate (in lb/hr).

A similar analysis was conducted on Unit 2 limestone addition rates. Similarly, there is minor improvement to achieve maximum design stoichiometry at full load based on the inlet sulfur. It is not recommended to increase the rates above design, due to the aforementioned effects of operating outside of design pH range. However, increasing stoichiometry would have to be done in conjunction with increasing the L/G ratio. The L/G, which is a measurement of the volume of liquid slurry recycled in comparison to the volumetric flow rate of gas passing through the absorber, also typically has an effect on removal efficiency. Since the limestone injection rate and the L/G ratio rely upon each other for the system to operate as design, it is difficult to predict performance improvement with increased limestone alone. As such, for LOS Unit 2, increased limestone stoichiometry will be reviewed in conjunction with increasing the L/G ratio as discussed in the next section.

Liquid-to-Gas Ratio

The L/G ratio in a WFGD is indicative of the total surface area of reagent available for the reaction with the acid gases in the flue gas, such as SO_2. L/G is an important parameter for WFGD systems to account for the design contact between the available reagent and SO_2 in the flue gas. A higher L/G ratio corresponds to more liquid volume coverage within the cross-sectional area of a WFGD vessel. As the L/G ratio increases, there is additional contact of the flue gas with the limestone slurry as it passes through the absorber vessel, which can increase the removal efficiency.

L/G ratio can be improved by increasing the liquid flowrate through each recycle spray header. WFGD spray headers are designed with a spray volume coverage required by the performance of the system. As inlet conditions vary over time, the spray flow can be adjusted to maintain the necessary spray for design performance. Additionally, adjustments in unit load will cause the L/G ratio to vary; however if the system is setup at a constant recycle slurry flow rate, the L/G ratio will be higher at lower loads, which provides higher SO_2 removal efficiencies.

S&L estimated recycle slurry flow rates based on pump operating data provided by LOS for Units 1 and 2. Based on the data provided, the Unit 1 pumps operate with three of the four spray levels always in service. Current industry practice for WFGD systems are such that the system is designed with a spare recycle pump and spray level in order to maintain SO_2 removal while performing maintenance activities on the recycle pumps. Furthermore, the recycle flow rate data suggest that all Unit 1 operating pumps are working at their maximum capacity at all times. This was confirmed by LOS operating personnel that explained that the recycle pumps are manually operated and not adjusted for operating load or SO_2 loading. This suggests there is no potential for increased L/G ratio without major modifications to the spray headers. For these reasons, changes to L/G ratio is not considered to be a technically feasible SO_2 reduction option for LOS Unit 1, and will not be evaluated further.

As mentioned in the previous section, Unit 2 is not operating at its maximum design L/G ratio. The design of the Unit 2 WFGD is based on four of five recycle pumps operating at maximum flow at full load, to satisfy the design operating profile; however, the facility has only been operating three at a time, due to lower inlet sulfur loading than design (3.9 lb/MMBtu) and is still maintaining SO_2 emissions below the permitted limit. Fuel forecasts suggest that the inlet sulfur loading could increase to 3.73 lb/MMBtu on a short term basis, within the next 5-10 years, from the baseline SO_2 fuel composition of 3.05 lb/MMBtu for Unit 2. As the facility starts to burn higher sulfur coal in comparison to the recent historical quality, the site personnel can manually place the fourth pump in service.

However, based on review of data provided by LOS, the flow rate of the pumps that are in operation is less than design, which is mainly due to the rigorous required maintenance to keep them at full efficiency and design flow rate. If the pumps are increased to maximum design capacity and the limestone is increased to the appropriate ratio (as referenced in the previous section), the Unit 2 WFGD would be expected to achieve a nominal reduction in SO_2 emissions at full load. For these reasons, operating changes resulting in an increase in Ca:S stoichiometry in conjunction with an increase in L/G is considered to be a technically feasible SO_2 control option for LOS Unit 2, and will be evaluated further. It is expected that the adjustment to station work practices may achieve a 15% reduction from the baseline SO_2 hourly rate (in lb/hr).

Additional Spray Level

Another method to increase L/G ratio in a WFGD system is to increase the amount of spray levels. As mentioned previously, Units 1 and 2 are designed with a spare spray level to account for a certain level of redundancy for maintenance purposes. If increased L/G ratio cannot be obtained by increasing the throughput of slurry through the existing spray headers, an additional recycle pump and spray header may be added. An additional spray level would increase the L/G ratio by 33% on Unit 1 and 20% on Unit 2.

The original equipment manufacturer (OEM) provided correction curves that suggest an additional 1% removal efficiency could be achieved with all pumps and spray levels in service at both LOS units. As such, it is expected that installing an additional spray level would improve LOS Unit 1 and 2 performance. However, S&L reviewed the absorber drawings for each unit and concludes there is no room for an additional slurry spray level. Due to the location of the mist eliminators which are directly above the highest spray level and the inlet flue gas duct located directly below the first spray level, there is no room to install another spray level unless the top of the absorber is extended to make room for another spray level. All of the internals in this section would need to be restructured including the outlet cone ductwork to the chimney. For these reasons, an additional spray header is not considered to be a technically feasible SO_2 control option for LOS Unit 1or 2, and will not be evaluated further.

Optimized Spray Level Coverage

Another option for improving the design of the WFGD system is by ensuring there is full coverage of the slurry spray through the cross-sectional area of the absorber. Improving distribution of the slurry as well as spray nozzle design can reduce localized flue gas slippage as well as increase L/G. Improvements to spray design can provide better pattern of coverage, finer droplet size and more even coverage.

S&L consulted the WFGD OEM to determine if there have been any developments in spray header design since the LOS WFGD's were installed. The OEM concluded that the LOS WFGD systems were originally designed with state of the art spray coverage and up/down nozzle patterns, which is consistent with the most modern WFGD systems. As such no additional improvements could be made to the spray nozzle design to improve the WFGD efficiency. For these reasons, optimizing the spray nozzle design is not considered to be a technically feasible SO_2 control option for LOS Unit 1or 2, and will not be evaluated further.

pH Buffer Additive

As discussed previously, there is a limit to the amount of fresh limestone makeup that can be added to the WFGD. WFGD systems require a delicate balance of pH to allow for proper reaction kinetics and limit the scaling potential within the system. As SO_2 from the flue gas dissolves in the slurry, the water becomes acidic. Limestone is added, which neutralizes the slurry. However, limestone does not dissolve readily, thus making it difficult to neutralize the SO_2 as it enters. Since the solubility of limestone is minimal, there is only a small amount of dissolved limestone on the surface of the slurry droplet to react with SO_2.

Additives have been developed for use in WFGD systems to improve the ability for limestone to neutralize and react with SO_2. Thus use of additives such as dibasic acid (DBA) increase the removal efficiency in WFGD systems. DBA is a mixture of dicarboxylic acids, or carbon chains with carboxylic acids. The DBA quickly combines with free hydrogen ions at the gas-liquid interface, which hinders the slurry from dropping in pH. The increased alkalinity raises the solubility of SO_2 within the limestone slurry, thus expanding the efficiency of the absorber column.

The use of DBA in conjunction with increasing fresh limestone injection rates is expected to provide the WFGD with an additional 1% SO_2 removal efficiency. This performance could be obtained for the expected fuel sulfur content up to 3.73 lb/MMBtu. The facility is currently equipped with two common limestone ball mills, one operating and one spare, and a forwarding system with four slurry pumps. Based on the maximum future fuel sulfur content, the ball mills and slurry forwarding systems have sufficient capacity to provide the additional limestone required for Units 1 and 2 while still maintaining complete redundancy. Additional equipment for the DBA addition system would require a small tank and pump to add to the slurry holding tank. As such, DBA and increased limestone makeup is determined to be a technically feasible option for providing additional SO_2 removal efficiency on LOS Units 1 and 2.

4.3.2.2 Technical Feasibility Summary

Table 4-9 and Table 4-10 summarize the results of the feasibility evaluation of available control options for LOS Units 1 and 2.

Table 4-9. Technically Feasible SO_2 Control Options for LOS Unit 1

SO_2 Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Existing FGD Operational Improvements:			
Limestone Quality	No	0%	Changing limestone quality in the existing WFGD control system is not a technically feasible operational change for LOS Unit 1.
Ca:S Stoichiometric Ratio	Yes	97.4%	Increasing the Ca:S stoichiometric ratio by increasing the quantity of fresh limestone to the system is considered a technically feasible option for LOS Unit 1.
L/G Ratio	No	0%	Increasing the slurry recirculation rate (L/G) on the existing WFGD control system is not a technically feasible option for LOS Unit 1.
Existing FGD Design Changes and Equipment Upgrades:			
Additional Spray Level	No	0%	Adding a spray level to the existing WFGD control system is not a technically feasible upgrade for LOS Unit 1.
Optimized Spray Level Coverage	No	0%	Optimizing the slurry spray level coverage on the existing WFGD control system is not a technically feasible option for LOS Unit 1.
pH Buffer Additive	Yes	98.2%	Incorporating pH buffer to the limestone slurry and increasing limestone addition rate is a technically feasible option for LOS Unit 1.

Note 1. Control percentage calculated using the baseline SO_2 coal quality of 3.12 lb/MMBtu and the achievable SO_2 emission rate for each technically feasible control option.

Table 4-10. Technically Feasible SO_2 Control Options for LOS Unit 2

SO_2 Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Existing FGD Operational Improvements:			
Limestone Quality	No	0%	Changing limestone quality in the existing WFGD control system is not a technically feasible operational change for LOS Unit 2.
Ca:S Stoichiometric Ratio	Yes	97.5%	Increasing the Ca:S stoichiometric ratio by increasing the quantity of fresh limestone to the system is considered a technically feasible option for LOS Unit 2, but should be done in conjunction with increasing the slurry recirculation rate (L/G).
L/G Ratio	Yes		
Existing FGD Design Changes and Equipment Upgrades:			
Additional Spray Level	No	0%	Adding a spray level to the existing WFGD control system is not a technically feasible upgrade for LOS Unit 2.
Optimized Spray Level Coverage	No	0%	Optimizing the slurry spray level coverage on the existing WFGD control system is not a technically feasible option for LOS Unit 2.
pH Buffer Additive	Yes	98.4%	Incorporating pH buffer to the limestone slurry and increasing limestone addition rate is a technically feasible option for LOS Unit 2.

Note 1. Control percentage calculated using the baseline SO_2 coal quality of 3.05 lb/MMBtu and the achievable SO_2 emission rate for each technically feasible control option.

4.3.3 Evaluate Technically Feasible SO_2 Control Options for Effectiveness

The technically feasible SO_2 control technologies are listed in Table 4-11 and Table 4-12 in descending order of control efficiency. They also provide control option-specific SO_2 emission rates in terms of lb/MMBtu. Emission rates shown represent average emission rates that the control options would be expected to achieve during normal operations on a long-term averaging basis.

Table 4-11. Evaluate Technically Feasible SO_2 Control Options by Effectiveness for LOS Unit 1 (Baseline Average Emissions)

Alt. No.	Control Technology	SO_2 Emission Rate (Note 1) lb/MMBtu	% Reduction from Baseline SO_2 Coal Quality (Note 2)	SO_2 Emission Rate (Note 1) lb/hr	SO_2 Emission Rate (Note 1) tons/yr
B	FGD Upgrades – pH Buffer Addition	0.055	98.2	102	427
A	FGD Operational Improvements – Ca:S Stoichiometry	0.08	97.4	148	622
--	Baseline (existing WFGD)	0.09	97.1	166	697
--	Permit Limit	0.15 (30-day)	95		

Note 1: Emission rates shown in Table 4-11 represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for LOS Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2: Baseline SO_2 coal quality is 3.12 lb/MMBtu. See Section 4.2 for additional details on coal sulfur.

Table 4-12. Evaluate Technically Feasible SO_2 Control Options by Effectiveness for LOS Unit 2 (Baseline Average Emissions)

Alt. No.	Control Technology	SO_2 Emission Rate (Note 1) lb/MMBtu	% Reduction from Baseline SO_2 Coal Quality (Note 2)	SO_2 Emission Rate (Note 1) lb/hr	SO_2 Emission Rate (Note 1) tons/yr
B	FGD Upgrades – pH Buffer Addition	0.05	98.4	189	772
A	FGD Operational Improvements – Ca:S Stoichiometry and L/G Ratio	0.075	97.6	283	1,158
--	Baseline (existing WFGD)	0.09	97.2	334	1,366
--	Permit Limit	0.15 (30-day)	95		

Note 1: Emission rates shown in Table 4-12 represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for LOS Unit 2. Emission rates are provided for comparative purposes, and should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Note 2: Baseline SO_2 coal quality is 3.05 lb/MMBtu. See Section 4.2 for additional details on coal sulfur.

Table 4-13 and Table 4-14 provide control option-specific SO_2 emission rates in terms of lb/MMBtu based on the projected future maximum emission rates. Emission rates shown represent the projected future maximum emission rates that the control options would be expected to achieve during normal operations.

Table 4-13. Evaluate Technically Feasible SO_2 Control Options by Effectiveness for LOS Unit 1 (Projected Future Maximum Emissions)

Alt. No.	Control Technology	SO_2 Emission Rate (Note 3) lb/MMBtu	% Reduction from Future SO_2 Coal Quality (Note 1)	SO_2 Emission Rate (Note 1) lb/hr	SO_2 Emission Rate (Note 2) tons/yr
B	FGD Upgrades – pH Buffer Addition	0.055	98.5	144	632
A	FGD Operational Improvements – Ca:S Stoichiometry	0.08	97.9	210	919
--	Baseline (existing WFGD)	0.09	97.6	235	1,030
--	Permit Limit	0.15 (30-day)	95		

Note 1: Future SO_2 coal quality is 3.73 lb/MMBtu. See Section 4.2 for additional details on coal sulfur.
Note 2. Annual SO_2 emissions based on 8,760 hours per year operation.
Note 3. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Table 4-14. Evaluate Technically Feasible SO_2 Control Options by Effectiveness for LOS Unit 2 (Projected Future Maximum Emissions)

Alt. No.	Control Technology	SO_2 Emission Rate (Note 3) lb/MMBtu	% Reduction from Future SO_2 Coal Quality (Note 1)	SO_2 Emission Rate (Note 1) lb/hr	SO_2 Emission Rate (Note 2) tons/yr
B	FGD Upgrades – pH Buffer Addition	0.05	98.7	257	1,123
A	FGD Operational Improvements – Ca:S Stoichiometry and L/G Ratio	0.075	98.0	385	1,685
--	Baseline (existing WFGD)	0.09	97.6	454	1,989
--	Current Permit Limit	0.15 (30-day)	95		

Note 1: Future SO_2 coal quality is 3.73 lb/MMBtu. See Section 4.2 for additional details on coal sulfur.
Note 2. Annual SO_2 emissions based on 8,760 hours per year operation.
Note 3. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

4.4 COSTS OF COMPLIANCE (STATUTORY FACTOR ONE)

The economic analysis performed as part of the four factor analysis examines the cost-effectiveness of each technically feasible control technology, on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. For units with existing controls, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual O&M costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of control equipment. Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25% and equipment life of 20 years.[32] Cost effectiveness ($/ton) of a particular control option is simply the annual cost ($/yr) divided by the annual reduction in annual emissions (tons/yr). In addition to cost-effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the incremental cost effectiveness of the more stringent control.

Capital and O&M cost estimates were developed for each of the technically feasible SO_2 control options. The LOS Units 1 and 2 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Units 1 and 2 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on Units 1 and 2-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the LOS Units 1 and 2 retrofit technologies as "concept screening" cost estimates generally based on parametric models, judgment, or analogy.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, contractor general and administrative (G&A) expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

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[32] The assumed 20-year equipment life is consistent with the control system equipment life used by NDDH in its evaluation of NO_X and SO_2 control technologies for BART-eligible sources. (see, e.g., ND Regional Haze Final SIP, Appendix C.1, "BART Determination Study for Leland Olds Station Units 1 & 2, Basin Electric Power Cooperative, August 2006, pgs. 64 (NOx controls) and 158 (SO2 controls). See also, ND Regional Haze Final SIP, Appendix C4, "NOx Best Available Control Technology Study for Milton R. Young Station Unit 1, Minnkota Power Cooperative, Inc., October 2006, pg. 3-22).

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements.[33] Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing WFGD systems.

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

4.4.1 SO_2 Average Annual Economic Evaluation

Table 4-15 and Table 4-16 present the capital costs and annual operating costs associated with installing and operating each technically feasible SO_2 control system for LOS Unit 1 and 2. They also show the average annual and incremental cost effectiveness for each control system. Additional cost details are provided in Appendix C.

Table 4-15. SO_2 Control Cost Summary (Average Annual)

LOS Unit No.	Alt. No.	SO_2 Control Option	Total Capital Investment $	Annual Capital Recovery Cost $/yr	Annual Operating Cost $/yr	Total Annual Cost $/yr
Unit 1	B	FGD Upgrades – pH Buffer Addition	$8,266,000	$677,000	$4,156,000	$4,833,000
	A	FGD Operational Improvements – Ca:S Stoichiometry	$0	$0	$752,000	$752,000
Unit 2	B	FGD Upgrades – pH Buffer Addition	$11,560,000	$947,000	$7,340,000	$8,287,000
	A	FGD Operational Improvements – Ca:S Stoichiometry and L/G Ratio	$0	$0	$1,439,000	$1,439,000

Note 1. Annual operating costs based on baseline SO_2 coal quality (3.12 and 3.05 lb/MMBtu for Units 1 and 2, respectively) and capacity factor during baseline SO_2 period for each LOS Unit.

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[33] Variable O&M costs are based on the future coal SO_2 of 3.66 lb/MMBtu

Table 4-16. SO_2 Emissions Control System Cost Effectiveness (Average Annual)

LOS Unit No.	Alt. No.	SO_2 Control Option	Total Annual Cost $	Expected Emission Reduction tons SO_2/yr	Average Annual Cost-Effectiveness $/ton SO_2 removed	Incremental Annual Cost-Effectiveness (Note 1) $/ton SO_2 removed
Unit 1	B	FGD Upgrades – pH Buffer Addition	$4,833,000	269	$17,948	$21,013
	A	FGD Operational Improvements – Ca:S Stoichiometry	$752,000	75	$10,021	
Unit 2	B	FGD Upgrades – pH Buffer Addition	$8,287,000	594	$13,946	$17,748
	A	FGD Operational Improvements – Ca:S Stoichiometry and L/G Ratio	$1,439,000	208	$6,906	

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual SO_2 emissions reductions (tons/yr) between a control option and the next most effective option.

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline SO_2 coal quality (3.12 and 3.05 lb/MMBtu for Units 1 and 2, respectively) and capacity factor during baseline SO_2 period for each LOS Unit.

Table 4-16 indicates that the average annual cost effectiveness of the technically feasible SO_2 control options for Unit 1 range from $10,021 per ton (FGD operational improvements – Increase Ca:S stoichiometric ratio) to $17,948 per ton (FGD upgrades – pH buffer addition) SO_2 removed; and for Unit 2 ranges from $6,906 per ton to $13,946 per ton of SO_2 removed.

Operational improvements to the Unit 1 existing WFGD system by improving Ca:S stoichiometric ratio is expected to achieve approximately 11% SO_2 reduction from the baseline for a cost effectiveness of approximately $10,000 per ton. This is due to the expected operating costs of increased limestone consumption in comparison with the limited additional SO_2 removal on an annual basis. Upgrading the existing WFGD system with pH buffer addition on Unit 1 is expected to achieve approximately 39% SO_2 reduction from baseline emission rates. The cost effectiveness of this option is approximately $18,000 per ton. The cost is mainly driven by pH buffer additive costs with limited annual SO_2 emission reduction. Compared to the operational improvements alone, the incremental cost effectiveness of the upgrades is approximately $21,000 per ton for Unit 1.

Operational improvements to the Unit 2 existing WFGD system by improving Ca:S stoichiometric ratio is expected to achieve approximately 15% SO_2 reduction from the baseline at a cost effectiveness of approximately $7,000 per ton. This is due to the expected operating costs of increased limestone consumption in comparison with the limited additional SO_2 removal on an annual basis. Upgrading the existing WFGD system with pH buffer addition on Unit 2 is expected to achieve approximately 44% SO_2 reduction from baseline emission rates. The cost effectiveness of this option is approximately $14,000 per ton. The cost is mainly driven by pH buffer additive costs with limited annual SO_2 emission reduction. Compared to the operational improvements alone, the incremental cost effectiveness of the upgrades is approximately $18,000 per ton for Unit 2.

4.4.2 SO_2 Potential-to-Emit Annual Economic Evaluation

Table 4-17 presents the capital costs and annual operating costs associated with building and operating each control system; annual operating costs are based on the units operating at 100% capacity factor and future coal quality considering potential variability.

Table 4-17. SO_2 Control Cost Summary (Projected Future Maximum)

LOS Unit No.	Alt. No.	SO_2 Control Option	Total Capital Investment $	Annual Capital Recovery Cost $/yr	Annual Operating Cost $/yr	Total Annual Cost $/yr
Unit 1	B	FGD Upgrades – pH Buffer Addition	$8,266,000	$677,000	$6,865,000	$7,542,000
	A	FGD Operational Improvements – Ca:S Stoichiometry	$0	$0	$2,019,000	$2,019,000
Unit 2	B	FGD Upgrades – pH Buffer Addition	$11,560,000	$947,000	$12,429,000	$13,376,000
	A	FGD Operational Improvements – Ca:S Stoichiometry and L/G Ratio	$0	$0	$4,078,000	$4,078,000

Note 1. Annual operating costs based on projected future maximum SO_2 coal quality (3.73 lb/MMBtu) and 100% capacity factor for each LOS Unit.

Table 4-18 shows the average annual and incremental cost effectiveness for each control system with emissions reductions and cost effectiveness values based on 100% capacity factors and projected future maximum emission rates. Additional cost details are provided in Appendix C.

Table 4-18. SO_2 Emissions Control System Cost Effectiveness (Projected Future Maximum)

LOS Unit No.	Alt. No.	SO_2 Control Option	Total Annual Cost $	Expected Emission Reduction tons SO_2/yr	Average Annual Cost-Effectiveness \$/ton SO_2 removed	Incremental Annual Cost-Effectiveness (Note 1) \$/ton SO_2 removed
Unit 1	B	FGD Upgrades – pH Buffer Addition	$7,542,000	398	$18,948	$19,237
	A	FGD Operational Improvements – Ca:S Stoichiometry	$2,019,000	111	$18,200	
Unit 2	B	FGD Upgrades – pH Buffer Addition	$13,376,000	865	$15,462	$16,552
	A	FGD Operational Improvements – Ca:S Stoichiometry and L/G Ratio	$4,078,000	303	$13,444	

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual SO_2 emissions reductions (tons/yr) between a control option and the next most effective option.

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline SO_2 coal quality (3.73 lb/MMBtu) and 100% capacity factor for each LOS Unit.

Table 4-18 indicates that the average annual cost effectiveness of the technically feasible SO_2 control options for Unit 1 range from $18,200 per ton (FGD operational improvements – Increase Ca:S stoichiometric ratio) to $18,948 per ton (FGD upgrades – pH buffer addition) SO_2 removed; and for Unit 2 ranges from $13,444 per ton to $15,462 per ton of SO_2 removed.

Operational improvements to the Unit 1 existing WFGD system by improving Ca:S stoichiometric ratio is expected to achieve approximately 11% SO_2 reduction from the baseline for a cost effectiveness of approximately $18,000 per ton. This is due to the expected operating costs of increased limestone consumption in comparison with the limited additional SO_2 removal on an annual basis. Upgrading the existing WFGD system with pH buffer addition on Unit 1 is expected to achieve approximately 39% SO_2 reduction from baseline emission rates. The cost effectiveness of this option is approximately $19,000 per ton. The cost is mainly driven by pH buffer additive costs with limited annual SO_2 emission reduction. Compared to the operational improvements alone, the incremental cost effectiveness of the upgrades is approximately $19,000 per ton for Unit 1.

Operational improvements to the Unit 2 existing WFGD system by improving Ca:S stoichiometric ratio is expected to achieve approximately 15% SO_2 reduction from the baseline at a cost effectiveness of approximately $13,000 per ton. This is due to the expected operating costs of increased limestone consumption in comparison with the limited additional SO_2 removal on an annual basis. Upgrading the existing WFGD system with pH buffer addition on Unit 2 is expected to achieve approximately 44% SO_2 reduction from baseline emission rates. The cost effectiveness of this option is approximately $15,000 per ton. The cost is mainly driven by pH buffer additive costs with limited annual SO_2 emission reduction. Compared to the operational improvements alone, the incremental cost effectiveness of the upgrades is approximately $16,000 per ton for Unit 2.

5. NO_X CONTROL EVALUATION

5.1 BASELINE NO_X EMISSIONS

The first step in developing the four factor analysis is to establish LOS Units 1 and 2 baseline NO_X emissions. To establish representative baseline emissions, S&L evaluated Units 1 and 2 operating data for the five year period between January 1, 2013 to September 30, 2018 to identify periods of normal operation (i.e., periods of operation when the boiler was not limited by infrequent or extraordinary operating restrictions). Based on review of fuels consumed, heat input to the boiler, boiler heat rates, power generation, and capacity factors, as well as input from Basin Electric, it was determined that the operating periods of January 1, 2013 to September 30, 2018 were representative of normal boiler operation. However, during the baseline operating period, the BART compliance emission control technologies were installed. SNCR systems for NO_X control were placed into service and considered optimized in September 2017 for Unit 1 and in April 2017 for Unit 2. Thus, the representative baseline periods for NO_X emissions for the LOS Units are:

Table 5-1. Representative Baseline Periods for NO_X Emissions

Pollutant	Representative Baseline Periods	
	LOS Unit 1	LOS Unit 2
NO_X Emissions	9/1/2017 to 9/30/2018	4/1/2017 to 9/30/2018

Baseline annual NO_X emissions were determined based on data obtained from the Units 1 and 2 CEMS that was reported to EPA's Clean Air Markets. The maximum 12-consecutive month annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons/yr). A 12-month average was used rather than 24-month averaging timeframe (as used in the SO_2 evaluation) due to the recent NO_X control optimization technology implementation. Representative baseline emission factors (in terms of pounds per million British Thermal Units (lb/MMBtu)) were developed using baseline annual emissions and the respective annual heat inputs. Table 4-2 provides a summary of the LOS Units 1 and 2 baseline NO_X emissions. Additional details are included in Appendix B.

Table 5-2: Baseline Actual NO_X Emissions

LOS Unit	Baseline Controls	NO_X Emission^(Note 1)^			Capacity Factor During Baseline Period	Current Permit Limits
		lb/hr	lb/MMBtu	tons/yr		
Unit 1	LNB / SOFA / SNCR	255	0.15	905	51%	0.19 lb/MMBtu (30-day average)
Unit 2	SOFA / SNCR	1,099	0.30	4,530	68%	0.35 lb/MMBtu (30-day average)

Note 1. Unit 1 annual NO_X emissions for period July 2017 to June 2018.
Note 2. Unit 2 annual NO_X emissions for period April 2017 to March 2018.

Table 5-3: Baseline Projected Future Maximum NO_X Emissions

LOS Unit	Baseline Controls	NO_X Emission^(Note 1)^			Capacity Factor for Future Maximum Emissions	Current Permit Limits
		lb/hr	lb/MMBtu	tons/yr		
Unit 1	LNB / SOFA / SNCR	406	0.15	1,779	100%	0.19 lb/MMBtu (30-day average)
Unit 2	SOFA / SNCR	1,528	0.30	6,692	100%	0.35 lb/MMBtu (30-day average)

Note 1. Baseline future maximum NO_X emission based on boiler design heat input of 2,622 MMBtu/hr (Unit 1) and 5,130 MMBtu/hr (Unit 2) and assumes 100% capacity factor.

5.2 NO_X EMISSIONS CONTROLS

5.2.1 Identify Available NO_X Control Options

Based on a review of available NO_X control technologies installed on existing opposed-fired pulverized coal boilers and cyclone boilers designed to fire lignite coal, NO_X control techniques can be divided into pre-combustion strategies and post-combustion controls. NO_X control options identified for potential application to LOS Unit 1 and 2 are listed in Table 5-4.

Table 5-4. Available NO_X Control Options

NO_X Control Technologies
Selective Catalytic Reduction - High Dust, Low Dust or Tail End Configuration (TE-SCR)
Optimized Selective Non-Catalytic Reduction (SNCR)
Rich Reagent Injection (RRI)
Optimized SCR + RRI
Gas Reburn
Innovative Technologies (i.e. NO_XStar, Water Injection, LoTOX, PerNO$_X$ide, Water Injection)

5.2.2 Technical Feasibility of Available NO_X Control Options

Potentially available NO_X control options identified in Table 5-4 were evaluated for technical feasibility (i.e. availability and applicability to LOS Unit 1 and 2) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options deemed to be technically infeasible, or options that have no practical application to LOS Unit 1 and 2, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emission performance level (i.e., controlled emission rate) for each.

5.2.2.1 Selective Catalytic Reduction

SCR is a process by which ammonia (NH_3) reacts with nitric oxide (NO) and nitrogen dioxide (NO_2), collectively NO_X, in the presence of a catalyst to reduce the NO_X to nitrogen (N_2) and water. SCR technology has been applied to NO_X-bearing flue gases generated from power generating facilities burning various types of coal, including bituminous, subbituminous, and Texas lignite). The principal reactions resulting in NO_X reduction are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NO_2 + 8NH_3 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

Because these reactions proceed slowly at typical boiler exit gas temperatures of a coal-fired steam EGU, a catalyst is used to increase the reaction rate between NO_X and ammonia. Depending on the specific constituents in the flue gas, a typical temperature range of 550°F to 780°F is necessary to achieve normal performance of the catalyst. For the typical coal-fired boiler, optimal performance will be in the range of approximately 650°F to 750°F.

In general, there are three candidate SCR configurations that can be employed on coal-fired steam EGUs. The SCR configuration designations generally describe the location of the SCR reaction vessel in relation to other post-combustion air quality control systems. Candidate SCR configurations include:

- High-dust configuration
- Low-dust configuration
- Tail-end configuration

Each of these configurations is described below as they may be applied at LOS Unit 1 and 2.

High-Dust Configuration

In a high-dust configuration, the SCR reactor is located in the flue gas stream between the economizer outlet and the air heater inlet. This configuration locates the SCR within the inherently optimal temperature range environment for NO_X reduction (i.e., 650°F to 750°F); however, flue gas characteristics at the economizer outlet can also have detrimental effects on the SCR catalyst. As an example, the high-dust SCR configuration exposes the SCR catalyst to high levels of fly ash loading. High levels of fly ash can result in significant erosion of the catalyst, resulting in more frequent cleaning cycles and catalyst replacement. A second major concern with the high-dust configuration at LOS Units 1 and 2 is the presence of high levels of sodium (both in the vapor-phase and as submicron aerosols) in the North Dakota lignite-derived flue gas. Sodium is a known SCR catalyst poison, and also affects the adhesive and cohesive characteristics of the fly ash, which in turn, would have an adverse effect on the SCR catalyst and reactor vessel.

SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation) or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition). Loss of catalyst activity through thermal degradation or poisoning is permanent, and reactivity can only be restored by replacing the catalyst.

In a North Dakota lignite application, SCR catalyst poisoning is expected to result from the presence of trace elements and strong alkaline substances in flue gas, including sodium (Na), potassium (K), calcium (Ca), and magnesium (Mg). Alkaline metals can chemically attach to active catalyst pore sites and cause deactivation. Sodium and potassium are of prime concern especially in their water-soluble forms, which are more mobile and can penetrate into the catalyst pores. Earth metals, especially calcium, can react with sulfur trioxide (SO_3) absorbed within the catalyst to form $CaSO_4$ and blind the catalyst.

North Dakota lignite contains relatively high levels of organically associated alkali and alkaline-earth elements, including Na, K, Ca, and Mg. Sodium levels in North Dakota lignite are typically 5 to 20 times higher than sodium levels in bituminous and subbituminous coals, and sodium compounds can represent between 5% and 11% of the ash generated from firing North Dakota lignite. These sodium levels, occurring in both the vapor phase and particulate phase, along with relatively high levels of potassium and calcium, significantly increase the potential for catalyst deactivation, plugging, and erosion. Based on the ash chemistry, a conventional high dust SCR arrangement would likely experience unacceptable catalyst deactivation rates.

As noted in Section 3.1.1.2, during the first Regional Haze planning period, NDDH prepared a comprehensive technical feasibility assessment of high dust SCR on lignite-fired boilers (North Dakota Regional Haze SIP, Appendix B-5).[34] The NDDH concluded, based on the unique characteristics of North Dakota lignite-derived flue gas, that the high-dust SCR configuration was not a technically feasible or commercially available NO_X control option for North Dakota lignite-fired boilers such as LOS Unit 1 and 2.[35] This determination was consistent with

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[34] See, North Dakota State Implementation Plan for Regional Haze, February 24, 2010, Appendix B.5, Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite, July 2009.

[35] See, North Dakota State Implementation Plan for Regional Haze, February 24, 2010, Appendix B.9, Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite, July 2009, pg. 19.

the NDDH's NO_X BACT determination for MRYS Units 1 & 2.[36] Reasons upon which NDDH based its conclusion that high-dust SCR was not a technically feasible option for North Dakota lignite-fired boilers included, but were not limit to:[37]

1) North Dakota lignite[38] has a higher organic matter content and contains a higher proportion of alkali metal constituents, especially sodium, than subbituminous coal. Approximately 75% of the total sodium in lignite is associated with the organic fraction of the lignite. During combustion, organic and water-soluble sodium vaporizes; consequently, combustion of the coal leads to higher flue-gas concentrations of alkali metals in vapor form.
2) The unburned or partially burned organic fraction of North Dakota lignite contains more sodium than other coals. Sodium can react with silicate particles causing a "stickiness" quality to the flue gas ash, resulting in increased ash deposition on heat transfer surfaces. Larger particles can fracture from heat-transfer surfaces (a.k.a. popcorn ash) and enter the flue gas stream. Consequently, deposition on surfaces of catalytic reactors occurs and rates of deposition are higher.
3) NO_X reduction occurs on the flat surfaces of a catalyst and in pores within the flat surfaces. The pores are open to the flue gas passing through the catalyst reactor. Condensed vapors, alkali sulfates and alkaline-earth oxides and silicates are minute particles (less than 1 microns), which enter pores of the catalyst (a.k.a. plugging) and prevent catalytic reaction with NO_X. Residual alkali vapors (Na, K, and Ca) displace hydrogen on fresh catalyst, which prevents catalytic reaction with NO_X (a.k.a poisoning) and reacts with sulfate to cause blinding of catalyst surfaces. Pore condensation of sodium also causes catalyst deactivation, which is a major deactivation mechanism. The rate of catalyst deactivation depends on the concentration and form of alkali in the flue gas; higher Na and K accelerate catalyst poisoning, blinding and plugging.
4) During the development of the initial planning period SIP, NDDH found that there were no SCR systems planned, constructed, or operating in the flue gas stream of boilers fired with North Dakota lignite. North Dakota lignite has certain coal characteristics that are uniquely different than Texas or Gulf Coast lignites, such as the larger proportion of organic matter and association of alkali, sodium specifically, with that organic matter.
5) Slipstream SCR reactors of the same design were installed at three power plants to test SCR for NO_X emissions control. One of the plants was cyclone fired with North Dakota lignite and the others with subbituminous coal. Deposition on the reactor surface after two months using the lignite was significantly greater; the deposits were rich in sodium, calcium, and sulfur. The tests confirmed catalyst blinding and

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[36] As noted in section 3.1.1.2, contemporaneous with the Regional Haze SIP/FIP process, NDDH also prepared a BACT analysis for MRYS Units 1 & 2. In its BACT analysis, NDDH concluded that SCR was technically infeasible on a lignite-fired cyclone boiler, and selected SNCR as BACT. On December 21, 2011, the District Court issued a decision finding that the State's conclusion that SCR was not technically feasible was not unreasonable. See, U.S. v. Minnkota, 831 F. Supp. 2d at 1127-30

[37] Findings and conclusions are summarized from the North Dakota Regional Haze SIP, Appendix B.5, pgs. 15-19.

[38] Although the BART determination specifically references Fort Union lignite, the findings would apply to all North Dakota lignites.

> plugging, but did not provide rates for catalyst deactivation. Tests also indicated that the deposits causing blinding and plugging of pores contained more sodium compared to Powder River Basin (PRB) coal.

Based on these findings, NDDH concluded that additional pilot scale testing would be required to assess issues specifically associated with the North Dakota lignite-generated flue gas characteristics, including potential impacts associated with:

- the high level of soluble alkali in North Dakota lignite;
- the potential abrasive qualities of North Dakota lignite ash; and
- particle size and sticky nature of high alkaline North Dakota lignite ash.

The NDDH concluded that without pilot scale testing the long term NO_X reduction efficiency, the volume of the reactor, the catalyst pitch and life of catalyst, could not be predicted with a high degree of confidence. Noting that the BART Guidelines do not require source owners/operators to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type, and that technologies in the pilot scale testing stages of development are not considered as "available" for purposes of BART, NDDH determined that high dust SCR was not available, and thus, not technically feasible for units combusting North Dakota lignite.[39]

Although the first planning period BART determinations, focused on North Dakota lignite-fired cyclone boilers (i.e., LOS Unit 2 and MRYS Units 1 & 2), technical issues regarding the high level of soluble alkali in North Dakota lignite, the particle size and sticky nature of high alkaline fly ash, and the potential abrasive qualities of North Dakota lignite ash would apply equally to wall-fired and tangentially fired boilers. Technical issues identified by NDDH during the first planning period would also apply to LOS Unit 1; therefore, findings and conclusions from the first planning period BART determinations (Regional Haze SIP, Appendix B.5) and the MRYS Unit 1 & 2 BACT analysis, are incorporated by reference into this four-factor analysis.

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[39] *Id.* at pg. 19. NDDH reached a similar conclusion in its BACT determination for NOx control on MRYS Units 1 & 2, finding that high-dust SCR had not been deployed on the same or a similar source, and that the flue gas characteristics of North Dakota lignite are significantly different from other sources that have applied high-dust SCR. The NDDH found that these unique characteristics present significant challenges to the successful application of high-dust SCR for NOx control, and that pilot testing would be needed to evaluate applicability of the control technology. Thus, NDDH concluded that because high-dust SCR is neither "available" nor "applicable" to the MRYS units, the control technology was technically infeasible and excluded from consideration as BACT. (See, Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2, April 2010).

Based on a review of SCR installations on coal-fired boilers and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) and the adhesive/cohesive characteristics and potential abrasive qualities of the North Dakota lignite-derived fly ash still remain a concern for North Dakota lignite-fired boilers. SCR has not been installed and successfully operated on a North Dakota lignite-fired boiler, and the bench scale and pilot-scale studies needed to better understand ash behavior and catalyst blinding/erosion with North Dakota lignite-derived fly ash, and to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been required or completed. Pilot-scale studies are needed to evaluate these issues to inform the development of advanced catalyst formulations, and to support the engineering and design studies needed to mitigate for potential deactivation routes (e.g., removing soluble alkali compounds from the flue gas and SCR design considerations such as catalyst formulation, catalyst pitch, reactor velocity, and catalyst surface and volume). Pilot-scale tests and engineering/design studies have not advanced since the first planning period's exhaustive analysis. These issues have not been resolved since the first planning period and still remain a significant barrier to the design and successful operation of high dust SCR on North Dakota lignite-fired boilers.

The BART Guidelines state that "[a] control technique is considered available…if it has reached the stage of licensing and commercial availability."[40] Commercial availability follows bench scale and laboratory testing and pilot scale testing. Consequently, the guidelines state that "you would not consider technologies in the pilot scale testing stages of development as 'available' for purposes of BART review."[41] Furthermore, source owners/operators are not expected to conduct extended trials to learn how to apply a technique on a dissimilar source type.[42] These BART guidelines also apply as a recommendation for the development of the LTS in the Round II Determination and four factor analysis.[43] Because there are still unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and engineering solutions have not yet been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is still not available, and thus, not a technically feasible NO_X control technology for LOS Unit 1 and 2.

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[40] 40 CFR Part 51 Appendix Y, Section D.2.1.
[41] Id.
[42] Id.
[43] See, Draft EPA Guidelines, pg. 183.

Low-Dust Configuration

The low-dust configuration is typically located in the flue gas stream between a hot-side ESP and the air heater inlet. Employing this configuration would represent a relatively low level of exposure to fly ash (with the exception of submicron ash particles), but a potentially high level of vapor-phase alkalis, such as sodium. Also, the location of this configuration in the flue gas path is inherently in an optimal temperature range for SCR technology of 650°F to 750°F. However, the cold-side ESP employed at LOS Units 1 and 2 for particulate control would preclude the application of a normal low-dust SCR configuration at this unit. A corollary to the low-dust/hot-side ESP configuration is the low-dust/cold-side ESP configuration. However, this low-dust configuration would require both a capital cost-intensive and operating cost-intensive gas-to-gas heater to facilitate reheating the flue gas to 550°F to 600°F. Considering the expected SO_3 levels in the flue gas from this configuration at LOS Unit 1 or 2, a gas temperature of 600°F would be appropriate to prevent formation of ammonium bisulfate/sulfate in the catalyst bed, while still supporting an acceptable reaction rate for NO_X reduction. Furthermore, there are no examples of this configuration being implemented on a North Dakota lignite-fired unit. Therefore, considering these significant financial disadvantages and the uncertainties associated with the efficient capture of sodium constituents in the flue gas by the cold-side ESP, this type of configuration is not a technically feasible NO_X control option for application at LOS Units 1 and 2.

Tail-End Configuration

In the tail-end configuration, the SCR reaction vessel is located in the flue gas stream after the particulate and FGD control systems. The potential advantage of a tail-end SCR (TE-SCR) configuration at LOS is that the flue gas will have passed through the WFGD system prior to the SCR catalyst. As such, there is the possibility that the mass transfer mechanism that results in the capture of SO_2 will also capture some of the vapor-phase sodium and the sodium-enriched submicron particles, reducing the risk of catalyst poisoning and/or deactivation.

Successful operation of the tail-end configuration would also require a capital and operating cost-intensive gas-to-gas heat exchanger to reheat the flue gas from approximately 140°F downstream of the existing WFGD to approximately 550°F. Due to the limited removal efficiency of SO_3 across a WFGD, the formation of ammonia bisulfate (ABS) is of concern. As such, an additional in-duct heating element should be employed to raise the SCR inlet temperature to 600°F, using natural gas duct burners. Since LOS does not have natural gas on site, a new pipeline would have to be constructed for approximately 26 miles. After the flue gas passes through the SCR (at approximately 550°F), it would pass through the hot side of the gas-to-gas heat exchanger to cool the flue gas to 150°F prior to the exhaust stack.

In addition, SO_3 emissions are expected to increase with a TE-SCR. SCR catalyst is known to oxidize SO_2-to-SO_3 as the flue gas passes through the layers of catalyst and has the potential to require additional air pollution control requirements for sulfuric acid mist. Therefore, if a TE-SCR is implemented, a hydrated lime dry sorbent injection (DSI) system could be required upstream of the WFGD to remove the potential increase in SO_3 from the SCR.

During the first planning period, NDDH initially concluded, based on preliminary information provided by SCR catalyst vendors, that the TE-SCR configuration would be a technically feasible option for units firing North Dakota lignite.[44] However, as part of the MRYS NO_X BACT determination process, detailed information describing the expected ash characteristics and flue gas characteristics was provided to two SCR catalyst vendors (CERAM Environmental, Inc. (CERAM) and Haldor Topsoe, Inc.). Based on their review of the data, both vendors concluded that they would not be able to provide a catalyst life guarantee for either low-dust or TE-SCR without pilot-scale testing.[45]

During the BACT review process, both companies made statements bringing into question the technical feasibility of either low-dust or TE-SCR. For example, CERAM stated that the high levels of sodium oxide (Na_2O) in the ash for North Dakota lignite are not commonly found in subbituminous and bituminous coals which are fired in boilers equipped with SCR systems, and that it was unaware of any SCR application experience in the industry with the level and form of sodium in the North Dakota lignite-derived ash. CERAM stated further that small aerosol particles can penetrate and neutralize active catalyst sites even in dry conditions, and that catalyst installed even in low dust and tail-end locations can be poisoned from exposure to the high levels of phosphorous, sodium, and potassium found in the mineral analyses provided for the MRYS BACT analysis.[46] Similarly, Haldor Topsoe stated that the potential exists that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a non-viable option for controlling NO_X emissions.

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[44] See, North Dakota Regional Haze SIP, Appendix B.5, pg. 25.

[45] See, United States v. Minnkota, 831 F. Supp. 2d, at 1117.

[46] *Id.*

Based on information provided by SCR design engineering firms and SCR catalyst vendors, NDDH made the following findings and conclusions with respect to the technical feasibility of low-dust and TE-SCR on a North Dakota lignite-fired boiler:[47]

1) There has never been a full scale SCR of any type installed on a facility that burns North Dakota lignite.
2) To determine technical feasibility of TE-SCR, one must compare the flue gas characteristics generated from firing North Dakota lignite to the flue gas characteristics of other source types to which these control technologies have been applied previously.
3) Flue gas characteristics of boilers firing North Dakota lignite are significantly different from other boilers where SCR has been applied.
4) North Dakota lignite contains high quantities of soluble sodium and potassium which can cause catalyst reaction site poisoning, blinding, and plugging of catalyst pores and channels, and that the soluble sodium and potassium can also form sulfates that can blind and plug the catalyst pores and plug the catalyst channels.
5) Both CERAM and Haldor Topsoe indicated that they would not provide a guarantee for the catalyst life without successful pilot scale testing being done.

Technologies in the pilot scale testing phase of development need not be considered as available control technologies. Based on the fact that SCR technology had not been installed nor effectively operated on an North Dakota lignite-fired unit, the lack of a commercially viable vendor guarantee, and the need to conduct pilot-scale testing to evaluate potentially significant operational and design issues, NDDH concluded that the use of SCR technology, including low-dust and TE-SCR, on the lignite-fired MRYS boilers would be technically infeasible.[48]

Although the MRYS BACT determination, and the initial planning period BART determinations, focused on North Dakota lignite-fired cyclone boilers (i.e., LOS Unit 2 and MRYS Units 1 & 2), technical issues regarding the high level of soluble alkali in North Dakota lignite-derived flue gas would also apply to LOS Unit 1. Therefore, findings and conclusions included in the MRYS Units 1 & 2 BACT analysis and the initial planning period BART determinations (Regional Haze SIP, Appendix B.5) are incorporated by reference into this four-factor analysis.

Based on a current review of SCR installations on coal-fired boilers, and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas

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[47] Findings and conclusions are summarized from United States v. Minnkota, pgs 1115-1116.

[48] Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2, April, 2010, pg. 21.

(including soluble sodium and potassium compounds) still remain a concern for North Dakota lignite-fired boilers. TE-SCR has not been demonstrated on a North Dakota lignite-fired boiler, and there are still significant technical concerns associated with the availability of existing SCR catalysts on a lignite-fired unit. Catalyst in a TE-SCR will still be vulnerable to alkali poisoning, pore pluggage and premature catalyst deactivation, and it is not known whether the comparatively high levels of soluble sodium and potassium in North Dakota lignite will be effectively removed by the upstream WFGD. Furthermore, the potential exists for fine particulate remaining in the flue gas to get into the catalyst pores reducing catalyst activity. Pilot-scale studies are needed to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been completed.

In order to understand the effect of North Dakota lignite-derived flue gas on TE-SCR catalyst, identify potential design solutions, and evaluate the technical feasibility and effectiveness of TE-SCR at LOS Unit 1 with any degree of certainty, pilot scale testing of the control configuration would be needed. Because there are unresolved issues associated with catalyst poisoning, it is very unlikely that Basin Electric could obtain a viable commercial offering for TE-SCR on LOS Unit 1 without extended pilot-scale tests.

During the first planning period NDDH determined that TE-SCR was not available, and thus, not a technically feasible NO_X control option for North Dakota lignite-fired boilers. Although the NDDH's control technology evaluation during the first planning period specifically focused on North Dakota lignite-fired cyclone boilers, technical issues regarding catalyst deactivation mechanisms associated with the high level of soluble alkali in North Dakota lignite would apply equally to wall-fired and tangentially-fired boilers. The administrative record developed during the first planning period, including the BART determinations and MRYS BACT analysis, supports the conclusion that TE-SCR is also not an available NO_X control option for LOS Unit 1. An evaluation of SCR installations and reported advances in SCR catalysts since the first planning period, coupled with the fact that TE-SCR has not been demonstrated on a North Dakota lignite-fired boiler, and the likelihood that Basin Electric could not obtain a viable commercial offering for TE-SCR without extended pilot-scale testing, continues to support the conclusion that TE-SCR is not an available NO_X control technology. Nevertheless, because the first planning period BART analysis (and the MRYS BACT analysis) focused on cyclone boilers, Basin Electric has elected to include TE-SCR as a potentially feasible control option and carry it forward to the cost impact evaluation (section 5.3.2) for LOS Unit 1. Based on controlled NO_X emissions achieved in practice at existing bituminous- and subbituminous-fired unit, S&L assumed that the TE-SCR control option could achieve an average controlled

NO_X emission rate of 0.05 lb/MMBtu. Due to the previous ruling on North Dakota lignite-fired cyclone boilers, SCR on will not be evaluated further on LOS Unit 2.

5.2.2.2 Optimized Selective Non-Catalytic Reduction

SNCR involves the direct injection of ammonia or urea ($(NH_2)_2CO$) at high flue gas temperatures (approximately 1,600ºF – 2,100ºF) in an oxidizing environment. The ammonia or urea reacts with NO_X in the flue gas to produce N_2 and water as shown below.

$$(NH_2)_2CO + 2NO + \tfrac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$

$$2NH_3 + 2NO + \tfrac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reagent injection can greatly affect NO_X removal efficiencies and the quantity of ammonia or urea that will pass through the SNCR unreacted (referred to as ammonia slip). In general, SNCR reactions are effective in the range of 1,600ºF – 2,100ºF. At temperatures below the desired operating range, the NO_X reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NO_X resulting in low NO_X reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Furnace geometry, urea spray coverage, and droplet size must be considered when developing good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reagent and flue gas in that temperature window. As the boiler cycles in load, the optimum injection region may change. Thus most facilities require multiple injection zones which are placed in and out of service as the unit ramps in load. This can include modifying the zones of injectors that are operating and different loads and temperatures.

Retractable multi-nozzle lances (MNLs) are sometimes used to improve SNCR performance, especially if the furnace exit flue gas temperatures are too high. The retractable lances allow injection into the appropriate temperature zone more so than wall injectors, depending on the unit load and temperatures. The MNLs also help improve performance by refining the spray pattern for quicker vaporization of the conveying water. MNLs are often used in conjunction with wall injection to provide optimized coverage while reducing reagent cost.

In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to-NO_X ratio, and fuel sulfur content. Increasing the normalized stoichiometric ratio (NSR) can improve NO_X removal. This is completed by increasing urea solution flow through the injectors or changing the concentration of urea in the solution. However, too high of reagent injection rates will increase the ammonia slip beyond the recommended 10 ppmvd limit. Above this concentration, there are expected to be major impacts to the formation of ammonia salts on the boiler tube banks, reducing heat transfer efficiency, and air heater baskets, causing corrosion.

Overall, the application of SNCR on pulverized coal or cyclone boilers is feasible due to having reasonable temperature windows and residence time; however, the potential NO_X reduction is boiler-specific. Based on the NDDH conclusions in the First Regional Haze Implementation Period, SNCR was determined to be cost-effective for NO_X control on Units 1 and 2. LOS Units 1 and 2 installed SNCR in 2014 and 2015, respectively, and started compliance with a new NO_X limit in April 2017. As such, SNCR systems on Units 1 and 2 have been operational during the baseline period. Therefore, confirmation of optimization of the existing system will be explored as an option on Units 1 and 2, since SNCR is included in the baseline.

Prior to implementing the SNCR systems on Units 1 and 2, LOS personnel tuned SOFA systems for better boiler stoichiometry control and installed combustion optimization systems. The effect of these two systems prior to implementation of the SNCR resulted in much lower NO_X formation in the Unit 1 and 2 boilers. As such, removal efficiencies of the SNCR are based on a pre-SNCR value which includes the benefit of modifications since the First Implementation Phase.

For LOS Unit 1, SNCR boiler computational fluid dynamics (CFD) modeling was completed to understand the best performance expected prior to implementation and tuning of the system. Based on the SOFA, LNB, and combustion optimization systems, SNCR was predicted to achieve 20% removal with an outlet NO_X rate just over 0.17 lb/MMBtu. Based on flow and NO_X CEMS data, average performance of the SNCR is currently slightly below 0.17 lb/MMBtu. As such, the current SNCR system is considered fully optimized based on the expected CFD modeling; any additional urea injection may result in negative impacts with ammonia slip emissions. Also, MNLs were initially modeled in addition to the wall injectors and were found to improve removal efficiency by another 6%; however, the optimal locations of the MNLs were determined to have physical interferences which would have limited the possibility of installation and thus were not installed. As such, MNLs are considered technically infeasible as part of this evaluation. For these reasons, SNCR optimization is not considered to be a technically feasible NO_X control option for LOS Unit 1, and will not be evaluated further.

As discussed previously, the SNCR on LOS Unit 2 was implemented after SOFA tuning, combustion optimization, and four vent ports were relocated. As such, the pre-SNCR baseline emission rate is much lower than the 0.67 lb/MMBtu uncontrolled baseline reported in the First Implementation Phase. S&L and Basin Electric consulted SNCR OEMs to determine the expected SNCR performance for a cyclone boiler similar to LOS Unit 2, considering the pre-SNCR baseline. The OEM, who performed a significant amount of modeling when the SNCR system was being designed on Unit 2, suggested that the SNCR system could be further optimized. Improvement of the stoichiometry would be required, by relocating all cyclone vent ports. Additionally, due to revised temperatures within the boiler from the new SOFA, vent port relocations, and combustion optimizers, the current urea injection lances are recommended to be relocated for better utilization of the reagent.

By optimizing LOS Unit 2's SNCR system based on additional vent port relocation and SNCR injection lance relocation, the unit may be able to achieve an additional 10% reduction from the annual baseline NO_X rate or approximately 0.27 lb/MMBtu at the boiler outlet at full load. This is consistent with greater than 25% reduction from an estimated pre-SNCR NO_X rate. In this case for LOS Unit 2, the limiting factor for optimized SNCR operation is full load. Overall, it is expected that optimization of the Unit 2 SNCR system at all loads is a technically feasible option to reduce NO_X emissions and will be evaluated further.

5.2.2.3 Rich Reagent Injection

Similar to SNCR, the concept of RRI is to use a nitrogen-containing additive (urea) injected into a reducing environment to promote peak NO_X reduction efficiency. RRI is a commercial technology for cyclone boilers only, thus is not an applicable option for LOS Unit 1. In contrast to SNCR, RRI typically is applied with only one injection level in the lower furnace near the cyclone barrels (temperature window of 2000°F-2600°F). The technology requires a sub-stoichiometric oxygen concentration near the barrels at <0.95. This allows for a higher injection rate of reagent without oxidizing to NO_X due to the sub-stoichiometry. Injection at this location also creates lower level of excess NH_3 emissions (ammonia slip), while injecting at an NSR of 2.0-3.0.

Due to the changes of the lower furnace stoichiometry, RRI is often not a technically feasible option at lower loads. Once the stoichiometric ratio increases to >1.0, there is the potential for NO_X generation due to the reaction of ammonia with oxygen, especially if the injection location and rate is not optimized. Based on these limitations, RRI alone is considered most effective at full load.

The RRI process is a commercially available process and has been predicted to typically reduce NO_X emissions by 20-40% at full load with no ammonia slip, but is highly dependent on the stoichiometry. However, this technology provides the most beneficial reduction at full load, due to the cyclone temperature window and stoichiometry. At mid- and low-loads, the predicted reduction is less than the current SNCR baseline operation at these loads. Therefore, low load operation is considered the limiting factor of RRI alone and the effectiveness of RRI is marginalized at mid-loads. SNCR would still be needed to achieve a similar reduction at low load. As such, RRI on its own is not a technically feasible NO_X reduction technology due to its limited operating conditions throughout all load ranges and will not be considered further.

5.2.2.4 Optimized SNCR + RRI

While RRI alone will provide beneficial NO_X reduction at full load only, coupling RRI with SNCR will provide a balanced approach to NO_X reduction through all load ranges. RRI and SNCR injectors are located at different elevations of the furnace and in different temperature windows. The system utilizes a high urea injection rate, staged at multiple locations throughout the boiler. The main advantage of this combined system is that the SNCR can provide better NO_X reduction at mid- and low-loads and at a lower NSR than RRI alone. Therefore, this combined system is expected to be able to provide a lower emission rate through all load ranges.

Similarly to SNCR and RRI, the only way SNCR + RRI will provide beneficial results is by relocating the remaining vent ports and keeping the SOFA tuned. This relocation will change the lower furnace O_2 stoichiometry, to be around 0.90 instead of 1.0. Due to negative impacts to the boiler with regards to slagging, 0.90 is the lowest stoichiometry that the unit can operate consistently with target coal quality. At full load, RRI + SNCR was modeled to provide reduction from pre-SNCR emissions. However, as discussed previously, RRI provides the largest benefit at full load; therefore, low- or mid-load operation would be the limiting factor.

Boiler CFD modeling of the SNCR and RRI systems was previously conducted with different assumptions of SOFA and vent port relocation performance. However, S&L consulted the CFD modeling company to provide insight into what performance could be achieved with the revised pre-SNCR baseline NO_X emission rate. This information was also provided to an SNCR+RRI system OEM who suggested that an additional 43% reduction from the annual baseline could be guaranteed at full load, which would provide an outlet emission rate of 0.17 lb/MMBtu. This is consistent with greater than 50% reduction from an estimated pre-SNCR NO_X rate.

Alternatively to the optimized SNCR case, low load operation is the limiting factor for SNCR+RRI performance. RRI becomes ineffective at low load and the OEM suggested that almost no NO_X reduction would occur at this load due to RRI. Initial modeling suggested that increasing the urea NSR to 3.0 at low load could achieve an additional 2% reduction, but there is a concern about ammonia slip rates with this operating profile.

The SNCR + RRI combination would require all new penetrations for the RRI system as well as the relocation of the existing SNCR system as discussed in 5.2.2.2. The RRI system will require a larger urea storage tank, additional water treatment equipment for solutionizing, additional pump forwarding capacity, new piping to lower boiler elevations, additional boiler penetrations, injectors, and all balance of plant related equipment. At the lower elevation for the RRI ports, the most optimal injection location happens to occurs at the same elevation of the windbox. Therefore specialized retractable and cooled injection lances with windbox modifications would be required. This design creates engineering and operational challenges that are normally avoided by injecting reagent in more accessible areas of the boiler.

Overall, the implementation of an RRI system along with optimization of the existing SNCR system is a technically feasible NO_X control option on Unit 2. Based on input from previous CFD modeling and SNCR OEMs, it is expected that LOS Unit 2 could achieve an outlet NO_X rate of 0.22 lb/MMBtu with an ammonia slip of 10 ppmvd with vent port relocation, optimized SNCR, and RRI.

5.2.2.5 Gas Reburn

Gas reburn is a retrofit technique that has been used to control NO_X emissions from coal- and oil-fired boilers. Gas reburn involves combustion in three distinct zones within the boiler: (1) a primary combustion zone, where the primary fuel is fired using conventional burners; (2) a reburn zone, where secondary fuel, typically natural gas, is introduced into the boiler; and (3) an overfire air burnout zone.

In the primary zone of coal-fired boilers, coal is fired through LNBs, at a rate corresponding to approximately 80% to 90% of the total heat input. Natural gas reburn fuel is then injected above the primary combustion zone under fuel-rich conditions at a rate corresponding to approximately 10% to 20% of the total heat input (on a Btu/hour basis). The fuel-rich reburn zone creates a reducing (sub-stoichiometric) region within the boiler where the natural gas, principally methane, breaks down to produce hydrocarbon radicals (CH and CH_2). The hydrocarbon radicals react with NO_X produced in the primary combustion zone to form nitrogen and water vapor. Because the natural gas is not completely combusted in the reburn zone, gases exiting the reburn zone will contain considerable CO and unburned hydrocarbons; therefore, additional OFA is introduced above the reburn zone to complete the combustion process.

Critical design parameters that affect the feasibility and performance of a gas reburn retrofit system include: (1) baseline NO_X concentration; (2) reburn zone temperature, residence time, and stoichiometry: (3) OFA burnout zone temperature and residence time; and (4) mixing of the reburn fuel and overfire air with the bulk flue gas.

Gas reburn can have a positive impact on emissions of NO_X; however, in order to make a meaningful prediction of the NO_X removal capabilities at LOS, extensive testing at each unit would be required because the performance is significantly dependent upon boiler operating characteristics. In addition, lack of natural gas available on site precludes the ability to test and implement this control option on LOS Units 1 and 2, which use fuel oil as the startup fuel. As such, gas reburn is not considered a technically feasible NO_X control technology at LOS Units 1 and 2.

5.2.2.6 Innovative Technologies

NO_XStar™

The NO_XStar™ process, also known as selective autocatalytic reduction (SACR), uses a continuous controlled amount of ammonia-based reagent with relatively small amounts of hydrocarbon to reduce NO_X emissions. The hydrocarbon is introduced into the flue gas at the convective pass of the boiler, with elevated temperatures. At the elevated temperatures, the hydrocarbon auto-ignites to form a plasma of free radicals that auto catalyzes the reaction of NH_3 and NO_X to form N_2 and H_2O. The hydrocarbon and ammonia are added through banks of nozzles in the superheat or reheat sections of the boiler. The injection location is determined by the location of the temperature windows for the "plasma creation zone" as well as the reaction zone for the ammonia.

To date, only one full-scale demonstration has been conducted to evaluate the technology on utility-sized boilers similar to LOS. The process is an emerging NO_X control, and there is limited information available to evaluate its technical feasibility and long-term effectiveness on a large lignite-fired boiler. Potential NO_X removal efficiencies would be a function of NH_3-NO_X mixing, flue gas temperature, flue gas composition, and residence time downstream of the injection lances.

Because this is an emerging technology, long-term full-scale demonstration testing is required to demonstrate its effectiveness at LOS. It is likely that extensive design engineering and testing would be required to evaluate the technical feasibility and long-term effectiveness of the control system. Detailed design of the lances, mixing, optimization of the reagent supply across the boiler convective pass, flue gas temperatures, and flow distribution would have to be studied. Interference with the tube pendants in the convective pass may also make this more difficult to install. Installing a hydrocarbon distribution grid may present a problem with large boilers because of the span needed to uniformly distribute the reagent, interference with the tube pendants in the convective pass, and an additional booster fan may be needed. As such, NO_XStar™ is not considered a technically feasible NO_X control technology at LOS.

PerNO$_X$ide

PerNO$_X$ide utilizes hydrogen peroxide (H_2O_2) to reduce NO_X emissions. Hydrogen peroxide is injected into the ducts ahead of the air preheater and oxidizes the NO to NO_2, which is then captured in a downstream FGD system. To date, the technology has only been tested on a pilot-scale, and it has not been demonstrated on any coal-fired boilers. It is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system on LOS. As such, PerNO$_X$ide is not considered a technically feasible NO_X control technology at LOS.

LoTOX®

The LoTO$_X$ system is a gas-phase, low-temperature oxidation system, wherein ozone is injected into the flue gas stream to oxidize NO and NO_2 to N_2O_5 before being removed in a WFGD. This highly oxidized species of NO_X is water-soluble and rapidly reacts with water to form nitric acid. The conversion of NO_X to nitric acid occurs as the N_2O_5 contacts liquid sprays in the WFGD. The nitric acid would react with the alkali compounds in the WFGD and would be eliminated via the WFGD waste and byproduct streams. The LoTO$_X$ system requires on demand ozone generation from a liquid oxygen supply.

The LoTO$_X$ system has been successfully applied in refinery applications however; there are no full-scale installations on coal-fired boilers. According to vendors, one coal-fired boiler demonstration on a 25-MW boiler was performed which showed 90% NO_X removal. It is likely that extensive design engineering and testing would be required to evaluate the scale-up potential and long-term effectiveness of the system at LOS. As such, LoTO$_X$ is not considered a technically feasible NO_X control technology at LOS.

Water Injection

The principle behind this technology is to inject an atomized water spray into the high-NO_X production zones of a cyclone burner or in the core of the flame for other furnaces. The water spray reduces the temperature and results in lower NO_X production within this zone. Developers claim that water injection through burners used in tangential-fired and wall-fired units will also lower the flame temperature and, hence, lower NO_X production. However, only laboratory results are available to demonstrate this technology's effectiveness in coal-fired applications.

Water injection is well demonstrated for combustion turbine applications for NO_X reduction. However, there is insufficient experience and demonstration data in coal-fired applications. As such, water injection is not considered a technically feasible NO_X control technology at LOS.

5.2.2.7 Technical Feasibility Summary

Table 5-5 and Table 5-6 summarize the results of the feasibility evaluation of available control options for LOS Unit 1 and 2.

Table 5-5. Technically Feasible NO_X Control Options for LOS Unit 1

NO_X Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Optimized Selective Non-Catalytic Reduction (SNCR)	No	0%	SNCR is not considered an available and technically feasible NO_X control technology for LOS Unit 1. Performance in the field was tuned to achieve the best computational model runs.
Rich Reagent Injection (RRI)	No	0%	RRI is not available on LOS Unit 1.
Optimized SNCR + RRI	No	0%	SNCR + RRI is not available on LOS Unit 1.
Gas Reburn	No	0%	Gas reburn is not considered an available or technically feasible NO_X control technology at LOS Unit 1.
Innovative Technologies: NO_XStar™ PerNO$_X$ide LoTO$_X$ Water Injection	No	0%	Innovative NO_X control technologies are evaluated in Section 5.2.2.6. In all cases, the technologies have not been demonstrated on a large North Dakota lignite-fired boiler. Extensive testing and design engineering would be required to evaluate the technical feasibility and long-term effectiveness of each innovative control system on LOS Units 1 and 2. Therefore, the innovative NO_X control technologies are not considered available control options and are not technically feasible NO_X control options for LOS Unit 1.
Selective Catalytic Reduction (SCR)			
High-dust configuration	No	0%	Due to significant unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and based on the finding that engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not an available or technically feasible NO_X control technology for LOS Unit 1.
Low-dust configuration	No	0%	Because LOS Unit 1 is equipped with existing WFGD control systems, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered an available or technically feasible NO_X control option for LOS Unit 1.
Tail-end configuration	Yes	82.8%	EPA's reconsideration of North Dakota's NO_X BART determination focused on cyclone boilers firing North Dakota lignite, and did not specifically address PC-boilers firing North Dakota lignite. Therefore, for consistency with the approach NDDH used during the First Implementation Period (i.e., assuming technical feasibility, TE-SCR will be carried forward to the four factor analysis on LOS Unit 1.

Note 1. Control percentage calculated using the uncontrolled NO_X emission rate and the achievable NO_X emission rate for each technically feasible control option.

Table 5-6. Technically Feasible NO_X Control Options for LOS Unit 2

NO_X Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Optimized Selective Non-Catalytic Reduction (SNCR)	Yes	60%	SNCR is considered an available and technically feasible NO_X control technology for LOS Unit 2. Computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO_X emissions is achievable without creating unacceptable operational issues.
Rich Reagent Injection (RRI)	No	0%	RRI is not considered a technically feasible NO_X control option at all loads at LOS Unit 2.
Optimized SNCR + RRI	Yes	67%	SNCR + RRI is considered an available and technically feasible NO_X control technology for LOS Unit 2. Computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the incremental reduction in NO_X emissions is achievable without creating unacceptable operational issues.
Gas Reburn	No	0%	Gas reburn is not considered an available or technically feasible NO_X control technology at LOS Unit 2.
Innovative Technologies: NO_XStar™ PerNO$_X$ide LoTO$_X$ Water Injection	No	0%	Innovative NO_X control technologies are evaluated in Section 5.2.2.6. In all cases, the technologies have not been demonstrated on a large North Dakota lignite-fired boiler. Extensive testing and design engineering would be required to evaluate the technical feasibility and long-term effectiveness of each innovative control system on LOS Units 1 and 2. Therefore, the innovative NO_X control technologies are not considered available control options and are not technically feasible NO_X control options for LOS Unit 2.
Selective Catalytic Reduction (SCR)			
High-dust configuration	No	0%	Due to significant unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion; and based on the finding that engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not an available or technically feasible NO_X control technology for LOS Unit 2.
Low-dust configuration	No	0%	Because LOS Unit 1 and 2 is equipped with existing WFGD control systems, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered an available or technically feasible NO_X control option for LOS Unit 2.

NO_X Control Option	Technically Feasible (Yes/No)	Control Percentage (Note 1)	Technical Feasibility Summary
Tail-end configuration	No	0%	Based on EPA's 2015 Notice of final action on reconsideration (see, 80 FR 8550), and the continued lack of demonstration testing and commercial guarantees, TE-SCR is considered to be a technically infeasible control option for LOS Unit 2.

Note 1. Control percentage calculated using the uncontrolled NO_X emission rate and the achievable NO_X emission rate for each technically feasible control option.

5.2.3 Evaluate Technically Feasible NO_X Control Options for Effectiveness

The technically feasible NO_X control technologies are listed in in descending order of control efficiency. Table 5-7 and Table 5-8 also provide control option-specific NO_X emission rates in terms of lb/MMBtu. Emission rates shown represent average emission rates that the control options would be expected to achieve during normal operations.

Table 5-7. Evaluate Technically Feasible NO_X Control Options by Effectiveness for LOS Unit 1 (Baseline Average Emissions)

Alt. No.	Control Technology	NO_X Emission Rate (Note 1) lb/MMBtu	% Reduction from Uncontrolled NO_X (Notes 2, 3)	NO_X Emission Rate (Note 1) lb/hr	NO_X Emission Rate (Note 1) tons/yr
A	Selective catalytic reduction (SCR) – tail-end configuration (Note 2)	0.05	83	82	292
--	Baseline (existing LNB / SOFA / SNCR)	0.15	47	255	905
--	Permit Limit	0.19 (30-day)	--		

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for LOS Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.
Note 2. Percent reduction from uncontrolled pre-BART (SNCR/OFA) upgrade NO_X emission rate of 0.29 lb/MMBtu.
Note 3. TE-SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of TE-SCR on LOS Unit 1. Nevertheless, during the initial planning period, NDDH concluded that TE-SCR was a technically feasible NO_X control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. For consistency with NDDH's conclusion from the first planning period, TE-SCR will be carried forward to the four factor analysis.

Table 5-8. Evaluate Technically Feasible NO_X Control Options by Effectiveness for LOS Unit 2 (Baseline Average Emissions)

Alt. No.	Control Technology	NO_X Emission Rate (Note 1) lb/MMBtu	% Reduction from Uncontrolled NO_X (Notes 2, 3)	NO_X Emission Rate (Note 1) lb/hr	NO_X Emission Rate (Note 1) tons/yr
B	Optimized SNCR + RRI	0.22	67	812	3,346
A	Optimized SNCR	0.27	60	997	4,107
--	Baseline (existing LNB / SOFA / SNCR)	0.30	56	1,099	4,530
--	Permit Limit	0.35 (30-day)	--		

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for LOS Unit 2. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.
Note 2. Percent reduction from uncontrolled pre-BART (SNCR/OFA) upgrade NO_X emission rate of 0.67 lb/MMBtu.

Table 5-9 provides control option-specific NO_X emission rates in terms of lb/MMBtu based on the projected future maximum emission rates. Emission rates shown represent the projected future maximum emission rates that the control options would be expected to achieve during normal operations.

Table 5-9. Evaluate Technically Feasible NO_X Control Options for Effectiveness - LOS Unit 1 (Projected Future Maximum Emissions)

Alt. No.	Control Technology	NO_X Emission Rate (Note 1) lb/MMBtu	% Reduction from Uncontrolled NO_X (Notes 2, 3)	NO_X Emission Rate (Note 1) lb/hr	NO_X Emission Rate (Note 1) tons/yr
A	Selective catalytic reduction (SCR) – tail-end configuration (Note 2)	0.05	83	131	574
--	Baseline (existing LNB / SOFA / SNCR)	0.15	47	406	1,779
--	Permit Limit	0.19 (30-day)	--		

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for LOS Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.
Note 2. Reduction from pre-BART (SNCR/OFA) upgrade NO_X emission rates of 0.29 lb/MMBtu.
Note 3. TE-SCR has not been installed on a North Dakota lignite-fired unit, and extended trials would be needed to better understand the design and operation of TE-SCR on LOS Unit 1. Nevertheless, during the initial planning period, NDDH concluded that TE-SCR was a technically feasible NO_X control technology for a North Dakota lignite-fired boiler, and evaluated the costs and cost-effectiveness of the control system. For consistency with NDDH's conclusion from the first planning period, TE-SCR will be carried forward to the four factor analysis.

Table 5-10. Evaluate Technically Feasible NO_X Control Options for Effectiveness - LOS Unit 2 (Projected Future Maximum Emissions)

Alt. No.	Control Technology	NO_X Emission Rate (Note 1) lb/MMBtu	% Reduction from Uncontrolled NO_X (Note 2)	NO_X Emission Rate (Note 1) lb/hr	NO_X Emission Rate (Note 1) tons/yr
B	Optimized SNCR + RRI	0.22	67	1,129	4,943
A	Optimized SNCR	0.27	60	1,385	6,067
--	Baseline (existing LNB / SOFA / SNCR)	0.30	56	1,528	6,692
--	Permit Limit	0.35 (30-day)	--		

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions for LOS Unit 1. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.
Note 2. Reduction from pre-BART (SNCR/OFA) upgrade NO_X emission rates of 0.67 lb/MMBtu.

5.3 NO_X COST OF COMPLIANCE (STATUTORY FACTOR ONE)

The economic analysis performed as part of the four factor analysis examines the cost-effectiveness of each technically feasible control technology, on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. For units with existing controls, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual O&M costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of control equipment. Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25% and equipment life of 20 years.[49] Cost effectiveness ($/ton) of a particular control option is simply the annual cost ($/yr) divided by the annual reduction in annual emissions (ton/yr). In addition to cost-effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the incremental cost effectiveness of the more stringent control.

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[49] The assumed 20-year equipment life is consistent with the control system equipment life used by NDDH in its evaluation of NO_X and SO_2 control technologies for BART-eligible sources. (see, e.g., ND Regional Haze Final SIP, Appendix C.1, "BART Determination Study for Leland Olds Station Units 1 & 2, Basin Electric Power Cooperative, August 2006, pgs. 64 (NOx controls) and 158 (SO_2 controls). See also, ND Regional Haze Final SIP, Appendix C4, "NOx Best Available Control Technology Study for Milton R. Young Station Unit 1, Minnkota Power Cooperative, Inc., October 2006, pg. 3-22).

Capital and O&M cost estimates were developed for each of the technically feasible NO_X control options. The LOS Units 1 and 2 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Units 1 and 2 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on Units 1 and 2-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the LOS Units 1 and 2 retrofit technologies as "concept screening" cost estimates generally based on parametric models, judgment, or analogy.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, contractor G&A expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements.[50] Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing SNCR systems.

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

5.3.1 NO_X Average Annual Economic Evaluation

Table 5-11 presents the capital costs and annual operating costs associated with building and operating each control system. Table 5-13 shows the average annual and incremental cost effectiveness for each control system. Annual

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[50] Variable O&M costs are based on the future SO_2 coal of 3.66 lb/MMBtu.

operating costs included in Table 5-11 are based on actual baseline period capacity factors of 61% for Unit 1 and 68% for Unit 2. The emissions reductions and cost effectiveness values included in Table 5-12 are based on baseline emission rates and projected actual emissions for each control option. Additional cost details are provided in Appendix D.

Table 5-11. NO$_X$ Control Cost Summary (Annual Average)

LOS Unit No.	Alt. No.	NO$_X$ Control Option	Total Capital Investment $	Annual Capital Recovery Cost $/yr	Annual Operating Cost $/yr	Total Annual Cost $/yr
Unit 1	A	Selective catalytic reduction (SCR) – tail-end configuration	$227,717,000	$18,662,000	$14,809,000	$33,471,000
Unit 2	B	Optimized SNCR + RRI	$8,562,000	$702,000	$3,594,000	$4,296,000
	A	Optimized SNCR	$3,089,000	$253,000	$549,000	$802,000

Table 5-12. NO$_X$ Emissions Control System Cost Effectiveness (Annual Average)

LOS Unit No.	Alt. No.	NO$_X$ Control Option	Total Annual Cost $	Expected Emission Reduction (Note 2) tons NO$_X$/yr	Average Annual Cost-Effectiveness (Note 2) $/ton NO$_X$ removed	Incremental Annual Cost-Effectiveness (Note 1) $/ton NO$_X$ removed
Unit 1	A	Selective catalytic reduction (SCR) – tail-end configuration	$33,471,000	613	$54,605	
Unit 2	B	Optimized SNCR + RRI (Note 3)	$4,296,000	1,183	$3,630	$4,594
	A	Optimized SNCR (Note 3)	$802,000	423	$1,896	

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual NO$_X$ emissions reductions (tons/yr) between a control option and the next most effective option.

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline NO$_X$ emission rate and capacity factor during baseline NO$_X$ period for each LOS Unit.

Note 3. Costs have not been included in this analysis for the subsequent loss in net generation or the cost to purchase replacement power. These costs would need to be inlcuded.

Table 5-12 indicates that the average annual cost effectiveness of the technically feasible NO_X control option for Unit 1 is $51,605 per ton (SCR – tail-end configuration); and for Unit 2 ranges from $1,896 per ton to $3,630 per ton NO_X removed.

TE-SCR system costs have been included for Unit 1 to remain consistent with the approach used by NDDH during the initial planning period. Based on preliminary cost estimates, the cost effectiveness of a TE-SCR system is approximately $54,600 per ton. The high cost is driven by the high capital expenses required for implementation with limited expected annual NO_X reduction, due to a low baseline emission rate on Unit 1.

Optimization of the existing SNCR system on Unit 2 is expected to achieve approximately 10% NO_X reduction from baseline emission rates. The cost effectiveness of this option is approximately $1,900 per ton. The cost is driven by the increased urea consumption and the relocation costs. If RRI is included in addition to the optimization of the SNCR, the cost effectiveness of the combined option is approximately $3,600 per ton, with a reduction of 26% from baseline emission rates. Compared to the optimized SNCR alone, the incremental cost effectiveness is approximately $4,600 per ton. Major increase to urea consumption rates with RRI is the driver of the cost for this option. It should also be noted that an additional $5.5 million is required for the RRI system implementation, which is ineffective while the unit is operating at low load. The facility is often dispatched at low load. Furthermore, the optimized SNCR and optimized SNCR + RRI options will also affect the units' net plant heat rate since the amount of water that will be injected with the urea will negatively impact boiler efficiency. Costs have not been included in this analysis, due to time constraints, for the subsequent loss in net generation which would increase the cost effectiveness of these two options. It would be expected that there would be a greater negative impact with the SNCR + RRI option. If requested, updated costs can be provided to NDDH.

5.3.2 NO_X Potential-to-Emit Economic Evaluation

Table 5-13 presents the capital costs and annual operating costs associated with building and operating each control system; annual operating costs are based on the units operating at 100% capacity factor. Table 5-14 shows the average annual and incremental cost effectiveness for each control system with emissions reductions and cost effectiveness values based on 100% capacity factors and potential-to-emit emission rates. Additional cost details are provided in Appendix D.

Table 5-13. NO_X Control Cost Summary (Projected Future Maximum)

LOS Unit No.	Alt. No.	NO_X Control Option	Total Capital Investment $	Annual Capital Recovery Cost $/yr	Annual Operating Cost (Note 1) $/yr	Total Annual Cost $/yr
Unit 1	A	Selective catalytic reduction (SCR) – tail-end configuration	$227,717,000	$18,662,000	$15,722,000	$34,384,000
Unit 2	B	Optimized SNCR + RRI	$8,562,000	$702,000	$4,868,000	$5,570,000
	A	Optimized SNCR	$3,089,000	$253,000	$739,000	$992,000

Note 1. Annual operating costs based on baseline NO_X emissions and 100% capacity factor for each LOS

Table 5-14. NO_X Emissions Control System Cost Effectiveness (Projected Future Maximum)

LOS Unit No.	Alt. No.	NO_X Control Option	Total Annual Cost $	Expected Emission Reduction tons NO_X/yr	Average Annual Cost-Effectiveness (Note 2) $/ton NO_X removed	Incremental Annual Cost-Effectiveness (Note 1) $/ton NO_X removed
Unit 1	A	Selective catalytic reduction (SCR) – tail-end configuration	$34,384,000	1,205	$28,528	
Unit 2	B	Optimized SNCR + RRI	$5,570,000	1,748	$3,186	$4,075
	A	Optimized SNCR	$992,000	625	$1,588	

Note 1. Incremental cost-effectiveness represents the incremental increase in annual costs ($/yr) divided by the incremental increase in annual NO_X emissions reductions (tons/yr) between a control option and the next most effective option.

Note 2. Expected emission reductions and average annual cost-effectiveness based on baseline NO_X emissions and 100% capacity factor for each LOS Unit.

Table 5-14 indicates that the average annual cost effectiveness of the technically feasible NO_X control option for Unit 1 is $28,528 per ton (SCR – tail-end configuration); and for Unit 2 ranges from $1,588 per ton to $3,186 per ton NO_X removed.

TE-SCR system costs have been included for Unit 1 to remain consistent with the approach used by NDDH during the initial planning period. Based on preliminary cost estimates, the cost effectiveness of a TE-SCR system is approximately $28,500 per ton. The high cost is driven by the high capital expenses required for implementation with limited expected annual NO_X reduction, due to a low baseline emission rate on Unit 1.

Optimization of the existing SNCR system on Unit 2 is expected to achieve approximately 10% NO_X reduction from baseline emission rates. The cost effectiveness of this option is approximately $1,600 per ton. The cost is driven by the increased urea consumption and the relocation costs. If RRI is included in addition to the optimization of the SNCR, the cost effectiveness of the combined option is approximately $3,200 per ton, with a reduction of 26% from baseline emission rates. Compared to the optimized SNCR alone, the incremental cost effectiveness is approximately $4,000 per ton. Major increase to urea consumption rates with RRI is the driver of the cost for this option. It should also be noted that an additional $5.5 million is required for the RRI system implementation, which is ineffective while the unit is operating at low load. The facility is often dispatched at low load. Furthermore, the optimized SNCR and optimized SNCR + RRI options will also affect the units' net plant heat rate since the amount of water that will be injected with the urea will negatively impact boiler efficiency. Costs have not been included in this analysis, due to time constraints, for the subsequent loss in net generation which would increase the cost effectiveness of these two options. It would be expected that there would be a greater negative impact with the SNCR + RRI option. If requested, updated costs can be provided to NDDH.

6. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO)

The time necessary for compliance is generally defined as the time needed for full implementation of the technically feasible control options. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. Therefore, compliance deadlines must consider the time necessary for compliance by setting a compliance deadline that provides a reasonable amount of time for the source to implement the control measure. Basin Electric assumes a greater or equal amount of time would be provided as during the first planning phase, which was five years.

Table 6-1 and Table 6-2 include estimated timeframes needed to implement each of the technically feasible controls. The estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; therefore, the scheduled activities identified below commence immediately after SIP approval and are subject to the maintenance outage schedules of the individual unit.

Table 6-1. SO_2 Emissions Control System Implementation Schedule

LOS Unit No.	SO_2 Control Option	Alt No.	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup / Training (months)	Compliance Date (months after SIP approval)
Unit 1	FGD Operational Improvements – Ca:S Stoichiometry (Note 1)	A	0	0	3	No later than 60 months
Unit 2	FGD Operational Improvements – Ca:S Stoichiometry and L/G Ratio (Note 1)	A	0	0	3	No later than 60 months
Unit 1 and 2	FGD Upgrades – pH Buffer Addition	B	4	4	4	No later than 60 months

Note 1. Although this option would not require design/fabrication and construction months, Basin Electric would need 2-3 months to update O&M manuals and personnel training for the change to the work practice of the existing WFGD systems.

Table 6-2. NO_X Emissions Control System Implementation Schedule

LOS Unit No.	NO_X Control Option	Alt No.	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup / Training (months)	Compliance Date (months after SIP approval)
Unit 2	Optimized SNCR	A	4	4	4	No later than 60 months
Unit 2	Optimized SNCR + RRI	B	6	6	4	No later than 60 months
Unit 1	Selective Catalytic Reduction (SCR) - Tail End Configuration	A	10	18	24	No later than 60 months

7. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE)

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal.

7.1 ENVIRONMENTAL IMPACTS

LOS Unit 1 is currently equipped with combustion optimizer/LNB/OFA/SNCR for NO_X control and WFGD for SO_2 control. LOS Unit 2 is equipped with combustion optimizer/SOFA/SNCR for NO_X control and WFGD for SO_2 control. The limestone reactant used in a WFGD system reacts with SO_2 in the flue gas to form calcium sulfate and calcium sulfite solids. The solids are either recycled to the system for reuse or removed from the system as nonhazardous solid waste. The existing wet scrubbing system also requires water to slurry the limestone prior to injection into the absorber. Based on the design of the control system, LOS Unit 1 and 2 currently use approximately 75 gpm and 153 gpm of water, respectively to slurry the limestone (at full load). In addition the Unit 1 and 2 SNCR systems use approximately 9 and 30 gpm, of water, respectively to dilute the urea reagent before injection in the boiler. Collateral environmental impacts associated with the existing LOS Units 1 and 2 control systems include water consumption and increased solid waste generation. There were no collateral impacts associated with the LNB/SOFA/OFA systems.

Based on a review of potential non-air quality environmental impacts, no significant collateral environmental impacts were identified for any of the SO_2 and NO_X control options included in this evaluation except for the TE-SCR option. The TE-SCR catalyst oxidizes some of the SO_2 to SO_3 in addition to catalyzing the reaction between NO_X and ammonia. There could be the potential for increased SO_3 emissions with the use of a TE-SCR. The SO_3 will react with the moisture in the stack to form sulfuric acid emissions. In addition the TE-SCR options utilize ammonia as the reagent for the reactions with NO_X to occur. There will be some ammonia slip emission from a TE-SCR in the range of 2 ppm. There is no means to capture the ammonia slip emissions from the TE-SCR since it would be installed downstream of the existing WFGD system. The implementation of the optimized SNCR can also increase ammonia emissions.

It is generally understood from previous visibility modeling efforts that increased ammonia injection has the opportunity of providing additional ammonia to the atmosphere. This increased ammonia availability within the emitted plume itself is known to contribute to increased visibility impairment due to more direct formation of ammonium sulfate and ammonium nitrate, more so in the winter months where fine particulate formation is ammonia limited.

7.2 ENERGY IMPACTS

Options that include increasing the Ca:S ratio will increase the auxiliary power consumption due to increased recycle pump operation and the TE-SCR option will increase pressure drop through the control system, increasing auxiliary power requirements. Both of these options will adversely affect the unit' net plant heat rate (Btu heat input per MW_{Net} output).[51] Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. In addition, the optimized SNCR and optimized SNCR + RRI options will also affect the units' net plant heat rate since the amount of water that will be injected with the urea will negatively impact boiler efficiency. Costs have not been included in this analysis, due to time constraints, for the subsequent loss in net generation.

Although several of the control options have energy impacts, none of the impacts are considered significant enough as to disqualify any of the options from consideration in the four factor analysis. In order to account for potential energy impacts associated with each option, the auxiliary power cost associated with operating the control systems have been included as an annual operating cost in the economic impact assessment.

7.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY

A summary of the Statutory Factor 3 environmental and energy impact analysis is provided in Table 7-1.

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[51] Heat rate represents the amount of heat input to the boiler (Btu) required to generate one megawatt (MW) net electric output and is reported as Btu/MW_{Net}.

Table 7-1. Summary of Energy and Non-Air Quality Environmental Impacts

Control Option	Collateral Environmental & Energy Impacts
Baseline	➢ LOS Units 1 and 2 are currently equipped with WFGD and SNCR control systems. Existing collateral environmental and energy impacts include: ➢ Solid WFGD by-product management and disposal ➢ Increased water consumption ➢ Increased auxiliary power requirements and heat rate penalty
<u>SO_2 Control Options</u>	
WFGD Operational Improvements	➢ Increased water consumption ➢ Increased solid by-product management and disposal ➢ Increased auxiliary power requirements and heat rate penalty
<u>NO_X Control Options</u>	
Selective Catalytic Reduction (SCR) - Tail End Configuration	➢ Increased auxiliary power requirements and heat rate penalty ➢ Potential increase in ammonia slip emissions ➢ Potential increase in SO_3 emissions
Optimized SNCR or SNCR + RRI	➢ Increased water consumption ➢ Increased auxiliary power requirements and heat rate penalty ➢ Potential increase in ammonia slip emissions

8. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR)

The evaluation of technically feasible NO_X and SO_2 controls options should consider the source's "remaining useful life" in determining the costs of compliance. The remaining useful life is the difference between the date that controls would be put in place and the date that the facility permanently ceases operation. If the remaining useful life of the unit is shorter than the useful life of a particular control option, the remaining useful life should be used annualizing costs. If the remaining useful life exceeds the useful life of the control options, the remaining use life has no effect on the cost evaluation.

Under the current LOS resource plan, the remaining useful life of LOS Unit 1 and 2 is greater than 20 years. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework.

9. CONCLUSIONS

At the request of NDDH, a four factor analysis was prepared for LOS Units 1 and 2 for use in their Round II Determination. The analysis identified technically feasible SO_2 and NO_X control options for the units, and evaluated each of the control measures for the following four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

The cost of compliance evaluation (Statutory Factor 1) prepared for SO_2 controls indicates that, from baseline emission rtes, the average annual cost effectiveness of the technically feasible SO_2 control options for Unit 1 ranges from $10,021 per ton (Alternative A) to $17,948 per ton SO_2 removed (Alternative B), and for Unit 2 ranges from $6,906 per ton (Alternative A) to $13,946 per ton SO_2 removed (Alternative B) from historical baselines. When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible SO_2 control options for Unit 1 ranges from $18,200 per ton (Alternative A) to $18,948 per ton SO_2 removed (Alternative B), and for Unit 2 ranges from $13,444 per ton (Alternative A) to $15,462 per ton SO_2 removed (Alternative B).

The cost of compliance evaluation prepared for NO_X controls indicates that, from baseline emission rates, the average annual cost effectiveness of the technically feasible NO_X control options for Unit 1 is $54,605 per ton NO_X removed (Alternative A), and for Unit 2 ranges from $1,896 per ton (Alternative A) to $3,630 per ton NO_X removed (Alternative B) from historical baselines. When evaluating projected future maximum emissions reductions, the average annual cost effectiveness of the technically feasible NO_X control options for Unit 1 is $28,528 per ton NO_X removed (Alternative A), and for Unit 2 ranges from $1,588 per ton (Alternative A) to $3,186 per ton NO_X removed (Alternative B). For Unit 2, Alternatives A and B will also affect the units' net plant heat rate since the amount of water that will be injected with the urea will negatively impact boiler efficiency. Both alternatives do not include additional costs that would be incurred due to the loss in net generation.

The time necessary for compliance (Statutory Factor 2) for the SO_2 control options ranges from 3 months (Alternative A) to 12 months (Alternative B). For NO_X control options, the time necessary for compliance ranges from 12 months (Alternatives A and B – Unit 2) to 52 months (Alternative A – Unit 1).

An evaluation of energy impacts and non-air environmental impacts (Statutory Factor 3) indicates that certain control options will increase auxiliary power requirements due to increased pressure drop, which would adversely impact net plant heat rate. Consequently, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output, or net output from the unit would decrease. Collateral environmental impacts include potential increases in water consumption, solid waste generation, sulfuric acid mist emissions and ammonia emissions.

Regarding remaining useful life (Statutory Factor 4), under the current Basin Electric resource plan, the remaining useful life of LOS Units 1 and 2 are considered to be greater than 20 years. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework.

Based on the results of the four factor analysis prepared for LOS SO_2 emissions reductions, WFGD Operational Improvements and WFGD Upgrades are cost prohibitive. The control cost evaluation indicates that the average cost effectiveness levels exceed $6,900 per ton SO_2 removed. Therefore, Basin Electric is proposing that the existing WFGD systems on Units 1 and 2 represent appropriate controls for the Round II Determination.

The four factor analysis prepared for LOS Units 1 indicates that additional NO_X controls are cost prohibitive. The cost effectiveness of installing a TE-SCR system on Unit 1 is over $28,000 per ton NO_X removed. Therefore, Basin Electric is proposing that the existing LNB / SOFA / SNCR system on Unit 1 represents appropriate controls for the Round II Determination. For Unit 2, the analysis indicates a cost effectiveness of $1,600 ton for the optimized SNCR alternative. The implementation of the optimized SNCR decreases the actual hourly mass emission rate by approximately 100 lb per hr (from historical baseline emissions). However, it can increase ammonia emissions, and that effect would result in additional haze formation. As such, a 5th factor analysis (visibility improvement using modeling) is recommended for this option to determine whether there is any or only a trivial amount of visibility improvement. Basin Electric requests that the NDDH withhold their Round II Determination until the Western Region Area Partnership's cumulative modeling platform are available so that a visibility improvement assessment can be conducted. Basin Electric will then perform a comparative visibility improvement analysis between the two control alternatives and submit the results to the NDDH for consideration.

It is generally understood from previous visibility modeling efforts that increased ammonia injection has the opportunity of providing additional ammonia to the atmosphere. This increased ammonia availability within the emitted plume itself is known to contribute to increased visibility impairment due to more direct formation of ammonium sulfate and ammonium nitrate, especially in the winter months where fine particulate formation is ammonia limited. In fact, it is during the winter months that the NO_X emissions have a visibility effect; the observed (and modeled) nitrate haze during the warmer months with more park visitation is negligible. As a result of the future modeling analysis, the actual visibility benefit of the optimized SNCR alternative may be considered minimal if not de-minimis.

For the Round II Determination, no change to the current Title V Operating Permit is proposed for SO_2 emissions on either LOS Unit 1 or 2 and no proposed change to the NO_X emissions on LOS Unit 1. Table ES-3 includes a summary of the proposed Round II Determination's strategy for NO_X, assessed NO_X emissions on a 30-day rolling average basis and a proposed Round II Determination's emission rate on a 30-day rolling average basis for LOS Unit 2. The proposed emissions limits include compliance margin to account for items such as variability in the operating load profile.

Table 9-1. Proposed Round II Determination's NO_X Emission Rate

LOS Unit No.	Pollutant	Assessed Emission Rate lb/MMBtu(Note 2) (30-day rolling average)	Proposed Round II Emission Rate(Note 1) (30-day rolling average)	Control Technology
Unit 2	NO_X	0.27	0.30	Optimized SNCR System

Note 1. The proposed Round II Determination's emission rate is a 14% reduction from the current permit limit of 0.35 lb NO_X/MMBtu, 30-day rolling avg.
Note 2. The assessed emission rate represents the average emission rate that LOS Unit 2 would be expected to achieve on an on-going long-term basis under normal operating conditions.

APPENDIX A

NORTH DAKOTA DEPARTMENT OF HEALTH LETTER

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

May 2, 2018

RECEIVED MAY 0 4 2018

Mr. Mike Paul
Basin Electric Power Coop.
1717 E Interstate Avenue
Bismarck, ND 58503-0564

Re: Regional Haze
Second Planning Period

Dear Mr. Paul:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

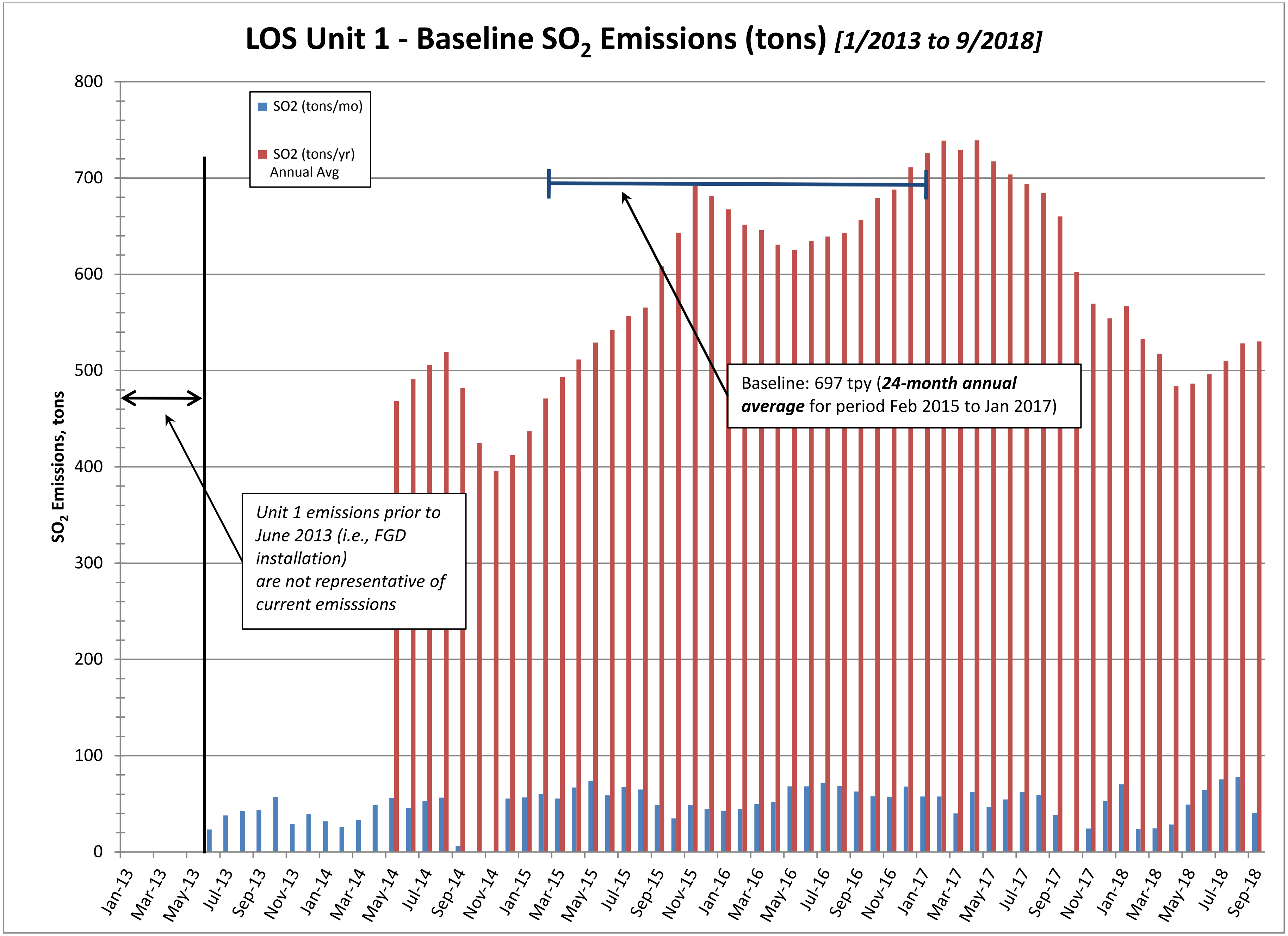
Terry O'Clair

Terry L. O'Clair
Director
Division of Air Quality

TLO/TB:saj
xc: Cris Miller, Basin Electric Power Coop.

APPENDIX B

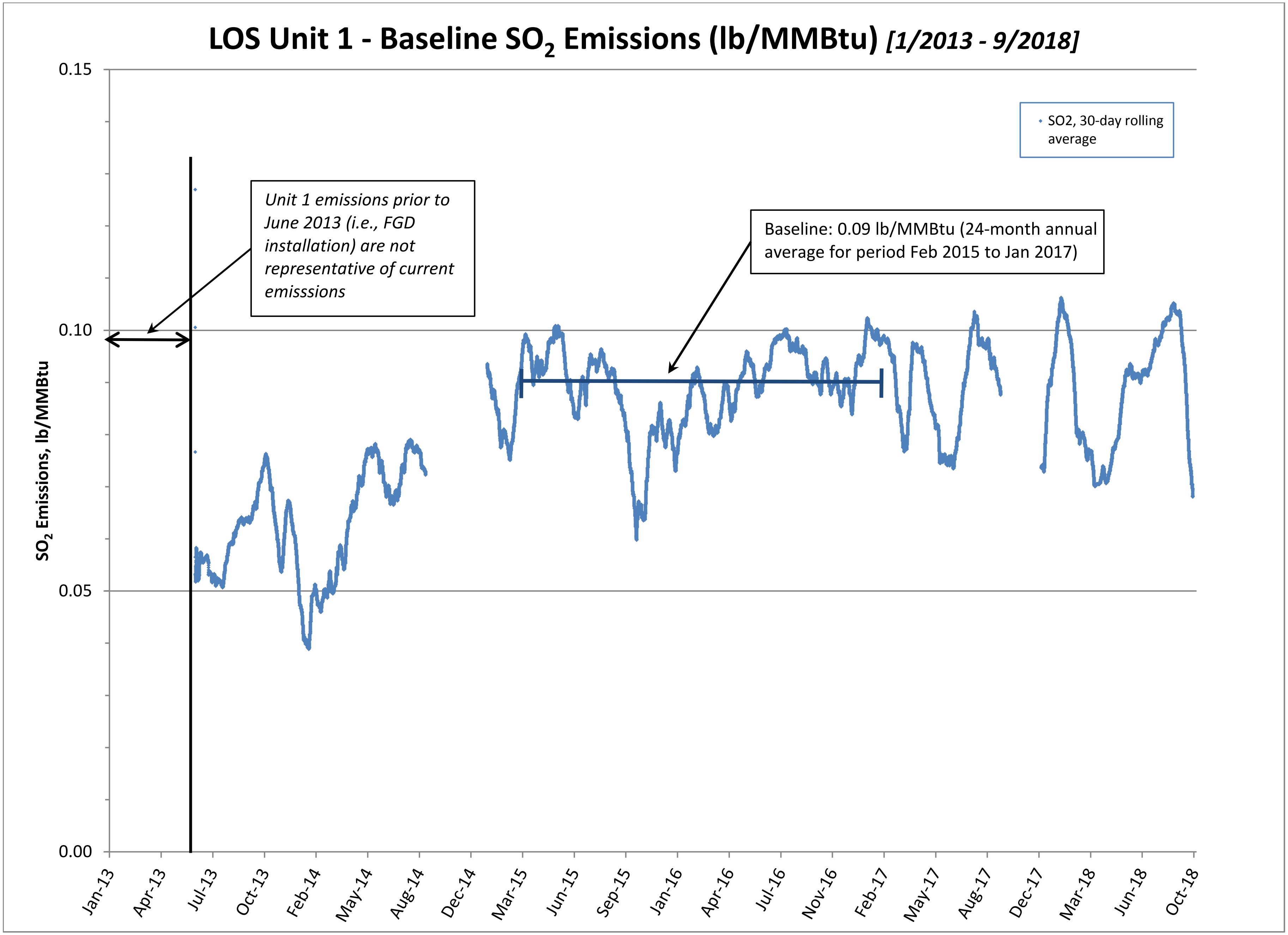
LELAND OLDS STATION UNITS 1 AND 2 BASELINE EMISSIONS



LOS Unit 1 - Baseline SO_2 Emissions (tons) *[1/2013 to 9/2018]*

Baseline: 697 tpy (***24-month annual average*** for period Feb 2015 to Jan 2017)

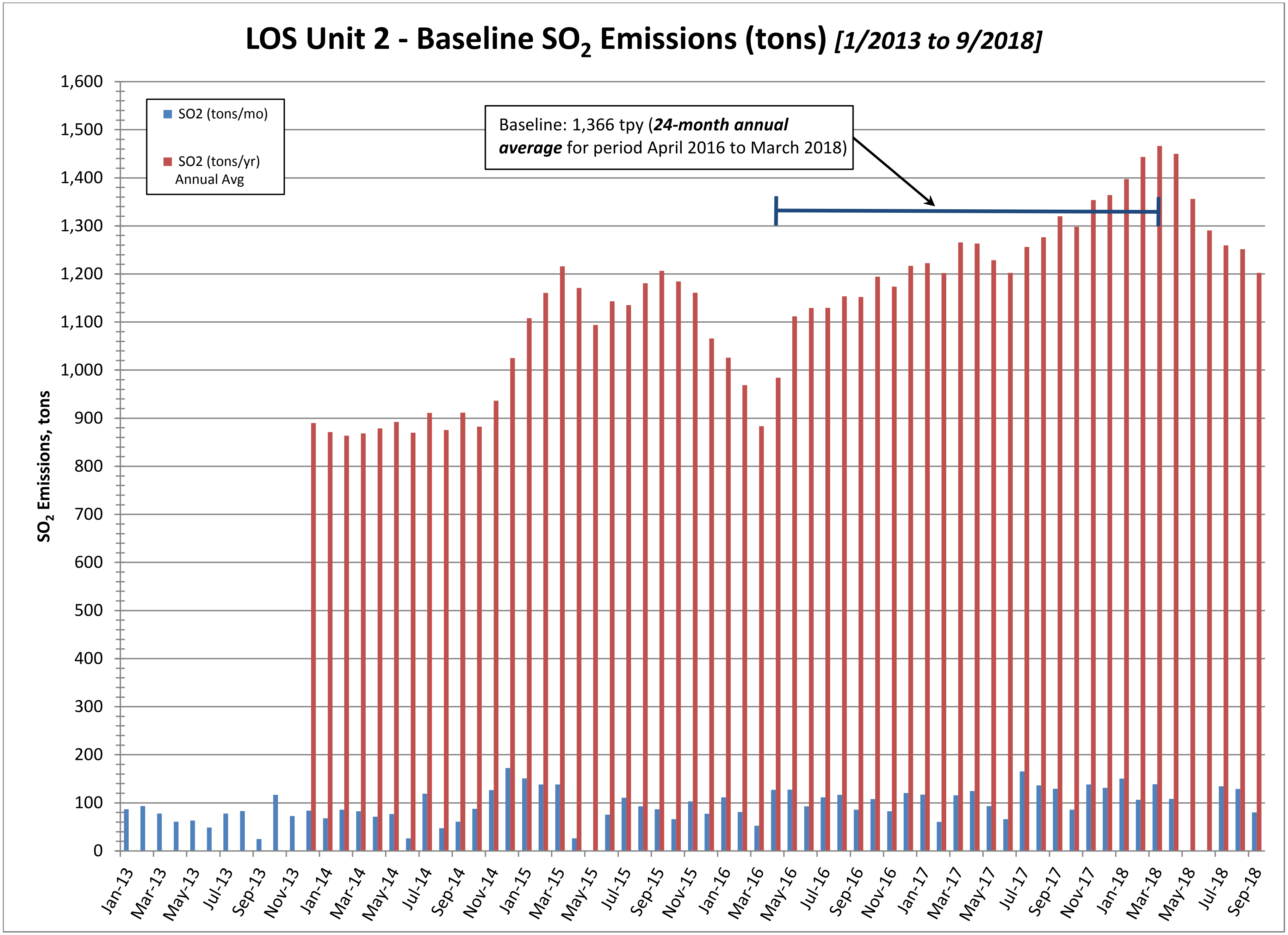
Unit 1 emissions prior to June 2013 (i.e., FGD installation) are not representative of current emisssions



LOS Unit 1 - Baseline SO_2 Emissions (lb/MMBtu) *[1/2013 - 9/2018]*

Unit 1 emissions prior to June 2013 (i.e., FGD installation) are not representative of current emisssions

Baseline: 0.09 lb/MMBtu (24-month annual average for period Feb 2015 to Jan 2017)


LOS Unit 2 - Baseline SO_2 Emissions (tons) *[1/2013 to 9/2018]*
SO2 (tons/mo)
SO2 (tons/yr) Annual Avg
Baseline: 1,366 tpy (***24-month annual average*** for period April 2016 to March 2018)
SO_2 Emissions, tons
1,600
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
Jan-13
Mar-13
May-13
Jul-13
Sep-13
Nov-13
Jan-14
Mar-14
May-14
Jul-14
Sep-14
Nov-14
Jan-15
Mar-15
May-15
Jul-15
Sep-15
Nov-15
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Mar-16
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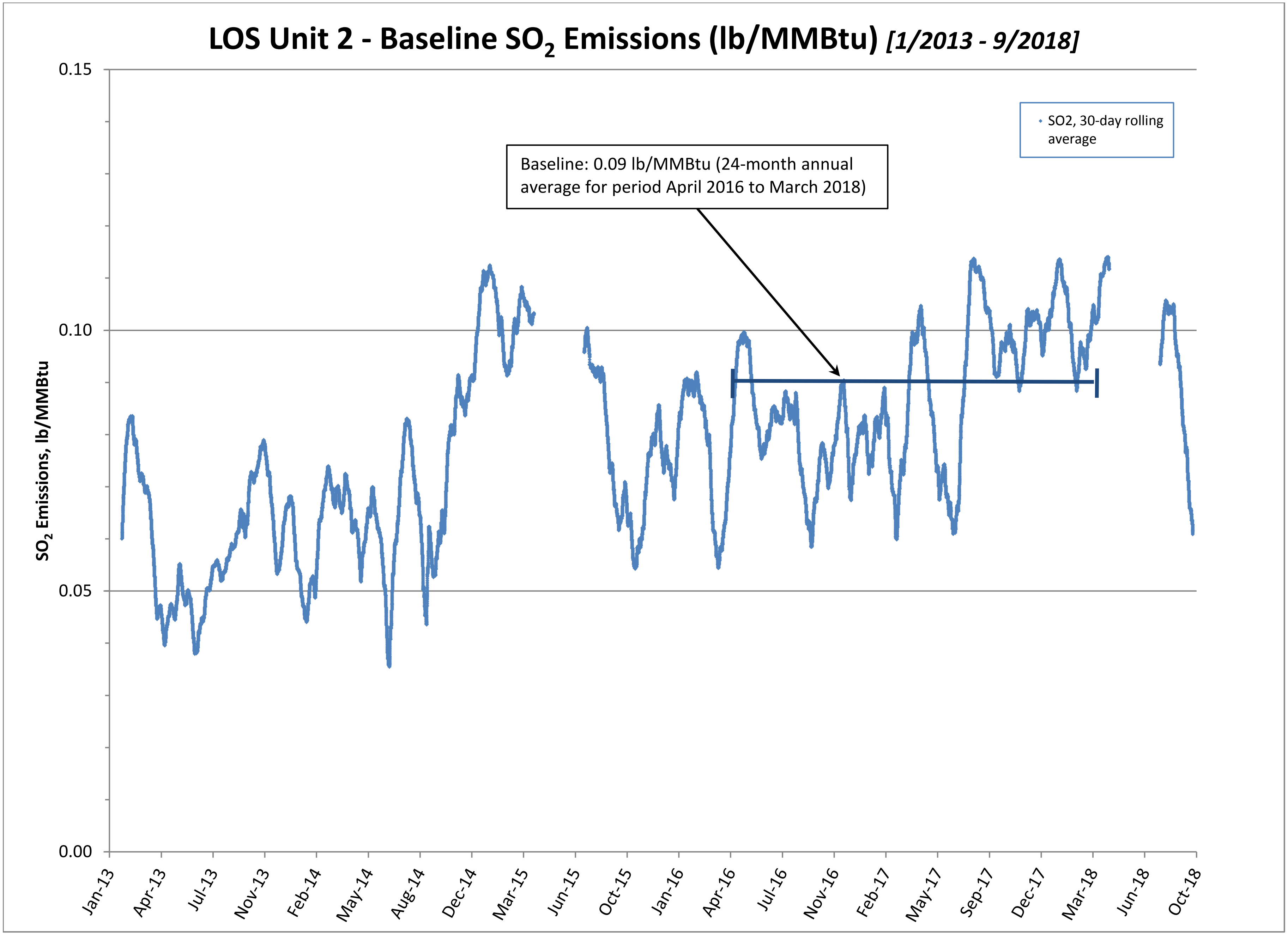
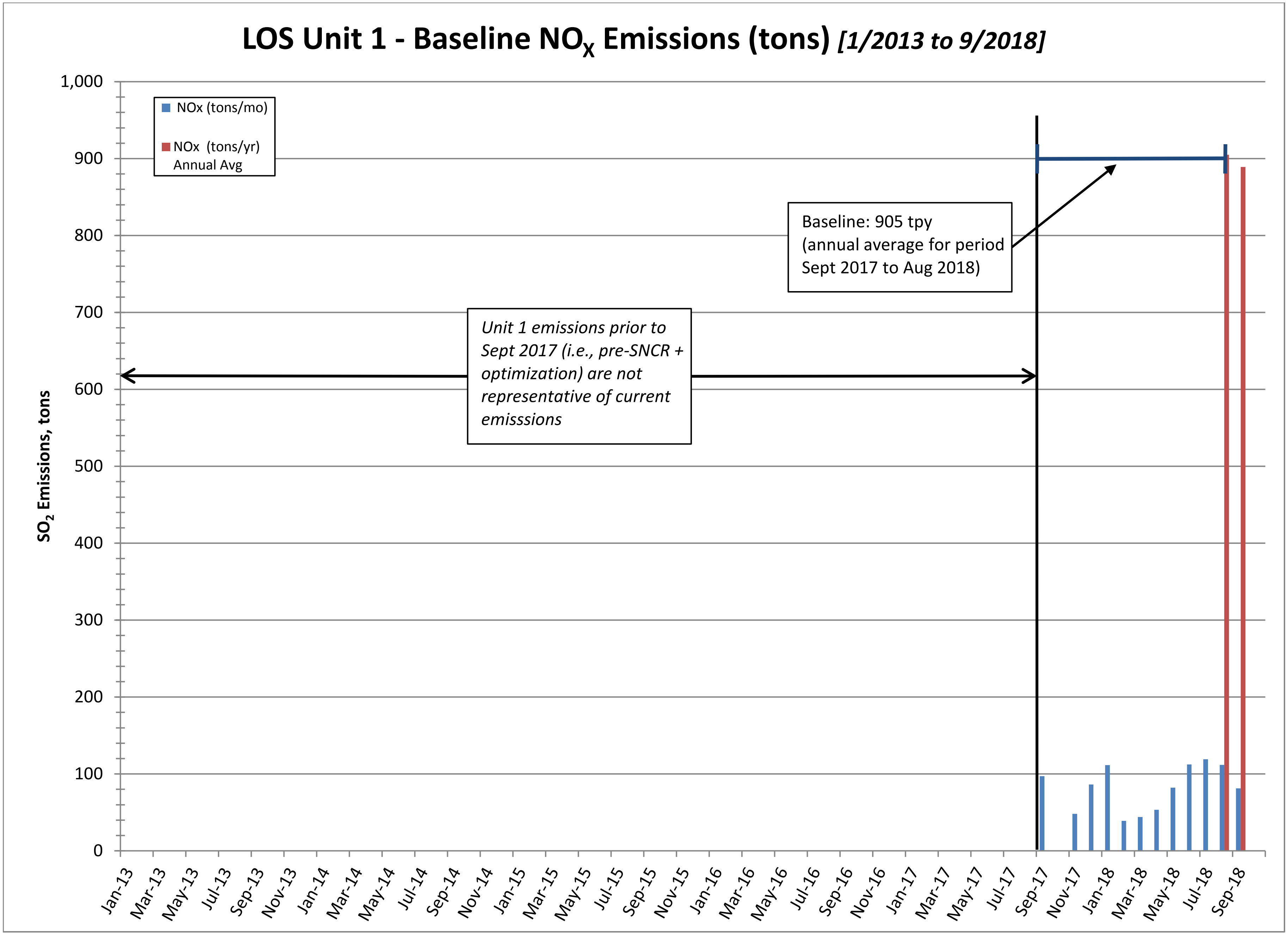
Mar-18
May-18
Jul-18
Sep-18

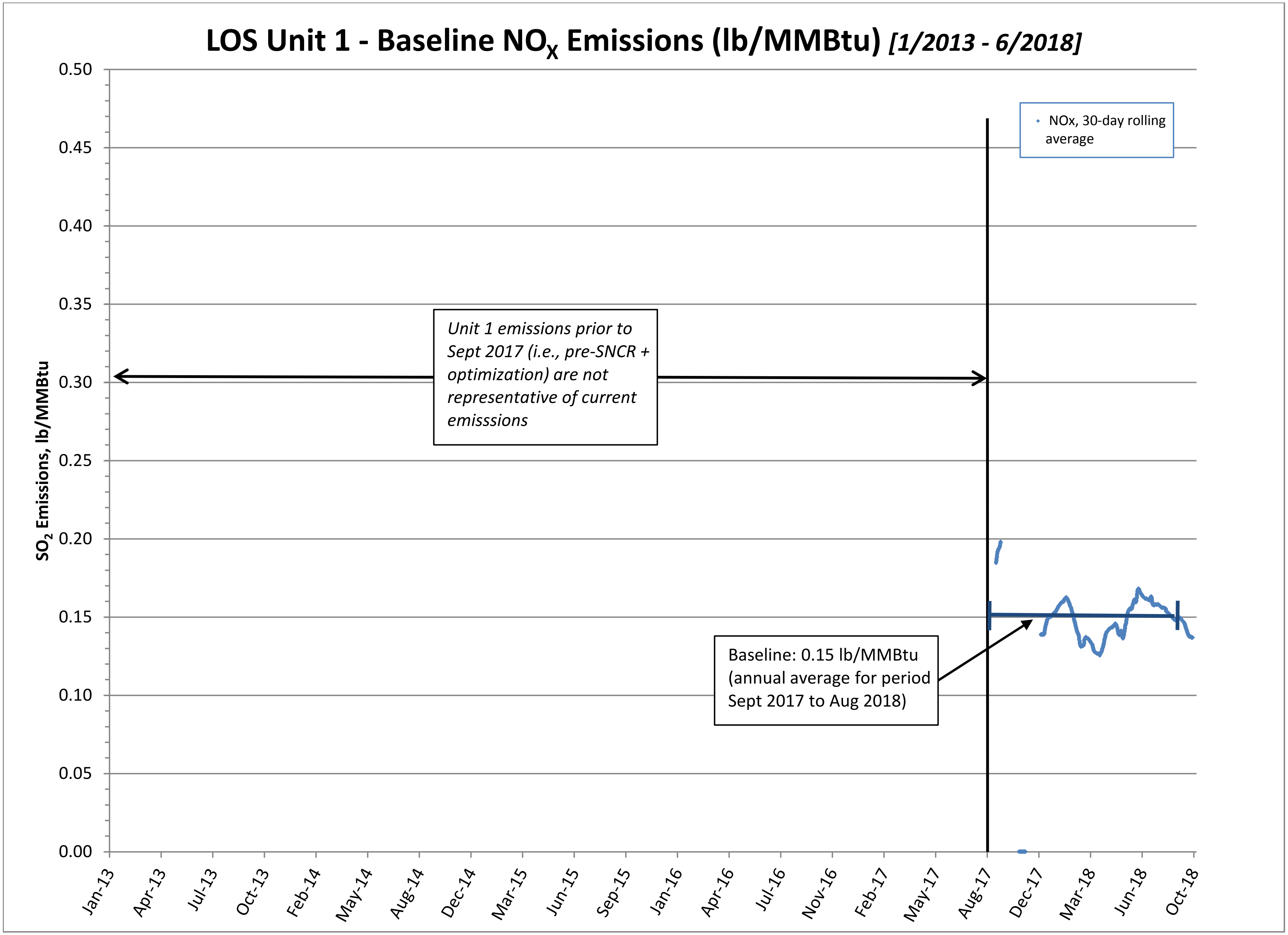

LOS Unit 2 - Baseline SO$_2$ Emissions (lb/MMBtu) *[1/2013 - 9/2018]*
SO$_2$ Emissions, lb/MMBtu
0.15
0.10
0.05
0.00
Jan-13
Apr-13
Jul-13
Nov-13
Feb-14
May-14
Aug-14
Dec-14
Mar-15
Jun-15
Oct-15
Jan-16
Apr-16
Jul-16
Nov-16
Feb-17
May-17
Sep-17
Dec-17
Mar-18
Jun-18
Oct-18
SO2, 30-day rolling average
Baseline: 0.09 lb/MMBtu (24-month annual average for period April 2016 to March 2018)

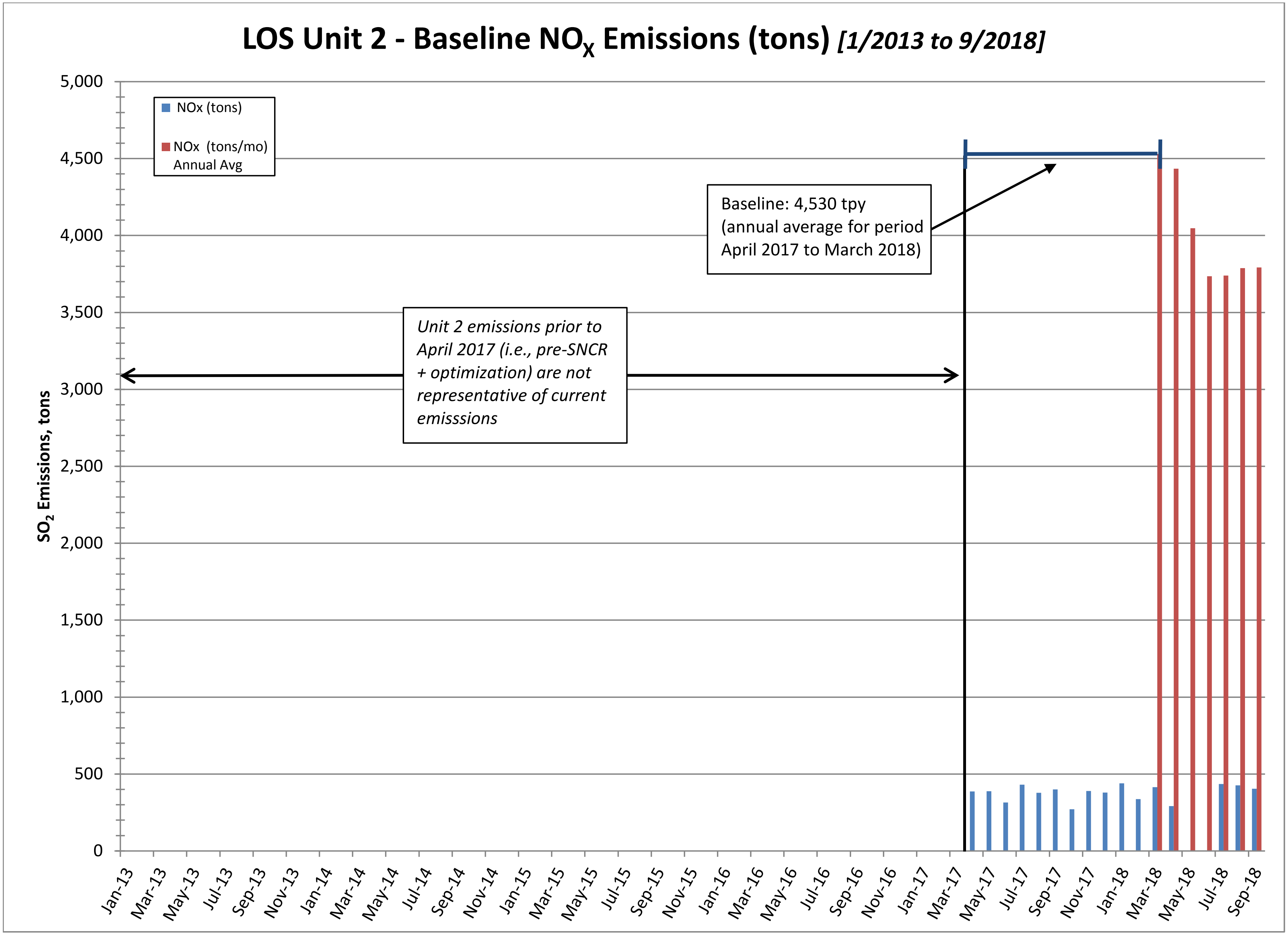


LOS Unit 1 - Baseline NO_X Emissions (tons) *[1/2013 to 9/2018]*

Baseline: 905 tpy
(annual average for period
Sept 2017 to Aug 2018)

Unit 1 emissions prior to Sept 2017 (i.e., pre-SNCR + optimization) are not representative of current emisssions

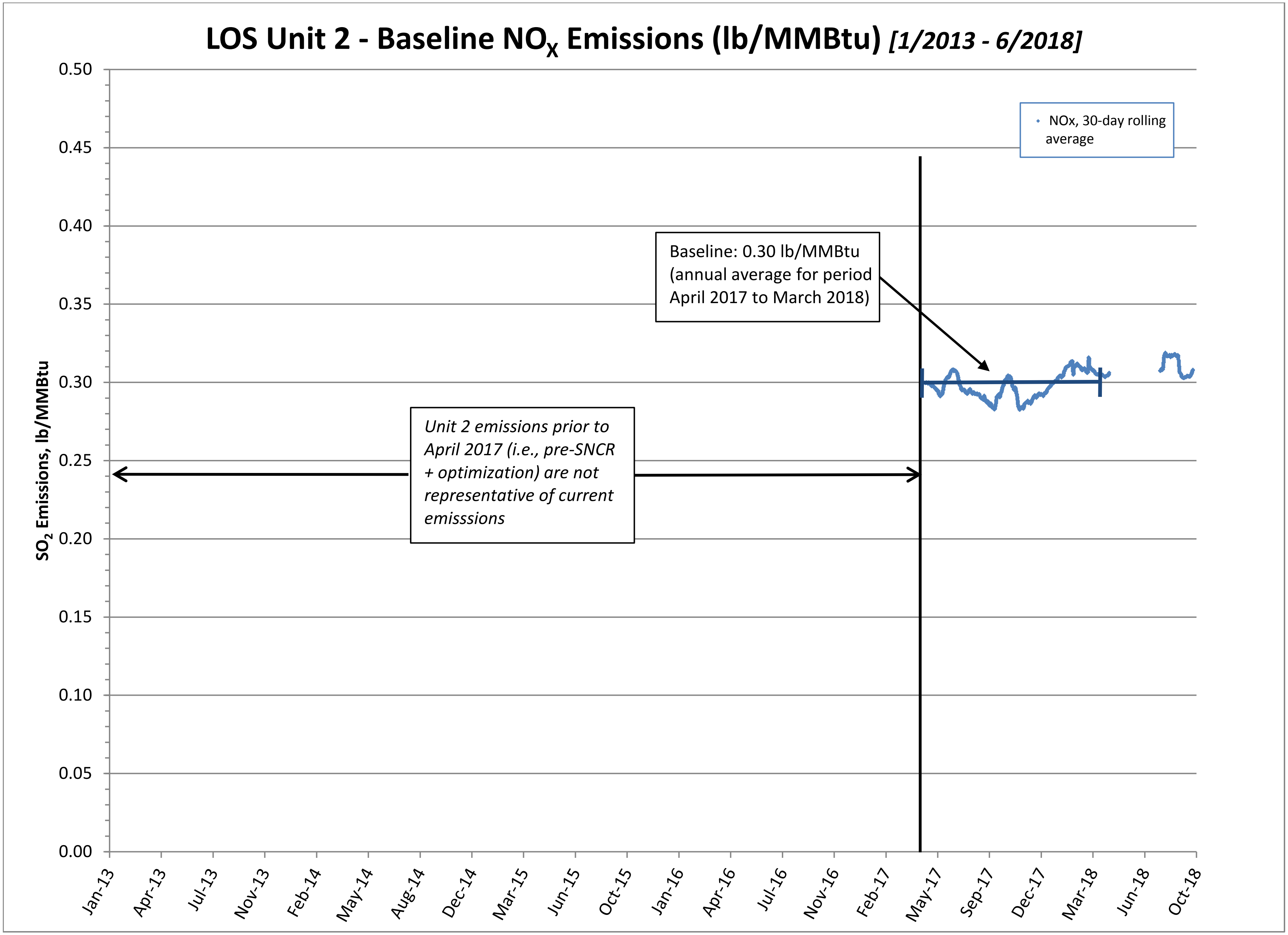

LOS Unit 1 - Baseline NO_X Emissions (lb/MMBtu) *[1/2013 - 6/2018]*
SO_2 Emissions, lb/MMBtu
0.50
0.45
0.40
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
Jan-13
Apr-13
Jul-13
Oct-13
Feb-14
May-14
Aug-14
Dec-14
Mar-15
Jun-15
Sep-15
Jan-16
Apr-16
Jul-16
Nov-16
Feb-17
May-17
Aug-17
Dec-17
Mar-18
Jun-18
Oct-18
NOx, 30-day rolling average
Unit 1 emissions prior to Sept 2017 (i.e., pre-SNCR + optimization) are not representative of current emisssions
Baseline: 0.15 lb/MMBtu (annual average for period Sept 2017 to Aug 2018)



LOS Unit 2 - Baseline NO_X Emissions (tons) *[1/2013 to 9/2018]*

Baseline: 4,530 tpy (annual average for period April 2017 to March 2018)

Unit 2 emissions prior to April 2017 (i.e., pre-SNCR + optimization) are not representative of current emisssions



LOS Unit 2 - Baseline NO_X Emissions (lb/MMBtu) *[1/2013 - 6/2018]*

Baseline: 0.30 lb/MMBtu (annual average for period April 2017 to March 2018)

Unit 2 emissions prior to April 2017 (i.e., pre-SNCR + optimization) are not representative of current emisssions

APPENDIX C

SO_2 CONTROL COST EFFECTIVENESS ESTIMATES

SO_2 CONTROL COST EFFECTIVENESS ESTIMATES

BASELINE CAPACITY FACTORS/EMISSIONS AND PROJECTED ACTUAL EMISSION RATES

Leland Olds Station Units 1 & 2
SO_2 Control Summary

Table 1. LOS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	15,538,351	30,867,575	- Unit 1: 24-month annual average for period February 2015 to January 2017 - Unit 2: 24-month annual average for period April 2016 to March 2018 - Capacity factor based on Design Hourly Heat Input (MMBtu/hr) and Annual Baseline Heat Input (MMBtu/yr) - Hourly emission rates based on Average Baseline Hourly Heat Input (MMBtu/hr)
Annual Capacity Factor	%	68%	69%	
Average Baseline Hourly Heat Input	MMBtu/hr	1,851	3,779	
Design Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

Table 2. SO_2 Control Effectiveness

	Unit 1					Unit 2				
Control Technology	**Control Efficiency**	**Expected Emissions**	**Emission Rate**	**Emission Rate**	**Expected Emissions Reduction**	**Control Efficiency**	**Expected Emissions**	**Emission Rate**	**Emission Rate**	**Expected Emissions Reduction**
	(%)	**(ton/year)**	**(lb/hr)**	**(lb/MMBtu)**	**(ton/year)**	**(%)**	**(ton/year)**	**(lb/hr)**	**(lb/MMBtu)**	**(ton/year)**
FGD Upgrades - pH Buffer Addition	98.2%	427	102	0.055	269	98.4%	772	189	0.05	594
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio						97.6%	1,158	283	0.075	208
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	97.4%	622	148	0.08	75					
Baseline (WFGD)	97.1%	697	166	0.09		97.2%	1,366	334	0.09	
Uncontrolled SO_2		24,248	5,777	3.12			48,170	11,793	3.12	

Table 3. SO_2 Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	**(tpy)**	**($)**	**($/year)**	**($/year)**	**($/year)**	**($)**	**($/ton)**	**($/ton)**
FGD Upgrades - pH Buffer Addition	427	269	$8,266,000	$677,000	$0	$4,156,000	$4,833,000	**$17,948**	$21,011
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	622	75	$0	$0	$0	$752,000	$752,000	**$10,021**	
Baseline Unit 1 (WFGD)	697								

Table 4. SO_2 Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	**(tpy)**	**($)**	**($/year)**	**($/year)**	**($/year)**	**($)**	**($/ton)**	**($/ton)**
FGD Upgrades - pH Buffer Addition	772	594	$11,560,000	$947,000		$7,340,000	$8,287,000	**$13,946**	$17,748
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio	1,158	208	$0	$0		$1,439,000	$1,439,000	**$6,906**	
Baseline Unit 2 (WFGD)	1,366								

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.09	
Post Upgrade SO_2 Emissions, lb/MMBtu	0.00	
Capacity Factor used of Cost Estimates (%)	68%	

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$0		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0		Included in equipment and materials cost
Sales Tax	$0		5% of Equipment/Material Cost
Freight	$0		5% of Equipment/Material Cost
Total PEC	$0		
Direct Installation Costs			
Labor	$0		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$0		2.5% of Labor
Mobilization / Demobilization	$0		1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$0		5% of Labor
Total Direct Installation Costs	$0		
Total Direct Costs (PEC + Direct Installation Costs)	**$0**		
Indirect Costs			
Contractor's General and Administration Expense	$0		10% of Total Direct Costs
Contractor's Profit	$0		5% of Total Direct Costs
Engineering, Procurement, & Project Services	$0		8% of Total Direct Costs
Construction Management/Field Engineering	$0		4% of Total Direct Costs
S-U / Commissioning	$0		1% of Total Direct Costs
Spare Parts	$0		0.5% of Total Direct Costs
Owner's Cost	$0		2% of Total Direct Costs
Total Indirect Costs	**$0**		
Contingency	**$0**		20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$0**		sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$	0.0820		20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)	**$0**		
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$148,000		Based on disposal rate of $8.70 per ton.
Increased Limestone Cost	$595,000		Based on limestone cost of $57 per ton.
DBA Cost	$0		Based on DBA cost of $500 per ton.
Increased Auxiliary Power Cost	$0		Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Increased Water Cost	$9,000		Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs	$752,000		
Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	$0		N/A
Supervisor Labor	$0		N/A
Maintenance Materials	$0		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0		Included in cost for maintenance materials.
Total Fixed O&M Cost	$0		
Indirect Operating Cost			
Property Taxes	$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$752,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	$0		
Annual Operating Cost	$752,000		
Total Annual Cost	**$752,000**		

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu		0.09
Post Upgrade SO_2 Emissions, lb/MMBtu		0.075
Capacity Factor used of Cost Estimates (%)		69%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$0	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$0	5% of Equipment/Material Cost
Freight		$0	5% of Equipment/Material Cost
Total PEC		$0	
Direct Installation Costs			
Labor		$0	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$0	2.5% of Labor
Mobilization / Demobilization		$0	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$0	5% of Labor
Total Direct Installation Costs		$0	
Total Direct Costs (PEC + Direct Installation Costs)		**$0**	
Indirect Costs			
Contractor's General and Administration Expense		$0	10% of Total Direct Costs
Contractor's Profit		$0	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$0	8% of Total Direct Costs
Construction Management/Field Engineering		$0	4% of Total Direct Costs
S-U / Commissioning		$0	1% of Total Direct Costs
Spare Parts		$0	0.5% of Total Direct Costs
Owner's Cost		$0	2% of Total Direct Costs
Total Indirect Costs		**$0**	
Contingency		**$0**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$0**	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)		**$0**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost		$233,000	Based on disposal rate of $8.70 per ton.
Increased Limestone Cost		$939,000	Based on limestone cost of $57 per ton.
DBA Cost		$0	Based on DBA cost of $500 per ton.
Increased Auxiliary Power Cost		$254,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Increased Water Cost		$13,000	Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs		$1,439,000	
Fixed O&M Costs			
Additional Operators per shift		0	Assume no additional operators
Operating Labor		$0	N/A
Supervisor Labor		$0	N/A
Maintenance Materials		$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$0	
Indirect Operating Cost			
Property Taxes		$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$0	
Total Annual Operating Cost		**$1,439,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$0	
Annual Operating Cost		$1,439,000	
Total Annual Cost		**$1,439,000**	

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Upgrades - pH Buffer Addition

SO_2 Control Option Description	**FGD Upgrades - pH Buffer Addition**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.09	0.09
Post Upgrade SO_2 Emissions, lb/MMBtu	0.06	0.05
Capacity Factor used of Cost Estimates (%)	68%	69%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$2,878,000	$4,027,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$144,000	$201,000	5% of Equipment/Material Cost
Freight	$144,000	$201,000	5% of Equipment/Material Cost
Total PEC	$3,166,000	$4,429,000	
Direct Installation Costs			
Labor	$1,919,000	$2,684,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$48,000	$67,000	2.5% of Labor
Mobilization / Demobilization	$29,000	$40,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$96,000	$134,000	5% of Labor
Total Direct Installation Costs	$2,092,000	$2,925,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$5,258,000**	**$7,354,000**	
Indirect Costs			
Contractor's General and Administration Expense	$526,000	$735,000	10% of Total Direct Costs
Contractor's Profit	$263,000	$368,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$421,000	$588,000	8% of Total Direct Costs
Construction Management/Field Engineering	$210,000	$294,000	4% of Total Direct Costs
S-U / Commissioning	$79,000	$110,000	1.5% of Total Direct Costs
Spare Parts	$26,000	$37,000	0.5% of Total Direct Costs
Owner's Cost	$105,000	$147,000	2% of Total Direct Costs
Total Indirect Costs	$1,630,000	$2,279,000	
Contingency	**$1,378,000**	**$1,927,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$8,266,000**	**$11,560,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)	**$677,000**	**$947,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$154,000	$245,000	Based on disposal rate of $8.70 per ton.
Increased Limestone Cost	$620,000	$989,000	Based on limestone cost of $57 per ton.
DBA Cost	$2,963,000	$5,265,000	Based on DBA cost of $500 per ton.
Increased Auxiliary Power Cost	$0	$254,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Increased Water Cost	$9,000	$14,000	Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs	$3,746,000	$6,767,000	
Fixed O&M Costs			
Additional Operators per shift	0	0	Assume no additional operators
Operating Labor	$0	$0	N/A
Supervisor Labor	$0	$0	N/A
Maintenance Materials	$79,000	$110,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$79,000	$110,000	
Indirect Operating Cost			
Property Taxes	$83,000	$116,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$83,000	$116,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$165,000	$231,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$331,000	$463,000	
Total Annual Operating Cost	**$4,156,000**	**$7,340,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$677,000	$947,000	
Annual Operating Cost	$4,156,000	$7,340,000	
Total Annual Cost	**$4,833,000**	**$8,287,000**	

SO_2 CONTROL COST EFFECTIVENESS ESTIMATES

100% CAPACITY FACTOR AND PROJECTED FUTURE MAXIMUM EMISSION RATES

Leland Olds Station Units 1 & 2
SO_2 Control Summary

Table 1. LOS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	22,968,720	44,938,800	- Unit 1: 24-month annual average for period February 2015 to January 2017 - Unit 2: 24-month annual average for period April 2016 to March 2018
Annual Capacity Factor	%	100%	100%	
Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

Table 2. SO_2 Control Effectiveness

	Unit 1					Unit 2				
Control Technology	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
FGD Upgrades - pH Buffer Addition	98.5%	632	144	0.055	398	98.7%	1,123	257	0.05	865
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio						98.0%	1,685	385	0.075	303
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	97.9%	919	210	0.08	111					
Baseline (WFGD)	97.6%	1,030	235	0.09		97.6%	1,989	454	0.09	
Uncontrolled SO_2		42,838	9,780	3.73			83,813	19,135	3.73	

Table 3. SO_2 Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)	($/ton)
FGD Upgrades - pH Buffer Addition	632	398	$8,266,000	$677,000	$0	$6,865,000	$7,542,000	**$18,948**	$19,237
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	919	111	$0	$0	$0	$2,019,000	$2,019,000	**$18,200**	
Baseline Unit 1 (WFGD)	1,030								

Table 4. SO_2 Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)	($/ton)
FGD Upgrades - pH Buffer Addition	1,123	865	$11,560,000	$947,000		$12,429,000	$13,376,000	**$15,462**	$16,552
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio	1,685	303	$0	$0		$4,078,000	$4,078,000	**$13,444**	
Baseline Unit 2 (WFGD)	1,989								

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.09	
Post Upgrade SO_2 Emissions, lb/MMBtu	0.00	
Capacity Factor used of Cost Estimates (%)	100%	

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	**Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$0		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0		Included in equipment and materials cost
Sales Tax	$0		5% of Equipment/Material Cost
Freight	$0		5% of Equipment/Material Cost
Total PEC	$0		
Direct Installation Costs			
Labor	$0		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$0		2.5% of Labor
Mobilization / Demobilization	$0		1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$0		5% of Labor
Total Direct Installation Costs	$0		
Total Direct Costs (PEC + Direct Installation Costs)	**$0**		
Indirect Costs			
Contractor's General and Administration Expense	$0		10% of Total Direct Costs
Contractor's Profit	$0		5% of Total Direct Costs
Engineering, Procurement, & Project Services	$0		8% of Total Direct Costs
Construction Management/Field Engineering	$0		4% of Total Direct Costs
S-U / Commissioning	$0		1% of Total Direct Costs
Spare Parts	$0		0.5% of Total Direct Costs
Owner's Cost	$0		2% of Total Direct Costs
Total Indirect Costs	**$0**		
Contingency	**$0**		20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$0**		sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)	**$0**		
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$397,000		Based on disposal rate of $8.70 per ton.
Increased Limestone Cost	$1,599,000		Based on limestone cost of $57 per ton.
DBA Cost	$0		Based on DBA cost of $500 per ton.
Increased Auxiliary Power Cost	$0		Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Increased Water Cost	$23,000		Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs	$2,019,000		
Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	$0		N/A
Supervisor Labor	$0		N/A
Maintenance Materials	$0		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0		Included in cost for maintenance materials.
Total Fixed O&M Cost	$0		
Indirect Operating Cost			
Property Taxes	$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$2,019,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	$0		
Annual Operating Cost	$2,019,000		
Total Annual Cost	**$2,019,000**		

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu		0.09
Post Upgrade SO_2 Emissions, lb/MMBtu		0.075
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS	**Cost (2018$)**		**Basis**
	Unit 1	**Unit 2**	
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$0	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$0	5% of Equipment/Material Cost
Freight		$0	5% of Equipment/Material Cost
Total PEC		$0	
Direct Installation Costs			
Labor		$0	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$0	2.5% of Labor
Mobilization / Demobilization		$0	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$0	5% of Labor
Total Direct Installation Costs		$0	
Total Direct Costs (PEC + Direct Installation Costs)		**$0**	
Indirect Costs			
Contractor's General and Administration Expense		$0	10% of Total Direct Costs
Contractor's Profit		$0	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$0	8% of Total Direct Costs
Construction Management/Field Engineering		$0	4% of Total Direct Costs
S-U / Commissioning		$0	1% of Total Direct Costs
Spare Parts		$0	0.5% of Total Direct Costs
Owner's Cost		$0	2% of Total Direct Costs
Total Indirect Costs		**$0**	
Contingency		**$0**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$0**	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)		**$0**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost		$729,000	Based on disposal rate of $8.70 per ton.
Increased Limestone Cost		$2,938,000	Based on limestone cost of $57 per ton.
DBA Cost		$0	Based on DBA cost of $500 per ton.
Increased Auxiliary Power Cost		$370,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Increased Water Cost		$41,000	Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs		$4,078,000	
Fixed O&M Costs			
Additional Operators per shift		0	Assume no additional operators
Operating Labor		$0	N/A
Supervisor Labor		$0	N/A
Maintenance Materials		$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$0	
Indirect Operating Cost			
Property Taxes		$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$0	
Total Annual Operating Cost		**$4,078,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$0	
Annual Operating Cost		$4,078,000	
Total Annual Cost		**$4,078,000**	

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Upgrades - pH Buffer Addition

SO_2 Control Option Description	**FGD Upgrades - pH Buffer Addition**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.09	0.09
Post Upgrade SO_2 Emissions, lb/MMBtu	0.06	0.05
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$2,878,000	$4,027,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$144,000	$201,000	5% of Equipment/Material Cost
Freight	$144,000	$201,000	5% of Equipment/Material Cost
Total PEC	$3,166,000	$4,429,000	
Direct Installation Costs			
Labor	$1,919,000	$2,684,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$48,000	$67,000	2.5% of Labor
Mobilization / Demobilization	$29,000	$40,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$96,000	$134,000	5% of Labor
Total Direct Installation Costs	$2,092,000	$2,925,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$5,258,000**	**$7,354,000**	
Indirect Costs			
Contractor's General and Administration Expense	$526,000	$735,000	10% of Total Direct Costs
Contractor's Profit	$263,000	$368,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$421,000	$588,000	8% of Total Direct Costs
Construction Management/Field Engineering	$210,000	$294,000	4% of Total Direct Costs
S-U / Commissioning	$79,000	$110,000	1.5% of Total Direct Costs
Spare Parts	$26,000	$37,000	0.5% of Total Direct Costs
Owner's Cost	$105,000	$147,000	2% of Total Direct Costs
Total Indirect Costs	$1,630,000	$2,279,000	
Contingency	**$1,378,000**	**$1,927,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$8,266,000**	**$11,560,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)	**$677,000**	**$947,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$408,000	$751,000	Based on disposal rate of $8.70 per ton.
Increased Limestone Cost	$1,644,000	$3,027,000	Based on limestone cost of $57 per ton.
DBA Cost	$4,380,000	$7,665,000	Based on DBA cost of $500 per ton.
Increased Auxiliary Power Cost	$0	$370,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Increased Water Cost	$23,000	$43,000	Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs	$6,455,000	$11,856,000	
Fixed O&M Costs			
Additional Operators per shift	0	0	Assume no additional operators
Operating Labor	$0	$0	N/A
Supervisor Labor	$0	$0	N/A
Maintenance Materials	$79,000	$110,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$79,000	$110,000	
Indirect Operating Cost			
Property Taxes	$83,000	$116,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$83,000	$116,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$165,000	$231,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$331,000	$463,000	
Total Annual Operating Cost	**$6,865,000**	**$12,429,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$677,000	$947,000	
Annual Operating Cost	$6,865,000	$12,429,000	
Total Annual Cost	**$7,542,000**	**$13,376,000**	

APPENDIX D

NO$_X$ CONTROL COST EFFECTIVENESS ESTIMATES

NO$_X$ CONTROL COST EFFECTIVENESS ESTIMATES

BASELINE CAPACITY FACTORS/EMISSIONS AND PROJECTED ACTUAL EMISSION RATES

Leland Olds Station Units 1 & 2
NO$_X$ Control Summary

Table 1. LOS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	11,681,110	30,419,273	- Unit 1: Annual average for period July 2017 to June 2018 - Unit 2: Annual average for period April 2017 to March 2018
Annual Capacity Factor	%	51%	68%	- Capacity factor based on Design Hourly Heat Input (MMBtu/hr) and Annual Baseline Heat Input (MMBtu/yr) - Hourly emission rates based on Average Baseline Hourly Heat Input (MMBtu/hr)
Average Baseline Hourly Heat Input	MMBtu/hr	1,646	3,692	
Design Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

Table 2. NO$_X$ Control Effectiveness

	Unit 1					Unit 2				
Control Technology	**Control Efficiency**	**Expected Emissions**	**Emission Rate**	**Emission Rate**	**Expected Emissions Reduction**	**Control Efficiency**	**Expected Emissions**	**Emission Rate**	**Emission Rate**	**Expected Emissions Reduction**
	(%)	**(ton/year)**	**(lb/hr)**	**(lb/MMBtu)**	**(ton/year)**	**(%)**	**(ton/year)**	**ndy's conceptual**	**(lb/MMBtu)**	**(ton/year)**
SCR - Tail-End Configuration	82.8%	292	82	0.05	613					
SNCR Optimization + RRI						67.2%	3,346	812	0.22	1,183
SNCR Optimization						59.7%	4,107	997	0.27	423
Baseline (Unit 1: LNB/ASOFA/SNCR, Unit 2: ASOFA/SNCR)	46.6%	905	255	0.15		55.6%	4,530	1,099	0.30	
Uncontrolled NOx		1,694	477	0.29			10,190	2,473	0.67	

Table 3. NO$_X$ Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of SO$_2$ Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	**(tpy)**	**($)**	**($/year)**	**($/year)**	**($/year)**	**($)**	**($/ton)**	**($/ton)**
SCR - Tail-End Configuration	292	613	$227,717,000	$18,662,000	$0	$14,809,000	$33,471,000	**$54,605**	
Baseline Unit 1	905								

Table 4. NO$_X$ Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of SO$_2$ Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	**(tpy)**	**($)**	**($/year)**	**($/year)**	**($/year)**	**($)**	**($/ton)**	**($/ton)**
SNCR Optimization + RRI	3,346	1,183	$8,562,000	$702,000	$0	$3,594,000	$4,296,000	**$3,630**	$4,594
SNCR Optimization	4,107	423	$3,089,000	$253,000	$0	$549,000	$802,000	**$1,896**	
Baseline Unit 2	4,530								

LOS Units 1 and 2
NO$_X$ Control Cost Evaluation
SNCR Optimization

NO$_X$ Control Option Description	SNCR Optimization	
	Unit 1	**Unit 2**
Baseline NO$_X$ Emissions, lb/MMBtu		0.30
Post Upgrade NO$_X$ Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		68%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$1,147,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$57,000	5% of Equipment/Material Cost
Freight		$57,000	5% of Equipment/Material Cost
Total PEC		$1,261,000	
Direct Installation Costs			
Labor		$646,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$16,000	2.5% of Labor
Mobilization / Demobilization		$10,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$32,000	5% of Labor
Total Direct Installation Costs		$704,000	
Total Direct Costs (PEC + Direct Installation Costs)		**$1,965,000**	
Indirect Costs			
Contractor's General and Administration Expense		$197,000	10% of Total Direct Costs
Contractor's Profit		$98,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$157,000	8% of Total Direct Costs
Construction Management/Field Engineering		$79,000	4% of Total Direct Costs
S-U / Commissioning		$29,000	1.5% of Total Direct Costs
Spare Parts		$10,000	0.5% of Total Direct Costs
Owner's Cost		$39,000	2% of Total Direct Costs
Total Indirect Costs		**$609,000**	
Contingency		**$515,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$3,089,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 8% interest.
Annualized Capital Costs (CRF x TCI)		**$253,000**	
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost		$369,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost		$0	Based on ammonia reagent cost of $700 per ton.
Water Cost		$8,000	Based on water cost of $1.47 per 1,000 gallons.
Steam Cost		$17,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost		$0	Based on hydrated lime cost of $150 per ton.
Catalyst Replacement Cost		$0	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost		$2,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Total Variable O&M Costs		$396,000	
Fixed O&M Costs			
Additional Operators per shift		0	
Operating Labor		$0	Assume $49.5/hr for each additional operator
Supervisor Labor		$0	N/A
Maintenance Materials		$29,500	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$29,500	
Indirect Operating Cost			
Property Taxes		$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$61,800	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$123,600	
Total Annual Operating Cost		**$549,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$253,000	
Annual Operating Cost		$549,000	
Total Annual Cost		**$802,000**	

LOS Units 1 and 2
NO_X Control Cost Evaluation
SNCR Optimization + RRI

NO_X Control Option Description	SNCR Optimization + RRI	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu		0.30
Post Upgrade NO_X Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		68%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$3,324,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$166,000	5% of Equipment/Material Cost
Freight		$166,000	5% of Equipment/Material Cost
Total PEC		$3,656,000	
Direct Installation Costs			
Labor		$1,642,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$41,000	2.5% of Labor
Mobilization / Demobilization		$25,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$82,000	5% of Labor
Total Direct Installation Costs		$1,790,000	
Total Direct Costs (PEC + Direct Installation Costs)		**$5,446,000**	
Indirect Costs			
Contractor's General and Administration Expense		$545,000	10% of Total Direct Costs
Contractor's Profit		$272,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$436,000	8% of Total Direct Costs
Construction Management/Field Engineering		$218,000	4% of Total Direct Costs
S-U / Commissioning		$82,000	1.5% of Total Direct Costs
Spare Parts		$27,000	0.5% of Total Direct Costs
Owner's Cost		$109,000	2% of Total Direct Costs
Total Indirect Costs		**$1,689,000**	
Contingency		**$1,427,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$8,562,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 8% interest.
Annualized Capital Costs (CRF x TCI)		**$702,000**	
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost		$2,490,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost		$0	Based on ammonia reagent cost of $700 per ton.
Water Cost		$57,000	Based on water cost of $1.47 per 1,000 gallons.
Steam Cost		$111,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost		$0	Based on hydrated lime cost of $150 per ton.
Catalyst Replacement Cost		$0	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost		$12,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Total Variable O&M Costs		$2,670,000	
Fixed O&M Costs			
Additional Operators per shift		1	
Operating Labor		$434,000	Assume $49.5/hr for each additional operator
Supervisor Labor		$65,000	N/A
Maintenance Materials		$82,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$581,000	
Indirect Operating Cost			
Property Taxes		$86,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$86,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$171,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$343,000	
Total Annual Operating Cost		**$3,594,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$702,000	
Annual Operating Cost		$3,594,000	
Total Annual Cost		**$4,296,000**	

LOS Units 1 and 2
NO$_X$ Control Cost Evaluation
SCR - Tail-End Configuration

NO$_X$ Control Option Description	SCR - Tail-End Configuration	
	Unit 1	**Unit 2**
Baseline NO$_X$ Emissions, lb/MMBtu	0.15	0.30
Post Upgrade NO$_X$ Emissions, lb/MMBtu	0.05	0.05
Capacity Factor used of Cost Estimates (%)	51%	68%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	**Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$76,672,000		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0		Included in equipment and materials cost
Sales Tax	$3,834,000		5% of Equipment/Material Cost
Freight	$3,834,000		5% of Equipment/Material Cost
Total PEC	$84,340,000		
Direct Installation Costs			
Labor	$55,521,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,388,000		2.5% of Labor
Mobilization / Demobilization	$833,000		1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$2,776,000		5% of Labor
Total Direct Installation Costs	$60,518,000		
Total Direct Costs (PEC + Direct Installation Costs)	**$144,858,000**		
Indirect Costs			
Contractor's General and Administration Expense	$14,486,000		10% of Total Direct Costs
Contractor's Profit	$7,243,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	$11,589,000		8% of Total Direct Costs
Construction Management/Field Engineering	$5,794,000		4% of Total Direct Costs
S-U / Commissioning	$2,173,000		1.5% of Total Direct Costs
Spare Parts	$724,000		0.5% of Total Direct Costs
Owner's Cost	$2,897,000		2% of Total Direct Costs
Total Indirect Costs	**$44,906,000**		
Contingency	**$37,953,000**		20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$227,717,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 8% interest.
Annualized Capital Costs (CRF x TCI)	**$18,662,000**		
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost	-$274,000		Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$242,000		Based on ammonia reagent cost of $700 per ton.
RO Water Cost	-$3,000		Based on water cost of $1.47 per 1,000 gallons.
Steam Cost	$181,000		Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$97,000		Based on hydrated lime cost of $150 per ton.
Catalyst Replacement and Disposal Cost	$2,081,000		Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost	$705,000		Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Total Variable O&M Costs	$3,029,000		
Fixed O&M Costs			
Additional Operators per Shift	1		
Operating Labor	$434,000		Assume $49.5/hr for each additional operator
Supervisor Labor	$65,000		15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$2,173,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0		Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,672,000		
Indirect Operating Cost			
Property Taxes	$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$4,554,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$9,108,000		
Total Annual Operating Cost	**$14,809,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	$18,662,000		
Annual Operating Cost	$14,809,000		
Total Annual Cost	**$33,471,000**		

NO_X CONTROL COST EFFECTIVENESS ESTIMATES

100% CAPACITY FACTOR AND PROJECTED FUTURE MAXIMUM EMISSION RATES

Leland Olds Station Units 1 & 2
NO_X Control Summary

Table 1. LOS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	22,968,720	44,938,800	- Unit 1: Annual average for period July 2017 to June 2018 - Unit 2: Annual average for period April 2017 to March 2018
Annual Capacity Factor	%	100%	100%	
Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

Table 2. NO_X Control Effectiveness

	Unit 1					Unit 2				
Control Technology	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
SCR - Tail-End Configuration	82.8%	574	131	0.05	1,205					
SNCR Optimization + RRI						67.2%	4,943	1,129	0.22	1,748
SNCR Optimization						59.7%	6,067	1,385	0.27	625
Baseline (Unit 1: LNB/ASOFA/SNCR, Unit 2: ASOFA/SNCR)	46.6%	1,779	406	0.15		55.6%	6,692	1,528	0.30	
Uncontrolled NOx		3,330	760	0.29			15,054	2,473	0.67	

Table 3. NO_X Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)	($/ton)
SCR - Tail-End Configuration	574	1,205	$227,717,000	$18,662,000	$0	$15,722,000	$34,384,000	**$28,528**	
Baseline Unit 1	1,779								

Table 4. NO_X Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)	($/ton)
SNCR Optimization + RRI	4,943	1,748	$8,562,000	$702,000	$0	$4,868,000	$5,570,000	**$3,186**	$4,075
SNCR Optimization	6,067	625	$3,089,000	$253,000	$0	$739,000	$992,000	**$1,588**	
Baseline Unit 2	6,692								

LOS Units 1 and 2
NO_X Control Cost Evaluation
SNCR Optimization

NO_X Control Option Description	**SNCR Optimization**	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu		0.30
Post Upgrade NO_X Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS	**Cost (2018$)**		**Basis**
	Unit 1	**Unit 2**	
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$1,147,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$57,000	5% of Equipment/Material Cost
Freight		$57,000	5% of Equipment/Material Cost
Total PEC		$1,261,000	
Direct Installation Costs			
Labor		$646,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$16,000	2.5% of Labor
Mobilization / Demobilization		$10,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$32,000	5% of Labor
Total Direct Installation Costs		$704,000	
Total Direct Costs (PEC + Direct Installation Costs)		**$1,965,000**	
Indirect Costs			
Contractor's General and Administration Expense		$197,000	10% of Total Direct Costs
Contractor's Profit		$98,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$157,000	8% of Total Direct Costs
Construction Management/Field Engineering		$79,000	4% of Total Direct Costs
S-U / Commissioning		$29,000	1.5% of Total Direct Costs
Spare Parts		$10,000	0.5% of Total Direct Costs
Owner's Cost		$39,000	2% of Total Direct Costs
Total Indirect Costs		**$609,000**	
Contingency		**$515,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$3,089,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$		0.0820	20 year life of equipment (years) @ 8% interest.
Annualized Capital Costs (CRF x TCI)		**$253,000**	
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost		$546,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost		$0	Based on ammonia reagent cost of $700 per ton.
Water Cost		$13,000	Based on water cost of $1.47 per 1,000 gallons.
Steam Cost		$24,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost		$0	Based on hydrated lime cost of $150 per ton.
Catalyst Replacement Cost		$0	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost		$3,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Total Variable O&M Costs		$586,000	
Fixed O&M Costs			
Additional Operators per shift		0	
Operating Labor		$0	Assume $49.5/hr for each additional operator
Supervisor Labor		$0	N/A
Maintenance Materials		$29,500	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$29,500	
Indirect Operating Cost			
Property Taxes		$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$61,800	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$123,600	
Total Annual Operating Cost		**$739,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$253,000	
Annual Operating Cost		$739,000	
Total Annual Cost		**$992,000**	

LOS Units 1 and 2
NO$_X$ Control Cost Evaluation
SNCR Optimization + RRI

NO$_X$ Control Option Description	SNCR Optimization + RRI	
	Unit 1	**Unit 2**
Baseline NO$_X$ Emissions, lb/MMBtu		0.30
Post Upgrade NO$_X$ Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$3,324,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$166,000	5% of Equipment/Material Cost
Freight		$166,000	5% of Equipment/Material Cost
Total PEC		$3,656,000	
Direct Installation Costs			
Labor		$1,642,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$41,000	2.5% of Labor
Mobilization / Demobilization		$25,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$82,000	5% of Labor
Total Direct Installation Costs		$1,790,000	
Total Direct Costs (PEC + Direct Installation Costs)		**$5,446,000**	
Indirect Costs			
Contractor's General and Administration Expense		$545,000	10% of Total Direct Costs
Contractor's Profit		$272,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$436,000	8% of Total Direct Costs
Construction Management/Field Engineering		$218,000	4% of Total Direct Costs
S-U / Commissioning		$82,000	1.5% of Total Direct Costs
Spare Parts		$27,000	0.5% of Total Direct Costs
Owner's Cost		$109,000	2% of Total Direct Costs
Total Indirect Costs		**$1,689,000**	
Contingency		**$1,427,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$8,562,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$		0.0820	20 year life of equipment (years) @ 8% interest.
Annualized Capital Costs (CRF x TCI)		**$702,000**	
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost		$3,679,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost		$0	Based on ammonia reagent cost of $700 per ton.
Water Cost		$84,000	Based on water cost of $1.47 per 1,000 gallons.
Steam Cost		$164,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost		$0	Based on hydrated lime cost of $150 per ton.
Catalyst Replacement Cost		$0	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost		$17,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Total Variable O&M Costs		$3,944,000	
Fixed O&M Costs			
Additional Operators per shift		1	
Operating Labor		$434,000	Assume $49.5/hr for each additional operator
Supervisor Labor		$65,000	N/A
Maintenance Materials		$82,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$581,000	
Indirect Operating Cost			
Property Taxes		$86,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$86,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$171,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$343,000	
Total Annual Operating Cost		**$4,868,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$702,000	
Annual Operating Cost		$4,868,000	
Total Annual Cost		**$5,570,000**	

LOS Units 1 and 2
NO_X Control Cost Evaluation
SCR - Tail-End Configuration

NO_X Control Option Description	SCR - Tail-End Configuration	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu	0.15	0.30
Post Upgrade NO_X Emissions, lb/MMBtu	0.05	0.00
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	**Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$76,672,000		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0		Included in equipment and materials cost
Sales Tax	$3,834,000		5% of Equipment/Material Cost
Freight	$3,834,000		5% of Equipment/Material Cost
Total PEC	$84,340,000		
Direct Installation Costs			
Labor	$55,521,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,388,000		2.5% of Labor
Mobilization / Demobilization	$833,000		1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$2,776,000		5% of Labor
Total Direct Installation Costs	$60,518,000		
Total Direct Costs (PEC + Direct Installation Costs)	**$144,858,000**		
Indirect Costs			
Contractor's General and Administration Expense	$14,486,000		10% of Total Direct Costs
Contractor's Profit	$7,243,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	$11,589,000		8% of Total Direct Costs
Construction Management/Field Engineering	$5,794,000		4% of Total Direct Costs
S-U / Commissioning	$2,173,000		1.5% of Total Direct Costs
Spare Parts	$724,000		0.5% of Total Direct Costs
Owner's Cost	$2,897,000		2% of Total Direct Costs
Total Indirect Costs	**$44,906,000**		
Contingency	**$37,953,000**		20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$227,717,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 8% interest.
Annualized Capital Costs (CRF x TCI)	**$18,662,000**		
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost	-$540,000		Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$475,000		Based on ammonia reagent cost of $700 per ton.
RO Water Cost	-$7,000		Based on water cost of $1.47 per 1,000 gallons.
Steam Cost	$357,000		Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$190,000		Based on hydrated lime cost of $150 per ton.
Catalyst Replacement and Disposal Cost	$2,081,000		Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost	$1,386,000		Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Total Variable O&M Costs	$3,942,000		
Fixed O&M Costs			
Additional Operators per Shift	1		
Operating Labor	$434,000		Assume $49.5/hr for each additional operator
Supervisor Labor	$65,000		15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$2,173,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0		Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,672,000		
Indirect Operating Cost			
Property Taxes	$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$4,554,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$9,108,000		
Total Annual Operating Cost	**$15,722,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	$18,662,000		
Annual Operating Cost	$15,722,000		
Total Annual Cost	**$34,384,000**		

BASIN ELECTRIC
POWER COOPERATIVE
A Touchstone Energy® Cooperative

November 20, 2019

Mr. James L. Semerad
North Dakota Department of Environmental Quality
918 East Divide Avenue, Second Floor
Bismarck, ND 58501-1947

Dear Mr. Semerad:

RE: Four Factor Analysis Updated Steam Costs for Leland Olds Station

As you are aware, Basin Electric Power Cooperative (Basin Electric) submitted a Round II Regional Haze Determination Four-Factor Analysis (Analysis) for the Leland Olds Station (LOS) on January 31, 2019. On July 26, 2019, Basin Electric submitted responses via e-mail to questions posed by the North Dakota Department of Environmental Quality (NDDEQ) regarding the Analysis.

Upon further review, Basin Electric has determined that the steam cost that was used in previous submittals was not accurate. Enclosed please find updated steam costs for LOS and revised cost-effectiveness of NOx reduction technologies reflective of this updated steam cost. This submittal is based on the best information Basin Electric has at this time. However, it is subject to change based on further analysis.

If you have any questions concerning this submittal, please do not hesitate to contact me at edukart@bepc.com or 701.557.5557.

Sincerely,

Erin Fox Dukart

Erin Fox Dukart
Senior Environmental Compliance Administrator

Enclosure

cc: Kentucky Sago
Tyler Schilke
Casey Mutzenberger
Matthew Ehrman
Jamey Backus

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NORTH DAKOTA ROUND II REGIONAL HAZE STATE IMPLEMENTATION PLAN DETERMINATION'S FOUR-FACTOR ANALYSIS FOR LELAND OLDS STATION

STEAM COST UPDATE

November 12, 2019

Project No. 13772-002

Sargent & Lundy

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000
www.sargentlundy.com

BASIN ELECTRIC POWER COOPERATIVE
A Touchstone Energy® Cooperative

November 12, 2019

NORTH DAKOTA ROUND II REGIONAL HAZE SIP DETERMINATION'S FOUR-FACTOR ANALYSIS FOR LELAND OLDS STATION

STEAM COST UPDATE

In January 2019, Sargent & Lundy LLC (S&L) prepared a Round II Regional Haze Four-Factor Analysis for the Leland Olds Station (LOS) on behalf of Basin Electric Power Cooperative (Basin). The analysis was prepared in response to a request made by the North Dakota Department of Environmental Quality (NDDEQ) and included an assessment of potentially available sulfur dioxide (SO_2) and nitrogen oxide (NOx) emission reduction technologies that could be applied to LOS Units 1 and 2. LOS Unit 1 is a nominal 220 MW lignite-fired pulverized coal steam electric generating unit equipped with low-NO_X burners (LNB), advanced separated overfire air (SOFA) and selective non-catalytic reduction (SNCR) for NO_X control and wet flue gas desulfurization (FGD) for SO_2 control. LOS Unit 2 is a nominal 440 MW lignite-fired cyclone boiler equipped with SOFA and SNCR for NOx control and wet FGD for SO_2 control.

Based on a review of available technologies, one NO_X emission reduction technology was determined to be technically feasible and available to LOS Unit 1: (1) installation of tail-end selective catalytic reduction (TE-SCR). Furthermore, only two NO_X emission reduction technologies were determined to be technically feasible and available to LOS Unit 2: (1) optimizing the existing SNCR system; and (2) installation of rich reagent injection (RRI). SNCR technology reduces NO_X in the flue gas by utilizing a urea $[(NH_2)_2CO]$ reagent. Aqueous urea solution is injected into the boiler where it is converted to ammonia (NH_3) which reacts with NO_X and oxygen to form molecular nitrogen and water vapor. The concept of RRI is similar to SNCR in that urea is injected into the boiler, specifically in the lower furnace to achieve NO_X reduction. Alternatively, SCR systems inject ammonia into the flue gas upstream of a catalyst bed to provide significant NOx reduction. Operating costs associated with both SNCR and RRI include the cost of the urea and steam used to produce the urea solution, while TE-SCR utilizes steam to reheat the flue gas prior to the catalyst bed.

Following submittal of the Four-Factor Analysis, Basin requested that S&L revisit the steam cost that was used to develop operating costs for the technically feasible NOx reduction technologies. The purpose of this supplemental report is to inform the NDDEQ of changes made to the steam costs and the impact of those changes on the cost-effectiveness of the NO_X reduction technologies. A brief description of the basis for the revised steam costs is provided as well as revisions to the steam cost calculations.

As part of the SNCR and RRI systems, liquid urea solution is injected into the boiler for NOx control. LOS currently purchases a dry urea for use in the existing SNCR which requires solutionizing prior to injection. As part of the urea solutionizing system, plant steam generated in the boiler is used to heat the reverse osmosis (RO) solutionizing water from 60°F to 165-180°F. Once the water reaches about 180°F it is transferred into a solutionizing tank. Dry urea is added to the solutionizing tanks via a dry urea connection at the top of each tank. Urea and heated water are added in a ratio to make a 50% aqueous solution of urea. The solution is mixed until the dry urea dissolves completely; a solutionizing pump then sends the solution to the urea storage tank(s).

S&L prepared the original four-factor analysis for different technologies based on an indicative steam cost of $1.06/MMBtu for both LOS units. Subsequently, based on site-specific cost information provided by LOS, it became apparent that these indicative costs were substantially lower than the steam production costs specific to LOS. As such, this prompted S&L to revisit the analysis with a more accurate forecast of steam costs at LOS. Steam production costs include the cost of lignite fuel, fuel handling costs, and boiler efficiency. Fuel costs make up a majority of the cost of steam production. Efficiency is also considered in the costs, as not all the heat from combusting coal is transferred to steam, since there are various heat losses within the boiler island.

LOS reviewed their fuel and operating cost projections through 2028 associated with steam generation in the boilers. LOS forecasts a lignite cost of $2.047/MMBtu in 2028 with fuel handling costs estimated to be $0.137/MMBtu, resulting in a total fuel cost of $2.184/MMBtu. In addition, LOS provided monthly operating reports for boiler efficiency on each unit. The average efficiency is approximately 80.43% and 82.25% for Unit 1 and Unit 2, respectively. These average efficiencies were used to calculate steam cost in conjunction with the fuel and material handling costs. As such, in order to account for the losses, nearly 20% more fuel is needed to generate the required steam for the urea solutionizing process. In conclusion, taking all the new site-specific information into account, the steam cost of $1.06/MMBtu was revised to $2.715/MMBtu for Unit 1 and $2.655 for Unit 2.

Accounting for changes to steam prices and other adjustments as described in the letter submitted to the NDDEQ dated July 26, 2019, the revised cost effectiveness values are included below. Revised cost effectiveness estimates are included in Attachment 1 for the annual average case and Attachment 2 for the future maximum case.

CONTROL TECHNOLOGY	**NOx Control Cost Effectiveness ($/ton)**	
	Annual Average	Future Max
SCR – Tail End Configuration (Unit 1)	$55,068	$28,990
SNCR Optimization with RRI (Unit 2)	$4,607	$4,063
SNCR Optimization (Unit 2)	$2,201	$1,895

Attachment 1: NOx Cost-Effectiveness Estimates

BASELINE CAPACITY FACTORS/EMISSIONS AND PROJECTED ACTUAL EMISSION RATES

Leland Olds Station Units 1 & 2
NO_X Control Summary

Table 1. LOS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	11,681,110	30,419,273	- Unit 1: Annual average for period July 2017 to June 2018 - Unit 2: Annual average for period April 2017 to March 2018 - Capacity factor based on Design Hourly Heat Input (MMBtu/hr) and Annual Baseline Heat Input (MMBtu/yr) - Hourly emission rates based on Average Baseline Hourly Heat Input (MMBtu/hr)
Annual Capacity Factor	%	51%	68%	
Average Baseline Hourly Heat Input	MMBtu/hr	1,646	3,692	
Design Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

Table 2. NO_X Control Effectiveness

	Unit 1					Unit 2				
Control Technology	**Control Efficiency**	**Expected Emissions**	**Emission Rate**	**Emission Rate**	**Expected Emissions Reduction**	**Control Efficiency**	**Expected Emissions**	**Emission Rate**	**Emission Rate**	**Expected Emissions Reduction**
	(%)	**(ton/year)**	**(lb/hr)**	**(lb/MMBtu)**	**(ton/year)**	**(%)**	**(ton/year)**	**(lb/hr)**	**(lb/MMBtu)**	**(ton/year)**
SCR - Tail-End Configuration	82.8%	292	82	0.05	613					
SNCR Optimization + RRI						67.2%	3,346	812	0.22	1,183
SNCR Optimization						59.7%	4,107	997	0.27	423
Baseline (Unit 1: LNB/ASOFA/SNCR, Unit 2: ASOFA/SNCR)	46.6%	905	255	0.15		55.6%	4,530	1,099	0.30	
Uncontrolled NOx		1,694	477	0.29			10,190	2,473	0.67	

Table 3. NO_X Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of NOx Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	**(tpy)**	**($)**	**($/year)**	**($/year)**	**($/year)**	**($)**	**($/ton)**	**($/ton)**
SCR - Tail-End Configuration	292	613	$227,717,000	$18,662,000	$0	$15,002,000	$33,664,000	**$54,920**	
Baseline Unit 1	905								

Table 4. NO_X Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of NOx Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	**(tpy)**	**($)**	**($/year)**	**($/year)**	**($/year)**	**($)**	**($/ton)**	**($/ton)**
SNCR Optimization + RRI	3,346	1,183	$11,342,000	$930,000	$0	$4,473,000	$5,403,000	**$4,566**	$5,890
SNCR Optimization	4,107	423	$3,089,000	$253,000	$0	$671,000	$924,000	**$2,185**	
Baseline Unit 2	4,530								

LOS Units 1 and 2
NO$_X$ Control Cost Evaluation
SNCR Optimization

NO$_X$ Control Option Description	**SNCR Optimization**	
	Unit 1	**Unit 2**
Baseline NO$_X$ Emissions, lb/MMBtu		0.30
Post Upgrade NO$_X$ Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		68%

CAPITAL COSTS	**Cost (2018$)**		**Basis**
	Unit 1	**Unit 2**	
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$1,147,000	
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$57,000	5% of Equipment/Material Cost
Freight		$57,000	5% of Equipment/Material Cost
Total PEC		$1,261,000	
Direct Installation Costs			
Labor		$646,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$16,000	2.5% of Labor
Mobilization / Demobilization		$10,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$32,000	5% of Labor
Total Direct Installation Costs		$704,000	
Total Direct Costs (PEC + Direct Installation Costs)		**$1,965,000**	
Indirect Costs			
Contractor's General and Administration Expense		$197,000	10% of Total Direct Costs
Contractor's Profit		$98,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$157,000	8% of Total Direct Costs
Construction Management/Field Engineering		$79,000	4% of Total Direct Costs
S-U / Commissioning		$29,000	1.5% of Total Direct Costs
Spare Parts		$10,000	0.5% of Total Direct Costs
Owner's Cost		$39,000	2% of Total Direct Costs
Total Indirect Costs		**$609,000**	
Contingency		**$515,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$3,089,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = i(1+ i)^n / (1 + i)^n - 1		0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)		**$253,000**	
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost		$369,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost		$0	Based on ammonia reagent cost of $700 per ton.
Water Cost		$8,000	Based on water cost of $1.47 per 1,000 gallons.
Steam Cost		$34,000	Based on steam cost of $2.184 per MMBtu.
Hydrated Lime Cost		$0	Based on hydrated lime cost of $150 per ton.
Catalyst Replacement Cost		$0	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost		$2,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Replacement Power Cost		$105,000	Based on heat rate penalty of 0.22% and replacement coal cost of $1.57/MBtu.
Total Variable O&M Costs		$518,000	

LOS Units 1 and 2
NO_X Control Cost Evaluation
SNCR Optimization

NO_X Control Option Description	SNCR Optimization	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu		0.30
Post Upgrade NO_X Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		68%

Fixed O&M Costs			
Additional Operators per shift		0	
Operating Labor		$0	Assume $49.5/hr for each additional operator
Supervisor Labor		$0	N/A
Maintenance Materials		$29,500	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$29,500	
Indirect Operating Cost			
Property Taxes		$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$61,800	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$123,600	
Total Annual Operating Cost		**$671,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$253,000	
Annual Operating Cost		$671,000	
Total Annual Cost		**$924,000**	

LOS Units 1 and 2
NO_X Control Cost Evaluation
SNCR Optimization + RRI

NO_X Control Option Description	SNCR Optimization + RRI	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu		0.30
Post Upgrade NO_X Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		68%

CAPITAL COSTS	Cost (2018$)		Basis
	Unit 1	Unit 2	
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$4,530,000	
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$227,000	5% of Equipment/Material Cost
Freight		$227,000	5% of Equipment/Material Cost
Total PEC		$4,984,000	
Direct Installation Costs			
Labor		$2,047,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$51,000	2.5% of Labor
Mobilization / Demobilization		$31,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$102,000	5% of Labor
Total Direct Installation Costs		$2,231,000	
Total Direct Costs (PEC + Direct Installation Costs)		**$7,215,000**	
Indirect Costs			
Contractor's General and Administration Expense		$722,000	10% of Total Direct Costs
Contractor's Profit		$361,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$577,000	8% of Total Direct Costs
Construction Management/Field Engineering		$289,000	4% of Total Direct Costs
S-U / Commissioning		$108,000	1.5% of Total Direct Costs
Spare Parts		$36,000	0.5% of Total Direct Costs
Owner's Cost		$144,000	2% of Total Direct Costs
Total Indirect Costs		**$2,237,000**	
Contingency		**$1,890,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$11,342,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)		**$930,000**	

OPERATING COSTS			Basis
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost		$2,490,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost		$0	Based on ammonia reagent cost of $700 per ton.
Water Cost		$57,000	Based on water cost of $1.47 per 1,000 gallons.
Steam Cost		$229,000	Based on steam cost of $2.184 per MMBtu.
Hydrated Lime Cost		$0	Based on hydrated lime cost of $150 per ton.
Catalyst Replacement Cost		$0	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost		$39,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Replacement Power Cost		$598,000	Based on heat rate penalty of 1.25% and replacement coal cost of $1.57/MBtu.
Total Variable O&M Costs		$3,413,000	

LOS Units 1 and 2
NO$_X$ Control Cost Evaluation
SNCR Optimization + RRI

NO$_X$ Control Option Description	SNCR Optimization + RRI	
	Unit 1	**Unit 2**
Baseline NO$_X$ Emissions, lb/MMBtu		0.30
Post Upgrade NO$_X$ Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		68%

Fixed O&M Costs			
Additional Operators per shift		1	
Operating Labor		$434,000	Assume $49.5/hr for each additional operator
Supervisor Labor		$65,000	N/A
Maintenance Materials		$108,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$607,000	
Indirect Operating Cost			
Property Taxes		$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$227,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$453,000	
Total Annual Operating Cost		**$4,473,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$930,000	
Annual Operating Cost		$4,473,000	
Total Annual Cost		**$5,403,000**	

LOS Units 1 and 2
NO_X Control Cost Evaluation
SCR - Tail-End Configuration

NO_X Control Option Description	SCR - Tail-End Configuration	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu	0.15	
Post Upgrade NO_X Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	51%	

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	**Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$76,672,000		$0
Instrumentation	$0		Included in equipment and materials cost
Sales Tax	$3,834,000		5% of Equipment/Material Cost
Freight	$3,834,000		5% of Equipment/Material Cost
Total PEC	$84,340,000		
Direct Installation Costs			
Labor	$55,521,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,388,000		2.5% of Labor
Mobilization / Demobilization	$833,000		1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$2,776,000		5% of Labor
Total Direct Installation Costs	$60,518,000		
Total Direct Costs (PEC + Direct Installation Costs)	**$144,858,000**		
Indirect Costs			
Contractor's General and Administration Expense	$14,486,000		10% of Total Direct Costs
Contractor's Profit	$7,243,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	$11,589,000		8% of Total Direct Costs
Construction Management/Field Engineering	$5,794,000		4% of Total Direct Costs
S-U / Commissioning	$2,173,000		1.5% of Total Direct Costs
Spare Parts	$724,000		0.5% of Total Direct Costs
Owner's Cost	$2,897,000		2% of Total Direct Costs
Total Indirect Costs	**$44,906,000**		
Contingency	**$37,953,000**		20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$227,717,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$18,662,000**		
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost	-$274,000		Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$242,000		Based on ammonia reagent cost of $700 per ton.
RO Water Cost	-$3,000		Based on water cost of $1.47 per 1,000 gallons.
Steam Cost	$374,000		Based on steam cost of $2.184 per MMBtu.
Hydrated Lime Cost	$97,000		Based on hydrated lime cost of $150 per ton.
Catalyst Replacement and Disposal Cost	$2,081,000		Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost	$705,000		Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Replacement Power Cost	$0		Based on replacement coal cost of $1.57/Mbtu.
Total Variable O&M Costs	$3,222,000		

LOS Units 1 and 2
NO_X Control Cost Evaluation
SCR - Tail-End Configuration

NO_X Control Option Description	SCR - Tail-End Configuration Unit 1	Unit 2
Baseline NO_X Emissions, lb/MMBtu	0.15	
Post Upgrade NO_X Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	51%	

	Unit 1	Unit 2	
Fixed O&M Costs			
Additional Operators per Shift	1		
Operating Labor	$434,000		Assume $49.5/hr for each additional operator
Supervisor Labor	$65,000		15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$2,173,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0		Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,672,000		
Indirect Operating Cost			
Property Taxes	$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$4,554,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$9,108,000		
Total Annual Operating Cost	**$15,002,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	$18,662,000		
Annual Operating Cost	$15,002,000		
Total Annual Cost	**$33,664,000**		

Attachment 2: NOx Cost-Effectiveness Estimates

100% CAPACITY FACTOR AND PROJECTED FUTURE MAXIMUM EMISSION RATE

Leland Olds Station Units 1 & 2
NO$_X$ Control Summary

Table 1. LOS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	22,968,720	44,938,800	- Unit 1: Annual average for period July 2017 to June 2018 - Unit 2: Annual average for period April 2017 to March 2018
Annual Capacity Factor	%	100%	100%	
Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

Table 2. NO$_X$ Control Effectiveness

	Unit 1					Unit 2				
Control Technology	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
SCR - Tail-End Configuration	82.8%	574	131	0.05	1,205					
SNCR Optimization + RRI						67.2%	4,943	1,129	0.22	1,748
SNCR Optimization						59.7%	6,067	1,385	0.27	625
Baseline (Unit 1: LNB/ASOFA/SNCR, Unit 2: ASOFA/SNCR)	46.6%	1,779	406	0.15		55.6%	6,692	1,528	0.30	
Uncontrolled NOx		3,330	760	0.29			15,054	2,473	0.67	

Table 3. NO$_X$ Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of NOx Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)	($/ton)
SCR - Tail-End Configuration	574	1,205	$227,717,000	$18,662,000	$0	$16,100,000	$34,762,000	**$28,841**	
Baseline Unit 1	1,779								

Table 4. NO$_X$ Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of NOx Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)	($/ton)
SNCR Optimization + RRI	4,943	1,748	$11,342,000	$930,000	$0	$6,101,000	$7,031,000	**$4,022**	$5,214
SNCR Optimization	6,067	625	$3,089,000	$253,000	$0	$920,000	$1,173,000	**$1,877**	
Baseline Unit 2	6,692								

Leland Olds Station Units 1 & 2
NO_X Control Summary

LOS Units 1 and 2
NO_X Control Cost Evaluation
SNCR Optimization

NO_X Control Option Description	SNCR Optimization	
	Unit 1	Unit 2
Baseline NO_X Emissions, lb/MMBtu		0.30
Post Upgrade NO_X Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS	Cost (2018$)		Basis
	Unit 1	Unit 2	
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$1,147,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$57,000	5% of Equipment/Material Cost
Freight		$57,000	5% of Equipment/Material Cost
Total PEC		$1,261,000	
Direct Installation Costs			
Labor		$646,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$16,000	2.5% of Labor
Mobilization / Demobilization		$10,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$32,000	5% of Labor
Total Direct Installation Costs		$704,000	
Total Direct Costs (PEC + Direct Installation Costs)		**$1,965,000**	
Indirect Costs			
Contractor's General and Administration Expense		$197,000	10% of Total Direct Costs
Contractor's Profit		$98,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$157,000	8% of Total Direct Costs
Construction Management/Field Engineering		$79,000	4% of Total Direct Costs
S-U / Commissioning		$29,000	1.5% of Total Direct Costs
Spare Parts		$10,000	0.5% of Total Direct Costs
Owner's Cost		$39,000	2% of Total Direct Costs
Total Indirect Costs		**$609,000**	
Contingency		**$515,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$3,089,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)		**$253,000**	
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost		$546,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost		$0	Based on ammonia reagent cost of $700 per ton.
Water Cost		$13,000	Based on water cost of $1.47 per 1,000 gallons.
Steam Cost		$50,000	Based on steam cost of $2.184 per MMBtu.
Hydrated Lime Cost		$0	Based on hydrated lime cost of $150 per ton.
Catalyst Replacement Cost		$0	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost		$3,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Replacement Power Cost		$155,000	Based on heat rate penalty of 0.22% and replacement coal cost of $1.57/MBtu.
Total Variable O&M Costs		$767,000	

LOS Units 1 and 2
NO_X Control Cost Evaluation
SNCR Optimization

NO_X Control Option Description	SNCR Optimization	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu		0.30
Post Upgrade NO_X Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		100%

Fixed O&M Costs			
Additional Operators per shift		0	
Operating Labor		$0	Assume $49.5/hr for each additional operator
Supervisor Labor		$0	N/A
Maintenance Materials		$29,500	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$29,500	
Indirect Operating Cost			
Property Taxes		$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$61,800	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$123,600	
Total Annual Operating Cost		**$920,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$253,000	
Annual Operating Cost		$920,000	
Total Annual Cost		**$1,173,000**	

LOS Units 1 and 2
NO_x Control Cost Evaluation
SNCR Optimization + RRI

NO_x Control Option Description	**SNCR Optimization + RRI**	
	Unit 1	**Unit 2**
Baseline NO_x Emissions, lb/MMBtu		0.30
Post Upgrade NO_x Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$4,530,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$227,000	5% of Equipment/Material Cost
Freight		$227,000	5% of Equipment/Material Cost
Total PEC		$4,984,000	
Direct Installation Costs			
Labor		$2,047,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$51,000	2.5% of Labor
Mobilization / Demobilization		$31,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$102,000	5% of Labor
Total Direct Installation Costs		$2,231,000	
Total Direct Costs (PEC + Direct Installation Costs)		**$7,215,000**	
Indirect Costs			
Contractor's General and Administration Expense		$722,000	10% of Total Direct Costs
Contractor's Profit		$361,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$577,000	8% of Total Direct Costs
Construction Management/Field Engineering		$289,000	4% of Total Direct Costs
S-U / Commissioning		$108,000	1.5% of Total Direct Costs
Spare Parts		$36,000	0.5% of Total Direct Costs
Owner's Cost		$144,000	2% of Total Direct Costs
Total Indirect Costs		**$2,237,000**	
Contingency		**$1,890,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$11,342,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)		**$930,000**	
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost		$3,679,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost		$0	Based on ammonia reagent cost of $700 per ton.
Water Cost		$84,000	Based on water cost of $1.47 per 1,000 gallons.
Steam Cost		$338,000	Based on steam cost of $2.184 per MMBtu.
Hydrated Lime Cost		$0	Based on hydrated lime cost of $150 per ton.
Catalyst Replacement Cost		$0	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost		$57,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Replacement Power Cost		$883,000	Based on heat rate penalty of 1.25% and replacement coal cost of $1.57/MBtu.
Total Variable O&M Costs		$5,041,000	

LOS Units 1 and 2
NO$_x$ Control Cost Evaluation
SNCR Optimization + RRI

NO$_x$ Control Option Description	SNCR Optimization + RRI	
	Unit 1	**Unit 2**
Baseline NO$_x$ Emissions, lb/MMBtu		0.30
Post Upgrade NO$_x$ Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		100%

Fixed O&M Costs			
Additional Operators per shift		1	
Operating Labor		$434,000	Assume $49.5/hr for each additional operator
Supervisor Labor		$65,000	N/A
Maintenance Materials		$108,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$607,000	
Indirect Operating Cost			
Property Taxes		$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$227,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$453,000	
Total Annual Operating Cost		**$6,101,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$930,000	
Annual Operating Cost		$6,101,000	
Total Annual Cost		**$7,031,000**	

LOS Units 1 and 2
NO_X Control Cost Evaluation
SCR - Tail-End Configuration

NO_X Control Option Description	SCR - Tail-End Configuration	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu	0.15	
Post Upgrade NO_X Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	100%	

CAPITAL COSTS	Cost (2018$) Unit 1	Unit 2	Basis
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$76,672,000		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0		Included in equipment and materials cost
Sales Tax	$3,834,000		5% of Equipment/Material Cost
Freight	$3,834,000		5% of Equipment/Material Cost
Total PEC	$84,340,000		
Direct Installation Costs			
Labor	$55,521,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,388,000		2.5% of Labor
Mobilization / Demobilization	$833,000		1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$2,776,000		5% of Labor
Total Direct Installation Costs	$60,518,000		
Total Direct Costs (PEC + Direct Installation Costs)	**$144,858,000**		
Indirect Costs			
Contractor's General and Administration Expense	$14,486,000		10% of Total Direct Costs
Contractor's Profit	$7,243,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	$11,589,000		8% of Total Direct Costs
Construction Management/Field Engineering	$5,794,000		4% of Total Direct Costs
S-U / Commissioning	$2,173,000		1.5% of Total Direct Costs
Spare Parts	$724,000		0.5% of Total Direct Costs
Owner's Cost	$2,897,000		2% of Total Direct Costs
Total Indirect Costs	**$44,906,000**		
Contingency	**$37,953,000**		20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$227,717,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$18,662,000**		
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost	-$540,000		Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$475,000		Based on ammonia reagent cost of $700 per ton.
RO Water Cost	-$7,000		Based on water cost of $1.47 per 1,000 gallons.
Steam Cost	$735,000		Based on steam cost of $2.184 per MMBtu.
Hydrated Lime Cost	$190,000		Based on hydrated lime cost of $150 per ton.
Catalyst Replacement and Disposal Cost	$2,081,000		Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost	$1,386,000		Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Replacement Power Cost	$0		Based on replacement coal cost of $1.57/MBtu.
Total Variable O&M Costs	$4,320,000		

LOS Units 1 and 2
NO_X Control Cost Evaluation
SCR - Tail-End Configuration

NO_X Control Option Description	SCR - Tail-End Configuration	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu	0.15	
Post Upgrade NO_X Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	100%	

	Unit 1	Unit 2	
Fixed O&M Costs			
Additional Operators per Shift	1		
Operating Labor	$434,000		Assume $49.5/hr for each additional operator
Supervisor Labor	$65,000		15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$2,173,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0		Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,672,000		
Indirect Operating Cost			
Property Taxes	$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$4,554,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$9,108,000		
Total Annual Operating Cost	**$16,100,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	$18,662,000		
Annual Operating Cost	$16,100,000		
Total Annual Cost	**$34,762,000**		

B.3.c – Communications

April 22, 2019 : 9:44 AM

To: *Erin Dukart*

From: *Bachman, Tom A.*
CC: *Stroh, David E.; Seligman, Angela N.*
Subject: *Leland Olds Station 4 Factor Analysis*
Attachments: *image004.png; image001.png; image005.png;*

Erin:

I note in Table 4-6 of the Four-Factors analysis that the uncontrolled SO2 emission rates assume all of the sulfur in the coal is emitted from the boiler. Based on the AP-42 emission factor for lignite, about 25% of the sulfur is retained in the bottom ash (varies depending on the sodium content of the ash). Using the AP-42 emission factor (30S), I calculate the uncontrolled emission rate at 2.80 lb/MMBtu. Since it is stated that 3.73 lb/MMBtu was used as the design basis for evaluating the SO2 controls, it appears this section should be revised.

The Four-Factors analysis indicates that SNCR was placed in to service at Leland Olds Unit 1 in September 2017 and April 2017 for Unit 2. Your April 18th email regarding the WRAP Regional Haze modeling indicates the average NOx emission rate from 2017-2018 was used. The 2028 projections for NOx are somewhat higher than the baseline emissions in the January 30, 2019 Four-Factors analysis (1,267 tons versus 905 for Unit 1 and 4,718 tons versus 4,530 tons for Unit 2) while the SO2 emissions essentially remained the same (700 tons versus 697 tons for Unit 1 and 1,371 tons versus 1,366 tons for Unit 2). Were the NOx emission rates (1.892 lb/MW-net) and 3.376 lb/MW-net) calculated using data from the entire year - 2017 - or just the part of the year when the SNCR was operating? What is the reason for NOx increasing but not SO2?

I assume the baseline emission rates in the Four-Factors analysis will be updated to match the 2028 projections? The Four-Factors analysis sections on baseline emissions (2028 projections) should include the 2028 generation forecast as part of the justification.

If you have any questions, please feel free to contact me.

Tom Bachman
Senior Environmental Engineer

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From: Bachman, Tom A.
Sent: Monday, April 15, 2019 10:55 AM
To: Erin Dukart <EDukart@bepc.com>; Stroh, David E. <deStroh@nd.gov>; Seligman, Angela N. <aseligman@nd.gov>
Cc: Mike Paul <MPaul@bepc.com>; Semerad, Jim L. <jsemerad@nd.gov>
Subject: RE: Leland Olds Station 4 Factor Analysis

Erin:

Thanks for the information.

I have reviewed the Leland Olds Station four-factors analysis and there are a couple of items that could be included in your resubmittal.

1. It is indicated that "Sargent and Lundy's conceptual cost estimating system" was used to develop certain costs. When

cost estimates are not based on EPA's Control Cost Manual, more documentation is required to substantiate the costs. Please supply additional data to support these costs.

1. The Tables in Appendix C indicate an economic life of 20 years and an interest rate of 7% were used in the economic analyses (Appendix D indicates 20 years and 8% interest). The capital recovery factor listed appears to be based on 20 years and 5.25% interest (5.25% was suggested by the Department). The tables should be corrected.

If you have any questions, please contact me.

Tom Bachman
Senior Environmental Engineer

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From: Erin Dukart <EDukart@bepc.com>
Sent: Friday, April 12, 2019 10:13 AM
To: Bachman, Tom A. <tbachman@nd.gov>; Stroh, David E. <deStroh@nd.gov>; Seligman, Angela N. <aseligman@nd.gov>
Cc: Mike Paul <MPaul@bepc.com>
Subject: Leland Olds Station 4 Factor Analysis

Mr. Bachman,

As you know, Basin Electric submitted Four Factor Analyses for the Leland Olds Station (LOS) and the Antelope Valley Station (AVS) on January 31, 2019. Since that submission, we have determined that the costs associated with Rich Reagent Injection (RRI) for LOS Unit 2 did not take into account the losses due to decreased efficiency. We are in the process of rectifying this oversight and determining what the appropriate and more accurate costs should be. We expect that analysis to be complete within the next few weeks and will submit it to the Department at that time. We apologize for any confusion as a result of this additional analysis, but wanted to let you know that it will be coming. If you have any questions, please don't hesitate to contact me.

Thanks,
Erin

Erin Fox Dukart
Environmental Compliance Administrator
Basin Electric Power Cooperative
1717 E Interstate Avenue | Bismarck, ND 58503
Direct: 701.557.5557 | Cell: 701.426.8116 | Fax: 701.557.5338
edukart@bepc.com | basinelectric.com

Stroh, David E.

From: Erin Dukart <EDukart@bepc.com>
Sent: Friday, July 26, 2019 11:31 AM
To: Stroh, David E.; Bachman, Tom A.; Seligman, Angela N.
Subject: Basin Electric Responses to LOS 4 Factor Analysis Comments
Attachments: FFA_Leland Olds Station - Response to Agency Comments_072619.pdf

Categories: RH Facility

Good morning,

Attached please find Basin Electric Power Cooperative's responses to the North Dakota Department of Environmental Quality's comments on the Leland Olds Station's Four-Factor Analysis. I apologize for not providing these responses to you sooner. If you have any questions or if there is additional information that we can provide, please contact me. The attachment contains the best information Basin Electric has at this time, but is subject to change based on further analysis.

Thanks,
Erin

Erin Fox Dukart
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NORTH DAKOTA ROUND II REGIONAL HAZE STATE IMPLEMENTATION PLAN DETERMINATION'S FOUR-FACTOR ANALYSIS FOR LELAND OLDS STATION

RESPONSE TO AGENCY COMMENTS

July 26, 2019
Project No. 13772-002

Sargent & Lundy

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Introduction

In January 2019, Sargent & Lundy LLC (S&L) prepared a Round II Regional Haze Four-Factor Analysis for the Leland Olds Station (LOS) on behalf of Basin Electric Power Cooperative (Basin). The analysis was prepared in response to a request made by the North Dakota Department of Environmental Quality (NDDEQ) and included an assessment of potentially available sulfur dioxide (SO_2) and nitrogen oxide (NOx) emission reduction technologies that could be applied to LOS Unit 1 and 2. As a result, two NOx emission reduction technologies were determined to be technically feasible and available to LOS Unit 2: (1) optimizing the existing selective non-catalytic reduction (SNCR) system; and (2) installation of rich reagent injection (RRI). The concept of RRI is similar to SNCR in that urea is injected into the boiler, specifically in the lower furnace to achieve NOx reduction.

Following submittal of the Four-Factor Analysis, Basin requested that S&L perform a technical and economic evaluation of the potential impact to the efficiency and net plant heat rate of LOS Unit 2 with the installation of either of these two technologies. These updates account for heat rate impacts associated with the technologies. The adjustments made are based on industry experience which suggests that the additional water injected into the boiler with the urea solution will partially quench the heat generated and lower furnace temperatures, thereby decreasing boiler efficiency. A decrease to the boiler efficiency will increase the unit heat rate and require additional fuel to be fired to generate the same power output. As such, the impact of heat rate degradation due to SNCR and RRI is accounted for in the economic analysis by including purchase of additional fuel as replacement power as part of the facility's variable operating costs. For LOS Unit 2, the increased urea injection rate for the optimized SNCR is estimated to result in a 0.22% heat rate penalty, while the SNCR + RRI option is estimated to result in a 1.25% penalty. The difference in the heat rate penalty is due to the much higher water injection rate with RRI and the resulting temperature impact.

Furthermore, Basin requested S&L to revisit the effort required to implement the future potential RRI system, specifically with regards to the compressed air system. A significant amount of compressed air is utilized to atomize the urea for injection near the cyclones. Upon further review, the LOS operators determined that there would need to be significant expansion of the existing compressed air system, used for the existing SNCR, if RRI would be incorporated. In addition, review of the RRI lance location determined that there would need to be special modifications required based on OEM recommendation.

The RRI configuration for the removal rates referenced in the FFA would require windbox modifications for the lance penetration. As such, S&L revised the capital and operating cost expenses to incorporate the appropriate compressed air system expansion and windbox modifications.

In addition, NDDEQ tendered comments to Basin on April 15 and April 22, 2019, regarding the LOS Four-Factor Analysis. The purpose of this document is to provide responses to the April 15 and April 22 comments from NDDEQ, and to provide updated cost effectiveness tables for LOS Unit 2 (included in Appendix A and B attached hereto) that take into account costs associated with impacts to the net plant heat rate from the installation and operation of SNCR and/or RRI and the required compressed air system expansion.

<u>NDDEQ Comment</u>

> It is indicated that "Sargent & Lundy's conceptual cost estimating system" was used to develop certain costs. When cost estimates are not based on EPA's Control Cost Manual, more documentation is required to substantiate the costs. Please supply additional data to support these costs.

<u>S&L/Basin Response</u>

> S&L has considerable experience with the federal and state environmental regulations affecting power plant operations, as well as the specification, evaluation, selection, and implementation of emission control technologies for both gas- and coal-fueled utility power facilities, including extensive experience with air pollution control technologies. For example, since 2000, S&L has provided, or is currently providing, engineering services for the implementation of over 40 wet FGD projects, 30 dry FGD projects, 25 dry sorbent injection (DSI) projects, 60 selective catalytic reduction projects (SCR) and 30 selective non-catalytic reduction (SNCR) projects all of which are technologies that were analyzed as part of the Four-Factor Analysis.
>
> Cost estimates for the Basin Four-Factor Analysis were, to the extent practical, prepared in accordance with the methodology described in EPA's Control Cost Manual and represent study-level cost estimates. Capital costs for major equipment were developed using equipment costs for similar sized units (adjusted for actual equipment sizing), an approach allowed by the Control Cost Manual. Site-specific balance-of-plant (BOP) costs that LOS would incur to retrofit the control

system onto the existing unit were estimated based on site-specific general arrangements and project-specific indirect cost factors. Default factors from EPA's Control Cost Manual were used to calculate indirect capital costs, as applicable. Specifically, cost estimates were prepared with the following general approach and site-specific information:

- Boiler operating parameters were reviewed and mass balances were prepared to calculate flue gas flows across the range of operating conditions and to size the air pollution control equipment.
- Fuel characteristics were evaluated and used to size the material handling, material storage, and piping systems.
- Plant design data were used to estimate absorber sizing, reagent storage and preparation systems, dewatering systems and byproduct handling systems for air pollution control equipment.
- Aerial views of the plant and plant general arrangements were used to identify the general vicinity in which major equipment would be located.

The capital cost estimates were prepared for the major control system components, equipment, material, labor, instrumentation, etc. Capital costs were annualized using the methodology described in the Control Cost Manual, and annual operating and maintenance (O&M) costs were added to the annualized cost of capital to generate a total annual cost. Detailed cost effectiveness worksheets were provided identifying the O&M costs including, variable O&M costs (i.e. reagent, waste disposal, auxiliary power and water), indirect operating costs (i.e. property taxes, insurance, and administrative services), and fixed O&M costs (i.e. operating personnel as well as maintenance material and labor) for all of the air pollution control options. Default factors from EPA's Control Cost Manual were used to calculate fixed O&M costs, as applicable. The approach used by S&L to generate capital cost estimates, O&M costs, and total annual costs is in accordance with the methodology outlined in the Control Cost Manual.

<u>NDDEQ Comment</u>

The tables in Appendix C indicate an economic life of 20 years and an interest rate of 7% were used in the economic analyses (Appendix D indicates 20 years and 8% interest). The capital recovery factor listed appears to be based on 20 years and 5.25% interest (5.25% was suggested by the Department). The tables should be corrected.

S&L/Basin Response

NDDEQ is correct that the capital recovery factor used in the Four-Factor Analysis is based on a 5.25% interest rate and 20 years. While the worksheet implied 7.0% interest rate was used, the calculation was correct by using 5.25%. S&L has provided cost effectiveness tables, correcting the typo, attached in Appendices A and B.

NDDEQ Comment

I note in Table 4-6 of the Four-Factor Analysis that the uncontrolled SO_2 emission rates assume all of the sulfur in the coal is emitted from the boiler. Based on the AP-42 emission factor for lignite, about 25% of the sulfur is retained in the bottom ash (varies depending on the sodium content of the ash). Using the AP-42 emission factor (30S), I calculate the uncontrolled emission rate at 2.80 lb/MMBtu. Since it is stated that 3.73 lb/MMBtu was used as the design basis for evaluating the SO_2 controls, it appears this section should be revised.

S&L/Basin Response

We appreciate the agency's comment regarding calculation of the baseline SO_2 inlet rate. S&L used projected future fuel analyses (sulfur and HHV) provided by Basin to calculate the baseline inlet SO_2 rate. Projections were based on the annual average fuel sulfur content and average heating value of the fuel for each year over the next 20 years, taking into account historical deviations seen in the coal quality. Coal data were provided to Basin by the Freedom Mine. The baseline SO_2 rate of 3.73 lb/MBtu represents the highest annual average SO_2 emission rate assuming 100% conversion of fuel sulfur to SO_2 and without taking into account any inherent SO_2 capture.

NDDEQ used the Fourth Edition Compilation of Air Pollutant Emissions Factors (AP-42) from 1985 to adjust the baseline inlet SO_2 rate. That edition of AP-42 includes an assumption for lignite fuels that, on average, 75% of the fuel sulfur will be converted to SO_2 (i.e. 3.73 lb SO_2/MBtu * 0.75 = 2.80 lb SO_2/MBtu). However, a more recent edition recommends using an emission factor of 30S (lb/ton) for lignite-fired cyclone boilers, where S = weight % sulfur content of the lignite on a wet basis (see, Fifth Edition Compilation of Air Pollutant Emissions Factors AP-42, Volume 1: Stationary Point and Area Sources, Chapter 1, Table 1.7-1). A conversion factor of 0.077 is used to convert from lb/ton to lb/MBtu assuming an average lignite heating value of 6,500 Btu/lb. Using this approach, the inlet SO_2 rate would be calculated as: (30)*(1.23)*(0.077) = 2.84 lb SO_2/MBtu.

Although the report states that S&L used an uncontrolled SO_2 rate of 3.73 lb/MBtu as the design basis for the Four-Factor Analysis, this value was only used for the Projected Future Maximum Case. Uncontrolled SO_2 rates of 3.12 lb SO_2/MBtu and 3.05 lb SO_2/MBtu for Units 1 and 2 (see Table 4-4 of the Four Factor Analysis), respectively were used for the Actual Average Case. In addition, since the LOS units already have new wet FGD's the only technically feasible SO_2 alternatives are upgrades to the existing wet FGD systems which are primarily O&M driven. Variable O&M costs that are impacted include reagent consumption such as pH buffer and limestone. Variable O&M costs were based on uncontrolled SO_2 rates of 3.12 lb SO_2/MBtu and 3.05 lb SO_2/MBtu for Units 1 and 2, respectively for the Actual Average Case. The difference between 2.80 lb SO_2/MBtu and 3.12 or 3.05 lb SO_2/MBtu will not have a significant impact on the FGD cost-effectiveness analysis because the variable O&M costs are relatively small.

NDDEQ Comment

The Four-Factor Analysis indicates that SNCR was placed in to service at Leland Olds Unit 1 in September 2017 and April 2017 for Unit 2. Your April 18th email regarding the WRAP Regional Haze modeling indicates the average NOx emission rate from 2017-2018 was used. The 2028 projections for NOx are somewhat higher than the baseline emissions in the January 30, 2019 Four-Factor Analysis (1,267 tons versus 905 for Unit 1 and 4,718 tons versus 4,530 tons for Unit 2) while the SO_2 emissions essentially remained the same (700 tons versus 697 tons for Unit 1 and 1,371 tons versus 1,366 tons for Unit 2). Were the NOx emission rates (1.892 lb/MW-net and 3.376 lb/MW-net) calculated using data from the entire year - 2017 - or just the part of the year when the SNCR was operating? What is the reason for NOx increasing but not SO_2? I assume the baseline emission rates in the Four-Factor Analysis will be updated to match the 2028 projections? The Four-Factor analysis sections on baseline emissions (2028 projections) should include the 2028 generation forecast as part of the justification.

S&L/Basin Response

Basin to respond.

APPENDIX A

SO_2 CONTROL COST EFFECTIVENESS ESTIMATES

SO_2 CONTROL COST EFFECTIVENESS ESTIMATES

BASELINE CAPACITY FACTORS/EMISSIONS AND PROJECTED ACTUAL EMISSION RATES

Leland Olds Station Units 1 & 2
SO_2 Control Summary

Table 1. LOS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	15,538,351	30,867,575	- Unit 1: 24-month annual average for period February 2015 to January 2017 - Unit 2: 24-month annual average for period April 2016 to March 2018 - Capacity factor based on Design Hourly Heat Input (MMBtu/hr) and Annual Baseline Heat Input (MMBtu/yr) - Hourly emission rates based on Average Baseline Hourly Heat Input (MMBtu/hr)
Annual Capacity Factor	%	68%	69%	
Average Baseline Hourly Heat Input	MMBtu/hr	1,851	3,779	
Design Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

Table 2. SO_2 Control Effectiveness

	Unit 1					Unit 2				
Control Technology	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
FGD Upgrades - pH Buffer Addition	98.2%	427	102	0.055	269	98.4%	772	189	0.05	594
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio						97.6%	1,158	283	0.075	208
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	97.4%	622	148	0.08	75					
Baseline (WFGD)	97.1%	697	166	0.09		97.2%	1,366	334	0.09	
Uncontrolled SO_2		24,248	5,777	3.12			48,170	11,793	3.12	

Table 3. SO_2 Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)	($/ton)
FGD Upgrades - pH Buffer Addition	427	269	$8,266,000	$677,000	$0	$4,156,000	$4,833,000	**$17,948**	$21,011
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	622	75	$0	$0	$0	$752,000	$752,000	**$10,021**	
Baseline Unit 1 (WFGD)	697								

Table 4. SO_2 Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)	($/ton)
FGD Upgrades - pH Buffer Addition	772	594	$11,560,000	$947,000		$7,340,000	$8,287,000	**$13,946**	$17,748
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio	1,158	208	$0	$0		$1,439,000	$1,439,000	**$6,906**	
Baseline Unit 2 (WFGD)	1,366								

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu		0.09
Post Upgrade SO_2 Emissions, lb/MMBtu		0.075
Capacity Factor used of Cost Estimates (%)		69%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$0	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$0	5% of Equipment/Material Cost
Freight		$0	5% of Equipment/Material Cost
Total PEC		$0	
Direct Installation Costs			
Labor		$0	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$0	2.5% of Labor
Mobilization / Demobilization		$0	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$0	5% of Labor
Total Direct Installation Costs		$0	
Total Direct Costs (PEC + Direct Installation Costs)		**$0**	
Indirect Costs			
Contractor's General and Administration Expense		$0	10% of Total Direct Costs
Contractor's Profit		$0	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$0	8% of Total Direct Costs
Construction Management/Field Engineering		$0	4% of Total Direct Costs
S-U / Commissioning		$0	1% of Total Direct Costs
Spare Parts		$0	0.5% of Total Direct Costs
Owner's Cost		$0	2% of Total Direct Costs
Total Indirect Costs		**$0**	
Contingency		**$0**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$0**	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)		**$0**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost		$233,000	Based on disposal rate of $8.70 per ton.
Increased Limestone Cost		$939,000	Based on limestone cost of $57 per ton.
DBA Cost		$0	Based on DBA cost of $500 per ton.
Increased Auxiliary Power Cost		$254,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Increased Water Cost		$13,000	Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs		$1,439,000	

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu		0.09
Post Upgrade SO_2 Emissions, lb/MMBtu		0.075
Capacity Factor used of Cost Estimates (%)		69%

Fixed O&M Costs			
Additional Operators per shift		0	Assume no additional operators
Operating Labor		$0	N/A
Supervisor Labor		$0	N/A
Maintenance Materials		$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$0	
Indirect Operating Cost			
Property Taxes		$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$0	
Total Annual Operating Cost		**$1,439,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$0	
Annual Operating Cost		$1,439,000	
Total Annual Cost		**$1,439,000**	

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Upgrades - pH Buffer Addition

SO_2 Control Option Description	**FGD Upgrades - pH Buffer Addition**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.09	0.09
Post Upgrade SO_2 Emissions, lb/MMBtu	0.055	0.05
Capacity Factor used of Cost Estimates (%)	68%	69%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$2,878,000	$4,027,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$144,000	$201,000	5% of Equipment/Material Cost
Freight	$144,000	$201,000	5% of Equipment/Material Cost
Total PEC	$3,166,000	$4,429,000	
Direct Installation Costs			
Labor	$1,919,000	$2,684,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$48,000	$67,000	2.5% of Labor
Mobilization / Demobilization	$29,000	$40,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$96,000	$134,000	5% of Labor
Total Direct Installation Costs	$2,092,000	$2,925,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$5,258,000**	**$7,354,000**	
Indirect Costs			
Contractor's General and Administration Expense	$526,000	$735,000	10% of Total Direct Costs
Contractor's Profit	$263,000	$368,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$421,000	$588,000	8% of Total Direct Costs
Construction Management/Field Engineering	$210,000	$294,000	4% of Total Direct Costs
S-U / Commissioning	$79,000	$110,000	1.5% of Total Direct Costs
Spare Parts	$26,000	$37,000	0.5% of Total Direct Costs
Owner's Cost	$105,000	$147,000	2% of Total Direct Costs
Total Indirect Costs	$1,630,000	$2,279,000	
Contingency	**$1,378,000**	**$1,927,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$8,266,000**	**$11,560,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$677,000**	**$947,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$154,000	$245,000	Based on disposal rate of $8.70 per ton.
Increased Limestone Cost	$620,000	$989,000	Based on limestone cost of $57 per ton.
DBA Cost	$2,963,000	$5,265,000	Based on DBA cost of $500 per ton.
Increased Auxiliary Power Cost	$0	$254,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Increased Water Cost	$9,000	$14,000	Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs	$3,746,000	$6,767,000	

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Upgrades - pH Buffer Addition

SO_2 Control Option Description	**FGD Upgrades - pH Buffer Addition**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.09	0.09
Post Upgrade SO_2 Emissions, lb/MMBtu	0.055	0.05
Capacity Factor used of Cost Estimates (%)	68%	69%

Fixed O&M Costs			
Additional Operators per shift	0	0	Assume no additional operators
Operating Labor	$0	$0	N/A
Supervisor Labor	$0	$0	N/A
Maintenance Materials	$79,000	$110,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$79,000	$110,000	
Indirect Operating Cost			
Property Taxes	$83,000	$116,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$83,000	$116,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$165,000	$231,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$331,000	$463,000	
Total Annual Operating Cost	**$4,156,000**	**$7,340,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$677,000	$947,000	
Annual Operating Cost	$4,156,000	$7,340,000	
Total Annual Cost	**$4,833,000**	**$8,287,000**	

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.09	
Post Upgrade SO_2 Emissions, lb/MMBtu	0.08	
Capacity Factor used of Cost Estimates (%)	68%	

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$0		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0		Included in equipment and materials cost
Sales Tax	$0		5% of Equipment/Material Cost
Freight	$0		5% of Equipment/Material Cost
Total PEC	$0		
Direct Installation Costs			
Labor	$0		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$0		2.5% of Labor
Mobilization / Demobilization	$0		1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$0		5% of Labor
Total Direct Installation Costs	$0		
Total Direct Costs (PEC + Direct Installation Costs)	**$0**		
Indirect Costs			
Contractor's General and Administration Expense	$0		10% of Total Direct Costs
Contractor's Profit	$0		5% of Total Direct Costs
Engineering, Procurement, & Project Services	$0		8% of Total Direct Costs
Construction Management/Field Engineering	$0		4% of Total Direct Costs
S-U / Commissioning	$0		1% of Total Direct Costs
Spare Parts	$0		0.5% of Total Direct Costs
Owner's Cost	$0		2% of Total Direct Costs
Total Indirect Costs	**$0**		
Contingency	**$0**		20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$0**		sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$0**		
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$148,000		Based on disposal rate of $8.70 per ton.
Increased Limestone Cost	$595,000		Based on limestone cost of $57 per ton.
DBA Cost	$0		Based on DBA cost of $500 per ton.
Increased Auxiliary Power Cost	$0		Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Increased Water Cost	$9,000		Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs	$752,000		

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.09	
Post Upgrade SO_2 Emissions, lb/MMBtu	0.08	
Capacity Factor used of Cost Estimates (%)	68%	

Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	$0		N/A
Supervisor Labor	$0		N/A
Maintenance Materials	$0		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0		Included in cost for maintenance materials.
Total Fixed O&M Cost	$0		
Indirect Operating Cost			
Property Taxes	$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$752,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	$0		
Annual Operating Cost	$752,000		
Total Annual Cost	**$752,000**		

SO_2 CONTROL COST EFFECTIVENESS ESTIMATES

100% CAPACITY FACTOR AND PROJECTED FUTURE MAXIMUM EMISSION RATES

Leland Olds Station Units 1 & 2
SO_2 Control Summary

Table 1. LOS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	22,968,720	44,938,800	- Unit 1: 24-month annual average for period February 2015 to January 2017 - Unit 2: 24-month annual average for period April 2016 to March 2018
Annual Capacity Factor	%	100%	100%	
Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

Table 2. SO_2 Control Effectiveness

	Unit 1					Unit 2				
Control Technology	**Control Efficiency**	**Expected Emissions**	**Emission Rate**	**Emission Rate**	**Expected Emissions Reduction**	**Control Efficiency**	**Expected Emissions**	**Emission Rate**	**Emission Rate**	**Expected Emissions Reduction**
	(%)	**(ton/year)**	**(lb/hr)**	**(lb/MMBtu)**	**(ton/year)**	**(%)**	**(ton/year)**	**(lb/hr)**	**(lb/MMBtu)**	**(ton/year)**
FGD Upgrades - pH Buffer Addition	98.5%	632	144	0.055	398	98.7%	1,123	257	0.05	865
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio						98.0%	1,685	385	0.075	303
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	97.9%	919	210	0.08	111					
Baseline (WFGD)	97.6%	1,030	235	0.09		97.6%	1,989	454	0.09	
Uncontrolled SO_2		42,838	9,780	3.73			83,813	19,135	3.73	

Table 3. SO_2 Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	**(tpy)**	**($)**	**($/year)**	**($/year)**	**($/year)**	**($)**	**($/ton)**	**($/ton)**
FGD Upgrades - pH Buffer Addition	632	398	$8,266,000	$677,000	$0	$6,865,000	$7,542,000	**$18,948**	$19,237
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio	919	111	$0	$0	$0	$2,019,000	$2,019,000	**$18,200**	
Baseline Unit 1 (WFGD)	1,030								

Table 4. SO_2 Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	**(tpy)**	**($)**	**($/year)**	**($/year)**	**($/year)**	**($)**	**($/ton)**	**($/ton)**
FGD Upgrades - pH Buffer Addition	1,123	865	$11,560,000	$947,000		$12,429,000	$13,376,000	**$15,462**	$16,552
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio	1,685	303	$0	$0		$4,078,000	$4,078,000	**$13,444**	
Baseline Unit 2 (WFGD)	1,989								

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.09	
Post Upgrade SO_2 Emissions, lb/MMBtu	0.08	
Capacity Factor used of Cost Estimates (%)	100%	

CAPITAL COSTS	**Cost (2018$)**		**Basis**
	Unit 1	**Unit 2**	
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$0		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0		Included in equipment and materials cost
Sales Tax	$0		5% of Equipment/Material Cost
Freight	$0		5% of Equipment/Material Cost
Total PEC	$0		
Direct Installation Costs			
Labor	$0		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$0		2.5% of Labor
Mobilization / Demobilization	$0		1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$0		5% of Labor
Total Direct Installation Costs	$0		
Total Direct Costs (PEC + Direct Installation Costs)	**$0**		
Indirect Costs			
Contractor's General and Administration Expense	$0		10% of Total Direct Costs
Contractor's Profit	$0		5% of Total Direct Costs
Engineering, Procurement, & Project Services	$0		8% of Total Direct Costs
Construction Management/Field Engineering	$0		4% of Total Direct Costs
S-U / Commissioning	$0		1% of Total Direct Costs
Spare Parts	$0		0.5% of Total Direct Costs
Owner's Cost	$0		2% of Total Direct Costs
Total Indirect Costs	**$0**		
Contingency	**$0**		20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$0**		sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$0**		
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$397,000		Based on disposal rate of $8.70 per ton.
Increased Limestone Cost	$1,599,000		Based on limestone cost of $57 per ton.
DBA Cost	$0		Based on DBA cost of $500 per ton.
Increased Auxiliary Power Cost	$0		Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Increased Water Cost	$23,000		Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs	$2,019,000		

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.09	
Post Upgrade SO_2 Emissions, lb/MMBtu	0.08	
Capacity Factor used of Cost Estimates (%)	100%	

Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional operators
Operating Labor	$0		N/A
Supervisor Labor	$0		N/A
Maintenance Materials	$0		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0		Included in cost for maintenance materials.
Total Fixed O&M Cost	$0		
Indirect Operating Cost			
Property Taxes	$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$0		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$0		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$2,019,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	$0		
Annual Operating Cost	$2,019,000		
Total Annual Cost	**$2,019,000**		

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu		0.09
Post Upgrade SO_2 Emissions, lb/MMBtu		0.075
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$0	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$0	5% of Equipment/Material Cost
Freight		$0	5% of Equipment/Material Cost
Total PEC		$0	
Direct Installation Costs			
Labor		$0	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$0	2.5% of Labor
Mobilization / Demobilization		$0	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$0	5% of Labor
Total Direct Installation Costs		$0	
Total Direct Costs (PEC + Direct Installation Costs)		**$0**	
Indirect Costs			
Contractor's General and Administration Expense		$0	10% of Total Direct Costs
Contractor's Profit		$0	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$0	8% of Total Direct Costs
Construction Management/Field Engineering		$0	4% of Total Direct Costs
S-U / Commissioning		$0	1% of Total Direct Costs
Spare Parts		$0	0.5% of Total Direct Costs
Owner's Cost		$0	2% of Total Direct Costs
Total Indirect Costs		**$0**	
Contingency		**$0**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$0**	sum of direct costs, indirect costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)		**$0**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost		$729,000	Based on disposal rate of $8.70 per ton.
Increased Limestone Cost		$2,938,000	Based on limestone cost of $57 per ton.
DBA Cost		$0	Based on DBA cost of $500 per ton.
Increased Auxiliary Power Cost		$370,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Increased Water Cost		$41,000	Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs		$4,078,000	

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio

SO_2 Control Option Description	**FGD Operational Improvements - Increase Ca:S Stoichiometric Ratio and L/G Ratio**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu		0.09
Post Upgrade SO_2 Emissions, lb/MMBtu		0.075
Capacity Factor used of Cost Estimates (%)		100%

	Unit 1	Unit 2	
Fixed O&M Costs			
Additional Operators per shift		0	Assume no additional operators
Operating Labor		$0	N/A
Supervisor Labor		$0	N/A
Maintenance Materials		$0	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$0	
Indirect Operating Cost			
Property Taxes		$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$0	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$0	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$0	
Total Annual Operating Cost		**$4,078,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$0	
Annual Operating Cost		$4,078,000	
Total Annual Cost		**$4,078,000**	

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Upgrades - pH Buffer Addition

SO_2 Control Option Description	**FGD Upgrades - pH Buffer Addition**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.09	0.09
Post Upgrade SO_2 Emissions, lb/MMBtu	0.055	0.05
Capacity Factor used of Cost Estimates (%)	100%	100%

CAPITAL COSTS	**Cost (2018$)**		**Basis**
	Unit 1	**Unit 2**	
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$2,878,000	$4,027,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$144,000	$201,000	5% of Equipment/Material Cost
Freight	$144,000	$201,000	5% of Equipment/Material Cost
Total PEC	$3,166,000	$4,429,000	
Direct Installation Costs			
Labor	$1,919,000	$2,684,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$48,000	$67,000	2.5% of Labor
Mobilization / Demobilization	$29,000	$40,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$96,000	$134,000	5% of Labor
Total Direct Installation Costs	$2,092,000	$2,925,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$5,258,000**	**$7,354,000**	
Indirect Costs			
Contractor's General and Administration Expense	$526,000	$735,000	10% of Total Direct Costs
Contractor's Profit	$263,000	$368,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$421,000	$588,000	8% of Total Direct Costs
Construction Management/Field Engineering	$210,000	$294,000	4% of Total Direct Costs
S-U / Commissioning	$79,000	$110,000	1.5% of Total Direct Costs
Spare Parts	$26,000	$37,000	0.5% of Total Direct Costs
Owner's Cost	$105,000	$147,000	2% of Total Direct Costs
Total Indirect Costs	$1,630,000	$2,279,000	
Contingency	**$1,378,000**	**$1,927,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$8,266,000**	**$11,560,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$	0.0820	0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$677,000**	**$947,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Increased Waste Disposal Cost	$408,000	$751,000	Based on disposal rate of $8.70 per ton.
Increased Limestone Cost	$1,644,000	$3,027,000	Based on limestone cost of $57 per ton.
DBA Cost	$4,380,000	$7,665,000	Based on DBA cost of $500 per ton.
Increased Auxiliary Power Cost	$0	$370,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Increased Water Cost	$23,000	$43,000	Based on water cost of $1.00 per 1000 gallons.
Total Variable O&M Costs	$6,455,000	$11,856,000	

LOS Units 1 and 2
SO_2 Control Cost Evaluation
FGD Upgrades - pH Buffer Addition

SO_2 Control Option Description	**FGD Upgrades - pH Buffer Addition**	
	Unit 1	**Unit 2**
Baseline SO_2 Emissions, lb/MMBtu	0.09	0.09
Post Upgrade SO_2 Emissions, lb/MMBtu	0.055	0.05
Capacity Factor used of Cost Estimates (%)	100%	100%

Fixed O&M Costs			
Additional Operators per shift	0	0	Assume no additional operators
Operating Labor	$0	$0	N/A
Supervisor Labor	$0	$0	N/A
Maintenance Materials	$79,000	$110,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$79,000	$110,000	
Indirect Operating Cost			
Property Taxes	$83,000	$116,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$83,000	$116,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$165,000	$231,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$331,000	$463,000	
Total Annual Operating Cost	**$6,865,000**	**$12,429,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$677,000	$947,000	
Annual Operating Cost	$6,865,000	$12,429,000	
Total Annual Cost	**$7,542,000**	**$13,376,000**	

APPENDIX B

NO_X CONTROL COST EFFECTIVENESS ESTIMATES

NO_X CONTROL COST EFFECTIVENESS ESTIMATES

BASELINE CAPACITY FACTORS/EMISSIONS AND PROJECTED ACTUAL EMISSION RATES

Leland Olds Station Units 1 & 2
NO_X Control Summary

Table 1. LOS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	11,681,110	30,419,273	- Unit 1: Annual average for period July 2017 to June 2018 - Unit 2: Annual average for period April 2017 to March 2018 - Capacity factor based on Design Hourly Heat Input (MMBtu/hr) and Annual Baseline Heat Input (MMBtu/yr) - Hourly emission rates based on Average Baseline Hourly Heat Input (MMBtu/hr)
Annual Capacity Factor	%	51%	68%	
Average Baseline Hourly Heat Input	MMBtu/hr	1,646	3,692	
Design Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

Table 2. NO_X Control Effectiveness

	Unit 1					Unit 2				
Control Technology	**Control Efficiency**	**Expected Emissions**	**Emission Rate**	**Emission Rate**	**Expected Emissions Reduction**	**Control Efficiency**	**Expected Emissions**	**Emission Rate**	**Emission Rate**	**Expected Emissions Reduction**
	(%)	**(ton/year)**	**(lb/hr)**	**(lb/MMBtu)**	**(ton/year)**	**(%)**	**(ton/year)**	**(lb/hr)**	**(lb/MMBtu)**	**(ton/year)**
SCR - Tail-End Configuration	82.8%	292	82	0.05	613					
SNCR Optimization + RRI						67.2%	3,346	812	0.22	1,183
SNCR Optimization						59.7%	4,107	997	0.27	423
Baseline (Unit 1: LNB/ASOFA/SNCR, Unit 2: ASOFA/SNCR)	46.6%	905	255	0.15		55.6%	4,530	1,099	0.30	
Uncontrolled NOx		1,694	477	0.29			10,190	2,473	0.67	

Leland Olds Station Units 1 & 2
NO$_X$ Control Summary

Table 3. NO$_X$ Control Cost Effectiveness - Unit 1

Control Technology	Emissions	Tons of NOx Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)	($/ton)
SCR - Tail-End Configuration	292	613	$227,717,000	$18,662,000	$0	$14,809,000	$33,471,000	**$54,605**	
Baseline Unit 1	905								

Table 4. NO$_X$ Control Cost Effectiveness - Unit 2

Control Technology	Emissions	Tons of NOx Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)	($/ton)
SNCR Optimization + RRI	3,346	1,183	$11,342,000	$930,000	$0	$4,355,000	$5,285,000	**$4,466**	$5,757
SNCR Optimization	4,107	423	$3,089,000	$253,000	$0	$654,000	$907,000	**$2,144**	
Baseline Unit 2	4,530								

LOS Units 1 and 2
NO_X Control Cost Evaluation
SNCR Optimization

NO_X Control Option Description	**SNCR Optimization**	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu		0.30
Post Upgrade NO_X Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		68%

CAPITAL COSTS	**Cost (2018$)**		**Basis**
	Unit 1	**Unit 2**	
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$1,147,000	
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$57,000	5% of Equipment/Material Cost
Freight		$57,000	5% of Equipment/Material Cost
Total PEC		$1,261,000	
Direct Installation Costs			
Labor		$646,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$16,000	2.5% of Labor
Mobilization / Demobilization		$10,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$32,000	5% of Labor
Total Direct Installation Costs		$704,000	
Total Direct Costs (PEC + Direct Installation Costs)		**$1,965,000**	
Indirect Costs			
Contractor's General and Administration Expense		$197,000	10% of Total Direct Costs
Contractor's Profit		$98,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$157,000	8% of Total Direct Costs
Construction Management/Field Engineering		$79,000	4% of Total Direct Costs
S-U / Commissioning		$29,000	1.5% of Total Direct Costs
Spare Parts		$10,000	0.5% of Total Direct Costs
Owner's Cost		$39,000	2% of Total Direct Costs
Total Indirect Costs		**$609,000**	
Contingency		**$515,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$3,089,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)		**$253,000**	
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost		$369,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost		$0	Based on ammonia reagent cost of $700 per ton.
Water Cost		$8,000	Based on water cost of $1.47 per 1,000 gallons.
Steam Cost		$17,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost		$0	Based on hydrated lime cost of $150 per ton.
Catalyst Replacement Cost		$0	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost		$2,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Replacement Power Cost		$105,000	Based on heat rate penalty of 0.22% and replacement coal cost of $1.57/MBtu.
Total Variable O&M Costs		$501,000	

LOS Units 1 and 2
NO$_X$ Control Cost Evaluation
SNCR Optimization

NO$_X$ Control Option Description	**SNCR Optimization**	
	Unit 1	**Unit 2**
Baseline NO$_X$ Emissions, lb/MMBtu		0.30
Post Upgrade NO$_X$ Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		68%

Fixed O&M Costs			
Additional Operators per shift		0	
Operating Labor		$0	Assume $49.5/hr for each additional operator
Supervisor Labor		$0	N/A
Maintenance Materials		$29,500	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$29,500	
Indirect Operating Cost			
Property Taxes		$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$61,800	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$123,600	
Total Annual Operating Cost		**$654,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$253,000	
Annual Operating Cost		$654,000	
Total Annual Cost		**$907,000**	

LOS Units 1 and 2
NO_X Control Cost Evaluation
SNCR Optimization + RRI

NO_X Control Option Description	SNCR Optimization + RRI	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu		0.30
Post Upgrade NO_X Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		68%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$4,530,000	
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$227,000	5% of Equipment/Material Cost
Freight		$227,000	5% of Equipment/Material Cost
Total PEC		$4,984,000	
Direct Installation Costs			
Labor		$2,047,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$51,000	2.5% of Labor
Mobilization / Demobilization		$31,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$102,000	5% of Labor
Total Direct Installation Costs		$2,231,000	
Total Direct Costs (PEC + Direct Installation Costs)		**$7,215,000**	
Indirect Costs			
Contractor's General and Administration Expense		$722,000	10% of Total Direct Costs
Contractor's Profit		$361,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$577,000	8% of Total Direct Costs
Construction Management/Field Engineering		$289,000	4% of Total Direct Costs
S-U / Commissioning		$108,000	1.5% of Total Direct Costs
Spare Parts		$36,000	0.5% of Total Direct Costs
Owner's Cost		$144,000	2% of Total Direct Costs
Total Indirect Costs		**$2,237,000**	
Contingency		**$1,890,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$11,342,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)		**$930,000**	
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost		$2,490,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost		$0	Based on ammonia reagent cost of $700 per ton.
Water Cost		$57,000	Based on water cost of $1.47 per 1,000 gallons.
Steam Cost		$111,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost		$0	Based on hydrated lime cost of $150 per ton.
Catalyst Replacement Cost		$0	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost		$39,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Replacement Power Cost		$598,000	Based on heat rate penalty of 1.25% and replacement coal cost of $1.57/MBtu.
Total Variable O&M Costs		$3,295,000	

LOS Units 1 and 2
NO_X Control Cost Evaluation
SNCR Optimization + RRI

NO_X Control Option Description	SNCR Optimization + RRI	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu		0.30
Post Upgrade NO_X Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		68%

Fixed O&M Costs			
Additional Operators per shift		1	
Operating Labor		$434,000	Assume $49.5/hr for each additional operator
Supervisor Labor		$65,000	N/A
Maintenance Materials		$108,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$607,000	
Indirect Operating Cost			
Property Taxes		$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$227,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$453,000	
Total Annual Operating Cost		**$4,355,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$930,000	
Annual Operating Cost		$4,355,000	
Total Annual Cost		**$5,285,000**	

LOS Units 1 and 2
NO_X Control Cost Evaluation
SCR - Tail-End Configuration

NO_X Control Option Description	SCR - Tail-End Configuration	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu	0.15	
Post Upgrade NO_X Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	51%	

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	**Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$76,672,000		$0
Instrumentation	$0		Included in equipment and materials cost
Sales Tax	$3,834,000		5% of Equipment/Material Cost
Freight	$3,834,000		5% of Equipment/Material Cost
Total PEC	$84,340,000		
Direct Installation Costs			
Labor	$55,521,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,388,000		2.5% of Labor
Mobilization / Demobilization	$833,000		1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$2,776,000		5% of Labor
Total Direct Installation Costs	$60,518,000		
Total Direct Costs (PEC + Direct Installation Costs)	**$144,858,000**		
Indirect Costs			
Contractor's General and Administration Expense	$14,486,000		10% of Total Direct Costs
Contractor's Profit	$7,243,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	$11,589,000		8% of Total Direct Costs
Construction Management/Field Engineering	$5,794,000		4% of Total Direct Costs
S-U / Commissioning	$2,173,000		1.5% of Total Direct Costs
Spare Parts	$724,000		0.5% of Total Direct Costs
Owner's Cost	$2,897,000		2% of Total Direct Costs
Total Indirect Costs	**$44,906,000**		
Contingency	**$37,953,000**		20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$227,717,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$18,662,000**		
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost	-$274,000		Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$242,000		Based on ammonia reagent cost of $700 per ton.
RO Water Cost	-$3,000		Based on water cost of $1.47 per 1,000 gallons.
Steam Cost	$181,000		Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$97,000		Based on hydrated lime cost of $150 per ton.
Catalyst Replacement and Disposal Cost	$2,081,000		Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost	$705,000		Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Replacement Power Cost	$0		Based on replacement coal cost of $1.57/Mbtu.
Total Variable O&M Costs	$3,029,000		

LOS Units 1 and 2
NO_X Control Cost Evaluation
SCR - Tail-End Configuration

NO_X Control Option Description	SCR - Tail-End Configuration	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu	0.15	
Post Upgrade NO_X Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	51%	

Fixed O&M Costs			
Additional Operators per Shift	1		
Operating Labor	$434,000		Assume $49.5/hr for each additional operator
Supervisor Labor	$65,000		15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$2,173,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0		Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,672,000		
Indirect Operating Cost			
Property Taxes	$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$4,554,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$9,108,000		
Total Annual Operating Cost	**$14,809,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	$18,662,000		
Annual Operating Cost	$14,809,000		
Total Annual Cost	**$33,471,000**		

NO_X CONTROL COST EFFECTIVENESS ESTIMATES

100% CAPACITY FACTOR AND PROJECTED FUTURE MAXIMUM EMISSION RATES

Leland Olds Station Units 1 & 2
NO$_X$ Control Summary

Table 1. LOS Units 1 & 2 Operating Parameters

Parameter	Units	Unit 1	Unit 2	Notes
Nominal Power Output	MW	220	440	
Annual Heat Input	MMBtu/yr	22,968,720	44,938,800	- Unit 1: Annual average for period July 2017 to June 2018 - Unit 2: Annual average for period April 2017 to March 2018
Annual Capacity Factor	%	100%	100%	
Hourly Heat Input	MMBtu/hr	2,622	5,130	Permit No. T5-F73004

Table 2. NO$_X$ Control Effectiveness

	Unit 1					Unit 2				
Control Technology	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/hr)	(lb/MMBtu)	(ton/year)
SCR - Tail-End Configuration	82.8%	574	131	0.05	1,205					
SNCR Optimization + RRI						67.2%	4,943	1,129	0.22	1,748
SNCR Optimization						59.7%	6,067	1,385	0.27	625
Baseline (Unit 1: LNB/ASOFA/SNCR, Unit 2: ASOFA/SNCR)	46.6%	1,779	406	0.15		55.6%	6,692	1,528	0.30	
Uncontrolled NOx		3,330	760	0.29			15,054	2,473	0.67	

Leland Olds Station Units 1 & 2
NO_X Control Summary

Table 3. NO_X Control Cost Effectiveness - Unit 1

Control Technology	**Emissions**	**Tons of NOx Removed**	**Total Capital Requirement**	**Annualized Capital Cost**	**Annualized Outage Cost**	**Total Annual Operating Costs**	**Total Annual Costs**	**Average Cost Effectiveness**	**Incremental Cost Effectiveness**
	(tpy)	**(tpy)**	**($)**	**($/year)**	**($/year)**	**($/year)**	**($)**	**($/ton)**	**($/ton)**
SCR - Tail-End Configuration	574	1,205	$227,717,000	$18,662,000	$0	$15,722,000	$34,384,000	**$28,528**	
Baseline Unit 1	1,779								

Table 4. NO_X Control Cost Effectiveness - Unit 2

Control Technology	**Emissions**	**Tons of NOx Removed**	**Total Capital Requirement**	**Annualized Capital Cost**	**Annualized Outage Cost**	**Total Annual Operating Costs**	**Total Annual Costs**	**Average Cost Effectiveness**	**Incremental Cost Effectiveness**
	(tpy)	**(tpy)**	**($)**	**($/year)**	**($/year)**	**($/year)**	**($)**	**($/ton)**	**($/ton)**
SNCR Optimization + RRI	4,943	1,748	$11,342,000	$930,000	$0	$5,927,000	$6,857,000	**$3,922**	$5,082
SNCR Optimization	6,067	625	$3,089,000	$253,000	$0	$894,000	$1,147,000	**$1,836**	
Baseline Unit 2	6,692								

LOS Units 1 and 2
NO_X Control Cost Evaluation
SNCR Optimization

NO_X Control Option Description	SNCR Optimization	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu		0.30
Post Upgrade NO_X Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS	**Cost (2018$)**		**Basis**
	Unit 1	**Unit 2**	
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$1,147,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$57,000	5% of Equipment/Material Cost
Freight		$57,000	5% of Equipment/Material Cost
Total PEC		$1,261,000	
Direct Installation Costs			
Labor		$646,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$16,000	2.5% of Labor
Mobilization / Demobilization		$10,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$32,000	5% of Labor
Total Direct Installation Costs		$704,000	
Total Direct Costs (PEC + Direct Installation Costs)		**$1,965,000**	
Indirect Costs			
Contractor's General and Administration Expense		$197,000	10% of Total Direct Costs
Contractor's Profit		$98,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$157,000	8% of Total Direct Costs
Construction Management/Field Engineering		$79,000	4% of Total Direct Costs
S-U / Commissioning		$29,000	1.5% of Total Direct Costs
Spare Parts		$10,000	0.5% of Total Direct Costs
Owner's Cost		$39,000	2% of Total Direct Costs
Total Indirect Costs		**$609,000**	
Contingency		**$515,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$3,089,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)		**$253,000**	
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost		$546,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost		$0	Based on ammonia reagent cost of $700 per ton.
Water Cost		$13,000	Based on water cost of $1.47 per 1,000 gallons.
Steam Cost		$24,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost		$0	Based on hydrated lime cost of $150 per ton.
Catalyst Replacement Cost		$0	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost		$3,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Replacement Power Cost		$155,000	Based on heat rate penalty of 0.22% and replacement coal cost of $1.57/MBtu.
Total Variable O&M Costs		$741,000	

LOS Units 1 and 2
NO_X Control Cost Evaluation
SNCR Optimization

NO_X Control Option Description	**SNCR Optimization**	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu		0.30
Post Upgrade NO_X Emissions, lb/MMBtu		0.27
Capacity Factor used of Cost Estimates (%)		100%

Fixed O&M Costs			
Additional Operators per shift		0	
Operating Labor		$0	Assume $49.5/hr for each additional operator
Supervisor Labor		$0	N/A
Maintenance Materials		$29,500	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$29,500	
Indirect Operating Cost			
Property Taxes		$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$30,900	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$61,800	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$123,600	
Total Annual Operating Cost		**$894,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$253,000	
Annual Operating Cost		$894,000	
Total Annual Cost		**$1,147,000**	

LOS Units 1 and 2
NO$_X$ Control Cost Evaluation
SNCR Optimization + RRI

NO$_X$ Control Option Description	**SNCR Optimization + RRI**	
	Unit 1	**Unit 2**
Baseline NO$_X$ Emissions, lb/MMBtu		0.30
Post Upgrade NO$_X$ Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		100%

CAPITAL COSTS	**Cost (2018$)** **Unit 1**	 **Unit 2**	**Basis**
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials		$4,530,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation		$0	Included in equipment and materials cost
Sales Tax		$227,000	5% of Equipment/Material Cost
Freight		$227,000	5% of Equipment/Material Cost
Total PEC		$4,984,000	
Direct Installation Costs			
Labor		$2,047,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding		$51,000	2.5% of Labor
Mobilization / Demobilization		$31,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency		$102,000	5% of Labor
Total Direct Installation Costs		$2,231,000	
Total Direct Costs (PEC + Direct Installation Costs)		**$7,215,000**	
Indirect Costs			
Contractor's General and Administration Expense		$722,000	10% of Total Direct Costs
Contractor's Profit		$361,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services		$577,000	8% of Total Direct Costs
Construction Management/Field Engineering		$289,000	4% of Total Direct Costs
S-U / Commissioning		$108,000	1.5% of Total Direct Costs
Spare Parts		$36,000	0.5% of Total Direct Costs
Owner's Cost		$144,000	2% of Total Direct Costs
Total Indirect Costs		**$2,237,000**	
Contingency		**$1,890,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)		**$11,342,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$		0.0820	20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)		**$930,000**	
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost		$3,679,000	Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost		$0	Based on ammonia reagent cost of $700 per ton.
Water Cost		$84,000	Based on water cost of $1.47 per 1,000 gallons.
Steam Cost		$164,000	Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost		$0	Based on hydrated lime cost of $150 per ton.
Catalyst Replacement Cost		$0	Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost		$57,000	Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Replacement Power Cost		$883,000	Based on heat rate penalty of 1.25% and replacement coal cost of $1.57/MBtu.
Total Variable O&M Costs		$4,867,000	

LOS Units 1 and 2
NO_X Control Cost Evaluation
SNCR Optimization + RRI

NO_X Control Option Description	SNCR Optimization + RRI	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu		0.30
Post Upgrade NO_X Emissions, lb/MMBtu		0.22
Capacity Factor used of Cost Estimates (%)		100%

Fixed O&M Costs			
Additional Operators per shift		1	
Operating Labor		$434,000	Assume $49.5/hr for each additional operator
Supervisor Labor		$65,000	N/A
Maintenance Materials		$108,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor		$0	Included in cost for maintenance materials.
Total Fixed O&M Cost		$607,000	
Indirect Operating Cost			
Property Taxes		$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance		$113,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration		$227,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost		$453,000	
Total Annual Operating Cost		**$5,927,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost		$930,000	
Annual Operating Cost		$5,927,000	
Total Annual Cost		**$6,857,000**	

LOS Units 1 and 2
NO$_X$ Control Cost Evaluation
SCR - Tail-End Configuration

NO$_X$ Control Option Description	SCR - Tail-End Configuration Unit 1	SCR - Tail-End Configuration Unit 2
Baseline NO$_X$ Emissions, lb/MMBtu	0.15	
Post Upgrade NO$_X$ Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	100%	

CAPITAL COSTS	Cost (2018$) Unit 1	Cost (2018$) Unit 2	Basis
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$76,672,000		Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0		Included in equipment and materials cost
Sales Tax	$3,834,000		5% of Equipment/Material Cost
Freight	$3,834,000		5% of Equipment/Material Cost
Total PEC	$84,340,000		
Direct Installation Costs			
Labor	$55,521,000		Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,388,000		2.5% of Labor
Mobilization / Demobilization	$833,000		1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$2,776,000		5% of Labor
Total Direct Installation Costs	$60,518,000		
Total Direct Costs (PEC + Direct Installation Costs)	**$144,858,000**		
Indirect Costs			
Contractor's General and Administration Expense	$14,486,000		10% of Total Direct Costs
Contractor's Profit	$7,243,000		5% of Total Direct Costs
Engineering, Procurement, & Project Services	$11,589,000		8% of Total Direct Costs
Construction Management/Field Engineering	$5,794,000		4% of Total Direct Costs
S-U / Commissioning	$2,173,000		1.5% of Total Direct Costs
Spare Parts	$724,000		0.5% of Total Direct Costs
Owner's Cost	$2,897,000		2% of Total Direct Costs
Total Indirect Costs	**$44,906,000**		
Contingency	**$37,953,000**		20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$227,717,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$	0.0820		20 year life of equipment (years) @ 5.25% interest.
Annualized Capital Costs (CRF x TCI)	**$18,662,000**		
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost	-$540,000		Based on dry urea reagent cost of $354 per ton.
Ammonia Reagent Cost	$475,000		Based on ammonia reagent cost of $700 per ton.
RO Water Cost	-$7,000		Based on water cost of $1.47 per 1,000 gallons.
Steam Cost	$357,000		Based on steam cost of $1.06 per MMBtu.
Hydrated Lime Cost	$190,000		Based on hydrated lime cost of $150 per ton.
Catalyst Replacement and Disposal Cost	$2,081,000		Based on catalyst cost of $8,000 per m^3 and catalyst replacement cost of $1,000 per m^3.
Auxiliary Power Cost	$1,386,000		Based on auxiliary power cost of $48.06 per MWh (Unit 1) and $40.47 (Unit 2).
Replacement Power Cost	$0		Based on replacement coal cost of $1.57/MBtu.
Total Variable O&M Costs	$3,942,000		

LOS Units 1 and 2
NO_X Control Cost Evaluation
SCR - Tail-End Configuration

NO_X Control Option Description	SCR - Tail-End Configuration	
	Unit 1	**Unit 2**
Baseline NO_X Emissions, lb/MMBtu	0.15	
Post Upgrade NO_X Emissions, lb/MMBtu	0.05	
Capacity Factor used of Cost Estimates (%)	100%	

	Unit 1	Unit 2	
Fixed O&M Costs			
Additional Operators per Shift	1		
Operating Labor	$434,000		Assume $49.5/hr for each additional operator
Supervisor Labor	$65,000		15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$2,173,000		Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0		Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,672,000		
Indirect Operating Cost			
Property Taxes	$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$2,277,000		1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$4,554,000		2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$9,108,000		
Total Annual Operating Cost	**$15,722,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	$18,662,000		
Annual Operating Cost	$15,722,000		
Total Annual Cost	**$34,384,000**		

B.4 – GRE CCS

B.4.a – Department Request

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

May 2, 2018

FILE

Ms. Mary Jo Roth
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369-4718

Re: Regional Haze
Second Planning Period

Dear Ms. Roth:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:
1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
Division of Municipal Facilities 701.328.5211
Division of Waste Management 701.328.5166
Division of Water Quality 701.328.5210

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair
Director
Division of Air Quality

TLO/TB:saj

B.4.b – Facility Response

GREAT
RIVER
ENERGY™

12300 Elm Creek Boulevard
Maple Grove, Minnesota 55369-4718
763-445-5000
greatriverenergy.com

September 12, 2019

Mr. James L. Semerad
Director, Division of Air Quality
North Dakota Department of Environmental Quality
918 E. Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

Dear Mr. Semerad:

Enclosed please find Great River Energy's *Coal Creek Station Units 1 and 2, Updated Best Available Retrofit Technology Analysis for NOx Emissions*.

Please let me know if you have any questions. I can be reached at 763-445-5212.

Sincerely,

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services

c: David Stroh
Tom Bachman
Greg Archer
Deb Nelson

Coal Creek Station Units 1 and 2

Updated Best Available Retrofit Technology Analysis for NOx Emissions

Prepared for
Great River Energy

September 2019

4300 MarketPointe Drive, Suite 200
Minneapolis, MN 55435
952.832.2600
www.barr.com

Coal Creek Station Units 1 and 2
Updated Best Available Retrofit Technology Analysis for NOx Emissions

September 2019

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List of Attachments

Attachment A:	Report "Best Available Retrofit Technology for NOx Emissions from Coal Creek Unit 2 - 2019 Update" September 4, 2019; Black & Veatch
Attachment B:	Report "Cost Estimate for SNCR Impact to Fly Ash Disposal and Sales – Great River Energy – Coal Creek Station" March 1, 2019; Golder Associates Inc.
Attachment C:	Report "Ammonia Slip Mitigation for SNCR Impacted Ash at the Coal Creek Station" March 22, 2019; Boral Resources
Attachment D:	Letter "Coal Creek Station Unit 2 NOx Emissions" March 5, 2018 from GRE to the NDDEQ
Attachment E-1:	Report "Protocol for BART-Related Visibility Impairment Modeling Analysis – Great River Energy – Coal Creek Station" July 2019; Barr Engineering Company
Attachment E-2:	Approval Correspondence from US EPA Region 8 and NDDEQ for the BART Modeling Protocol; August 7 and 8, 2019

1 Introduction

Great River Energy (GRE) retained Barr Engineering Co. (Barr) to complete an updated analysis and evaluation of Best Available Retrofit Technology (BART) for NOx emissions at Coal Creek Station Units 1 and 2. Barr is an environmental and engineering consulting services firm with over 800 employees founded in 1966 with ten offices located in the United States and in Canada. Barr has provided environmental regulatory and technical services to GRE associated with the regional haze regulations at Coal Creek Station and at Stanton Station since 2005.[1] Specifically, Barr completed the BART evaluation and report in December 2007 for Coal Creek Station as well as supplemental analyses and updates through 2012 that are appended to the North Dakota Department of Environmental Quality's (NDDEQ's) State Implementation Plan (SIP) for regional haze.[2] Barr has also completed several other BART analyses for facilities in the power industry and other industrial sectors in North Dakota and other states.

The purpose of this case-by-case BART analysis of NOx emissions at Units 1 and 2 is to provide updated information to NDDEQ for the regional haze SIP record.

1.1 Overview of Steps and Factors for Conducting Case-by-Case BART

This case-by-case BART analysis for NOx emissions at Units 1 and 2 updates and readdresses the five basic steps described in EPA's "Guidelines for BART Determinations Under the Regional Haze Rule" (EPA BART Guidelines).[3]

Barr has completed a dispersion modeling analysis using the CALPUFF modeling platform to evaluate Step 5 in the BART analysis. The corresponding dispersion modeling protocol for Step 5 is provided in Attachment E to this report.

The five steps are summarized as follows:

Step 1: Identify all Control Technologies
The first step in the analysis is to identify all available retrofit control technologies for each applicable emission unit.

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[1] GRE has permanently ceased operations at Stanton Station, a 180 MW coal-fired power plant located just outside of Stanton, North Dakota. For informational purposes, Stanton Station's retirement results in an actual annual emissions reduction of 2,329 tpy SO_2 and 1,589 tpy NOx based on the average annual reported emissions for the last five calendar years of plant operation (2012 to 2016).

[2] North Dakota Department of Environmental Quality (formerly the North Dakota Department of Health), "North Dakota State Implementation Plan for Regional Haze," Adopted February 24, 2010 as supplemented and amended through December 20, 2012.

[3] 40 CFR 51, Appendix Y.

Step 2: Eliminate Technically Infeasible Options
In the second step, the technical feasibility of each control option identified in step one is evaluated with respect to source-specific factors. Technologies which are determined to be technically infeasible are eliminated from further consideration.

Step 3: Evaluate Control Effectiveness
In step three, the remaining controls are ranked based on the design control efficiency at the expected emission rate as compared to the emission rate before addition of controls.

Step 4: Evaluate Impacts and Document Results
The fourth step utilizes an engineering analysis to document the impacts of each remaining control technology option. The impacts analyses include: 1) costs of compliance, 2) energy impacts, 3) non-air quality environmental impacts, and 4) remaining useful life of the source.

Step 5: Evaluate Visibility Impacts
The fifth step simulates the degree of visibility improvement upon application of an additional emissions control technology. This study is conducted using the CALPUFF dispersion model.

Pursuant to the EPA BART Guidelines, application of the 5-step BART analysis *"identifies the best system of continuous emission reduction taking into account the following six factors:*

1) *The available retrofit control options,*
2) *Any pollution control equipment in use at the source (which affects the availability of options and their impacts),*
3) *The costs of compliance with control options,*
4) *The remaining useful life of the facility,*
5) *The energy and non-air quality environmental impacts of control options, and*
6) *The visibility impacts analysis."*[4]

For purposes of consistency with the Black & Veatch technical report in Attachment A, Barr consolidates and orders the BART factors as follows:

Factor 1: Costs of compliance
Factor 2: Energy and non-air environmental impacts
Factor 3: Pollution control equipment in use at the source
Factor 4: Remaining useful life of the source
Factor 5: Visibility impacts

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[4] 40 CFR 51, Subpart Y, subsection IV.A.

The methodology for analyzing these BART factors is described further in Section 2. The recommended BART, summarized in Section 1.2, is based on technical conclusions described in this report for these five factors.

1.2 Proposed NOx BART Determination for Units 1 and 2

In summary, based on our independent analysis and review of the attached third-party reports and the conservative nature of the cost analyses conducted for Factor #1, Barr concludes that potentially available additional NOx emissions control technologies do not represent BART for Units 1 and 2.

- Selective catalytic reduction (SCR) is neither technically feasible as a retrofit control technology at Coal Creek Station nor is it cost-effective. Additionally, the estimated increase in sulfuric acid mist emissions due to an SCR system at Units 1 and 2 offsets much of the modeled visibility improvement that would otherwise occur from a reduction in NOx emissions.
- Selective non-catalytic reduction (SNCR) is not cost-effective as well as potentially creates significant environmental impacts related to ammoniated fly ash.

Both SCR and SNCR pose serious risks that would need to be studied further through extensive pilot testing to determine if the technical concerns in Section 3.1.2 and 3.1.3 and adverse environmental impacts in Section 3.3 could be avoided or mitigated at Coal Creek Station.

Based on a review of recent emissions data with current emissions controls at Unit 2 and the anticipated completion of the same advanced combustion controls (LNC3+) for NOx to be installed at Unit 1 in the first half of 2020, Units 1 and 2 are expected to perform under anticipated normal operations at an annual average emissions rate of 0.13 pounds of NOx per million British thermal units heat input (lb NOx/MMBtu). Variability in NOx emissions during the year will continue to occur as a function of variable unit load (i.e., ramping in response to Midcontinent Independent System Operator or MISO) and the potential for low coal sodium concentrations (see Section 2.1). Taking into consideration these inherent variabilities affecting NOx emissions performance in order to determine the shorter-term average (i.e., 30-day rolling average) emissions rate impact on NOx performance, Barr recommends a BART emissions limit of 0.15 lb NOx/MMBtu with compliance demonstrated using the existing 40 CFR 75 certified continuous emissions monitoring systems (CEMS).

2 BART Analysis Methodology

Barr has conducted an updated examination of the five BART factors for Coal Creek Station Units 1 and 2. Barr's analysis of Factors #1 through #4 considers information developed in recently completed detailed evaluations and technical reports produced by third-party subject matter experts. These reports are provided as attachments. They represent work by Black & Veatch for a Unit 2 NOx BART evaluation of BART factors #1 through #4 in Attachment A and from Golder Associates (Golder) and Boral Resources (Boral) for impacts at Units 1 and 2 related to ammoniated fly ash in Attachments B and C, respectively. Section 3 of this report reviews and incorporates these analyses where relevant to the BART factors.

With respect to the Black & Veatch report, Barr provides additional analysis and context to their evaluation, where appropriate. For example, Black & Veatch estimated costs for available emissions control technologies using both the EPA Air Pollution Control Cost Manual[5] (EPA Control Cost Manual) methodology and a "site-specific methodology" incorporating actual costs from installation at another source that are scaled to Coal Creek Station. Barr has completed its own evaluation of costs for available controls also using the EPA Control Cost Manual.

Section 2.1 summarizes the anticipated NOx emissions rates from Unit 1 and 2 used to establish the anticipated annual emissions reduction from the application of additional emissions controls.

Sections 2.2 through 2.7 outline the approach to determining availability and technical feasibility of emissions controls and their corresponding impacts evaluated against the BART factors.

2.1 Current NOx Emissions Performance Levels for BART Analysis

The EPA BART Guidelines at 40 CFR 51, Appendix Y state:

> *"The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period."*

The initial BART evaluation used actual emission rates for the same time period used to determine the visibility baseline, which was a 3-year period of emission inventory data from 2000 to 2002. Due to the passage of time, this current BART analysis appropriately updates these emissions rates to reflect existing controls as well as updated operating conditions and emissions performance at Units 1 and 2. These updated NOx emissions levels shall take into consideration the DryFining™ technology[6] and any other

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[6] DryFining™ is an innovative technology developed by GRE that reduces moisture and refines lignite coal, increasing the efficiency and performance of the fuel while reducing emissions. It became operational at Units 1 and 2 in 2010.

combustion controls.[7] Both units utilize "low NOx coal-and-air nozzles with close-coupled and separated overfire air," which is referred to as LNC3. Since the time of the initial modeling conducted over a decade ago, Unit 2 installed larger registers;[8] this system of additional separated overfire air, closed-couple overfire air, and low NOx burners, are together referred to as LNC3+.

Unit 1 is scheduled to install the same LNC3+ technology in the first half of 2020. Therefore, Unit 1 and Unit 2 are assumed to be equivalent in their NOx emissions performance for purposes of estimating emissions reductions from the implementation of control technologies assessed in this BART analysis. Since these two units are of the same size and design, the five-factor BART analysis in Section 3 is the same for Unit 1 and Unit 2. Correspondingly, Barr's analysis and the referenced work by Black & Veatch, Golder, and Boral apply to both units.[9]

Unit 2's annual NOx performance currently averages 0.13 pounds per million British thermal units (lb/MMBtu), which reflects an improvement in NOx emissions performance as compared to the time frame after LNC3+ was installed. Figure 2-1 illustrates 30-day rolling average NOx emissions levels on a parts per million (ppm) and lb/MMBtu basis at Unit 2 from January 1, 2018 to July 31, 2019. Actual NOx emissions during this time frame averaged 0.127 lb/MMBtu (rounded to 0.13 lb/MMBtu) with daily variability in NOx emissions between 0.10 and 0.19 lb/MMBtu. On a parts per million (ppm) concentration basis, the 30-day rolling average concentration varies from 52 to 68 ppm.

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[7] See also Great River Energy's February 10, 2012 report, "Coal Creek Station Units 1 and 2 Best Available Retrofit Technology Refined Analysis for NOx Emissions." Section 2.2.

[8] Ibid. Larger registers allow for a greater ability to tune combustion staging and thus improve control of NOx emissions.

[9] Black and Veatch conducted their analysis on Unit 2 only as it currently operates with LNC3+ and is thus also representative of future operation at Unit 1, which is expected to operate with LNC3+ by mid-2020. Effectively, Black and Veatch's analysis and conclusions for Unit 2 are applicable also to Unit 1.

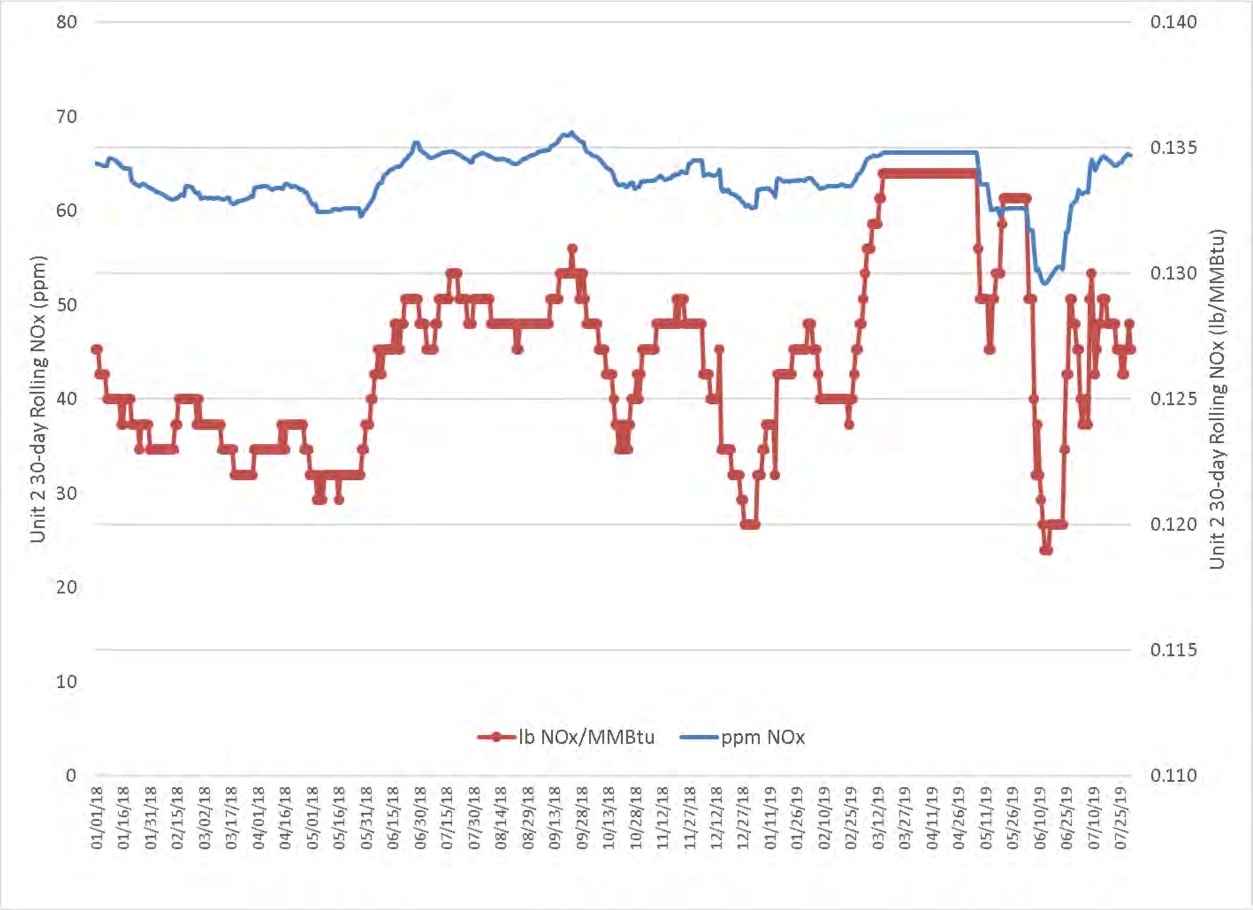

Figure 2-1: Unit 2 30-day Rolling NOx Emissions Performance (lb/MMBtu and ppm)

Operation of these combustion controls at Unit 2 have been demonstrated to be in a well-tuned state for combustion-based pollutants like carbon monoxide (CO) and NOx. A study[10] was conducted by Alstom Power (now General Electric) in 2015 at Unit 2 to comply with the EPA's Mercury Air Toxics Standards for Utilities (MATS) regulation. Alstom Power determined that the boiler with LNC3+ controls was found to be "well maintained and operated" and "well tuned for full load operation" while monitoring the flue gas for oxygen, NOx, and CO. Minor adjustments to oxygen levels had no effect on NOx emissions and any adjustments for the existing separated overfire air (SOFA) system settings resulted in increased NOx emissions. When Unit 1 is commissioned with LNC3+ controls next year, it also will be tuned to meet performance specifications, including for combustion pollutants. Barr recommends performing the commissioning and tuning process across the expected range of operating loads at Unit 1.

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[10] See Attachment A at Appendix H for "Unit's #1 and #2 MATS Tuning Executive Summary Report", Alstom Power, June 2015.

In a March 5, 2018, letter to the NDDEQ (see Attachment D), GRE noted two key operational factors that were inhibiting additional reductions in NOx emissions at Unit 2:

1) Low sodium levels in the lignite provided by the nearby Falkirk Mine, and

2) Load variability when Coal Creek Station is required to ramp up and down based on demands from MISO, GRE's independent system operator.

An updated analysis of these factors, as applied to anticipated operations at Units 1 and 2, is provided in Sections 2.1.1 and 2.1.2.

Accounting for these operational factors and review of long-term actual NOx performance levels that have been achieved in recent years, the annual NOx emissions performance at Unit 2 (and at Unit 1 following LNC3+ installation in early 2020) is 0.13 lb/MMBtu for purposes of determining the emissions reduction effectiveness, costs, and other impacts of additional controls evaluated in Section 3.

2.1.1 Lignite Sodium Content Variability

There are two key variables that affect NOx performance. One of them is lignite sodium content. GRE notes in the March 5, 2018 letter that low-sodium coal has a *"pronounced impact on the amount of slagging; as sodium levels drop, less slagging occurs."* Reduced slagging creates *"greater heat absorption in the lower zone of the boiler and less heat reaches the upper reheat and superheat zones of the boiler. This lowers unit efficiency and raises the heat rate. As a result, CCS2 (Unit 2) must burn more coal to produce the same amount of electricity."*

Since the time of this letter, GRE has been coordinating with the Falkirk Mine (Mine)[11] to help improve the minimum lignite sodium concentration to at least 2 percent sodium oxide (Na_2O) in the ash. The Mine works to support this and other lignite characteristics (i.e., heat content, ash, and sulfur) by manually blending lignite from multiple piles at the mine site. Sodium in the lignite ash is highly variable at the Falkirk Mine. Core samples taken at areas of the Falkirk Mine representing future (20-year projection) mine activity show sodium content data that range from less than 1% to over 14%.[12]

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[11] The Falkirk Mine is owned and operated by North American Coal Corporation. It is a separate stationary source from Coal Creek Station under the Clean Air Act permitting programs.

[12] See Attachment A at Appendix A.4 for a chart summarizing the mine core sample sodium data.

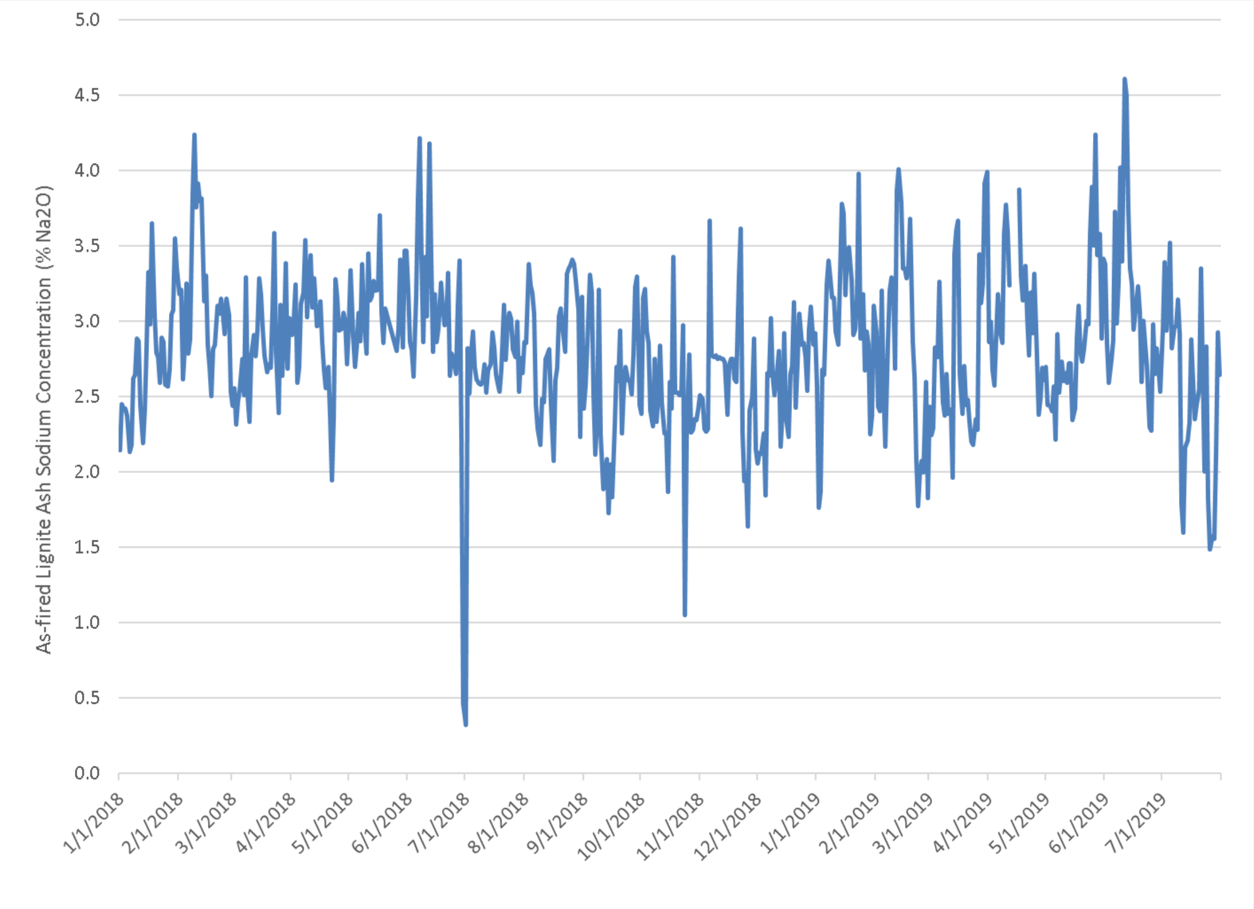

Figure 2-2: Daily Lignite Ash Sodium Content (As-fired) from January 1, 2018 to July 31, 2019

Improvements made to support a minimum sodium content have helped to address the heat absorption and unit efficiency issues, resulting in improved lb NOx/MMBtu performance. Figure 2-2 illustrates the daily as-fired sodium levels in the lignite ash at Coal Creek Station since 2018. However, sodium variability in the lignite fed to Units 1 and 2 will continue to occur based on Mine projections. At times, sodium levels are below 2 percent and at other times the levels are much higher than 2 percent, which creates other technical feasibility issues associated with add-on emissions controls. Specifically, higher sodium levels that will occur at times from the Falkirk Mine will cause ammonium bisulfate generation associated with SCR and corresponding deactivation of the SCR catalyst, as described in Section 3.1.2.

2.1.2 Unit Load Variability

The second key variable that affects NOx performance is load variability. In the May 5, 2018 letter, GRE describes that Coal Creek Station, which was designed as a baseload generation plant, experienced an increasing number of load-following events due increased production of renewable energy and grid pricing signals. The impact of load shifts such as ramping up or down or operating at low-load, causes an increase in NOx emissions on a lb/MMBtu basis as compared to baseload operation.

More recently in 2018 and 2019, Units 1 and 2 have not been required to follow load as much, resulting in reduced cycling at night and corresponding reduced load variability. This, along with higher sodium levels in the lignite, have resulted in an improved NOx performance level of 0.13 lb/MMBtu on an annual average. However, with the continued growth and reduced costs of renewable energy supply, changes in energy demand, and other market factors, it is reasonable to assume that future load variability at Units 1 and 2 may increase from levels experienced recently.

In summary, unit load variability is expected to continue and will be a critical consideration in estimating NOx emissions levels with current emissions control technologies of DryFining™ and LNC3+ as well as for the technical feasibility of new emissions controls at Units 1 and 2.

2.2 Identify and Rank Available and Technically Feasible Retrofit Emission Control Technologies

Consistent with Steps 1 through 3 of the BART analysis (summarized in Section 1.1) and prior to completing a five-factor analysis of each emissions control technology via Steps 4 and 5, commercially available and technically feasible emission control options for Units 1 and 2 must first be identified and ranked in order of control effectiveness. Potentially available emission control options include both add-on control equipment and process improvement applications. All control options identified as available and technically feasible are then evaluated against the five BART factors.

In order to be considered available and technically feasible, an emissions control must have been previously installed and operated successfully on a similar source under similar physical and operating conditions. Novel controls that have not been demonstrated on full-scale, coal-fired utilities are not considered as part of this analysis. Instead, this evaluation focuses on commercially demonstrated control options.

For purposes of this analysis, only those technologies that have the potential to achieve an overall NOx emissions less than 0.13 lb/MMBtu are considered. Importantly, the control effectiveness of a retrofit technology will generally not be as high for a unit that has relatively low NOx emissions, like Coal Creek, as it would be for a unit with higher emissions. In other words, standard percent reductions may not be applicable and site-specific design considerations should be used when practical.

2.3 Factor #1 – Cost of Compliance

Factor #1 considers and estimates, as needed, the capital and annual operating and maintenance (O&M) costs of the control measure. Costs of emissions controls follow the accounting principles and methodologies in the EPA Control Cost Manual unless more refined site-specific estimates are available. Note that the methods in the EPA Control Cost Manual provide for a more simplified approach to estimate costs, but their application may not completely represent actual installation and operational costs due to site-specific considerations as described in this report. This is especially true for Coal Creek Station due to the location and operation of its unique DryFining™ and stack reheat systems, as described in Section 3.2.

Under Factor #1, the annualized cost of installation and operation, on a dollars per ton of pollutant removed ($/ton) basis, of the control measure, referred to as "average cost effectiveness," is compared to a cost effectiveness threshold that is determined by the NDDEQ. Generally, if the average cost effectiveness is greater than the threshold, the cost is considered to not be reasonable, pending an evaluation of other factors.

The cost of an emissions control measure is derived using capital and annual operation and maintenance (O&M) costs. Capital costs generally refer to the money required to design and build the system. This includes direct costs, such as equipment purchases, and installation costs. Indirect costs, such as engineering and construction field expenses and lost revenue due to additional unit downtime to install the additional control measure(s), are considered as part of the capital calculation. Annual O&M costs include labor, supplies, utilities, etc., as used to determine the annualized cost in the numerator of the cost effectiveness value. The denominator of the cost effectiveness value (tons of pollutant removed) is derived as the difference in: 1) anticipated annual emissions using the current emissions control measures (baseline emissions), as described in Section 2.1, in tons per year (tpy), and 2) expected annual emissions performance through installation of the additional retrofit control measure (controlled emissions), also in tpy.

For purposes of calculating baseline emissions at each unit, GRE uses the annual NOx performance level of 0.13 lb/MMBtu in conjunction with the maximum heat input capacity[13] and projected annual utilization (also called annual capacity factor or ACF)[14] of the unit to determine an annual tpy value. Over the past 10 years, Coal Creek Station averages 87% plant utilization, as shown in Table 2-1. GRE considers this value representative of projected operations for purposes of determining annualized emissions.

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[13] The represented nominal heat input capacity in Coal Creek Station's Title V Permit is 6,015 MMBtu/hr for Unit 1 and 6,022 MMBtu/hr for Unit 2, both of which are approximately equivalent to 605 MW nominal capacity at 10 MMBtu/MW (6,050 MMBtu/hr) that Barr uses in the cost analysis. At times, the short-term firing rate may exceed these values due to swings in lignite heat content and operating factors. These other values are reasonable for determining short-term (i.e., 24-hour) maximum actual emissions.

[14] Annual capacity factor is defined by EPA (40 CFR 60 Subpart Dc) as "... the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity..."

Table 2-1: Annual Average Capacity Factors at Coal Creek Station Unit 1 and Unit 2

Year	Annual Capacity Factor	
	Unit 1	Unit 2
2009	94.2%	92.7%
2010	93.8%	79.6%
2011	81.6%	89.0%
2012	92.4%	90.9%
2013	92.4%	83.3%
2014	87.8%	88.2%
2015	89.3%	87.3%
2016	86.3%	72.9%
2017	70.8%	85.0%
2018	91.6%	90.5%
10yr Average	**88%**	**86%**
Plant Average	**87%**	

The calculated cost effectiveness value for each control measure is compared to a cost effectiveness threshold established by the NDDEQ. The NDDEQ's original BART cost thresholds were based on the "high cost" value of $3,000 per ton listed in the June 1999 WRAP Annex to Grand Canyon Visibility Transport Commission (GCVTC) Report.[15] GRE scaled this 1999 value to today's dollars using the Chemical Engineering Plant Cost Index (CEPCI).[16] The CEPCI is an industrial plant index that is considered more representative for purposes of this analysis than general cost indices such as the Consumer Price Index (CPI). The average cost effectiveness threshold in current dollars is calculated to be $4,630 per ton.[17]

2.4 Factor #2 – Energy and Non-air Environmental Impacts

Factor #2 involves consideration of the energy and non-air environmental impacts of each control measure. Non-air quality impacts may include solid (ash) or hazardous waste generation and

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[15] Cited by EPA in the "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations" proposed rule; 69 FR 25198; May 5, 2004.

[16] More information on CEPCI may be found at this link: https://www.chemengonline.com/pci-home.https://www.chemengonline.com/pci-home. The CEPCI is accessible by subscription through "Chemical Engineering" magazine. The CEPCI scaling factors for this analysis compare 1999 values to December 2018 values.

[17] The NDDEQ also calculated an incremental cost effectiveness (cost effectiveness between two control measures) threshold in addition to the average cost effectiveness threshold for the BART evaluations. Barr does not use the incremental cost effectiveness criterion in the Factor #1 evaluation.

treatment/disposal, wastewater discharges from a control device, increased water consumption, and land use. The environmental impact analysis is conducted based on consideration of site-specific circumstances.

The energy impact analysis considers whether use of an emissions control technology results in any significant or unusual energy penalties or benefits. Energy use may be evaluated on an energy used per unit of production basis; energy used per ton of pollutant controlled or total annual energy use.

2.5 Factor #3 – Pollution Control Equipment at the Source

Factor #3 considers pollution control equipment in use or anticipated to be used in the near future at the source when determining the availability and impacts of additional retrofit controls. Section 2.1 describes the DryFining™ and LNC3+ technologies at Units 1 and 2 that correspond to a NOx emissions performance of 0.13 lb/MMBtu. The evaluation of other control technologies shall consider the ongoing application of these technologies when determining if the additional control is effective in further reducing NOx.

Because the NOx emissions rate at Coal Creek Station of 0.13 lb/MMBtu is relatively low as compared to uncontrolled coal-fired units, the corresponding control efficiency for additional NOx controls applied at Coal Creek Station will inherently not be as high. In order to provide a clearer understanding of NOx emissions at the stack when evaluating additional controls in this evaluation, Barr examines the controlled emissions on a lb/MMBtu basis in relationship to the 0.13 lb/MMBtu value.

2.6 Factor #4 – Remaining Useful Life of the Source

Factor #4 is the remaining useful life of the source, which is considered to be the difference between the date that additional emissions controls will be put in place and the date that the facility permanently ceases operation. Generally, the remaining useful life of the source is assumed to be longer than the useful life of the emissions control measure unless there is an enforceable cease-operation requirement. In the presence of an enforceable end date, the cost calculation can use a shorter period to amortize the capital cost.

For the purpose of this evaluation, the remaining useful life of both Unit 1 and Unit 2 is assumed to be longer than the useful life of the additional emission control measures. Therefore, the expected useful life of the control measure is used to calculate the emissions reductions, amortized costs, and the resulting cost per ton ($/ton).

2.7 Factor #5 – Visibility Impacts

The EPA BART Guidelines also require consideration of the degree of visibility improvement resulting from application of the retrofit technology when determining BART for an individual source. The CALPUFF program models how a pollutant contributes to visibility impairment with consideration for the background atmospheric ammonia, ozone and meteorological data. Additionally, the interactions between the visibility impairing pollutants NOx, SO_2 and PM_{10} (and the speciated components of particulate matter) can play a large part in predicting impairment.

Barr and GRE communicated with EPA Region 8 and the NDDEQ air quality staff to develop the dispersion modeling protocol for evaluating Factor #5.[18] The dispersion modeling protocol and corresponding agency approval correspondence is contained in Attachment E-1 and E-2 to this report.

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[18] US EPA Region 8 provided draft comments on GRE's March 5, 2019 draft protocol document in April 8, 2019 correspondence from Monica Morales to Jim Semerad of the NDDEQ. Great River Energy provided responses to the comments on May 3, 2019, followed by a May 13, 2019 teleconference between staff at US EPA Region 8, NDDEQ, Great River Energy, and Barr Engineering Company.

3 Five-Factor BART NOx Analysis at Units 1 and 2

Section 3.1 identifies NOx emissions control technologies and summarizes available and technically feasible controls at Units 1 and 2 using Steps 1 through 3 of the BART analysis. Sections 3.2 through 3.6 evaluate each of the five BART factors for the retrofit control technologies that are assumed to be technically feasible.

For purposes of not duplicating the narrative in the other technical reports in Attachments A, B, and C, Sections 3.1 through 3.5 refer to these reports and add additional context or information based on Barr's independent evaluation.

Section 3.7 summarizes conclusions of this updated NOx BART analysis.

3.1 Identification and Ranking of Technically Feasible Retrofit Controls

Barr has conducted a review of potentially available NOx control technologies and evaluated the technically feasibility of NOx retrofit controls at Units 1 and 2.

3.1.1 Identification of Available NOx Controls at Units 1 and 2

In the 2007 BART Analysis[19] for Coal Creek Station, Barr identified several potentially available NOx control technologies and conducted a corresponding technical feasibility analysis. In this update, Barr has reviewed its previous BART analyses contained in the NDDEQ's regional haze SIP record as well as Black & Veatch's recent evaluation provided in Attachment A. From this review, a few additional types of NOx control technologies, which are additional forms of catalytic reduction, were identified:

- Tri-Mer® UltraCat ceramic filters with SCR catalyst incorporated into the ceramic filter matrix.
- Fabric filter bags with SCR catalyst incorporated into the filter bags. Manufacturers include Haldor Topsoe CataFlex™ and Gore® DeNOx Catalytic Filter Bags
- Use of mid-temperature range SCR catalyst; this catalyst is capable of NOx reduction down to 300°F, potentially available from IBIDEN CERAM and Shell.

A technical feasibility evaluation of each of these additional emissions controls is described below in this section. None of these emissions controls are considered technically feasible for Coal Creek Station.

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[19] December 12, 2007, "Coal Creek Station Units 1 and 2 Best Available Retrofit Technology Analysis." This report is attached as Appendix C.2 to the NDDEQ's "North Dakota State Implementation Plan for Regional Haze", February 24, 2010.

In summary, consistent with Barr's findings in its earlier reports, the only available NOx control technologies that could reduce annual emissions less than the 0.13 lb/MMBtu level described in Section 2.1 and that are potentially applicable to Coal Creek Station, pending the technical feasibility evaluation, is SCR and SNCR.[20] The technical feasibility and control effectiveness evaluation for these two types of emissions controls is provided in Sections 3.1.2 and 3.1.3, respectively.

The 2007 BART Analysis noted that wet scrubbing NOx control technologies, such as Tri-NOx and low temperature oxidation (LoTOx™), were considered commercially available and were also presumed to be applicable (technically feasible) to a source type like Coal Creek Station. These technologies were not BART due to very high costs and significant environmental impacts (i.e., wastewater). Barr has since queried the EPA's RACT/BACT/LAER Clearinghouse (RBLC),[21] which shows no such installations on large (greater than 250 MMBtu/hr) coal fired boilers to date. Because no known installations of these control types have been completed on a source type that is of similar size and with similar characteristics as at Units 1 and 2, these technologies are not technically feasible for BART and are not evaluated further. If these technologies were to be assessed against the five BART factors, Barr expects that the same conclusions would be made with respect to substantial economic and non-air environmental impacts.

UltraCat

The advantage of Ultra Cat is that the SCR catalyst is protected by being imbedded in the ceramic filter matrix. It is intended for high temperature applications such as glass manufacturing. Accordingly, it should be able to withstand the adverse effects of sodium in the boiler fly ash because the fly ash is filtered out before the flue gas can come in contact with the SCR catalyst particles. It is unknown at this time whether or not the sodium in the fly ash may cause plugging of the ceramic filter pores in the same way that sodium causes plugging in SCR catalyst pores.

UltraCat is not a viable retrofit option for Coal Creek Station, because it has not been implemented on a process that is close to the size of the Coal Creek Station boiler. Tri-Mer, UltraCat's manufacturer, indicates that the UltraCat modules are only capable of processing 30,000 actual cubic feet per minute (acfm) each and the maximum number of modules recommended per application is ten (300,000 acfm maximum). By comparison, the air flow rate out of the Coal Creek Station economizers exceeds 3,000,000 acfm at 830°F. Therefore, this technology is not feasible and is not further evaluated.

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[20] The EPA BART Guidelines describe technical feasibility using two key concepts: "availability" (e.g., commercially demonstrated technology for sale) and "applicability." With respect to applicability, EPA describes the evaluation as follows: *"Generally, such a demonstration involves an evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology. Alternatively, a demonstration of technical infeasibility may involve a showing that there are unresolvable technical difficulties with applying the control to the source (e.g., size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability, and adverse side effects on the rest of the facility)."*

[21] EPA's RBLC is accessed at https://cfpub.epa.gov/rblc/index.cfm?action=Home.Home

Catalytic Filter Bags

The advantage of catalytic filter bags is that the SCR catalyst is protected by enclosing the SCR catalyst inside a fabric filter bag. Catalytic filter bags are intended for multi-pollutant controls in applications where a fabric filter is used for particulate control. Thus, it should be able to withstand the adverse effects of sodium in the boiler fly ash because the fly ash is filtered out before the flue gas can come in contact with the catalyst.

Catalytic filter bags are not a technically feasible BART control for Coal Creek Station, because no known installations of this technology have been implemented on a process functionally comparable to the Coal Creek Station boilers. Additionally, Coal Creek Station uses electrostatic precipitators (ESPs) for particulate matter control instead of a baghouse, so this would require an entirely new baghouse complex with a corresponding extended several-month plant outage, which is impracticable and is thus not a viable retrofit option for further evaluation.

"Mid-Temperature" SCR Catalyst

Shell-CRI SCR catalyst is rated from 280°F to 750°F. IBIDEN CERAM indicates its SCR catalyst may be effective to a certain degree from 300°F to 1,050°F. The outlet temperatures of the Units 1 and 2 air preheaters are approximately 350°F.

However, these control applications in practice are for very-low-sulfur fuel based exhaust only (e.g., natural gas, scrubbed refinery fuel gas). IBIDEN CERAM confirmed that sulfur levels at Units 1 and 2 downstream of the ESP are too high for installing an SCR, especially at lower operating temperatures (300°F to 400°F) where ammonium bisulfate generation causes catalyst deactivation and plugging.

Effectively, the SO_2/SO_3 concentrations would need to be near 0 ppm for SCR to be viable for this option; otherwise, sulfuric acid would be formed as a side reaction on the SCR catalyst, ammonium bisulfate would form due to the reaction of ammonium and sulfuric acid, and catalyst plugging and deactivation would occur as a result. Therefore, this technology is not technically feasible at Units 1 and 2 and is not further evaluated.

3.1.2 SCR Technical Feasibility and Control Effectiveness Analysis

An SCR system has two types of arrangements: "high-dust" (reactor is located upstream of the particulate control system) and "low-dust" (reactor is located downstream of the particulate control system). In the 2007 BART Analysis, Barr ascertained that a high-dust system was technically infeasible at Units 1 and 2 "due to the likelihood of catalyst surface plugging caused by high sodium concentrations," and that "a low-dust SCR would require reheat to bring the stream temperature back to the effective range after it is cooled for particulate removal, but is a technical feasible option for NOx reduction."

Barr's conclusion that a low-dust SCR is technically feasible (i.e., it is available and applicable to the source type) is unchanged with this update. The particulate controls will capture most of the sodium-bearing fly ash particles, and thus may mitigate SCR catalyst deactivation that is expected to otherwise occur with a high-dust SCR. However, in order for the SCR to be most effective at controlling NOx emissions from Units 1 and 2 that are already entering the system at a relatively low emissions rate (0.13 lb/MMBtu annualized), the exhaust gas from the outlet of the ESP must be reheated though a new fuel-fired reheat system to increase its temperature up to an SCR operating design of approximately 650°F. Subsequently, the gas leaving the SCR must then be cooled to the SO_2 scrubber inlet design temperature of 300°F. Designing and installing such reheating and cooling systems are expected to have significant economic impact and will have material environmental impacts due to associated air emissions from firing additional natural gas to reheat the exhaust. Barr believes that Black and Veatch's reported high-level cost estimate of the flue gas reheat and cooling systems at $17 to $20 million is reasonable, but actual installed costs may be higher than this when accounting for other site-specific factors. Therefore, a low-dust SCR will have a demonstrably higher economic impact than a high-dust SCR system, if the high-dust SCR system were determined to be technically feasible.

With respect to the technical feasibility of high-dust SCR, Barr's conclusion from 2007 that it is technically infeasible at Units 1 and 2 remains unchanged. Barr concurs with Black and Veatch's analysis and conclusion that an SCR catalyst supplier is unable to ensure reliable performance and catalyst life given significant concerns with potential plugging and catalyst deactivation unless extended trials (i.e., pilot testing with the exhaust characteristics of Units 1 and 2) are performed. The EPA generally does not consider a control technology to be technically feasible in this instance:[22]

> *"Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type."*

Given that the physical characteristics of the coal burned at Coal Creek Station and the associated exhaust gas stream flow and characteristics are outside the realm of installed SCR systems and because pilot testing and extended trials would be required to assess operational risks associated with catalyst deactivation, SCR is not technically feasible.

Notwithstanding that a high-dust SCR at Units 1 and 2 is not technically feasible for BART, Barr conservatively carries forward SCR into the five-factor BART evaluation to assess the related costs and non-air quality impacts of applying this technology at Coal Creek Station. In doing so, the five-factor BART evaluation for high-dust SCR effectively also covers the impacts of a low-dust SCR, noting that the economic impact of a low-dust SCR will be higher than a high-dust SCR due to reheat and cooling systems, as described above.

Barr completed an independent search of the RBLC database for utility-sized coal-fired boilers for SCR systems and performance levels. Determinations for Best Available Control Technology (BACT) and Lowest Achievable Emissions Rate (LAER) are generally more stringent than that for BART. Accordingly, the RBLC data provides information consistent with the best controls on recently constructed new and modified coal-fired utility boilers. Please see Attachment F for the RBLC summary tables. The RBLC listings range

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[22] USEPA, "Draft New Source Review Workshop Manual," October 1990, Page B.18.

from 0.05 to 0.25 lb/MMBtu with an average of 0.084 lb/MMBtu (9 listings). For comparison, Black and Veatch reports a SCR control effectiveness of 0.05 to 0.08 lb NOx/MMBtu from their review of actual SCR performance data recently collected from the Western Regional Air Partnership (WRAP) and EPA's Clean Air Markets Division (CAMD). The only empirical data available to represent the best performance to be expected is that of existing large power plants burning Texas lignite, which achieve 0.062 to 0.075 lb/MMBtu annual performance levels per Black and Veatch's review of the WRAP data.[23] As these units are most representative of the actual performance at lignite-fired units, a range of SCR catalyst performance levels at 0.06 and 0.08 lb NOx/MMBtu is established for purposes of the five-factor evaluation.

Actual SCR performance at Coal Creek Station is likely to not be as effective as at the Texas facilities based on the comparatively greater sodium content and other constituents of North Dakota lignite affecting the SCR catalyst as compared to that of Texas lignite. In the last two years, the as-fired lignite ash sodium content averaged 3% with variability generally of +/- 1% with deviation intermittently beyond these levels, as shown in Figure 2.2. The lignite ash sodium content has been and is expected, at times, to be greater than 4%, which is the maximum sodium percentage in IBIDEN CERAM's catalyst design.[24] Additionally, lignite ash sodium content data at the Falkirk mine, as summarized in Black and Veatch's report,[25] shows that 27% of all samples have a sodium content greater than 4% and that 9% of all samples were greater than 10% sodium content. By comparison, the sodium content in Texas lignite ash is consistently lower than that in North Dakota lignite ash. For example, one literature reference summarizes Texas lignite ash sodium levels between 0.59 and 1.67%, whereas North Dakota lignite ash sodium is shown as 5.8%.[26] In summary, the expected degradation and decreased performance of SCR catalyst in North Dakota lignite units is anticipated to be much more prevalent than at units firing lower sodium fuel like that in Texas.

Barr notes that the Black & Veatch report estimates the SCR control costs for a range of performance specifications at 0.04, 0.06, and 0.08 lb NOx/MMBtu. The estimated performance level of 0.04 lb NOx/MMBtu provided by the catalyst supplier was only for a one-time initial performance test. IBIDEN-Ceram, the SCR catalyst supplier, was uncertain of the degradation of catalyst performance over time in the presence of the high sodium content of the lignite coal burned at Coal Creek Station and required pilot testing to ascertain this critical design information during sustained operations. Correspondingly, Barr believes that 0.04 lb/MMBtu is not a demonstrable performance level for sustained operations at

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[23] See Attachment A at Section 3.1 and Appendix F.

[24] See Attachment A at Appendix E.

[25] See Attachment A at Appendix A.4.

[26] The Babcock and Wilcox Company, "Steam: its generation and use," 41st Edition (2005), Chapter 9, Table 6 "Properties of U.S. Coals."

Coal Creek Station and that 0.06 lb/MMBtu is the best level of performance that can reasonably be expected based on established information to date.

Further, there are site-specific barriers to the installation of SCR at Coal Creek Station. The existing DryFining™ system and the stack reheat system[27] would need to be removed to tie SCR duct work into the boiler house and then be reconfigured, requiring an extended several-month outage, which is impracticable. Importantly, DryFining™ and stack reheat system are an integral part of the Coal Creek Station design to meet SO_2 BART requirements and must be preserved. DryFining™ also is used to remove moisture and improve the properties such as the heat content of lignite coal prior to combustion, thus improving NOx performance and the energy efficiency of the Coal Creek Station boilers.

Finally, Barr acknowledges the technical feasibility work at Coal Creek Station that was completed by Fuel Tech, a company that provides emissions control technologies for power plants and other sectors, as summarized in the Black and Veatch report.[28] In examining application of their ASCR® hybrid technology, Fuel Tech also noted process concerns with sodium levels causing significant catalyst deactivation. Because of this and other concerns (e.g., spatial limitations), Fuel Tech would not recommend using its ASCR technology at Coal Creek Station and, at a minimum, would need pilot testing to determine catalyst operation and performance. Therefore, this technology is not further evaluated.

3.1.3 SNCR Technical Feasibility and Control Effectiveness Analysis

In its 2007 BART Analysis, Barr ascertained that SNCR technology is available and is applicable to the source type with an estimated emissions performance level of 0.108 lb/MMBtu. Since the time of this report, NOx controls that have been (and will be) installed at Units 1 and 2, namely DryFining™ and LNC3+ combustion controls, will significantly decrease NOx emissions to an annual level of 0.13 lb/MMBtu, as compared to 0.22 lb/MMBtu evaluated in the 2007 BART Analysis. A NOx level of 0.13 lb/MMBtu at Unit 2 is generally equivalent to 65 ppm NOx depending on fuel and operating conditions. The EPA Control Cost Manual for SNCR denotes several concerns:

- *"Sources with stable temperatures of 1550°F to 1950°F, uncontrolled NOx emissions above 200 ppm, and residence times of 1 second are generally well suited to SNCR and attain the highest levels of NOx control."*

  This reported NOx concentration is over three times the actual level at Coal Creek Station.

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[27] The current Coal Creek Station exhaust stack is a dry stack and is not designed to accommodate water condensation in the stack. The reheat system is used to add sufficient heat to the stack to prevent water condensation for most operating conditions. Black and Veatch determined that the cost of replacing the existing stack with a new wet stack that could accommodate water condensation would cost at least $16 million.

[28] See Attachment A at Section 2.2.13.

- *"Figure 1.8 shows an example of the NOx reduction efficiency that can be achieved for an uncontrolled NOx level of 120 parts per million (ppm) and various ammonia slip levels."*

  In this figure, EPA shows that a high normalized stoichiometric ratio (NSR) is needed for the SNCR system to have a meaningful impact on NOx reductions at this uncontrolled concentration level, which is approximately twice that at Coal Creek Station.

  A higher NSR results in increased ammonia slip. EPA notes several problems with ammonia slip, such as: *"Ammonia-sulfur salts can plug, foul, and corrode downstream equipment such as air heaters, ducts, and fans. Lastly, the ability to sell the fly ash as a secondary product is affected by its ammonia concentration."*

- *"Although there is significant scatter, Figure 1.1c shows a trend of increasing reductions with increasing baseline NOx levels for utility boilers. Specifically, the reductions range from 20 percent when the baseline NOx concentration is about 0.2 lb/MMBtu to 35 percent when the baseline NOx concentration is about 0.8 lb/MMBtu."*

  Figure 1.1c for SNCR applied at coal-fired boilers shows no SNCR systems installed at boilers with an uncontrolled NOx level less than ~0.19 lb/MMBtu. By comparison, the current NOx performance level at Coal Creek Station is 0.13 lb/MMBtu. Even using the EPA-estimated 20 percent reduction from a 0.2 lb/MMBtu level results in controlled emissions that are higher than the current NOx performance level.

Barr completed an independent search of the RBLC database for utility-sized coal-fired boilers for SNCR systems and performance levels. Determinations for Best Available Control Technology (BACT) and Lowest Achievable Emissions Rate (LAER) are generally more stringent than that for BART, so the RBLC data provides information consistent with the best controls on recently constructed new and modified coal-fired utility boilers. Please see Attachment F for the RBLC summary tables. The RBLC listings range from 0.07 to 0.36 lb NOx/MMBtu (7 listings). However, five of these listings are for circulating fluidized bed (CFB) boilers, which are significantly different source type and exhaust characteristics that pulverized coal (PC) boilers like Unit 1 and 2. The two PC boilers with SNCR are shown with NOx performance levels of 0.35 and 0.36 lb/MMBtu.

For comparison, Black and Veatch reports a SNCR control effectiveness of 0.10 to 0.11 lb NOx/MMBtu from their review of Fuel Tech's site-specific assessment for SNCR at Unit 2. The SNCR proposal prepared by Fuel Tech is based on onsite testing of Unit 2 to collect data to prepare site-specific computational fluid dynamic (CFD) model and chemical kinetic model (CKM) of the boiler. Barr agrees with Black and Veatch's analysis and conclusion that SNCR NOx performance at Units 1 and 2 would be ~0.10 lb/MMBtu, at best, given that the chemical equilibrium of the SNCR reactions shifts and NOx re-formation rates make it difficult to achieve further NOx emission reductions.[29] The EPA SNCR Control Cost Manual also notes this limitation.

SNCR control is highly dependent upon boiler operating conditions and the ability of the control system to inject reagent into the boiler at optimal rates in the appropriate locations and at expected temperature and residence times. The Fuel Tech proposal indicates that their SNCR control system can be integrated with the boiler's control system to be load-following, which is an anticipated operating condition at Units 1 and 2 (see Section 2.1.2). In theory, the proposed Fuel Tech SNCR system should be able to achieve the NOx reductions under routine variable loading, although they did not explicitly study it. As such, Barr considers the additional Multiple Nozzle Lances (MNL) option with its associated reagent injection rate and high stoichiometric ratio and ammonia slip from Fuel Tech as necessary elements for SNCR to address variable load conditions within the boiler.

3.2 Factor #1 Evaluation – Costs of Compliance

Barr has updated its cost evaluation from historical BART reports for high-dust SCR and for SNCR using the EPA Control Cost Manual methodology. Barr also has reviewed, for comparison, Black and Veatch's estimated costs for SCR and SNCR using both the general EPA Control Cost Manual methodology and a "site-specific methodology" incorporating actual costs from installation at another source that are scaled to Coal Creek Station. In summary, Barr's costs for high-dust SCR and for SNCR are comparable to Black and Veatch's estimates and would result in compliance costs that are much greater than the NDDEQ's cost effectiveness threshold.

3.2.1 SCR Cost Evaluation

Barr has populated the EPA SCR control cost spreadsheet with information relevant to Units 1 and 2. In doing so, it is noted that that the EPA SCR control cost spreadsheets in this application will inherently underestimate the actual cost of SCR at Coal Creek Station. The EPA SCR cost correlations do not take into account the actual catalyst volume requirements, and resulting reactor size, for a specific application when calculating the cost of SCR. Based on the significant uncertainty of SCR catalyst performance and reliability under significant sodium variability conditions (see Section 2.1.1) at Coal Creek Station, IBIDEN CERAM's SCR catalyst proposal[30] and related communications with CERAM staff have identified that the specified catalyst volume is more than twice than that calculated in the EPA SCR Control Cost spreadsheet at a suggested performance level of 0.04 lb/MMBtu.[31] The EPA SCR control cost spreadsheet cannot

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[29] See Attachment A at Section 2.2.12, page 2-18 and Section 4.1.2, page 4-14.

[30] See Attachment A at Appendix E for IBIDEN CERAM proposal.

[31] IBIDEN CERAM has requested that the actual catalyst volume be noted as business confidential but that it is at least twice the catalyst volume calculated in the EPA Control Cost Manual for reducing NOx emissions at a Coal Creek Station unit from 0.13 to 0.04 lb/MMBtu, which is 24,433 ft^3. The catalyst volume calculated using the EPA spreadsheet at 0.06 and 0.08 lb/MMBtu levels is less than this value because the volume is a function of NOx emissions reduction.

readily be updated to accurately calculate the cost of SCR for CCS as it cannot account for the actual catalyst requirements recommended by the SCR catalyst supplier. Barr has not updated the spreadsheet to calculate the cost with catalyst volume and reactor size that reflects the IBIDEN CERAM's specification, and we note that the actual SCR cost is expected to be much higher than that calculated herein using the EPA spreadsheet.

As described in Section 3.1.2, Barr believes that a NOx control effectiveness range of 0.06 to 0.08 lb NOx/MMBtu on a sustained basis should be used in the control cost analysis due to the high potential for catalyst deactivation resulting from high sodium variability in the Falkirk lignite coal ash.

To be conservative (i.e., resulting in a lower estimated cost) in its estimate of catalyst replacement cost, Barr uses EPA Method 2 in the SCR Control Cost spreadsheet instead of EPA Method 1. Method 2 is an empirical correlation which estimates catalyst replacement costs based on industry experience. It relies on boiler capacity to estimate catalyst replacement costs. EPA Method 1 calculates the catalyst cost based on the anticipated catalyst replacement cycle. The EPA's recommended approach is to assume that one-third of the catalyst is replaced each year. However, the Coal Creek Station units normally operate on a 3-year maintenance outage cycle, so using the typical annual catalyst replacement cycle would not account for the costs and lost revenue of additional shutdowns for catalyst replacement. Following Method 1 assuming complete catalyst replacement at the end of the IBIDEN CERAM's estimated three-year life is consistent with Coal Creek Station's current operating practices, but results in a higher catalyst replacement cost. Method 2 is selected by Barr for determining catalyst replacement costs because it is generally representative of industry experience and results in a conservative (lower) estimated cost than the 3-year replacement cycle consistent with the IBIDEN-CERAM proposal.

Barr's estimates of control costs are summarized in Table 3-1.

Table 3-1: Barr's SCR Control Costs, per Unit Basis

NOx Performance Level	Installed Capital Cost ($)	Annualized Capital Cost ($/yr)	Annual Operating Costs ($/yr)	Total Annualized Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
0.06 lb/MMBtu	$192 million	$12.8 million	$3.9 million	$16.7 million	1,614	$10,351
0.08 lb/MMBtu	$180 million	$12.1 million	$3.4 million	$15.4 million	1,153	$13,391

In comparing Barr's estimate to Black and Veatch's estimate using the EPA Control Cost spreadsheets, Barr notes three primary differences:

1) The SCR catalyst cost used in the EPA spreadsheet must include the purchase cost, installation cost, spent catalyst removal cost and spent catalyst disposal costs. The catalyst cost of $118/ft^3 used in the Black & Veatch spreadsheets appears to include only the purchase cost and thus may underestimate actual costs. The EPA's default value of $227/ft^3 is recommended as it considers the other necessary catalyst activities.

2) Barr uses the gross MW rating of each Coal Creek Station unit to calculate the associated heat input and annual emissions (at 87% capacity factor) that are used to estimate the emissions reduction, whereas Black and Veatch uses a lower estimate from EPRI's Vista model.
3) Barr's estimated range of sustained NOx performance is 0.06 and 0.08 lb/MMBtu as described above. Black and Veatch also considered a performance level of 0.04 lb/MMBtu.

These differences do not change the conclusion that both Barr's and Black and Veatch's cost estimates are much greater than the cost effectiveness threshold of $4,630/ton NOx removed.

Barr believes that a low-dust SCR will be more costly than the high-dust SCR due to the required reheat and cooling system that would need to be designed and installed. Therefore, the cost for a low-dust SCR is also much greater than the cost effectiveness threshold.

Black and Veatch also prepared a cost estimate using "site-specific methodology" from another project. Barr does not have access to the underlying data used to scale project costs and thus has no comments on the accuracy of the analysis other than to note that using actual project costs generally should provide more accurate results than default assumptions in the EPA Control Cost spreadsheet. Black and Veatch's cost effectiveness results for SCR at 0.06 lb/MMBtu is $11,233/ton,[32] which compares closely to Barr's estimate. Table 3-2 summarizes Barr's and Black and Veatch's results from the SCR cost effectiveness analyses.

Table 3-2: SCR Pollution Control Cost Effectiveness Summary, per Unit Basis

	Pollution Control Cost Effectiveness ($/ton)		
NOx Performance Level	Barr Estimate using EPA Methodology	Black & Veatch Estimate using EPA Methodology	Black & Veatch Estimate using Site-specific Approach
0.04 lb/MMBtu	N/A	$8,157	$8,737
0.06 lb/MMBtu	$10,351	N/A	$11,233
0.08 lb/MMBtu	$13,391	N/A	$15,727

A critical physical complication with installation of SCR at Coal Creek Station that is not included in the cost effectiveness results above is the design of ductwork to accommodate the SCR. As described in the following points, both the existing DryFining™ system and the stack reheat system would need to be removed to tie SCR duct work into the boiler house and then be reconfigured, requiring an extended outage of 6 to 18 months as estimated by Black and Veatch.

- DryFining™ is used to remove moisture and improve the properties such as the heat content of lignite coal prior to combustion, thus improving NOx performance. This process also improves the

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[32] See Attachment A at Table 4-5.

energy efficiency of the Coal Creek Station boilers and reduces SO_2. DryFining™ is an integral part of the Coal Creek Station design to meet its SO_2 BART requirements. Therefore, this capability must be preserved. (See also Factor #3.)

- The current Coal Creek Station exhaust stack is a dry stack and is not designed to accommodate water condensation in the stack. The reheat system is used to add sufficient heat to the stack to prevent water condensation for certain operating conditions. For reference, Black & Veatch determined that the cost of replacing the existing stack with a new wet stack that could accommodate water condensation would cost at least $16 million. This cost is not currently considered in the Table 3-1 estimate.

Effectively, these systems need to be removed and reconfigured in order to create space for installation of the SCR. Barr agrees with Black & Veatch's estimate that the plant outage would be approximately 6 to 18 months. The costs in lost revenue and in designing and implementing a reconfiguration of these systems are substantial and have not been included in the Table 3-1 estimate.

In summary, Barr believes that application of SCR is not cost effective for BART.

3.2.2 SNCR Cost Evaluation

Barr has examined the cost of an SNCR system by populating the EPA SNCR control cost spreadsheet with information relevant to Units 1 and 2. The EPA Control Cost Manual for SNCR and the associated spreadsheet estimate of the capital cost for SNCR are based primarily on size of the boiler and desired level of NOx control. In this case, Barr uses the 0.10 lb/MMBtu performance level specified by Fuel Tech, noting that the necessary additional costs for multiple nozzle lances (MNL) to achieve this performance level are not part of the EPA Control Cost spreadsheet or methodology.

Barr's estimate of SNCR control costs is summarized in Table 3-3.

Table 3-3: Barr's SNCR Control Costs, per Unit Basis

NOx Performance Level	Installed Capital Cost ($)	Annualized Capital Cost ($/yr)	Annual Operating Costs ($/yr)	Total Annualized Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
0.10 lb/MMBtu	$12.8 million	$1.1 million	$4.4 million	$5.4 million	692	$7,818

This cost effectiveness value aligns closely with that estimated by Black and Veatch using the EPA Control Cost spreadsheet and is more than 50% higher than the cost effectiveness threshold of $4,630/ton NOx removed.

Because the correlations used in the Control Cost Manual do not include an option to account for advanced design features like multiple nozzle lances (MNL) that are described in Fuel Tech's proposal,[33] the EPA spreadsheet underestimates the actual expected cost. This difference is apparent when comparing the cost in Table 3-2 to the cost estimate from Black & Veatch using the site-specific methodology, which results in a cost effectiveness value of $8,899/ton NOx removed. Barr believes that this estimate based on Fuel Tech's proposal is more accurate than that using the EPA methodology and results in a cost that is nearly twice the cost effectiveness threshold. Table 3-4 summarizes Barr's and Black and Veatch's results from the SNCR cost effectiveness analyses.

Table 3-4: SNCR Pollution Control Cost Effectiveness Summary, per Unit Basis

	Pollution Control Cost Effectiveness ($/ton)		
NOx Performance Level	Barr Estimate using EPA Methodology	Black & Veatch Estimate using EPA Methodology	Black & Veatch Estimate using Site-specific Approach
0.10 lb/MMBtu	$7,818	$7,279	$8,899
0.11 lb/MMBtu	N/A	$11,082	$11,145

An important consideration for cost and environmental impacts that is not directly included in Barr's or Black and Veatch's cost estimates is the effect of SNCR ammonia slip on lost fly ash sales and added ash disposal costs. GRE currently sells its fly ash as a raw material for concrete production. In order to meet a NOx control level of 0.10 lb NOx/MMBtu with SNCR, ammonia slip concentrations estimated by Fuel Tech are expected to be between 5 ppm and 10 ppm. This representation is also consistent with the EPA Control Cost Manual for SNCR. An ammonia slip rate of 10 ppm is highly probable due to load variability (see Section 2.1.2) and will thus adversely affect the chemistry of the fly ash.

GRE commissioned Golder Associates (Golder) and Boral Resources (Boral), in conjunction with the Fuel Tech report of expected ammonia slip from installation of SNCR, to evaluate the potential for adverse impacts of ammoniated fly ash. Golder's report in Attachment B concludes that higher ammonia concentrations in fly ash caused by SNCR create material risk in the marketability and sale of fly ash. To mitigate this risk of fly ash disposal instead of beneficial reuse, installation of an ammonia slip mitigation (ASM) technology is prudent. Boral has developed an ASM technology, noting that the technology is no longer in use and has not yet been applied to a large, lignite-fired unit. Boral could not provide a guarantee on the successful application of the technology at Coal Creek Station. See Attachment C for the Boral document.

Golder developed a conceptual design of ASM at Coal Creek Station. They note that there are potential conditions under which the ammonia concentration of the produced fly ash may not be treatable with the ASM system. Golder predicts a reasonable future scenario wherein an additional 20% of fly ash produced

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[33] See Attachment, Appendix E for Fuel Tech proposal.

annually cannot be treated to acceptable levels and will thus need to be disposed instead of beneficially reused. Golder provides a cost estimate associated with these reduced sales and the application of the ASM technology. Barr agrees with Golder that, for budgeting and cost estimate purposes, the application of SNCR will require application of ASM technology and will result in an increase in fly ash that needs to be disposed. These costs have not been directly included in the current cost estimate to be conservative.

In summary, Barr believes that application of SNCR is not cost effective for BART even without considering the expected mitigation and disposal costs associated with ammoniated fly ash.

3.3 Factor #2 Evaluation – Energy and Non-Air Environmental Impacts

Barr has evaluated the energy and non-air environmental impacts associated with implementation of SCR and SNCR. In conjunction with our evaluation, Barr has also reviewed Black & Veatch's analysis of these impacts associated with these technologies as well as Golder's report of impacts due to ammoniated fly ash from SNCR.

A key environmental impact from high-dust SCR is the production of sulfuric acid as a side reaction with the SCR process chemistry. Sulfuric acid, which is not captured within the boiler or associated downstream emission control, is released to the atmosphere as sulfuric acid mist (SAM). In addition to causing an unsightly "blue plume" from the exhaust stack, SAM is emitted as aerosol particles that contribute to visibility impairment. Therefore, the visibility impacts of SAM emissions must be considered in the analysis of visibility improvements from SCR, or the costs of controlling SAM emissions must be included in the SCR control cost analysis. Using the calculation procedures in a 2018 publication from Electric Power Research Institute,[34] SAM emissions of approximately 415 tons per year per unit are estimated as a result of the SCR catalyst with a 5% oxidation rate at Coal Creek Station.[35] Calculations of estimated SAM generation due to SCR at Units 1 and 2 are provided in Attachment H-2.

A low-dust SCR will require a fuel-fired reheat burner system, which will result in additional energy usage and collateral air emissions of NOx and other combustion pollutants.

Black & Veatch estimates the energy (due to auxiliary power consumption) and water consumption impacts of both technologies. The water demands for the SNCR system is estimated at 70 to 80 million gallons annually. Additionally, ammonia slip from these technologies will result in increased nitrogen in the scrubber that eventually is routed to the evaporation ponds. See Attachment A at Section 4.3 for a description of these impacts.

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[34] See Attachment H-1. Electric Power Research Institute, "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," March 2018.

[35] The 5% oxidation rate was provided by IBIDEN CERAM and is referenced in Black and Veatch's report at Attachment A, Appendix E, Table 1.

Also for SNCR, Section 3.2.2 summarizes the risks due to increased fly ash disposal as a result of ammoniated fly ash. Golder estimates a scenario wherein an additional 92,000 tons annually of fly ash will need to be disposed in a landfill instead of beneficially reused, representing an 81 percent increase in the amount of fly ash disposed compared to current conditions.

In summary, the energy and environmental-related impacts from the application of SCR or SNCR at Units 1 and 2 are significant and support the conclusion that neither technology is BART.

3.4 Factor #3 Evaluation – Pollution Control Equipment at the Source

Section 2.1 describes the use of DryFining™ and LNC3+ combustion controls that define the annual NOx performance level of 0.13 lb/MMBtu at Units 1 and 2 for purposes of determining emissions reductions due to additional retrofit controls. The current technologies are designed to be used for the foreseeable future.

3.5 Factor #4 Evaluation – Remaining Useful Life

Since Coal Creek Station will continue to operate for the foreseeable future, the EPA defined defaults for useful life of the SCR (30 years) and SNCR (20 years) are used to calculate emission reductions, amortized costs, and cost effectiveness on a dollar per ton basis.

3.6 Factor #5 Evaluation – Visibility Impacts

The visibility impairment contribution for different emission rate scenarios can be determined using the CALMET, CALPUFF, POSTUTIL, and CALPOST modeling tools. The modeling protocol at Attachment E-1 describes the emissions control scenarios to be evaluated and the CALPUFF model inputs, including the meteorological data set and background atmospheric ammonia and ozone concentrations along with the functions of the POSTUTIL and CALPOST post processing elements. The CALPOST output files provide two methods with which to assess the expected post-BART visibility improvement: the 98th percentile change in visibility, and the number of days on which a source exceeds an impairment threshold of 1.0 dV or 0.5 dV.

3.6.1 Determining 24-Hour Maximum Emission Rates for BART Emissions Control Scenarios

To be consistent with use of the highest daily emissions for pre-control visibility impacts, the emissions control scenarios reflecting the application of additional BART technologies to be used for the visibility impacts analysis should reflect the anticipated maximum 24-hour average basis. Emission rates and stack parameters for the emissions control scenarios used for visibility modeling are summarized in Table 3-3 and Table 3-4 and are described further in Attachment E-1. Note also that the generation of sulfuric acid mist due to SCR is estimated in Attachment H-2 and is included in the modeled particulate matter emissions rate, consistent with EPA guidance.[36]

In summary, the emissions control scenarios are as follows:

- Scenarios #0 and #1 reflect historical emissions controls at Units 1 and 2 that have since been upgraded to those identified in Scenario #2;
- Scenario #2 reflects current/anticipated emissions performance with DryFining™ and LNC3+ controls;
- Scenario #3 reflects the addition of SNCR to Scenario #2 at a performance level of 0.10 lb/MMBtu, and
- Scenarios #4A and #4B reflect the addition of SCR to Scenario #2 at a performance level of 0.04 and 0.06 lb/MMBtu, respectively.

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[36] April 8, 2019, correspondence from US EPA to the NDDEQ on the draft modeling protocol at Comment #19: *"If evaluating SCR, we recommend that PM10 emissions be adjusted to account for the associated increase in sulfuric acid emissions (as a subcomponent of PM). See Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, 2018 Update, Electric Power Research Institute, March 2018."*

Table 3-5: BART Eligible Sources Screening Analysis Emission Rates

Emissions Control Scenario	Unit	Emissions Control Technologies	Stack Parameters (see Table 3-4)	PM10$^{(1)}$ (lb/hr)	SO2 (lb/hr)	NOx (lb/hr)
#0 (2000 to 2002 Actual Emissions)	U1	LNC3	Pre SO_2 BART	249.2	5733.5	1772.3
	U2	LNC3	Pre SO_2 BART	216.1	4969.3	1822.4
#1	U2	LNC3, DryFining™, SO_2 BART	Post SO_2 BART	90.2	979	1233
	U2	LNC3, DryFining™, SO_2 BART	Post SO_2 BART	90.3	955	1233
#2	U1	LNC3+, DryFining™, SO_2 BART	Post SO_2 BART	90.2	979	898
	U2	LNC3+, DryFining™, SO_2 BART	Post SO_2 BART	90.3	955	898
#3	U1	LNC3+, DryFining™, SO_2 BART, SNCR	Post SO_2 BART	90.2	979	695
	U2	LNC3+, DryFining™, SO_2 BART, SNCR	Post SO_2 BART	90.3	955	695
#4A	U1	LNC3+, DryFining™, SO_2 BART, SCR@0.04	Post SO_2 BART	199.2	979	280
	U2	LNC3+, DryFining™, SO_2 BART, SCR@0.04	Post SO_2 BART	199.3	955	280
#4B	U1	LNC3+, DryFining™, SO_2 BART, SCR@0.06	Post SO_2 BART	199.2	979	415
	U2	LNC3+, DryFining™, SO_2 BART, SCR@0.06	Post SO_2 BART	199.3	955	415

Note(s):

Modeled particulate for all Emissions Control Scenarios except #4 is speciated into the following component percentages: coarse (PMC = 32.0%), fine (PMF = 33.9%), secondary organic aerosols (SOA = 6.6%), elemental carbon (EC = 1.3%), and sulfate (SO4 = 26.3%), using particulate speciation profiles for coal fired boilers as recommended by the National Park Service (NPS). For Emissions Control Scenario #4, consideration of sulfuric acid formation from the application of SCR technology contributes 109 lb/hr to the particulate emissions, modeled as sulfate.

Table 3-6: BART Eligible Sources Screening Analysis Stack Parameters

Unit	X Coord.[1] (km)	Y Coord.[1] (km)	Stack Height (m)	Base Elevation (m)	Stack Diam. (m)	Exit Velocity (m/s)	Exit Temp. (K)
Coal Creek 1 – Pre SO_2 BART	63.387	376.062	201.0	602.0	6.7	25.9	358.5
Coal Creek 2 – Pre SO_2 BART	63.492	376.068	201.0	602.0	6.7	24.9	354.5
Coal Creek 1 – Post SO2 BART	63.387	376.062	206.4	602.0	7.85	18.6	334
Coal Creek 2 – Post SO2 BART	63.492	376.068	206.4	602.0	7.85	18.0	332

Note(s):
(1) Coordinates reflect North Dakota Lambert Projection

3.6.2 Modeled Results

Visibility impairment is modeled using the meteorological data for the years 2000, 2001, and 2002 for the historical, current/anticipated, and BART emission scenarios. Results for the 98th percentile impacts and number of days above 0.5 dV and 1.0 dV at Lostwood Wilderness Area (LWA) and Theodore Roosevelt National Park (TRNP) North, South and Elkhorn Ranch units are summarized in Table 3-5 through Table 3-7.

As illustrated by the modeled visibility impacts, the future expected performance reflected in Scenario #2 for anticipated emissions controls and corresponding NOx performance at Units 1 and 2 represents a significant improvement in facility-wide impacts from the original baseline. For example, the change in visibility impairment between Scenario #0 and Scenario #2 is generally between 1.0 to 2.0 Δ-dV on a 98th percentile comparison, depending on the Class I area and meteorological year.

The change in NOx emissions rate between Scenario #2 and those scenarios representing additional controls evaluated in this report, Scenario #3 (addition of SNCR) or #4 (SCR), results in an average change of only ~0.1 Δ-dV on a 98th percentile comparison, depending on the Class I area and meteorological year. We also note that the sulfuric acid mist generated due to SCR has an appreciable impact on visibility impairment such that it effectively offsets much of the improvement in visibility that would otherwise occur from a reduction in NOx emissions. In some cases, the visibility impairment is higher with SCR than with existing emissions controls modeled in Scenario #2.

Table 3-7: Year 2000 Visibility Modeling Results

Description		Visibility Impairment											
		TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood Wilderness Area		
Emissions Control Scenario	Units	Days Above 0.5 Δ-dV	Days Above 1.0 Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	Days Above 1.0 Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	Days Above 1.0 Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	Days Above 1.0 Δ-dV	98th % Δ-dV
#0: LNC3	1 & 2	35	17	1.959	35	19	1.780	25	15	1.412	54	34	2.155
#1: LNC3, DryFining™, SO_2 BART	1 & 2	11	5	0.660	12	5	0.647	8	3	0.599	20	5	0.916
#2: LNC3+, DryFining™, SO_2 BART	1 & 2	10	4	0.552	10	4	0.540	8	1	0.501	19	4	0.729
#3: LNC3+, DryFining™, SO_2 BART, SNCR	1 & 2	8	3	0.506	7	3	0.476	4	1	0.440	15	4	0.637
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	1 & 2	8	2	0.558	8	4	0.518	4	1	0.416	21	4	0.775
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	1 & 2	9	3	0.596	13	4	0.557	5	1	0.461	24	4	0.852

Table 3-8: Year 2001 Visibility Modeling Results

Description		Visibility Impairment											
		TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood Wilderness Area		
Emissions Control Scenario	Units	Days Above 0.5 Δ-dV	Days Above 1.0 Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	Days Above 1.0 Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	Days Above 1.0 Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	Days Above 1.0 Δ-dV	98th % Δ-dV
#0: LNC3	1 & 2	36	16	1.653	29	21	1.378	27	12	1.626	45	28	2.842
#1: LNC3, DryFining™, SO_2 BART	1 & 2	7	2	0.474	10	3	0.571	8	1	0.526	21	5	0.873
#2: LNC3+, DryFining™, SO_2 BART	1 & 2	7	2	0.416	8	3	0.502	6	1	0.443	19	4	0.745
#3: LNC3+, DryFining™, SO_2 BART, SNCR	1 & 2	4	2	0.394	6	2	0.422	3	1	0.392	15	4	0.713
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	1 & 2	6	2	0.462	8	2	0.529	4	1	0.451	19	7	0.967
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	1 & 2	7	2	0.492	8	2	0.557	6	1	0.491	22	7	0.992

Table 3-9: Year 2002 Visibility Modeling Results

Description		Visibility Impairment											
		TRNP South Unit			TRNP North Unit			TRNP Elkhorn Ranch			Lostwood Wilderness Area		
Emissions Control Scenario	Units	Days Above 0.5 Δ-dV	Days Above 1.0 Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	Days Above 1.0 Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	Days Above 1.0 Δ-dV	98th % Δ-dV	Days Above 0.5 Δ-dV	Days Above 1.0 Δ-dV	98th % Δ-dV
#0: LNC3	1 & 2	39	23	3.131	40	26	2.692	28	18	2.173	39	26	1.980
#1: LNC3, DryFining™, SO_2 BART	1 & 2	22	11	1.279	18	8	1.145	14	6	0.987	17	2	0.689
#2: LNC3+, DryFining™, SO_2 BART	1 & 2	20	9	1.048	15	6	0.970	10	5	0.806	12	0	0.566
#3: LNC3+, DryFining™, SO_2 BART, SNCR	1 & 2	18	6	0.911	15	5	0.841	9	3	0.706	8	0	0.504
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	1 & 2	19	8	1.011	16	7	0.796	12	4	0.746	16	0	0.670
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	1 & 2	20	8	1.052	17	7	0.842	12	4	0.825	16	0	0.704

3.7 Conclusion

After assessing and weighing the five BART factors and considering the conservative nature of the economic analysis performed, Barr concludes that additional NOx emissions control technologies applied to Units 1 and 2, namely selective catalytic reduction and selective non-catalytic reduction, are not BART.

High-dust selective catalytic reduction (SCR) is neither technically feasible as a retrofit control technology at Coal Creek Station nor is it cost-effective with an estimated total capital investment of nearly $200 million and an annualized cost that is over twice the cost effectiveness threshold. Additionally, the estimated increase in sulfuric acid mist emissions due to an SCR system at Units 1 and 2 offsets much of the modeled visibility improvement that would otherwise occur from a reduction in NOx emissions. Low-dust SCR is also not cost-effective and has energy impacts and combustion emissions associated with a required fuel-fired reheat burner system.

Selective non-catalytic reduction (SNCR) is not cost-effective as well as potentially creates significant environmental impacts related to ammoniated fly ash.

Based on a review of recent emissions data at Unit 2 and the planned completion of installation of the same advanced combustion controls (LNC3+) for NOx at Unit 1 in the first half of 2020, Units 1 and 2 are expected to perform at an annual average emissions rate of 0.13 pounds of NOx per million British thermal units heat input (lb NOx/MMBtu) using DryFining™ and LNC3+ emissions controls.

Taking into consideration these inherent variabilities affecting NOx emissions performance and to determine the shorter-term average (i.e., 30-day rolling average) emissions rate impact on NOx performance on a heat input basis, Barr recommends a BART emissions limit of 0.15 lb NOx/MMBtu, which is less than the EPA's presumptive BART level of 0.17 lb/MMBtu on a 30-day rolling average.[37] This recommended limit is informed by actual NOx emissions levels that have occurred at Unit 2 during "high load high sodium," "low load high sodium," "high load low sodium," and "low load low sodium" conditions. For example, the average hourly Unit 2 NOx emissions at low load high sodium is 0.206 lb/MMBtu. Although GRE expects to operate primarily in high load high sodium, all of the other conditions are expected to occur at times in the future and will have an appreciable impact on the 30-day rolling average.

Figure 3-1 illustrates the effect of low load and low sodium on the 30-day rolling average. For example, an operating scenario may occur in the springtime (i.e., during mild weather) when Coal Creek Station is in a load-following mode for several days during a 30-day time frame. Considering the time for ramping up and ramping down and sustained low load conditions, it is reasonable to consider that a unit may operate in low load for several hours per day and for several days during the 30-day period. Based on the

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[37] The EPA presumptive NOx emission limit of 0.17 lb/MMBtu is at 40 CFR 51, Appendix Y, Section IV.E.5, Table 1, for a tangential-fired unit firing lignite.

interpolation of NOx emissions at high load and low load conditions (assuming high sodium during the 30-day period), GRE would be able to operate in low load mode for approximately 6 hours per day for the 30-day period in order to meet the 0.15 lb/MMBtu limit.

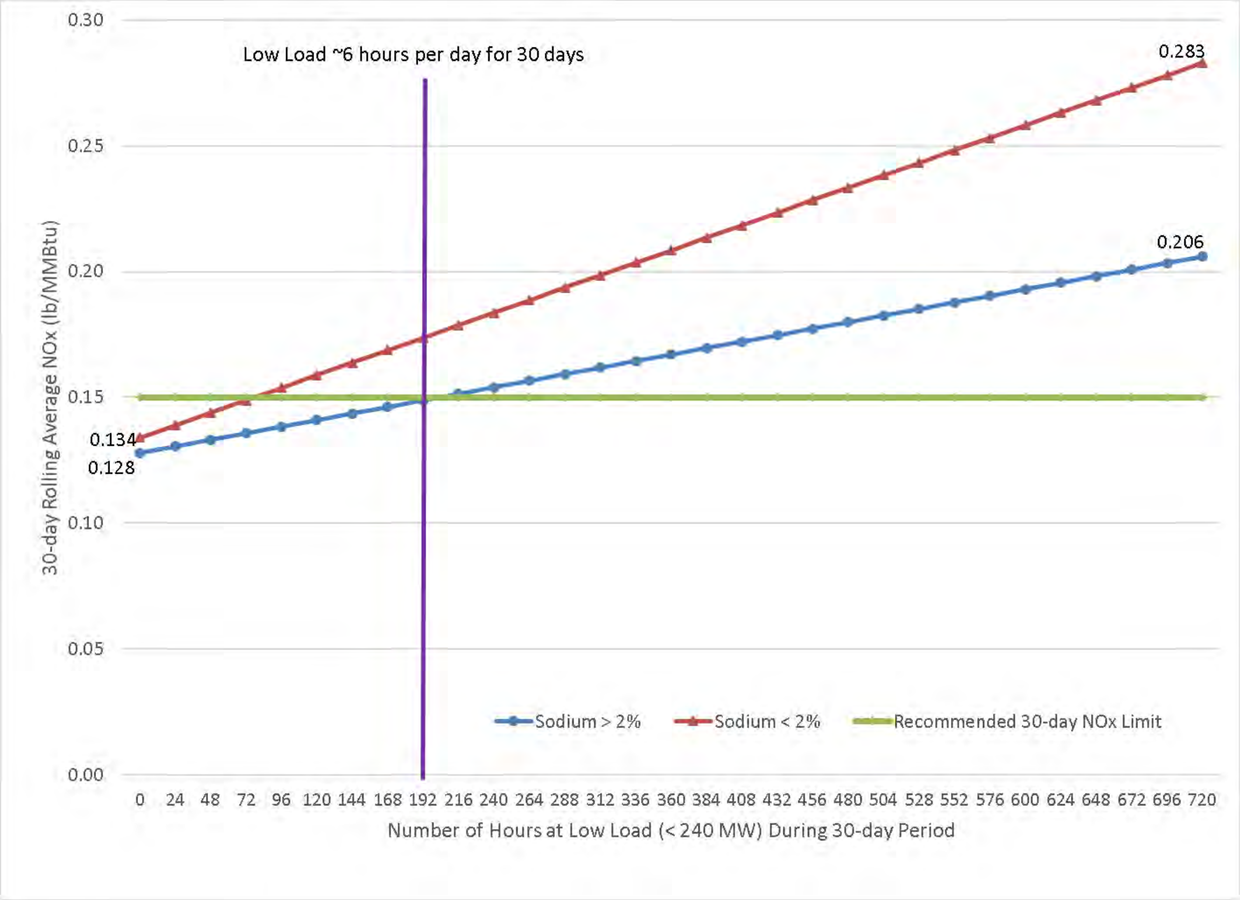

Figure 3-1: NOx Emissions as a Function of Operating Load and Lignite Sodium Variability

Attachments A through H-2

Coal Creek Station Units 1 and 2

Updated Best Available Retrofit Technology Analysis for NOx Emissions

Prepared for
Great River Energy

September 2019

Attachment A

Report “Best Available Retrofit Technology for NOx Emissions from Coal Creek Unit 2 - 2019 Update” September 4, 2019; Black & Veatch

BEST AVAILABLE RETROFIT TECHNOLOGY FOR NOx EMISSIONS FROM COAL CREEK UNIT 2

2019 Update

BLACK & VEATCH PROJECT NO. 400075
BLACK & VEATCH FILE NO. 400075.1000

PREPARED FOR

GREAT RIVER ENERGY

Great River Energy

4 SEPTEMBER 2019

BLACK & VEATCH

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1.0 Introduction & Executive Summary

Great River Energy (GRE) contracted with Black & Veatch to assess four factors of the five-factor BART analysis of NO_X reduction technologies for their Coal Creek Station's Unit 2 ("Coal Creek Unit 2").[1] This report describes the assessment and its results.

Coal Creek Station consists of two coal-fired electric generating units. Both boilers are tangentially-fired boilers manufactured by Combustion Engineering (CE, now a part of General Electric, or GE), and each unit produces about 605 MW (gross) of power. Coal Creek Station is a mine-mouth facility located near Underwood, North Dakota and burns lignite coal from the co-located Falkirk Mine. The facility's annual capacity factor is 87% based on a 10-year average, which includes planned outages. Unit 2 has a nominal rating of 605 MW, and it currently emits 0.13 lb/MMBtu of NO_X as an annual average. The first generation of separated over-fired air registers were installed on Unit 2 in 1998. In 2007, GRE expanded the over-fired air registers on Unit 2 to be low NO_X level 3 ("LNC3," referring to the combination of closed coupled overfired air, separated overfired air, and low NO_X burners). In addition to LNC3, GRE installed and began operating its novel multi-pollutant reduction technology, "DryFining™" in 2010.[2] Together, the enlarged overfire air registers and DryFining™ technology are combined as "LNC3+" for NO_X reductions.

Black & Veatch is an international engineering firm with vast experience within the power industry. Starting with scrubber designs in the 1960s, Black & Veatch has been involved with 87 air quality control (AQC) projects, with 17 of those related to NO_X control technologies. This includes three NO_X controls-related installations in last five years. Black & Veatch's role on these projects has varied from full engineering, procurement, and construction (EPC) to owner's engineer (OE). Black & Veatch has also provided many engineering services to power clients, including permitting support, risk analyses, and developing BART reports. Since 2006, Black & Veatch has helped numerous clients with fifteen BART analyses, and this does not include many more efforts related to requirements for Maximum Achievable Control Technology (MACT) and Lowest Achievable Emission Rate (LAER).

This report addresses four of the five BART factors: (1) costs of compliance, (2) certain energy and non-air quality environmental impacts of compliance,[3] (3) pollution control equipment in use or in existence at the source, and (4) the remaining useful life of the source. 42 U.S.C. § 7491(g)(2). The fifth BART factor, the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology, *see id.*, will be addressed in a separate report. Black & Veatch identified a number of technologies for NOx control at Coal Creek Unit 2. A number of these technologies were not carried forward for further analysis because they were not expected to provide substantial NO_X reductions, were not commercially available, or specific circumstances

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[1] A BART analysis for NOx controls at Unit 1 is contained in a separate report.

[2] As EPA has explained, DryFining™ is an innovative technology developed by GRE that reduces moisture and refines lignite coal, increasing the efficiency and performance of the fuel while reducing emissions. 83 Fed. Reg. 18248, 18251 (Apr. 26, 2018).

[3] The impacts to GRE's fly ash reuse program are addressed in a separate report.

preclude their application to Coal Creek Station. Black & Veatch ultimately analyzed selective noncatalytic reduction (SNCR) (with and without multi-level nozzle (MNL) enhancements) and selective catalytic reduction (SCR). SCR was determined to be likely infeasible, but it was analyzed to provide a conservative approach to this report.

Table 1-1 summarizes the cost estimates for the analyzed technologies, which show that none of the technologies are cost-effective. The prior North Dakota BART SIP considered cost effectiveness above $3,650/ton to be excessive, which was adjusted for inflation to $4,100/ton in the 2011/2012 NO_X BART determination.[4] If adjusted to 2018 dollars using the Chemical Engineering Plant Cost Index, this value is $4,630/ton. The assessed technologies are well above this threshold. In fact, the cost-effectiveness values of the technologies far exceed the values that other states and EPA have determined to be unreasonable in other BART determinations.

Table 1-1 Technology Cost Estimates

TECHNOLOGY	TOTAL CAPITAL INVESTMENT	TOTAL ANNUAL COST ($/YR)	EFFECTIVENESS ($/TON NO_X)	INCREMENTAL COST ($/TON)
SCR	$190,920,000	$17,590,000	$8,737[5]	$8,652
SNCR w/ MNL	$16,570,000	$5,970,000	$8,899	$4,764
SNCR	$12,740,000	$4,860,000	$11,145	NA

These cost-effectiveness values, along with the other three BART factors addressed in this report (energy and non-air quality environmental impacts, existing controls, and remaining useful life), indicate that none of the considered control technologies are likely to constitute BART.

1.1 REPORT APPROACH

This report follows the methodologies laid out in EPA's BART Guidelines, 40 CFR Part 51, Appendix Y. As described in the BART Guidelines, the first step of the BART analysis is to identify all available retrofit control technologies. These are defined as control technologies with "a practical potential for application to the emission unit." The second step is to eliminate technically infeasible options. A technology must be commercially available and demonstrated at sources under similar operating conditions to be considered technically feasible. The definition of technically feasible is considered the same as an "applicable" technology, per 40 CFR Part 51, Appendix Y. Per this definition, an applicable technology must be commercially available (i.e. it has

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[4] Supporting Material, *North Dakota Supplemental NOx BART Determination for Coal Creek Station Supplement No. 2 to SIP for Regional Haze* at App. B.2.1, page 16 (Jan. 2, 2013), Docket ID EPA-R08-OAR-2010-0406-0428 (September 2012 Supplemental Evaluation of NOx BART Determination for CCS 1 and 2).

[5] The cost-effectiveness value SCR reflects a best-case scenario emission rate of 0.04 lb/MMBtu. For reasons discussed in Section 3.1, the achievable emission rate for Coal Creek Unit 2 is more likely in the range of 0.06-0.08 lb/MMBtu, which would result in even higher cost-effectiveness calculations.

sufficient pilot scale and existing commercial demonstrations to be installed at the facility of interest) and "reasonably be installed and operated on the source type under consideration." The third step is the evaluation of the controls' effectiveness, and the fourth step evaluates the impacts (i.e., costs, energy impacts, non-air quality environmental impacts, and remaining useful life) of the remaining control technologies.

This report assesses control costs using two separate methodologies, both of which are consistent with the BART Guidelines and the guidance in EPA's Air Pollution Control Cost Manual (mentioned from hereon as the Cost Manual). First, this report utilizes EPA's Cost Manual Excel spreadsheets to calculate the costs of SCR and SNCR. Second, this report also uses, where possible, costs from site-specific vendor quotes and costs based on recent Black & Veatch SCR and SNCR reference projects to provide a more accurate site-specific assessment of these technologies for Coal Creek Unit 2. The reference project costs used in this study come from very recent projects (within 5 years) of similar size (within 150 MW), in similar climates (e.g. severe winters). The line item costs from these projects were compared to the line item requirements for the assessed controls for Coal Creek Unit 2 and were adjusted as necessary (both upward and downward) to account for differences between the projects. As with the vendor quotes, the resulting line item cost estimates are tailored to Unit 2.

Both the BART Guidelines and the Cost Manual explicitly authorize the use of site-specific costs. The BART Guidelines instruct that "[t]he cost analysis should also take into account any site-specific design or other conditions . . . that affect the cost of a particular BART technology option." 40 CFR Part 50, Appendix Y. Information for this site-specific assessment can come from "additional information" outside the Cost Manual, including information supplied by vendors that affects assumptions regarding purchased equipment costs, equipment life, replacement of major components, or any other element. *See id.*, n.15. As the Cost Manual notes, site-specific vendor quotes are *significantly* more accurate than the "study" estimate provided by the Cost Manual methodology.[6]

EPA has recognized the greater accuracy of site-specific cost estimates in its Regional Haze actions in other Region 8 states. In its partial Federal Implementation Plan (FIP) for Wyoming covering Basin Electric's Laramie River Unit 1, EPA revised its cost analysis to incorporate site-specific cost estimates provided by Basin Electric, explaining, "Per EPA's Control Cost Manual (CCM), use of site specific cost estimates is preferable to the use of generalized costs where those site specific costs can be supported and are appropriate."[7] Similarly, in its partial FIP for Utah addressing Hunter Unit 1, EPA accepted both the catalyst volume and SCR design suggested by

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[6] Cost Manual, Introduction, Chapter 2, Cost Estimation: Concepts and Methodology, at 6-7.

[7] *Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze*, 79 Fed. Reg. 5032, 5039 (Jan. 30, 2014).

Sargent & Lundy for its BART determination.[8] EPA "acknowledge[d] that States (and EPA in promulgating a FIP) may deviate from the Control Cost Manual provided their analysis is reasonable and the deviations are documented…. Under the BART Guidelines, as explained above, we have the discretion to deviate (or not) from the CCM, so long as our analysis is reasonable and deviations are documented."[9] EPA concluded that it "properly [took] into account additional (i.e. outside the CCM) information when it is warranted to use it in our cost estimates, and rejected additional information when it was not warranted to use it in our cost estimates."[10]

1.2 CURRENT CONDITIONS AT COAL CREEK

A major limitation to controlling NO_X is the load variability at Coal Creek Station. Historically, Coal Creek Station has been base-loaded with very infrequent load reductions over 30-day rolling periods. As more renewable resources have become available throughout the upper Midwest, Coal Creek increasingly has been required to reduce load or to vary load in response to these intermittent renewable resources. Coal Creek Station's units are designed as base load units but are expected to respond more frequently to the transforming mix of renewable generation in MISO.

Coal Creek Unit 2 emitted ∽0.13 lb/MMBtu of NO_X as an annual average in 2017 and 2018, with occasional dips down to 0.12 lb/MMBtu as a 24-hour value during optimal conditions and increases to 0.17 lb/MMBtu in poor conditions. Due to coal sodium and load variability, these emission rates can increase. They are lower than what is commonly observed from other coal-fired electric generating units (EGUs) and indicate that Coal Creek Unit 2 has gone through extensive tuning procedures to optimize the combustion process. In a study performed by Alstom Power (now GE)[11] in 2015 to comply with the NESHAPs MATS rule, the boiler was found to be well tuned with limited adjustments possible for improving the emissions.

The baseline emission rate of 0.13 lb/MMBtu on an annual average was used for this report's evaluation of control technologies. Combustion calculations were done using EPRI's Vista model. Coal information used for the combustion calculations and as part of design considerations/modeling, can be found in Appendix A.

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[8] *Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze*, 81 Fed. Reg. 43894, 43917 (July 5, 2016).

[9] EPA, *Response to Comments for the Federal Register Notice for Air Quality State Implementation Plans; Approvals and Promulgations: Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Partial Approval and Partial Disapproval*, at 269. EPA Docket ID EPA-R08-OAR-2015-0463-0208.

[10] *Id.*

[11] See Appendix H.

2.0 Initial Technology Screening

There are many available methods to control NO_X emissions but some are not applicable to Coal Creek Station due to their lack of operational experience on units of similar size or operating on similar fuels. It is therefore important to narrow down the list of NO_X control technologies from those that are commercially available to those that are truly applicable for a retrofit installation at Coal Creek Station. Coal Creek Unit 2's baseline of 0.13 lb NO_X/MMBtu, as an annual average, is below the presumptive BART limit of 0.17 lb/MMBtu.[12] Any NO_X reductions must be considered within the context of Coal Creek Unit 2's already low emissions. Some technologies may generally claim NO_X reductions over 40 percent, but these reductions are achieved only when the starting NO_X emissions are much higher than Coal Creek Unit 2's. When the baseline NO_X emissions are low, NO_X removal is more difficult, and reduction capabilities of the technologies will be less. This is important, because a site-specific design is required to fully assess reduction capabilities given the low NO_X baseline. Standard methods based on industry-wide, average data will lead to inaccurate inputs and conclusions. Steps 1 and 2 of the assessment delve deeper into this issue.

2.1 STEP 1 – IDENTIFY NO_X CONTROL TECHNOLOGIES

There are two approaches to achieve a reduction in NO_X emissions: combustion control and post-combustion control. Combustion control methods seek to suppress NO_X formation during the combustion process by controlling the flame temperature and fuel/oxygen ratio. These methods include low NO_X burners (LNBs), overfire air (OFA), and neural network combustion optimization systems. Post-combustion controls use chemical reactions with a reagent to remove NO_X from the flue gas, such as selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) systems. SNCR and SCR use either urea or ammonia as a reagent, with the SCR also utilizing catalyst (often multiple layers) to promote the chemical reactions with NO_X.

The first step of a BART analysis is to identify all available retrofit control technologies that potentially could be applied to the facility. NO_X control technologies that were identified as available for retrofit at Coal Creek Station are listed below with a short summary of each technology in the following sub-sections. The listed control technologies meet a minimum level of proven capabilities (e.g., the technologies have been implemented on coal-fired facilities, not just bench and pilot tests). While there may be additional technologies not covered here, their lack of demonstrated performance precludes them from evaluation in this study.

A summary of all identified NO_X control technologies that meet a minimum amount of proven capabilities is provided in Table 2-1.

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[12] 40 CFR Part 51, Appendix Y, Section IV.E.5 (Table 1).

Table 2-1 Overview of NO_X Control Technologies' Initial Screening

TECHNOLOGY	REF SECTION	DESCRIPTION
ECOTUBE	2.2.1	Retractable lances inject air at a high velocity into the furnace above the primary burner zone.
Flue Gas Recirculation (IFGR or FGR)	2.2.2	A portion of the flue gas is extracted downstream of the economizer and re-injected at or near the burner combustion zone or within the existing combustion air ductwork. This location allows for a reduction in excess combustion air, which contributes more nitrogen that can form NO_X. Recirculated flue gas can also lower NO_X formation by lengthening the flame, which reduces maximum flame combustion temperature. This reduction in flame temperature reduces NO_X formation, because NO_X formation is increased at elevated temperatures.
Low NO_X Burners (LNB)	2.2.3	Replace existing LNBs with the most technologically advanced LNBs on the market.
LoTOx	2.2.4	Injection of ozone to react with NO_X to form N_2O_5, which is captured by a downstream WFGD.
Natural Gas Reburn	2.2.5	Provide a row of natural gas burners above the primary combustion zone in the furnace to complete combustion, creating CO_2 with oxygen from the NO_X molecules, reducing NO_X back to elemental N_2 and O_2.
Neural Networks	2.2.6	Optimizing computer controls to maximize NO_X reductions.
NOxStar™ and NOxStar Plus™	2.2.7	Ammonia and a hydrocarbon (natural gas) is injected into the flue gas when 1,600 – 1,800° F. The ammonia reduces NO_X and the hydrocarbon reacts with ammonia slip, allowing higher ammonia injection rates.
Overfire Air	2.2.8	Works by reducing the excess air in the primary combustion (burner) zone, which enhances the combustion staging effect and further reduces NO_X emissions. Any residual unburned fuel, such as CO and unburned carbon that escapes the main burner zone, is subsequently oxidized as the OFA is introduced.
Regenerative Selective Catalytic Reduction (RSCR)	2.2.9	Ammonia is injected into the flue gas stream downstream of all air quality control equipment, with a thermal oxidizer and duct burner providing the necessary heat input to allow the catalyst to promote NO_X reduction by ammonia.
ROFA & ROTAMIX	2.2.10	OFA and SNCR combination using a rotating air system to maximize effectiveness.
Selective Catalytic Reduction (SCR)	2.2.11	Ammonia is injected into the flue gas stream upstream of a catalyst, which helps the ammonia reduce NO_X into nitrogen and water. The catalyst is housed in a reactor in the ductwork, usually between the economizer and air heater.

TECHNOLOGY	REF SECTION	DESCRIPTION
Selective Non-Catalytic Reduction (SNCR)	2.2.12	The process involves injecting a urea (H2N - CO - NH2) solution at multiple levels in the boiler, where the flue gas temperature ranges from 800 to 1100 °C (1500 to 2000 °F). The urea solution is pumped to the boiler and atomized with compressed air at the injection nozzles.
SNCR/SCR Hybrid	2.2.13	SNCR is used to reduce NO_X from the furnace, and high ammonia slip is used by a single layer of catalyst to further reduce NO_X.

2.2 STEP 2 – ELIMINATE INFEASIBLE NO_X CONTROL OPTIONS

The second step is to eliminate technically infeasible control technologies. This requires determining whether "technical difficulties would preclude the successful use of the control option on the emissions unit under review" based on physical, chemical, or engineering principles. 40 CFR Part 51, Appendix Y, Section IV.D.2.2. Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. *Id.* For a technology to be capable of being applied, it must be "available" and "applicable." A technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. *Id.* EPA does "not expect a source owner to conduct extended trials to learn how to apply a technology on a total new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as 'available' for purposes of BART review." *Id.*

The technologies identified in Table 2-1 are explained in greater detail in the subsequent sections. As a result of the analysis in this step, only the technologies that are expected to provide the highest NO_X reductions and are considered technically feasible at Coal Creek Unit 2 are carried forward for further evaluation; technologies with nominal reductions or lack of demonstrations at units similar to Coal Creek Station are eliminated from consideration. Further, two technologies were carried forward despite one being determined to be technically infeasible and the other presenting significant concerns about feasibility, to be conservative in this report's approach. An overview of the determination to eliminate the technologies is provided in Table 2-2.

Table 2-2 Evaluation to Eliminate Control Options

TECHNOLOGY	BEST ACHIEVED EMISSIONS REDUCTION	EXPECTED EMISSIONS REDUCTION AT UNIT 2	PROVEN ON SIMILAR FACILITIES?	EVALUATION
ECOTUBE	30-90% (per ECOMB)	Not available due to lack of experience	No	Technology not carried forward per discussion in Section 2.2.1

TECHNOLOGY	BEST ACHIEVED EMISSIONS REDUCTION	EXPECTED EMISSIONS REDUCTION AT UNIT 2	PROVEN ON SIMILAR FACILITIES?	EVALUATION
Flue Gas Recirculation (IFGR or FGR)	Up to 40-60% depending on level of FGR	10-15%, depending on level of FGR	Yes	Technology not carried forward due to high maintenance costs seen on previous systems, along with limited space for installation.
Low NO_X Burners (LNB)	Up to 20%	0-5% (system already well tuned with LNBs)	Yes	Technology not carried forward due to currently installed burners being state of the art
LoTOx	30-95+% (per Linde)	Not available due to lack of experience, specifically at large units	No	Technology not carried forward per discussion in Section 2.2.4
Mobotec ROFA & ROTAMIX	Up to 75%	5-23%	No	ROFA is essentially the same as the existing Unit 2 (t-fired system with OFA); ROTAMIX essentially is an SNCR combined with the ROFA system so SNCR is carried forward.
Natural Gas Reburn	Up to 40-60% depending on baseline emissions	10-20%	No	Not carried forward because of lack of natural gas line, natural gas price volatility, limited experience at facilities of 600 MW, and minimal expected reductions at Coal Creek.
Neural Networks	Varied and nominal	0-5%	Yes	Not carried forward due to nominal NO_X reductions.
NOxStar™ and NOxStar Plus™	Up to 50%	Not available due to lack of experience	No	Not carried forward due to lack of natural gas line and pilot testing required.
Overfire Air	Up to 40-50%	Already installed	Yes	Currently installed with limited room for improvement
Regenerative Selective Catalytic Reduction (RSCR)	Up to 85%	69%	No	Not carried forward due to lack of experience at units larger than 100 MW
Selective Catalytic Reduction (SCR)	Up to 90%	69%	Yes	Considered for further evaluation, despite feasibility concerns.

TECHNOLOGY	BEST ACHIEVED EMISSIONS REDUCTION	EXPECTED EMISSIONS REDUCTION AT UNIT 2	PROVEN ON SIMILAR FACILITIES?	EVALUATION
Selective Non-Catalytic Reduction (SNCR)	Up to 50%	15-23%	Yes	Considered for further evaluation.
SNCR/SCR Hybrid	Up to 50-60%	33%	Yes	Not carried forward due to technical infeasibility.

2.2.1 ECOTUBE

The ECOTUBE System, by ECOMB, is a boiler combustion improvement and NO_X reduction technology. Retractable lance tubes that penetrate the boiler above the primary burner zone inject high-velocity air as well as reagents. The lance tubes work to create turbulent airflow and to increase the residence time for the air/fuel mixture. In principle, the OFA (see Section 2.2.8) and SNCR (see Section 2.1.12) control strategies are combined in this technology.

The water-cooled ECOTUBEs are automatically retracted from the boiler on a regular basis and cleaned to remove layers of soot and other depositions. Additional benefits in terms of furnace combustion are increases in efficiency and reduced fuel usage and corrosion and erosion in the boiler and backend equipment. However, there are no existing installations on boilers of similar type or size as Coal Creek Station. Currently the largest installation is on two 270 MW coal-fired units in France while most of the installations are well under 100 MW and typically at municipal waste or biomass facilities. Scaling the technology up in size from the current largest installation to the size necessary at Coal Creek Station would present risk due to the need for significant technology development and design modifications and would make the system a first-of-its-kind for this size of unit and operation on this type of fuel. Even if ECOTUBE had more apt experience on a unit like Coal Creek Station, the technology combines two technologies that are also evaluated in this report: OFA (which is already installed at Coal Creek Station) and SNCR. For these reasons, ECOTUBE will not be carried forward in this study.

2.2.2 Flue Gas Recirculation

Injection of flue gas into the combustion air, known as Flue Gas Recirculation (FGR), is a proven method for controlling NO_X production from gas-fired utility boilers.

FGR acts to reduce NO_X formation by reducing peak flame temperatures. In conventional applications, the recirculated flue gas is typically extracted from the boiler outlet duct upstream of the air heater. The flue gas is then returned through a separate duct and hot gas fan to the combustion air duct that feeds the windbox. The recirculated flue gas is mixed with the combustion air via air foils or other mixing devices in the duct. At Coal Creek Station this technology would require installation of a separate hot gas fan to move flue gas from the boiler exit to the air supply ducting at the windbox inlet, where mixing of the air and flue gas must be uniformly achieved by installation of appropriate mixing devices. However, experience has shown that this type of installation requires heavy maintenance due to the particulates in the flue gas eroding equipment as would be present with Falkirk Mine's lignite ash content. It is possible to take flue gas downstream of the particulate control device, but this would require more ductwork, requiring space that is limited around the Coal Creek Station boilers. Furthermore, FGR systems can cause maintenance problems that have led utilities to decommission their FGR systems. For these reasons, FGR will not be carried forward in this study.

2.2.3 Low NO_X Burners

All low NO_X burners (LNB) offered commercially for application to coal-fired boilers control the formation and emission of NO_X through some form of staged combustion. The basic NO_X reduction principles for LNBs are to control and balance the fuel and airflow to each burner, and to control the amount and position of secondary air in the burner zone so that fuel devolatization and high temperature zones are not oxygen rich. In this process, the mixing of the fuel and the air by the burner is controlled in such a way that ignition and initial combustion of the coal takes place under oxygen deficient conditions, while the mixing of a portion of the combustion air is delayed along the length of the flame.

The objective of this process is to drive the fuel-bound nitrogen out of the coal as quickly as possible, under conditions where no oxygen is present, where it will be forced to form molecular nitrogen, rather than be oxidized to NO_X. Any nitrogen escaping the initial fuel-rich region has a greater opportunity to be converted to NO_X as the combustion process is completed. The net result of staged combustion is usually longer and/or wider flames, due to this delayed mixing process. This is also one of the main reasons why low NO_X combustion is normally associated with the potential for increased carbon in ash and higher CO emissions, as the combustion process begins to encroach on cooled boiler surfaces.

Coal Creek Unit 2 currently uses LNBs. Any additional NO_X reductions that could be achieved by changing burners would vary significantly by burner, as this largely depends on the age and type of LNB. Every major outage, the LNBs are inspected and refurbished, so only nominal upgrades to the existing LNBs are available. Since the Coal Creek Station units are operating at a low NO_X emission rate, substantial reductions in NO_X emissions are not expected from either refurbishing or installing new LNBs, so they will not be carried forward in this study.

2.2.4 LoTOX

The LoTOx technology is the low temperature gas-phase oxidation of NO_X by ozone injection. In this method, ozone is injected into the flue gas upstream of a wet flue gas desulfurization (WFGD) system. The ozone reacts with the NO and NO_2 to form nitrogen pentoxide (N_2O_5). The nitrogen pentoxide formed is soluble in water and can be removed from the flue gas using the WFGD system. The nitrate production (gypsum wash water) from this technology is captured in the FGD waste product. Most regulatory agencies are very strict about nitrate release into water systems, so Coal Creek Station's evaporation pond would need to be evaluated for potential changes to their chemistry. LoTOx also consumes significant amounts of power, resulting from the multiple ozone generators required to produce the ozone for the process. The power consumption is expected to be comparable to what is needed for a conventional FGD system, which is significantly higher than the power consumption from an SCR.

The LoTOx technology offers high NO_X removal efficiency with a reported potential of 15 to 25 percent savings in capital cost over an SCR with no ammonia slip at small, non-EGU facilities. LoTOx has no commercial installations on coal-fired power plants according to AECOM, the exclusive licensee of the technology. There were some studies of LoTOx on coal-fired power plants in the early parts of the century, but some form of pilot testing would be mandatory before even a cost estimate could be provided for installing LoTOx at Coal Creek Station. Although LoTOx is technically commercially available through AECOM, it will not be carried forward in this study due to its lack of demonstrated performance.

2.2.5 Natural Gas Reburn

The natural gas reburning process employs three separate combustion zones to reduce NO_X emissions. The first zone consists of the normal combustion zone in the lower furnace, which is formed by the existing burners. In this zone, 75 to 80 percent of the total fuel heat input is introduced. The first zone burners are operated with about 10 percent excess air (a 1:10 stoichiometric ratio). A second combustion zone (the reburn zone) is created above the lower furnace by operating a row of conventional natural gas burners at a stoichiometric ratio less than 1.0. This technology also has the potential for increased furnace corrosion (especially with higher sulfur fuels) due to the reducing atmosphere in the lower furnace.

The substoichiometric reburn zone causes NO_X produced in the lower furnace to be reduced to molecular nitrogen and oxygen, because the oxygen stripped from the NO_X molecules is combined with the more active carbon monoxide molecules to form carbon dioxide as combustion is completed in the upper furnace. Fuel burnout is completed in the third zone (the burnout zone) by the introduction of OFA. Sufficient OFA is introduced to complete combustion of the unburned materials in the upper furnace with an overall excess air rate for the boiler of 15 to 20 percent. Reburn technology has demonstrated NO_X reduction of 40 to 65 percent. However, at Coal Creek Station, this is expected to be much less and more on the order of 10 to 20 percent due to the low NO_X baseline.

Sufficient residence time (adequate furnace height) in the reburn and OFA zones is a key factor in determining whether the reburning technology can be applied. Successful retrofit of this technology requires space within the boiler to allow adequate residence time for both the additional burning zone (0.4 to 0.6 second) and the associated OFA burnout zone (0.6 to 0.9 second). When this space is available, reburning can be highly effective, but a low residence time will limit system performance.

Natural gas reburn was part of multiple pilot test programs in the 1990s, and while this led to some permanent installations, many have since been decommissioned or are not operating while still installed. Currently, natural gas reburn installations are scarce, and finding recent performance information about natural gas reburn is difficult, particularly for facilities comparable in size to Coal Creek Station. In Black & Veatch's discussions with other clients over the last several years regarding NO_X controls, natural gas reburn has consistently been averted due to multiple reasons. These include the lack of natural gas at the facility, the volatile price of natural gas, the general inexperience within industry with natural gas reburn, uncertainty on what type of performance could be expected, and expected adverse impacts to overall plant performance.

All of these concerns apply to Coal Creek Station and serve as justification for not carrying natural gas reburn forward as a viable technology. Additionally, GRE currently does not have a supply of natural gas at Coal Creek Station, so a new line would need to be built. As of March 2019, the industry average price for installing natural gas lines is $1-2 million/mile. There is a current natural gas line that runs parallel to Highway 83, approximately four miles away from the plant. This line would need to be expanded to accommodate delivery of natural gas sufficient for natural gas reburn. If the gas line along Highway 83 is not expanded, then the closest gas lines are currently in in Minot (66 miles away) and Bismarck (50 miles away).

Furthermore, concrete evidence is not readily available that natural gas reburn can reduce NO_X emissions by sufficient amounts at a unit the size of Coal Creek Station, especially with its low starting baseline emissions. While natural gas reburn has shown NO_X reductions in excess of 40 percent, the performance is expected to exponentially decline as starting baseline emissions are lowered to the baseline emissions of Coal Creek Station. Overall plant performance will also suffer from installing natural gas reburn, because natural gas burns at lower temperatures than coal, though it is difficult to quantify the decrease in plant efficiency without more data. The lack of industry experience and uncertainties with natural gas reburn disqualifies this technology from further evaluation.

2.2.6 Neural Network Systems

Recent advances in computer hardware and software technology have enabled some power generation facilities to improve their competitive position by implementing cost-effective optimization solutions. This solution, commonly referred to as "boiler optimization" or "neural network systems," provides simultaneous improvements in both plant efficiency and emissions. Neural network computing differs from traditional computing in that engineering, statistical, and first-law principles have been replaced by complex, time varying, nonlinear relationships. Neural network systems use real-time operational data extracted from a plant Distributed Control System (DCS), to "learn" solutions from plant operational experience, and improve plant performance by continuously adapting to changes in plant operation.

Neural network systems also supplement other NO_X reduction strategies. Some of these include LNB, OFA and post-combustion controls such as SCR and SNCR. These systems are also used to help boiler manufacturers tune boilers with poor combustion characteristics, or after an LNB retrofit or other boiler modifications, such as OFA.

The amount of reduction in NO_X emissions from neural networks is highly dependent on the facility's current operations, as units operating further away from their optimal efficiencies will benefit the most from neural networks. With respect to Coal Creek Station, Unit 2 already has achieved a low NO_X emission rate. As mentioned, Alstom Power (now GE) conducted a study on Unit 2 as part of MATS NO_X/CO optimization, and they concluded that Coal Creek Unit 2 was well tuned. In comparison to other NOx emission control technologies, neural networks are capable of achieving only minor reductions.

Coal Creek Station has experimented with a few forms of intelligent controls in the past (intelligent soot-blowers and coal-flow algorithm models), both of which did not work and have been since decommissioned in favor of their operators' ability to effectively control the unit. Space is also limited for installing any potential drives for the burners due to the existing layout of the burners in the unit, several of which are nearly adjacent, restricting the scope of a neural network. Considering that neural networks would have a limited, if any, impact on NO_X emissions at Coal Creek Unit 2, and because there is limited physical space for additional installations, they will not be carried forward in this study for Coal Creek Station.

2.2.7 NOXStar™ and NOXStar Plus™

NOXStar™ is the trademarked name for a NO_X control technology that involves the injection of ammonia and a hydrocarbon (typically natural gas) into the flue gas path of a coal-fired boiler at around 1,600 - 1,800° F. The ammonia reduces NO_X through a selective non-catalytic reduction (SNCR) reaction, with the hydrocarbon minimizing the ammonia slip. This enables higher reagent injection rates for NO_X reductions than achievable with a typical SNCR technology.

NOXStar™ eliminates the need for (1) installation of a catalyst reactor and the associated capital costs, (2) economizer modifications, and (3) major outages. By not requiring a catalyst layer the associated problems of chemical poisoning, physical plugging, and sintering due to temperature excursions, pressure drop requiring new ID fans, and disposal of a hazardous solid waste are avoided. The other advantage of the NOXStar™ system is that the conversion of SO_2 to SO_3 is said to be negligible, thus eliminating one of the main drawbacks of the SCR technology.

For installations where the NOx reduction requirements are greater than can be achieved with NOXStar™, the NOXStar™ Plus system incorporates a single layer of in-duct catalyst into the system. This arrangement is similar to a hybrid SCR/SNCR system with the addition of the hydrocarbon injection to minimize ammonia slip.

The major consideration for the NOXStar™ technology is that it currently has only one major installation in the US on a coal fired unit and may require the installation of a single layer of in-duct catalyst (NOXStar™ Plus) to achieve advertised levels of NO_X reduction. Injecting reagent with lower catalyst volumes resembles an SNCR/SCR hybrid (ASCR), and, as described later, is a technology evaluated later in this report. Extensive research was done in an attempt to obtain more information on these systems, but an organization representing NOXStar™ in the US has not been identified. Similarly, no performance information has been obtained. In addition, there is currently no supply of supplemental natural gas at the existing plant site.

Information and reports from the original equipment manufacturer (OEM) state that up to 50 percent reduction has been shown with NOXStar™. However, research has been unable to validate these results from any other sources. Therefore, pilot testing would be required to determine what level of NO_X reductions could be achieved at Coal Creek Station. It is expected that due to Coal Creek Station's low baseline emissions, significantly fewer NO_X reductions would be achieved with this technology. Given that pilot testing is needed, NOXStar™ and NOXStar™ Plus will not be carried forward as part of this study for Coal Creek Station.

2.2.8 Overfire Air (OFA) System

OFA works by reducing the excess air in the burner zone, thereby enhancing the combustion staging effect and further reducing NO_X emissions. Any residual unburned material, such as CO and unburned carbon, which inevitably escapes the main burner zone, is subsequently oxidized as the OFA is added.

The performance that can be expected from a given OFA system depends upon a number of factors. As the amount of OFA is increased, the stoichiometry in the burner zone decreases and a point is reached at which CO emissions reach high levels and become uncontrollable. The point at which this occurs can be boiler- and coal-type specific, particularly if a fuel is in anyway difficult to burn, and will also depend upon the extent to which it is possible to balance flows between the individual cyclones or burners. As the OFA amount approaches 10 to 15 percent, the probability for individual burners operating under overall fuel-rich conditions increases, such that pockets of very high CO emissions and unburned carbon will be formed. Similarly, fuel rich operation at burners close to the water walls can begin to lead to local slag formation and increased tube wastage rates, particularly if slagging is an ongoing problem and the coals have a high sulfur content. A fairly high level of unburned material leaving the burner zone can be accommodated by proper overfire port design, where requirements call for rapid and complete mixing of the OFA with the boiler flue gases.

Aggressively staging combustion to reduce NO_X emissions creates a reducing environment in the boiler and can damage the boiler water wall tubes. The reducing environment attacks the iron oxides in the tube metal and can lead to pin holes in the boiler tubes. This phenomenon is referred to as tube wastage. Poor staging in the boiler could lead to tube wastage resulting in an increase in the amount of maintenance and in the worst-case scenario may require a forced outage to repair the tubes.

OFA already exists at Coal Creek Unit 2. Increased circumferential cracking was experienced when the LNC3+ technology was first operated. Adjustments in the flame location and staging of the air in the furnace have reduced excessive circumferential cracking to a certain extent but have not completely eliminated the phenomenon. Operation of an OFA requires an extensive level of tube repairs in the reduction zone during each major outage. Operators are now better at managing the LNC3+ for low NOx operations while minimizing slagging and circumferential cracking during baseload operation. As noted elsewhere in this report, coal sodium and load variability can exacerbate slagging and circumferential cracking due to changes in flame location, affecting low NOx operation.

The expected increase in NO_X removal by optimizing the existing OFA ports is minimal, on the order of less than five (5) percent. Therefore, as a NO_X reduction technology, OFA will not be carried forward in this study for Coal Creek Station.

2.2.9 Regenerative Selective Catalytic Reduction (RSCR)

Babcock Power provides a variation of the typical SCR (see Section 2.2.11), installing the SCR at the tail end of the air quality control (AQC) train, prior to the chimney. Termed as Regenerative Selective Catalytic Reduction (RSCR), the tail end SCRs are typically more costly than high-dust SCR's, mainly because the flue gas needs to be reheated from the FGD exit temperature of approximately 140° F to at least 450° F, and tail end SCRs consume a larger footprint due to a larger SCR box and the heat exchanger. RSCR typically is used for biomass applications where the exhaust gas poisons are too great for a high-dust SCR catalyst.

First, the reagent is injected into the flue gas. The flue gas then passes through a regenerative thermal oxidizer (RTO), which is a large ceramic bed that can absorb and release heat into the flue gas. The flue gas is heated up by the RTO and then passes through the first layer of SCR catalyst. After that, the flue gas passes a duct burner, which provides more heat to the flue gas, and then through the second layer of catalyst. Finally, it passes through another RTO. This time, the flue gas is used to heat up the second RTO. Once the flue gas has used up all the heat in the first RTO, the cycle is reversed, and the second RTO is used as the heat source. This cycle repeats itself again and again, as long as NO_X control is required.

RSCRs generally have much less, if any, impact to the existing ductwork and boiler house structure, whereas the high dust arrangement would require many retrofit modifications. Fewer modifications result in shorter construction and tie-in schedules (e.g. 18-24 months from design to commercial operation of a high dust system, and less than 9 months for tail end). Additionally, less catalyst volume is needed for the tail end application, since the majority of the particulate and SO_2 (including the trace elements that poison the catalyst) have been removed. This also leads to longer catalyst life compared to high dust systems.

One major disadvantage of an RSCR system is an ammonia slip of ~3-4 ppm, which is higher than an SCR. Ammonia slip from an SCR is mostly removed by downstream FGD systems and particulate controls, but that is not the case with an RSCR system that is located immediately before the stack. Any ammonia slip will simply exit the stack as an emission. In addition to the ammonia slip, RSCRs achieve slightly less NO_X removal rates than SCRs (>93 percent for high dust SCR and >85 percent for tail end RSCR), depending on the NO_X baseline. For Coal Creek Station, the NO_X removal rate is expected to be well below 85%, given its low NOx baseline.

RSCRs have not been installed at coal-fired facilities of Coal Creek Station's size. Babcock Power, the leading vendor of the technology, would not provide a budgetary quote for this effort based on the vendor's determination that this is not a good application for an RSCR. The technology has been installed at many facilities, but the largest to date is only 54 MW. Babcock Power limits the applications to units 100 MW and smaller due to concerns about increasing the reactor sizes. Therefore, while RSCR could be capable of providing NO_X reductions for Coal Creek Station, it will not be carried forward due to an installation at Coal Creek Station being first of a kind for the technology and the unwillingness of the supplier to offer this technology for units of this size.

2.2.10 ROFA and ROTAMIX

AECOM provides a NO_X reduction system that combines LNBs, OFA, and SNCR technologies into an integrated system. The system uses a modified OFA system with mixing characteristics achieved through implementing a rotation to the OFA. This system is called ROFA™ - Rotating Opposed Firing Air. In addition, ROTAMIX™ can be added to the system, which consists of adding urea or ammonia injection into the ROFA™ air nozzles. The extra mixing produced by combining the overfire air nozzles with the reagent injection, results in improved mixing and a more homogeneous temperature profile in the boiler. These technologies were formerly provided by Mobotec but is now currently commercially available through AECOM.

ROFA is effectively a tangential fired boiler with OFA ports. Because Coal Creek Unit 2 is comprised of a tangential fired boiler, meaningful NO_X reductions are not expected from installing ROFA. Furthermore, ROTAMIX is essentially an SNCR with proprietary nozzles and injection system, and as explained later, SNCR is carried forward for further evaluation. Therefore, ROFA and ROTAMIX's benefit to Coal Creek Unit 2 are effectively captured elsewhere in this study. These specific technologies are not carried forward.

2.2.11 Selective Catalytic Reduction (SCR)

2.2.11.1 Technical Background on SCR

SCR systems are the most widely used post-combustion NO_X control technology for achieving significant reductions in NO_X emissions. In SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent. Some large utility boiler SCR installations have been able to lower NO_X emission to rates as low as 0.04 lb/MMBtu, but this is contingent on the unit's operating characteristics. Based on recent data from the Western Regional Air Partnership (WRAP) and EPA's Clean Air Markets Division (CAMD), SCRs on units of similar size as Coal Creek Unit 2 emit NO_X at a rate of 0.05 to 0.08 lb/MMBtu on an annual average.[13] As will be discussed further in Section 3.1, the vendor quote was based on an emission rate of 0.04 lb/MMBtu, although the emission rate at Coal Creek Unit 2 likely would be higher based on the experience of other similar units.

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[13] Based on information from http://www.wrapair2.org/EGU.aspx and https://ampd.epa.gov/ampd/.

NO_X and ammonia reagent react to form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.05 (on a NO_X reduction basis) with very low ammonia slip (unreacted ammonia emissions). A simplified schematic diagram of a typical SCR reactor is illustrated in Figure 2-1. However, most modern SCR systems are built without a bypass systems and sonic horns are used in place of steam or air sootblowers.

The SCR reactor is the housing for the catalyst. The reactor is basically a widened section of ductwork modified by the addition of gas flow distribution devices, catalyst, catalyst support structures, access doors, and soot blowers. An ammonia injection grid is located upstream of the SCR reactor. The SCR reactor is typically elevated above and behind the air heater, and gas flow direction through the reactor is vertically downward for coal fired applications. There are two types of SCR arrangements: “high-dust” and “low-dust.” In a high-dust SCR arrangement, the reactor is located between the outlet of the economizer and the inlet of the air heater. The high-dust system is typically the most economical and preferred arrangement where physically possible. A low-dust arrangement would locate the SCR after the particulate control device to remove most of the dust from the flue gas stream. This arrangement is preferred when the fly ash contains a high level of catalyst poisons (sodium, arsenic, etc.), and removing most of the fly ash from the flue gas will prolong the catalyst life. Additional discussion of low-dust SCR arrangements in relation to Coal Creek Unit 2 are provided in Appendix B. This report focuses on discussion of high-dust arrangements, as a low-dust arrangement would be even more expensive than a high-dust SCR. Because a high-dust arrangement is determined to be not cost-effective as discussed in Section 4.1.1.2, a low-dust arrangement would be even less cost-effective.

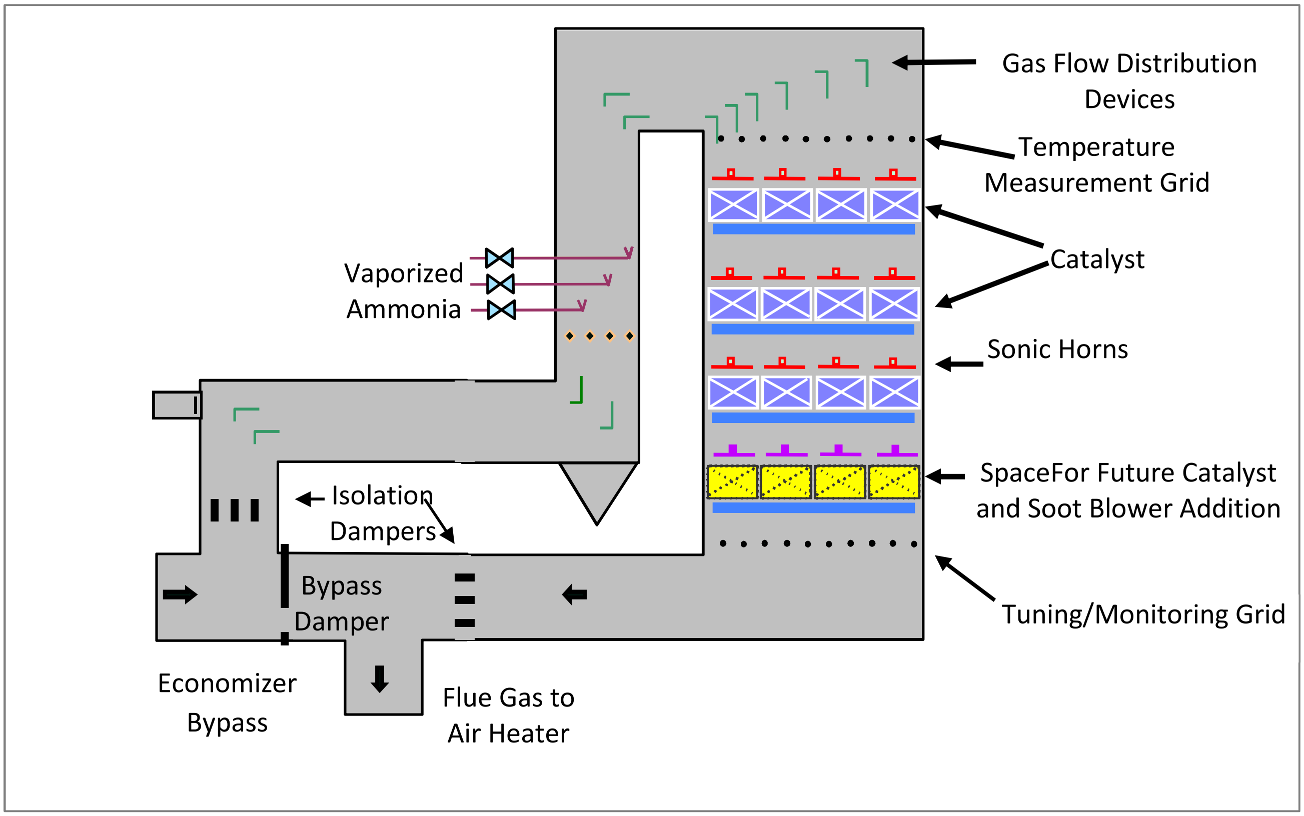

Figure 2-1 **Schematic Diagram of Typical SCR Reactor**

The ammonia reagent for the SCR systems can be supplied by anhydrous ammonia, aqueous ammonia, or by conversion of urea to ammonia. Since the ammonia is vaporized prior to contact with the catalyst, the selection of ammonia type does not influence the catalyst performance. However, the selection of ammonia type does affect all other subsystem components, including reagent storage, vaporization, injection control, and balance-of-plant requirements. Anhydrous ammonia was assumed for this report, as it is the least expensive and most commonly used reagent.

SCR systems have a variety of interfacing system requirements to support operations. These impacts predominately relate to draft, auxiliary power, soot blowing steam, gas temperature, controls, ductwork, reactor footprint, and air heater. Dependent on arrangement and performance requirements, draft losses can range from 4 to 10 in. w.g. This can be compensated with the addition of ID booster fans. As needed, ductwork, and/or boiler box reinforcement need to be considered. In conjunction with the fan modification, the upgrade of the auxiliary power system might be necessary, which might also be triggered by ammonia supply system requirements.

The major impact of the SCR system can be seen at the air heater where there are two primary areas of concern. One is the formation and deposition of ammonium bisulfate (ABS) on the air heater surface. This will cause an increase in the pressure drop of the air heater and reduced heat transfer, negatively affecting unit efficiency. The other potential danger for the air heater is high concentrations of SO_3 in the flue gas, which increase ahead of the air heater from SCR and SO_2

interactions. Acid gas dewpoint is a function of the acid concentrations (such as SO_3) in the flue gas, so the acid dew point of the flue gas increases after the SCR. This is an important consideration, because the flue gas temperatures significantly decrease after the air heater, potentially below the acid gas dewpoint. During low load operation and in the presence of air leakage, acid gases can condense in the air heater and lead to plugging and corrosion. Several measures can be taken to avoid or correct this situation. Most important is the right composition of the catalyst to minimize the SO_2 to SO_3 conversion rate. Another operational remedy is to change the boiler soot blowing program to shorter cycles. This will reduce the economizer outlet temperature and subsequently the conversion rate of SO_2 to SO_3 downstream of the SCR. Otherwise, modifications to the air heater and downstream equipment, or installation of an SO_3 mitigation system, is required to prevent corrosion.

2.2.11.2 Technical Feasibility of SCR

While SCR is an industry-proven NO_X reduction technology, it has not been proven on units burning North Dakota lignite. There are two primary technical challenges with SCR and North Dakota lignite: catalyst plugging and catalyst fouling. In fact, the North Dakota Department of Health (NDDH) determined in 2009 that high-dust SCRs are not technically feasible for units combusting North Dakota lignite due to these issues.[14] This determination was based heavily on the performance of a high-dust SCR pilot test at a lignite-fired boiler at Coyote Station.[15] There, plugging was observed at the catalyst inlet due to the high levels of alkalis, namely sodium (Na), in the fly ash, which can form alkali sulfates that deactivate catalyst and alkali oxides that physically blind catalyst surfaces.[16] Coal Creek Station would face similar challenges with the sodium content of its lignite coal. As shown in Appendix A, recent samples from the Falkirk Mine show a range of 0-14 percent sodium, approximately 27 percent of the samples are above four percent. While the fly ash analysis from GRE's coal has consistently been under four percent as an annual average, with the average Na_2O weight percent being just above two percent, short term sodium spikes can be expected, increasing the operational risk of SCR catalysts and LNC3+ as discussed in this report.

Given that nearly a decade has passed since the NDDH determination, Black & Veatch conducted additional investigations into the feasibility of SCR at the Coal Creek Station to assess any technological advancements. Black & Veatch contacted three catalyst vendors to provide preliminary guarantees as part of a budgetary quote based on an average coal sodium content of 4 percent. Even at a 4 percent sodium level, one vendor did not provide a budgetary quote. Two vendors provided quotes, one of which requested to remain anonymous.[17] IBIDEN Ceram was the only vendor to provide a formal quote for purposes of the cost analysis in this Report. Their

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[14] Best Available Retrofit Technology – Selective Catalytic Reduction, Technical Feasibility Analysis for North Dakota Lignite. Division of Air Quality, ND Department of Health. July/2009.

[15] *Id.*

[16] North Dakota RH SIP, Appendix C.2, Great River Energy, Coal Creek Stations, Units 1 and 2, BART Analysis, Revised December 12, 2007, Document ID EPA-R08-OAR-2010-0406-0006.

[17] Because this vendor requested to remain anonymous, its information cannot be relied upon for purposes of this analysis.

quotation and experience lists are included in Appendix E. IBIDEN Ceram considers the actual sodium range levels of North Dakota lignite (0-14 percent) to be potentially prohibitive and believes they cannot be addressed through catalyst pitch and design, without first performing a pilot test. Pitch refers to the width of the catalyst cell and the wall thickness, so catalysts with smaller pitches are more prone to experience plugging issues. The SCR catalyst used in the study at Coyote Station had a 6 mm pitch, but many current catalysts use a larger pitch. However, the upper end of the North Dakota lignite sodium content range is outside of Ceram's operating experience, and they expect that even a catalyst with a larger pitch would experience an impracticably high deactivation rate as a result of the sodium levels.[18] According to Ceram, because there is no direct experience in the industry with SCR catalyst installed on a unit firing ND lignite, it is difficult to determine with a high level of certainty what the long term impacts will be on the SCR catalyst. A pilot study would confirm the likely deactivation rate, and would require approximately 2,000 to 5,000 hours of operational data.

Ceram suggested that catalyst deactivation concerns could be addressed by the installation of the SCR in a tail-end arrangement (i.e., after all pollution control equipment). Tail-end SCRs, which are a type of low-dust SCR, are more expensive than high dust arrangements due to the need to reheat the flue gas prior to entering the SCR and the potential need to cool the flue gas prior to entering the stack. Flue gas exiting the scrubber is approximately 135° F; for the tail-end SCR to be effective the flue gas needs to be reheated to approximately 500° F. To provide this reheat, a natural gas line would need to be installed to Coal Creek. Additionally, the experience of tail-end SCR applications in the United States is minimal and is limited to small installations. Multiple manufacturers were approached for their experience list. Of these, only Babcock Power has installed tail-end SCR's in the United States, all of them at Oak Creek Power Station units ranging from 261 to 312 MW. Other manufacturers such as GE and Mitsubishi-Hitachi only have installations overseas at unit under 200 MW. Due to this lack of experience, and because the cost a tail-end SCR would be greater than the cost of a high dust SCR, only the high-dust SCR was carried forward for a cost analysis. See Appendix B for further explanation of the additional costs associated with low-dust SCRs, which would include tail-end SCRs.

The concerns about the impact of North Dakota lignite from the Falkirk Mine on the catalyst is shared by Fuel Tech, the vendor of the SCR/SNCR hybrid technology. Fuel Tech has concerns with catalyst erosion associated with the Falkirk Mine coal and would not provide any performance guarantees on the SCR portion of the hybrid technology, even if the sodium content could be guaranteed to remain below four percent, until more is known about the effects of North Dakota lignite ash on catalyst performance and deactivation. Like CERAM, Fuel Tech recommends that pilot scale testing be performed to obtain actual operational data to prove catalyst operation and performance.

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[18] A trace element analysis was conducted, and IBIDEN Ceram did not have any concerns with the other poisons' concentrations.

In light of NDDH's prior infeasibility determination, as well as the more recent information obtained by Black & Veatch, plugging and catalyst poisoning likely would render an SCR technically infeasible at Coal Creek Unit 2. Nevertheless, SCR is carried forward to Step 3 in order provide a conservative approach to this BART analysis.[19] In addition, because of the specific technical challenges associated with the installation of SCR at Coal Creek Station, it is critical that a site-specific design be considered when assessing costs.

2.2.12 Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR) systems reduce NO_X emissions by injecting a reagent at multiple levels in the steam generator as illustrated in Figure 2-2. SNCR systems rely solely on reagent injection rather than a catalyst. With respect to reagent injection, there are several critical variables: reagent injection temperature, reagent/gas mixing, and residence time for adequate reaction time to achieve NO_X reductions. SNCR systems can use either ammonia or urea as the reagent. On coal-fired power plants, urea is the predominant reagent of choice. NO_X reactions are delayed when using urea, because the urea must be converted to ammonia. This delay in reaction allows better reagent distribution in the boiler. Urea is injected above the burners and in the upper part of furnace, where the flue gas temperature ranges from 1,500 to 2,200° F. It is important to note that furnace temperatures of a pulverized coal fired boiler can range between 2,500 to 3,000° F. Therefore, the site-specific injection points are critical for maximizing NO_X reductions.

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[19] In addition to the concerns about coal sodium levels plugging and/or deactivating the catalyst, there is extremely limited installation space for an SCR. See Section 2.3.1 for further information.

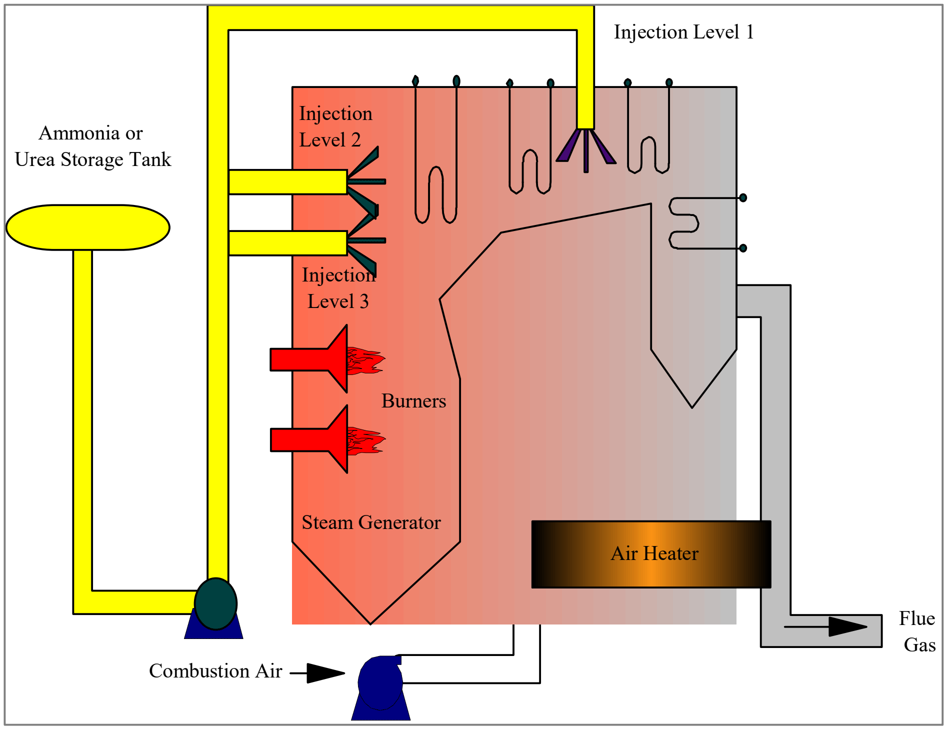

Figure 2-2 **Schematic of SNCR System with Multiple Injection Levels**

SNCR systems are capable of achieving NO_X emission reductions of 50 to 60 percent in optimum conditions (adequate reaction time, temperature, and reagent/ flue gas mixing, baseline NO_X over 0.35 lb/MMBtu, multiple levels of injectors) with ammonia slip levels ranging from 5 to 50 ppmvd. Lower ammonia slip values are achieved with lower NO_X reduction requirements. Typically, optimum conditions are difficult to consistently achieve, resulting in emission reduction levels of 20 to 40 percent over longer averaging periods. Potential performance is very site-specific and varies with fuel type, steam generator size, allowable ammonia slip, furnace CO concentrations, and steam generator heat transfer characteristics.

SNCR systems reduce NO_X emissions using the same reduction reaction mechanism as SCRs, but without a catalyst. Most of the undesirable chemical reactions occur when reagent is injected at temperatures above or below the optimum range. At best, these undesired reactions consume reagent with no reduction in NO_X emissions while. At worst, the oxidation of ammonia can generate more NO_X. Accordingly, NO_X reductions and overall reaction stoichiometry are very sensitive to the temperature of the flue gas at the reagent injection point. This is particularly complicated for SNCR applications on boilers larger than 100 MW.

Reagent injection lances are usually located between the boiler soot blowers in the pendent superheat section, and installation will require minor modifications to the water walls. Optimum injector location is mainly a function of temperature and residence time. To accommodate SNCR reaction temperature and boiler turndown requirements, multiple levels of injection lances are normally installed. A flue gas residence time of at least 0.3 second in the optimum temperature range is desired to assure adequate SNCR performance. Residence times in excess of 1 second yield high NO_X reduction levels even under less than ideal mixing conditions.

Computational Fluid Dynamics (CFD) and Chemical Kinetic Modeling (CKM) should be performed to establish the optimum ammonia injection locations and flow patterns for a specific boiler. The EPA Cost Manual Chapter 1, Section 1.2.5 states under Other Considerations under Computational Fluid Dynamics (CFD) and Chemical Kinetic Modeling (CKM), "Each boiler unit has a unique temperature and flow gradient with areas of high flow and stagnation. In addition, temperature and flow profiles vary according to the load capacity under which the boiler is operating. A mathematical model is developed to describe this stratification and variation of important species such as NO_X and SO_3 in the flow stream. To develop the model, the flue gas temperature and velocity within the boiler are measured at many locations. These measurements are used in a CFD model for the convective passes of the boiler. The model predicts the temperature and gas flow within the boiler for various operating conditions and injection scenarios."

There is limit to overall reductions achievable by SNCR. Per the Institute of Clean Air Companies (ICAC), "As temperature increases, the 'critical' or equilibrium NO_X concentration at a given oxygen concentration increases. At high enough temperatures, any reduction of NO_X to below the critical level by SNCR or other means will be counteracted by the rapid oxidation of nitrogen to re-form NO_X. For this reason, at sufficiently high temperatures and baseline NO_X levels below the critical concentration, injection of ammonia or urea into the flue gas will result in increased NO_X levels. If, however, the baseline NO_X concentration is above the critical level, NO_X reduction will result. For typical coal and oil-fired steam boilers, critical NO_X levels are 70-90 ppm (ca. 0.1 lb/MMBtu) in the upper furnace."[20]

Coal Creek Unit 2 operates at NO_X emissions near the critical point, as identified by the ICAC, of 0.1 lb/MMBtu. Even though minimal reductions are expected from an SNCR, it is still a well proven technology that can reduce Coal Creek Station's low NO_X emissions. Therefore, SNCR is determined to be feasible and is carried forward in this analysis.

2.2.13 SNCR/SCR Hybrid

The SNCR/SCR hybrid system uses components and operating characteristics of both SNCR and SCR systems. The result is a NO_X reduction alternative that is lower in capital cost than a full SCR but operating at a higher NO_X reduction than just an SNCR system.

The SNCR component of the hybrid system is identical to the SNCR system described previously, except that the hybrid system may have more levels of multiple lance nozzles for reagent injection. This will increase the capital cost of the SNCR component of the hybrid system. During operation, the SNCR system would be allowed to inject higher amounts of reagent into the flue gas. This increased reagent flow has a twofold effect: NO_X reduction within the boiler is

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[20] Institute of Clean Air Companies (ICAC). *Selective Non-Catalytic Reduction (SNCR) for controlling NOx Emissions*. February 2008

increased while ammonia slip also increases. The ammonia that slips from the SNCR is then used as the reagent for the catalyst.

There are two design philosophies for using this excess ammonia slip. The most conservative hybrid systems use the catalyst as an ammonia slip "scrubber" with some nominal NO_X reductions. As with in-duct systems, the flue gas velocity through the catalyst is an important factor in design. Operating ammonia in this mode allows maximum NO_X reduction within the boiler by the SNCR while minimizing the catalyst volume requirement. This results in a relatively cheaper overall installation, but without maximum NO_X reductions. The second philosophy uses a larger catalyst volume, albeit smaller than a full SCR, to obtain greater levels of additional NO_X reduction within the space constraints of the boiler. The additional reduction is a function of the quantity of ammonia slip, catalyst volume, and distribution of ammonia to NO_X within the flue gas.

Fuel Tech is the leading vendor of SNCR/SCR hybrid systems, termed ASCR®.[21] Fuel Tech has installed a hybrid on multiple coal-fired power plants, including one that is close in size to Coal Creek Station. Fuel Tech assessed Coal Creek Unit 2 and identified concerns with insufficient space available for an ASCR in the boiler building. Due to the existing DryFining™ and reheat systems, there is no room for installation of an ASCR. The system would be required to be installed outside the boiler house, which eliminates the benefits of an ASCR.

Fuel Tech also identified concerns with catalyst erosion associated with North Dakota lignite from the Falkirk Mine. Specifically, Fuel Tech states:

> In addition to the spatial limitations, FTEK has several process concerns regarding the sodium (Na) levels in the fuel/ash and sulfur trioxide (SO_3) levels in flue gas. SO_3 in the presence of ammonia (NH_3), in the form of ammonia slip, from the SCR process could lead to ammonium bisulfate plugging in the air heater. Additionally, the SO_3 concentration in the flue gas may convert the Na in the solid phase to a gaseous phase which may cause significant catalyst deactivation. For these reasons, FTEK would not recommend the deployment of the ASCR technology on CCS Unit 2. We would not be willing to provide any performance guarantees on the SCR portion at this time until more is known about the effects of North Dakota lignite ash on catalyst performance and deactivation. FTEK would recommend that pilot scale testing should be performed to obtain actual operational data and learn more about North Dakota lignite and prove catalyst operation and performance.[22]

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[21] Fuel Tech is a respected vendor of emission control technology for EGUs. In Region 8 alone, EPA has based final Regional Haze actions in part on data provided by Fuel Tech in Montana, 77 Fed. Reg. 57864, 57885 (Sept. 18, 2012) (relying on Fuel Tech control efficiency estimate); North Dakota, 77 Fed. Reg. 20894, 20897 (Apr. 6, 2012) (relying on SNCR capital costs derived from Fuel Tech budgetary proposal); Utah, 81 Fed. Reg. 43,894, 43,917 (July 5, 2016) (relying on subcontractor report that used Fuel Tech reagent and urea costs); and Wyoming, 79 Fed. Reg. 5032, 5144 (Jan. 30, 2014) (relying on Fuel Tech for utilization factor, urea costs, and emission reduction values).

[22] FuelTech Budgetary Quotation; January 21, 2019. Included in Appendix E.

For these reasons, Fuel Tech does not recommend the hybrid technology as feasible at Coal Creek Unit 2. Because the hybrid technology is technically infeasible for Coal Creek Station, it is not carried forward.

3.0 Step 3 – Evaluate Control Effectiveness of Remaining Technologies

For this step of the BART analysis, the SCR and SNCR are evaluated on their effectiveness in removing NO_X. The metric used to determine control effectiveness is lb/MMBtu. This lb/MMBtu metric is eventually converted to a ton/year estimate based upon a projected annual capacity factor. For Coal Creek Station, the annual capacity factor is 87% based on a 10-year average.[23]

3.1 SCR

As explained in Section 2.2.11, there are significant site-specific risks that make an SCR infeasible at Coal Creek Station, but the technology is carried forward for further analysis to be conservative. Industry experience has shown that SCRs are capable of achieving NO_X emissions as low as 0.04 lb/MMBtu, with a range of 0.04 to 0.08 on units larger than 550MW. Table 3-1 shows units with SCRs located in Texas and within the WRAP states, along with their annual average emissions.[24]

Table 3-1 WRAP and Texas Units with SCRs and Emissions(1)

DESCRIPTION	COUNT IN DATA SET	ANNUAL AVERAGE EMISSIONS RANGE (LB/MMBTU)
Units with SCR	23	0.039 – 0.08
Units with SCR; > 550 MWg	11	0.039 – 0.08
Units with SCR; > 550 MWg; Burning Lignite	2	0.062 – 0.075
Total Units in Data Set	80(2)	

Notes:
1. Data obtained from the EPA Acid Rain Database and the Energy Information Administration.
2. Number does not include units scheduled for retirement.

Only ten (10) of twenty-three (23) units regularly emit 0.0499 lb/MMBtu NO_X or less on an annual average basis, and none of these nine units burns lignite coal. It is important to highlight that large units with SCRs burning Texas lignite operate at higher emission rates of 0.062 to 0.075 lb/MMBtu as an annual average.

A range of 0.04 to 0.08 lb/MMBtu is assessed in this report based on industry experience at units of similar types and sizes as Coal Creek. Note that some installations at coal fired power plants are capable of reducing NO_X emissions from baseline values by over 90 percent, but the

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[23] *See* Section 1.0.

[24] Complete data is available in Appendix F.

percent removal rate expected at Coal Creek Station is lower due to the lower NO_X baseline of 0.13 lb/MMBtu as an annual average.

3.2 SNCR

As an industry leading expert, Fuel Tech was contracted to perform a site-specific assessment for an SNCR's NO_X reductions and associated costs for Coal Creek Unit 2. In October 2018, Fuel Tech mobilized a team to Coal Creek for gathering boiler and emissions data at various loads over a week's worth of tests. These data were then fed into Fuel Tech's proprietary CKM and CFD models to determine site-specific injection locations, urea injection rates, and associated NO_X reductions across the load range of the Coal Creek Unit 2 boiler. The analysis resulted in an estimated reduction percentage of around 15 percent at baseload with a 10ppm slip using a basic SNCR system. Fuel Tech also evaluated an SNCR system using their proprietary multi-nozzle lances (MNL) to obtain better reagent distribution and NO_X reduction. With the MNLs, Fuel Tech estimates a NO_X reduction of 23 percent with a 10ppm slip at baseload.

Fuel Tech's NO_X reduction estimates were lower with an ammonia slip guarantee of 5 ppm (10 and 18 percent with and without MNLs, respectively). Less ammonia injection equals less ammonia slip, which corresponds to lower NOx reductions. When SNCR vendors attempt to optimize injection, urea is injected in a much more limited fashion, leading to varying ammonia slip rates across the boiler. Due to uncertainty with the varying ammonia concentrations (e.g. stratification across the duct) and how a lower slip greatly restricts an SNCR's performance, Fuel Tech did not provide a 2 ppm ammonia slip guarantee. Table 3-2 shows the ammonia slip and reduction percentages expected with an SNCR. While NOx reduction percentages would be significantly lower at 2 ppm slip, the rate of decreased NO_X reduction will increase as the ammonia slip decreases (e.g., removal at 2 ppm would be less than 10% when using MNLs).

Table 3-2 Ammonia Slip and Removal Efficiency

AMMONIA SLIP	REMOVAL % WITHOUT MNLS	REMOVAL % WITH MNLS
5 ppm	10	18
10 ppm	15	23

3.3 SUMMARY OF CONTROL EFFECTIVENESS

Table 3-3 summarizes the results of the technologies' control effectiveness.

Table 3-3 Effectiveness of Remaining Control Technologies

TECHNOLOGY	EXPECTED CONTROL EFFICIENCY (%)	EXPECTED GUARANTEED EMISSIONS (LB/MMBTU)
Selective Catalytic Reduction (SCR)	69	0.04
Selective Catalytic Reduction (SCR)	54	0.06
Selective Catalytic Reduction (SCR)	38	0.08
SNCR w/ Multi-Nozzle Lances	23	0.10
Selective Non-Catalytic Reduction (SNCR)	15	0.11

4.0 Step 4 – Evaluate Impacts and Document Results

Per Appendix Y to 40 CFR Part 51, the fourth step of a BART analysis is reviewing the impacts of each control technology in terms of four categories: the cost of compliance, energy impacts, non-air quality environmental impacts, and remaining useful life.

4.1 COST OF COMPLIANCE

Cost estimates for each of the remaining technologies were developed using two separate methodologies for Coal Creek Unit 2.

First, costs for SCR and SNCR were calculated using the EPA Cost Manual spreadsheets.

Second, site specific costs were developed for SCR and SNCR based on budgetary quotes from vendors and cost information from past Black & Veatch projects for similar retrofits. The cost of compliance was based on NO_X baseline emissions of 0.13 lb/MMBtu as an annual average. The tons/year of NO_X removed was calculated from this baseline and the projected annual capacity factor, which is 87 percent based on a 10-year average. Each technology was sized to achieve the highest practical emissions reductions for Coal Creek Station, and sensitivity analyses were run with both SCR and SNCR as discussed below.

The Cost Manual was followed for guidance on what line items to include, as well as sizing and cost estimating calculations for those line items. Again, Black & Veatch used site-specific information from vendors and its own recent SCR and SNCR projects, where appropriate, to make the cost estimates more accurate. Where required, equipment costs were scaled to account for the difference in expected size and performance, based on the on-site inspection of Coal Creek Unit 2 performed by Black & Veatch. Explanations of the cost estimates are provided in the subsections below.

The cost of compliance can be broken down into capital and annual costs. Capital costs generally refer to the money required to design and build the system. This includes direct costs, such as equipment purchases, and installation costs, such as foundations and installation of mechanical equipment. Indirect costs, such as engineering and construction field expenses, are also considered. All of these items sum up to provide the Total Capital Investment (TCI).

Annual costs include the ongoing expenditures to operate and maintain the system. Some noteworthy items are maintenance materials, yearly emissions testing, reagent consumption, utilities consumption (e.g. water and power), and disposal costs.

Table 4-4 and Table 4-5 summarize the costs and effectiveness of each of the technologies.

Table 4-1 Cost of Compliance for Technologies (2018 dollars) Using EPA Spreadsheets

TECHNOLOGY	TOTAL CAPITAL INVESTMENT	TOTAL ANNUAL COST ($/YR)	EFFECTIVENESS ($/TON NO_X)
SCR	$195,655,000	$16,417,000	$8,157
SNCR w/ MNL(1)	$12,534,000	$4,867,000	$7,279
SNCR	$12,179, 000	$4,833,000	$11,082

Notes:

1. SNCR w/ MNL cost only changed the removal rate from 15 percent, which is expected from “typical” SNCR systems, and 23 percent, which Fuel Tech expects with their MNL package. Associated costs with the MNL package as described in the site-specific sections are not covered in the EPA spreadsheets.

Table 4-2 Cost of Compliance for Technologies (2018 dollars) Using Site-Specific Approach

TECHNOLOGY	TOTAL CAPITAL INVESTMENT	TOTAL ANNUAL COST ($/YR)	EFFECTIVENESS ($/TON NO_X)
SCR(1)	$190,920,000	$17,590,000	$8,737
SNCR w/ MNL	$16,570,000	$5,970,000	$8,899
SNCR	$12,740,000	$4,860,000	$11,145

Notes:

1. The SCR cost is conservatively based on NO_X emissions of 0.04 lb/MMBtu. See Table 4-5 for how the $/ton changes with different emissions.

4.1.1 SCR

As discussed in Section 2.2.11, costs are assessed for SCR despite the fact that the technology appears infeasible for Coal Creek Station. The costs estimated using two methodological approaches (the EPA Cost Manual spreadsheet methodology and the site-specific methodology) are displayed in Table 4-3.

Table 4-3 Cost of Compliance for SCR Technologies (2018 dollars)

TECHNOLOGY	TOTAL CAPITAL INVESTMENT	TOTAL ANNUAL COST ($/YR)	EFFECTIVENESS ($/TON NO_X)
SCR (EPA Spreadsheet)	$195,655,000	$16,417,000	$8,157
SCR (Site-specific Approach)	$190,920,000	$17,590,000	$8,737

Notes:

1. The SCR costs are based on NO_X emissions of 0.04 lb/MMBtu. See Table 4-5 for how the $/ton changes with different emissions.
2. The EPA Spreadsheet Total Annual Cost and Effectiveness values were developed using the Method 2 calculation which is stated as being applicable to “coal-fired utility boilers” and does not reflect site specific catalyst volumes. The EPA Spreadsheet catalyst volume calculated is approximately half of the site-specific catalyst volume determined necessary by IBIDEN Ceram.

4.1.1.1 EPA Cost Manual Spreadsheet Methodology

The EPA provides a spreadsheet for estimating SCR costs according to the Cost Manual. This spreadsheet uses key site variables such as unit MW, fuel type, NO_X removal rate, and reagent use, and applies the EPA Cost Manual methodology and formulas to these site variables to calculate TCI and total annual costs, which are then used to derive an overall $/ton cost effectiveness estimate. As shown in Appendix G, Coal Creek Unit 2 variables were added to this spreadsheet. Similar to the site-specific methodology outlined in Section 4.1.1.2, the most restrictive NO_X reduction of 69 percent was used with the spreadsheet based on an annual emission rate of 0.04 lb/MMbtu.

The Cost Manual spreadsheet calculates a TCI of $195.7 million, and a cost effectiveness of $8,157/ton NO_X removed, according to 2018 dollars. This value was calculated by using a retrofit factor of 1.0, but the congestion at Coal Creek Unit 2 would justify an increase to the retrofit factor. As observed by Black and Veatch engineers, and as is discussed in more detail below in Section 4.1.1.2, Coal Creek Unit 2's unique DryFining™ and reheat systems occupy the space that typically would be used for installation of an SCR. If the retrofit factor is increased to 1.25 (Cost Manual spreadsheet identifies a range of 1 to 1.5), then the TCI increases to $244.6 million with a cost effectiveness of $9,906/ton NO_X removed.

The Total Annual Cost and Cost Effectiveness values were developed using the EPA Spreadsheet Method 2 calculation alternative which does not use site specific catalyst volumes. The spreadsheet does calculate an estimated catalyst volume that is approximately half the amount of the site-specific catalyst volume determined necessary by IBIDEN Ceram. The greater site specific catalyst volume would be expected to result in a higher Total Annual Cost and Effectiveness cost compared to the EPA Spreadsheet default volume.

4.1.1.2 Site-Specific Methodology

A high-dust arrangement was selected for this study's assessment of costs, because low-dust configurations would be more expensive at Coal Creek Station, given the need for both flue gas reheat and cooling, as discussed in Appendix B. If the cost of the high-dust arrangement is deemed to be cost-prohibitive, it is reasonable to assume that a cost analysis for a low-dust arrangement would result in the same conclusion.

The SCR and ancillary equipment were sized based on the most restrictive emission rate of 0.04 lb/MMBtu as an annual average. Catalyst vendors were provided the plant's expected flue gas information downstream of the economizer, based on the ultimate coal analysis of the lignite burned at Coal Creek Station. Trace elemental analysis of the ash at Coal Creek Station was also evaluated for catalyst poisons (sodium, arsenic, etc.). For purposes of this site-specific cost analysis only, IBIDEN Ceram provided a budgetary proposal for their catalyst in a high-dust SCR arrangement, despite their recommendation against a high-dust SCR at Coal Creek Station due to the sodium content of the coal. This proposal assumes a NOx inlet rate of 0.13 lb/MMBtu (approximately 60 ppm).

The most recent SCR project Black & Veatch has executed was on a 450 MW facility that burns PRB in 2014/2015. Black & Veatch completed an SCR installation in 2009 on a unit similarly sized to Coal Creek Station, but this unit burned an eastern coal that is significantly different from North Dakota lignite. Therefore, the more recent 450 MW SCR project was used as a more appropriate reference case for Coal Creek Station. Escalation factors for differently sized equipment were used, with appropriate parameters used for comparing equipment (e.g. reactor housing was scaled according to the catalyst volume, rather than total flue gas flow rate or units' MW). Inflation from the Chemical Engineering Plant Cost Index (CEPCI) per year was also applied.

Certain items had an elevation factor applied to the costs. The referenced project was at an elevation well over 6,000 feet, and Coal Creek Station is located at 1,940 feet, resulting in a ratio of 0.849. As the atmospheric pressure increases, the volumetric flow rate decreases according to Boyle's Law, so this elevation factor was applied as a cost adjustment where applicable. The Cost Manual uses it as a straight multiplier in some of its equations (e.g., equation 2.41). So, for equipment related to air gas flow, a multiplier of 0.849 was applied.

Table 4-4 provides a summary of the costs for the SCR, with subsequent sections explaining the specific categories of costs used to develop the overall cost estimate. More specific SCR cost information can be found in Appendix C, with the cost sheets provided in Appendix D.

Table 4-4 SCR Cost Summary Using Site-Specific Methodology

CATEGORY	US DOLLARS (2018)
Purchased Equipment Cost (PEC)	$49,830,000
Direct Installation Cost (DIC)	$69,130,000
Total Direct Cost (DC = PEC+DIC)	*$118,960,000*
Indirect Costs (IC)	$71,960,000
Total Capital Investment (TCI = DC + IC)	**$190,920,000**
Direct Annual Cost (DAC), no ash impacts	$4,370,000
Indirect Annual Cost (IDAC)	$13,220,000
Total Annual Cost (TAC = DAC + IDAC)	**$17,590,000**
$/Ton NO_X removed	**$8,737**

As discussed in Section 3.1, industry experience has shown that SCRs are capable of achieving NO_X emissions as low as 0.04 lb/MMBtu, with a range of 0.04 to 0.08 on units larger than 550MW. For the purpose of this cost evaluation, the conservative emission rate of 0.04 lb/MMBtu will be used. However, the unique technical risks associated with North Dakota lignite, as described in this document, may drive this emission rate higher to be more consistent with larger installed SCR systems. In particular, large units with SCRs burning Texas lignite operate at higher emission rates of 0.062 to 0.075 lb/MMBtu as an annual average. If the costs for an SCR are assumed to be the same across NO_X emission rates, the sensitivity of $/ton according to different NO_X removal rates is provided in Table 4-5.

Table 4-5 SCR Cost with NO_X Emissions Summary (2018 dollars) Using Site-Specific Methodology

NO_X EMISSION	$/TON
0.04	8,737
0.06	11,233
0.08	15,727

Figure 4-1 shows a general location of where the SCR would be located at Coal Creek Station (ducts and SCR box in red). The general congestion close by the boiler building and elevated construction are evident in the picture. Coal Creek Station installed a novel multipollutant reduction technology ("DryFining™") that processes and dries the lignite prior to combustion. Consequently, the back of the boiler has additional conveyors, processing equipment and DryFining™ baghouses, which are not present on other coal fired units. In addition, Coal Creek Station installed a reheat system in order to run wet scrubbers with a dry stack to meet BART SO_2 limits, as another unique feature, which further restricts available space in the back of the boiler where SCRs are traditionally located. As observed by Black & Veatch engineers, and as illustrated in Figure 4-2, the congestion from these systems preclude installation of an SCR in inside the boiler house. Rather, an SCR installation at Coal Creek Unit 2 must be customized for these unique constraints. Significant parts of DryFining™ and reheat systems would still need to be removed to make space for the SCR ductwork, and then reconfigured for re-installation. As discussed below, this report takes a conservative approach and does not include an estimate of the costs for the reconfiguration.

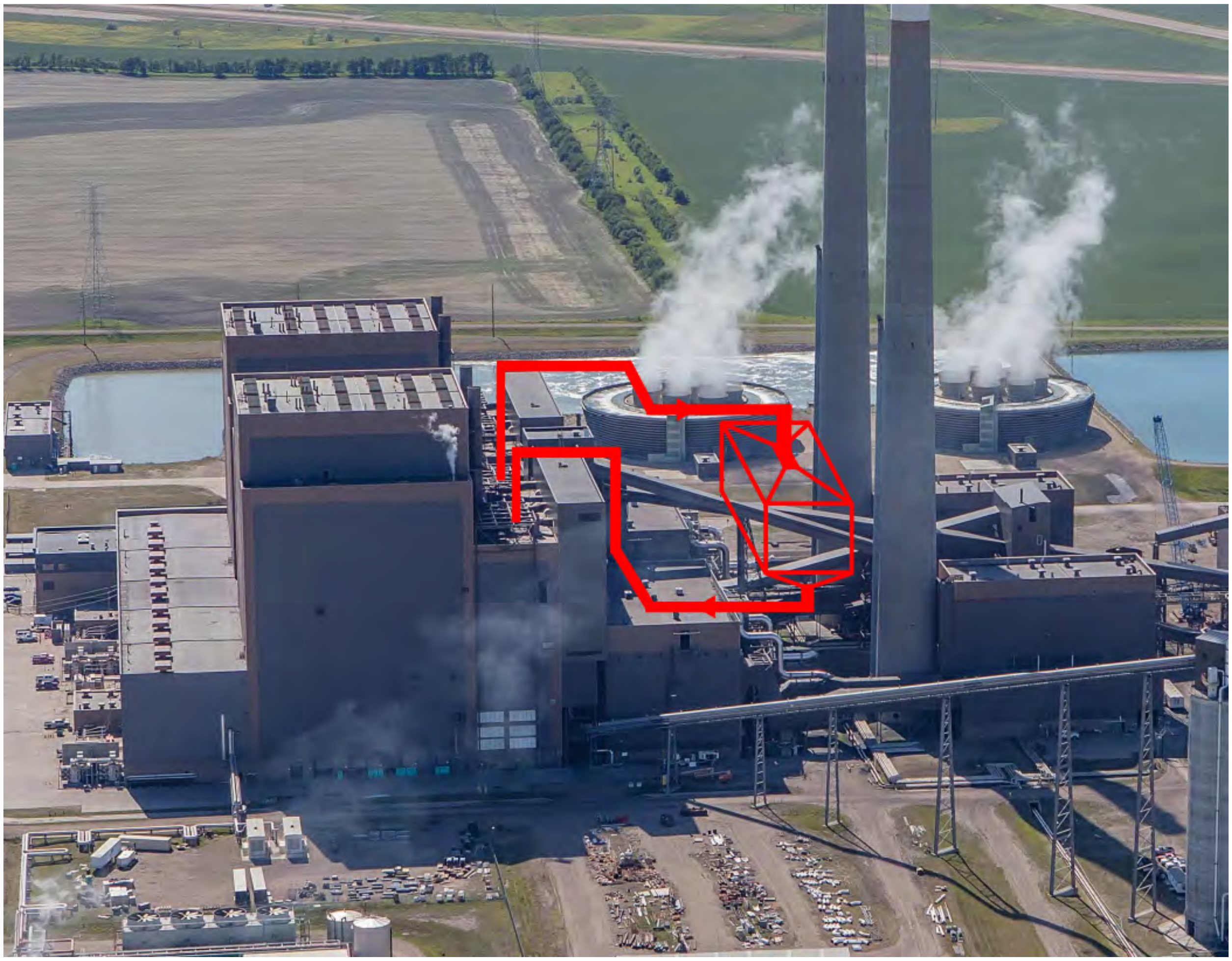

Figure 4-1 **General Sketch of SCR Location**

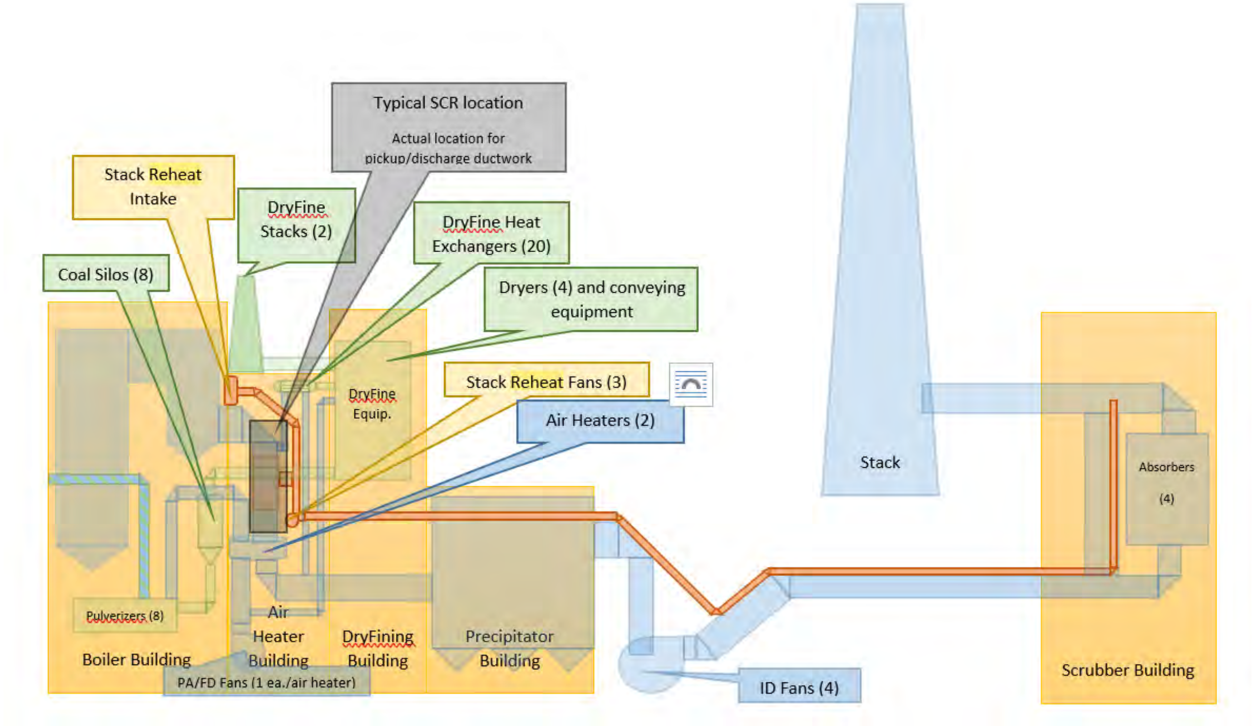

Figure 4-2 **Equipment in Boiler Building around ductwork tie-in at Coal Creek Unit 2**

4.1.1.2.1 Purchased Equipment Costs

Purchased Equipment Costs (PEC) refers to the cost of purchasing equipment for the SCR from vendors. Significant site-specific costs generally exceeding $1 million are described below, and explanations of the minor line items can be found in Appendix C. The total PEC for Coal Creek Station's SCR is $49.83 million.

Figure 4-1 shows a general location of where the SCR would be located at Coal Creek Station (ducts and SCR box in red). The general congestion close by the boiler building and elevated construction are evident in the picture.

- **Reactor Housing** – New steel for the catalyst/reactor housing is required. This does not include new ductwork connecting the reactor to the existing ductwork. The price for this was escalated from the Black & Veatch SCR reference project based on the difference in its catalyst volume and the one provided by IBIDEN Ceram. The catalyst volume was calculated based on the actual volumetric flow rate. Therefore, an elevation adjustment factor was not applied to this cost. Total cost for reactor housing is estimated to be $3.7 million.
- **Ammonia Injection Grid and Dilution Skid** – An ammonia injection grid is necessary to achieve optimal ammonia injection. A dilution skid is used to help deliver the anhydrous ammonia to the injection grid at a ratio of about 20:1 (air:ammonia). Since the size of the grid corresponds to the size of the reactor, the

difference in catalyst volume was also used to escalate the price. This cost is estimated to be $2.3 million.

- **Initial Fill of Catalyst** –The catalyst quoted by IBIDEN Ceram is a honeycomb type with a makeup of about 80 percent titanium, 5-10 percent tungsten, and 0-3 percent vanadium. The balance of the catalyst is ceramic material. The volume of catalyst was selected based on having three layers, with a spare layer, and a 24,000 hour life span, consistent with plant outage schedules. [25]

  Based on the coal type and flue gas characteristics IBIDEN Ceram calculated a catalyst volume approximately 2 times greater than the EPA spreadsheet estimate. Coal Creek Unit 2's higher temperature and potential poisons in North Dakota lignite resulted in IBIDEN Ceram calculating a higher volume than a "typical" installation for purposes of this cost assessment, although Ceram expects that this higher volume may be insufficient to address the deactivation rate likely to result from the high sodium levels in North Dakota lignite. This cost is estimated to be $6.1 million.
- **Ductwork** – The cost of ductwork was escalated from the SCR reference project's costs based on the units' MW, because the ductwork at a coal fired units is reflective of the plant's overall size, not the SCR catalyst volume or ammonia consumption rate. Due to the congestion around the boiler building, the ductwork modifications and additions required to provide flue gas from the economizer to the SCR, and from the SCR to the air pre-heater, are complex. Black & Veatch's reference project used in this cost estimate had much more available space for installing an SCR. Therefore, the pricing was scaled to account for a more congested arrangement as well as difference in sizing requirements. This value is reasonable considering that the location of the SCR in this study is elevated above the ID fans due to limited real estate. There are also potential places beside Coal Creek Unit 2 and on the backside of Coal Creek Unit 1, but since there are complications with ductwork at any of the locations, above the ID fans was chosen. However, offsetting the cost increase from the higher exponent is an adjustment for elevation, or multiplying by the elevation factor of 0.849. This cost is estimated to be $5.3 million.
- **Air Heater Modifications** – Modifications are necessary to bolster the air preheater from increased SO_3 in the flue gas from the catalyst converting SO_2. Sulfuric acid is more likely to form with increased levels of SO_3, resulting in corrosion problems of downstream equipment like the air preheater. This is particularly a concern with coals with higher sulfur content, as noted by IBIDEN Ceram. Due to the

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[25] The catalyst costs estimated in this report are conservative. IBIDEM Ceram certifies its catalyst life for 24,000 hours or 36 months from date of delivery, whichever comes first. Because of ordering lead time, catalyst would be stored on-site for several months before installation during the next outage, decreasing the lifespan of that catalyst prior to the mandatory shipment of the next supply. This means that catalyst will be ordered more frequently than the lifespan guarantee, resulting in higher costs than are estimated here.

temperatures exiting the economizer (around 830° F), the catalyst best suited for the flue gas conditions at Coal Creek Unit 2 will oxidize about 5 percent of the SO_2. The flue gas is expected to have around 831 ppm of SO_2. If 5 percent is converted to SO_3, this will result in over 40 ppm of SO_3.

In addition to concerns about air heater corrosion, SO_3 is not readily captured by WFGD systems, resulting in noticeable blue plumes from the stack when the emissions exceed 10 ppm. One solution to the corrosion and blue plume issues is to install an SO_3 mitigation system (often termed SAM, or sulfuric acid mitigation). Current methods of reducing SO_3 in flue gas include injecting a sorbent such as hydrated lime, trona, sodium bicarbonate, or soda ash. Estimating a cost for this type of supplemental system is not part of this study, but based on past projects Black & Veatch would expect a minimum of $10 million to fully engineer, procure, and construct this system.

The Cost Manual provides an equation (equation 2.43) to estimate the cost of air preheater modifications, and this equation resulted in ~ $10.5 million.[26] Although the Cost Manual contemplates the application of air heater enhancements only for bituminous coal, B&V performed this calculation because of IBIDEN Ceram's concern about the economizer exit temperature and SO_3 creation across the catalyst. Some form of costs associated with increased SO_3 levels should be included, and the Cost Manual's value for air preheater modification was chosen instead of developing costs for a new SAM system.

- **Structural Steel** – In addition to the steel required for the reactor housing and ductwork, support steel must be purchased. This price was scaled up from the reference project based on the units' difference in MW. A significant portion of the steel is related to the ductwork that had an elevation adjustment factor applied to its cost. Therefore, the same adjustment is made to the steel. This cost is estimated to be $10.6 million.

4.1.1.2.2 Direct Installation Costs (DIC)

The DIC combines with the PEC to give the total direct costs (DC). As its name would imply, direct installation costs (DIC) refer to the costs directly associated with physically installing the SCR. Construction costs are often higher than the PEC, especially for retrofits. Coal Creek Station presents unique retrofit challenges because of existing reheat and DryFining™ equipment located on the back of the boiler. Therefore, site-specific design considerations are critical to deriving more accurate cost estimates. A general retrofit factor of some percentage was not universally applied. The following items were included in the DIC – see Appendix D for the values. The DIC was estimated using actual costs from the Black & Veatch reference project, which was also a retrofit.

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[26] The EPA cost spreadsheet does not include a cost adder for air heater modifications when operating on lignite fuel. When bituminous fuel is selected an air heater modification price of approximately $10,900,000 is shown.

- **Subsurface Construction** – Prior to installing any foundations or equipment, earth/soil/concrete must be moved along with any underground utility lines. Once this is done, all foundations, piles, ductbank, and embedments can be installed. This price was scaled up from the reference project based on the units' difference in MW. The previous project had more real estate for construction than Coal Creek Station. Therefore, these costs were adjusted by a slightly higher factor of 1.2 to account for physical constraints. This cost is estimated to be $4.1 and $1.1 million for earthwork/undergrounds and foundations, respectively.
- **Superstructure Construction** – In addition to the reactor and ductwork, a cost for installing a heated building around the SCR was included. Coal Creek Station experiences temperatures well below freezing, and to accommodate maintenance during the winter months, a heated enclosure is needed. The referenced SCR project by Black & Veatch was also located in an area with harsh winters. Consequently, the price of a heated building was used for this estimate. Since superstructures relate to equipment processing flue gas, the elevation adjustment factor was applied. Similar to the subsurface construction costs, costs were adjusted by factor of 1.2 to account for the congestion differences between the reference project and Coal Creek Station. This cost is estimated to be $28.4 and $15.2 million for the reactor/ductwork and the heated building, respectively. A significant portion of this cost is due to multiple large cranes required to build an elevated structure such as the SCR at Coal Creek Station.
- **Demolition and Rebuild** – Space inside and around the boiler building is very congested at Coal Creek Station. It will be extremely difficult to locate SCRs inside the boiler building. Based on Black & Veatch's initial assessment of the facility, including a site inspection and review of applicable engineering drawings, it was determined that, an SCR would have to be elevated and located above the ID fans, requiring more ductwork outside of the boiler house than typical installations. This is accounted for in the line item for ductwork and structural steel.

  An additional line item was included to account for the rework inside the boiler house that will be required to tie-in the new ductwork connecting the new SCR to the old ducts. Inside the boiler building, there is a reheat system that takes in ambient air and is heated by the hot duct pantlegs entering the air preheater. As part of the SO_2 BART control strategy, this reheat gas is then directed to the stack, where it mixes with the flue gas leaving the WFGD and raises the overall exhaust gas temperature in order to maintain a dry stack. This reheat system is adjacent to the economizer outlet where SCR ductwork is typically connected. After the SCR duct tie-ins are made, the ductwork needs to exit the boiler building to the new SCR reactor. Due to existing equipment and steel inside the boiler building, the best option is routing the new duct work through the roof. However, GRE's DryFining™ system has ductwork and baghouse equipment in this area. Therefore, rework would be needed to relocate or demo/rebuild the equipment that is in the way (See Figure 4-1). In brief, the reheat system, heat exchangers, and stacks would be removed in order to create space for installation of the SCR, and then reconfigured for reinstallation[27]. The removal of these systems would necessitate an outage of approximately 6 to 18 months depending on the final configuration and amount of demolition and relocation required. The cost for this lost revenue would be significant but is not accounted for in this analysis. Access to the SCR could be preserved for the necessary periodic catalyst replacement and other maintenance.

Given the unique congestion issues, site-specific cost estimates must be used for the demolition and rebuild of the reheat or DryFining™ ducts. If the reheat section is abandoned, then a wet chimney would be needed. The costs for new stacks are expensive. Based on a past project, a new, wet chimney at Coal Creek Station would cost at least $16 million. Using past labor rates (manhours and wages) from Black & Veatch projects, the cost to demo and rebuild the reheat ductwork alone is estimated to be $2.8 million based on the tonnage of Corten steel. This cost did not include the expenses to relocate/reroute significant parts of the DryFining™ and reheat equipment, which would require more detailed design work to accomplish. As such, it is viewed as more cost effective to retrofit the reheat duct work. Therefore, the wet chimney option was not incorporated into the cost estimate.

There is a large amount of steel and equipment associated with the DryFining™ system. Based on a high-level review of drawings, the cost to demolish and rebuild the DryFining™ equipment interfering with the new duct is estimated to be around $5 million. The costs utilized in this analysis could increase as specific design requirements are analyzed.

- **Mechanical Construction** – This line item deals with installing the mechanical equipment (e.g. pumps, tanks, piping, catalyst layers, etc.). Once the foundations and structures are installed, the mechanical construction costs should be comparable to the referenced project, so the previous project's cost was escalated based on the units' difference in MW. This cost is estimated to be $6.6 million.
- **Electrical Construction** – This line item deals with installing the electrical equipment. The previous project's cost was escalated based on the units' difference in MW. This cost is estimated to be $4.4 million.

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[27] The cost estimate for this study uses a conservative approach by basing re-installation of all equipment in a configuration similar to the current arrangement. It is expected that the re-installation will actually require significant re-design including potentially relocating equipment to a new building outside the existing boiler house.

4.1.1.2.3 Indirect Costs

Indirect costs (IC) refer to those costs associated with executing a project that are not directly attributable to purchased equipment or installation. This includes the following:

- Engineering
- Construction and field expenses[28]
- Owner's cost
- Startup
- Performance tests
- Contingencies

The Cost Manual does not provide a specific equation for estimating IC. Rather, indirect costs are accounted for in their capital cost equations that comprise the total capital investment. Developing site-specific costs for Coal Creek Station allows the IC values to be explicitly estimated. The costs were calculated as a percentage of the direct costs, based on the reference project's final financials. This cost is estimated to be $72 million.

4.1.1.2.4 Total Capital Investment

Total Capital Investment (TCI) is the total sum of the DC, IC, and other project costs that must be paid to execute the project. This calculation of TCI does not include Allowable Funds Used During Construction (AFUDC), royalty allowances, preproduction cost, inventory capital, and initial catalyst and chemicals. These costs were provided in the 1998 and 2002 update of the Cost Manual, but then removed from the SCR chapter in the May 2016 update. Since these other costs are no longer part of the Cost Manual, they are not included in this cost analysis.

Using site-specific design information and costs from Black & Veatch's reference project, the TCI was calculated to be $190,920,000. The reference project used by Black & Veatch in developing this cost estimate was ~450 MW unit, and the total in 2014/2015 dollars was ~ $175 million. The reference project included new ID fans. Some actual indirect and installation costs were unique to the reference project. Considering that Coal Creek Station does not need new ID fans, it saves nearly $20 million in equipment and installation costs. However, Coal Creek Station is over 30 percent larger with a larger amount of demolition and rebuild required. These differences support the estimated TCI as an appropriate cost estimate. If the costs for DryFining™ and reheat systems' demolition and rebuild are excluded, the TCI is $176,430,000, or very similar to the reference project.

4.1.1.2.5 Direct Annual Costs

Direct annual costs include variable and fixed costs. Fixed annual costs are those that a plant owner will have to pay every year. The Cost Manual assumes that operating labor is 4 hours a day due to the SCR system, which equates to half a full-time employee. An annual salary of $149,365 was used for this cost estimate based on GRE's cost for operators (based on an hourly

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[28] Construction and field expenses include costs for crane and scaffolding.

cost of $71.81/hr). There is also a cost associated with maintenance labor and materials, and the Cost Manual assumes this to be 0.5 percent of the TCI (former editions used 1.5 percent). Black & Veatch included a cost for testing the catalyst activity and fly ash based on past estimates.

In addition to fixed annual costs, variable annual costs exist due to the SCR system. A capacity factor of 0.87 (based on a ten-year average) was provided by GRE and applied to all variable costs. The Cost Manual's Equation 2.58 and 2.59 were used for calculating the cost of reagent consumption and power consumption. The reagent consumption was calculated using a stoichiometric ratio of 1.05, an outlet emission of 0.04 lb/MMBtu, and a 2 ppm ammonia slip. The cost of anhydrous ammonia was provided with delivery included to Bismarck[29] by truck. Equations 2.60 and 2.62 were used to calculate the cost from the SCR's power consumption. The cost of power was provided by GRE.

Another variable cost is for replacing catalyst. IBIDEN Ceram's catalyst volume was provided based on a 24,000 hour-lifespan , or three years from the date of delivery, whichever comes first. Coal Creek Unit 2 undergoes a planned major outage every three years, so catalyst replacement may or may not align with this schedule. The plan would be to replace all of the catalyst layers during the major outage. The cost of catalyst was taken from the vendor quote, and a future worth factor (FWF) was applied per the Cost Manual. The FWF "amortizes the catalyst cost over the years preceding the actual catalyst purchase." Since this cost would occur every three years, it was divided by three to determine the annual impact.

For each layer of catalyst that is replaced, the removed catalyst must be properly disposed. Therefore, a disposal cost was applied based on a $10.50/ton rate provided by GRE. The total DAC is estimated to be $4.4 million.

4.1.1.2.6 Indirect Annual Costs

Indirect annual costs include administrative costs, property taxes, insurance, overhead, and capital recovery. Insurance and property taxes were assumed to either be nominal or non-existent for the SCR. Overhead was assumed to be negligible since administrative costs comprise a significant portion of overhead costs. Equation 2.69 was used to calculate the administrative costs, and the capital recovery was calculated by the annuity formula based on 5.25 percent interest and a 30-year life. The interest rate was provided by the NDDH (from the EPA), and the 30-year life was taken from the Cost Manual. In general, the capital recovery can be understood as an equal payment over "n" years (in this case 30), so that the current value of the total payments is equivalent to the total capital investment at the specified interest rate. The total IDAC is estimated to be $13.2 million.

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[29] The anhydrous ammonia supplier stated that the material would be shipped from Minnesota, so the cost for delivery to Coal Creek Station in lieu of Bismarck is expected to be slightly higher (approximately 50 additional miles). To ensure a conservative estimate, this additional cost is not included.

4.1.1.2.7 SCR Cost Effectiveness Sensitivity

Based on Equation 2.73, the cost effectiveness was calculated by dividing the total annual costs (the sum of direct and indirect costs) by the total tons of NO_X removed per year. The removal rate was based on a conservative outlet emission of 0.04 lb/MMBtu, which as explained in Section 4.1.1, may be higher upon actual installation and operation. The cost effectiveness based on this emission rate is estimated to be \$8,737/ton NO_X removed. The cost effectiveness is estimated to be \$11,233/ton NOx removed based on an emission rate of 0.06 lb/MMBtu, and \$15,727/ton NOx removed based on an emission rate of 0.08 lb/MMBtu.

4.1.2 SNCR

Costs were calculated for SNCR using both EPA's cost manual spreadsheet methodology, and a site-specific approach, as summarized in Table 4-6. The high dollar cost per ton of NOx removed reflects the low baseline NOx emissions at Coal Creek Unit 2, and the limited additional reductions achievable through SNCR. The unit operates at NOx emissions near the critical point of 0.1 lb/MMBtu, at which the injection of ammonia or urea will actually result in *increased* NOx levels.

Table 4-6 Cost of Compliance for SNCR Technologies (2018 dollars)

TECHNOLOGY	TOTAL CAPITAL INVESTMENT	TOTAL ANNUAL COST ($/YR)	EFFECTIVENESS ($/TON NO_X)
SNCR w/MNL (EPA Spreadsheet)	\$12,534,000	\$4,867,000	\$7,279
SNCR w/MNL (Site-specific Approach)	\$16,570,000	\$5,970,000	\$8,899
SNCR (EPA Spreadsheet)	\$12,179, 000	\$4,833,000	\$11,082
SNCR (Site-specific Approach)	\$12,740,000	\$4,860,000	\$11,145

4.1.2.1 EPA Cost Manual Spreadsheet Methodology

EPA provides a spreadsheet for estimating SNCR costs according to the Cost Manual. This spreadsheet uses key site variables such as baseline NO_X emissions, and normalized stoichiometric ratio (NSR). The spreadsheet applies the EPA Cost Manual Methodology and formulas to these site variables to calculate screening level NOx reductions and associated TCI and total annual costs, which are then used to derive an overall \$/ton cost effectiveness estimate. As shown in Appendix G, Coal Creek Unit 2 variables were added to this spreadsheet. Similar to the site-specific methodology outlined in Section 4.1.2.2, Fuel Tech's site-specific NSR estimate was used in the spreadsheet calculations. For reasons discussed in this report, the Cost Manual prioritizes the use of vendor-specific NSR calculations where available.

The Cost Manual spreadsheet calculates a TCI for SNCR without MNL of $12.2 million, and a cost effectiveness of $11,082/ton NO_X removed, according to 2018 dollars. This value was calculated by using a retrofit factor of 1.0. The Cost Manual spreadsheet calculates a TCI for SNCR with MNL of $12.5 million, and a cost effectiveness of $7,279/ton NOx removed, according to 2018 dollars. This value was calculated by using a retrofit factor of 1.0. The spreadsheet's calculation of MNL cost does not account for site-specific design considerations. Rather, it applies default stoichiometric ratios based on higher MNL percentage removal than would be achieved at CCS Unit 2, resulting in an underestimation of cost effectiveness.

4.1.2.2 Site-Specific Methodology

This analysis provides a vendor-specific estimate by following the Cost Manual's Section 1.3.2 Design Parameters for Detailed/Performance Specifications in Chapter 1 for Selective Non-Catalytic Reduction (SNCR). A detailed analysis was conducted to design and calculate the performance of an SNCR specifically taking into consideration Coal Creek Station's unique boiler over its operational range. As stated in the EPA Pollution Control Cost Manual: "SNCR system design is a proprietary technology. Extensive details of the theory and correlations that can be used to estimate design parameters such as the required NSR are not published in the technical literature Furthermore, the design is highly site-specific. In light of these complexities, SNCR system design is generally undertaken by providing all of the plant and boiler-specific data to the SNCR system supplier, who specifies the required NSR and other design parameters based on prior experience and computational fluid dynamics and chemical kinetic modeling."[30]

This report contains cost quotations from Fuel Tech for the design and build of the SNCR system and engineering estimates from Black & Veatch for the installation and construction of the SNCR system. Two system costs were provided by Fuel Tech, one for a system with standard injection lances and another with additional Multiple Nozzle Lances (MNL). The MNL is a proprietary lance designed to provide optimal reagent coverage, particularly at high temperature locations. Fuel Tech estimated that using MNLs along with the standard wall lances provides an 8 percent further reduction in NO_X at baseload. Table 4-7 provides a summary of these two system costs, with descriptions of the costs in following subsections. Refer to Appendix D for details of the individual items' costs. The site-specific cost calculations incorporate the NSR calculated by Fuel Tech.

As stated in the EPA Cost Manual, a system supplier can "more accurately predict the NSR for a given boiler" than the values calculated using the Cost Manuals simplified estimation procedure by accounting for the following factors:[31]

- Reaction temperature range available within the boiler superheater (radiative and convective section) and primary reheater (convective section or cavity) region. If the required temperature window occurs in the radiant section of the boiler, NSR

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[30] EPA Cost Manual, Chapter 1: Selective Noncatalytic Reduction

[31] Chapter 1: Selective Noncatalytic Reduction, at 1-39.

could decrease. However, if the temperature window occurs in the convective section, NSR may increase.

- Residence time available in the desirable temperature range. The required NSR decreases as the available residence time increases.
- Degree of mixing between the injected chemical and the flue gases. NSR decreases as the degree of mixing increases.
- Ammonia slip vs. required NO_X reduction. Tighter constraints on ammonia slip would dictate lower NSRs, thereby limiting the achievable NO_X reduction."

Fuel Tech's NSR values were developed using proprietary CFD and CKM models that account for Coal Creek Unit 2's low baseline NO_X emissions among other variables, which are close to the critical NO_X level of 0.1 lb/MMBtu. SNCR needs more reagent as it approaches the critical emissions level, increasing the NSR.

Although Fuel Tech observed NOx emissions of 0.12 lb/MMBtu and a heat input of 5,971 MMBtu/h during its field testing for the SNCR quote, they confirmed the reduction percentage would be the same for a nominally higher baseline (0.13 lb/MMBtu). Therefore urea usage rates were calculated using the same reduction percentage but based on the baseline value of 0.13 lb/MMBtu of NO_X at a heat input of 6,022 MMBtu/h, which reflect the average conditions at Coal Creek Unit 2.

Table 4-7 SNCR Cost Summary Using Site-Specific Methodology

CATEGORY	US DOLLARS (2018) STANDARD LANCES	US DOLLARS (2018) MULTIPLE NOZZLE LANCE
Purchased Equipment Cost (PEC)	$3,040,000	$4,800,000
Direct Installation Cost (DIC)	$6,690,000	$7,860,000
Total Direct Cost (DC = PEC+DIC)	*$9,730,000*	*$12,660,000*
Indirect Costs (IC)	$3,010,000	$3,910,000
Total Capital Investment (TCI = DC + IC)	**$12,740,000**	**$16,570,000**
Direct Annual Cost (DAC), no ash impacts	$3,820,000	$4,610,000
Indirect Annual Cost (IDAC)	$1,040,000	$1,360,000
Total Annual Cost (TAC = DAC + IDAC)	**$4,860,000**	**$5,970,000**
$/Ton NO_X removed	**$11,145**	**$8,899**

4.1.2.2.1 Purchased Equipment Costs

The PEC primarily consists of the SNCR system that is provided by a supplier/vendor. A budgetary quote from Fuel Tech was used for the PEC, as covering most line items. Costs that were not covered, such as balance of plant piping and electrical, were included in the installation costs. The total PEC for Coal Creek Unit 2's SNCR was $3 million with wall injectors only and $4.8 million with the MNLs.

- **Vendor's Scope of Work** – Fuel Tech was contracted to gather field data and conduct CFD and CKM modeling to develop a budgetary proposal, due to their industry experience and expertise with SNCRs. Other vendor quotes were not solicited. Their quote included a urea storage tank, dilution water skid, injection nozzles, metering equipment, and miscellaneous components.

  A 50 percent urea solution was assumed, which would be delivered by truck. An unloading panel is therefore required to transfer the solution from the truck to the holding tank. The trucks have an unloading pump, so the unloading panel solely functions as an indicator of the storage tank level to let the operator know when the truck can be unloaded. The urea storage tanks have a residence time of 30 days. Three storage tanks, each at 70,000 gallons, were included in the proposal from the vendor to meet the 30-day requirement. The storage tank is made of fiber reinforced plastic (FRP), and a typical 14-foot diameter was used for sizing.

  Fuel Tech provided two options of injectors for Coal Creek Unit 2; one standard option with three different levels of wall injectors, and another option with the same wall injectors but with additional MNLs. The standard injectors (termed G-1) attach to newly installed ports, and are designed to provide the optimum reagent coverage per the CFD modeling done by Fuel Tech. Zone 1 of the three injection levels also comes with an automatic retract device for the lances in order to protect them when not in use.

  The MNL option achieves lower NO_X emissions than the standard wall injectors, because they are designed to provide better reagent coverage. Each MNL has nozzles spaced at various intervals along the whole length of the lance. Cooling water and atomizing air are fed throughout the lance. Each lance can be retracted from the boiler, similar to a soot blower. In addition to extra, larger ports for the MNLs, spools for cooling water are required, increasing the price for the MNL option. The total PEC for Coal Creek Unit 2's SNCR was $3 million with wall injectors only and $4.8 million with the MNLs.

4.1.2.2.2 Direct Installation Costs

Various balance of plant items, such as foundations, piping, electrical, were not included in the PEC. These items are included in the direct installation costs similar to the reference SNCR project.

- **Subsurface Construction** – An SNCR system will need some foundational and subsurface work to install major system components, most notably the urea storage tanks. This price was scaled up from the SNCR reference project based on the units' difference in area of the installed equipment, with some reductions due to costs associated with the reference project's firewater system. No adjustments to the firewater system were included for Coal Creek Station.

The MNLs allow better reagent coverage, so more chemical reactions occur in the flue gas. More reagent can therefore be injected while staying below the ammonia slip requirements, and this higher reagent flow rate results in a higher storage volume. The SNCR with MNLs therefore has a higher subsurface construction cost to account for the additional storage tank capacity. This cost is estimated to be $1.9 million for the SNCR without MNLs, and $2.1 million with the MNLs.

- **Superstructure Construction** – Similar to the SCR, an enclosure was provided for major pieces of equipment for the SNCR, such as the storage tanks. This is recommended for operations and maintenance at installations with severe weather conditions, like Coal Creek Station. The reference project was in an environment that endured harsh winters, and likewise had a heated enclosure for major pieces of equipment. No additional ductwork, piers, columns, or other superstructures are needed for an SNCR. Therefore, this line item solely deals with the heated enclosure. The circulation module is provided by Fuel Tech with an enclosure, so the difference in square footage of the remaining modules was used to escalate the costs from the reference project. This cost is estimated to be $1.4 million, regardless of whether MNLs are included.
- **Mechanical Construction** – This line items deals with the cost of installing all the vendor supplied equipment, as well as procuring and installing balance of plant equipment. The estimated cost was escalated from the reference project based on the units' difference in reagent flow rate. This cost is estimated to be $2.3 and $2.8 million without and with the MNLs, respectively.

4.1.2.2.3 Indirect Costs

Indirect costs (IC) refer to those costs associated with executing a project that are not directly attributable to purchased equipment or installation. This includes the following:

- Engineering
- Construction and field expenses
- Owner's cost
- Startup
- Performance tests
- Contingencies

The costs were calculated as a percentage of the direct costs, based on the reference project's final financials. This cost is estimated to be $3 and $3.9 million without and with the MNLs, respectively.

4.1.2.2.4 Total Capital Investment

Total Capital Investment (TCI) is the total sum of the DC, IC, and other project costs that must be paid to execute the project. This calculation of TCI does not include Allowable Funds Used During Construction (AFUDC), royalty allowances, preproduction cost, and inventory capital, or initial catalyst and chemicals. These costs were removed from the SNCR chapter of the Cost Manual in the May 2016 update, so they are not included in the overall cost. This cost is estimated to be \$12.7 and \$16.6 million without and with the MNLs, respectively.

4.1.2.2.5 Direct Annual Costs

The direct annual costs for an SNCR were calculated based on the Cost Manual's instructions. The fixed costs included zero additional costs for operating personnel, because the plant's existing operators should be able to incorporate the SNCR's relatively simple system into their current workload. A 1.5 percent cost against the TCI was applied for the annual maintenance and labor costs.

The variable costs for the SNCR were based on a 50 percent reagent solution as-received, with it being diluted to 10 percent prior to injection. The reagent, power, and water consumption rates were taken from the budgetary estimate from Fuel Tech. The reagent cost was provided by Cervantes-Delgado, as-delivered to Bismarck.[32] GRE provided the cost of power and water. Equation 1.47 of the Cost Manual was also used to account for additional fuel consumed to vaporize the reagent solution, and the price of coal was provided by GRE. This cost is estimated to be \$3.8 and \$4.6 million without and with the MNLs, respectively.

4.1.2.2.6 Indirect Annual Costs

The indirect annual costs included administrative charges and the cost for capital recovery. The insurance, property taxes, and other indirect costs are assumed to be zero in the Cost Manual, so these costs were not included in this estimate. Equations 1.52 through 1.55 were used to calculate administrative charges and the cost for capital recovery (based on a 5.25 percent interest rate and a 20-year life per the Cost Manual). This cost is estimated to be \$1and \$1.36 million without and with the MNLs, respectively.

4.1.2.2.7 SNCR Cost Effectiveness

Based on Equation 2.73, the cost effectiveness was calculated by dividing the total annual costs (the sum of direct and indirect costs) by the total tons of NO_X removed per year. The removal rate was based on the removal efficiencies provided by Fuel Tech: a 15% removal rate for the SNCR and a 23% removal rate for the SNCR with the MNLs. The cost effectiveness based on these removal rates are estimated to be \$11,145 and \$8,899 per ton of NO_X removed without and with the MNLs.

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[32] Cervantes-Delgado stated the urea would be shipped from North Dakota but did not provide an exact location. The differential cost for shipping to Coal Creek Station in lieu of Bismarck is expected to be minor enough as to not impact the calculated direct annual costs.

4.2 COST EFFECTIVENESS

The cost effectiveness of each of the technologies was calculated according to Equation 2.73 of the Cost Manual (SCR section) and 40 CFR 51, Appendix Y, Section IV, D. The cost effectiveness is a value that compares the annualized cost of the technology per ton of pollutant removed. There are two technologies to be considered for cost effectiveness: SCR and SNCR. SNCR was found to be the cheapest option on total annualized costs, but the SCR was the cheapest on a dollar per ton basis when assessed based on tons of NO_X removed.

In addition to the total cost effectiveness, the incremental cost effectiveness was calculated according to 40 CFR 51, Appendix Y. The SNCR annualized cost was used as the basis. The SNCR with MNLs and the SCR were assessed on incremental cost effectiveness from the SNCR basis and adjusted by the difference in TAC and the tons of NO_X removed. Table 4-8 and Table 4-9 shows the average cost effectiveness values in $(TAC)/ton NO_X removed (per annual basis). Figure 4-3 is a graph of total annualized costs versus emissions reductions. The high cost effectiveness for SNCR is due to Coal Creek's already low NO_X emission rate. Unit 2 is emitting NO_X near the critical value for SNCR systems, where further removal is not possible. This explains why the SNCR's removal capabilities are limited, driving the $/ton value higher.

As can be seen, the cost effectiveness of all the considered technologies exceeds thresholds determined to be reasonable in other BART determinations, under both calculation methodologies. The North Dakota BART SIP considered cost effectiveness above $3,650/ton to be excessive, which was adjusted for inflation to $4,100/ton in the 2011/2012 NO_X BART.[33] If adjusted to 2018 dollars, the NDDH cost effectiveness threshold is approximately $4,630/ton. The cost-effectiveness of the technologies also exceeds the values that other states and EPA have determined to be unreasonable in other BART determinations, including Nevada, which determined controls to be not cost-effective at $1,190/ton to $2,102/ton in 2012.[34] Most recently, EPA has proposed to approve Arkansas's determination that controls are not cost-effective at $5,387/ton to $5,420/ton. 83 Fed. Reg. 62204, 62220-22 (Nov. 30, 2018).

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[33] Supporting Material, *North Dakota Supplemental NOx BART Determination for Coal Creek Station Supplement No. 2 to SIP for Regional Haze* at App. B.2.1, page 16 (Jan. 2, 2013), Docket ID EPA-R08-OAR-2010-0406-0428 (September 2012 Supplemental Evaluation of NOx BART Determination for CCS 1 and 2).

[34] 77 Fed. Reg. 17334 (Mar. 26, 2012) (EPA approval); Nevada Dept. of Envtl. Prot., Revised Nevada Division of Environmental Protection BART Determination Review of NV Energy's Fort Churchill Generating Station Units 1 and 2, at 5-7 (Oct. 15, 2009), EPA Docket No. EPA-R09-OAR-2011-0130-0004.

Table 4-8 Overall and Incremental Cost Effectiveness (2018 US Dollars) – Using EPA Spreadsheets

TECHNOLOGY	TAC	TON NO_X REMOVED	EFFECTIVENESS ($/TON NO_X)	INCREMENTAL COST ($/TON)
SNCR	$4,833,000	436	$11,082	--
SNCR w/ MNL	$4,867,000	669	$7,279	$146
SCR[35]	$16,417,000	2,013	$8,157	$8,594

Table 4-9 Overall and Incremental Cost Effectiveness (2018 US Dollars) – Site Specific Methodology

TECHNOLOGY	TAC	TON NO_X REMOVED	EFFECTIVENESS ($/TON NO_X)	INCREMENTAL COST ($/TON)
SNCR	$4,860,000	436	$11,145	--
SNCR w/ MNL	$5,970,000	669	$8,899	$4,764
SCR[36]	$17,590,000	2,012	$8,737	$8,652

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[35] The calculations for SCR are based on an assumed emission rate of 0.04 lb/MMBtu, but as explained in Section 3.1, a range of 0.06-0.08 lb/MMBtu is more reasonable. If the higher emission rates are used, the cost effectiveness of SCR would be even higher.

[36] The calculations for SCR are based on an assumed emission rate of 0.04 lb/MMBtu, but as explained in Section 3.1, a range of 0.06-0.08 lb/MMBtu is more reasonable. If the higher emission rates are used, the cost effectiveness of SCR would be even higher.

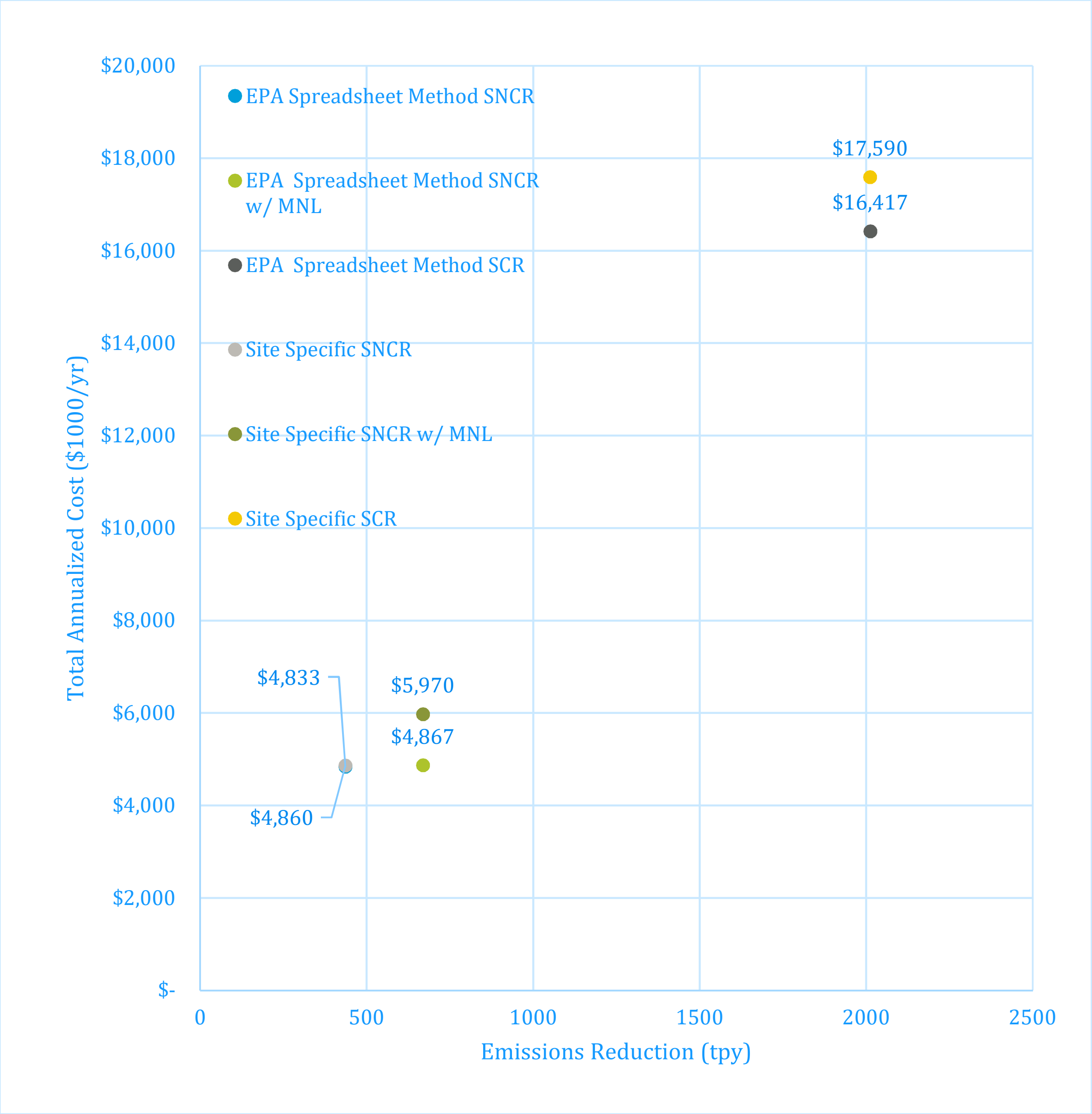

Figure 4-3 **TAC vs Emissions Reduction**

4.3 ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS

SCR and SNCR have energy and water consumption impacts.[37] The energy impacts are primarily related to the auxiliary power consumption of the systems and were included in the cost estimates under the variable annual costs. Similarly, water costs were included as appropriate. Both technologies also would impact GRE's award-winning fly ash reuse program. These impacts

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[37] All three technologies also would impact GRE's award-winning fly ash reuse program. These impacts are discussed in another report.

are discussed in another report. Please refer to the sheets in Appendix D for further information on the power and water demand of each technology.

4.3.1 SCR

Energy demands from the SCR system are associated the power consumed by the additional pressure drop that the ID fans need to provide, the dilution air blowers, heaters, ammonia pumps, and other minor auxiliary loads. The Cost Manual's equation 2.60 was used for estimating the total power consumption for the SCR, which included increased ID fan loads and resulted in about 3.5 MW.

Ammonia slip will lead to increased nitrogen to the scrubber, which ultimately will be deposited in the evaporation ponds. This nitrogen will act as a nutrient to plants, potentially increasing future pond maintenance requirements and associated costs.

4.3.2 SNCR

For SNCR, power consumption should be nominal, because there is an insignificant impact to the flue gas pressure drop. The urea pumps and dilution skid would be the main power consumers. The power consumption was provided by the SNCR vendor and was listed as 75 and 95 kW with and without MNLs, respectively. Other indirect energy impacts, such as the energy to produce reagents, were not considered in this study.

The SNCR also would consume water as part of the urea injection system, as the urea solution is reduced to 10 percent by weight prior to injection. The water demands are in the mid-100 gpm, which multiplied by an 87 percent capacity factor and 8,760 hours per year, results in about 70 to 80 million gallons per year. This additional water consumption could require an increase in the water appropriations permit.

Ammonia slip will lead to increased nitrogen to the scrubber, which ultimately will be deposited in the evaporation ponds. This nitrogen will act as a nutrient to plants, potentially increasing future pond maintenance requirements and associated costs.

4.4 POLLUTION CONTROL EQUIPMENT IN USE/EXISTING AT THE SOURCE

Coal Creek Unit 2 already has existing NOx controls in place that have yielded a low NOx emissions baseline. The facility uses LNBs, DryFining™, OFA, and tuning to achieve this low emission rate. DryFining™, in particular, is a unique technology developed by GRE that reduces moisture and refines lignite coal, increasing the efficiency and performance of the fuel while reducing emissions.[38] Coal Creek Unit 2 employs an electrostatic precipitator (ESP) for collecting particulate matter such as fly ash. After the ESP, flue gas passes through a wet flue gas desulfurization (WFGD) system that removes acid gas from the system.

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[38] 83 Fed. Reg. 18248, 18251 (Apr. 26, 2018).

Coal Creek Unit 2 has a higher economizer temperature than many installations, and this elevated temperature will result in more SO_2/SO_3 conversion across an SCR catalyst. Modifications due to SO_3 are discussed further in Section 2.2.11, most notably the air heater.

The WFGD's acid removal should not be adversely affected. Ammonia can act as a base or acid, and it will be absorbed in the WFGD solute. At the low concentrations of ammonia slip the technologies are designed for, ammonia should not adversely affect the solution's pH or chemistry.

4.5 REMAINING USEFUL LIFE OF ANY POTENTIALLY AFFECTED SOURCES

Consistent with GRE's resource plan, Coal Creek Station will continue to operate for at least 30 years. The facility is well managed and operated. Further, long term investments have been made in the plant (e.g. DryFining™ and HVDC converter replacements). Therefore, the lifetimes of the evaluated technologies were kept at the Cost Manual's values (30 years for SCR and 20 for SNCR), as opposed to lesser values based on a limited forecast of Coal Creek Unit 2's life.

5.0 Conclusion

The specific challenges associated with the combustion of North Dakota lignite, as well as the extremely limited space for the installation of controls in the boiler house, significantly limit the feasibility of NOx controls on Coal Creek Unit 2. There are significant concerns about the technical feasibility of SCR but the technology was carried forward for further review, along with SNCR, in order to provide a conservative approach to this BART analysis.

This further review revealed that neither of the controls are cost-effective, regardless of the cost assessment methodology employed. SCR and SNCR (both with and without MNL) far exceed the $4,630/ton threshold (adjusted for inflation) that has been applied by NDDH in past BART determinations, as well as exceeding the values determined by other states and EPA to be unreasonable. These high cost-effectiveness values were calculated using both site-specific cost assessments and EPA's spreadsheet methodology. The high values reflect the low NOx emission rate of 0.13 lb/MMBtu, as an annual average, already achieved at Coal Creek Unit 2 through the implementation of LNC3+. This low NOx baseline limits the availability of further NOx reductions. For example, SNCR would achieve minimal reductions, as the facility operates near the critical point of 0.1 lb/MMBtu, after which the injection of ammonia or urea actually results in *increased* NOx emissions. In light of these cost effectiveness values, as well the low NOx baseline and the energy and non-air environmental impacts of the considered controls, none of the three technologies are determined to be BART.

Appendix A. Coal Creek VISTA Model Parameters

A.1 FUEL DATA

Fuel Data			
Case Descriptor			
	Evaluation	Calibration 21 Aug	
	Run Date	Oct 9 2018 1:43PM	
	Case Number	0	
	Unit	Coal Creek U2- 21 Aug	
	Load Curve	21-Aug	
	Fuel Description	Coal Creek	
	Gas Cofire Percentage (Average)	0	
Coal Properties			
	Description		
	Higher Heating Value	6612.00	Btu/lbm
	Higher Heating Value, Min	6446.70	Btu/lbm
	Higher Heating Value, Max	6777.30	Btu/lbm
	Lower Heating Value	6052.55	Btu/lbm
	Lower Heating Value, Min	0.00	Btu/lbm
	Lower Heating Value, Max	0.00	Btu/lbm
Proximate Analysis			
	Basis	Wet	
	Moisture	31.43	%
	Moisture, Min	29.54	%
	Moisture, Max	33.32	%
	Ash	12.89	%
	Ash, Min	9.93	%
	Ash, Max	15.85	%
	Volatile Matter	28.57	%
	Fixed Carbon	27.11	%
Ultimate Analysis			
	Basis	Wet	
	Carbon	39.17	%
	Carbon, Min	36.82	%
	Carbon, Max	41.52	%
	Hydrogen	2.58	%
	Hydrogen, Min	2.43	%
	Hydrogen, Max	2.73	%
	Nitrogen	0.63	%
	Nitrogen, Min	0.43	%
	Nitrogen, Max	0.83	%
	Sulfur	0.61	%
	Sulfur, Min	0.43	%
	Sulfur, Max	0.79	%

Chlorine	0.00	%
Chlorine, Min	0.00	%
Chlorine, Max	0.00	%
Oxygen (by difference)	12.69	%
Ash Analysis		
Silica (SiO2)	47.18	%
Alumina (Al2O3)	13.39	%
Titania (TiO2)	0.57	%
Iron Oxide (Fe2O3)	7.43	%
Lime (CaO)	12.13	%
Magnesia (MgO)	3.90	%
Potassium (K2O)	1.94	%
Sodium (Na2O)	3.02	%
Sulfur Trioxide (SO3)	10.30	%
Phosphorous (P2O5)	0.02	%
Strontium (SrO)	0.00	%
Barium (BaO)	0.00	%
Manganese (Mn3O4)	0.00	%
Undetermined	0.12	%
Ash Temperatures		
Initial Deformation (Reducing)	2108.00	F
Softening (Reducing)	2144.00	F
Hemispherical (Oxidizing)	2194.00	F
Miscellaneous Properties		
Hardgrove Grindability	37.00	
Hardgrove Grindability, Min	31.45	
Hardgrove Grindability, Max	42.55	
T250	2405.00	F
T250, Min	2284.75	F
T250, Max	2525.25	F
Equilibrium Moisture	34.30	%
SO2 Production	1.84	lbm/MBtu
Ash Production	19.49	lbm/MBtu
Hg Production	0.00	lbm/TBtu
Alternate Solid Fuel Properties		
Non-Coal Percent	0.00	%
Renewables Percent	0	%
Trace Elements		
Arsenic (As)	0	ppm
Lead (Pb)	0	ppm
Mercury (Hg)	0	ppm
Gas Properties		
Description		
Higher Heating Value (Mass Basis)	0.00	Btu/lbm

Higher Heating Value (Volume Basis)	0.00	Btu/in3
Lower Heating Value (Mass Basis)	0.00	Btu/lbm
Lower Heating Value (Volume Basis)	0.00	Btu/in3
Gas Density	0.00	lb/ft3
Gas Density, Min	0.00	lb/ft3
Gas Density, Max	0.00	lb/ft3
Moisture	0.00	%
Oil Properties		
Description		
Higher Heating Value (Mass Basis)	0.00	Btu/lbm
Higher Heating Value (Volume Basis)	0.00	Btu/in3
Lower Heating Value (Mass Basis)	0.00	Btu/lbm
Lower Heating Value (Volume Basis)	0.00	Btu/in3
Density	0.00	lb/ft3
Carbon	0.00	%
Hydrogen	0.00	%
Nitrogen	0.00	%
Sulfur	0.00	%
Moisture	0.00	%
Ash	0.00	%
Oxygen	0.00	%

A.2 FULL LOAD UNIT PERFORMANCE

Full Load Unit Performance		
Case Descriptor		
Evaluation	Calibration 21 Aug	
Run Date	Oct 9 2018 1:43PM	
Case Number	0	
Unit	Coal Creek U2- 21 Aug	
Load Curve	21-Aug	
Fuel Description	Coal Creek	
Full Load Unit Operation		
Gross Power	602.57	MW
Net Power	563.42	MW
Boiler Efficiency, HHV Basis	80.27	%
Boiler Efficiency, LHV Basis	87.69	%
Net Turbine Heat Rate	7818.00	Btu/kWh
Net Unit Heat Rate, HHV Basis	10416.20	Btu/kWh
Net Unit Heat Rate, LHV Basis	9534.84	Btu/kWh
Fuel Burn Rate		
Total Heat Input, HHV Basis	5868.68	MBtu/hr

Total Heat Input, LHV Basis	5372.12	MBtu/hr
Coal Burn Rate, Mass Basis	443.79	ton/hr
Coal Burn Rate, HHV Basis	5868.68	MBtu/hr
Coal Burn Rate, LHV Basis	5372.12	MBtu/hr
Alt Solid Fuel Burn Rate, Mass Basis	0.00	ton/hr
Alt Solid Fuel Burn Rate, HHV Basis	0.00	MBtu/hr
Alt Solid Fuel Burn Rate, LHV Basis	0.00	MBtu/hr
Gas Burn Rate, Volumetric Basis	0.00	kcfm
Gas Burn Rate, HHV Basis	0.00	MBtu/hr
Gas Burn Rate, LHV Basis	0.00	MBtu/hr
Oil Burn Rate, Mass Basis	0.00	ton/hr
Oil Burn Rate, Volumetric Basis	0.00	gal/min
Oil Burn Rate, HHV Basis	0.00	MBtu/hr
Oil Burn Rate, LHV Basis	0.00	MBtu/hr
Boiler Efficiency		
Higher Heating Value Basis		
Latent	8.25	%
Sensible	7.81	%
Unburned Carbon	1.00	%
Radiation and Convection	0.40	%
Margin and Unaccounted	2.27	%
Total	80.27	%
Lower Heating Value Basis		
Latent	0.00	%
Sensible	8.38	%
Unburned Carbon	1.07	%
Radiation and Convection	0.43	%
Margin and Unaccounted	2.43	%
Total	87.69	%
Net Turbine Heat Rate Adjustments		
Base by Input	7818.00	Btu/kWh
Superheat Temperature/Spray	0.00	Btu/kWh
Reheat Temperature/Spray	0.00	Btu/kWh
Sootblowing Steam	0.00	Btu/kWh
Air Preheat Steam	0.00	Btu/kWh
Steam Driven Fans	0.00	Btu/kWh
SCR Reheat Steam	0.00	Btu/kWh
FGD Reheat Steam	0.00	Btu/kWh
Ambient Temperature	0.00	Btu/kWh
Ambient Relative Humidity	0.00	Btu/kWh
Circulating Water Inlet Temperature	0.00	Btu/kWh
Coal Cleaning/Drying Steam	0.00	Btu/kWh
Adjusted Net Turbine Heat Rate	7818.00	Btu/kWh

Turbine Load Correction	
Superheat Temp	0.00 kW
Superheat Spray	0.00 kW
Reheat Temp	0.00 kW
Reheat Spray	0.00 kW
Sec. Reheat Temp (Double Reheat)	0.00 kW
Sec. Reheat Spray (Double Reheat)	0.00 kW
Total Correction	0.00 kW
Unburned Combustible Details	
Calculation Source	
NOx LOI Predictor's LOI Prediction Used	No
NOx LOI Predictor's LOI Prediction	0.00 %
Vista's LOI Prediction	2.97 %
LOI Results Used in Analysis	
Total LOI	3.42 %
Fly Ash LOI	2.97 %
Bottom Ash LOI	4.46 %

A.3 COMBUSTION AIR-GAS COMPOSITION

Combustion Air and Gas Composition	
Case Descriptor	
Evaluation	Calibration 21 Aug
Run Date	Oct 9 2018 1:43PM
Case Number	0
Unit	Coal Creek U2- 21 Aug
Load Curve	21-Aug
Fuel Description	Coal Creek
Combustion Air and Flue Gas Composition	
Based on Air Heater Leakage	11.72 %
Based on Excess Air Percentage	17.11 %
Excess Oxygen Percentage	2.66 %
O2 Analyzer Type	Wet
O2 Measurement Basis	Mole Basis
Total Furnace Stoichiometry	5.73664
Total Furnace Stoichiometry, Including Air Inleakage	5.73664
Air Entering PA Fans	
Temperature	74.62 F
Pressure	0.00 inwg
Moisture	10008.23 lbm/hr
Oxygen	463291.81 lbm/hr
Nitrogen	1512820.50 lbm/hr
Argon	26470.99 lbm/hr

Air Entering FD Fans		
Temperature	74.62	F
Pressure	0.00	inwg
Moisture	18727.72	lbm/hr
Oxygen	866926.19	lbm/hr
Nitrogen	2830837.25	lbm/hr
Argon	49533.36	lbm/hr
Gas Exiting Economizer		
Temperature	830.75	F
Pressure	-5.50	inwg
Ash Flow Rate	82923.63	lbm/hr
Moisture	508931.47	lbm/hr
Oxygen	181628.98	lbm/hr
Nitrogen	3832362.00	lbm/hr
Argon	67252.06	lbm/hr
Sulfur Dioxide	10698.31	lbm/hr
Sulfur Trioxide	148.71	lbm/hr
Carbon Dioxide	1259058.88	lbm/hr
Chlorine	0.00	lbm/hr
Nitrogen Oxide[39]	1130.74	lbm/hr
Nitrogen Dioxide[39]	34.97	lbm/hr
Mercury	0.00	lbm/hr
Gas at Air Heater Outlet		
Temperature	347.90	F
Pressure	-12.54	inwg
Ash Flow Rate	83002.21	lbm/hr
Moisture	512332.81	lbm/hr
Oxygen	339748.94	lbm/hr
Nitrogen	4348683.00	lbm/hr
Argon	76286.52	lbm/hr
Sulfur Dioxide	10698.31	lbm/hr
Sulfur Trioxide	84.56	lbm/hr
Carbon Dioxide	1259058.88	lbm/hr
Chlorine	0.00	lbm/hr
Nitrogen Oxide	1130.74	lbm/hr
Nitrogen Dioxide	34.97	lbm/hr
Mercury	0.00	lbm/hr

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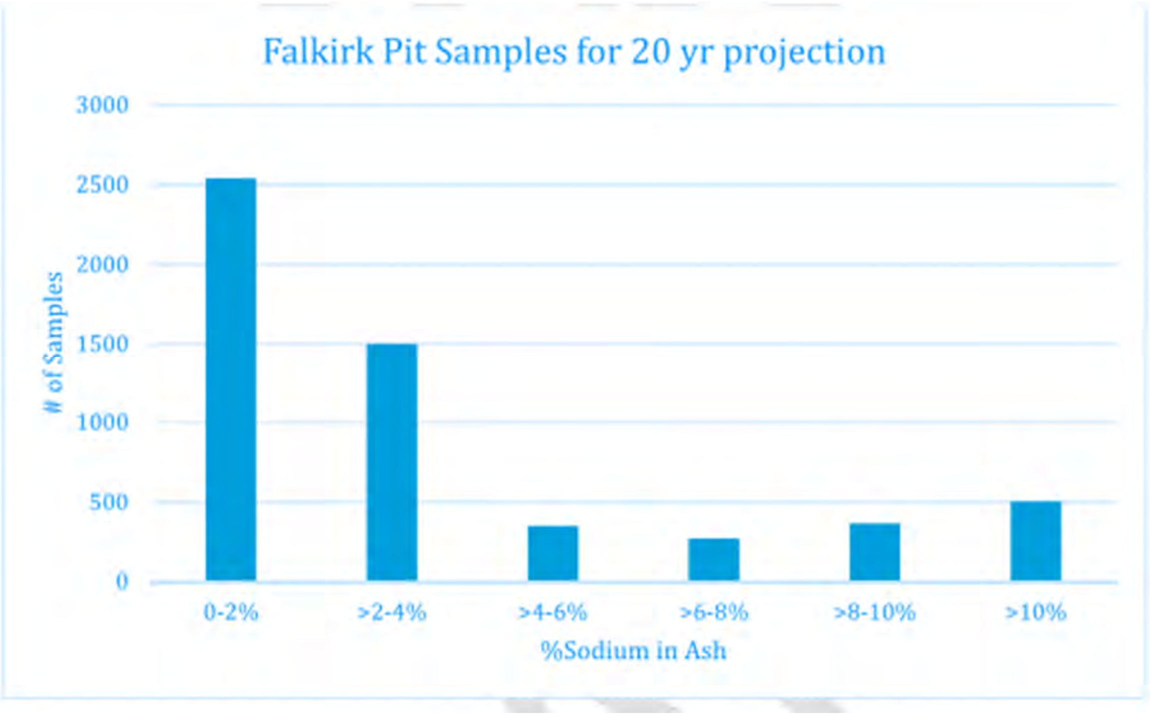
[39] Nitrogen Oxide and Nitrogen Dioxide values shown are the VISTA model output values used to calculate the initial NOx emission rate of 126 ppm provided to IBIDEN Ceram in October 2018. Following this initial communication, the actual Unit 2 emission rate of 60 ppm was provided to IBIDEN Ceram. IBIDEN Ceram confirmed they are able to achieve 69% reduction for both inlet NOx values of 126 ppm and 60 ppm, as Case 1 and Case 2 respectively, (see quotation in Appendix D).

A.4 FALKIRK PIT SAMPLES – 20 YEAR PROJECTION



Appendix B. Technical Discussion of Low-Dust SCR

Although this BART analysis assesses high-dust SCR, low-dust SCR also was initially considered. Low-dust SCR was not assessed further because it would be more expensive than a high-dust SCR. Since a high-dust SCR was determined to be not cost-effective, there was no need to conduct a cost analysis for a low-dust SCR. The high costs of low-dust SCR are driven by two factors: (1) heating and cooling requirements, and (2) the potential need for a natural gas line. These factors would increase the costs of SCR *above* the high-dust SCR costs already assessed in the body of this report.

First, Coal Creek Station would be required to install a system for reheating the flue gas before it passes through the low-dust SCR, as well as a system for cooling down the flue gas after the SCR. The low dust arrangement is commonly installed after the air preheater, resulting in temperatures in the mid-300s°F, which is too low for a catalyst to work. Thus, the inlet temperature to the low-dust SCR must be increased. The flue gas temperature must then be reduced after passing through the low-dust SCR to accommodate the wet flue gas desulfurization (WFGD) system at Coal Creek Unit 2. There is very little temperature drop across the SCR, so flue gas leaving the SCR would be near 600° F. The WFGD is not designed with sufficient spray capacity to lower incoming flue gas from 600° F to its operating conditions. The WFGD mist eliminators are designed to 300° F, but the flue gas temperature would need to be dropped well below this due to performance considerations. The absorber vessels typically operate with the flue gas at 11 ft/s, and the plant operates to maintain the velocity below 18 ft/s to prevent carryover. As the flue gas temperature increases, the volume and velocity increase. Elevated temperatures and increased velocities will also have an adverse impact on the SO_2 removal percentage. Accordingly, the SCR outlet temperature would have to be lowered for the WFGD to operate as designed.

There are multiple ways to accomplish the cooling and heating methods, and two were examined as part of this study. The first method would be to install heating equipment that uses combustion for adding heat, such as a thermal oxidizer, and then a cooling system that uses some form of external heat reject to exchange heat with the flue gas, such as a fluid system (e.g. glycol or Dowtherm A) with coils inside the duct and fin fans outside. Based on a 2007 estimate for a thermal oxidizer and applying the general 6/10 rule of escalation for volume and temperature differences and a 3 percent inflation rate, a general equipment cost of $1.43 million was calculated. Additional BOP equipment (e.g. structural steel) would be required, so a high-level factor of 2x can be used for the BOP equipment. Applying a 2x factor for installation then a high-level cost of $5.7 million is obtained for the heater section. The cooling section is more complicated, as determining costs would require piping lengths, fans, coolant, etc. Glycol is not suitable for the temperature ranges, so Dowtherm A was identified as a heat exchange fluid. Using past quotes for air cooled heat exchangers and a budgetary quote from Dow Chemical, a cooling system was estimated to cost $11.3 million. This includes a 2x factor for installation. Due to uncertainty with piping, this price could be higher upon implementation. Combined with the heater, the total cost for this option is about $17 million.

The second method would be using a gas/gas heat exchanger, similar to an air preheater. At a high level, Ljungstrom style of gas/gas heat exchangers (2x50 percent) would cost about $17.1 million to install. This cost will likely be higher due to additional ductwork that needs to be installed, but without doing detailed engineering, a precise cost estimate cannot be determined.

If the selected heating system relies upon natural gas, there would be significant additional costs. Coal Creek Station does not have a natural gas line to supply natural gas burners, so one would need to be constructed. Generally, it costs about $1-2 million per mile of installed natural gas line, as discussed in Section 2.2.5.

Appendix C. Discussions of Minor Line Items in Cost Estimates

C.1 SCR

C.1.1 Purchased Equipment Costs

- **Anhydrous Ammonia Tank** – This is based on 30 days of storage capacity. Due to the severe winter conditions and remote location of Coal Creek Station, 30 days of capacity is needed to provide ample reserves in case of road closures. This time frame was provided by GRE. The cost from the reference project's anhydrous ammonia tank was scaled down based on the tank's capacity.
- **Air Compressors** – GRE has stated that the existing air compressor system was recently upgraded, with a new, fourth compressor having been installed. New compressors were assumed not to be needed, but the cost of two new compressed air receivers (2 x 100%) were included. By not requiring new air compressors approximately $150k was avoided in PEC.
- **Vaporizers** – Anhydrous ammonia is fully vaporized before being delivered to the dilution skid. The price of a vaporizer skid from the reference project was scaled down according to the differences in ammonia consumption rates.
- **Ammonia Unloading Skids** – Ammonia is assumed to come by trucks, so a method of unloading the ammonia and transferring it to the storage tank is required. The price from the reference SCR project was used without any scaling, because the number of deliveries and size of trucks were expected to be similar.
- **Ammonia Supply Pump Skid** – Pumps are required to feed the ammonia to the SCR, and the reference project's price was scaled down according to the differences in ammonia consumption rates.
- **Miscellaneous Ammonia Handling and Injection Equipment** – This line item includes general miscellaneous items not covered above, such as piping, a mixing chamber, etc. The overall cost of all purchased equipment for the ammonia handling and injection contract, minus the equipment specifically identified, was used for this cost and adjusted based on the difference in MW between Coal Creek Station and the referenced project. The ammonia consumption rate was not used, because the amount of miscellaneous equipment is more related to the overall size of the units. Piping for example will have larger spans to traverse on a larger boiler, so even if the ammonia consumption rate is lower, the total piping material will be more.

- **Ash Handling Modifications** – Fly ash will separate out from the flue gas stream as it passes through the SCR reactor and catalyst layers. The fly ash is collected in a hopper at the bottom of the SCR, and this needs to be connected to the existing fly ash system. The cost for this was scaled from the reference project's costs based on the units' size difference in MW.
- **Electrical Equipment** – This covers the costs for electrical equipment (e.g. transformers, cabling, etc.) that are required for an SCR. This price was scaled up from the reference project based on the units' difference in MW.
- **Induced Draft or Booster Fans** – No costs were included for new ID fans or booster fans. Black & Veatch's reference project installed new ID fans, and if those costs are applied to Unit 2, nearly 20 million dollars (including installation) would have been added to the overall capital cost. The pressure drop across the catalyst layers is expected to be anywhere from 2.1 to 2.60 inches w.g. (according to IBDIEN Ceram), and including the ductwork, LPA screen, and mixing devices, over 6 inches w.g. of pressure drop can be expected. Coal Creek Unit 2 has four, identical ID fans with VFDs, and all of them normally operate at a speed around 640 rpm. The fan curve shows that at 705 rpm, the fans provide about 19 inches w.g. of pressure rise, and at 880 rpm, the fans provide about 37.5 inches of pressure rise. These readings are taken at 2.1 million lb/h of flue gas, which was calculated from the results of a stack test in 2017, here near 8.4 million lb/h of flue gas was measured. Considering where the fans are currently operating, there is enough margin available in the fans' capabilities to overcome the pressure losses from a new SCR.
- **Sonic Horns** – There are two traditional ways of cleaning SCR catalysts from various deposits that can plug up catalyst, soot blowing and sonic horns. Both have been shown to work, but prices for sonic horns were readily available when developing the cost estimates for this report. Therefore, sonic horns were used in the cost estimate. A change to soot blowers would not significantly increase the overall SCR price. An elevation adjustment factor was applied after escalating the cost from the reference facility based on MW.
- **LPA Screens** – A screen is placed upstream of the SCR catalyst to collect large particle ash (LPA). This price was scaled up based on the units' difference in catalyst volume, and the cost was adjusted according to the elevation.
- **Flow Modeling** – Physical models at 1/12 of the actual scale are often used when designing and building an SCR, because CFD models often are not precise in predicting ash flow patterns. The price from the reference project was used without any adjustment, because the price difference is expected to be nominal.

- **Instruments and Controls** – As with any system, instrumentation will be needed to provide process data for operators. SCRs do not require as much instrumentation as other control systems, like a flue gas desulfurization (FGD) system, but costs for additional instruments are required. Based on the reference project, a general 2 percent of the total capital costs is applied.
- **NO_X Monitoring** – NO_X analyzers and associated equipment are provided as a process control. This is separate from a continuous emissions monitoring system (CEMS), as there is already a NO_X CEMS at Coal Creek Station. The price from the reference project was used without any adjustment, because the cost of analyzers and the associated equipment should be nearly constant. This cost is estimated to be $1.3 million.
- **Taxes and Freight** – A general 7 percent tax (confirmed by GRE) and 5 percent freight charge are applied against the total capital costs. These numbers can fluctuate, but neither will have a significant impact on the overall price. This cost is estimated to be $3 and $2.2 million for taxes and freight, respectively.

C.1.2 Direct Installation Costs

- **Spare Parts, Training, Technical Assistance** – When installing a system, it is routine to have a set number of spare parts in the warehouse for startup and for turning over to the owner. Training and technical assistance from vendors is also necessary to properly install and startup the equipment. The previous project's cost was escalated based on the units' difference in MW.

C.2 SNCR

C.2.1 Purchased Equipment Costs

- **Vendor's Scope of Work** – Solutions such as urea must be continuously agitated to ensure the solids stay in solution, so a circulation module was included in Fuel Tech's quote. The circulation module includes two pumps and a strainer, with appropriate instrumentation, connected to the storage tank and metering module. Due to the cold temperatures at Coal Creek Station, a weather enclosure for the circulation module was included by Fuel Tech.

  Prior to being injected into the furnace, the urea solution is diluted with water (to 10 percent in Fuel Tech's design), which is provided by the plant. Fuel Tech has provided a strainer/pump system to account for the SNCR's pressure and flow requirements. In addition to the dilution module, a metering module is in Fuel Tech's scope of supply. The metering module regulates the flow and pressure of diluted solution to each injection zone, and due to its criticality, some form of weather protection is necessary. This was not included in Fuel Tech's scope of supply though, but rather it is in the Balance of Plant's scope, described in the subsection below.

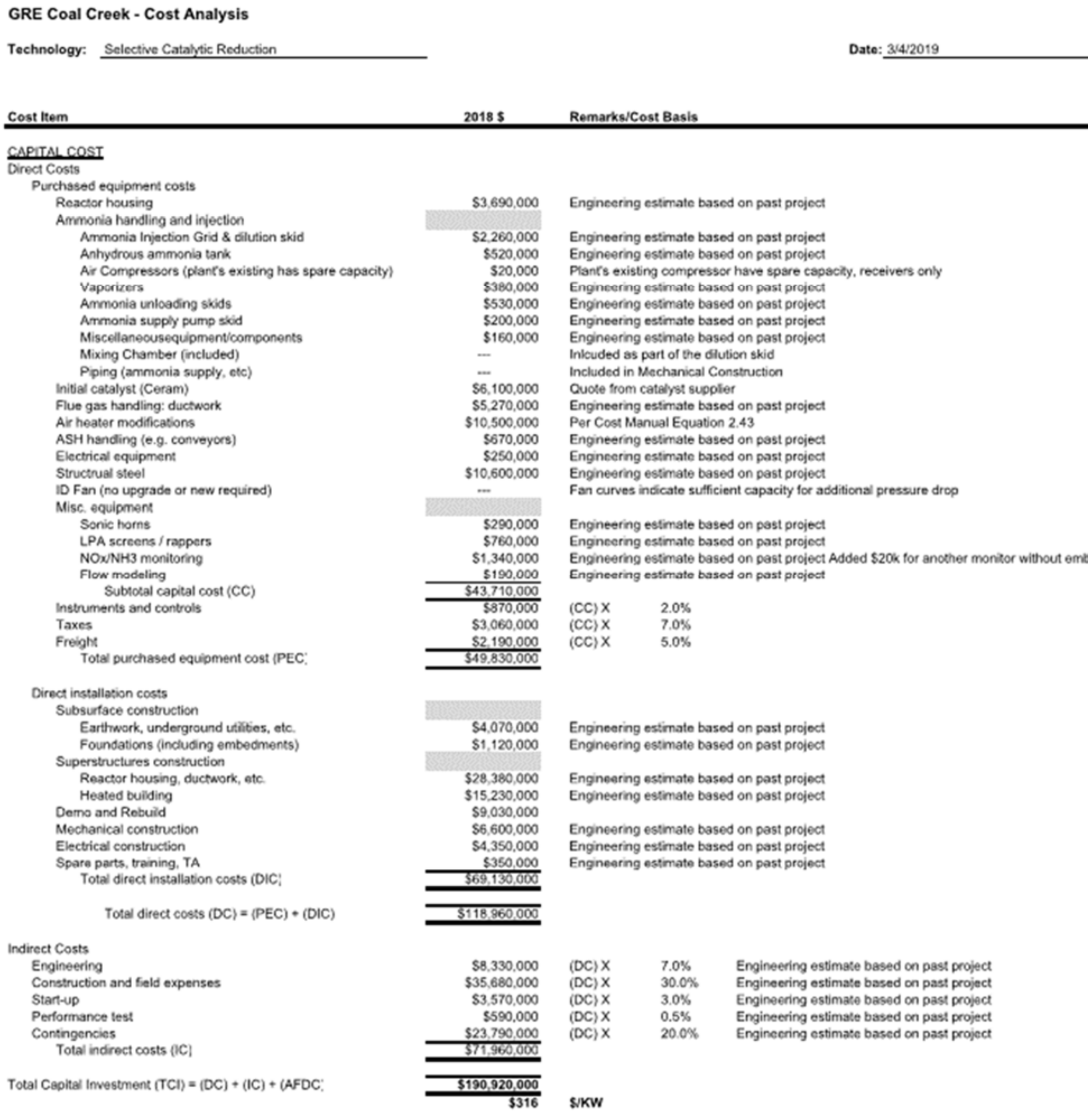
After the metering modules, distribution modules mix the reagent with atomizing air. Compressed instrument air was assumed to be provided by the plant, because there is sufficient capacity in the existing compressed air system. The distribution modules are located near the injectors.

- **Air Compressors** – A cost for two receivers was included in the cost estimate. Coal Creek Station's instrument air system has sufficient capacity. By not requiring new air compressors approximately $150k was avoided in PEC.
- **Monitoring Equipment** – The existing CEMS may be used for monitoring but to minimize ammonia consumption, individual monitors will be required in each furnace. The monitors will provide the necessary process control to allow operational control of each furnace, minimizing ammonia costs. The value included for the monitors was minimal and has no significant impact on the total project cost.
- **Taxes and Freight** – A general 7 percent tax (confirmed by GRE) and 5 percent freight charge are applied against the total capital costs. These numbers can fluctuate, but neither will have a significant impact on the overall price.

C.2.2 Direct Installation Costs

- **Electrical Construction** – This line item deals with installing the electrical equipment. The previous project's cost was escalated based on the units' difference in reagent flow rate.
- **Boiler Modifications** – New ports for the injection lances will be required, so new boiler penetrations will be needed. Babcock Power was contacted to obtain a general, high level cost for providing seal boxes and penetrations to be installed on site by GRE. GRE's labor costs and past experience, on the time required to install boiler penetrations, were used to calculate a general cost for the new ports. This is higher for the system with MNLs, because the MNLs are additional penetrations that are larger than traditional wall injectors.
- **Spare Parts, Training, Technical Assistance** – When installing a system, it is routine to have a set number of spare parts in the warehouse for startup and for turning over to the owner. Training and technical assistance from vendors is also necessary to properly install and startup the equipment. The previous project's cost was escalated based on the units' difference in reagent flow rate.

Appendix D. Site Specific Cost Estimate Summary Sheets

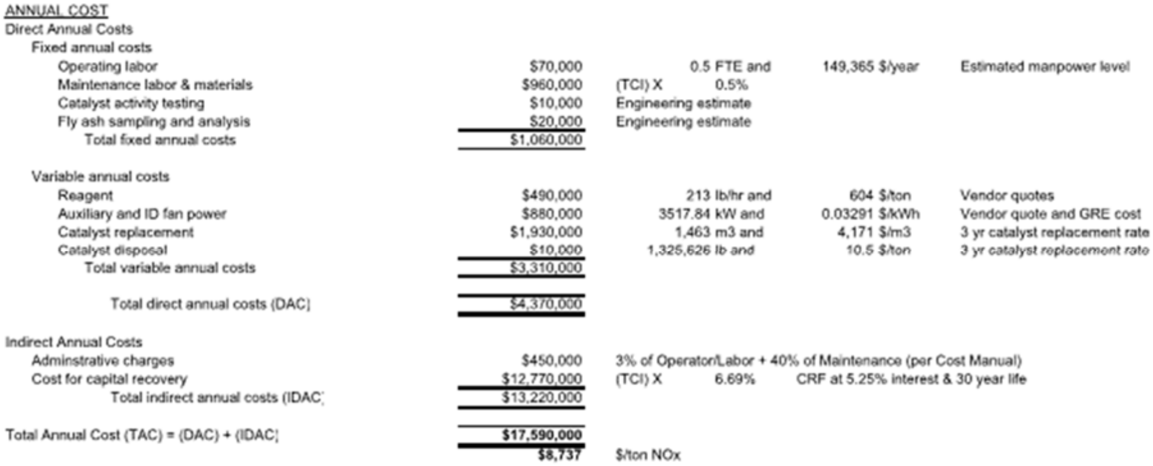


GRE Coal Creek - Cost Analysis

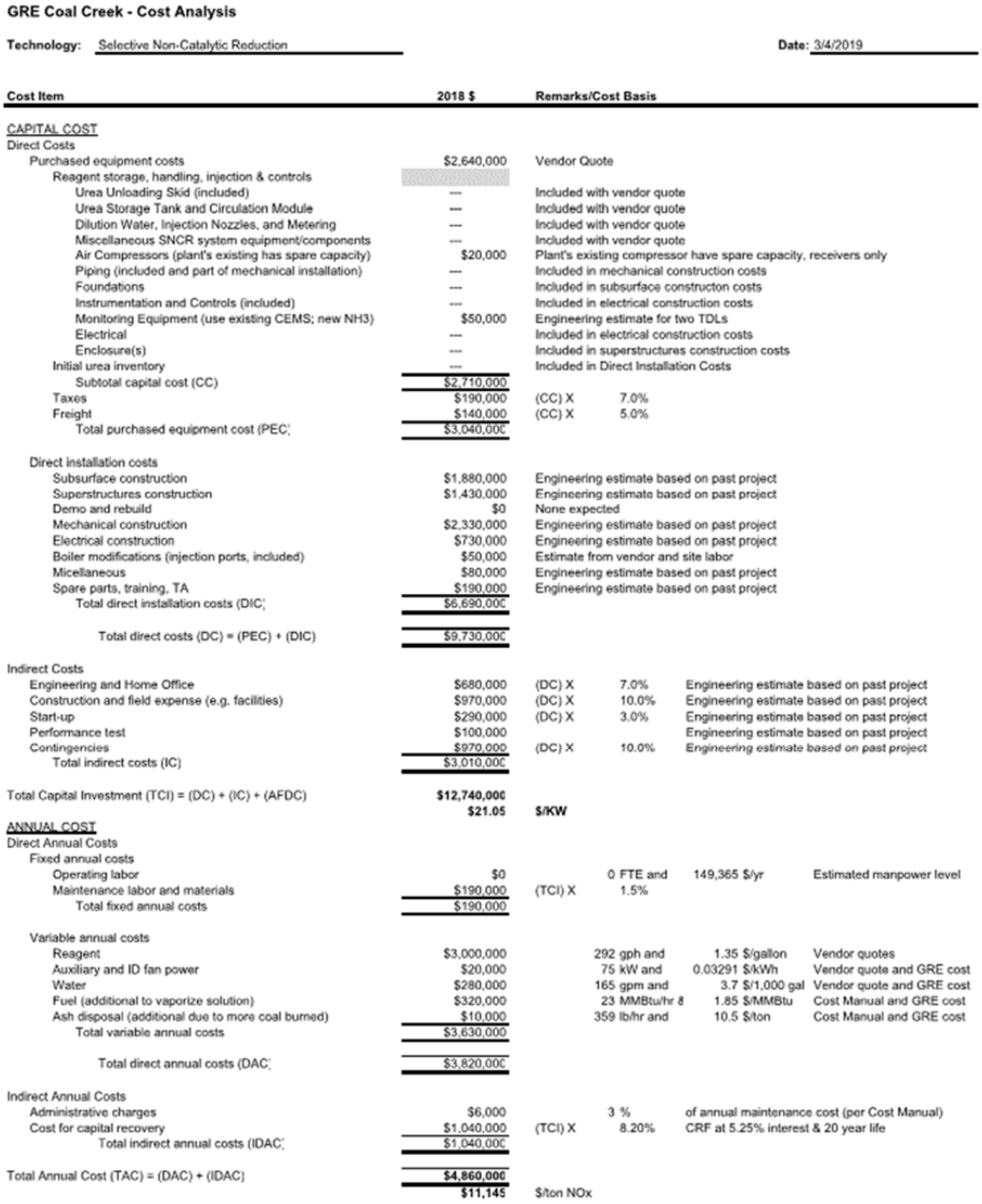
Technology: Selective Catalytic Reduction

Date: 3/4/2019

Cost Item	2018 $	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
Reactor housing	$3,690,000	Engineering estimate based on past project		
Ammonia handling and injection				
Ammonia Injection Grid & dilution skid	$2,260,000	Engineering estimate based on past project		
Anhydrous ammonia tank	$520,000	Engineering estimate based on past project		
Air Compressors (plant's existing has spare capacity)	$20,000	Plant's existing compressor have spare capacity, receivers only		
Vaporizers	$380,000	Engineering estimate based on past project		
Ammonia unloading skids	$530,000	Engineering estimate based on past project		
Ammonia supply pump skid	$200,000	Engineering estimate based on past project		
Miscellaneousequipment/components	$160,000	Engineering estimate based on past project		
Mixing Chamber (included)	---	Inlcuded as part of the dilution skid		
Piping (ammonia supply, etc)	---	Included in Mechanical Construction		
Initial catalyst (Ceram)	$6,100,000	Quote from catalyst supplier		
Flue gas handling: ductwork	$5,270,000	Engineering estimate based on past project		
Air heater modifications	$10,500,000	Per Cost Manual Equation 2.43		
ASH handling (e.g. conveyors)	$670,000	Engineering estimate based on past project		
Electrical equipment	$250,000	Engineering estimate based on past project		
Structrual steel	$10,600,000	Engineering estimate based on past project		
ID Fan (no upgrade or new required)	---	Fan curves indicate sufficient capacity for additional pressure drop		
Misc. equipment				
Sonic horns	$290,000	Engineering estimate based on past project		
LPA screens / rappers	$760,000	Engineering estimate based on past project		
NOx/NH3 monitoring	$1,340,000	Engineering estimate based on past project Added $20k for another monitor without emb		
Flow modeling	$190,000	Engineering estimate based on past project		
Subtotal capital cost (CC)	$43,710,000			
Instruments and controls	$870,000	(CC) X	2.0%	
Taxes	$3,060,000	(CC) X	7.0%	
Freight	$2,190,000	(CC) X	5.0%	
Total purchased equipment cost (PEC)	$49,830,000			
Direct installation costs				
Subsurface construction				
Earthwork, underground utilities, etc.	$4,070,000	Engineering estimate based on past project		
Foundations (including embedments)	$1,120,000	Engineering estimate based on past project		
Superstructures construction				
Reactor housing, ductwork, etc.	$28,380,000	Engineering estimate based on past project		
Heated building	$15,230,000	Engineering estimate based on past project		
Demo and Rebuild	$9,030,000			
Mechanical construction	$6,600,000	Engineering estimate based on past project		
Electrical construction	$4,350,000	Engineering estimate based on past project		
Spare parts, training, TA	$350,000	Engineering estimate based on past project		
Total direct installation costs (DIC)	$69,130,000			
Total direct costs (DC) = (PEC) + (DIC)	$118,960,000			
Indirect Costs				
Engineering	$8,330,000	(DC) X	7.0%	Engineering estimate based on past project
Construction and field expenses	$35,680,000	(DC) X	30.0%	Engineering estimate based on past project
Start-up	$3,570,000	(DC) X	3.0%	Engineering estimate based on past project
Performance test	$590,000	(DC) X	0.5%	Engineering estimate based on past project
Contingencies	$23,790,000	(DC) X	20.0%	Engineering estimate based on past project
Total indirect costs (IC)	$71,960,000			
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$190,920,000**			
	$316	**$/KW**		



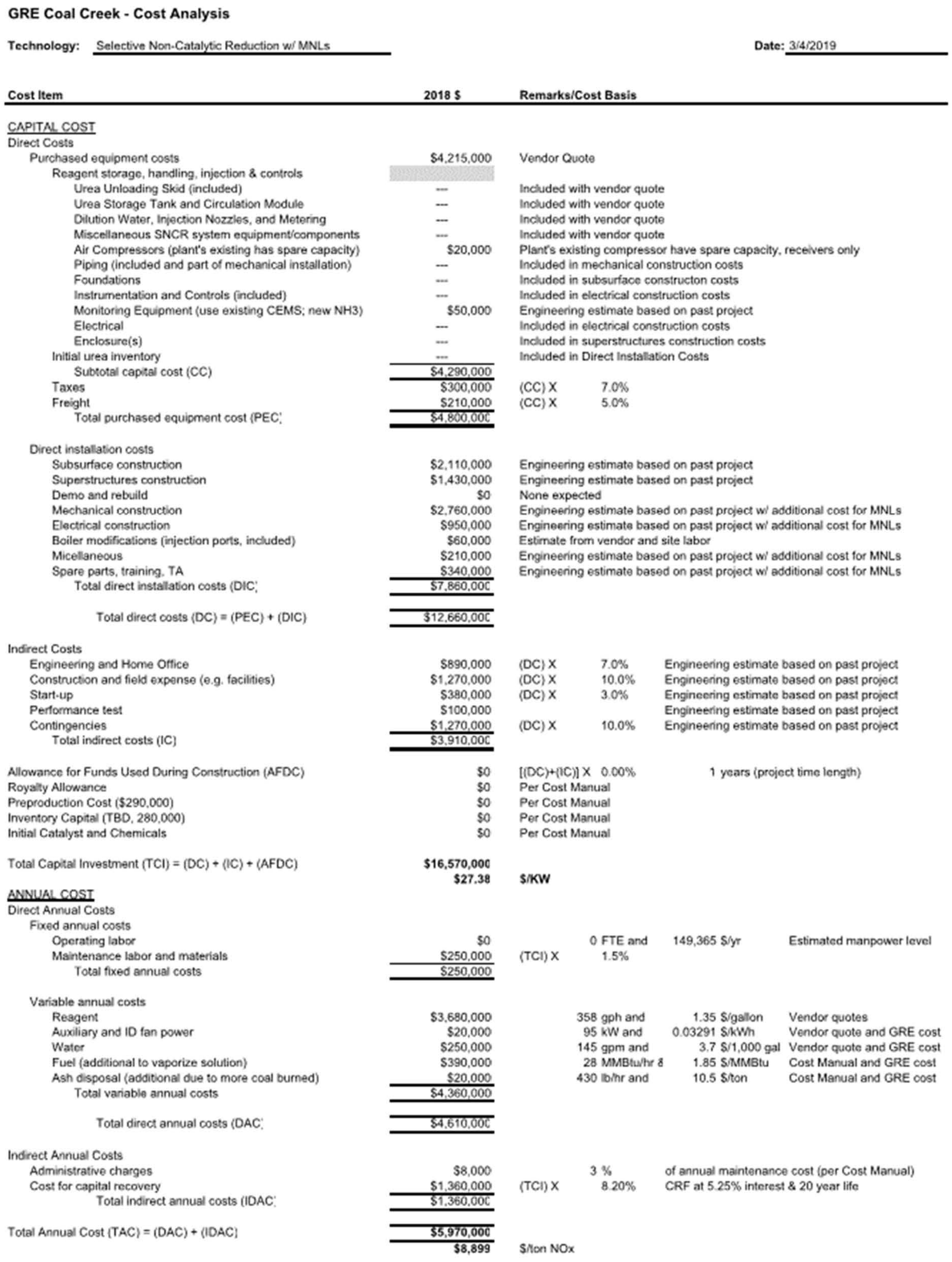
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Operating labor	$70,000	0.5 FTE and	149,365 $/year	Estimated manpower level
Maintenance labor & materials	$960,000	(TCI) X 0.5%		
Catalyst activity testing	$10,000	Engineering estimate		
Fly ash sampling and analysis	$20,000	Engineering estimate		
Total fixed annual costs	$1,060,000			
Variable annual costs				
Reagent	$490,000	213 lb/hr and	604 $/ton	Vendor quotes
Auxiliary and ID fan power	$880,000	3517.84 kW and	0.03291 $/kWh	Vendor quote and GRE cost
Catalyst replacement	$1,930,000	1,463 m3 and	4,171 $/m3	3 yr catalyst replacement rate
Catalyst disposal	$10,000	1,325,626 lb and	10.5 $/ton	3 yr catalyst replacement rate
Total variable annual costs	$3,310,000			
Total direct annual costs (DAC)	$4,370,000			
Indirect Annual Costs				
Adminstrative charges	$450,000	3% of Operator/Labor + 40% of Maintenance (per Cost Manual)		
Cost for capital recovery	$12,770,000	(TCI) X 6.69%		CRF at 5.25% interest & 30 year life
Total indirect annual costs (IDAC)	$13,220,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$17,590,000**			
	$8,737	$/ton NOx		



GRE Coal Creek - Cost Analysis

Technology: Selective Non-Catalytic Reduction **Date:** 3/4/2019

Cost Item	2018 $	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs	$2,640,000	Vendor Quote			
Reagent storage, handling, injection & controls					
Urea Unloading Skid (included)	---	Included with vendor quote			
Urea Storage Tank and Circulation Module	---	Included with vendor quote			
Dilution Water, Injection Nozzles, and Metering	---	Included with vendor quote			
Miscellaneous SNCR system equipment/components	---	Included with vendor quote			
Air Compressors (plant's existing has spare capacity)	$20,000	Plant's existing compressor have spare capacity, receivers only			
Piping (included and part of mechanical installation)	---	Included in mechanical construction costs			
Foundations	---	Included in subsurface construction costs			
Instrumentation and Controls (included)	---	Included in electrical construction costs			
Monitoring Equipment (use existing CEMS; new NH3)	$50,000	Engineering estimate for two TDLs			
Electrical	---	Included in electrical construction costs			
Enclosure(s)	---	Included in superstructures construction costs			
Initial urea inventory	---	Included in Direct Installation Costs			
Subtotal capital cost (CC)	$2,710,000				
Taxes	$190,000	(CC) X	7.0%		
Freight	$140,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$3,040,000				
Direct installation costs					
Subsurface construction	$1,880,000	Engineering estimate based on past project			
Superstructures construction	$1,430,000	Engineering estimate based on past project			
Demo and rebuild	$0	None expected			
Mechanical construction	$2,330,000	Engineering estimate based on past project			
Electrical construction	$730,000	Engineering estimate based on past project			
Boiler modifications (injection ports, included)	$50,000	Estimate from vendor and site labor			
Micellaneous	$80,000	Engineering estimate based on past project			
Spare parts, training, TA	$190,000	Engineering estimate based on past project			
Total direct installation costs (DIC)	$6,690,000				
Total direct costs (DC) = (PEC) + (DIC)	$9,730,000				
Indirect Costs					
Engineering and Home Office	$680,000	(DC) X	7.0%	Engineering estimate based on past project	
Construction and field expense (e.g. facilities)	$970,000	(DC) X	10.0%	Engineering estimate based on past project	
Start-up	$290,000	(DC) X	3.0%	Engineering estimate based on past project	
Performance test	$100,000			Engineering estimate based on past project	
Contingencies	$970,000	(DC) X	10.0%	*Engineering estimate based on past project*	
Total indirect costs (IC)	$3,010,000				
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$12,740,000**				
	$21.05	**$/KW**			
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Operating labor	$0		0 FTE and	149,365 $/yr	Estimated manpower level
Maintenance labor and materials	$190,000	(TCI) X	1.5%		
Total fixed annual costs	$190,000				
Variable annual costs					
Reagent	$3,000,000		292 gph and	1.35 $/gallon	Vendor quotes
Auxiliary and ID fan power	$20,000		75 kW and	0.03291 $/kWh	Vendor quote and GRE cost
Water	$280,000		165 gpm and	3.7 $/1,000 gal	Vendor quote and GRE cost
Fuel (additional to vaporize solution)	$320,000		23 MMBtu/hr 8	1.85 $/MMBtu	Cost Manual and GRE cost
Ash disposal (additional due to more coal burned)	$10,000		359 lb/hr and	10.5 $/ton	Cost Manual and GRE cost
Total variable annual costs	$3,630,000				
Total direct annual costs (DAC)	$3,820,000				
Indirect Annual Costs					
Administrative charges	$6,000		3 %	of annual maintenance cost (per Cost Manual)	
Cost for capital recovery	$1,040,000	(TCI) X	8.20%	CRF at 5.25% interest & 20 year life	
Total indirect annual costs (IDAC)	$1,040,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$4,860,000**				
	$11,145	$/ton NOx			



GRE Coal Creek - Cost Analysis

Technology: Selective Non-Catalytic Reduction w/ MNLs

Date: 3/4/2019

Cost Item	2018 $	Remarks/Cost Basis
CAPITAL COST		
Direct Costs		
Purchased equipment costs	$4,215,000	Vendor Quote
Reagent storage, handling, injection & controls		
Urea Unloading Skid (included)	---	Included with vendor quote
Urea Storage Tank and Circulation Module	---	Included with vendor quote
Dilution Water, Injection Nozzles, and Metering	---	Included with vendor quote
Miscellaneous SNCR system equipment/components	---	Included with vendor quote
Air Compressors (plant's existing has spare capacity)	$20,000	Plant's existing compressor have spare capacity, receivers only
Piping (included and part of mechanical installation)	---	Included in mechanical construction costs
Foundations	---	Included in subsurface constructon costs
Instrumentation and Controls (included)	---	Included in electrical construction costs
Monitoring Equipment (use existing CEMS; new NH3)	$50,000	Engineering estimate based on past project
Electrical	---	Included in electrical construction costs
Enclosure(s)	---	Included in superstructures construction costs
Initial urea inventory	---	Included in Direct Installation Costs
Subtotal capital cost (CC)	$4,290,000	
Taxes	$300,000	(CC) X 7.0%
Freight	$210,000	(CC) X 5.0%
Total purchased equipment cost (PEC)	$4,800,000	
Direct installation costs		
Subsurface construction	$2,110,000	Engineering estimate based on past project
Superstructures construction	$1,430,000	Engineering estimate based on past project
Demo and rebuild	$0	None expected
Mechanical construction	$2,760,000	Engineering estimate based on past project w/ additional cost for MNLs
Electrical construction	$950,000	Engineering estimate based on past project w/ additional cost for MNLs
Boiler modifications (injection ports, included)	$60,000	Estimate from vendor and site labor
Micellaneous	$210,000	Engineering estimate based on past project w/ additional cost for MNLs
Spare parts, training, TA	$340,000	Engineering estimate based on past project w/ additional cost for MNLs
Total direct installation costs (DIC)	$7,860,000	
Total direct costs (DC) = (PEC) + (DIC)	$12,660,000	
Indirect Costs		
Engineering and Home Office	$890,000	(DC) X 7.0% Engineering estimate based on past project
Construction and field expense (e.g. facilities)	$1,270,000	(DC) X 10.0% Engineering estimate based on past project
Start-up	$380,000	(DC) X 3.0% Engineering estimate based on past project
Performance test	$100,000	Engineering estimate based on past project
Contingencies	$1,270,000	(DC) X 10.0% Engineering estimate based on past project
Total indirect costs (IC)	$3,910,000	
Allowance for Funds Used During Construction (AFDC)	$0	[(DC)+(IC)] X 0.00% 1 years (project time length)
Royalty Allowance	$0	Per Cost Manual
Preproduction Cost ($290,000)	$0	Per Cost Manual
Inventory Capital (TBD, 280,000)	$0	Per Cost Manual
Initial Catalyst and Chemicals	$0	Per Cost Manual
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$16,570,000**	
	$27.38	**$/KW**
ANNUAL COST		
Direct Annual Costs		
Fixed annual costs		
Operating labor	$0	0 FTE and 149,365 $/yr Estimated manpower level
Maintenance labor and materials	$250,000	(TCI) X 1.5%
Total fixed annual costs	$250,000	
Variable annual costs		
Reagent	$3,680,000	358 gph and 1.35 $/gallon Vendor quotes
Auxiliary and ID fan power	$20,000	95 kW and 0.03291 $/kWh Vendor quote and GRE cost
Water	$250,000	145 gpm and 3.7 $/1,000 gal Vendor quote and GRE cost
Fuel (additional to vaporize solution)	$390,000	28 MMBtu/hr & 1.85 $/MMBtu Cost Manual and GRE cost
Ash disposal (additional due to more coal burned)	$20,000	430 lb/hr and 10.5 $/ton Cost Manual and GRE cost
Total variable annual costs	$4,360,000	
Total direct annual costs (DAC)	$4,610,000	
Indirect Annual Costs		
Administrative charges	$8,000	3 % of annual maintenance cost (per Cost Manual)
Cost for capital recovery	$1,360,000	(TCI) X 8.20% CRF at 5.25% interest & 20 year life
Total indirect annual costs (IDAC)	$1,360,000	
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$5,970,000**	
	$8,899	$/ton NOx

Appendix E. Supporting Documentation for Cost Estimates

IBIDEN CERAM

Black & Veatch
Attn. Mr. Mark Dittus
11401 Lamar Ave
Overland Park, Kansas 66211

June 18, 2019

Budgetary Catalyst Proposal for GRE Coal Creek SCR Project
B&V No. 400075.60.1000
CERAM Proposal No. GH190617-1 - Confidential

Dear Mr. Dittus:

With reference to your request for a budgetary quotation from the June 13, 2019 conference call, IBIDEN CERAM, Inc. (CERAM) is pleased to provide Black & Veatch (B&V) with our budgetary proposal for supplying selective catalytic reduction (SCR) catalyst for the Great River Energy (GRE) Coal Creek SCR Project. We have based our catalyst design on the design data e-mailed by B&V on October 9, 2018 and further correspondence provided in both May and June 2019. Our proposal described herein is based on supplying honeycomb catalyst manufactured at our production plant located in Frauental, Austria. Since 1985, CERAM has produced over 180,000 m^3 of SCR homogeneous honeycomb and plate type catalyst for over 1,600 applications and is a world leader in the supply of this product. CERAM has proposed using our [redacted] pitch honeycomb catalyst for this application due to the high temperature and required specific surface area.

B&V specified that the catalyst would be in a high dust arrangement or immediately downstream of the economizer boiler section. There were no design constraints on the size or number of SCR reactors or catalyst layers required to meet the DeNOx demand (e.g., 69% NOx reduction and 2 ppmvdc ammonia slip for 24,000 hours). The design information indicated the fuel to be North Dakota (ND) lignite. CERAM does not have direct experience with ND lignite, but we have developed a wide portfolio of experience and have mainly focused on “dirty” gas applications. While not every application has the exact same design basis, we do have experience with other lignite and brown coal fired applications using both of our honeycomb and plate catalysts. However, the high levels of sodium oxide (Na_2O) (>4%) in the ash for the ND lignite are not commonly found in sub-bituminous, bituminous and other lignite coals based on our supplied experience. Moreover, the ND coal analysis indicates there are high levels of various other catalyst poisons (arsenic, potassium, etc.) and masking agents (calcium sulfate, etc.,) that must be taken into consideration in an SCR catalyst design. Table 1 summarizes our budgetary catalyst design for the project. Additional design details are provided in Attachment A. Table 2 summarizes the scope of supply, delivery, and budgetary pricing regarding this offering.

Table 1. GRE Coal Creek SCR Catalyst Design Summary(1)

Catalyst Design:		
Catalyst Pitch / Element Length, mm	[redacted] / [redacted]	
No. of Reactors / Initial Layers Installed	2 / 3	
Module Arrangement per Layer	13 x 9	
Catalyst Volume/Reactor, m^3	[redacted]	
Performance:(2),(3)	**Case 1**	**Case 2**
Inlet NOx, ppmvd act. O_2	126	60
Outlet NOx, ppmvd act. O_2	39 (69% reduction)	18.6 (69% reduction)
Initial Pressure Drop, in. w.g.	2.1 (clean) / 2.6 (dirty)	
Initial Ammonia Slip, ppmvd ref. O_2	2	
Initial SO_2 to SO_3 Oxidation Rate, %	5	
Guarantee Life, (hours)	24,000 (or 36 months from delivery); Dependent on Pilot Scale Test Results	

Notes:

1. Reference Attachment A (CERAM data sheet) for further information.
2. SO_2 to SO_3 oxidation design for ammonia on conditions ($\alpha = 1$).
3. Guarantees for NOx reduction, ammonia slip, pressure drop and SO_2 to SO_3 oxidation for Test A only (reference proposal for further information).

Table 2 – GRE Coal Creek
Catalyst Scope of Supply and Budgetary Pricing

Scope of Supply:
Production Testing and Documentation
Catalyst with Steel Module Frames
Module-to-Module and Module-to-Reactor Wall Seals
50% of the Frames with 1 Removable Full Size Test Element
20 Replacement Test Elements
Cover Grates for Each Module
Four Lifting Frames
Operation & Maintenance Manuals & Required Performance Curves
Catalyst Module, Lifting Frame and Seal Drawings (6 weeks after receipt of order)
Protective Crating to the Site
Freight to Jobsite (DDP to site; Assume delivery 1st quarter 2021)

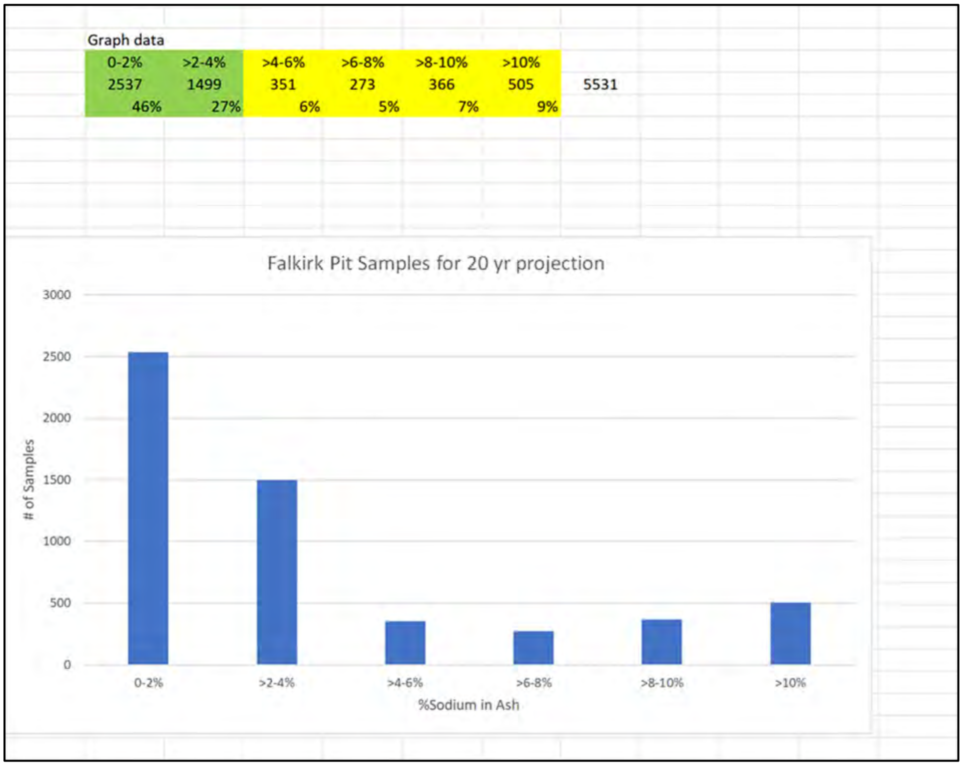
Budgetary Pricing: (Validity is 60 Days) Base Design: [redacted] Pitch Catalyst ([redacted])	$6,100,000

Note:

(1) CERAM is willing to work with GRE and B&V with regards to payment terms in order to meet the project requirements. We understand that at this point in the project the main commercial driver is the performance guarantees and budgetary catalyst scope of supply pricing.

Catalyst Deactivation

CERAM's experience with sodium levels greater than 4% has shown that catalyst deactivation would be higher than a typical bituminous or sub-bituminous coal fired application. Figure 1 shows the percentages of sodium from the Falkirk mine based on 5,531 samples. Our catalyst design was based on a maximum sodium percentage of 4% (12% ash). The data indicates that for approximately 27% of the samples the sodium percentage would be greater than 4%. While CERAM does not have direct experience with firing North Dakota lignite, we based our current design on our biomass experience (e.g., wood, switch grass, etc.,) where there are also high alkalis, such as potassium and sodium. However, the upper range of sodium shown in the ND lignite data set is outside our operating experience. Therefore, we expect the catalyst deactivation to be accelerated due to the higher levels of sodium (>4%).



Graph data

0-2%	>2-4%	>4-6%	>6-8%	>8-10%	>10%	
2537	1499	351	273	366	505	5531
46%	27%	6%	5%	7%	9%	

Figure 1. Sodium in ash percentages from the Falkirk Pit samples based on 20 year projections provided by GRE/B&V.

CERAM's experience with biomass applications in a high dust arrangement were successful because we were able to take advantage of the lower flame temperature (e.g., less oxidized poisons) with using a bubbling fluidized bed (BFB) boiler and the nature of a BFB where there is available sorbent (e.g., limestone) that can absorb a portion of the catalyst poisons and a large portion of the ash is entrained. Pulverized coal (PC) boilers in a high dust arrangement can lead to an increase in deactivation due to the higher local flame temperature and areas of incomplete combustion that both can lead to a severe increase in oxidized poisons, such as sodium oxide, arsenic trioxide, etc.

Catalyst deactivation due to the high sodium levels will occur based on normal operations from the formation of sodium aerosols and from poisoning that would occur during outages. The effects of sodium in the particulate form can be controlled by maintaining warm and dry conditions on the catalyst at all times during layup conditions of the SCR reactor. However, if there are moist conditions on the catalyst, such as condensation during an outage then the particulate bound sodium will leach into the pore structure of the catalyst where catalyst poisoning will occur. Small aerosol particles will penetrate and neutralize active catalyst sites even in dry conditions; however the effect is much worse when moisture is present. The current catalyst management plan from GRE and B&V would be to replace all of the catalyst every three years due to Coal Creeks expected three year outage cycle. CERAM agrees this would eliminate the effects of deactivation during scheduled outages, since all six levels of catalyst would be replaced, however the forced outages must also be taken into consideration. There must be no moisture in the SCR reactor during layup or when the SCR is isolated for example during an unexpected boiler outage. In this regard, maintaining temperatures greater than or equal to 300 F would be recommended. Prior to short term isolation the catalyst layers should be air purged with dry acid free air to prevent condensation of moisture on the catalyst surface and never isolate the reactor with flue gas. Startups and the time needed to put the SCR in surface would need to be minimized/optimized to reduce the effects of deactivation. Due to the possibility of high sodium concentrations, CERAM would recommend a full SCR bypass system be installed. During lay-up periods the catalyst would need to remain warm and dry perhaps by using an air drying or dehumidification system.

Catalyst Performance Guarantees

Catalyst deactivates due to the exposure of flue gas. It is known in the industry that catalyst deactivation is a result of the operating conditions and fuels fired, and is independent of catalyst type or manufacturer. The goal of properly designing catalyst is to accurately predict the rate of catalyst deactivation for a given project. Since there is no direct experience in the industry with SCR catalyst installed on a unit firing ND lignite, it is difficult to determine with a high level of certainty what the long term impacts will be on the SCR catalyst. As such, it is very risky and difficult to provide life guarantees for this application until further field testing is performed to fully assess the long term impacts.

Based on the budgetary catalyst design included herein, CERAM would be willing to provide initial (Test A) performance guarantees which would include NOx reduction, ammonia slip, SO_2 to SO_3 conversion rate, pressure drop and ammonia slip. Additional, data that would be very useful would be to understand the concentrations and particle size distribution of the probable catalyst poisons from firing ND lignite. The most critical information is how the small particles which are present in the flue gas stream will affect the catalyst by either poisoning or fouling mechanisms. CERAM believes that with additional field testing information that catalyst life guarantees could also be provided. The budgetary design presented is for a 24,000 hour or 3 year period to reflect the planned outage schedule at Coal Creek, however CERAM is unable to offer end of life performance guarantees given the potential for high sodium levels without additional field information. CERAM would recommend a pilot test using CERAM's CoPilot® Test Reactor, or a similar device to develop long term trends associated with catalyst deactivation.

The pilot test program would involve flue gas exposure of one to several catalyst elements under conditions that would replicate the actual SCR system. CERAM recommends at least 2,000 hours of exposure per catalyst sample. As many as 5,000 hours of exposure would be preferred. Based on participation in such a pilot test program, CERAM would be able to provide 24,000 hour life guarantees for this project. In this situation, CERAM would prefer to work in an "open book" manner to design the catalyst with direct input from B&V and GRE with regards to catalyst design and sizing margin.

We hope this proposal meets your expectations. Please contact John Cochran (john.cochran@ceram-usa.com) or myself (greg.holscher@ceram-usa.com) at 913-239-9896 should you have any questions or need any further information.

Yours sincerely,
IBIDEN CERAM, Inc.

Gregory A. Holscher

Gregory A. Holscher, Ph.D.
Senior Applications Engineer

cc: Mr. Paul Lee (B&V)
Mr. John Cochran (CERAM)
Mr. Kurt Orehovsky (CERAM)

Enclosures

1. Attachment A – CERAM Data Sheets

Reference List

for plate catalyst projects as of July 2018

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Fuel	Configuration	Shipped quantity	Delivery date
1.	**KW Dürnrohr**	EVN	EVN	AUT	Steam Power Plant	Bituminous Coal	High Dust	2 m³	2010
2.	**KW Mehrum**	Kraftwerk Mehrum	Kraftwerk Mehrum	DEU	Steam Power Plant	Bituminous Coal	High Dust	165 m³	2011
3.	**Laziska Unit 12**	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	295 m³	2011
4.	**China Steel Unit # 7**	Fuel Tech	China Steel Corp.	TWN	Steam Power Plant	Bituminous Coal	High Dust	25 m³	2012
5.	**Laziska Unit 11**	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	295 m³	2012
6.	**Kozienice Unit 6**	Termokimik	Elektrownia "Kozienice" S.A	POL	Steam Power Plant	Bituminous Coal	High Dust	379 m³	2012
7.	**KS 1/2**	Strabag	Formosa Plastics Corporation (FPG)	TWN	Steam Power Plant	Bituminous Coal	High Dust	92 m³	2012
8.	**JH 1**	Strabag	FPG	TWN	Steam Power Plant	Bituminous Coal	High Dust	54 m³	2012
9.	**LP1**	Strabag	FPG	TWN	Steam Power Plant	Bituminous Coal	High Dust	54 m³	2012
10.	**JH 1 Spare Layer**	Strabag	FPG	TWN	Steam Power Plant	Bituminous Coal	High Dust	29 m³	2012
11.	**Samkwang Glass**	Haelim Eng. Co.	Samkwang Glass Co.	KOR	Glass Trough	Natural Gas	Low Dust	12 m³	2012
12.	**KCC GF #1**	Hae Cheon Industrial Co. Ltd	Kumkang Korea Chemical Co, Ltd	KOR	Glass Trough	Natural Gas	Low Dust	15 m³	2012
13.	**JP1 Spare Layer**	FPG	FPG	TWN	Steam Power Plant	Bituminous Coal	High Dust	37 m³	2012
14.	**Yushe Unit 3**	Huaneng	Huaneng	CHN	Steam Power Plant	Bituminous Coal	High Dust	425 m³	2012
15.	**Maasvlakte Unit 1**	E.ON	E.ON	NDL	Steam Power Plant	Bituminous Coal	High Dust	265 m³	2012
16.	**Yonghung #4**	KOSEP	KOSEP	KOR	Steam Power Plant	Bituminous Coal	High Dust	445 m³	2013
17.	**Polaniec**	Termokimik	GDF Suez	POL	Steam Power Plant	Bituminous Coal	High Dust	255 m³	2013
18.	**Maasvlakte Unit 2**	E.ON	E.ON	NDL	Steam Power Plant	Bituminous Coal	High Dust	265 m³	2013
19.	**Elm Road Unit 2**	WE Energies	WE Energies	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	295 m³	2013
20.	**Yushe Unit 4**	Huaneng	Huaneng	CHN	Steam Power Plant	Bituminous Coal	High Dust	425 m³	2013
21.	**KS 3**	Strabag	FPG	TWN	Steam Power Plant	Bituminous Coal	High Dust	77 m³	2013
22.	**KP 1**	Strabag	FPG	TWN	Steam Power Plant	Bituminous Coal	High Dust	61 m³	2013
23.	**Laziska Unit 10**	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	295 m³	2013
24.	**Kozienice Unit 7**	Termokimik	Elektrownia "Kozienice" S.A	POL	Steam Power Plant	Bituminous Coal	High Dust	379 m³	2013
25.	**China Steel Unit # 6**	Fuel Tech	China Steel Corp.	TWN	Steam Power Plant	Bituminous Coal	High Dust	51 m³	2013

Reference List

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Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Fuel	Configuration	Shipped quantity	Delivery date
26.	**Nexen Tire**	Haelim Eng. Co.	Nexen Tire Co. Ltd.	KOR	Industrial Plant	Pet Coke	High Dust	10 m³	2013
27.	**TYC**	Strabag	Ta-Yuan Cogeneration Co., Ltd.	TWN	Steam Power Plant	Bituminous Coal	High Dust	51 m³	2013
28.	**Hadong #8 Replacement**	KOSPO	KOSPO	KOR	Steam Power Plant	Bituminous Coal	High Dust	93 m³	2013
29.	**China Steel Unit # 8**	Fuel Tech	China Steel Corp.	TWN	Steam Power Plant	Bituminous Coal	High Dust	51 m³	2013
30.	**Nantong Fiber 8&9**	Jiangsu Sunco Boiler Co. Ltd.	Nantong Cellulose Fibers Co.	CHN	Steam Power Plant	Bituminous Coal	High Dust	92 m³	2013
31.	**Boryeong TPP # 6**	KOMIPO	KOMIPO	KOR	Steam Power Plant	Bituminous Coal	High Dust	223 m³	2013
32.	**HanFeng #1**	Huaneng	Huaneng	CHN	Steam Power Plant	Bituminous Coal	High Dust	890 m³	2013
33.	**Pleasant Prairie Unit 1**	WE Energies		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	404 m³	2014
34.	**HanFeng #2**	Huaneng	Huaneng	CHN	Steam Power Plant	Bituminous Coal	High Dust	890 m³	2014
35.	**Pleasant Prairie Unit 2**	WE Energies		USA	Steam Power Plant	Bituminous Coal	High Dust	404 m³	2014
36.	**Laziska Unit 9**	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	295 m³	2014
37.	**Kozienice Unit 5**	Termokimik	Elektrownia "Kozienice" S.A	POL	Steam Power Plant	Bituminous Coal	High Dust	379 m³	2014
38.	**Nanyang Tianyi Unit 4**	Dongfang Boiler Group Co. Ltd.	Nanyang Tianyi Power Generation Co.,Ltd.	CHN	Steam Power Plant	Bituminous Coal	High Dust	736 m³	2014
39.	**Nantong Fiber 6**	Jiangsu Sunco Boiler Co. Ltd.	Nantong Cellulose Fibers Co.	CHN	Steam Power Plant	Bituminous Coal	High Dust	38 m³	2014
40.	**Nanyang Yahekou #1**	Tongfang Environment Co. Ltd.	Nanyang Yahekou Power Generation Co.,Ltd.	CHN	Steam Power Plant	Bituminous Coal	High Dust	453 m³	2014
41.	**Torrevaldaliga L1**	ENEL		ITA	Steam Power Plant	Bituminous Coal	High Dust	216 m³	2014
42.	**Sostanj Unit 6**	ALSTOM Boiler Deutschland GmbH	TES Termoelektrana Sostanj	SLO	Steam Power Plant	Lignite Coal	High Dust	584 m³	2014
43.	**Taean #6**	Korea Western Power Co.	Korea Western Power Co.	KOR	Steam Power Plant	Bituminous Coal	High Dust	556 m³	2014
44.	**Detmarovice 3&4**	Strabag	CEZ	CZE	Steam Power Plant	Bituminous Coal	High Dust	429 m³	2014
45.	**Rybnik 7&8**	Strabag	EDF Poland	POL	Steam Power Plant	Bituminous Coal	High Dust	604 m³	2014
46.	**Nantong Fiber 2nd supply**	Nantong Sanpu Electrical&Mechanical	Nantong Cellulose Fibers Co.	CHN	Steam Power Plant	Bituminous Coal	High Dust	38 m³	2014
47.	**KS1 Spare Layer**	Strabag	Formosa Plastics Corporation (FPG)	TWN	Steam Power Plant	Bituminous Coal	High Dust	19 m³	2014
48.	**Nantong Fiber 7**	Jiangsu Sunco Boiler Co. Ltd.	Nantong Cellulose Fibers Co.	CHN	Steam Power Plant	Bituminous Coal	High Dust	38 m³	2014
49.	**Ningbo 2**	Strabag	Formosa Chemicals & Fibre Corporation Co., Ltd.	CHN	Steam Power Plant	Bituminous Coal	High Dust	165 m³	2014
50.	**KCC GF #7**	Hae Cheon Industrial Co. Ltd	Kumkang Korea Chemical Co, Ltd	KOR	Glass Trough	Natural Gas	Low Dust	77 m³	2014

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Fuel	Configuration	Shipped quantity	Delivery date
51.	**SK3**	Strabag		TWN	Steam Power Plant	Bituminous Coal	High Dust	153 m^3	2014
52.	**Laziska Unit 12**	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	26 m^3	2014
53.	**Bialystok Boiler K7+K8**	Strabag	Elektrocieplownia Bialystok	POL	Steam Power Plant	Bituminous Coal	High Dust	212 m^3	2014/2015
54.	**Torrevaldaliga L2**	ENEL		ITA	Steam Power Plant	Bituminous Coal	High Dust	216 m^3	2015
55.	**Torrevaldaliga L3**	ENEL		ITA	Steam Power Plant	Bituminous Coal	High Dust	216 m^3	2015
56.	**Hawthorn Unit 5 - Layer 1**	KCP&L	GPES	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	278 m^3	2015
57.	**Nantong Fiber #5**	Nantong Sanpu Electrical&Mechanical	Nantong Cellulose Fibers Co.	CHN	Steam Power Plant	Bituminous Coal	High Dust	38 m^3	2015
58.	**KS2 Spare Layer**	Strabag	FPG	TWN	Steam Power Plant	Bituminous Coal	High Dust	38 m^3	2015
59.	**Oak Grove**	Luminant		USA		Lignite Coal		36 m^3	2015
60.	**Amos Unit 1**	AEP	AEP	USA	Steam Power Plant	Bituminous Coal	High Dust	472 m^3	2015
61.	**Kozienice Unit 4**	Termokimik	Elektrownia "Kozienice" S.A	POL	Steam Power Plant	Bituminous Coal	High Dust	379 m^3	2015
62.	**KW Heyden**	E.ON	E.ON	DEU	Steam Power Plant	Bituminous Coal	High Dust	439 m^3	2015
63.	**Laziska Unit 11**	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	13 m^3	2015
64.	**La Cygne Unit 1**	KCP&L	GPES	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	491 m^3	2015
65.	**TREA Breisgau**	EEW Energy from Waste Saarbrücken GmbH		DEU	Steam Power Plant	Municipal Waste	Low Dust	34 m^3	2015
66.	**Nantong Fiber #6 Spare**	Nantong Cellulose Fibers Co.		CHN	Steam Power Plant	Bituminous Coal	High Dust	19 m^3	2015
67.	**Brown Unit 3**	Kentucky Utilities		USA	Steam Power Plant	Bituminous Coal	High Dust	340 m^3	2015
68.	**BASF Yeosu Plant**	BASF		KOR	Steam Power Plant	Bituminous Coal	High Dust	24 m^3	2015
69.	**Nantong Fiber Unit 10 & 11**	Nantong Cellulose Fibers Co.		CHN	Steam Power Plant	Bituminous Coal	High Dust	57 m^3	2015
70.	**Ostroleka K2 + K3**	Termokimik		POL	Steam Power Plant	Bituminous Coal	High Dust	455 m^3	2015
71.	**Laziska Unit 12 repl. 2015**	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	117 m^3	2015
72.	**Laziska Unit 12**	Strabag	PKE S.A. Laziska Power Plant	POL	Steam Power Plant	Bituminous Coal	High Dust	117 m^3	2015
73.	**Duke Gibson Unit 5**	Duke Energy		USA	Steam Power Plant	Bituminous Coal	High Dust	101 m^3	2015
74.	**Nantong Fiber Phase 3**	Nantong Sanpu Electrical and Mechanical Technology		CHN	Steam Power Plant	Bituminous Coal	High Dust	28 m^3	2015
75.	**Hawthorn Unit 5 - Layer 2**	KCP&L	GPES	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	278 m^3	2016

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Fuel	Configuration	Shipped quantity	Delivery date
76.	**Kozienice Unit 8**	Termokimik	Elektrownia "Kozienice" S.A	POL	Steam Power Plant	Bituminous Coal	High Dust	379 m^3	2016
77.	**Kyger Creek Unit 1-5**	AEP	AEP	USA	Steam Power Plant	PRB & Bituminous Coal	High Dust	630 m^3	2016
78.	**Pleasant Prairie Unit 1 + 2**	WE Energies		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	906 m^3	2016
79.	**Campbell Unit 3**	Consumers Energy		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	1011 m^3	2016
80.	**Sikierki K2**	Andritz AG		POL	Steam Power Plant	Bituminous Coal	High Dust	88 m^3	2016
81.	**Yonghung #4 RP**	KOSEP		KOR	Steam Power Plant	Bituminous Coal	High Dust	142 m^3	2016
82.	**KS-1 2nd Spare Layer**	Yara Taiwan		CHN	Steam Power Plant	Bituminous Coal	High Dust	15 m^3	2016
83.	**TREA Breisgau**	EEW Energy		DEU	Steam Power Plant	Municipal Waste	Low Dust	27 m^3	2016
84.	**LongChen Hubei**	Yara		CHN	Steam Power Plant	Bituminous Coal	High Dust	106 m^3	2016
85.	**Laziska Unit 12**	Yara	PKE S.A. Laziska Power Plant	PL	Steam Power Plant	Bituminous Coal	High Dust	6 m^3	2016
86.	**FP1**	Yara Taiwan		TWN	Steam Power Plant	Bituminous Coal	High Dust	133 m^3	2016
87.	**Detmarovice K3**	Strabag/Yara		CZE	Steam Power Plant	Bituminous Coal	High Dust	56 m^3	2016
88.	**Boswell Unit 3**	Minnesota Power		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	211 m^3	2016
89.	**Yahekou #1**	JiangHe Mechanical		CHN	Steam Power Plant	Bituminous Coal	High Dust	227 m^3	2016
90.	**Gheco One**	Laborelec		THA	Steam Power Plant	Bituminous Coal	High Dust	307 m^3	2016
91.	**Iatan Unit 2**	KCP&L		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	472 m^3	2016
92.	**Sibley Unit 3**	KCP&L		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	227 m^3	2016
93.	**LongChen Hubei**	Yara Taiwan	Long Chen Paper Corporation	CHN	Steam Power Plant	Bituminous Coal	High Dust	106 m^3	2016
94.	**Bowen Unit 2**	Southern Company		USA	Steam Power Plant	Bituminous Coal	High Dust	330 m^3	2016
95.	**Scherer Unit 2**	Southern Company		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	642 m^3	2016
96.	**Crist Unit 7**	Southern Company		USA	Steam Power Plant	Bituminous Coal	High Dust	295 m^3	2016
97.	**FP1**	Yara Taiwan	Mai-Liao Power Corporation	Taiwan	Steam Power Plant	Bituminous Coal	High Dust	133 m^3	2016
98.	**EWB Bern**	Energie Wasser Bern		CH	Steam Power Plant	Municipal Waste	Low Dust	41 m^3	2016
99.	**HP5**	Yara Taiwan	Formosa Petrochemical Corp.	TWN	Steam Power Plant	Bituminous Coal	High Dust	165 m^3	2016
100.	**HP1**	Yara Taiwan	Formosa Petrochemical Corp.	TWN	Steam Power Plant	Bituminous Coal	High Dust	74 m^3	2016

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Fuel	Configuration	Shipped quantity	Delivery date
101.	**Tianyi**	JiangHe Mechanical		CHN	Steam Power Plant	Bituminous Coal	High Dust	368 m^3	2016
102.	**Hadong #8**	KOSPO		KOR	Steam Power Plant	Bituminous Coal	High Dust	46 m^3	2016
103.	**KY1**	Yara Taiwan		TWN	Steam Power Plant	Bituminous Coal	High Dust	21 m^3	2016
104.	**KY2 + KY3**	Yara Taiwan		TWN	Steam Power Plant	Bituminous Coal	High Dust	42 m^3	2016
105.	**Nantong Fiber**	Nantong Sanpu		CHN	Steam Power Plant	Bituminous Coal	High Dust	28 m^3	2016
106.	**Opole Unit 5 + 6**	GE Boiler Deutschland	PGE Górnictwo i Energetyka Konwencjonalna S.A.	PL	Steam Power Plant	Bituminous Coal	High Dust	2064 m^3	2016/2017
107.	**Mill Creek Unit 3+4**	LG&E / Kentucky Uti.	LG&E / Kentucky Uti.	USA	Steam Power Plant	Bituminous Coal	High Dust	566 m^3	2016/2017
108.	**Duyen Hai 3**	Babcock & Wilcox		VIE	Steam Power Plant	Bituminous Coal	High Dust	675 m^3	2017
109.	**Four Corners Unit 4+5**	Babcock Power Inc.		USA	Steam Power Plant	Bituminous Coal	High Dust	3171 m^3	2017
110.	**Sibley Unit 3**	KCP&L		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	453 m^3	2017
111.	**Taiwan PJT**	JGC C&C		TWN	Steam Power Plant	Bituminous Coal	High Dust	30 m^3	2017
112.	**Barry 5**	Southern Company		USA	Steam Power Plant	Bituminous Coal	High Dust	400 m^3	2017
113.	**Gorgas Unit 10**	Southern Company		USA	Steam Power Plant	Bituminous Coal	High Dust	413 m^3	2017
114.	**Polaniec Unit #7**	Engie Energia Polska		PL	Steam Power Plant	Bituminous Coal	High Dust	256 m^3	2017
115.	**Scherer Unit 3**	Southern Company		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	642 m^3	2017
116.	**TREA Breisgau**	EEW Energy from Waste Saarbrücken GmbH		DE	Steam Power Plant	Municipal Waste	Low Dust	54 m^3	2017
117.	**Laziska Unit 10**	Strabag	PKE S.A. Laziska Power Plant	PL	Steam Power Plant	Bituminous Coal	High Dust	51 m^3	2017
118.	**KCC GF #3 & #6**	Haecheon		KOR	Glass trough	Natural Gas	Low Dust	16 m^3	2017
119.	**Bowen Unit 4**	Southern Company	Southern Company	USA	Steam Power Plant	Bituminous Coal	High Dust	8 m^3	2017
120.	**Iatan Unit 1**	KCP&L	KCP&L	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	493 m^3	2017
121.	**Nantong Fiber**			CN	Steam Power Plant	Bituminous Coal	High Dust	33 m^3	2017
122.	**EWB Bern**	Energie Wasser Bern	Energie Wasser Bern	CH	Steam Power Plant	Municipal Waste	Low Dust	14 m^3	2017
123.	**Kollenbach Platte**	Yara	Yara	D	Cement Plant	Fossile Fuels + Additional Fuels	High Dust	3 m^3	2017
124.	**Sostanj**	TES Termoelektrana Sostanj		SLO	Steam Power Plant	Lignite Coal	High Dust	292 m^3	2017
125.	**Ostroleka K1**	Termokimik	Termokimik	PL	Steam Power Plant	Bituminous Coal	High Dust	228 m^3	2018

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Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Fuel	Configuration	Shipped quantity	Delivery date
126.	**Ottumwa Unit 1**	BPI/Alliant Energy	Alliant Energy	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	1246 m^3	2018
127.	**Crist Unit 7**	Southern Company	Southern Company	USA	Steam Power Plant	Bituminous Coal	High Dust	590 m^3	2018
128.	**Kyger Creek Unit 1-5**	AEP	AEP	USA	Steam Power Plant	PRB & Bituminous Coal	High Dust	630 m^3	2018
129.	**Sibley 3**	KCP&L	KCP&L	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	38 m^3	2018
130.	**Bowen Unit 1**	Southern Company	Georgia Power Company	USA	Steam Power Plant	Bituminous Coal	High Dust	727 m^3	2018
131.	**Laziska Unit 9**	Strabag	PKE S.A. Laziska Power Plant	PL	Steam Power Plant	Bituminous Coal	High Dust	46 m^3	2018
132.	**TREA Breisgau**	EEW Energy from Waste Saarbrücken GmbH		DEU	Steam Power Plant	Municipal Waste	Low Dust	34 m^3	2015
133.	**KCC GF #3**	Hae Cheon Industrial Co. Ltd		KOR	Glass Trough	Natural Gas	Low Dust	11 m^3	2018
134.	**Uvelia Herstal**	Laborelec		BE	Steam Power Plant	Municipal Waste	Low Dust	53 m^3	2018
135.	**Han Glass**	Hacheon Industry		KOR	Glass Trough	Natural Gas	Low Dust	21 m^3	2018
136.	**Gheco One**	Laborelec		THA	Steam Power Plant	Bituminous Coal	High Dust	307 m^3	2018
137.	**Nantong Fiber**	Nantong Sanpu		CHN	Steam Power Plant	Bituminous Coal	High Dust	38 m^3	2018
138.	**Boswell Unit 3**	Minnesota Power	Boswell Energy Center	USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	169 m^3	2018
139.	**Hitachinaka**	TEPCO		JPN	Steam Power Plant	Bituminous Coal	High Dust	833 m^3	2018
140.	**Parish Unit 7**	NRG		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	455 m^3	2019
141.	**Parish Unit 5**	NRG		USA	Steam Power Plant	PRB/Sub-bituminous	High Dust	769 m^3	2019
142.	**Opole Unit 5**	GE Boiler Deutschland	PGE Górnictwo i Energetyka Konwencjonalna S.A.	PL	Steam Power Plant	Bituminous Coal	High Dust	258 m^3	2019
	Total							**40321 m^3**	

Reference List for Coal
for Honeycomb Catalyst
as of August 2018

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
1.	**FHKW Mellach**	SGP	STEWEAG	AUT	Bituminous Coal, High Dust	287 m³	1986
2.	**Altbach**	Steinmüller	EnBW	DEU	Coal / Oil	132 m³	1987 / 88
3.	**Wedel I/II**	Steinmüller	HEW	DEU	Coal, High Dust	370 m³	1987
4.	**FHKW Mellach 4. Lage**	SGP	STEWEAG	AUT	Bituminous Coal, High Dust	94 m³	1988
5.	**Karlsruhe**	DBA	EnBW	DEU	Coal, Tail End	60 m³	1988
6.	**Bexbach**	EVT	SaarEnergie	DEU	Coal, High Dust	858 m³	1988
7.	**Herne 1, 2, 3**	KWH	STEAG	DEU	Coal, Tail End	501 m³	1989
8.	**Voerde West I/II**	KWH	STEAG	DEU	Coal, Tail End	535 m³	1989
9.	**Lünen 11**	KWH	STEAG	DEU	Coal, Tail End	243 m³	1989
10.	**Lünen 10**	KWH	STEAG	DEU	Coal, Tail End	94 m³	1989
11.	**Weiher 3**	Steinmüller	SaarEnergie	DEU	Coal, High Dust	617 m³	1990
12.	**BHKW Voitsberg 3**	SGP	Österr. Draukraftwerke	AUT	Brown Coal, High Dust	405 m³	1990
13.	**STEAG Repl., 1 layer**	STEAG	STEAG	DEU	Coal, Tail End	46 m³	1991
14.	**Tiefstack**	Steinmüller		DEU	Coal	212 m³	1992
15.	**Bexbach**	Saarbergwerke AG		DEU	Coal, High Dust	286 m³	1992
16.	**BHKW Voitsberg 3**	SGP	Österr. Draukraftwerke	AUT	Brown Coal, High Dust, Additional Delivery	60 m³	1992
17.	**RDK7**	BASF	EnBW	DEU	Coal, High Dust	182 m³	1993
18.	**Fiume Santo**	IDRECO	ENEL	ITA	Coal / Oil	602 m³	1994 / 96
19.	**Bremen Block 5**	BASF	Stadtwerke Bremen	DEU	Coal, High Dust	46 m³	1994
20.	**Mannheim**	BASF	GKW Mannheim	DEU	Coal, High Dust	168 m³	1994
21.	**Lünen 11**	BASF	STEAG	DEU	Coal, Tail End	80 m³	1994
22.	**Ibbenbüren**	BASF	Preussag / RWE	DEU	Coal, Tail End	143 m³	1994
23.	**SW Bremen Block 6**	BASF	Stadtwerke Bremen	DEU	Coal	124 m³	1995
24.	**Tiefstack**	BASF		DEU	Coal	86 m³	1995
25.	**FHKW Mellach**	AEE	STEWEAG	AUT	Bituminous Coal, High Dust, Additional Delivery	95 m³	1995
26.	**RDK7**	BASF	EnBW	DEU	Coal, Additional Delivery	182 m³	1995
27.	**Vado Ligure**	Termokimik	ENEL	ITA	Coal, High Dust	560 m³	1997 / 98
28.	**SW Bremen KW Hafen 5**	BASF	Stadtwerke Bremen	DEU	Coal, Additional Delivery	59 m³	1997

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Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
29.	**SW Bremen KW Hafen 6**	BASF	Stadtwerke Bremen	DEU	Coal, Additional Delivery	125 m^3	1997
30.	**SW Bremen HKW Hastedt**	BASF	Stadtwerke Bremen	DEU	Coal, Additional Delivery	47 m^3	1997
31.	**SW Bremen KW Hafen 6**	BASF	Stadtwerke Bremen	DEU	Coal, Additional Delivery	60 m^3	1997
32.	**SW Bremen**	BASF	Stadtwerke Bremen	DEU	Coal	37 m^3	1998
33.	**GKM Mannheim Block 7**	BASF	GKW Mannheim	DEU	Coal, Additional Delivery	168 m^3	1998
34.	**GKM Mannheim Block 8**	BASF	GKW Mannheim	DEU	Coal, Additional Delivery	195 m^3	1998
35.	**Sulcis 3**	ENEL	ENEL	ITA	Coal / Oil, Tail End	127 m^3	1999
36.	**SW Bremen HKW Hastedt**	BASF	Stadtwerke Bremen	DEU	Coal, High Dust, Additional Delivery	48 m^3	1999
37.	**La Spezia**	ENEL	ENEL	ITA	Coal, High Dust	525 m^3	2000
38.	**Homer City Unit 1, 2, 3**	BASF	ABB	USA	Coal, High Dust	1913 m^3	2000
39.	**Stuart Unit 1, 2, 3, 4**	Black & Veatch	Dayton Power & Light	USA	Coal, High Dust	2792 m^3	2001/2/3
40.	**KW Bexbach**	BASF	Saarenergie	DEU	Coal, High Dust, Additional Delivery	6 m^3	2001
41.	**KW Weiher 3**	BASF	Saarenergie	DEU	Coal, High Dust, Additional Delivery	369 m^3	2001
42.	**RDK 7**	BASF	EnBW	DEU	Coal, High Dust, Additional Delivery	198 m^3	2001
43.	**Vado Ligure**	ENEL	Tirreno Power	ITA	Coal, High Dust, Additional Delivery	87 m^3	2001
44.	**Dallman Station Unit 31, 32, 33**	Black & Veatch	City of Springfield	USA	Bituminous Coal, High Dust	498 m^3	2002/3
45.	**Coffeen Unit 2**	HRC	Ameren Energy / Sargent & Lundy	USA	Coal, High Dust	711 m^3	2002
46.	**Killen**	Black & Veatch	Dayton Power & Light	USA	Coal, Low Dust	326 m^3	2002
47.	**Michigan City Unit 12**	Black & Veatch	NIPSCO	USA	Coal, High Dust	583 m^3	2002
48.	**KW Weiher 3**	BASF	Saarenergie	DEU	Coal, High Dust, Additional Delivery	369 m^3	2002
49.	**HKW 1 Kraftwerk Altbach**	BASF	Neckarwerke	DEU	Coal, High Dust, Additional Delivery	132 m^3	2002
50.	**Homer City**	BASF	Midwest Generation / ALSTOM POWER	USA	Coal, High Dust, Additional Delivery	196 m^3	2002
51.	**Vado Ligure**	Interpower	Interpower	ITA	Coal, High Dust, Additional Delivery	88 m^3	2002
52.	**Coffeen Unit 1**	HRC	Ameren Energy / Sargent & Lundy	USA	Coal, High Dust	438 m^3	2003
53.	**Culley Unit 3**	Black & Veatch	Sigeco	USA	Coal, High Dust	304 m^3	2003
54.	**Schahfer Unit 14**	Black & Veatch	NIPSCO	USA	Coal, High Dust	583 m^3	2003
55.	**Edwards Station Unit 3**	LLNA	AES / Cilco	USA	Coal, High Dust	434 m^3	2003
56.	**Bailly 8**	Black & Veatch	NIPSCO	USA	Coal, High Dust	531 m^3	2003

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57.	**Duck Creek Unit 1**	LLNA	AES / Cilco	USA	Coal, High Dust	555 m^3	2003
58.	**Cheswick Station # 1**	Babcock & Wilcox	Orion Power Midwest	USA	Coal, High Dust	861 m^3	2003
59.	**Coffeen Unit 1**	HRC	Ameren Energy / Sargent & Lundy	USA	Coal, High Dust, Additional Delivery	219 m^3	2003
60.	**HKW Wedel I**	BASF	HEW	DEU	Coal, High Dust, Additional Delivery	59 m^3	2003
61.	**FUSINA**	ENEL	ENEL	ITA	Coal, High Dust	104 m^3	2003
62.	**Vado Ligure**		Interpower	ITA	Coal, High Dust, Additional Delivery	11 m^3	2003
63.	**HKW Wedel I, 2nd layer**	BASF	HEW	DEU	Coal, High Dust, Additional Delivery	60 m^3	2004
64.	**Brindisi Nord Unit 3 & 4**	Termokimik	Edipower	ITA	Coal, High Dust	660 m^3	2004
65.	**Warrick Unit 4**	Black & Veatch	Sigeco	USA	Coal, High Dust	354 m^3	2004
66.	**Brown Unit 1, 2**	Black & Veatch	Sigeco	USA	Coal, High Dust	708 m^3	2004
67.	**KW Bexbach**	BASF	Saarenergie	DEU	Coal, High Dust, Additional Delivery	286 m^3	2004
68.	**Voerde Block A**	BASF	STEAG	DEU	Coal, High Dust, Additional Delivery	350 m^3	2004
69.	**Scholven E**	BASF	E.ON	DEU	Coal, High Dust, Additional Delivery	193 m^3	2004
70.	**Homer City Unit 3**	Midwest Generation	Midwest Generation / ALSTOM POWER	USA	Coal, High Dust, Additional Delivery	246 m^3	2004
71.	**Samcheonpo TPP # 3 & 4**	Halla	KOSEP	KOR	Coal, High Dust	904 m^3	2004
72.	**Vado Ligure**		Interpower	ITA	Coal, High Dust, Additional Delivery	22 m^3	2004
73.	**Scholven B**	BASF	E.ON	DEU	Coal, High Dust, Additional Delivery	193 m^3	2004
74.	**Voerde Block B**	BASF	STEAG	DEU	Coal, High Dust, Additional Delivery	350 m^3	2004
75.	**Brown Unit 1**	Black & Veatch	Sigeco	USA	Coal, High Dust, Additional Delivery	152 m^3	2005
76.	**Warrick Unit 4**	Black & Veatch	Sigeco	USA	Coal, High Dust, Additional Delivery	177 m^3	2005
77.	**Stuart Unit 4**	Dayton Power & Light	Dayton Power & Light	USA	Coal, High Dust, Additional Delivery	473 m^3	2005
78.	**Scholven C**	BASF	E.ON	DEU	Coal, High Dust, Additional Delivery	193 m^3	2005
79.	**Edwards Station Unit 3**	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	203 m^3	2005
80.	**Coffeen Unit 1**	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	219 m^3	2005
81.	**Scholven D**	BASF	E.ON	DEU	Coal, High Dust, Additional Delivery	193 m^3	2005
82.	**FHKW Mellach**	VERBUND	VERBUND	AUT	Coal, High Dust, Additional Delivery	94 m^3	2005
83.	**Vado Ligure**	Tirreno Power	Tirreno Power	ITA	Coal, High Dust, Additional Delivery	87 m^3	2005
84.	**GKK Kiel**	BASF	E.ON	DEU	Coal, High Dust	185 m^3	2005

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85.	**Scholven C**	BASF	E.ON	DEU	Coal, High Dust, Additional Delivery	193 m³	2005
86.	**La Spezia 3&4**	ENEL Produzione	ENEL	ITA	Coal, High Dust, Additional Delivery	179 m³	2005
87.	**Duck Creek Unit 1**	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	203 m³	2005
88.	**Yonghung Unit 4**	HHI	KOSEP	KOR	Coal, High Dust	369 m³	2005
89.	**HKW Heilbronn, Block 7**	BASF	EnBW	DEU	Coal, High Dust	141 m³	2005
90.	**KW Münster, K25**	BASF	EnBW	DEU	Coal, High Dust	38 m³	2005
91.	**Ruien Unit 3, 4, 5**	Termokimik	Electrabel / Tractebel	BEL	Coal, High Dust	642 m³	2006/07/08
92.	**Fusina 1&2**	Termokimik	Enelpower SpA	ITA	Coal, High Dust	320 m³	2006
93.	**A.B. Brown Unit 2**	VECTREN	VECTREN	USA	Coal, High Dust, Additional Delivery	152 m³	2006
94.	**Vado Ligure**	Tirreno Power	Tirreno Power	ITA	Coal, High Dust, Additional Delivery	174 m³	2006
95.	**Wushashan Unit 4**	Tsinghua Tongfang Ltd.	Datang International Co.	CHN	Coal, High Dust	308 m³	2006
96.	**Voerde Block B**	BASF	STEAG	DEU	Coal, High Dust, Additional Delivery	350 m³	2006
97.	**Dallman Unit 31**	City of Springfield	City of Springfield	USA	Coal, High Dust Replacement	47 m³	2007
98.	**Michigan City Unit 12**	NIPSCO	NIPSCO	USA	Coal, High Dust, Additional Delivery	278 m³	2007
99.	**Thomas Hill Unit 3**	Associated Electric Coop.	Associated Electric Coop.	USA	Coal, High Dust	802 m³	2007
100.	**Coffeen Unit 2**	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	357 m³	2007
101.	**Duck Creek Unit 1**	Ameren Energy	Ameren Energy	USA	Coal, High Dust Replacement	202 m³	2007
102.	**Fusina**	ENEL	ENEL	ITA	Coal, High Dust Replacement	104 m³	2007
103.	**Gaobeidian 1+4**	Tongfang	Huaneng Beijing	CHN	Coal, High Dust	461 m³	2007
104.	**Edwards Unit 3**	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	203 m³	2007
105.	**Schahfer Unit 14**	NIPSCO	NIPSCO	USA	Coal, High Dust, Additional Delivery	278 m³	2007
106.	**Vado Ligure**	Tirreno Power	Tirreno Power	ITA	Coal, High Dust, Additional Delivery	340 m³	2008/2009
107.	**SJRPP Unit 1+2**	JEA	JEA	USA	Coal, High Dust	1540 m³	2008/2009
108.	**Dallman Unit 4**	Foster Wheeler	City of Springfield	USA	Coal, High Dust, Additional Delivery	198 m³	2008
109.	**Thomas Hill Unit 1-2**	Associated Electric Coop.	Associated Electric Coop.	USA	Coal, High Dust	656 m³	2008
110.	**Coffeen Unit 1**	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	450 m³	2008
111.	**Mannheim Block 8**	BASF	GKM Mannheim	DEU	Coal, High Dust Additional Delivery	195 m³	2008
112.	**Coffeen Unit 2**	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	366 m³	2008

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113.	**Duck Creek Unit 1**	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	405 m³	2008
114.	**Fusina 3+4**	ENEL	ENEL	ITA	Coal, High Dust, Additional Delivery	52 m³	2008
115.	**Springfield Missouri Unit 1**	Babcock & Wilcox	CUSMO	USA	Coal, High Dust	236 m³	2008
116.	**Bailly Unit 7**	NIPSCO	NIPSCO	USA	Coal, High Dust	304 m³	2008
117.	**Sibley Unit 3**	Babcock Power	Aquilla	USA	Coal, High Dust, Additional Delivery	405 m³	2008
118.	**Killen Unit 2**	Dayton Power & Light	Dayton Power & Light	USA	Coal, Low Dust, Additional Delivery	164 m³	2008
119.	**KW Bergkamen Block A**	BASF	Evonic	DEU	Coal, High Dust, Additional Delivery	262 m³	2008
120.	**Mannheim Block 7**	BASF	GKM Mannheim	DEU	Coal, High Dust, Additional Delivery	195 m³	2008
121.	**Michigan 12**	NIPSCO	NIPSCO	USA	Coal High Dust Additional Delivery	236 m³	2008
122.	**Bailly 8**	NIPSCO	NIPSCO	USA	Coal High Dust Additional Delivery	178 m³	2008
123.	**Tiefstack**	BASF		DEU	Coal, Hight Dust, Additional Delivery	53 m³	2008
124.	**Coffeen Unit 2**	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	366 m³	2009
125.	**SJRPP Spare Layer 1**	JEA	JEA	USA	Coal, High Dust, Additional Delivery	257 m³	2009
126.	**Crystal River Unit 5**	Babcock & Wilcox	Progress Energy	USA	Coal, High Dust	759 m³	2009
127.	**SJRPP Additional Layer 2**	JEA	JEA	USA	Coal, High Dust	257 m³	2009
128.	**Ameren Spare Layer**	Ameren Energy	Ameren Energy	USA	Coal, High Dust, Additional Delivery	366 m³	2009
129.	**Amos Unit 2**	AEP	AEP	USA	Coal, High Dust	34 m³	2009
130.	**Nanticoke Unit 7 + 8**	OPG	OPG	CAN	Coal, High Dust	410 m³	2009
131.	**Fusina 3+4**	ENEL	ENEL	ITA	Coal, High Dust, Additional Delivery	52 m³	2009
132.	**Scholven**	BASF	E.ON	DEU	Coal, High Dust, Additional Delivery	193 m³	2009
133.	**Mannheim Block 6**	BASF	GKM Mannheim	DEU	Coal, High Dust, Additional Delivery	120 m³	2009
134.	**KP-R Project**	JGC C&C	IHI	JPN	Coal, High Dust	182 m³	2009
135.	**Stuart**	Dayton Power & Light	Dayton Power & Light	USA	Coal, High Dust, Additional Delivery	540 m³	2009
136.	**Bruce Mansfield**	First Energy	First Energy	USA	Coal, High Dust	704 m³	2009
137.	**Big Sandy 2**	AEP	AEP	USA	Coal, High Dust	38 m³	2009
138.	**Shidongkou Unit 1+2**	Huaneng	Huaneng	CHN	Coal, High Dust	880 m³	2009
139.	**Vado Ligure**	Tirreno Power	Tirreno Power	ITA	Coal, High Dust, Additional Delivery	113 m³	2009
140.	**Wygen 3 - Unit 5**	Babcock & Wilcox	Babcock & Wilcox	USA	Coal, High Dust	152 m³	2009

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141.	**Yingkou Unit 1+2**	Huaneng	Huaneng / Harbin Boiler	CHN	Coal, High Dust	631 m^3	2009
142.	**Yuhuan Unit 4**	Huaneng	Huaneng / Harbin Boiler	CHN	Coal, High Dust	818 m^3	2009
143.	**Jinling Unit 1+2**	Huaneng	Huaneng / Harbin Boiler	CHN	Coal, High Dust	1300 m^3	2009
144.	**Pingliang Unit 1+2**	Huaneng	Huaneng / Harbin Boiler	CHN	Coal, High Dust	710 m^3	2009
145.	**Fuzhou Phase 3 - Unit 1+2**	Huaneng	Huaneng	CHN	Coal, High Dust	860 m^3	2009
146.	**Fuzhou Phase 1+2 - Unit 1**	Huaneng	Huaneng / Tongfang	CHN	Coal, High Dust	264 m^3	2009
147.	**Brindisi Sud**	ENEL	ENEL	ITA	Coal, High Dust	531 m^3	2009
148.	**Shinta PS3**	Envirgy Taiwan		TWN	Coal, High Dust	48 m^3	2009
149.	**GHECO - One**	Doosan		THA	Coal, High Dust	454 m^3	2010
150.	**Yuhuan Unit 1, 2 + 3**	Huaneng	Huaneng Beijing	CHN	Coal, High Dust	2453 m^3	2010
151.	**Dallman Station Unit 33**	Black & Veatch	City of Springfield	USA	Bituminous Coal, High Dust, Additional Delivery	86 m^3	2010
152.	**Sines Power Plant Unit 1-4**	Alstom	EDP	PRT	Coal, High Dust, Wood pellets, High Temp.	1460 m^3	2010
153.	**CUSMO Springfield Unit 2**	Foster Wheeler	CUSMO	USA	Coal, High Dust	304 m^3	2010
154.	**Crystal River Unit 4**	Babcock & Wilcox	Progress Energy	USA	Coal, High Dust	759 m^3	2010
155.	**Fuzhou Phase I+II Unit 2, 3, 4**	Huaneng	Huaneng	CHN	Coal, High Dust	793 m^3	2010
156.	**Haimen Unit 3**	Huaneng		CHN	Coal High Dust	649 m^3	2010
157.	**Yueyang Unit #5 + Unit #6**	Huaneng		CHN	Coal High Dust	1002 m^3	2010
158.	**Lamamora Brescia**	Termokimik	A2A	ITA	Coal High Dust	78 m^3	2010
159.	**Fusina 3+4**	ENEL	ENEL	ITA	Coal, High Dust, Additional Delivery	46 m^3	2010
160.	**Roxboro Unit 4**	Progress Energy	Progress Energy	USA	Coal Low Dust	396 m^3	2010
161.	**Vado Ligure**	Tirreno Power	Tirreno Power	ITA	Coal, High Dust, Additional Delivery	114 m^3	2010
162.	**Ciuden**	Integral	Ciuden Ciudad de la Energia	ESP	Coal High Dust	16 m^3	2010
163.	**King Plant**	Xcel Energy Service	Xcel Energy Service	USA	Coal High Dust	302 m^3	2011
164.	**Yeosu Cogeneration**	Hyundai	HDEC	KOR	Coal High Dust, CFBC-Boiler	160 m^3	2011
165.	**Sibley Unit 3**	KCP&L	KCP&L	USA	Coal High Dust Additional Delivery	203 m^3	2011
166.	**Bailly Unit 3**	Black & Veatch	NIPSCO	USA	Coal, High Dust	178 m^3	2011
167.	**Brindisi Sud**	ENEL	ENEL	ITA	Coal, High Dust	531 m^3	2011
168.	**Schahfer Unit 14**	NIPSCO	NIPSCO	USA	Coal, High Dust, Additional Delivery	236 m^3	2011

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169.	**Roxboro Unit 2**	Progress Energy	Progress Energy	USA	Coal High Dust	371 m³	2011
170.	**Mayo Unit 1**	Progress Energy	Progress Energy	USA	Coal Low Dust	385 m³	2011
171.	**La Cygne Unit 1**	KCP&L	KCP&L	USA	Coal High Dust	422 m³	2011
172.	**Nebraska City Unit 2**	OPPD	OPPD	USA	Coal, High Dust	260 m³	2011
173.	**Thomas Hill Unit 2**	AECI	AECI	USA	Coal, High Dust, Additional Delivery	148 m³	2011
174.	**Dallman Unit 33**	CWLP	CWLP	USA	Coal, High Dust, Additional Delivery	104 m³	2011
175.	**Bailly Unit 7**	NIPSCO	NIPSCO	USA	Coal, High Dust Additional Delivery	108 m³	2011
176.	**La Cygne Unit 1**	KCP&L	KCP&L	USA	Coal, High Dust, Additional Delivery	474 m³	2011
177.	**Asheville Unit 1 - Layer 1&2**	Progress Energy	Progress Energy	USA	Coal, High Dust	293 m³	2011
178.	**Cardinal Unit 3 - part 1**	AEP	AEP	USA	Coal, High Dust	298 m³	2011
179.	**CUSMO Unit 1**	Cusmo	Cusmo	USA	Coal, High Dust, Additional Delivery	119 m³	2011
180.	**Michigan City Unit 12**	NIPSCO	NIPSCO	USA	Coal, High Dust, Additional Delivery	236 m³	2011
181.	**KW Bergkamen - Bock A**	BASF	STEAG	DEU	Coal, High Dust, Additional Delivery	262 m³	2011
182.	**HKW Wedel - Block 2**	BASF	Vattenfall	DEU	Coal, High Dust, Additional Delivery	53 m³	2011
183.	**Asheville Unit 2 - Layer 2**	Progress Energy	Progress Energy	USA	Coal, High Dust	106 m³	2011
184.	**Cardinal Unit 3**	AEP	AEP	USA	Coal, Low Dust	424 m³	2011/2013
185.	**Westfalen Block D+E**	BASF	RWE	DEU	Coal High Dust	1960 m³	2012
186.	**Edgewater Unit 5**	Babcock Power		USA	Coal High Dust	708 m³	2012
187.	**Brown Unit 3**	Babcock Power		USA	Coal High Dust	607 m³	2012
188.	**Bailly Unit 8 - Repl. 2012**	NIPSCO	NIPSCO	USA	Coal, High Dust Additional Delivery	178 m³	2012
189.	**Bailly Unit 7 - Repl. 2012**	NIPSCO	NIPSCO	USA	Coal, High Dust Additional Delivery	6 m³	2012
190.	**Dallman Unit 33**	CWLP	CWLP	USA	Coal, High Dust Additional Delivery	78 m³	2012
191.	**Brindisi Sud Unit 4**	Termokimik	ENEL	ITA	Coal, High Dust	956 m³	2012
192.	**King Plant**	Xcel Energy " Utility Repl"	Xcel Energy " Utility Repl"	USA	Coal, High Dust Additional Delivery	301 m³	2012
193.	**Roxboro Unit 1**	Progress Energy	Progress Energy	USA	Coal, High Dust	209 m³	2012
194.	**Schahfer Unit 14**	NIPSCO	NIPSCO	USA	Coal, High Dust, Additional Delivery	236 m³	2012
195.	**Brindisi Sud**	ENEL	ENEL	ITA	Coal, High Dust	319 m³	2012
196.	**Crystal River Unit 5**	Babcock & Wilcox	Progress Energy	USA	Coal, High Dust, Additional Delivery	379 m³	2012

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197.	**Dallman Unit 4**	City of Springfield	City of Springfield	USA	Bituminous Coal, High Dust, Additional Delivery	103 m³	2012
198.	**HKW Wedel - Block 1**	BASF	Vattenfall	DEU	Coal, High Dust, Additional Delivery	54 m³	2012
199.	**Pingliang Unit 1+2 Spare Layer**	Huaneng	Huaneng Pingliang	CHN	Coal High Dust, Additional Delivery	452 m³	2012
200.	**Eemshaven Block A+B**	BASF	RWE	DEU	Coal High Dust	1960 m³	2012/2013
201.	**Project KR**	JGC C&C	IHI	JPN	Coal fired Boiler	273 m³	2013
202.	**Roxboro Unit 3**	Progress Energy	Progress Energy	USA	Coal, High Dust, Additional Delivery	371 m³	2013
203.	**Michigan City Unit 12**	NIPSCO	NIPSCO	USA	Coal, High Dust, Additional Delivery	236 m³	2013
204.	**Crystal River Unit 4**	Progress Energy		USA	Coal High Dust, Additional Delivery	379 m³	2013
205.	**Sibley Unit 3**	KCP&L	KCP&L	USA	Coal High Dust Additional Delivery	202 m³	2013
206.	**Iatan Unit 1**	KCP&L	KCP&L	USA	Coal High Dust	465 m³	2013
207.	**GKM Block 9**	BASF	Alstom / GKM Mannheim	DEU	Coal, High Dust	619 m³	2013
208.	**Nebraska City Unit 2**	OPPD	OPPD	USA	Coal, High Dust, Additional Delivery	584 m³	2013
209.	**Asheville Unit 1**	Progress Energy	Progress Energy	USA	Coal, High Dust, Additional Delivery	93 m³	2013
210.	**Shidongkou Spare Layer #1+2**	Huaneng	Huaneng	CHN	Coal, High Dust, Additional Delivery	438 m³	2013
211.	**Bailly Unit 7 + Unit 8**	NIPSCO	NIPSCO	USA	Coal High Dust Additional Delivery	279 m³	2013
212.	**Schahfer Unit 14**	NIPSCO	NIPSCO	USA	Coal, High Dust, Additional Delivery	236 m³	2013
213.	**Nantong Fiber TPP #10&11**	Jiangsu Kehang		CHN	Coal High Dust, SNCR & SCR Hybrid	51 m³	2013
214.	**Qinbei 1st and 2nd batch**	Huaneng	Huaneng	CHN	Coal fired Boiler	549 m³	2013
215.	**Shidongkou Phase 1 Unit #3**	Huaneng	Huaneng	CHN	Coal fired Boiler	296 m³	2013
216.	**Shidongkou Phase 1 Unit 4**	Huaneng	Huaneng	CHN	Coal High Dust	296 m³	2013
217.	**Dummy Eemshaven Block A+B**	BASF	RWE / Alstom	DEU	Coal High Dust	163 m³	2013
218.	**Mannheim Block 7**	BASF	GKM Mannheim	DEU	Coal High Dust	21 m³	2013
219.	**Yudong #1 + #2**	Beijing Longdian	Huadian	CHN	Coal High Dust	572 m³	2013
220.	**Pingliang Phase 1 Unit #1 + #2**	Huaneng	Huaneng	CHN	Coal High Dust	525 m³	2013
221.	**Gheco One Spare**	Doosan	Gheco One Co. Ltd.	THA	Coal High Dust, Additional Delivery	114 m³	2013
222.	**Sichuan Vinylon #1 + #2**	Beijing Bozhi Weide Env. Tech. Co. Ltd.		CHN	Coal fired Boiler	405 m³	2013
223.	**Yingkou Phase 1 Unit 1+2**	Huaneng	Huaneng	CHN	Coal High Dust	569 m³	2013
224.	**Gaobeidian Spare Layer**	Huaneng	Huaneng	CHN	Coal High Dust	77 m³	2013

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225.	**Eerduosi Unit 4**	Dongfang Boiler Group		CHN	Coal High Dust	359 m^3	2013
226.	**Tiefstack NR**	Vattenfall	Vattenfall	DEU	Coal High Dust	35 m^3	2013
227.	**JTEC Unit 2 3rd Layer Addition**	Cusmo		USA	Coal High Dust	152 m^3	2014
228.	**Springs**	BASF		DEU	Coal High Dust	21 m^3	2014
229.	**La Spezia**	ENEL	ENEL	ITA	Coal High Dust, Additional Delivery	163 m^3	2014
230.	**Dummy Module Sostanj Unit 6**	Alstom		SVN	Brown Coal, High Dust	111 m^3	2014
231.	**Fusina L1**	ENEL	ENEL	ITA	Coal High Dust	91 m^3	2014
232.	**Cardinal Unit 3**	AEP	AEP	USA	Coal High Dust, Additional Delivery	287 m^3	2014
233.	**Mannheim Block 7**	BASF	GKM Mannheim	DEU	Coal, Additional Delivery	63 m^3	2014
234.	**Dallmann U 31,32,33**	City of Springfield	City of Springfield	USA	Coal High Dust, Additional Delivery	203 m^3	2014
235.	**Pingliang Phase 1 Unit #3 + #4**	Huaneng	Huaneng	CHN	Coal fired Boiler	523 m^3	2014
236.	**King Plant**	Xcel Energy	Xcel Energy	USA	Coal High Dust, Additional Delivery	301 m^3	2014
237.	**Stanton Unit 1**	Black & Veatch	Orlando Utilities Commission	USA	Coal, High Dust	586 m^3	2014
238.	**Teko 4N**	Effeleon		SVK	Coal High Dust	43 m^3	2014
239.	**Guacolda Unit 1**	ANDRITZ Energy & Environment	Empresa Guacolda Energia	CHL	Coal High Dust	207 m^3	2014
240.	**Yichang #1&2**	Beijing Bozhi Weide Environment	Sinopec	CHN	Coal High Dust	172 m^3	2014
241.	**Yichang #3**	Beijing Bozhi Weide Environment	Sinopec	CHN	Coal High Dust	85 m^3	2014
242.	**Voerde Block A&B**	STEAG Aktiengesellschaft	STEAG Aktiengesellschaft	DEU	Coal High Dust, Additional Delivery	700 m^3	2014
243.	**Shidongkou #2 Partial Repl.**	Huaneng Shanghai Shidongkou	Huaneng Shanghai Shidongkou	CHN	Coal fired Boiler Additional Delivery	175 m^3	2014
244.	**Iatan Unit 2**	KCP&L	KCP&L	USA	Coal High Dust	445 m^3	2014
245.	**Lansing Unit 4**	Alliant Energy	Alliant Energy	USA	Coal High Dust	169 m^3	2015
246.	**Fusina L2**	ENEL	ENEL	ITA	Coal High Dust	91 m^3	2015
247.	**Kumho Petrochemical**	Pure Tech Korea Corp.	Kumho	KOR	Coal, Tail End	231 m^3	2015
248.	**OPPD Nebraska**	OPPD	OPPD	USA	Coal, High Dust, Additional Delivery	351 m^3	2015
249.	**Los Barrios**	Termokimik Corp.	E.ON	ES	Coal High Dust	524 m^3	2015
250.	**Monfalcone Unit 1**	Termokimik Corp.	A2A	ITA	Coal High Dust	235 m^3	2015
251.	**Monfalcone Unit 2**	Termokimik Corp.	A2A	ITA	Coal High Dust	235 m^3	2015
252.	**ZAK Kedzierzyn**	Termokimik Corp.	ZAK S.A.	PL	Coal High Dust	59 m^3	2015

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253.	**Litoral Unit 2**	Termokimik Corp.	ENEL	ES	Coal High Dust	465 m^3	2015
254.	**Teko 4S**	Effeleon		SVK	Coal High Dust	64 m^3	2015
255.	**La Spezia**	ENEL	ENEL	ITA	Coal High Dust, Additional Delivery	280 m^3	2015
256.	**USS K7**	Effeleon		SVK	Coal High Dust	94 m^3	2015
257.	**Mannheim Block 7**	BASF	GKM Mannheim	DEU	Coal High Dust, Additional Delivery	62 m^3	2015
258.	**JP Madgett Dairyland**	DPC	DPC	USA	Coal High Dust	391 m^3	2015
259.	**Brown Unit 3**	Kentucky Utilities	Kentucky Utilities	USA	Coal High Dust; Additional Delivery	303 m^3	2015
260.	**Tiefstack NR 2015**	Vattenfall Wärme Hamburg GmbH	Vattenfall Wärme Hamburg GmbH	DEU	Coal High Dust, Additional Delivery	71 m^3	2015
261.	**Crystal River Unit 5**	Babcock & Wilcox	Progress Energy Florida Inc.	USA	Coal High Dust, Additional Delivery	379 m^3	2015
262.	**GK Kiel**	E.ON Kraftwerke GmbH	E.ON Kraftwerke GmbH	DEU	Coal high dust, Additional Delivery	186 m^3	2015
263.	**Dallmann U 31-32**	CWLP	CWLP	USA	Coal high dust, Additional Delivery	71 m^3	2015
264.	**Bailly Unit 7**	Nipsco		USA	Coal high dust, Additional Delivery	102 m^3	2015
265.	**Michigan City Unit 12**	Nipsco		USA	Coal high dust, Additional Delivery	279 m^3	2015
266.	**Schahfer Unit 14**	Nipsco		USA	Coal high dust, Additional Delivery	279 m^3	2015
267.	**GHECO One Spare Layer**	Laborelec	Glow Energy PCL	THA	Coal High Dust	114 m^3	2015
268.	**Quanlin #1-#3**	Beijing Chinsuny Environmental Prot.		CHN	Coal fired boiler	492 m^3	2016/2017
269.	**Sines Repl. A-D**	EDP	Energias de Portugal	PRT	Coal High Dust + Wood Pellets High Temperature	1802 m^3	2016/2017
270.	**Litoral Unit 1**	Termokimik Corp.	ENEL	ES	Coal High Dust	403 m^3	2016
271.	**USS K6**	Effeleon		SVK	Coal High Dust	94 m^3	2016
272.	**Maizuru Unit 1**	Kansai Electricity Power Company		JPN	Coal High Dust, addtitional Delivery	263 m^3	2016
273.	**Ostroleka K3**	Termokimik Corp.	Energa Ostroleka	PL	Coal / Biomass high dust	223 m^3	2016
274.	**Mannheim Block 7**	BASF	GKM Mannheim	DEU	Coal High Dust; Additional Delivery	167 m^3	2016
275.	**Maasvlakte**	Envirotherm	UNIPER	NL	Coal High Dust	250 m^3	2016
276.	**Litoral Unit 2 Exchange Modules**	Termokimik Corp.	ENEL	IT	Coal high dust; Additional Delivery	4 m^3	2016
277.	**Litoral Unit 1 Exchange Modules**	Termokimik Corp.	ENEL	IT	Coal high dust; Additional Delivery	3 m^3	2016
278.	**Brindisi Sud**	ENEL	ENEL	IT	Coal high dust	320 m^3	2016
279.	**Litoral Unit 1 Layer 3**	Termokimik Corp.	ENEL	IT	Coal high dust	201 m^3	2016
280.	**Litoral Unit 2 Layer 3**	Termokimik Corp.	ENEL	IT	Coal high dust	233 m^3	2016

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
281.	**Teko 4S**	Effeleon GmbH	Energyco S.r.o.	CZE	Coal high dust, Additional Delivery	9 m^3	2016
282.	**Teko 4N Spare Layer**	Effeleon		SK	Coal high dust; Additional Delivery	22 m^3	2016
283.	**Maizuru Repair Elements**	The Kansai Electric Power Co. Inc.	The Kansai Electric Power Co. Inc.	JPN	Coal fired boiler	18 m^3	2016
284.	**Plomin 2**	Alstom Italy	TE Plomin d.o.o.	HRV	Coal High Dust	222 m^3	2017
285.	**Nebraska Unit 2**	ODDP		USA	Coal High Dust; Additional Delivery	351 m^3	2017
286.	**Fusina 2017**	ENEL	ENEL	IT	Coal high dust	314 m^3	2017
287.	**Lansing Unit 4 RP 2017**	Alliant Energy		USA	Coal high dust	175 m^3	2017
288.	**Columbia Unit 2**	Andritz	Alliant Energy	USA	Coal high dust	759 m^3	2017
289.	**Michigan City Unit 12**	Nipsco	Nipsco	USA	Coal high dust; Additional Delivery	236 m^3	2017
290.	**Dallman Unit 31/32/33**	CWLP	CWLP	USA	Coal high dust; Additional Delivery	139 m^3	2017
291.	**Dallman Unit 4**	CWLP	CWLP	USA	Coal high dust; Additional Delivery	9 m^3	2017
292.	**Dummy Module Opole Unit 5**	GE Boiler Deutschland	PGE	PL	Coal high dust	175 m^3	2017
293.	**Hammond Unit 4**	Southern Company	Southern Company	USA	Coal high dust	219 m^3	2017
294.	**King Station**		Xcel Energy	USA	Coal, High Dust, Additional Delivery	302 m^3	2017
295.	**Luoyuan 1 + 2**	Fujian Longking	Huaneng	CHN	Coal fired boiler	981 m^3	2017
296.	**GKM Block 9**	BASF	Grosskraftwerk Mannheim AG	DEU	Coal high dust; Additional Delivery	309 m^3	2017
297.	**Sulcis**	ENEL Produzione S.p.A.	ENEL Produzione S.p.A.	IT	Coal tail end	137 m^3	2017
298.	**Nordjyllandsvaerket**	Envirotherm	Nordjyllandsvaerket	DEU	Coal high dust	19 m^3	2017
299.	**Los Barrios**	Termokimik Corp.		IT	Coal high dust, Additional Delivery	262 m^3	2017
300.	**ZW Nowa**	GE Power Schweden AB	TAMEH Tauron ArcelorMittal Energy Holding	PL	Coal tail end	175 m^3	2017
301.	**Long Phu 1 TTP**	Termokimik Corp.	Consortium: Russia Power Machines, Slovakia BTG Holding and PetroVietnam	VNM	Bituminous Coal high dust	1200 m^3	2017
302.	**Plomin 2**	Alstom Power Italia S.p.A.	Alstom Italien	KR	Coal High Dust; Additional Delivery	111 m^3	2017
303.	**Heilbronn Block 7**	EnBW Energie Baden-Württemberg AG	EnBW Energie Baden-Württemberg AG	DEU	Coal High Dust; Additional Delivery	283 m^3	2017
304.	**Hassyan #1,#2,#3,#4**	GE Power Inc.		UAE	Coal High Dust	1963 m^3	2017/2018/2019/2020
305.	**RDK 8**	EnBW Energie Baden-Württemberg AG	EnBW Energie Baden-Württemberg AG	DEU	Coal, High Dust	321 m^3	2018
306.	**Sugözü Unit 10 + 20**	Termokimik Corp.	ISKEN (Steag + OYAK)	TUR	Bituminous Coal High Dust	1320 m^3	2018
307.	**Fusina 3+4**	ENEL	ENEL	ITA	Coal, High Dust, Additional Delivery	226 m^3	2018
308.	**Fusina 3+4**	ENEL	ENEL	ITA	Coal, High Dust, Additional Delivery	244 m^3	2018

Curr.No.	Project	Client	End user / Engineering company	Plant location	Application	Shipped quantity	Delivery date
309.	**Dallman Unit 31/32/33**	CWLP	CWLP	USA	Coal high dust; Additional Delivery	109 m³	2018
310.	**JP Madgett Unit 6 - Third Layer**	DPC	DPC	USA	Coal, High Dust, Additional Delivery	253 m³	2018
311.	**Karita PS**	Kyushu		JPN	Coal High Dust	155 m³	2018
312.	**Gaston**	Alabama Power	APC - Gaston Plant	USA	Coal High Dust	472 m³	2018
313.	**Schahfer Unit 14**	Nipsco		USA	Coal High Dust, Additional Delivery	236 m³	2018
314.	**Tsuruga Unit #1**	Hokuriku Electric Power		JPN	Coal High Dust, Additional Delivery	140 m³	2018
315.	**Hirono #5 (part 1+part 2)**	Tepco		JPN	Coal High Dust, Additional Delivery	165 m³	2018
316.	**Brindisi Sud - Unit 2**	ENEL		ITA	Coal High Dust, Additional Delivery	863 m³	2018
317.	**YES Replacement**	Yokkaichi Energy Service		JPN	Coal High Dust, Additional Delivery	21 m³	2018
318.	**Michigan City Unit 12**	Nipsco		USA	Coal High Dust, Additional Delivery	236 m³	2018
319.	**Nebraska City Unit 2**	OPPD	OPPD	USA	Coal High Dust, Additional Delivery	351 m³	2019
320.	**Dallman Unit 4 Spare Modules**	CWLP	CWLP	USA	Coal high dust; Additional Delivery	9 m³	2019
321.	**Dallman Unit 31, 32, 33**	CWLP	CWLP	USA	Coal high dust; Additional Delivery	109 m³	2019
	Total					**156151 m³**	

FUEL TECH
Technologies to enable clean efficient energy

Dale Pfaff
Regional Sales Manager

January 21, 2019

Ms. Megan Berge
Baker Botts LLP
1299 Pennsylvania Ave, NW
Washington, D.C. 20004
P: (202) 639-1308

SUBJECT: GREAT RIVER ENERGY – REQUEST FOR PROPOSAL

COAL CREEK STATION UNIT 2 NOxOUT® SNCR SYSTEM
FUEL TECH BUDGETARY PROPOSAL NO. 18-B-064, REVISION 2 – REDACTED

Dear Ms. Berge:

Fuel Tech, Inc. (FTEK) is pleased to submit our preliminary and budgetary Proposal 18-B-064, Revision 2, to Great River Energy (GRE) for the Coal Creek Station (CCS) Unit 2. The following proposal provides the technical, performance, and commercial details for the FTEK Selective Non-Catalytic Reduction (SNCR) system for CCS Unit 2 located in Underwood, ND.

FTEK's scope includes the design and supply of the SNCR system including reagent storage, forwarding, metering, distribution, and injection equipment including field startup and optimization services. The reagent storage has been sized for thirty (30) days of storage and the system will be controlled via the Plant's Honeywell DCS System.

The process performance provided in this budgetary proposal is based on the furnace mapping information measured during the week of October 22, 2018. We have provided NOx reduction performance for 5 and 10 ppm ammonia slip cases. This revision includes the addition of four (4) additional wall injectors and one (1) 4-pack Distribution Module on Zone 2. There is no change to performance.

FTEK's SNCR reduction system is designed to cover a boiler load range of 185 – 600 MWg (~31 – 100% MCR). If the load range was decreased to 50 – 100% MCR, the Zone 1 Injectors (lowest level in the furnace) may be eliminated. FTEK could investigate the scope, cost, and utility consumption impacts of this change upon request.

We trust the information provided in the Offering meets your needs. In the meantime, please do not hesitate to contact me if there are any questions or comments.

Sincerely,

Dale Pfaff

Dale Pfaff
Regional Sales Manager

cc:

Mary Jo Roth, GRE	William Cummings, FTEK
Greg Heinz, GRE	Kevin Dougherty, FTEK
Paul Lee, B&V	Terry Brown, FTEK
Mark Dittus, B&V	Bob Mazzone, FTEK

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Great River Energy

Budgetary Request for Quotation

NOxOUT® Selective Non-Catalytic Reduction System for Coal Creek Station Unit 2

REDACTED VERSION

Fuel Tech Proposal No. 18-B-064, Revision 2		Date Submitted: January 21, 2019

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1. EXECUTIVE SUMMARY

1.1. Introduction

In response to Great River Energy (GRE) and the Request for Quotation, Fuel Tech, Inc. (FTEK) is providing this preliminary and budgetary Proposal for our NOxOUT® Selective Non-Catalytic NOx Reduction (SNCR) system for the Coal Creek Station Unit 2. FTEK's scope of supply includes the design, supply, and commissioning of our NOx reduction technologies applied to the 600 MWg tangential fired boiler located in Underwood, ND.

1.2. Unit Description

Coal Creek Station Unit 2 is a 600 MWg Combustion Engineering tangential fired boiler with eight corners and a divided furnace. The boiler fires 100% ND lignite coal with a permitted heat input of 6,022 MMBTU/hr. A maximum heat input of 5,971 MMBTU/hr was recorded at full load during the testing period and is used in FTEK's evaluation.

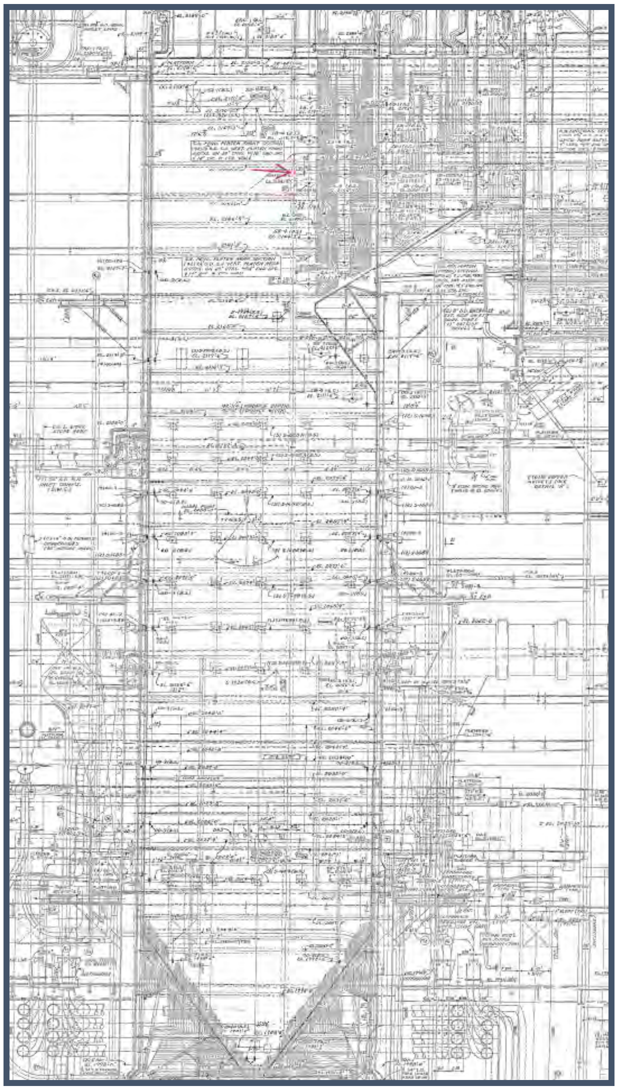


Figure 1 - GRE Coal Creek Unit 2

The Unit has Foster Wheeler Low NOx Combustion System with close coupled over fire air (CCOFA) and separated over fire air (SOFA) systems. The NOx baseline concentration of 0.121 lb/MMBtu used in FTEK's evaluation corresponds to the average emissions measured during the temperature mapping tests performed under full load conditions. For this proposal effort, the SNCR reduction system is designed to cover a load range of 185 – 600 MWg (~31 – 100% MCR). If the load range was decreased to 50 – 100% MCR, the Zone 1 Injectors (lowest level in the furnace) may be eliminated.

1.3. Proposal Summary

FTEK has evaluated our SNCR process at 5 ppm and 10 ppm ammonia slip levels for GRE's consideration. The process design tables are broken down by 1) Wall Injectors only and Wall Injectors plus Multiple Nozzle Lances (MNLs) at 5 ppm slip and, 2) Wall Injectors only and Wall Injectors plus MNLs at 10 ppm ammonia slip. This proposal scope focuses on the 10 ppm ammonia slip scenarios. The NOxOUT SNCR process description and expected NOx reduction performance results of the SNCR system are detailed in Sections 2 and 3, respectively.

The equipment and engineering scope of supply summary is provided in Section 4 of this Proposal. FTEK utilized the urea flow rate at full load for thirty (30) days of 50% aqueous urea storage based on the 10 ppm ammonia slip case. Therefore, FTEK has included four (4) 70,000-gallon FRP tank with a circulation module. The reagent storage tanks include heat pads and insulation while the circulation module includes a pre-fabricated building to be located outdoors near the tank. All other modules must be located indoors for freeze protection

The FTEK modules will include NEMA 4 junction boxes that will be controlled via the Owner's DCS System. At this writing, our scope of supply is based on our standard equipment specifications and manufacturers. Our scope of supply and drawings are provided in Sections 4 and 5, respectively.

FTEK will provide SAMA Logic diagrams and functional descriptions for programming by others. BOP engineering, air compressors, and water systems required for the SNCR systems shall be provided by others. The scope of supply by others and utility requirements are detailed in Section 6.

The NOxOUT aqueous urea and dilution water specifications are provided in Section 7. FTEK will review the Owner's water sources to help determine the best water source for dilution of the urea for injection. The engineering, equipment fabrication, and delivery milestone schedule has been detailed in Section 8.

The budgetary and preliminary pricing and payment terms are provided in Section 9. FTEK has provided pricing, expected utility demands, and other information based on the following scope definitions:

- Case 1 – Wall Injectors plus MNLs, 10 ppm Ammonia Slip
- Case 2 – Wall Injectors Only, 10 ppm Ammonia Slip

Pricing includes start up and optimization field services with travel and daily expenses included. Should additional mandays be required above and beyond what was specified in the FTEK Offering, Appendix C1, FTEK Field Service Rates, has been included in Section 10. Fuel Tech has based our commercial offering on our Exhibit C3 – FTEK Commercial Terms and Conditions included in Section 11. As always, FTEK will review and negotiate in good faith once the GRE commercial terms and conditions are provided.

FTEK is the world's leading supplier of combustion and post combustion NOx reduction technologies. These include low NOx Burners, over-fire air systems, urea based SNCR, advanced SCR, and the ULTRA Conversion system for SCR reagent feed. Fuel Tech's commercial experience includes over (108) LNB and OFA systems, (650+) NOxOUT® SNCR/advanced SCR systems, (132) ULTRA® Systems, and 50,000 MW of SCR experience.

FTEK has engineered SNCR systems for a variety of boiler configurations, loads, and process requirements. Our experience encompasses unique challenges including large units with difficult boiler geometry and high temperature furnace conditions, fuel variations and blends, wide operating load ranges, and non-optimal injection locations, all while providing our customers with the maximum, repeatable, and long-term NOx reduction performance expectations and guarantees. A few examples of FTEK's commercial and confidential SNCR experience on large, tangentially fired, coal boilers with low NOx baselines include:

- Confidential Client Names REDACTED

FTEK has more installed SNCR applications than any other firm and the longest-running applications on very large utility furnaces. The total installed base includes more than 590 units firing all types of fossil, biomass, and industrial fuels. More than 50 of these applications are on coal fired units larger than 400MW, and several which are larger than 600MW. A partial experience list is provided for review in Section 12.

2. FUEL TECH SNCR PROCESS DESCRIPTION

Fuel Tech's urea-based selective non-catalytic reduction (SNCR) Process is a post-combustion NOx reduction method that reduces NOx through a controlled injection of an aqueous urea solution into the combustion gas path of fossil-fired and waste-fired boilers, furnaces, incinerators, or heaters. The most commonly used reagent consists of a 50% urea solution plus a small amount of additives for scale and corrosion control. This reagent is readily available and requires no special safety precautions for handling.

The predominant overall reaction is described as:

$$CO(NH_2)_2 + 2NO + 1/2\ O_2 \Rightarrow 2N_2 + CO_2 + 2H_2O$$
$$\text{Urea + Nitrogen Oxide} \Rightarrow \text{Nitrogen + Carbon Dioxide + Water}$$

Fuel Tech has enhanced the basic SNCR technology by developing chemical injection hardware, widening the applicable temperature range, and process control expertise required for commercial applications. Fuel Tech's urea based SNCR technology is the NOxOUT® process. In addition to NOxOUT which utilizes low energy, air atomized injectors, Fuel Tech is also offering High Energy Reagent Technology (HERT™) which utilizes mechanically atomized injectors and carrier air for injection into the furnace.

Two key parameters that affect the process performance are flue gas temperature and the reagent distribution. The NOx reducing reaction is temperature sensitive; by-product emissions become significant at lower than the optimum temperature range while chemical utilization and NOx reduction decrease at higher than the optimum. This optimum temperature range is specific to each application. The reagent needs to be distributed within this optimum temperature zone to obtain the best performance. Typically, the distribution is more difficult for large units and for units with high flue gas velocity.

Fuel Tech's SNCR Processes are designed with the aid of Computational Fluid Dynamics (CFD) and Chemical Kinetic Model (CKM) in addition to results from field tests. The CFD model simulates flue gas flows and temperature inside a unit while the CKM calculates the reaction between urea and NOx based on temperature and flow information from CFD. A combination of these two models determines the optimum temperature region and the optimum injection strategy to distribute the reagent. With an ability to estimate NOx reduction, a model study can be performed to determine if an application is a right fit for the process.

Chemical injectors developed by Fuel Tech facilitate the reagent distribution. The NOxOUT injection system utilizes air-atomized injectors which direct the urea solution into the combustion gas path. The droplet size distribution and spray coverage developed by the injectors promote efficient contact between the chemical and the NOx in the flue gas.

The Multiple Nozzle Lance is designed to provide chemical coverage in high temperature locations where the wall injectors cannot be installed due to concerns of urea impinging on the convective surfaces. MNLs are added to the injection strategy if high levels of reduction are required, if the temperature window is very narrow due to low baseline NOx, or if the upper furnace flue gas temperature and CO concentration are excessive. Each MNL is supplied with a retract mechanism to remove the lance from the boiler cavity when the lance is not in use, or if loss of cooling water flow, high cooling water temperature or loss of atomization air flow occurs.

Fuel Tech's SNCR Processes provide effective boiler load following capabilities. Through the computer modeling, an injection strategy is developed that makes use of multilevel injection, control of reagent concentration, droplet size and spray patterns, as well as jet penetration.

Several years of field-testing indicate that NOxOUT systems are applicable on various types of units firing many different fuels. The process was successfully proven on units fired with coal, oil, gas, wood or municipal solid or hazardous waste. These units varied in size and type: package boilers, process heaters, incinerators, circulating or bubbling fluidized beds, waste heat boilers, utility boilers. By being a post-combustion process, unit size and type and fuel type have some, but not a major effect on the process.

There are substantial benefits gained from the application of NOxOUT systems compared to first generation NOx control technologies, such as ammonia injection. These benefits are briefly summarized below:

- Use of non-toxic, non-hazardous chemicals.
- Potentially lower capital cost due to the lack of large system compressors and elimination of anhydrous ammonia storage, handling, and safety equipment.
- Lower operating costs resulting primarily from minimization of gas (steam or compressed air) requirements.
- Inherently more effective control of chemical distribution for better mixing with the use of liquid rather than gas-based reagents, thereby resulting in better chemical utilization.

3. PROCESS DESIGN TABLE (PARTIALLY REDACTED)

Unit Identification	Unit 2
Type of Unit	600 MW CE T-Fired, Eight (8) Corner, Divided Furnace
Type of Fuel	North Dakota Lignite
Load Range	30 – 100% MCR

Type of Fuel	**U/M**	**Lignite (10/23/18 avg. fuel analysis)**	**Lignite (10/24/18 avg. fuel analysis)**	**Lignite (from CUS)**	**Lignite (10/23/18 avg. fuel analysis)**
Load		Full Load, 600 MW	Mid Load, 350 MW	Low Load, 185 MW	Full Load, 600 MW
GHI	(MMBtu/hr)	5971	3461	2019	5971
Baseline NOx	(lb/hr)	722.4	494.9	450.2	722.4
Measured Baseline NOx	(lb/MMBtu)	0.121	0.143	0.223	0.121
Controlled NOx at Stack	(lb/MMBtu)	0.109	0.097	0.134	0.099
Guaranteed NOx Reduction from Baseline Above	(%)	10	32	40	18
Average NH3 Slip @ Economizer Outlet, Guaranteed	**(ppmd)**	**5**			
REDACTED					
50% Aqueous Urea Flow Rate, Expected	(gph)	REDACTED			
50% Aqueous Urea Flow Rate, Guaranteed	(gph)	239	62	71	336
No. of Injectors per Level (Retracts = Y/N		REDACTED			REDACTED

Type of Fuel	**U/M**	**Lignite (10/23/18 avg. fuel analysis)**	**Lignite (10/24/18 avg. fuel analysis)**	**Lignite (from CUS)**	**Lignite (10/23/18 avg. fuel analysis)**
Load		Full Load, 600 MW	Mid Load, 350 MW	Low Load, 185 MW	Full Load, 600 MW
GHI	(MMBtu/hr)	5971	3461	2019	5971
Baseline NOx	(lb/hr)	722.4	494.9	450.2	722.4
Measured Baseline NOx	(lb/MMBtu)	0.121	0.143	0.223	0.121
Controlled NOx at Stack	(lb/MMBtu)	0.103	0.090	0.123	0.093
Guaranteed NOx Reduction from Baseline Above	(%)	15	37	45	23
Average NH3 Slip @ Economizer Outlet, Guaranteed	**(ppmd)**	**10**			
REDACTED					
50% Aqueous Urea Flow Rate, Expected	(gph)	REDACTED			
50% Aqueous Urea Flow Rate, Guaranteed	(gph)	343	86	93	411
No. of Injectors per Level (Retracts = Y/N		REDACTED			REDACTED

Process Notes:

1. The FTEK guarantees the NOx reduction, ammonia slip, and urea flow values stated above provided that the final system is designed to the strict adherence to the model results, the baseline NOx is not higher than what is indicated on the process design table, the installation of injection ports are per FTEK's guidance, and the use of FTEK's metering and injection equipment. The performance guarantee results would be transferred to commercial performance guarantee language in the final commercial sale of equipment agreement of the SNCR System.
2. Ammonium bisulfate formation is not expected to be a concern since the S content is less than 1%.
3. For this proposal effort, the SNCR reduction system is designed to cover a load range of 185 – 600 MWg (~31 – 100% MCR). If the load range was decreased to 50 – 100% MCR, the Zone 1 Injectors (lowest level in the furnace) may be eliminated.

4. FUEL TECH SCOPE OF SUPPLY

4.1. Base Equipment Scope of Supply Summary

Equipment Summary Case 1 – Wall Injector plus MNL 10 ppm Ammonia Slip:

Equipment Description	Quantity
Reagent Storage and Circulation Module	
Aqueous Urea Truck Unloading Panel	One (1)
NOxOUT Reagent FRP Storage Tanks, Single Wall, Heat Traced and Insulated, Thirty (30) Days Storage	Four (4) 70,000 Gallon
Circulation Module, Two (2) 100% Redundant Pumps with Enclosure for outdoor placement and Return Pressure Control Station. Junction Box for Control by DCS.	One (1)
Metering, Distribution, and Injection – Indoor Placement,	
Dilution Water Module w/ Two (2) 100% Redundant Pumps. Junction Box for Control by DCS.	One (1)
Metering Module (s) w/ Junction Box for Control by DCS.	One (1) MM-HF-3Z for Wall Injectors One (1) MM-HF-1Z for MNLs
Distribution Module (s)	Eight (8) DM NX 5 Four (4) DM NX 6 One (1) DM NX 4
Injectors – NOxOUT Air Atomized Injectors	Sixty-eight (68) – NOxOUT
Automatic Retracts for Zone 1 Wall Injectors	Twenty-four (24)
Distribution Module, MNL	Two (2) – DM-MNL -2M
MNL Injectors w/Retracts, 26' Inserted Length	Four (4)
MNL cooling water Supply/Return Spool Pieces	One (1) Lot
Engineering and Field Services	
Process and Project Engineering	Included
SAMA Logic Diagrams and Functional Descriptions	Included
Field Start Up, Optimization, and Training Services	Included

Equipment Summary Case 2 – Wall Injectors Only 10 ppm Ammonia Slip:

Equipment Description	Quantity
Reagent Storage and Circulation Module	
Aqueous Urea Truck Unloading Panel	One (1)
NOxOUT Reagent FRP Storage Tanks, Single Wall, Heat Traced and Insulated, Thirty (30) Days Storage	Three (3) 70,000 Gallon
Circulation Module, Two (2) 100% Redundant Pumps with Enclosure for outdoor placement and Return Pressure Control Station. Junction Box for Control by DCS.	One (1)

Equipment Description	Quantity
Metering, Distribution, and Injection – Indoor Placement	
Dilution Water Module w/ Two (2) 100% Redundant Pumps. Junction Box for Control by DCS.	One (1)
Metering Module (s) w/ Junction Box for Control by DCS.	One (1) MM-HF-3Z for Wall Injectors
Distribution Module (s)	Eight (8) DM NX 5 Four (4) DM NX 6 One (1) DM NX 4
Injectors – NOxOUT Air Atomized Injectors	Sixty-eight (68) – NOxOUT
Automatic Retracts for Zone 1 Wall Injectors	Twenty-four (24)
Engineering and Field Services	
Process and Project Engineering	Included
SAMA Logic Diagrams and Functional Descriptions	Included
Field Start Up, Optimization, and Training Services	Included

4.2. Detailed Equipment Descriptions (REDACTED)

REDACTED

4.3. Fuel Tech Standard Manufacturer's List (REDACTED)

REDACTED

4.4. System and Equipment Engineering Services

Engineering - Fuel Tech will provide Project and Process Engineering and the following drawings:

- Process Flow Diagrams (PFDs)
- P&IDs
- Module General Arrangement Drawings
- Foundation Dead Loads
- Injector Locations
- Electrical Schematics and Bill of Materials
- Electrical Panel Layout Drawings
- Interconnection Diagrams
- SAMA Logic Diagrams and Functional Descriptions

FTEK will provide three (3) drawing submittal cycles as follows:

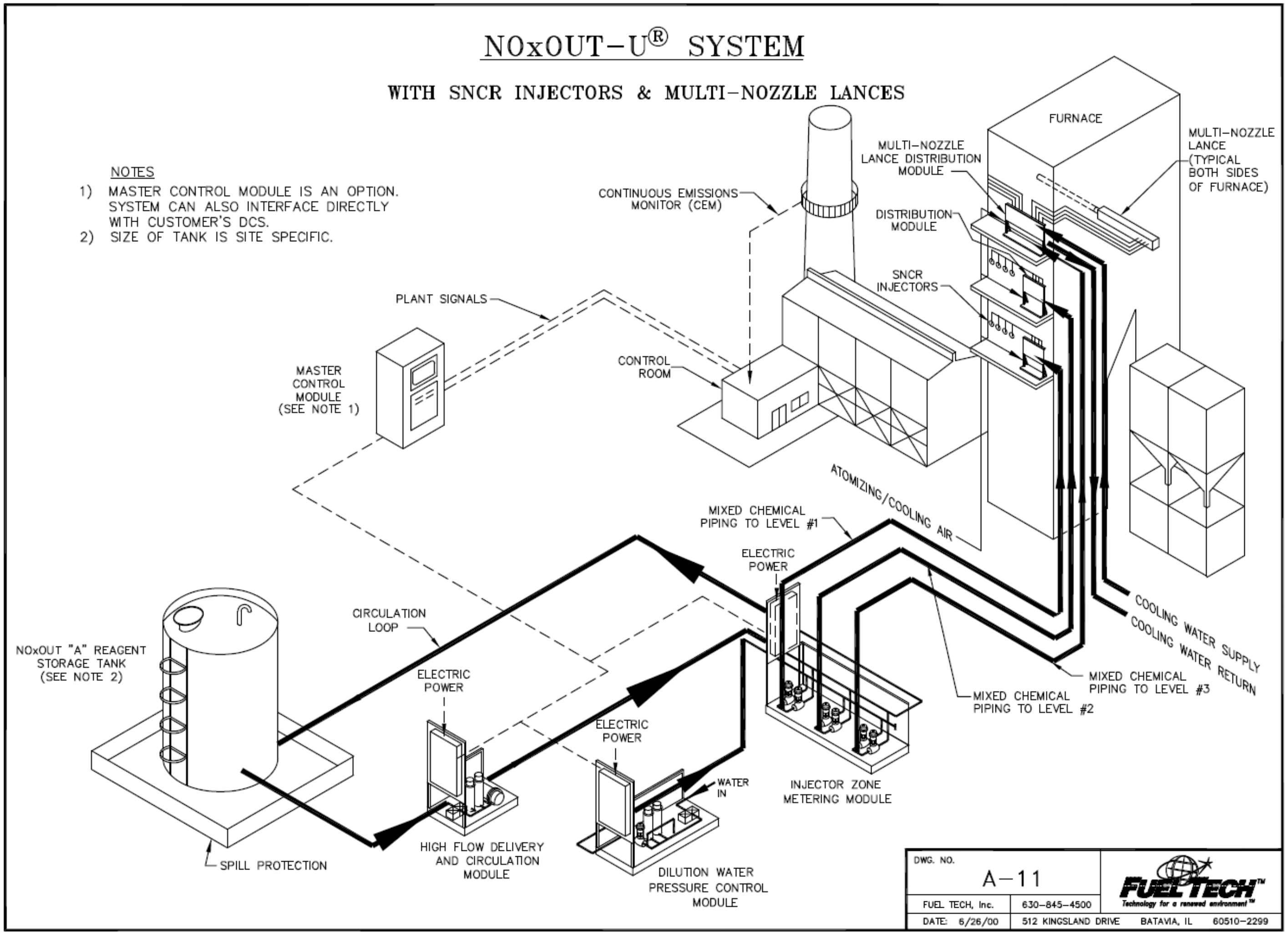
1. Drawings submitted for review and comment.
2. Drawings submitted for Fabrication
3. As-built Drawings as Needed

Engineering Services

- Process and Project Engineering
- Project Engineering and Project Management
- Engineering Kickoff Meeting/Bi-Weekly Update Conference Call/Webinar Meetings as Required
- Field Installation Support, Start-up, and Optimization Services
- Training Services and Training Manuals,
    - One (1) Electronic Version
    - Ten (10) hard copies
- Operation and Maintenance Manuals
    - One (1) Electronic Version
    - Four (4) Hard Copies

5. PROPOSAL DRAWINGS (PARTIALLY REDACTED)

The following proposal drawings are preliminary in nature and are intended to provide general reference to the equipment offering. Actual dimensions and weights will be provided during the design phase of the Project.



DESIGNS REPRESENTED ON THIS DRAWING ARE THE PROPERTY OF FUEL TECH. ALL RIGHTS ARE RESERVED. ANY USE OTHER THAN THAT DESCRIBED IN THE CUSTOMER CONTRACT REQUIRES WRITTEN PERMISSION.

Figure 2 - Typical System Isometric

6. SCOPE OF SUPPLY BY OTHERS

1. Offloading of All Fuel Tech Supplied Equipment
2. Installation Labor and Materials for Fuel Tech, Inc. Supplied Equipment.
3. BOP and Installation Engineering, Installation Project Management
4. Interconnecting Piping and Wiring of Fuel Tech, Inc. Supplied Equipment.
5. No Costs were included for Performance or Bid Bonding
6. Professional Engineering Stamps if required
7. Implement Control Logic Schemes into Plant DCS (as required).
    a. Procurement of DCS Hardware (as required)
    b. Graphic Screens Development and Programming
    c. SNCR-related Distributed Control System Programming
8. Air Compressors.
9. Chemical Supply: Licensed Quality or Industrial Grade urea (50% Solution).
10. Plant service water (NOxOUT® reagent) or demineralized water (unstabilized urea).
11. NOx, Ammonia, and CO Monitoring Equipment, if Required.
12. Boiler Penetrations, wall boxes, and water wall tube modifications for Injectors.
13. Boiler Scaffolding as needed
14. Tank Foundation and Structural Support for System Modules.
15. Appropriate Indoor Location/Building and Freeze Protection for FTEK Equipment as Required.
16. Permits as Required
17. Taxes as Required
18. Asbestos and Lead Paint Abatement, if Required
19. System Performance Testing
20. Spare Parts
21. Estimated System Utilities per Unit:

Description - Total	**Instrument Air, SCFM** (80 PSIG 70 °F)	**Atomizing Air, SCFM** (100 PSIG, Clean)	**Dilution Water, GPM** (60 PSIG/60 °F)	**MNL Cooling Water, GPM** (Clean, Inlet ≤ 120 °F, ≥ 150 PSIG)	**Power, kW** (480 or 120 VAC)
Case 1 - SNCR System w/Wall Injectors Plus MNLs	40, intermittent	1,010	145	300	95
Case 2 - SNCR System w/Wall Injectors Only	30, intermittent	720	165	N/A	75

7. UREA AND DILUTION WATER INFORMATION

7.1. Specifications for Urea and Dilution Water

Depending on the quality of water available for urea dilution at the Metering Module, either a licensed reagent (NOxOUT A or HP identified below) or unstabilized urea may be used. If an unstabilized urea of any concentration is used, the water quality requirements are much more stringent. The urea and dilution water specifications for SNCR operation with stabilized and unstabilized urea are provided below:

Quality Specifications for Aqueous Urea

Description	NOxOUT® A	NOxOUT® HP	Unstabilized Urea
	Modified 50% Aqueous Solution of Urea	Modified 50% Aqueous Solution of Urea	50% Aqueous Solution of Urea
Density (g/ml @ 25° C)	1.13 – 1.15	1.13 – 1.15	1.085 -1.105
pH	7.0 – 10.8	7.0 -10.8	7.0 -10.8
Appearance	Light Yellow, Clear to Slightly Hazy	Light Yellow, Clear to Slightly Hazy	Light Yellow, Clear to Slightly Hazy
Salt Out Freeze Point	64 degrees F (18 degrees C)	64 degrees F (18 degrees C)	64 degrees F (18 degrees C)
Foam	Foam Lasts > 15 seconds after bottle is shaken	Foam Lasts > 15 seconds after bottle is shaken	Not Applicable
Free NH3	< 5000 ppm	< 5000 ppm	< 5000 ppm
Biuret Content	< 5000 ppm	< 5000 ppm	< 5000 ppm
Organic Phosphate	55 – 85 ppm as PO4	22 -40 ppm as PO4	Not Applicable
Orthophosphate	< 6 ppm as PO4	<6 ppm as PO4	<2 ppm as PO4
Total Suspended Solids	< 10 ppm	<10 ppm	<10 ppm
Urea Makeup Water	Total Hardness as $CaCO_3$ ≤ 300 ppm	Total Hardness as $CaCO_3$ ≤ 150 ppm	Total Hardness as $CaCO_3$ ≤ 20 ppm

Quality Specifications for Dilution Water

Parameter	NOxOUT® A	NOxOUT® HP	Unstabilized Urea
Total Hardness as CaCO3 (ppm)	<450	<150	<20
M" Alkalinity as CaCO3" (ppm)	<300	<100	<100
Conductivity (µmho)	>5 and <2500	>5 and <1000	>5 and <1000
Silica as SiO2 (ppm)	<60	<60	<60
Iron as Fe (ppm)	<1	<1	<1
Manganese as Mn (ppm)	<0.3	<0.3	<0.3
Phosphate as P (ppm)	<1	<1	<1
Sulfate as SO4 (ppm)	<200	<200	<200
Turbidity & Suspended Solids (NTU)	<10 NTU	<10 NTU	<10 NTU
pH	<8.3	<8.3	<8.3

7.2. Urea Supplier Information

Licensee	Address	Contact Person	Telephone/Fax
CDI, Inc.	P.O. Box 9083 Brea, CA 92821 -or- 471 W. Lambert Rd Suite 100 Brea, CA 92821	Luis Cervantes	714.990.3940 714.329.2281 (cell) 714.990.4073 (fax)
Distribution Points	– Crossett, AR – Casa Grande, AZ - City of Industry, CA – Imperial, CA – San Jose, CA – Stockton, CA – Greeley, CO – Jacksonville, FL – Augusta, GA – Kimberly, ID – Baltimore, MD – St. Paul, MN – Albany, NY – Elizabeth, NY – Cincinnati, OH – Lima, OH – Deer Island, OR – Russellville, SC – Memphis, TN – Houston, TX – Lufkin, TX – Pasco, WA		
QLF	328 Bucklin Street Suite 200 LaSalle, IL 61301	Randy Saini	815.224.1553 815.228.5711 (cell)
Distribution Points	–La Salle, IL – Dunlap, IA – Wellsville, OH – Menomonie, WI		
PCS Nitrogen, Inc	1101 Skokie Blvd Northbrook, IL 60062	Jennifer A. Zagorski	847.849.4377 847.612.5301 847.849.4489
Distribution Points	– Augusta, GA - Lima, OH		
Monson Companies, Inc.	One Runway Rd P.O. Box 2405 South Portland, ME 04116-2406	Jeff Pellerin	207.885.5072 x 423 207.885.0569 (fax)
Distribution Points	– South Portland, ME		
The Andersons, Inc.	480 W. Dussel Drive P.O. Box 119 Maumee, OH 43537	Rod Erny	419.897.3687
Distribution Points	– Logansport, IN – Maumee, OH		
Colonial Chemical Co.	78 Carranza Rd Tabernacle, NJ 08088	Eric Wegelius	609.268.1200 x 112 609.268.2117 (fax)
Distribution Points	– Frederick, MD – Tabernacle, NJ-Monroe, LA – Hempstead, TX –Webberville, MI-Raeford, NC – Morrisville, PA – St. Paul, MN – Shakopee, MN		

Information Needed by Licensees:

- Company Name
- Location
- Scheduled Start-Up Date
- If rail delivery- specify railroad
- NOxOUT® Reagent Type Required (A,HP,LT)
- NOxOUT® Reagent Usage Rate
- NOxOUT® Reagent Storage Tank Size

8. TYPICAL FTEK SNCR PROJECT SCHEDULE

The schedule below is typical of SNCR projects with MNLs and of similar size and scope.

EVENT	RESPONSIBILITY	WEEKS FROM ORDER DATE
Receipt of Order	Customer	0
Begin Project Design	Fuel Tech	1
Submit Preliminary P&ID and PFD Drawings	Fuel Tech	6
Customer PFD/P&ID Drawing Comments Received	Customer	8
Submit Mechanical General Arrangement Drawings	Fuel Tech	10
Customer Drawing Comments Received/Release for Procurement and Fabrication	Customer	14
Submit Electrical Drawings	Fuel Tech	14
Submit SAMAs and Functional Descriptions	Fuel Tech	20
Begin Equipment Fabrication	Fuel Tech	20
Equipment Testing and FAT	Fuel Tech/Customer	40
Equipment Shipment	Fuel Tech	44
Equipment Delivery	Fuel Tech	46
Complete Equipment Installation	Customer	TBD
Begin Start-Up & Testing	Fuel Tech	1-2 weeks after completion of installation
Begin Optimization	Fuel Tech	2-4 weeks
Compliance Testing	Customer	TBD

Notes

1. Dates and durations subject to change based on contract release date and turnaround times for drawing approvals. FTEK's schedule is based on clients review and comment period of two (2) weeks or less.
2. FTEK will provide three (3) drawing submittal cycles as follows:
    a. Drawings submitted for review and comment.
    b. Drawings submitted for Fabrication
    c. As-built Drawings as Needed
3. Additional drawing submittals may be provided as a cost adder.
4. A more accurate schedule may be provided during a commercial proposal phase.

9. PRICING AND PAYMENT TERMS

9.1. Pricing (REDACTED)

For the design, supply, and field services for the SNCR system defined in this Proposal, FTEK quotes the preliminary and budgetary pricing of:

REDACTED

The installation shall be by others. Should additional field time be required beyond what is provided, the mandays and expenses will be invoiced per Appendix C-1, Field Service Rates. The current offering is based on FTEK standard equipment specifications and commercial terms and conditions.

9.2. Payment Terms

- 10% Upon receipt of Letter of Intent, Purchase Order, or Contract
- 40% Upon Release of fabrication by the Buyer
- 40% Upon date of shipment of equipment, or thirty days after notification to buyer that equipment is ready to ship, whichever occurs first.
- 10% After successful completion of acceptance test or six (6) months after receipt of equipment, whichever occurs first.

10. EXHIBIT C1 – FUEL TECH FIELD SERVICE PRICING (REDACTED)

11. FTEK EXHIBIT C3 – COMMERCIAL TERMS AND CONDITIONS (REDACTED)

12. FUEL TECH PARTIAL EXPERIENCE LISTS (REDACTED)

SNCR Partial Experience List – U.S. Tangential Fired Units, Coal (REDACTED)

Lee, Paul (Denver)

From: Carlos Cervantes <cac@cervantes-delgado.com>
Sent: Tuesday, October 23, 2018 12:03 PM
To: Lee, Paul (Denver)
Subject: 50% High Purity Urea Solution

Hello Paul,

I have some budgetary numbers for you on the subject material delivered to Bismarck, ND.

We have a supply facility about an hour away that can provide the highest purity urea available which would alleviate any impurity issues within the Nox system.

50% High Purity Urea Solution FOB delivered to Bismarck, ND
$1.35/gallon
Full Truck Load quantities are 5000 gallons

Please let me know if there’s any information you require.

Best regards,

Carlos Cervantes
Cervantes-Delgado, Inc.
AirBlueFluids, Inc.
Cell: 562) 505-2171
Fax: 714) 990-4073
E-mail: cac@cervantes-delgado.com
www.cervantes-delgado.com
www.airbluefluids.com

Black and Veatch
Attention: Paul Lee

Paul

Below is your request for budgetary pricing for Anhydrous Ammonia delivered to Bismarck, ND.

Product: Commercial Grade Anhydrous Ammonia 99.5%
Delivery: Bulk truck and driver
Quantity: 34,000 to 36,000 pounds
Product Price: $0.2885, per pound, delivered
Freight: Included in product price
Fuel Surcharge: $450
Hazmat Fee: Waived

Product: Premium Grade Anhydrous Ammonia 99.995%
Delivery: Bulk truck and driver
Quantity: 34,000 to 36,000 pounds
Product Price: $0.60, per pound, delivered
Freight: Included in product price
Fuel Surcharge: $450 estimated
Hazmat Fee: Waived

This quote is good for 60 days.

Deliveries are typically made during weekdays with four (4) hours of unloading time. Weekend and holiday deliveries are available for an additional charge. Additional unloading time will be billed at an additional $100 per hour.

If you have any other questions please contact me.

Thank you

Lee, Paul (Denver)

From: Jay Guyton <jguyton@centralsteelservice.com>
Sent: Thursday, December 27, 2018 1:07 PM
To: Lee, Paul (Denver)
Subject: RE: Corten Pricing

Hi Paul,

CW indicates a Per Hundred Pound measurement, often referred to as “Per Hundred Weight” pricing or “CWT”, our system does not allow 3 letters in that field. If you changed to “$.6950” as mentioned below, that would become the Price Per Pound. I hope this helps, the prices & totals on our quote is accurate, let me know if you have any other questions.

Best Regards,

Jay Guyton
Central Steel Service, Inc.
2764 Welborn Street
Pelham, AL 35124
(P) 800-868-6798
(F) 205-663-3391

CS
Central Steel Service, Inc.
“Serving our Customers Since 1981”

From: Lee, Paul (Denver) <LeeP@bv.com>
Sent: Thursday, December 27, 2018 2:00 PM
To: Jay Guyton <jguyton@centralsteelservice.com>
Subject: FW: Corten Pricing

Jay,

Mack Van Eaton has been helping me with some estimates for steel. Your name was on the attached quote I received from them, so I figured it’d be best to ask you questions directly. The cost of coten plate is listed at 69.5 “CW”, at 81,680 lbs. Multiplying the two results in 5,676,760, but your quote lists 56,767.60. Can you confirm what CW means, and that the “69.50” is actually $0.6950?

Thank you,

Paul Lee, P.E.*
Boiler and Air Quality Group, Energy
*Licensed in CO
Black & Veatch
4600 South Syracuse Street, Suite 800, Denver, CO 80237
O +1 720-834-4303
E LeeP@BV.com

From: Elliott, Carl <CElliott@babcockpower.com>
Sent: Friday, November 30, 2018 3:12 PM
To: Lee, Paul (Denver)
Cc: Dittus, M. H. (Mark); Pauly, Josh S.
Subject: Re: 470005.60.1000 181129 Budgetary Quote for Boiler Wall Penetrations

We do have erection capabilities in house via TEI Construction. They are open shop/ non union so they will have a significantly different price than union. Will this site accept non union?

Carl P. Elliott
Babcock Power Inc.
Sr. Account Executive
3805 SW Sandstone Dr.
Lees Summit, MO 64082

Mobile: 816.527.7590

CElliott@babcockpower.com
http://www.babcockpower.com

Sent from my iPhone

On Nov 30, 2018, at 2:00 PM, Lee, Paul (Denver) <LeeP@bv.com> wrote:

> Thanks a lot Carl. I have a few outstanding questions.
>
> I have a cost estimate for installing boiler penetrations, but it's old and likely specific to this particular client. With that said, does Babcock offer installation services, and if yes, what would it cost to install these?
>
> Additionally, I know I didn't provide the refractory material, but since it's a general consumable during construction, would you have any idea how much a generic refractory would cost on a sq ft or tonnage basis?
>
> Thank you,

Paul Lee, P.E.*
Boiler and Air Quality Group, Energy
*Licensed in CO
Black & Veatch
4600 South Syracuse Street, Suite 800, Denver, CO 80237
O +1 720-834-4303
E LeeP@BV.com

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From: Elliott, Carl [mailto:CElliott@babcockpower.com]
Sent: Friday, November 30, 2018 6:49 AM
To: Lee, Paul (Denver) <LeeP@bv.com>
Cc: Dittus, M. H. (Mark) <DittusM@bv.com>; Pauly, Josh S. <PaulyJS@bv.com>
Subject: RE: 470005.60.1000 181129 Budgetary Quote for Boiler Wall Penetrations

Each opening panel will consist of 6 tubes 18 inches long with seal box attached. Budgetary cost is $3,000 per opening panel.

No refractory is included in the estimate for the seal boxes nor is any modifications to the existing casing or insulation.

Please let me know if you need any other information.

Regards
Carl

Carl P. Elliott
Sr Account Executive

<image001.jpg>

BABCOCK POWER SERVICES
A Babcock Power Inc. Company
3805 SW Sandstone Dr | Lees Summit, MO 64082

mobile | 816-527-7590

email | CElliott@babcockpower.com

web | https://www.babcockpower.com

From: Lee, Paul (Denver) <LeeP@bv.com>
Sent: Thursday, November 29, 2018 2:14 PM
To: Elliott, Carl <CElliott@babcockpower.com>
Cc: Dittus, M. H. (Mark) <DittusM@bv.com>; Pauly, Josh S. <PaulyJS@bv.com>
Subject: RE: 470005.60.1000 181129 Budgetary Quote for Boiler Wall Penetrations

Carl,

Per our recent phone call, I have the following from our client:

"Our original tubing is 1.75" O.D. x .188" MWT SA210-A1 tubing on 2.25" centers. Typically .188" MWT tubing is not readily available and we buy .203" MWT tubing."

If there’s anything else that you need, please let me know.

Thank you,

Paul Lee, P.E.*
Boiler and Air Quality Group, Energy
*Licensed in CO
Black & Veatch
4600 South Syracuse Street, Suite 800, Denver, CO 80237
O +1 720-834-4303
E LeeP@BV.com

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From: Lee, Paul (Denver)
Sent: Thursday, November 29, 2018 11:09 AM
To: Elliott, Carl <CElliott@babcockpower.com>
Cc: Dittus, M. H. (Mark) <DittusM@bv.com>; Pauly, Josh S. <PaulyJS@bv.com>
Subject: 470005.60.1000 181129 Budgetary Quote for Boiler Wall Penetrations

PRIVILEGED AND CONFIDENTIAL – PREPARED AT THE DIRECTION OF COUNSEL

Carl,

Thank you for willing to help on this project. The project is looking into NOx controls, including SNCR, and for the SNCR, we would need new penetrations for the injection lances. Please see the information below, and if there’s anything else you need, please let me know.

Tube Material: SA210A1
Tube OD: 1 ¾”
Membrane Thickness: ½”
Number of openings: The SNCR will need three levels of lances, one with 24 penetrations, and two levels of 20 penetrations each.
Opening Size: Each injector is 3” OD

Please let me know if you need anything else. Thank you again,

Paul Lee, P.E.*
Boiler and Air Quality Group, Energy
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4600 South Syracuse Street, Suite 800, Denver, CO 80237
O +1 720-834-4303
E LeeP@BV.com

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From: Puski, Suzette <SPuski@babcockpower.com>
Sent: Wednesday, May 29, 2019 8:58 AM
To: Lee, Paul (Denver) <LeeP@bv.com>
Cc: Elliott, Carl <CElliott@babcockpower.com>; Erickson, Clayton <cerickson@babcockpower.com>
Subject: RE: 400075.60.1000 181010 RSCR Budgetary Quote Request

Paul,
Thanks for the call.
We have supplied both:

- High dust SCRs on units firing lignite coal (Luminant Oak Grove Units 1&2) that had a flue gas flow of 2,485,181 acfm per SCR reactor and
- Tail-end SCRs (WE Energy Oak Creek Units 5&6 and Units 7&8) that had a peak flue gas flow of 1,613,105 acfm per SCR reactor

The scope of supply on the tail-end SCR project included that gas-to-gas heat exchanger.
We can review the current burner design to see if lower NOx emissions area feasible.
We also can provide options for gas and dual-fuel conversion including utilitizing alternative fuels such as ethanol.

Sincerely,

Suzette M. Puski
Business Development Manager

BABCOCK POWER ENVIRONMENTAL
A Babcock Power Inc. Company
26 Forest St., Suite 300 | Marlborough, MA 01752

office | 508-854-3636
mobile | 508-340-7836
email | SPuski@babcockpower.com
web | https://www.babcockpower.com/bpe/

From: Lee, Paul (Denver) <LeeP@bv.com>
Sent: Tuesday, May 28, 2019 1:11 PM
To: Puski, Suzette <SPuski@babcockpower.com>
Cc: Elliott, Carl <CElliott@babcockpower.com>; Erickson, Clayton <cerickson@babcockpower.com>
Subject: RE: 400075.60.1000 181010 RSCR Budgetary Quote Request I

This message is from OUTSIDE THE COMPANY - be CAUTIOUS, particularly with links and attachments.

Suzette,

Thanks for the assistance over the last several months on various questions, including the email chain below. We are actually still finalizing the report that your RSCR feedback supported. At the time, we focused our cost estimates on high-dust SCRs, but after some changes in direction, I'd like to approach BPEI on more "traditional tail-end SCR."

Based on the information below in my initial email, does Riley Engineering have any tail-end SCR experience in the size range requested?

I'm writing you and those copied since Riley is under BPEI, but if I should be going to someone else, please forward as necessary.

Thank you,

Paul Lee, P.E.*
Boiler and Air Quality Group, Energy
*Licensed in CO
Black & Veatch
4600 South Syracuse Street, Suite 800, Denver, CO 80237
O +1 720-834-4303
E LeeP@BV.com

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From: Puski, Suzette <SPuski@babcockpower.com>
Sent: Thursday, October 11, 2018 2:59 PM
To: Lee, Paul (Denver) <LeeP@bv.com>
Cc: Elliott, Carl <CElliott@babcockpower.com>; Erickson, Clayton <cerickson@babcockpower.com>
Subject: RE: 400075.60.1000 181010 RSCR Budgetary Quote Request

Paul,
For an RSCR application. This will not be very practical to do as the foot print gets quite large for the flue gas flow requested.
See the following plot plan for a 54 MW RSCR. That is our largest RSCR system to date. The system is modular in design so the number of compartments can be increase but we cannot go larger in compartment size due to limits of maintaining fast acting dampers. We estimate largest practical size for an RSCR is 100 MW.

For this application we recommend a traditional tail-end SCR with an induct burner and gas/gas heat exchanger. It is not as energy efficient in terms of heat recovery (75% vs 95%) as an RSCR but it is more practical in terms of footprint. It can also meet future emissions requirements if necessary. Riley has tail-end SCR experience and a lot of experience in fitting SCRs in tight spots at the economizer outlet above the air heater inlet.

If you have any questions, please give me a call. If you can provide some GAs of the plant for us to provide a better response, we'd be happy to address this further.

Sincerely,

Suzette M. Puski
Principal Business Dev Spec

BabcockPower
ENVIRONMENTAL
a Babcock Power Inc. company

BABCOCK POWER ENVIRONMENTAL
A Babcock Power Inc. Company
26 Forest St., Suite 300 | Marlborough, MA 01752

office | 508-854-3636
mobile | 508-340-7836
email | SPuski@babcockpower.com
web | https://www.babcockpower.com/bpe/

From: Elliott, Carl
Sent: Wednesday, October 10, 2018 1:33 PM
To: Puski, Suzette <SPuski@babcockpower.com>; Erickson, Clayton <cerickson@babcockpower.com>
Subject: Fwd: 400075.60.1000 181010 RSCR Budgetary Quote Request

Please see below.

Carl P. Elliott
Babcock Power Inc.
Sr. Account Executive
3805 SW Sandstone Dr.
Lees Summit, MO 64082

Mobile: 816.527.7590

CElliott@babcockpower.com
http://www.babcockpower.com

Sent from my iPhone

Begin forwarded message:

From: "Lee, Paul (Denver)" <LeeP@bv.com>
Date: October 10, 2018 at 11:00:31 AM CDT
To: "Elliott, Carl" <CElliott@babcockpower.com>
Cc: "Dittus, M. H. (Mark)" <DittusM@bv.com>, "Pauly, Josh S." <PaulyJS@bv.com>, "'megan.berge@bakerbotts.com'" <megan.berge@bakerbotts.com>, "laura.williams@BakerBotts.com" <laura.williams@BakerBotts.com>
Subject: 400075.60.1000 181010 RSCR Budgetary Quote Request

Carl,

Per our phone conversation last week, please see below some information for a budgetary quote of an RSCR. I understand that the units that these are be investigated for are larger than what BPEI has done in the past, so they may not be a good fit. However, per the study that I am doing, I must at least evaluate them at a superficial level.

Parameter	**Units**	**Case 1**	**Case 2**
Flow rate	lb/hr	7,927,427	
	acfm	2,203,068	
Site Elevation	ft	1940	
Stack Pressure	in. w.g.	-1.1	
Fuel Burn Rate	MMBtu/hr	5,868.7	
Stack Temperature	F	147.4	
Inlet NOx	ppmvd actual O2	126	
	lb/MMBtu	0.13	
O2	Vol%,wet	4.9	
O2 reference	Vol%,dry	3.0	
H2O	Vol%,wet	16.4	
CO2	Vol%,wet	14.4	
SO2	ppmvd actual O2	48	
SO3	ppmvd actual O2	9	
Particulate	lb/hr	28.50	
Outlet NOx (guarantee)	ppmvd actual O2	39	
Ammonia Slip (guarantee)	ppmvd ref. O2	2	
SO2 to SO3 Oxidation Rate (guarantee)	%	0.5/catalyst layer	
Operating Hours (guarantee)	hours	24,000	

If you need anything else, please let me know. Thank you,

Paul Lee, P.E.*
Boiler and Air Quality Group, Energy
*Licensed in CO
Black & Veatch
4600 South Syracuse Street, Suite 800, Denver, CO 80237
O +1 720-834-4303
E LeeP@BV.com

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FUEL TECH
Technologies to enable clean efficient energy™

Dale Pfaff
Regional Sales Manager

December 20, 2018

Ms. Megan Berge
Baker Botts LLP
1299 Pennsylvania Ave, NW
Washington, D.C. 20004
P: (202) 639-1308

SUBJECT: GREAT RIVER ENERGY – REQUEST FOR PROPOSAL COAL CREEK STATION UNIT 2 ADVANCED SCR SYSTEM TECHNOLOGY EVALUATION AND SYSTEM COSTS FUEL TECH BUDGETARY PROPOSAL NO. 18-B-064, ADDENDUM 1

Dear Ms. Berge:

Fuel Tech, Inc. (FTEK) is pleased to submit our preliminary and budgetary Proposal 18-B-064, Addendum 1, to Great River Energy (GRE) for the Coal Creek Station (CCS) Unit 2. The following evaluation provides the technical, performance, and commercial details for the FTEK Advanced Selective Catalytic Reduction (ASCR™) system for CCS Unit 2 located in Underwood, ND.

FTEK's ASCR evaluation assumes the NOxOUT® Selective Non-Catalytic Reduction (SNCR) system has already been installed on CCS Unit 2 (pricing, performance, and scope provided previously under separate cover). The scope of supply for the FTEK's ASCR Process would include the ASCR system design, process review, ammonia injection grids (AIGs), and our ULTRA System Urea conversion technology to convert urea to ammonia for the AIGs. Our systems would be controlled via the Plant's Honeywell DCS System.

CC Unit 2 Unit Description and ASCR Layout:

Coal Creek Station Unit 2 is a 600 MWg Combustion Engineering tangential fired boiler with eight corners and a divided furnace. The boiler fires 100% ND lignite coal with a heat input of 5,971 MMBTU/hr at full load. The Unit has Foster Wheeler Low NOx Combustion System with close coupled over fire air (CCOFA) and separated over fire air (SOFA) systems. The NOx baseline at full load is 0.121 lb/MMBTU.

For the ASCR system layout, it is assumed the SNCR system is already deployed and is controlling NOx down to 0.103 lb/MMBTU. See FTEK's Proposal 18-B-064 for the SNCR performance. The SNCR performance utilized for the ASCR design incorporates our combined injection strategy of wall injectors + multiple nozzle lances (MNLs) with a 10 ppm ammonia slip at the economizer outlet.

The ASCR system would replace the existing ductwork from the economizer outlet to the air preheater (APH) inlet. This ASCR system would include two (2) SCR reactors that would be expanded to provide the appropriate catalyst quantity and flue gas flow distribution requirements.

The current SCR performance includes 2 layers of catalyst to provide 33% NOx reduction with an ammonia slip of 2 ppm at the catalyst outlet. Each SCR reactor train would include an ammonia injection frid (AIG), turning vanes, distribution devices and catalyst reactor as highlighted in the following Figure.

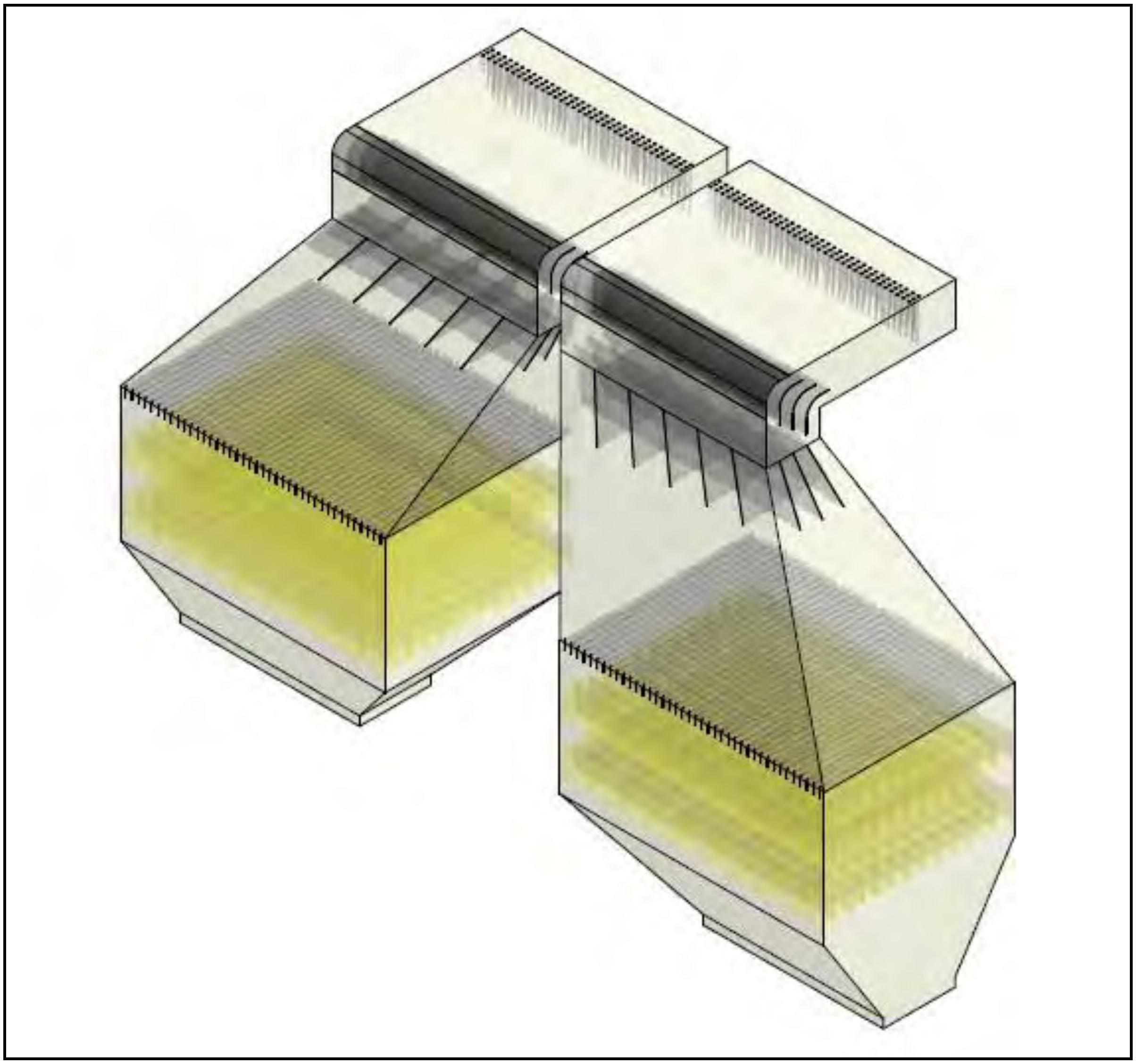

Figure 1 - GRE Coal Creek Unit 2 ASCR Preliminary Layout

See Appendices for more detailed drawings of the ASCR layout.

FTEK ASCR Process Description:

NOxOUT® Selective Non-Catalytic Reduction (SCNR) of NOx Process

Fuel Tech's urea-based SNCR Process is a post-combustion NOx reduction method that reduces NOx through a controlled injection of an aqueous urea solution into the combustion gas path of fossil-fired and waste-fired boilers, furnaces, incinerators, or heaters. The most commonly used reagent consists of a 50% urea solution plus a small amount of additives for scale and corrosion control. This reagent is readily available and requires no special safety precautions for handling.

The predominant overall reaction is described as:

$$CO(NH_2)_2 + 2NO + 1/2\ O_2 \Rightarrow N_2 + CO_2 + 2H_2O$$

Urea + Nitrogen Oxide ⇨ Nitrogen + Carbon Dioxide + Water

Fuel Tech has enhanced the basic SNCR technology by developing chemical injection hardware, widening the applicable temperature range, and process control expertise required for commercial applications. Fuel Tech's urea based SNCR technology is the NOxOUT® process.

Two key parameters that affect the process performance are flue gas temperature and the reagent distribution. The NOx reducing reaction is temperature sensitive; by-product emissions become significant at lower than the optimum temperature range while chemical utilization and NOx reduction decrease at higher than the optimum. This optimum temperature range is specific to each application. The reagent needs to be distributed within this optimum temperature zone to obtain the best performance. Typically, the distribution is more difficult for large units and for units with high flue gas velocity.

Fuel Tech's SNCR Processes are designed with the aid of Computational Fluid Dynamics (CFD) and Chemical Kinetic Model (CKM) in addition to results from field tests. The CFD model simulates flue gas flows and temperature inside a unit while the CKM calculates the reaction between urea and NOx based on temperature and flow information from CFD. A combination of these two models determines the optimum temperature region and the optimum injection strategy to distribute the reagent. With an ability to estimate NOx reduction, a model study can be performed to determine if an application is a right fit for the process.

Chemical injectors developed by Fuel Tech facilitate the reagent distribution. The NOxOUT injection system utilizes air-atomized injectors which direct the urea solution into the combustion gas path. The droplet size distribution and spray coverage developed by the injectors promote efficient contact between the chemical and the NOx in the flue gas.

Fuel Tech's SNCR Processes provide effective boiler load following capabilities. Through the computer modeling, an injection strategy is developed that makes use of multilevel injection, control of reagent concentration, droplet size and spray patterns, as well as jet penetration.

Several years of field-testing indicate that NOxOUT systems are applicable on various types of units firing many different fuels. The process has been commercially proven on units fired with coal, oil, gas, wood or municipal solid or hazardous waste. These units varied in size and type: package boilers, process heaters, incinerators, circulating or bubbling fluidized beds, waste heat boilers, utility boilers. By virtue of being a post-combustion process, unit size and type and fuel type have some, but not a major effect on the process.

There are substantial benefits gained from the application of NOxOUT systems compared to first generation NOx control technologies, such as ammonia injection. These benefits are briefly summarized below:

- Use of non-toxic, non-hazardous chemicals.
- Potentially lower capital cost due to the lack of large system compressors and elimination of anhydrous ammonia storage, handling, and safety equipment.
- Lower operating costs resulting primarily from minimization of gas (steam or compressed air) requirements.
- Inherently more effective control of chemical distribution for better mixing with the use of liquid rather than gas-based reagents, thereby resulting in better chemical utilization.

Advanced Selective Catalytic Reduction (ASCR®) of NOx

Fuel Tech is a leader in development and deployment of a layered approach to NOx reduction combining technologies such as combustion modifications, SNCR, and a smaller implementation of SCR catalyst. Where SCR is involved, the combination of such proven technologies has come to be known as ASCR® Advanced SCR, or ASCR.

The SCR process is a post-combustion NO_X reduction method that employs the use of catalyst to promote the conversion of nitrogen oxides (NOx) to nitrogen and water vapor in the flue gas. This conversion occurs between the combustion area and the exhaust gas stack in a specially designed ductwork section, called the SCR Reactor, which contains the catalyst. As the NO_X and ammonia laden flue gas passes over the catalyst, the nitrogen monoxide (NO) and nitrogen dioxide (NO_2) combine with ammonia (NH_3) to form nitrogen (N_2) and water (H_2O), via the following exothermic reactions.

$$4NO + 4NH_3 + O_2 \Rightarrow 4N_2 + 6H_20 \ (-406.9 \text{ kJ/mol NO})$$

$$6NO_2 + 8NH_3 \Rightarrow 7N_2 + 12H_20 \ (-455.9 \text{ kJ/mol } NO_2)$$

As long as a mixture of NO and NO_2 is present, the following faster reaction happens in parallel.

$$NO + NO_2 + 2NH_3 \Rightarrow 2N_2 + 3H_20 \ (-757.3 \text{ kJ/mol NO})$$

The distinguishing features that set Fuel Tech's ASCR technology apart are our commercial experience and state-of-the-art design capabilities that together allow us to understand the working relationships of the combined NO_X reduction technologies. These capabilities also allow FTEK to evaluate each application and tailor a solution that maximizes the contribution of each technology in our suite of offerings without pushing any one process to the point that it impacts boiler operation or negatively impacts another NO_X reduction process downstream.

The ASCR process offers operational benefits due to its ability to quickly adapt to process condition changes and the fact that each deployed technology component can be optimized independently. This advantage manifests itself through a robust range of potential responses to process upsets or non-ideal operating conditions, and presents the opportunity for optimized urea consumption and lower operating costs.

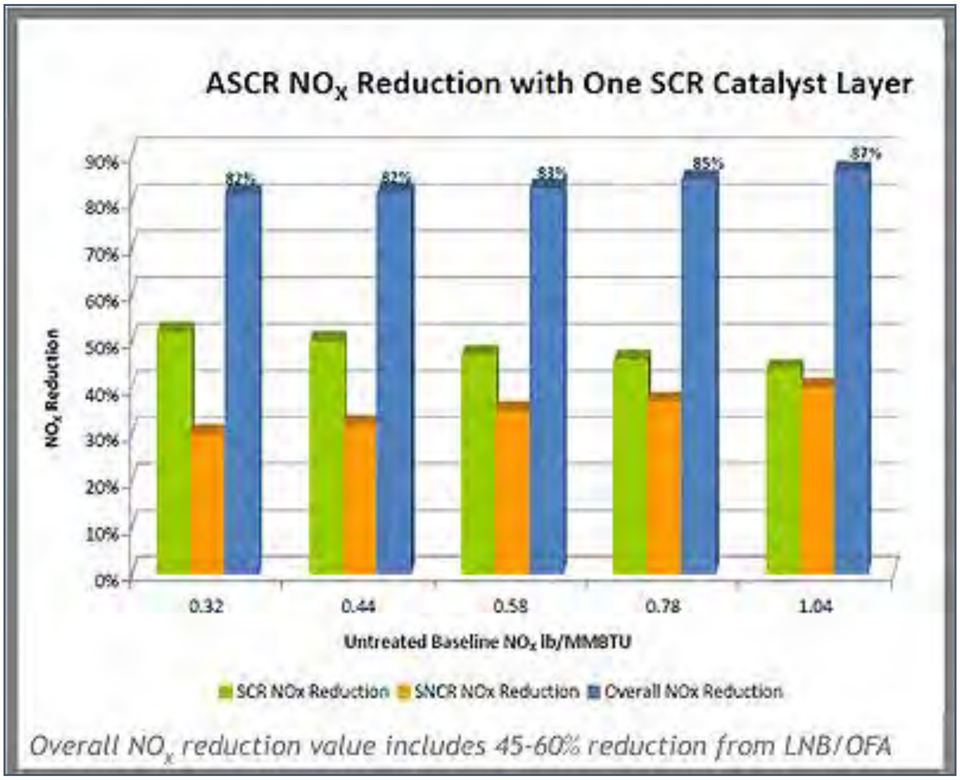

Figure 2 - NOx Reduction with Combined Technologies

By utilizing an integrated technology approach, the catalyst quantity, weight, and space requirements can be minimized, potentially leading to the elimination of new foundations and the need to install new "steel to grade". Fuel Tech works with industry leading catalyst suppliers to determine the appropriate catalyst type and formulation for each application. With the concept of a smaller implementation of catalyst compared to standalone SCR, the ASCR system has the added benefit of minimizing the rate of SO_2 to SO_3 conversion which is a precursor to ammonium sulfate/bisulfate formation in the air heater. This low conversion rate allows for a broader unit operating range and fuel flexibility. In addition, the reduced volume of catalyst demands less time for replacement which results in shorter maintenance outages.

ASCR can be implemented in stages over time, providing financial advantages of both lower total installed capital costs and the ability to stage capital expenditures. Due to the various cost savings of a smaller SCR implementation, an ASCR system can achieve full scale SCR equivalent NOx reductions at 30-70% of the capital cost. Advanced SCR has now been applied on units up to 650 MWg.

ULTRA Process Description (Urea Conversion to Ammonia for SCR)

Fuel Tech's ULTRA™ process is a patented approach that converts safe Urea reagent to Ammonia for use on new Selective Catalytic Reduction (SCR) systems and in retrofit applications for existing systems. The ULTRA technology offers a cost effective solution for simplifying on–site ammonia generation for SCR applications of all types.

The ULTRA System provides ammonia reagent to an SCR by controlling the injection of high quality aqueous urea into a compactly and specifically designed duct maintained within the appropriate temperature window. The reactions of the ULTRA Process are described as:

$$\mathrm{CO(NH2)2 + H20 \rightarrow NH3 + HNCO}$$

Urea + Water → Ammonia + Isocyanic Acid

$$\mathrm{HNCO + H2O \rightarrow NH3 + CO2}$$

Isocyanic Acid + Water → Ammonia + Carbon Dioxide

The use of urea in the ULTRA System eliminates all ammonia handling requirements so that the expenses, safety, and environmental concerns are eliminated. The urea solution is readily available for delivery in solution or in dry form for on-site solutionizing and requires no special safety precautions for handling which allows the aqueous solution to be stored in atmospheric tanks.

The aqueous urea solution, at a specific flow rate, is introduced into the hot air stream in at the top of the Decomposition Chamber. The chamber is specifically designed with the appropriate flow paths, residence time and post chamber HNCO catalyst to achieve a 100% conversion of urea to ammonia product.

The urea reagent is sprayed through proprietary chemical injectors developed by Fuel Tech to facilitate the reagent distribution, droplet size, and flow rate. Utilizing pressurized air from customer's existing plant compressed air system; these injectors atomize and direct the reagent into the dilution air stream of the ULTRA System.

The airflow through the Decomposition Chamber including the urea injection will be modeled using a computational fluid dynamics model with proprietary droplet trajectory modeling. This will insure proper evaporation, mixing, and decomposition of injected urea reagent within the heated air stream.

The gas stream leaving the Decomposition Chamber containing the SCR reagent is then routed to the AIG. The pressure, flow, and temperature are monitored to conform to the requirements of the SCR system design and to maintain proper ULTRA operations.

The control of the urea injection will be based on a hardwired reagent demand signal from the Owner’s DCS. A short residence time in the decomposition chamber will allow a rapid response time for SCR reagent production. The system will be able to shutdown almost instantaneously through halting of urea injection.

The ULTRA Process thermally decomposes urea and does not involve hydrolysis. The ULTRA design and process is simple to operate and has no disposal requirements for by-products during operation, start-up, and shutdown. The added benefits include the system’s ability to be brought off line quickly, with very responsive boiler load following capabilities.

The features of the ULTRA system include:

- Safe Reagent Supply
- Skid mounted system for easy installation
- No requirement for formaldehyde free urea supply
- No hazardous material disposal that is common with the hydrolysis urea conversion process.
- Simplified process and controls compared to other systems (patent pending)
- Designed for maximum system availability and minimum maintenance
- Load following controls for safe operation and easy system shutdown
- Low pressure operation
- Fuel Tech's proven experience with urea-based systems
- Experience with proven system components

System supported by Fuel Tech's field personnel with startup, optimization and service experience.

FTEK Process Performance for GRE CCS Unit 2

Unit Identification	Unit 2
Type of Unit	600 MW CE T-Fired, Eight (8) Corner, Divided Furnace
Type of Fuel	North Dakota Lignite
Load Range	100% MCR

ASCR Expected Process Design Table

Parameter	U/M	Units
Plant Elevation at Grade	ft above MSL	1940
Atmospheric Pressure at Grade	atm	0.93
Fuel		ND Lignite Coal
Flue Gas Analysis (at catalyst inlet)		
Flue Gas Flow, wet	SCFM	1,372,588
Flue Gas Flow, wet	lb/hr	6,143,001
Boiler Heat Input	mmBTU/hr	5,971
O2	% (by Volume)	2.60%
CO2	% (by Volume)	13.82%
N2	% (by Volume)	67.88%
H2O	% (by Volume)	15.61%
NOx, After SNCR w/MNLs, 10 ppm Slip	lb/mmBTU	0.103
SO2	ppm, dry @ Ref O2	830
SO3	ppm, dry @ Ref O2	9
NH3 from SNCR	ppmw @ Op O2	10.00
Temperature	°F	820
Duct Pressure (Gauge)	inH2O	-5.5
Fly Ash Flow	lb/hr	82,924
Emissions and SCR Performance Requirements:		
Post SNCR NOx Emission Rate to Catalyst	lb/mmBTU	0.103
SCR Outlet NOx Emission Rate	lb/mmBTU	0.069
Catalyst SO2 to SO3 Oxidation Rate	%	4.0%
Ammonia Slip @ Catalyst Outlet	ppm, dry @ Ref O2	2
Catalyst lifetime	hours	16000
Catalyst draft loss (dirty)	in H2O	1.94
NO:NOx ratio (by volume)		0.90
Catalyst and NH3 Design		
Catalyst Type (Honeycomb or Plate)		Honeycomb

Parameter	U/M	Units
Pitch	mm	7.4
# of reactors	#	2
# of modules per reactor per layer	#	117
# of layers per reactor	#	2
Single Layer Depth	mm	1,300
Total catalyst volume per reactor	m3	493.1
Total catalyst weight per reactor	lb	679,770
Ammonia Consumption per reactor	lb/hr	44.8
SCR Minimum Operating Temperature	°F	592

ULTRA System Expected Process Design Table

Two (2) Chambers Required - Information below is Per Chamber		
ULTRA Heating Type	**U/M**	**Electric**
Case		Full Load
Flue gas flow	lb/hr	6143001
Baseline NOx	lb/MMBTU	0.103
Target NOx	lb/MMBTU	0.069
NOx Reduction	%	33
NH3 slip	ppm	2
Temperature requirements		
Dilution Air Temperature	(°F)	-31
Temperature at Decomposition Chamber outlet	(°F)	550
Pre-injection temperature at Decomposition Chamber	(°F)	856
At Decomposition Chamber outlet		
Ammonia Flow	(lb/hr)	47.9
Ammonia to air ratio	(vol%)	2.72
Total flow at Decomposition Chamber outlet	(scfm)	664
Total flow at Decomposition Chamber outlet	(lb/hr)	2923
Injection and duct burner requirements		
50% Aqueous Urea Flow Rate	(gph)	18.1

Two (2) Chambers Required - Information below is Per Chamber		
ULTRA Heating Type	**U/M**	**Electric**
Air flow through Decomposition Chamber	(scfm)	600
Air flow through Decomposition Chamber	(lb/hr)	2683
Injection air	(scfm)	15
Requirement to raise the temperature to pre-injection		
Heat Input (Electrical Heater)	(kW)	192

For FTEK to provide system and performance guarantees, we would be responsible for the design and supply of all ASCR “smart parts” which would include the flow modeling, SCR and reagent system process design, catalyst specification and procurement, internal flow and catalyst cleaning devices, and reagent and AIG system design and procurement. For the purpose of this evaluation, our current scope only includes the ASCR process design and modeling, reagent and AIG systems design and supply, and field services. See “Scope of Supply by Others” below.

FTEK Scope of Supply

Description	Quantity
Ammonia Injection Grid, Design and Supply, Lances and Distribution Manifolds. Shipped loose for installation by Others	Two (2)
ULTRA Urea Conversion – Redundant Ambient Air Fans, Electric Heaters, Decomposition Chamber, Metering and Distribution Modules, w/Junction Boxes	Two (2)
ASCR Process Engineering Services including Flow Modeling, System Layout, Process Performance Review, and Preliminary General Arrangement Drawings for Ducts, SCR Reactor, and Internal Flow Distribution Devices	One (1) Lot

Scope of Supply by Others, BOP, and Utility Requirements

1. Offloading of All Fuel Tech Supplied Equipment
2. Installation Labor and Materials for Fuel Tech, Inc. Supplied Equipment.
3. BOP and Installation Engineering, Installation Project Management
4. Interconnecting Piping and Wiring of Fuel Tech, Inc. Supplied Equipment.
5. Demolition of Existing Ductwork
6. Building and Boiler House Structural Steel Review and Redesign to Support New ASCR Ductwork, and SCR Reactor. Review of Building Interferences.
7. Cost for Demolition, New Structural Steel, Foundations, and Boiler House Modifications as Needed.

8. Costs for New Ductwork, Internal Flue Gas Flow Distribution Devices, Catalyst, Catalyst Reactor (Ductwork, Supports, and Seals), and External Insulation.
9. Sonic Horns and SCR Cleaning Devices (quantity TBD by others)
    a. Operated on sequencing (typically, 10 seconds every 10 minutes)
10. Evaluate ID Fan Capacity and Boiler (Implosion Study) for Additional SCR Pressure Drop. Provide Modifications/Upgrades as Needed.
11. Replacement of Stack Reheat System and All Modified Equipment.
12. No Costs were included for Performance or Bid Bonding
13. Professional Engineering Stamps if required
14. Implement Control Logic Schemes into Plant DCS (as required).
    a. Procurement of DCS Hardware (as required)
    b. Graphic Screens Development and Programming
    c. SNCR-related Distributed Control System Programming
15. Project Controls – Scheduling and Master Milestone Schedule
16. Air Compressors.
17. Chemical Supply: Licensed Quality or Industrial Grade urea (50% Solution).
18. Plant service water (NOxOUT® reagent) or demineralized water (unstabilized urea).
19. NOx, Ammonia, and CO Monitoring Equipment, if Required.
20. Structural Support for System Modules.
21. Appropriate Indoor Location/Building and Freeze Protection for FTEK Equipment as Required.
22. Permits as Required
23. Taxes as Required
24. Asbestos and Lead Paint Abatement, if Required
25. System Performance Testing
26. Spare Parts
27. Estimated System Utilities, Total:

Description - Total	**Instrument Air, SCFM** (80 PSIG 70 °F)	**Atomizing Air, SCFM** (100 PSIG, Clean)	**Flush Water, GPM** (60 PSIG/60 °F)	**Power, kW** (480 VAC) (1)
ULTRA System, Total	10	30	2 (Intermittent)	450
	Catalyst Pressure Drop, “W.C.	**SCR System Pressure Drop, “W.C.**	**Additional 50% Aqueous Urea Usage, GPH**	**Sonic Horn Air, SCFM** (80 PSIG 70 °F) (2)
ASCR, Total	2.0	4.0	36	320 (cycled, intermittent)

Note 1: Electric heaters and blowers

Note 2: Based on four (4) sonic horns being required with 40 – 80 SCFM per horn air consumption.

Schedule and Pricing:

The following is a preliminary schedule for the FTEK provided equipment and engineering:

- ASCR Modeling, Design, and Layout – Twenty (20) Weeks from Receipt of PO.
- ULTRA System and AIG Design and Supply – Thirty (30) Weeks from Receipt of PO or Twenty-Six (26) Weeks from Confirmation of ASCR Confirmed Ammonia Demand Flow.

For the components, engineering, and field technical assistance detailed in this evaluation, FTEK quotes the preliminary and budgetary pricing of [redacted].

FTEK Recommendations and Design Concerns

FTEK has performed a "high level" evaluation of the ASCR process for GRE CCS Unit 2. As stated previously, the ASCR process is a component of a layered approach to NOx reduction combining technologies of combustion modifications/optimization, SNCR, and a smaller implementation of SCR catalyst. Upon preview of the system sizing and layout requirements, there are significant retrofit impacts for the catalyst reactors that must be considered.

The backend of Unit 2 has a split flue gas ductwork configuration leaving the economizer and entering the air heaters. Due to the ash loading of the ND Lignite at 10 – 12% ash and an "Si + Al" total > 80%, the ash particles are harder and may be erosive at higher velocities. Therefore, the catalyst face velocity has to be lowered to ~ 15 fps to minimize catalyst erosion. The ductwork expansion required to achieve adequate face velocities while providing adequate NOx reduction will require significant retrofit design consideration and will prove very costly. The ASCR duct expansion would require changes to and redesign of both the existing boiler structural steel and the stack reheat system.

In addition to the spatial limitations, FTEK has several process concerns regarding the sodium (Na) levels in the fuel/ash and sulfur trioxide (SO3) levels in flue gas. SO3 in the presence of ammonia (NH3) in the form of ammonia slip from the SCR process could lead to ammonium bisulfate plugging in the air heater. Additionally, the SO3 concentration in the flue gas may convert the Na in the solid phase to a gaseous phase which may cause significant catalyst deactivation.

To provide acceptable NOx reduction "activity" and catalyst life expectancy, the existing catalyst formulation has a ~2% oxidation rate per layer. This will cause SO2 in the flue gas to be converted to SO3 which in turn could lead to ammonium bisulfate pluggage of the catalyst and air heater along with accelerated catalyst deactivation rates due to Na poisoning.

For these reasons, FTEK would not recommend the deployment of the ASCR technology on CCS Unit 2. We would not be willing to provide any performance guarantees on the SCR portion at this time until more is known about the effects of ND lignite ash on catalyst performance and deactivation. FTEK would recommend that pilot scale testing should be performed to obtain actual operational data and learn more about the ND Lignite and prove catalyst operation and performance.

We trust this information meets your needs. Upon completion of your review, please do not hesitate to contact me if there are any questions or comments. Thank you.

Sincerely,

Dale Pfaff

Dale Pfaff
Regional Sales Manager

cc:
Mary Jo Roth, GRE
Greg Heinz, GRE
Paul Lee, B&V
Mark Dittus, B&V
William Cummings, FTEK
Kevin Dougherty, FTEK
Terry Brown, FTEK
Mark Siebeking, FTEK
Joe DiFiglio, FTEK
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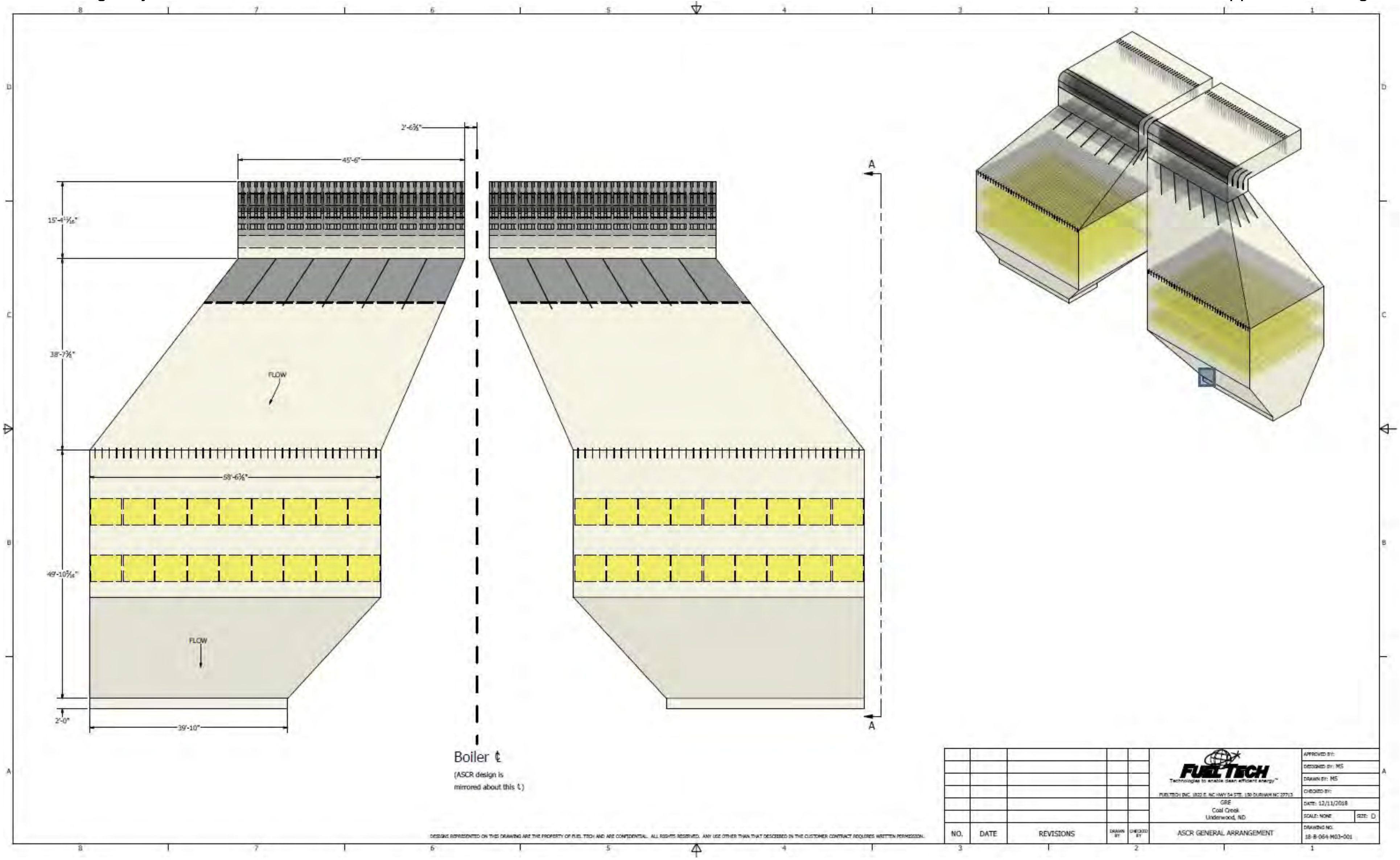
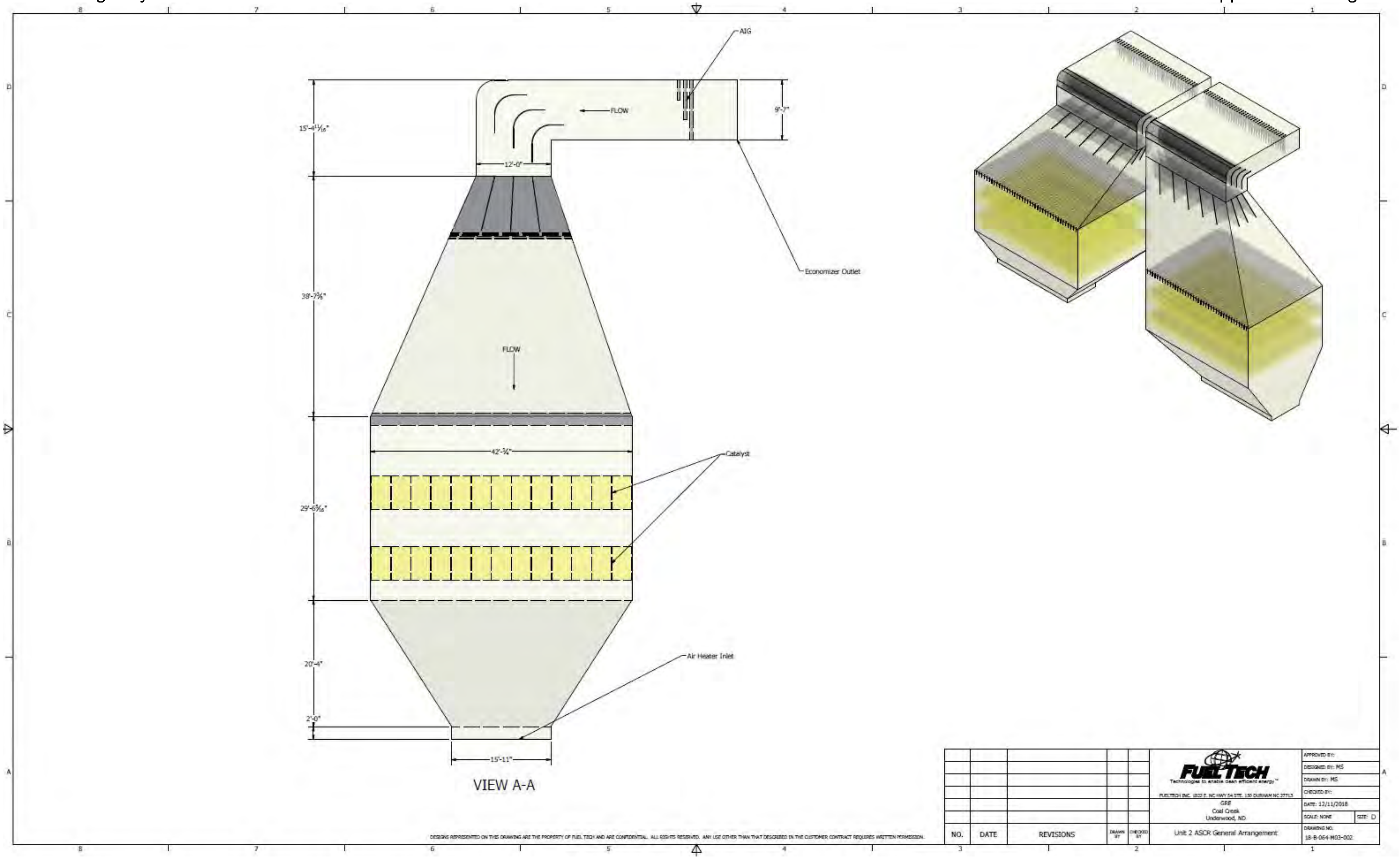


NO.	DATE	REVISIONS	DRAWN BY	CHECKED BY

FUEL TECH
Technologies to enable clean efficient energy™
FUELTECH INC. 1822 E. NC HWY 54 STE. 150 DURHAM NC 27713
GRE
Coal Creek
Underwood, ND
ASCR GENERAL ARRANGEMENT

APPROVED BY:
DESIGNED BY: MS
DRAWN BY: MS
CHECKED BY:
DATE: 12/11/2018
SCALE: NONE
SIZE: D
DRAWING NO.
18-B-064-M03-001



VIEW A-A

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FUELTECH INC. 1022 E. NC HWY 54 STE. 150 DURHAM NC 27713
GRE
Coal Creek
Underwood, ND
Unit 2 ASCR General Arrangement

APPROVED BY:
DESIGNED BY: MS
DRAWN BY: MS
CHECKED BY:
DATE: 12/11/2018
SCALE: NONE
SIZE: D
DRAWING NO.
18-B-064-M03-002

Appendix F. Texas and WRAP Data

Consolidated List of Units With SCR's

	State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Operating Time	Notes	Nameplate Capacity (MW)	Nameplate Capacity Factor	Heat Rate (mmbtu/kwhr)	Case 1 MW-h (85% or Higher)	Nox ER	SO2 ER	NOx (tons)	SO2 Tons	Gross Load (MW-h)	Avg. NOx Rate (lb/MMBtu)	SO2 ER	NOx (tons)	SO2 (tons)	CO2 (short tons)	Heat Input (MMBtu)	Owner	Operator	Unit Type	Fuel Type (Primary)	Fuel Type (Secondary)	SO2 Control(s)	NOx Control(s)
1	AZ	Coronado Generating Station	6177	U2B	2014	7,082		411	79%	10,311						2,854,256	0.101	0.029	1,503	433	3,086,666	2.94E+07	Salt River Project	Salt River Project	Dry bottom turbo-fired boiler	Coal-Sub	Diesel Oil	Wet Limestone	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction (Began May 03, 2014)
	AZ	Coronado Generating Station	6177	U2B	2015	8,209	SCR Installed		84%	10,267						3,018,364	0.061	0.021	933	327	3,250,081	3.10E+07	Salt River Project	Salt River Project	Dry bottom turbo-fired boiler	Coal	Diesel Oil	Wet Limestone	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
	AZ	Coronado Generating Station	6177	U2B	2016	8,077			78%	10,317						2,804,657	0.057	0.023	814	333	3,034,761	2.89E+07	Salt River Project	Salt River Project	Dry bottom turbo-fired boiler	Coal	Diesel Oil	Wet Limestone	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
	AZ	Coronado Generating Station	6177	U2B	2017	6,677			62%	10,934	85%	2017	2017			2,223,067	0.057	0.010	682	125	2,549,221	2.43E+07	Salt River Project	Salt River Project	Dry bottom turbo-fired boiler	Coal	Diesel Oil	Wet Limestone	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
									Average HR =	10,457	3,059,561	0.057	0.010	913	165														
2	AZ	Springerville Generating Station	8223	4	2014	6,961		458	69%	9,071						2,784,838	0.075	0.077	956	972	2,648,205	2.53E+07	Salt River Project	Tucson Electric Power Company	Dry bottom wall-fired boiler	Coal-Sub	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
	AZ	Springerville Generating Station	8223	4	2015	8,534			75%	9,013						3,017,577	0.082	0.073	1,114	998	2,851,762	2.72E+07	Salt River Project	Tucson Electric Power Company	Dry bottom wall-fired boiler	Coal	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
	AZ	Springerville Generating Station	8223	4	2016	7,360			62%	9,520						2,504,794	0.076	0.082	906	976	2,498,784	2.38E+07	Salt River Project	Tucson Electric Power Company	Dry bottom wall-fired boiler	Coal	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
	AZ	Springerville Generating Station	8223	4	2017	6,359			57%	9,411	85%	2017	2017			2,288,847	0.081	0.081	875	872	2,257,831	2.15E+07	Salt River Project	Tucson Electric Power Company	Dry bottom wall-fired boiler	Coal	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
									Average HR =	9,254	3,411,013	0.081	0.081	1,282	1,278														
3	AZ	Springerville Generating Station	8223	TS3	2014	8,594		458	78%	9,533						3,118,860	0.074	0.061	1,102	902	3,117,113	2.97E+07	Tri-State Generation & Transmission	Tucson Electric Power Company	Dry bottom wall-fired boiler	Coal	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
	AZ	Springerville Generating Station	8223	TS3	2015	8,463			73%	9,754						2,919,676	0.077	0.060	1,094	851	2,986,089	2.85E+07	Tri-State Generation & Transmission	Tucson Electric Power Company	Dry bottom wall-fired boiler	Coal	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
	AZ	Springerville Generating Station	8223	TS3	2016	7,122			57%	9,826						2,304,336	0.075	0.071	847	802	2,373,882	2.26E+07	Tri-State Generation & Transmission	Tucson Electric Power Company	Dry bottom wall-fired boiler	Coal	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
	AZ	Springerville Generating Station	8223	TS3	2017	7,500			68%	9,377	85%	2017	2017			2,736,666	0.076	0.082	989	1,054	2,689,665	2.57E+07	Tri-State Generation & Transmission	Tucson Electric Power Company	Dry bottom wall-fired boiler	Coal	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
									Average HR =	9,623	3,411,013	0.076	0.082	1,251	1,348														
4	CO	Comanche (470)	470	3	2014	6,467		857	58%	8,958						4,372,431	0.068	0.075	1,333	1,459	4,092,522	3.9E+07	Holly Cross Energy, Intermountain Rural Electric Authority, Public Service Company of Colora	Public Service Company of Colorado	Tangentially-fired	Coal-Sub	Natural Gas	Dry Lime FGD	Selective Catalytic Reduction
	CO	Comanche (470)	470	3	2015	6,788			62%	9,132						4,655,984	0.066	0.074	1,405	1,569	4,451,716	4.3E+07	Holly Cross Energy, Intermountain Rural Electric Authority, Public Service Company of Colora	Public Service Company of Colorado	Tangentially-fired	Coal	Natural Gas	Dry Lime FGD	Selective Catalytic Reduction
	CO	Comanche (470)	470	3	2016	8,019	representative year		72%	9,157						5,415,053	0.065	0.083	1,625	2,057	5,189,414	5.0E+07	Holly Cross Energy, Intermountain Rural Electric Authority, Public Service Company of Colora	Public Service Company of Colorado	Tangentially-fired	Coal	Natural Gas	Dry Lime FGD	Selective Catalytic Reduction
	CO	Comanche (470)	470	3	2017	7,228	major overhaul year		69%	9,041	85%	2017	2017			5,151,840	0.066	0.083	1,543	1,944	4,876,027	4.7E+07	Holly Cross Energy, Intermountain Rural Electric Authority, Public Service Company of Colora	Public Service Company of Colorado	Tangentially-fired	Coal	Natural Gas	Dry Lime FGD	Selective Catalytic Reduction
									Average HR =	9,072	6,379,733	0.066	0.083	1,919	2,416														
5	CO	Craig	6021	C2	2014	8,549		446	89%	9,854						3,478,093	0.265	0.056	4,603	963	3,594,700	3.4E+07	Pacificorp Energy Generation, Platte River Power Authority, Salt River Project, Tri-State Gener	Tri-State Generation & Transmission	Dry bottom wall-fired boiler	Coal-Sub	Pipeline Natural G	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
	CO	Craig	6021	C2	2015	7,629			73%	10,153						2,864,597	0.250	0.050	3,681	733	3,050,268	2.9E+07	Pacificorp Energy Generation, Platte River Power Authority, Salt River Project, Tri-State Gener	Tri-State Generation & Transmission	Dry bottom wall-fired boiler	Coal	Pipeline Natural G	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
	CO	Craig	6021	C2	2016	8,710			81%	9,812						3,182,674	0.247	0.046	3,899	723	3,275,089	3.1E+07	Pacificorp Energy Generation, Platte River Power Authority, Salt River Project, Tri-State Gener	Tri-State Generation & Transmission	Dry bottom wall-fired boiler	Coal	Pipeline Natural G	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
	CO	Craig	6021	C2	2017	6,915	SCR 2017 (.08 by permit)		63%	10,109	85%	2018ytd	2017			2,452,258	0.219	0.045	2,787	562	2,599,907	2.5E+07	Pacificorp Energy Generation, Platte River Power Authority, Salt River Project, Tri-State Gener	Tri-State Generation & Transmission	Dry bottom wall-fired boiler	Coal	Pipeline Natural G	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
									Average HR =	9,982	3,323,894	0.059	0.045	979	752														
6	CO	Hayden	525	H1	2014	8,458		190	88%	11,384						1,467,997	0.399	0.120	3,406	1,001	1,714,639	1.7E+07	Pacificorp Energy Generation, Public Service Company of Colorado	Public Service Company of Colorado	Dry bottom wall-fired boiler	Coal-Bit	Diesel Oil, Natural	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
	CO	Hayden	525	H1	2015	6,895	outage for scr install		68%	11,395						1,128,821	0.325	0.120	2,158	773	1,319,710	1.3E+07	Pacificorp Energy Generation, Public Service Company of Colorado	Public Service Company of Colorado	Dry bottom wall-fired boiler	Coal	Diesel Oil, Natural	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction (Began Aug 25, 2015)
	CO	Hayden	525	H1	2016	8,335			73%	11,453						1,208,976	0.043	0.122	294	842	1,420,606	1.4E+07	Pacificorp Energy Generation, Public Service Company of Colorado	Public Service Company of Colorado	Dry bottom wall-fired boiler	Coal	Diesel Oil, Natural	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
	CO	Hayden	525	H1	2017	8,671	representative		79%	11,456	85%	2017	2017			1,315,755	0.043	0.122	319	921	1,546,563	1.5E+07	Pacificorp Energy Generation, Public Service Company of Colorado	Public Service Company of Colorado	Dry bottom wall-fired boiler	Coal	Diesel Oil, Natural	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
									Average HR =	11,422	1,414,740	0.043	0.122	343	987														
7	CO	Hayden	525	H2	2014	7,668		275	81%	10,030						1,954,302	0.268	0.125	2,656	1,226	2,011,222	2.0E+07	Pacificorp Energy Generation, Public Service Company of Colorado, Salt River Project	Public Service Company of Colorado	Tangentially-fired	Coal-Bit	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
	CO	Hayden	525	H2	2015	8,449			83%	10,005						2,013,568	0.272	0.120	2,734	1,214	2,066,903	2.0E+07	Pacificorp Energy Generation, Public Service Company of Colorado, Salt River Project	Public Service Company of Colorado	Tangentially-fired	Coal	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
	CO	Hayden	525	H2	2016	7,123	outage for scr install		61%	9,840						1,462,241	0.173	0.119	1,209	855	1,476,317	1.4E+07	Pacificorp Energy Generation, Public Service Company of Colorado, Salt River Project	Public Service Company of Colorado	Tangentially-fired	Coal	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction (Began Jun 29, 2016)
	CO	Hayden	525	H2	2017	7,830	representative		65%	9,563	85%	2017	2017			1,571,940	0.045	0.123	337	921	1,542,384	1.5E+07	Pacificorp Energy Generation, Public Service Company of Colorado, Salt River Project	Public Service Company of Colorado	Tangentially-fired	Coal	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction
									Average HR =	9,860	2,050,628	0.045	0.123	457	1,239														
8	CO	Pawnee	6248	1	2014	6,453	scr/scrubber install	552	60%	10,992						2,921,982	0.107	0.343	1,690	5,508	3,367,395	3.2E+07	Public Service Company of Colorado	Public Service Company of Colorado	Dry bottom wall-fired boiler	Coal-Sub	Natural Gas	Dry Lime FGD (Bega	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction (Began Jun 28, 2014)
	CO	Pawnee	6248	1	2015	8,139			76%	11,637						3,700,385	0.049	0.084	1,050	1,810	4,514,415	4.3E+07	Public Service Company of Colorado	Public Service Company of Colorado	Dry bottom wall-fired boiler	Coal	Natural Gas	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
	CO	Pawnee	6248	1	2016	6,618	overhaul		61%	11,065						2,933,263	0.051	0.092	840	1,494	3,402,982	3.2E+07	Public Service Company of Colorado	Public Service Company of Colorado	Dry bottom wall-fired boiler	Coal	Natural Gas	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
	CO	Pawnee	6248	1	2017	8,432	representative		79%	10,965	85%	2017	2017			3,807,684	0.055	0.091	1,157	1,906	4,375,178	4.2E+07	Public Service Company of Colorado	Public Service Company of Colorado	Dry bottom wall-fired boiler	Coal	Natural Gas	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
									Average HR =	11,165	4,112,426	0.055	0.091	1,265	2,096														
9	NM	Four Corners Steam Elec Station	2442	4	2014	7,166		818	73%	10,489						5,240,673	0.523	0.146	14,570	4,024	5,638,855	5.5E+07	Arizona Public Service Company, El Paso Electric Company, Public Service Company of New M	Arizona Public Service Company	Cell burner boiler	Coal-S&B		Wet Lime FGD	Low NOx Cell Burner
	NM	Four Corners Steam Elec Station	2442	4	2015	7,689			78%	10,397						5,610,305	0.524	0.125	15,427	3,648	5,978,648	5.8E+07	Arizona Public Service Company, El Paso Electric Company, Public Service Company of New M	Arizona Public Service Company	Cell burner boiler	Coal		Wet Lime FGD	Low NOx Cell Burner
	NM	Four Corners Steam Elec Station	2442	4	2016	5,927			55%	9,073						3,968,546	0.494	0.133	9,216	2,399	3,693,588	3.6E+07	Arizona Public Service Company, El Paso Electric Company, Public Service Company of New M	Arizona Public Service Company	Cell burner boiler	Coal		Wet Lime FGD	Low NOx Cell Burner
	NM	Four Corners Steam Elec Station	2442	4	2017	6,628	SCR & SO2 controls		59%	9,144	85%	Per APS	Per APS			4,221,464	0.484	0.114	9,654	2,204	3,960,402	3.9E+07	Arizona Public Service Company, El Paso Electric Company, Public Service Company of New M	Arizona Public Service Company	Cell burner boiler	Coal		Wet Lime FGD	Low NOx Cell Burner
									2016-17 Average HR =	9,109	6,091,573	0.080	0.050	2,219	1,387														
10	NM	Four Corners Steam Elec Station	2442	5	2014	5,996		818	57%	11,140						4,093,242	0.512	0.176	11,903	4,012	4,679,593	4.6E+07	Arizona Public Service Company, El Paso Electric Company, Public Service Company of New M	Arizona Public Service Company	Cell burner boiler	Coal-S&B		Wet Lime FGD	Low NOx Cell Burner
	NM	Four Corners Steam Elec Station	2442	5	2015	7,547			73%	11,122						5,208,945	0.506	0.183	14,807	5,310	5,944,382	5.8E+07	Arizona Public Service Company, El Paso Electric Company, Public Service Company of New M	Arizona Public Service Company	Cell burner boiler	Coal		Wet Lime FGD	Low NOx Cell Burner
	NM	Four Corners Steam Elec Station	2442	5	2016	5,388			47%	9,098						3,381,920	0.506	0.131	8,137	2,013	3,156,597	3.1E+07	Arizona Public Service Company, El Paso Electric Company, Public Service Company of New M	Arizona Public Service Company	Cell burner boiler	Coal		Wet Lime FGD	Low NOx Cell Burner
	NM	Four Corners Steam Elec Station	2442	5	2017	4,723	SCR & SO2 controls		40%	9,193	85%	Per APS	Per APS			2,836,197	0.494	0.120	6,637	1,566	2,674,206	2.6E+07	Arizona Public Service Company, El Paso Electric Company, Public Service Company of New M	Arizona Public Service Company	Cell burner boiler	Coal		Wet Lime FGD	Low NOx Cell Burner
									2016-17 Average HR =	9,146	6,091,573	0.080	0.050	2,228	1,393														
11	SD	Big Stone	6098	1	2014	8,325		450	72%	10,634						2,825,223	0.687	0.922	10,507	13,845	3,150,887	3.0E+07	Montana Dakota Utilities Company, Northwestern Public Service Company, Otter Tail Power	Otter Tail Power Company	Cyclone boiler	Coal	Diesel Oil, Wood		Overfire Air
	SD	Big Stone	6098	1	2015	4,628	outage for installation of new contro		40%	10,636						1,563,251	0.338	0.578	3,148	4,805	1,743,876	1.7E+07	Montana Dakota Utilities Company, Northwestern Public Service Company, Otter Tail Power	Otter Tail Power Company	Cyclone boiler	Coal	Diesel Oil, Wood	Dry Lime FGD (Bega	Overfire Air Selective Catalytic Reduction (Began Aug 26, 2015)
	SD	Big Stone	6098	1	2016	7,845	first full year of new controls		56%	10,749						2,188,753	0.083	0.070	962	827	2,467,531	2.4E+07	Montana Dakota Utilities Company, Northwestern Public Service Company, Otter Tail Power	Otter Tail Power Company	Cyclone boiler	Coal	Diesel Oil, Wood	Dry Lime FGD	Overfire Air Selective Catalytic Reduction
	SD	Big Stone	6098	1	2017	7,818			55%	10,867	85%	2017.000	2017.000			2,182,037	0.085	0.071	984	846	2,487,044	2.4E+07	Montana Dakota Utilities Company, Northwestern Public Service Company, Otter Tail Power	Otter Tail Power Company	Cyclone boiler	Coal	Diesel Oil, Wood	Dry Lime FGD	Overfire Air Selective Catalytic Reduction
									Average HR =	10,722	3,350,700	0.085	0.071	1,520	1,281														
12	WY	Dry Fork Station	56609	1	2014	8,491		484	85%	9,627						3,600,642	0.039	0.051	657	884	3,635,543	3.5E+07	Basin Electric Power Cooperative	Basin Electric Power Cooperative	Dry bottom wall-fired boiler	Coal-Sub		Dry Lime FGD	Selective Catalytic Reduction
	WY	Dry Fork Station	56609	1	2015	8,241			82%	9,353						3,482,118	0.042	0.053	672	870	3,415,742	3.3E+07	Basin Electric Power Cooperative	Basin Electric Power Cooperative	Dry bottom wall-fired boiler	Coal		Dry Lime FGD	Selective Catalytic Reduction
	WY	Dry Fork Station	56609	1	2016	7,522			73%	9,480						3,113,897	0.044	0.062	632	912	3,096,028	3.0E+07	Basin Electric Power Cooperative	Basin Electric Power Cooperative	Dry bottom wall-fired boiler	Coal		Dry Lime FGD	Selective Catalytic Reduction
	WY	Dry Fork Station	56609	1	2017	8,357			84%	9,701	85%	2017	2017			3,556,561	0.041	0.061	697	1,047	3,618,571	3.5E+07	Basin Electric Power Cooperative	Basin Electric Power Cooperative	Dry bottom wall-fired boiler	Coal		Dry Lime FGD	Selective Catalytic Reduction
									Average HR =	9,540	3,601,630	0.041	0.061	710	1,043														
13	WY	Jim Bridger	8066	BW73	2014	8,584		608	72%	9,824						3,834,914	0.195	0.149	3,762	2,806	3,951,360	3.8E+07	Idaho Power Company, Pacificorp Energy Generation	Pacificorp Energy Generation	Tangentially-fired	Coal-Sub		Sodium Based	Low NOx Burner Technology w/ Closed-coupled OFA
	WY	Jim Bridger	8066	BW73	2015	6,342			51%	9,872						2,728,896	0.187	0.146	2,574	1,971	2,825,458	2.7E+07	Idaho Power Company, Pacificorp Energy Generation	Pacificorp Energy Generation	Tangentially-fired	Coal		Sodium Based	Selective Catalytic Reduction (Began Nov 25, 2015) Low NOx Burner Technology w/ Closed-coupled OFA
	WY	Jim Bridger	8066	BW73	2016	6,537	scr installed		54%	9,637						2,869,464	0.052	0.150	698	2,068	2,900,368	2.8E+07	Idaho Power Company, Pacificorp Energy Generation	Pacificorp Energy Generation	Tangentially-fired	Coal		Sodium Based	Selective Catalytic Reduction Low NOx Burner Technology w/ Closed-coupled OFA
	WY	Jim Bridger	8066	BW73	2017	8,555			62%	10,008	85%	2017	2017			3,314,263	0.050	0.141	825	2,336	3,478,833	3.3E+07	Idaho Power Company, Pacificorp Energy Generation	Pacificorp Energy Generation	Tangentially-fired	Coal		Sodium Based	Selective Catalytic Reduction Low NOx Burner Technology w/ Closed-coupled OFA
									Average HR =	9,835	4,529,402	0.050	0.141	1,116	3,137														
14	WY	Jim Bridger	8066	BW74	2014	8,551		608	72%	8,731						3,839,283	0.199	0.149	3,446	2,497	3,515,699	3.4E+07	Idaho Power Company, Pacificorp Energy Generation	Pacificorp Energy Generation	Tangentially-fired	Coal-Sub		Sodium Based	Low NOx Burner Technology w/ Closed-coupled OFA
	WY	Jim Bridger	8066	BW74	2015	8,551			73%	9,592						3,867,900	0.198	0.141	3,777	2,620	3,891,030	3.7E+07	Idaho Power Company, Pacificorp Energy Generation	Pacificorp Energy Generation	Tangentially-fired	Coal		Sodium Based	Low NOx Burner Technology w/ Closed-coupled OFA
	WY	Jim Bridger	8066	BW74	2016	7,092			51%	10,495						2,740,617	0.166	0.144	2,429	2,066	3,016,617	2.9E+07	Idaho Power Company, Pacificorp Energy Generation	Pacificorp Energy Generation	Tangentially-fired	Coal		Sodium Based	Selective Catalytic Reduction (Began Nov 10, 2016) Low NOx Burner Technology w/ Closed-coupled OFA
	WY	Jim Bridger	8066	BW74	2017	8,549	scr installed		63%	9,832	85%	2017	2017			3,364,727	0.049	0.144	812	2,377	3,469,649	3.3E+07	Idaho Power Company, Pacificorp Energy Generation	Pacificorp Energy Generation	Tangentially-fired	Coal		Sodium Based	Selective Catalytic Reduction Low NOx Burner Technology w/ Closed-coupled OFA
									Average HR =	9,662	4,529,402	0.049	0.144	1,074	3,144														
15	WY	Wygen I	55479	1	2014	8,451		90	100%	11,228						785,891	0.133	0.079	589	348	925,438	8.8E+06	Black Hills Wyoming, LLC, Municipal Energy Agency of Nebraska	Black Hills Power, Inc	Dry bottom wall-fired boiler	Coal		Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
	WY	Wygen I	55479	1	2015	8,739			104%	11,150						817,684	0.131	0.068	601	311	956,230	9.1E+06	Black Hills Wyoming, LLC, Municipal Energy Agency of Nebraska	Black Hills Power, Inc	Dry bottom wall-fired boiler	Coal		Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
	WY	Wygen I	55479	1	2016	8,495			100%	11,116						788,705	0.135	0.078	592	343	919,488	8.8E+06	Black Hills Wyoming, LLC, Municipal Energy Agency of Nebraska	Black Hills Power, Inc	Dry bottom wall-fired boiler	Coal		Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
	WY	Wygen I	55479	1	2017	8,575			102%	11,405	100%	2017	2017			801,831	0.128	0.099	587	455	959,101	9.1E+06	Black Hills Wyoming, LLC, Municipal Energy Agency of Nebraska	Black Hills Power, Inc	Dry bottom wall-fired boiler	Coal		Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
									Average HR =	11,225	788,400	0.128	0.099	565	440														
16	WY	Wygen II	56319	1	2014	8,694		95	92%	10,637						765,450	0.062	0.047	251	193	853,939	8.1E+06	Cheyenne Light, Fuel and Power	Black Hills Power, Inc	Dry bottom wall-fired boiler	Coal		Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
	WY	Wygen II	56319	1	2015	8,001			89%	10,855						742,314	0.057	0.043	229	174	845,111	8.1E+06	Cheyenne Light, Fuel and Power	Black Hills Power, Inc	Dry bottom wall-fired boiler	Coal		Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
	WY	Wygen II	56319	1	2016	8,734			97%	10,641						808,471	0.055	0.056	237	240	902,317	8.6E+06	Cheyenne Light, Fuel and Power	Black Hills Power, Inc	Dry bottom wall-fired boiler	Coal		Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
	WY	Wygen II	56319	1	2017	8,410			98%	10,937	100%					819,518	0.051	0.060	228	267	940,032	9.0E+06	Cheyenne Light, Fuel and Power	Black Hills Power, Inc	Dry bottom wall-fired boiler	Coal		Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
									Average HR =	10,768	832,200	0.051	0.060	228	267														
17	WY	Wygen III	56596	1	2014	8,390		116	91%	10,130						928,015	0.043	0.054	187	254	985,958	9.4E+06	Black Hills Power, Inc, Consolidated WY Municipalities Electric Power System JPB, Montana D	Black Hills Power, Inc	Dry bottom wall-fired boiler	Coal-Sub		Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
	WY	Wygen III	56596	1	2015	7,936			85%	10,043						862,698	0.046	0.049	173	214	908,725	8.7E+06	Black Hills Power, Inc, Consolidated WY Municipalities Electric Power System JPB, Montana D	Black Hills Power, Inc	Dry bottom wall-fired boiler	Coal		Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
	WY	Wygen III	56596	1	2016	8,161			89%	10,208						903,794	0.041	0.050	176	232	967,612	9.2E+06	Black Hills Power, Inc, Consolidated WY Municipalities Electric Power System JPB, Montana D	Black Hills Power, Inc	Dry bottom wall-fired boiler	Coal		Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
	WY	Wygen III	56596	1	2017	7,903			84%	10,489	90%					852,169	0.043	0.063	179	280	937,422	8.9E+06	Black Hills Power, Inc, Consolidated WY Municipalities Electric Power System JPB, Montana D	Black Hills Power, Inc	Dry bottom wall-fired boiler	Coal		Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
									Average HR =	10,218	1,016,160	0.043	0.063	224	326														
	ND	Coal Creek	6030	2	2014	8,317		605	92%	9,535						4,879,864	0.143	0.341	3,287	7,940	5,065,733	4.7E+07	Great River Energy	Great River Energy	Tangentially-fired	Coal-Lig		Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
	ND	Coal Creek	6030	2	2015	8,429			90%	9,644						4,775,408	0.157	0.338	3,499	7,776	5,013,823	4.6E+07	Great River Energy	Great River Energy	Tangentially-fired	Coal		Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
	ND	Coal Creek	6030	2	2016	7,194			77%	9,491						4,056,301	0.136	0.293	2,564	5,633	4,191,281	3.8E+07	Great River Energy	Great River Energy	Tangentially-fired	Coal		Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
	ND	Coal Creek	6030	2	2017	8,283	SO2 controls added - use 2018		89%	9,495	90%	2017	2018			4,721,086	0.130	0.147	2,889	3,296	4,880,276	4.5E+07	Great River Energy	Great River Energy	Tangentially-fired	Coal		Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
									Average HR =	9,541	4,768,243	0.130	0.142	2,957	3,230														
18	NV	TS Power Plant	56224	1	2014	7,513		242	40%							1,564,200	0.047		339	239	1,487,421	1.4E+07	Newmont Nevada Energy Investment LLC	Newmont Nevada Energy Investment LLC	Dry bottom wall-fired boiler	Coal	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
	NV	TS Power Plant	56224	1	2015	8,026			25%							960,405	0.048		232	114	1,009,783	9.6E+06	Newmont Nevada Energy Investment LLC	Newmont Nevada Energy Investment LLC	Dry bottom wall-fired boiler	Coal	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
	NV	TS Power Plant	56224	1	2016	8,164			25%							994,073	0.049		233	116	993,318	9.5E+06	Newmont Nevada Energy Investment LLC	Newmont Nevada Energy Investment LLC	Dry bottom wall-fired boiler	Coal	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
	NV	TS Power Plant	56224	1	2017	8,233			28%							1,081,870	0.049		257	148	1,097,749	1.0E+07	Newmont Nevada Energy Investment LLC	Newmont Nevada Energy Investment LLC	Dry bottom wall-fired boiler	Coal	Diesel Oil	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
									Average HR =	#DIV/0!	1,907,928	0.130	0.142	#DIV/0!	#DIV/0!														
19	TX	J K Spruce	7097	**2	2014	6,975		875		9,556						5,406,238	0.048	0.009	1,228	226	5,300,513	5.2E+07	City of San Antonio	City of San Antonio	Tangentially-fired	Coal-Sub		Wet Limestone	Selective Catalytic Reduction
	TX	J K Spruce	7097	**2	2015	5,843				10,242						2,706,186	0.046	0.006	633	84	2,843,837	2.8E+07	City of San Antonio	City of San Antonio	Tangentially-fired	Coal-Sub		Wet Limestone	Selective Catalytic Reduction
	TX	J K Spruce	7097	**2	2016	5,550				9,883						3,248,413	0.050	0.009	795	151	3,293,951	3.2E+07	City of San Antonio	City of San Antonio	Tangentially-fired	Coal-Sub		Wet Limestone	Selective Catalytic Reduction
	TX	J K Spruce	7097	**2	2018	6,915				9,681						4,400,356	0.047	0.008	995	181	4,370,672	4.3E+07	City of San Antonio	City of San Antonio	Tangentially-fired	Coal		Wet Limestone	Selective Catalytic Reduction
	TX	J K Spruce	7097	**2	2017	6,677				9,659						3,760,387	0.049	0.008	892	148	3,726,494	3.6E+07	City of San Antonio	City of San Antonio	Tangentially-fired	Coal		Wet Limestone	Selective Catalytic Reduction
									Average HR =	9,866	0	0.130	0.142	0	0														
20	TX	Oak Grove	6180	1	2014	8,249		840		9,441						7,130,788	0.071	0.115	2,449	3,861	7,329,006	6.7E+07	Oak Grove Management Company LLC	Oak Grove Management Company LLC	Tangentially-fired	Coal-Lig	Pipeline Natural G	Wet Limestone	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
	TX	Oak Grove	6180	1	2015	8,011				9,664						6,768,075	0.071	0.078	2,346	2,553	7,120,485	6.5E+07	Oak Grove Management Company LLC	Oak Grove Management Company LLC	Tangentially-fired	Coal-Lig	Pipeline Natural G	Wet Limestone	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
	TX	Oak Grove	6180	1	2017	8,450				9,522						7,343,191	0.072	0.127	2,512	4,442	7,612,561	7.0E+07	Oak Grove Management Company LLC	Oak Grove Management Company LLC	Tangentially-fired	Coal-Lig	Pipeline Natural G	Wet Limestone	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
	TX	Oak Grove	6180	1	2016	7,388				9,845						6,212,457	0.075	0.109	2,166	3,334	6,658,215	6.1E+07	Oak Grove Management Company LLC	Oak Grove Management Company LLC	Tangentially-fired	Coal	Pipeline Natural G	Wet Limestone	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
	TX	Oak Grove	6180	1	2018	8,315				9,550						7,192,075	0.074	0.130	2,453	4,453	7,477,355	6.9E+07	Oak Grove Management Company LLC	Oak Grove Management Company LLC	Tangentially-fired	Coal	Pipeline Natural G	Wet Limestone	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
									Average HR =	9,645	0	0.130	0.142	0	0														
21	TX	Sandow	6648	4	2014	7,958		600		9,844						4,792,750	0.064	0.930	1,466	21,938	5,136,676	4.7E+07	Luminant Generation Company LLC	Luminant Generation Company LLC	Tangentially-fired	Coal-Lig		Wet Limestone	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
	TX	Sandow	6648	4	2015	8,184				9,939						4,516,400	0.064	0.932	1,427	20,925	4,886,940	4.5E+07	Luminant Generation Company LLC	Luminant Generation Company LLC	Tangentially-fired	Coal-Lig		Wet Limestone	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
	TX	Sandow	6648	4	2018	240				10,657						122,036	0.062	0.750	36	487	141,590	1.3E+06	Luminant Generation Company LLC	Luminant Generation Company LLC	Tangentially-fired	Coal-Lig		Wet Limestone	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
	TX	Sandow	6648	4	2016	7,888				9,822						4,383,004	0.067	0.562	1,465	12,105	4,686,781	4.3E+07	Luminant Generation Company LLC	Luminant Generation Company LLC	Tangentially-fired	Coal		Wet Limestone	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
	TX	Sandow	6648	4	2017	8,064				9,948						4,464,335	0.067	0.786	1,466	17,446	4,835,292	4.4E+07	Luminant Generation Company LLC	Luminant Generation Company LLC	Tangentially-fired	Coal		Wet Limestone	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
									Average HR =	10,092	0	0.130	0.142	0	0														
22	TX	W A Parish	3470	WAP7	2014	8,183		577		9,367						4,143,520	0.049	0.701	941	13,606	4,066,295	3.9E+07	NRG Energy, Inc	NRG Energy, Inc	Tangentially-fired	Coal-Sub	Pipeline Natural Gas		Selective Catalytic Reduction
	TX	W A Parish	3470	WAP7	2015	6,824				9,198						3,479,366	0.042	0.705	668	11,277	3,353,369	3.2E+07	NRG Energy, Inc	NRG Energy, Inc	Tangentially-fired	Coal-Sub	Pipeline Natural Gas		Selective Catalytic Reduction
	TX	W A Parish	3470	WAP7	2016	6,525				9,449						2,986,930	0.045	0.651	604	9,184	2,948,540	2.8E+07	NRG Energy, Inc	NRG Energy, Inc	Tangentially-fired	Coal-Sub	Pipeline Natural Gas		Selective Catalytic Reduction
	TX	W A Parish	3470	WAP7	2017	7,997				8,798						3,848,578	0.047	0.612	733	10,358	3,523,198	3.4E+07	NRG Energy, Inc	NRG Energy, Inc	Tangentially-fired	Coal	Pipeline Natural Gas		Selective Catalytic Reduction
	TX	W A Parish	3470	WAP7	2018	8,246				8,463						4,032,458	0.049	0.642	756	10,959	3,563,273	3.4E+07	NRG Energy, Inc	NRG Energy, Inc	Tangentially-fired	Coal	Pipeline Natural Gas		Selective Catalytic Reduction
									Average HR =	8,977	0	0.130	0.142	0	0														
23	TX	W A Parish	3470	WAP8	2014	8,313		610		9,843						4,481,612	0.047	0.131	1,032	2,886	4,625,523	4.4E+07	NRG Energy, Inc	NRG Energy, Inc	Tangentially-fired	Coal-Sub	Pipeline Natural G	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection
	TX	W A Parish	3470	WAP8	2015	7,603				9,362						4,046,576	0.047	0.126	888	2,381	3,971,103	3.8E+07	NRG Energy, Inc	NRG Energy, Inc	Tangentially-fired	Coal-Sub	Pipeline Natural G	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection
	TX	W A Parish	3470	WAP8	2017	8,224				10,294						4,297,991	0.056	0.087	1,213	1,929	3,459,991	4.4E+07	NRG Energy, Inc	NRG Energy, Inc	Tangentially-fired	Coal-Sub	Pipeline Natural G	Sodium Based W	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection
	TX	W A Parish	3470	WAP8	2018	5,040				10,527						2,666,222	0.049	0.077	662	1,085	2,126,266	2.8E+07	NRG Energy, Inc	NRG Energy, Inc	Tangentially-fired	Coal	Pipeline Natural G	Sodium Based W	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection
	TX	W A Parish	3470	WAP8	2016	7,731				10,054						3,792,115	0.045	0.163	856	3,112	4,011,512	3.8E+07	NRG Energy, Inc	NRG Energy, Inc	Tangentially-fired	Coal	Pipeline Natural G	Sodium Based (Bega	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection
									Average HR =	10,059	0	0.130	0.142	0	0														

ARIZONA UNITS

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Operating Time	Notes	Nameplate Capacity (MW)	Nameplate Capacity Factor	Heat Rate (mmbtu/kwhr)	Case 1 MW-h (85% or Higher)	Nox ER	SO2 ER	NOx (tons)	SO2 Tons	Gross Load (MW-h)	Avg. NOx Rate (lb/MMBtu)	SO2 ER	NOx (tons)	SO2 (tons)	CO2 (short tons)	Heat Input (MMBtu)	Operator	SO2 Control(s)	NOx Control(s)
AZ	Apache Station	160	2	2014	8,616				10,696						1,476,833	0.349		2,773	2,037	1,615,243	1.58E+07	Arizona Electric Power Cooperative	Wet Lime FGD	Overfire Air
AZ	Apache Station	160	2	2015	7,793				10,545						965,130	0.337		1,801	1,139	1,033,100	1.02E+07	Arizona Electric Power Cooperative	Wet Lime FGD	Overfire Air
AZ	Apache Station	160	2	2016	8,530				10,308						1,018,624	0.351		1,950	400	1,063,400	1.05E+07	Arizona Electric Power Cooperative	Wet Lime FGD	Overfire Air
AZ	Apache Station	160	2	2017	5,665	on gas as of Dec 2017			10,245	2018 YTD Scaled	2018ytd				745,075	0.334		1,319	123	773,625	7.63E+06	Arizona Electric Power Cooperative	Wet Lime FGD	Overfire Air
						2018 ytd on gas		2018 YTD HR =	10,255	993,185	0.066	0.000	338	0	723,880	0.066		252	2	440,055	7.4E+06			
AZ	Apache Station	160	3	2014	7,853		204	82%	10,544						1,456,758	0.418	0.361	3,228	2,774	1,573,255	1.54E+07	Arizona Electric Power Cooperative	Wet Lime FGD	Overfire Air
AZ	Apache Station	160	3	2015	8,221			68%	10,266						1,209,671	0.426	0.229	2,682	1,423	1,268,718	1.24E+07	Arizona Electric Power Cooperative	Wet Lime FGD	Overfire Air
AZ	Apache Station	160	3	2016	8,242			67%	10,335						1,198,004	0.440	0.090	2,796	556	1,261,877	1.24E+07	Arizona Electric Power Cooperative	Wet Lime FGD	Overfire Air
AZ	Apache Station	160	3	2017	6,912	SNCR 2017 (0.23 by permit)		58%	10,365	85%	2018ytd	2017			1,037,289	0.304	0.035	1,663	188	1,097,580	1.08E+07	Arizona Electric Power Cooperative	Wet Lime FGD	Overfire Air
								Average HR =	10,377	1,518,984	0.184	0.035	1,450	275										
AZ	Cholla	113	1	2014	8,181										858,272	0		980	604	989,512	9.64E+06	Arizona Public Service Company	Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
AZ	Cholla	113	1	2015	7,182										684,665	0		807	457	801,503	7.81E+06	Arizona Public Service Company	Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
AZ	Cholla	113	1	2016	1,946										144,280	0		166	91	189,502	1.85E+06	Arizona Public Service Company	Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
AZ	Cholla	113	1	2017	5,855	2025 retirement									441,275	0		452	244	567,943	5.54E+06	Arizona Public Service Company	Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
AZ	Cholla	113	2	2014	7,722										1,835,723	0		2,783	1,136	1,929,360	1.88E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
AZ	Cholla	113	2	2015	5,836	retired									1,210,852	0		1,859	1,131	1,291,665	1.26E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
AZ	Cholla	113	3	2014	7,244										1,733,323	0		2,094	657	1,963,436	1.91E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
AZ	Cholla	113	3	2015	6,737										1,436,790	0		1,677	664	1,668,927	1.63E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
AZ	Cholla	113	3	2016	3,873										659,839	0		674	342	760,142	7.41E+06	Arizona Public Service Company	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
AZ	Cholla	113	3	2017	7,520	2025 retirement									1,418,113	0		1,519	644	1,679,754	1.64E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
AZ	Cholla	113	4	2014	8,098										2,893,267	0		3,089	1,410	3,327,849	3.24E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
AZ	Cholla	113	4	2015	7,386										2,731,159	0		2,913	1,331	3,067,174	2.99E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
AZ	Cholla	113	4	2016	6,692										1,921,469	0		1,896	902	2,062,972	2.01E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
AZ	Cholla	113	4	2017	7,151	2025 retirement									2,162,256	0		2,099	868	2,465,458	2.40E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
AZ	Coronado Generating Station	6177	U1B	2014	8,233		411	90%	10,435						3,239,136	0.287	0.028	4,949	475	3,545,141	3.38E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
AZ	Coronado Generating Station	6177	U1B	2015	7,313			72%	10,517						2,576,389	0.283	0.026	3,931	355	2,841,827	2.71E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
AZ	Coronado Generating Station	6177	U1B	2016	8,191			78%	10,718						2,790,532	0.280	0.017	4,275	256	3,136,725	2.99E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
AZ	Coronado Generating Station	6177	U1B	2017	6,597	Seasonal curtailment		61%	10,656	85%	2017	2017			2,213,265	0.286	0.008	3,472	97	2,473,461	2.36E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
						shutdown or scr by 2025		Average HR =	10,581	3,059,561	0.286	0.008	4,636	133										
AZ	Coronado Generating Station	6177	U2B	2014	7,082		411	79%	10,311						2,854,256	0.101	0.029	1,503	433	3,086,666	2.94E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction (Began May 03, 2014)
AZ	Coronado Generating Station	6177	U2B	2015	8,209	SCR Installed		84%	10,267						3,018,364	0.061	0.021	933	327	3,250,081	3.10E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
AZ	Coronado Generating Station	6177	U2B	2016	8,077			78%	10,317						2,804,657	0.057	0.023	814	333	3,034,761	2.89E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
AZ	Coronado Generating Station	6177	U2B	2017	6,677			62%	10,934	85%	2017	2017			2,223,067	0.057	0.010	682	125	2,549,221	2.43E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
								Average HR =	10,457	3,059,561	0.057	0.010	913	165										
AZ	Irvington Generating Station	126	4	2014	7,149										560,391	0		970	1,085	488,867	5.95E+06	Tucson Electric Power Company		Low NOx Burner Technology w/ Overfire Air
AZ	Irvington Generating Station	126	4	2015	8,193	switched to gas									614,608	0		993	1,147	526,679	6.44E+06	Tucson Electric Power Company		Low NOx Burner Technology w/ Overfire Air
AZ	Navajo Generating Station	4941	1	2014	7,948										6,088,476	0		5,547	1,760	5,948,505	5.80E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Other
AZ	Navajo Generating Station	4941	1	2015	8,578										5,531,389	0		5,250	1,510	5,812,504	5.67E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Other
AZ	Navajo Generating Station	4941	1	2016	8,237										4,620,415	0		4,225	1,401	4,848,561	4.73E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Other
AZ	Navajo Generating Station	4941	1	2017	7,764										4,734,108	0		4,487	1,624	4,792,196	4.67E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Other
AZ	Navajo Generating Station	4941	2	2014	8,716										6,544,594	0		6,402	1,883	6,819,858	6.65E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Other
AZ	Navajo Generating Station	4941	2	2015	8,089										5,046,841	0		4,644	1,362	5,192,041	5.06E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Other
AZ	Navajo Generating Station	4941	2	2016	7,034										4,226,130	0		3,817	1,046	4,509,340	4.40E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Other
AZ	Navajo Generating Station	4941	2	2017	8,196										5,274,845	0		5,034	1,521	5,641,961	5.50E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Other
AZ	Navajo Generating Station	4941	3	2014	8,228										6,152,497	0		5,942	2,023	6,091,831	5.94E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Other
AZ	Navajo Generating Station	4941	3	2015	6,879										4,304,750	0		4,015	897	4,487,197	4.37E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Other
AZ	Navajo Generating Station	4941	3	2016	8,025										4,464,103	0		3,965	1,139	4,609,931	4.49E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Other
AZ	Navajo Generating Station	4941	3	2017	8,159										5,109,135	0		5,040	1,870	5,458,994	5.32E+07	Salt River Project	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Other
AZ	Springerville Generating Station	8223	1	2014	8,160		425	85%	8,380						3,161,001	0.180	0.211	2,406	2,790	2,778,307	2.65E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
AZ	Springerville Generating Station	8223	1	2015	8,473			57%	9,200						2,124,354	0.167	0.198	1,660	1,931	2,049,792	1.95E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
AZ	Springerville Generating Station	8223	1	2016	7,512			63%	9,009						2,330,775	0.174	0.201	1,862	2,112	2,202,173	2.10E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
AZ	Springerville Generating Station	8223	1	2017	4,979			47%	8,882	85%	2017	2017			1,763,834	0.174	0.231	1,400	1,809	1,643,140	1.57E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
								Average HR =	8,868	3,163,061	0.174	0.231	2,445	3,239										
AZ	Springerville Generating Station	8223	2	2014	6,583		425	69%	8,703						2,556,787	0.175	0.139	1,966	1,552	2,333,663	2.23E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
AZ	Springerville Generating Station	8223	2	2015	8,097			83%	8,771						3,098,602	0.184	0.147	2,522	1,999	2,850,372	2.72E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
AZ	Springerville Generating Station	8223	2	2016	8,053			82%	8,839						3,050,607	0.172	0.182	2,339	2,451	2,827,990	2.70E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
AZ	Springerville Generating Station	8223	2	2017	7,578			74%	8,620	85%	2017	2017			2,766,082	0.159	0.184	1,911	2,197	2,500,577	2.38E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
								Average HR =	8,733	3,163,061	0.159	0.184	2,199	2,546										
AZ	Springerville Generating Station	8223	4	2014	6,961		458	69%	9,071						2,784,838	0.075	0.077	956	972	2,648,205	2.53E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
AZ	Springerville Generating Station	8223	4	2015	8,534			75%	9,013						3,017,577	0.082	0.073	1,114	998	2,851,762	2.72E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
AZ	Springerville Generating Station	8223	4	2016	7,360			62%	9,520						2,504,794	0.076	0.082	906	976	2,498,784	2.38E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
AZ	Springerville Generating Station	8223	4	2017	6,359			57%	9,411	85%	2017	2017			2,288,847	0.081	0.081	875	872	2,257,831	2.15E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
								Average HR =	9,254	3,411,013	0.081	0.081	1,282	1,278										
AZ	Springerville Generating Station	8223	TS3	2014	8,594		458	78%	9,533						3,118,860	0.074	0.061	1,102	902	3,117,113	2.97E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
AZ	Springerville Generating Station	8223	TS3	2015	8,463			73%	9,754						2,919,676	0.077	0.060	1,094	851	2,986,089	2.85E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
AZ	Springerville Generating Station	8223	TS3	2016	7,122			57%	9,826						2,304,336	0.075	0.071	847	802	2,373,882	2.26E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
AZ	Springerville Generating Station	8223	TS3	2017	7,500			68%	9,377	85%	2017	2017			2,736,666	0.076	0.082	989	1,054	2,689,665	2.57E+07	Tucson Electric Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
								Average HR =	9,623	3,411,013	0.076	0.082	1,251	1,348										

COLORADO UNITS

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Operating Time	Notes	Nameplate Capacity (MW)	Nameplate Capacity Factor	Heat Rate (mmbtu/kwhr)	Case 1 MW-h (85% or Higher)	Nox ER	SO2 ER	NOx (tons)	SO2 Tons	Gross Load (MW-h)	Avg. NOx Rate (lb/MMBtu)	SO2 ER (calculated)	NOx (tons)	SO2 (tons)	CO2 (short tons)	Heat Input (MMBtu)	Operator	SO2 Control(s)	NOx Control(s)
CO	Cherokee	469	3	2014	8,359										1,146,551	0.336		1,997	1,008	1,210,943	1.2E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Cherokee	469	3	2015	4,302	retired in 2015									484,233	0.300		792	546	525,017	5.1E+06	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Cherokee	469	4	2014	7,343		381	67%	10,366						2,233,454	0.286	0.153	3,341	1,771	2,372,875	2.3E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Cherokee	469	4	2015	7,511			63%	11,392						2,100,364	0.271	0.158	3,407	1,892	2,453,615	2.4E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Cherokee	469	4	2016	8,507			65%	10,825						2,170,966	0.281	0.162	3,382	1,901	2,397,497	2.4E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Cherokee	469	4	2017	5,507	switched to gas 10/1/17		40%	11,217	**2018 YTD scaled**	**2018ytd**				1,350,720	0.227	0.160	1,763	1,211	1,511,429	1.5E+07	Public Service Company of Colorado	Dry Lime FGD (Retired Sep 30, 2017)	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
								2018 YTD HR =	**11,159**	**999,043**	**0.071**	**0.000**	**397**	**4**	**749,283**	**0.071**		**305**	**3**	**495,658**	**8.4E+06**			
CO	Comanche (470)	470	1	2014	6,909										2,120,602	0.130	0.077	1,236	726	1,969,836	1.9E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Comanche (470)	470	1	2015	8,140										2,227,104	0.116	0.074	1,210	753	2,105,836	2.0E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Comanche (470)	470	1	2016	8,127										2,374,450	0.122	0.083	1,360	917	2,312,778	2.2E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Comanche (470)	470	1	2017	7,785	2022 retirement									2,241,968	0.118	0.088	1,255	922	2,167,267	2.1E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Comanche (470)	470	2	2014	8,494										2,546,995	0.161	0.076	2,089	972	2,660,153	2.6E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Comanche (470)	470	2	2015	8,122										2,529,243	0.148	0.076	1,930	973	2,679,647	2.6E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Comanche (470)	470	2	2016	6,935										2,009,589	0.154	0.082	1,622	855	2,150,996	2.1E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Comanche (470)	470	2	2017	8,390	2025 retirement									2,663,858	0.162	0.085	2,211	1,146	2,817,988	2.7E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Comanche (470)	470	3	2014	6,467		857	58%	8,958						4,372,431	0.068	0.075	1,333	1,459	4,092,522	3.9E+07	Public Service Company of Colorado	Dry Lime FGD	Selective Catalytic Reduction
CO	Comanche (470)	470	3	2015	6,788			62%	9,132						4,655,984	0.066	0.074	1,405	1,569	4,451,716	4.3E+07	Public Service Company of Colorado	Dry Lime FGD	Selective Catalytic Reduction
CO	Comanche (470)	470	3	2016	8,019	representative year		72%	9,157						5,415,053	0.065	0.083	1,625	2,057	5,189,414	5.0E+07	Public Service Company of Colorado	Dry Lime FGD	Selective Catalytic Reduction
CO	Comanche (470)	470	3	2017	7,228	major overhaul year		69%	9,041	85%	2017	2017			5,151,840	0.066	0.083	1,543	1,944	4,876,027	4.7E+07	Public Service Company of Colorado	Dry Lime FGD	Selective Catalytic Reduction
								Average HR =	9,072	6,379,733	0.066	0.083	1,919	2,416										
CO	Craig	6021	C1	2014	7,017										2,865,104	0.260	0.056	3,768	799	3,013,854	2.9E+07	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021	C1	2015	8,528										3,211,196	0.246	0.048	4,015	770	3,350,710	3.2E+07	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021	C1	2016	7,597										2,685,878	0.239	0.044	3,246	582	2,778,517	2.6E+07	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021	C1	2017	8,341	12/31/2025 retirement									3,002,868	0.246	0.045	3,784	674	3,165,996	3.0E+07	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021	C2	2014	8,549		446	89%	9,854						3,478,093	0.265	0.056	4,603	963	3,594,700	3.4E+07	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021	C2	2015	7,629			73%	10,153						2,864,597	0.250	0.050	3,681	733	3,050,268	2.9E+07	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021	C2	2016	8,710			81%	9,812						3,182,674	0.247	0.046	3,899	723	3,275,089	3.1E+07	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021	C2	2017	6,915	SCR 2017 (.08 by permit)		63%	10,109	85%	2018ytd	2017			2,452,258	0.219	0.045	2,787	562	2,599,907	2.5E+07	Tri-State Generation & Transmission	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
								Average HR =	9,982	3,323,894	0.059	0.045	979	752										
CO	Craig	6021	C3	2014	8,594		535	79%	9,166						3,678,328	0.314	0.119	5,368	2,001	3,535,935	3.4E+07	Tri-State Generation & Transmission	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021	C3	2015	6,817			56%	9,428						2,610,918	0.278	0.126	3,635	1,548	2,581,666	2.5E+07	Tri-State Generation & Transmission	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021	C3	2016	8,330			67%	9,281						3,138,915	0.289	0.140	4,324	2,038	3,055,449	2.9E+07	Tri-State Generation & Transmission	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Craig	6021	C3	2017	8,157	SNCR 2017 (.28 by permit)		68%	9,263	85%	2018ytd	2017			3,168,884	0.278	0.126	4,158	1,848	3,078,662	2.9E+07	Tri-State Generation & Transmission	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
								Average HR =	9,284	3,982,121	0.212	0.126	3,919	2,328										
CO	Hayden	525	H1	2014	8,458		190	88%	11,384						1,467,997	0.399	0.120	3,406	1,001	1,714,639	1.7E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
CO	Hayden	525	H1	2015	6,895	outage for scr install		68%	11,395						1,128,821	0.325	0.120	2,158	773	1,319,710	1.3E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction (Began Aug 25, 2015)
CO	Hayden	525	H1	2016	8,335			73%	11,453						1,208,976	0.043	0.122	294	842	1,420,606	1.4E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
CO	Hayden	525	H1	2017	8,671	representative		79%	11,456	85%	2017	2017			1,315,755	0.043	0.122	319	921	1,546,563	1.5E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
								Average HR =	11,422	1,414,740	0.043	0.122	343	987										
CO	Hayden	525	H2	2014	7,668		275	81%	10,030						1,954,302	0.268	0.125	2,656	1,226	2,011,222	2.0E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Hayden	525	H2	2015	8,449			83%	10,005						2,013,568	0.272	0.120	2,734	1,214	2,066,903	2.0E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Hayden	525	H2	2016	7,123	outage for scr install		61%	9,840						1,462,241	0.173	0.119	1,209	855	1,476,317	1.4E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction (Began Jun 29, 2016)
CO	Hayden	525	H2	2017	7,830	representative		65%	9,563	85%	2017	2017			1,571,940	0.045	0.123	337	921	1,542,384	1.5E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction
								Average HR =	9,860	2,050,628	0.045	0.123	457	1,239										
CO	Martin Drake	492	5	2014	2,657										112,643	0.352		217	278	128,601	1.2E+06	Colorado Springs Utilities		Low NOx Burner Technology (Dry Bottom only)
CO	Martin Drake	492	5	2015	5,565										225,456	0.350		493	580	288,172	2.8E+06	Colorado Springs Utilities		Low NOx Burner Technology (Dry Bottom only)
CO	Martin Drake	492	5	2016	161	retired									3,777	0.312		9	6	4,680	5.1E+04	Colorado Springs Utilities		Low NOx Burner Technology (Dry Bottom only)
CO	Martin Drake	492	6	2014	6,460		75	67%	12,039						438,015	0.226	0.482	608	1,272	550,003	5.3E+06	Colorado Springs Utilities		Low NOx Burner Technology (Dry Bottom only) (Retired Sep 30, 2014) Low NOx Burner Technology w/ Overfire Air (Began Oct 01, 2014
CO	Martin Drake	492	6	2015	8,141			79%	11,884						520,784	0.215	0.468	670	1,448	648,813	6.2E+06	Colorado Springs Utilities		Low NOx Burner Technology w/ Overfire Air
CO	Martin Drake	492	6	2016	7,271	so2 controls installed		60%	11,715						396,380	0.208	0.312	490	724	485,441	4.6E+06	Colorado Springs Utilities	Dual Alkali (Began Sep 26, 2016)	Low NOx Burner Technology w/ Overfire Air
CO	Martin Drake	492	6	2017	7,916			68%	11,382	85%	2017	2018 YTD			447,960	0.215	0.032	556	82	532,618	5.1E+06	Colorado Springs Utilities	Dual Alkali	Low NOx Burner Technology w/ Overfire Air
								Average HR =	11,755	558,450	0.215	0.027	706	89										
CO	Martin Drake	492	7	2014	5,979		132	62%	10,848						711,437	0.232	0.493	924	1,902	805,676	7.7E+06	Colorado Springs Utilities		Low NOx Burner Technology (Dry Bottom only) (Retired Feb 28, 2014) Low NOx Burner Technology w/ Overfire Air (Began Mar 01, 2014
CO	Martin Drake	492	7	2015	7,237			66%	10,822						766,225	0.228	0.466	972	1,932	867,270	8.3E+06	Colorado Springs Utilities		Low NOx Burner Technology w/ Overfire Air
CO	Martin Drake	492	7	2016	8,125	so2 controls installed		65%	10,587						750,809	0.231	0.224	941	892	832,747	7.9E+06	Colorado Springs Utilities	Dual Alkali (Began Feb 08, 2016)	Low NOx Burner Technology w/ Overfire Air
CO	Martin Drake	492	7	2017	8,355			71%	10,632	85%	2017	2018 YTD			821,351	0.228	0.058	1,016	254	915,125	8.7E+06	Colorado Springs Utilities	Dual Alkali	Low NOx Burner Technology w/ Overfire Air
								Average HR =	10,722	982,872	0.228	0.021	1,200	111										
CO	Nucla	527	1	2014	5,613										468,196	0.272		764	931	566,900	5.5E+06	Tri-State Generation & Transmission	Fluidized Bed Limestone Injection	Other
CO	Nucla	527	1	2015	5,582										462,616	0.321		952	978	593,806	5.8E+06	Tri-State Generation & Transmission	Fluidized Bed Limestone Injection	Other
CO	Nucla	527	1	2016	3,053										248,712	0.296		499	440	338,684	3.3E+06	Tri-State Generation & Transmission	Fluidized Bed Limestone Injection	Other
CO	Nucla	527	1	2017	1,272	12/31/2022 retirement									101,250	0.306		212	153	136,310	1.3E+06	Tri-State Generation & Transmission	Fluidized Bed Limestone Injection	Other
CO	Pawnee	6248	1	2014	6,453	scr/scrubber install	552	60%	10,992						2,921,982	0.107	0.343	1,690	5,508	3,367,395	3.2E+07	Public Service Company of Colorado	Dry Lime FGD (Began Jul 26, 2014)	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction (Began Jun 28, 2014)
CO	Pawnee	6248	1	2015	8,139			76%	11,637						3,700,385	0.049	0.084	1,050	1,810	4,514,415	4.3E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
CO	Pawnee	6248	1	2016	6,618	overhaul		61%	11,065						2,933,263	0.051	0.092	840	1,494	3,402,982	3.2E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
CO	Pawnee	6248	1	2017	8,432	representative		79%	10,965	85%	2017	2017			3,807,684	0.055	0.091	1,157	1,906	4,375,178	4.2E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
								Average HR =	11,165	4,112,426	0.055	0.091	1,265	2,096										
CO	Rawhide Energy Station	6761	101	2014	8,546		294	92%	9,502						2,370,324	0.126	0.081	1,412	909	2,362,195	2.3E+07	Platte River Power Authority	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Rawhide Energy Station	6761	101	2015	7,515			82%	9,098						2,117,425	0.128	0.079	1,230	763	2,020,406	1.9E+07	Platte River Power Authority	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Rawhide Energy Station	6761	101	2016	8,582			94%	9,100						2,425,694	0.119	0.080	1,307	879	2,315,027	2.2E+07	Platte River Power Authority	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Rawhide Energy Station	6761	101	2017	8,323			93%	8,982	2017=93%	2017	2017			2,400,176	0.120	0.081	1,292	869	2,261,061	2.2E+07	Platte River Power Authority	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
								Average HR =	9,170	2,400,176	0.120	0.081	1,317	888										
CO	Ray D Nixon	8219	1	2014	6,966		207	80%	10,099						1,445,021	0.237	0.454	1,734	3,315	1,530,192	1.5E+07	Colorado Springs Utilities		Low NOx Burner Technology (Dry Bottom only)
CO	Ray D Nixon	8219	1	2015	8,131			93%	9,631						1,683,911	0.236	0.458	1,919	3,717	1,700,668	1.6E+07	Colorado Springs Utilities		Low NOx Burner Technology (Dry Bottom only)
CO	Ray D Nixon	8219	1	2016	7,211			72%	10,213						1,312,755	0.209	0.445	1,400	2,983	1,405,587	1.3E+07	Colorado Springs Utilities		Low NOx Burner Technology (Dry Bottom only) (Retired Nov 10, 2016) Low NOx Burner Technology w/ Overfire Air (Began Nov 11, 2016
CO	Ray D Nixon	8219	1	2017	7,398	so2 controls installed		80%	9,984	85%	2017	2018 YTD			1,459,312	0.164	0.205	1,196	1,494	1,527,837	1.5E+07	Colorado Springs Utilities	Dry Lime FGD (Began May 25, 2017	Low NOx Burner Technology w/ Overfire Air
								Average HR =	9,982	1,541,322	0.164	0.072	1,262	554										
CO	Valmont	477	5	2014	7,605										1,112,872	0.352		2,060	889	1,213,520	1.2E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Valmont	477	5	2015	7,660										1,126,581	0.329		1,945	876	1,216,289	1.2E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Valmont	477	5	2016	7,717										1,076,052	0.331		1,764	871	1,104,730	1.1E+07	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
CO	Valmont	477	5	2017	1,811	retired in 2017									234,267	0.278		299	169	215,265	2.1E+06	Public Service Company of Colorado	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

MONTANA UNITS

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Operating Time	Notes	Nameplate Capacity (MW)	Nameplate Capacity Factor	Heat Rate (mmbtu/kwhr)	Case 1 MW-h (85% or Higher)	Nox ER	SO2 ER	NOx (tons)	SO2 Tons	Gross Load (MW-h)	Avg. NOx Rate (lb/MMBtu)	SO2 ER	NOx (tons)	SO2 (tons)	CO2 (short tons)	Heat Input (MMBtu)	Operator	SO2 Control(s)	NOx Control(s)
MT	Colstrip	6076	1	2014	8,292										2,254,365	0.320		3,893	2,603	2,504,418	2.4E+07	P P & L Montana, LLC	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	1	2015	8,055										2,144,281	0.327		3,797	2,038	2,370,011	2.3E+07	P P & L Montana, LLC, Talen Montan	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	1	2016	6,779										1,824,035	0.340		3,475	1,740	2,089,555	2.0E+07	Talen Montana, LLC	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	1	2017	6,788	2022 retirement									1,792,272	0.344		3,236	1,936	1,945,022	1.9E+07	Talen Montana, LLC	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	2	2014	8,458										2,279,561	0.308		3,957	3,518	2,586,849	2.5E+07	P P & L Montana, LLC	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	2	2015	6,956										1,857,608	0.216		2,229	1,848	2,188,185	2.1E+07	P P & L Montana, LLC, Talen Montan	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	2	2016	8,045										2,152,697	0.144		1,737	2,056	2,486,107	2.4E+07	Talen Montana, LLC	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	2	2017	8,043	2022 retirement									2,180,091	0.159		1,890	2,526	2,445,267	2.3E+07	Talen Montana, LLC	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
MT	Colstrip	6076	3	2014	6,994		778	73%	10,157						5,006,381	0.159	0.087	4,093	2,207	5,333,125	5.1E+07	P P & L Montana, LLC	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
MT	Colstrip	6076	3	2015	8,448			90%	9,964						6,116,257	0.164	0.095	5,053	2,903	6,391,958	6.1E+07	P P & L Montana, LLC, Talen Montan	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
MT	Colstrip	6076	3	2016	8,146			83%	9,977						5,633,089	0.158	0.093	4,505	2,603	5,894,410	5.6E+07	Talen Montana, LLC	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
MT	Colstrip	6076	3	2017	7,251			74%	9,816	85%	2017	2017			5,029,733	0.149	0.092	3,753	2,280	5,178,018	4.9E+07	Talen Montana, LLC	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
								Average HR =	9,979	5,792,988	0.149	0.092	4,301	2,669										
MT	Colstrip	6076	4	2014	7,915		778	81%	10,109						5,551,215	0.164	0.088	4,592	2,474	5,885,405	5.6E+07	P P & L Montana, LLC	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
MT	Colstrip	6076	4	2015	8,481			91%	10,084						6,170,099	0.165	0.092	5,160	2,864	6,525,755	6.2E+07	P P & L Montana, LLC, Talen Montan	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
MT	Colstrip	6076	4	2016	7,385			75%	9,821						5,118,577	0.151	0.093	3,817	2,328	5,272,267	5.0E+07	Talen Montana, LLC	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
MT	Colstrip	6076	4	2017	8,449			84%	9,480	85%	2017	2017			5,705,121	0.154	0.088	4,195	2,382	5,672,252	5.4E+07	Talen Montana, LLC	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
								Average HR =	9,873	5,792,988	0.154	0.088	4,410	2,519										
MT	Hardin Generating Station	55749	U1	2014	7,175										766,446	0.079		359	391	931,025	8.9E+06	Colorado Energy Management, LLC	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
MT	Hardin Generating Station	55749	U1	2015	5,424										553,747	0.079		259	297	672,240	6.4E+06	Colorado Energy Management, LLC	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
MT	Hardin Generating Station	55749	U1	2016	3,532										392,352	0.079		185	209	483,941	4.6E+06	Colorado Energy Management, LLC	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
MT	Hardin Generating Station	55749	U1	2017	1,379	retired in 2017?									133,348	0.080		66	72	169,936	1.6E+06	Colorado Energy Management, LLC	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
MT	J E Corette	2187	2	2014	5,283										622,024	0.260		864	1,620	687,763	6.6E+06	P P & L Montana, LLC		Low NOx Burner Technology w/ Closed-coupled OFA
MT	J E Corette	2187	2	2015	1,470										164,196	0.270		234	435	184,427	1.8E+06	P P & L Montana, LLC, Talen Montana, LLC		Low NOx Burner Technology w/ Closed-coupled OFA
MT	Lewis & Clark	6089	B1	2014	7,679		50	72%	12,772						317,318	0.368	0.516	753	1,045	440,778	4.1E+06	Montana Dakota Utilities Company	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
MT	Lewis & Clark	6089	B1	2015	6,123			56%	12,412						244,033	0.372	0.452	573	685	329,141	3.0E+06	Montana Dakota Utilities Company	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
MT	Lewis & Clark	6089	B1	2016	7,574			66%	11,931						287,157	0.361	0.020	624	35	372,294	3.4E+06	Montana Dakota Utilities Company	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
MT	Lewis & Clark	6089	B1	2017	6,351			57%	12,485	85%	2017	2017			249,664	0.368	0.016	579	25	338,821	3.1E+06	Montana Dakota Utilities Company	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
								Average HR =	12,400	372,300	0.368	0.016	848	37										

NEVADA UNITS

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Operating Time	Notes	Nameplate Capacity (MW)	Nameplate Capacity Factor	Heat Rate (mmbtu/kwhr)	Case 1 MW-h (85% or Higher)	Nox ER	SO2 ER	NOx (tons)	SO2 Tons	Gross Load (MW-h)	Avg. NOx Rate (lb/MMBtu)	SO2 ER	NOx (tons)	SO2 (tons)	CO2 (short tons)	Heat Input (MMBtu)	Operator	SO2 Control(s)	NOx Control(s)
NV	North Valmy	8224	1	2014	7,740										1,662,293	0.288		2,243	6,363	1,600,173	1.5E+07	Sierra Pacific Power Company		Low NOx Burner Technology (Dry Bottom only)
NV	North Valmy	8224	1	2015	7,662										1,256,560	0.293		1,688	4,470	1,211,930	1.2E+07	Sierra Pacific Power Company		Low NOx Burner Technology (Dry Bottom only)
NV	North Valmy	8224	1	2016	3,433										557,937	0.321		797	1,848	513,084	4.9E+06	Sierra Pacific Power Company		Low NOx Burner Technology (Dry Bottom only)
NV	North Valmy	8224	1	2017	2,327										353,877	0.365		587	1,232	341,292	3.3E+06	Sierra Pacific Power Company		Low NOx Burner Technology (Dry Bottom only)
NV	North Valmy	8224	2	2014	6,372										1,340,468	0.326		2,229	1,454	1,376,276	1.3E+07	Sierra Pacific Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)
NV	North Valmy	8224	2	2015	2,116										328,737	0.294		580	413	376,075	3.6E+06	Sierra Pacific Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)
NV	North Valmy	8224	2	2016	3,134										535,465	0.291		839	431	575,186	5.5E+06	Sierra Pacific Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)
NV	North Valmy	8224	2	2017	2,441										403,652	0.297		674	356	439,962	4.2E+06	Sierra Pacific Power Company	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)
NV	Reid Gardner	2324	1	2014	6,938										639,070	0.371		1,320	1,502	727,266	6.9E+06	NV Energy	Sodium Based	Low NOx Burner Technology (Dry Bottom only)
NV	Reid Gardner	2324	2	2014	6,447										582,068	0.277		841	266	648,112	6.2E+06	NV Energy	Sodium Based	Low NOx Burner Technology (Dry Bottom only)
NV	Reid Gardner	2324	3	2014	4,625										421,853	0.269		579	252	459,477	4.4E+06	NV Energy	Sodium Based	Low NOx Burner Technology (Dry Bottom only)
NV	Reid Gardner	2324	4	2014	5,190										1,041,722	0.177		933	488	1,108,732	1.1E+07	NV Energy	Sodium Based	Low NOx Burner Technology w/ Overfire Air
NV	Reid Gardner	2324	4	2015	2,727										479,359	0.198		524	287	553,241	5.3E+06	NV Energy	Sodium Based	Low NOx Burner Technology w/ Overfire Air
NV	Reid Gardner	2324	4	2016	2,277										382,880	0.195		423	232	453,183	4.3E+06	NV Energy	Sodium Based	Low NOx Burner Technology w/ Overfire Air
NV	Reid Gardner	2324	4	2017	1,632										292,772	0.220		389	168	382,487	3.6E+06	NV Energy	Sodium Based	Low NOx Burner Technology w/ Overfire Air
NV	TS Power Plant	56224	1	2014	7,513		242	74%							1,564,200	0.047		339	239	1,487,421	1.4E+07	Newmont Nevada Energy Investmer	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
NV	TS Power Plant	56224	1	2015	8,026			45%							960,405	0.048		232	114	1,009,783	9.6E+06	Newmont Nevada Energy Investmer	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
NV	TS Power Plant	56224	1	2016	8,164			47%							994,073	0.049		233	116	993,318	9.5E+06	Newmont Nevada Energy Investmer	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
NV	TS Power Plant	56224	1	2017	8,233			51%							1,081,870	0.049		257	148	1,097,749	1.0E+07	Newmont Nevada Energy Investmer	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction

NEW MEXICO UNITS

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Operating Time	Notes	Nameplate Capacity (MW)	Nameplate Capacity Factor	Heat Rate (mmbtu/kwhr)	Case 1 MW-h (85% or Higher)	Nox ER	SO2 ER	NOx (tons)	SO2 Tons	Gross Load (MW-h)	Avg. NOx Rate (lb/MMBtu)	SO2 ER	NOx (tons)	SO2 (tons)	CO2 (short tons)	Heat Input (MMBtu)	Operator	SO2 Control(s)	NOx Control(s)
NM	Escalante	87	1	2014	7,586		257	66%	10,014						1,492,632	0.340	0.098	2,579	732	1,567,634	1.5E+07	Tri-State Generation & Transmission	Wet Limestone	Other
NM	Escalante	87	1	2015	8,061			65%	9,501						1,462,298	0.351	0.122	2,450	847	1,457,200	1.4E+07	Tri-State Generation & Transmission	Wet Limestone	Other
NM	Escalante	87	1	2016	8,784			62%	9,885						1,402,342	0.351	0.130	2,437	899	1,453,830	1.4E+07	Tri-State Generation & Transmission	Wet Limestone	Other
NM	Escalante	87	1	2017	6,989			53%	9,972	85%	2017	2017			1,186,946	0.355	0.123	2,125	728	1,241,436	1.2E+07	Tri-State Generation & Transmission	Wet Limestone	Other
								Average HR =	9,843	1,913,622	0.355	0.123	3,343	1,159										
NM	Four Corners Steam Elec Station	2442	4	2014	7,166		818	73%	10,489						5,240,673	0.523	0.146	14,570	4,024	5,638,855	5.5E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
NM	Four Corners Steam Elec Station	2442	4	2015	7,689			78%	10,397						5,610,305	0.524	0.125	15,427	3,648	5,978,648	5.8E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
NM	Four Corners Steam Elec Station	2442	4	2016	5,927			55%	9,073						3,968,546	0.494	0.133	9,216	2,399	3,693,588	3.6E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
NM	Four Corners Steam Elec Station	2442	4	2017	6,628	SCR & SO2 controls		59%	9,144	85%	Per APS	Per APS			4,221,464	0.484	0.114	9,654	2,204	3,960,402	3.9E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
								2016-17 Average HR =	9,109	6,091,573	0.080	0.050	2,219	1,387										
NM	Four Corners Steam Elec Station	2442	5	2014	5,996		818	57%	11,140						4,093,242	0.512	0.176	11,903	4,012	4,679,593	4.6E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
NM	Four Corners Steam Elec Station	2442	5	2015	7,547			73%	11,122						5,208,945	0.506	0.183	14,807	5,310	5,944,382	5.8E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
NM	Four Corners Steam Elec Station	2442	5	2016	5,388			47%	9,098						3,381,920	0.506	0.131	8,137	2,013	3,156,597	3.1E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
NM	Four Corners Steam Elec Station	2442	5	2017	4,723	SCR & SO2 controls		40%	9,193	85%	Per APS	Per APS			2,836,197	0.494	0.120	6,637	1,566	2,674,206	2.6E+07	Arizona Public Service Company	Wet Lime FGD	Low NOx Cell Burner
								2016-17 Average HR =	9,146	6,091,573	0.080	0.050	2,228	1,393										
NM	San Juan	2451	1	2014	6,636										1,921,740	0.278		2,837	656	2,072,892	2.0E+07	Public Service Company of New Me	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	1	2015	6,263										1,852,664	0.274		2,719	604	1,991,705	1.9E+07	Public Service Company of New Me	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	1	2016	7,783										2,489,619	0.225		2,941	598	2,701,314	2.6E+07	Public Service Company of New Me	Wet Limestone	Selective Non-catalytic Reduction Low NOx Burner Technology w/ Overfire Ai
NM	San Juan	2451	1	2017	7,893										2,481,790	0.221		2,869	519	2,694,589	2.6E+07	Public Service Company of New Me	Wet Limestone	Selective Non-catalytic Reduction Low NOx Burner Technology w/ Overfire Ai
NM	San Juan	2451	2	2014	7,753										2,472,849	0.281		3,457	641	2,544,448	2.4E+07	Public Service Company of New Me	Wet Limestone	Overfire Air
NM	San Juan	2451	2	2015	7,460										2,287,448	0.274		3,235	622	2,405,109	2.3E+07	Public Service Company of New Me	Wet Limestone	Overfire Air
NM	San Juan	2451	2	2016	7,171										2,222,434	0.279		3,252	361	2,388,994	2.3E+07	Public Service Company of New Me	Wet Limestone	Overfire Air
NM	San Juan	2451	2	2017	7,082										2,172,695	0.276		3,208	462	2,374,022	2.3E+07	Public Service Company of New Me	Wet Limestone	Overfire Air
NM	San Juan	2451	3	2014	7,966										3,535,553	0.265		5,053	2,056	3,903,064	3.7E+07	Public Service Company of New Me	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	3	2015	7,751										3,069,126	0.263		4,331	1,211	3,323,149	3.2E+07	Public Service Company of New Me	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	3	2016	7,471										3,111,924	0.266		4,479	830	3,372,729	3.2E+07	Public Service Company of New Me	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	3	2017	7,790										3,489,703	0.276		5,378	2,264	3,980,653	3.8E+07	Public Service Company of New Me	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	4	2014	7,973										3,574,585	0.278		5,215	1,616	3,823,861	3.6E+07	Public Service Company of New Me	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	4	2015	7,038										2,880,673	0.273		4,246	1,078	3,131,026	3.0E+07	Public Service Company of New Me	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	4	2016	7,928										3,566,642	0.221		4,229	1,141	3,962,433	3.8E+07	Public Service Company of New Me	Wet Limestone	Low NOx Burner Technology w/ Overfire Air
NM	San Juan	2451	4	2017	8,160										3,833,600	0.222		4,725	1,281	4,411,439	4.2E+07	Public Service Company of New Me	Wet Limestone	Low NOx Burner Technology w/ Overfire Air

NORTH DAKOTA & SOUTH DAKOTA UNITS

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Operating Time	Notes	Nameplate Capacity (MW)	Nameplate Capacity Factor	Heat Rate (mmbtu/kwhr)	Case 1 MW-h (85% or Higher)	Nox ER	SO2 ER	NOx (tons)	SO2 Tons	Gross Load (MW-h)	Avg. NOx Rate (lb/MMBtu)	SO2 ER	NOx (tons)	SO2 (tons)	CO2 (short tons)	Heat Input (MMBtu)	Operator	SO2 Control(s)	NOx Control(s)
ND	Antelope Valley	6469	B1	2014	7,030	LNB + SOFA installed	435	77%	10,582						2,940,648	0.201	0.373	3,196	5,809	3,387,856	3.1E+07	Basin Electric Power Cooperative	Dry Lime FGD	Overfire Air (Retired May 27, 2014) Low NOx Burner Technology w/ Closed-coupled/Separated OFA (Began May 28, 2014)
ND	Antelope Valley	6469	B1	2015	8,291			92%	10,574						3,509,998	0.112	0.340	2,103	6,312	4,040,771	3.7E+07	Basin Electric Power Cooperative	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
ND	Antelope Valley	6469	B1	2016	8,374			94%	10,344						3,591,136	0.126	0.391	2,358	7,254	4,044,308	3.7E+07	Basin Electric Power Cooperative	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
ND	Antelope Valley	6469	B1	2017	7,329			81%	9,840	94%	2017	2017			3,080,412	0.109	0.347	1,662	5,259	3,299,953	3.0E+07	Basin Electric Power Cooperative	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
								Average HR =	10,335	3,581,141	0.109	0.347	2,015	6,422										
ND	Antelope Valley	6469	B2	2014	8,134		435	86%	11,060						3,293,979	0.322	0.383	6,052	6,975	3,966,340	3.6E+07	Basin Electric Power Cooperative	Dry Lime FGD	Overfire Air
ND	Antelope Valley	6469	B2	2015	8,582			94%	10,991						3,599,800	0.360	0.340	7,283	6,716	4,307,548	4.0E+07	Basin Electric Power Cooperative	Dry Lime FGD	Overfire Air
ND	Antelope Valley	6469	B2	2016	6,619	LNB + SOFA installed		72%	10,688						2,752,701	0.183	0.346	2,683	5,089	3,203,057	2.9E+07	Basin Electric Power Cooperative	Dry Lime FGD	Overfire Air (Retired Jun 10, 2016) Low NOx Burner Technology w/ Closed-coupled/Separated OFA (Began Jun 11, 2016)
ND	Antelope Valley	6469	B2	2017	8,507			94%	10,432	94%	2017	2017			3,599,546	0.108	0.405	2,045	7,603	4,088,142	3.8E+07	Basin Electric Power Cooperative	Dry Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
								Average HR =	10,793	3,581,141	0.108	0.405	2,089	7,826										
SD	Big Stone	6098	1	2014	8,325		450	72%	10,634						2,825,223	0.687	0.922	10,507	13,845	3,150,887	3.0E+07	Otter Tail Power Company		Overfire Air
SD	Big Stone	6098	1	2015	4,628	outage for installation of new controls		40%	10,636						1,563,251	0.338	0.578	3,148	4,805	1,743,876	1.7E+07	Otter Tail Power Company	Dry Lime FGD (Began Aug 31, 2015)	Overfire Air Selective Catalytic Reduction (Began Aug 26, 2015)
SD	Big Stone	6098	1	2016	7,845	first full year of new controls		56%	10,749						2,188,753	0.083	0.070	962	827	2,467,531	2.4E+07	Otter Tail Power Company	Dry Lime FGD	Overfire Air Selective Catalytic Reduction
SD	Big Stone	6098	1	2017	7,818			55%	10,867	85%	2017	2017			2,182,037	0.085	0.071	984	846	2,487,044	2.4E+07	Otter Tail Power Company	Dry Lime FGD	Overfire Air Selective Catalytic Reduction
								Average HR =	10,722	3,350,700	0.085	0.071	1,520	1,281										
ND	Coal Creek	6030	1	2014	7,985		605	89%	9,796						4,724,861	0.203	0.341	4,697	7,885	5,039,198	4.6E+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
ND	Coal Creek	6030	1	2015	8,404			90%	9,852						4,776,889	0.219	0.326	5,087	7,667	5,123,402	4.7E+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
ND	Coal Creek	6030	1	2016	8,272			89%	9,628						4,719,439	0.193	0.336	4,327	7,643	4,946,752	4.5E+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
ND	Coal Creek	6030	1	2017	6,721	SO2 controls added - use 2018		73%	9,712	90%	#2 2017	2018			3,843,539	0.182	0.166	3,361	3,096	4,063,791	3.7E+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
						Nox @ 0.13 per new controls		Average HR =	9,747	4,768,243	0.130	0.143	3,021	3,323										
ND	Coal Creek	6030	2	2014	8,317		605	92%	9,535						4,879,864	0.143	0.341	3,287	7,940	5,065,733	4.7E+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
ND	Coal Creek	6030	2	2015	8,429			90%	9,644						4,775,408	0.157	0.338	3,499	7,776	5,013,823	4.6E+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
ND	Coal Creek	6030	2	2016	7,194			77%	9,491						4,056,301	0.136	0.293	2,564	5,633	4,191,281	3.8E+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
ND	Coal Creek	6030	2	2017	8,283	SO2 controls added - use 2018		89%	9,495	90%	2017	2018			4,721,086	0.130	0.147	2,889	3,296	4,880,276	4.5E+07	Great River Energy	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
								Average HR =	9,541	4,768,243	0.130	0.142	2,957	3,230										
ND	Coyote	8222	B1	2014	7,641		450	74%	11,046						2,914,829	0.700	0.794	11,374	12,777	3,505,391	3.2E+07	Otter Tail Power Company	Dry Lime FGD	
ND	Coyote	8222	B1	2015	8,308	derate for mechanical		52%	11,053						2,058,997	0.774	0.772	8,820	8,786	2,477,576	2.3E+07	Otter Tail Power Company	Dry Lime FGD	
ND	Coyote	8222	B1	2016	6,746	separated overfire air added		66%	10,477						2,586,763	0.580	0.876	7,772	11,873	2,950,668	2.7E+07	Otter Tail Power Company	Dry Lime FGD	Overfire Air (Began Jun 15, 2016)
ND	Coyote	8222	B1	2017	7,595			70%	10,744	85%	2017	2017			2,778,245	0.424	0.901	6,378	13,444	3,249,673	3.0E+07	Otter Tail Power Company	Dry Lime FGD	Overfire Air
								Average HR =	10,830	3,350,700	0.424	0.901	7,688	16,344										
ND	Leland Olds	2817	1	2014	6,543		216	59%	10,656						1,119,902	0.234	0.069	1,373	412	1,299,228	1.2E+07	Basin Electric Power Cooperative	Wet Lime FGD	Low NOx Burner Technology (Dry Bottom only) Overfire Air
ND	Leland Olds	2817	1	2015	8,528			80%	10,390						1,519,408	0.237	0.086	1,814	681	1,718,734	1.6E+07	Basin Electric Power Cooperative	Wet Lime FGD	Low NOx Burner Technology (Dry Bottom only) Overfire Air
ND	Leland Olds	2817	1	2016	8,366			79%	10,397						1,497,217	0.247	0.091	1,856	711	1,694,775	1.6E+07	Basin Electric Power Cooperative	Wet Lime FGD	Low NOx Burner Technology (Dry Bottom only) Overfire Air
ND	Leland Olds	2817	1	2017	6,747	SNCR Optimized - use 2018		64%	10,381	85%	2018	2017			1,205,582	0.177	0.089	1,121	554	1,362,585	1.3E+07	Basin Electric Power Cooperative	Wet Lime FGD	Low NOx Burner Technology (Dry Bottom only) Overfire Air
								Average HR =	10,456	1,608,336	0.147	0.089	1,236	745										
ND	Leland Olds	2817	2	2014	7,972		440	72%	10,258						2,763,953	0.365	0.072	5,202	1,025	3,086,694	2.8E+07	Basin Electric Power Cooperative	Wet Lime FGD	Overfire Air
ND	Leland Olds	2817	2	2015	6,935			65%	9,940						2,487,888	0.367	0.086	4,557	1,066	2,692,426	2.5E+07	Basin Electric Power Cooperative	Wet Lime FGD	Overfire Air
ND	Leland Olds	2817	2	2016	8,172	SNCR Optimized		77%	10,232						2,965,565	0.366	0.080	5,434	1,217	3,303,589	3.0E+07	Basin Electric Power Cooperative	Wet Lime FGD	Overfire Air
ND	Leland Olds	2817	2	2017	8,110			77%	10,128	85%	2017	2017			2,953,693	0.293	0.091	4,418	1,364	3,256,756	3.0E+07	Basin Electric Power Cooperative	Wet Lime FGD	Overfire Air
								Average HR =	10,140	3,276,240	0.293	0.091	4,873	1,515										
ND	Milton R Young	2823	B1	2014	7,988		257	89%	9,552						2,002,732	0.334	0.038	3,205	361	2,082,651	1.9E+07	Minnkota Power Cooperative, Inc.	Wet Lime FGD Wet Limestone	Overfire Air Selective Non-catalytic Reduction
ND	Milton R Young	2823	B1	2015	7,063			78%	10,099						1,747,255	0.333	0.069	2,950	606	1,921,157	1.8E+07	Minnkota Power Cooperative, Inc.	Wet Lime FGD Wet Limestone	Overfire Air Selective Non-catalytic Reduction
ND	Milton R Young	2823	B1	2016	8,433			94%	10,969						2,105,676	0.331	0.079	3,841	909	2,514,616	2.3E+07	Minnkota Power Cooperative, Inc.	Wet Lime FGD Wet Limestone	Overfire Air Selective Non-catalytic Reduction
ND	Milton R Young	2823	B1	2017	8,298			91%	10,508	91%	2017	2017			2,058,278	0.330	0.084	3,579	905	2,354,650	2.2E+07	Minnkota Power Cooperative, Inc.	Wet Lime FGD Wet Limestone	Overfire Air Selective Non-catalytic Reduction
								Average HR =	10,282	2,048,701	0.330	0.084	3,477	881										
ND	Milton R Young	2823	B2	2014	6,730		477	72%	9,887						3,018,256	0.335	0.115	5,004	1,710	3,248,684	3.0E+07	Minnkota Power Cooperative, Inc.	Dual Alkali Wet Lime FGD	Overfire Air Selective Non-catalytic Reduction
ND	Milton R Young	2823	B2	2015	8,187			88%	9,939						3,661,385	0.336	0.117	6,123	2,129	3,961,751	3.6E+07	Minnkota Power Cooperative, Inc.	Dual Alkali Wet Lime FGD	Overfire Air Selective Non-catalytic Reduction
ND	Milton R Young	2823	B2	2016	6,113			65%	9,824						2,709,570	0.335	0.130	4,466	1,729	2,897,990	2.7E+07	Minnkota Power Cooperative, Inc.	Dual Alkali Wet Lime FGD	Overfire Air Selective Non-catalytic Reduction
ND	Milton R Young	2823	B2	2017	8,487			91%	10,088	91%	2017	2017			3,811,876	0.333	0.130	6,390	2,507	4,186,682	3.8E+07	Minnkota Power Cooperative, Inc.	Dual Alkali Wet Lime FGD	Overfire Air Selective Non-catalytic Reduction
								Average HR =	9,934	3,802,453	0.333	0.130	6,293	2,463										
ND	R M Heskett	2790	B2	2014	8,012		75	75%	11,173						493,010	0.360	0.849	995	2,339	599,718	5.5E+06	Montana Dakota Utilities Company		
ND	R M Heskett	2790	B2	2015	7,947			71%	11,446						463,437	0.367	0.771	989	2,046	577,507	5.3E+06	Montana Dakota Utilities Company		
ND	R M Heskett	2790	B2	2016	7,754			69%	11,543						453,257	0.387	0.721	1,016	1,887	569,610	5.2E+06	Montana Dakota Utilities Company		
ND	R M Heskett	2790	B2	2017	7,888	New SO2 controls in 2017		69%	11,494	85%	2017	2018			455,535	0.371	0.567	985	1,485	570,011	5.2E+06	Montana Dakota Utilities Company	Fluidized Bed Limestone Injection (Began Apr 16, 2017)	
								Average HR =	11,414	558,450	0.371	0.464	1,181	1,479										
ND	Spiritwood Station	56786	1	2014	2,769		106	10%	24,637						91,481	0.682		1,294	1,415	245,389	2.3E+06	Great River Energy	Dry Lime FGD Fluidized Bed Limesto	Overfire Air Selective Non-catalytic Reduction
ND	Spiritwood Station	56786	1	2015	7,214				37,449						133,881	0.098		235	67	545,513	5.0E+06	Great River Energy	Dry Lime FGD Fluidized Bed Limesto	Overfire Air Selective Non-catalytic Reduction
ND	Spiritwood Station	56786	1	2016	8,535				#DIV/0!							0.095		289	17	576,798	6.2E+06	Great River Energy	Dry Lime FGD Fluidized Bed Limesto	Overfire Air Selective Non-catalytic Reduction
ND	Spiritwood Station	56786	1	2017	8,138				#DIV/0!							0.103		284	21	549,640	5.6E+06	Great River Energy	Dry Lime FGD Fluidized Bed Limesto	Overfire Air Selective Non-catalytic Reduction
State	Facility Name		Unit ID	Year	# of Months Reported		SO2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	CO2 (short tons)	Heat Input (MMBtu)													
ND	Spiritwood Station		1	2018	12		41	0.102	262	538,577	5.2E+06													
ND	Stanton	2824	1	2014	8,276											0.224		1,056	2,493	1,000,026	9.5E+06	Great River Energy		Low NOx Burner Technology (Dry Bottom only)
ND	Stanton	2824	1	2015	7,559											0.207		872	2,076	880,520	8.4E+06	Great River Energy		Low NOx Burner Technology (Dry Bottom only)
ND	Stanton	2824	1	2016	7,543											0.219		1,052	2,412	963,783	9.2E+06	Great River Energy		Low NOx Burner Technology (Dry Bottom only)
ND	Stanton	2824	1	2017	1,248											0.273		175	395	143,161	1.4E+06	Great River Energy		Low NOx Burner Technology (Dry Bottom only)
ND	Stanton	2824	10	2014	7,537											0.313		606	98	408,205	3.9E+06	Great River Energy	Dry Lime FGD	Low NOx Burner Technology w/ Separated OFA
ND	Stanton	2824	10	2015	5,983											0.356		580	88	341,271	3.3E+06	Great River Energy	Dry Lime FGD	Low NOx Burner Technology w/ Separated OFA
ND	Stanton	2824	10	2016	4,193											0.405		489	67	252,392	2.4E+06	Great River Energy	Dry Lime FGD	Low NOx Burner Technology w/ Separated OFA
ND	Stanton	2824	10	2017	974											0.445		126	28	59,469	5.7E+05	Great River Energy	Dry Lime FGD	Low NOx Burner Technology w/ Separated OFA

UTAH-WYOMING UNITS

	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Operating Time	Notes	Nameplate Capacity (MW)	Nameplate Capacity Factor	Heat Rate (mmbtu/kwhr)	Case 1 MW-h (85% or Higher)	Nox ER	SO2 ER	NOx (tons)	SO2 Tons	Gross Load (MW-h)	Avg. NOx Rate (lb/MMBtu)	SO2 ER	NOx (tons)	SO2 (tons)	CO2 (short tons)	Heat Input (MMBtu)	Operator	SO2 Control(s)	NOx Control(s)
UT	Bonanza	7790	43101	2014	8,513		500	85%	10,444						3,699,706	0.361	0.072	7,057	1,390	3,964,491	3.9E+07	Deseret Generation & Transmission	Wet Limestone	Low NOx Burner Technology (Dry Bottom only)
UT	Bonanza	7790	43101	2015	8,432			83%	9,935						3,624,644	0.376	0.071	6,837	1,276	3,694,587	3.6E+07	Deseret Generation & Transmission	Wet Limestone	Low NOx Burner Technology (Dry Bottom only)
UT	Bonanza	7790	43101	2016	7,619			74%	10,744						3,258,715	0.314	0.075	5,574	1,305	3,592,217	3.5E+07	Deseret Generation & Transmission	Wet Limestone	Low NOx Burner Technology (Dry Bottom only)
UT	Bonanza	7790	43101	2017	8,412			83%	11,012	85%	2017	2017			3,621,755	0.264	0.066	5,379	1,319	4,092,085	4.0E+07	Deseret Generation & Transmission	Wet Limestone	Low NOx Burner Technology (Dry Bottom only)
								Average HR =	10,534	3,719,277	0.264	0.066	5,179	1,296										
UT	Carbon	3644	1	2014	8,601										542,580	0.448		1,317	3,798	595,007	5.8E+06	Pacificorp Energy Generation		
UT	Carbon	3644	1	2015	2,512										155,178	0.478		399	1,074	170,345	1.7E+06	Pacificorp Energy Generation		
UT	Carbon	3644	2	2014	8,459										834,808	0.467		1,952	5,443	851,956	8.3E+06	Pacificorp Energy Generation		
UT	Carbon	3644	2	2015	2,511										267,364	0.470		649	1,742	280,972	2.7E+06	Pacificorp Energy Generation		
WY	Dave Johnston	4158	BW41	2014	8,580										778,026	0.386		1,552	2,632	834,126	8.0E+06	Pacificorp Energy Generation		
WY	Dave Johnston	4158	BW41	2015	8,643										813,898	0.392		1,707	3,150	912,696	8.7E+06	Pacificorp Energy Generation		
WY	Dave Johnston	4158	BW41	2016	7,697										721,113	0.382		1,499	2,838	807,557	7.7E+06	Pacificorp Energy Generation		
WY	Dave Johnston	4158	BW41	2017	8,335										743,729	0.359		1,477	2,925	856,948	8.2E+06	Pacificorp Energy Generation		
WY	Dave Johnston	4158	BW42	2014	7,908										739,403	0.418		1,688	2,681	836,651	8.0E+06	Pacificorp Energy Generation		
WY	Dave Johnston	4158	BW42	2015	8,690										817,508	0.404		1,836	3,273	950,718	9.1E+06	Pacificorp Energy Generation		
WY	Dave Johnston	4158	BW42	2016	8,595										824,538	0.424		1,943	3,370	958,243	9.1E+06	Pacificorp Energy Generation		
WY	Dave Johnston	4158	BW42	2017	8,299										777,277	0.394		1,750	3,177	915,548	8.7E+06	Pacificorp Energy Generation		
WY	Dave Johnston	4158	BW43	2014	8,256										1,638,352	0.231		1,949	802	1,757,772	1.7E+07	Pacificorp Energy Generation	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
WY	Dave Johnston	4158	BW43	2015	7,616										1,474,020	0.225		1,773	840	1,619,469	1.5E+07	Pacificorp Energy Generation	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
WY	Dave Johnston	4158	BW43	2016	7,985										1,553,256	0.220		1,767	872	1,667,937	1.6E+07	Pacificorp Energy Generation	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
WY	Dave Johnston	4158	BW43	2017	7,212										1,381,807	0.230		1,656	788	1,489,014	1.4E+07	Pacificorp Energy Generation	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
WY	Dave Johnston	4158	BW44	2014	8,369										2,509,778	0.133		1,653	1,577	2,584,028	2.5E+07	Pacificorp Energy Generation	Dry Lime FGD	Low NOx Burner Technology w/ Separated OFA
WY	Dave Johnston	4158	BW44	2015	8,187										2,512,701	0.135		1,690	1,511	2,596,691	2.5E+07	Pacificorp Energy Generation	Dry Lime FGD	Low NOx Burner Technology w/ Separated OFA
WY	Dave Johnston	4158	BW44	2016	8,085										2,483,174	0.135		1,732	1,447	2,673,598	2.5E+07	Pacificorp Energy Generation	Dry Lime FGD	Low NOx Burner Technology w/ Separated OFA
WY	Dave Johnston	4158	BW44	2017	7,169										2,056,566	0.134		1,473	1,319	2,258,266	2.2E+07	Pacificorp Energy Generation	Dry Lime FGD	Low NOx Burner Technology w/ Separated OFA
WY	Dry Fork Station	56609	1	2014	8,491		484	85%	9,627						3,600,642	0.039	0.051	657	884	3,635,543	3.5E+07	Basin Electric Power Cooperative	Dry Lime FGD	Selective Catalytic Reduction
WY	Dry Fork Station	56609	1	2015	8,241			82%	9,353						3,482,118	0.042	0.053	672	870	3,415,742	3.3E+07	Basin Electric Power Cooperative	Dry Lime FGD	Selective Catalytic Reduction
WY	Dry Fork Station	56609	1	2016	7,522			73%	9,480						3,113,897	0.044	0.062	632	912	3,096,028	3.0E+07	Basin Electric Power Cooperative	Dry Lime FGD	Selective Catalytic Reduction
WY	Dry Fork Station	56609	1	2017	8,357			84%	9,701	85%	2017	2017			3,556,561	0.041	0.061	697	1,047	3,618,571	3.5E+07	Basin Electric Power Cooperative	Dry Lime FGD	Selective Catalytic Reduction
								Average HR =	9,540	3,601,630	0.041	0.061	710	1,043										
UT	Hunter	6165	1	2014	6,982		525	62%	9,355						2,836,273	0.257	0.090	3,419	1,193	2,722,387	2.7E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
UT	Hunter	6165	1	2015	8,580			76%	9,355						3,483,969	0.201	0.083	3,274	1,352	3,344,103	3.3E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
UT	Hunter	6165	1	2016	8,454			67%	9,254						3,088,802	0.196	0.064	2,806	916	2,932,570	2.9E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
UT	Hunter	6165	1	2017	7,093			59%	9,252	85%	2017	2017			2,713,038	0.201	0.069	2,518	862	2,575,291	2.5E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
								Average HR =	9,304	3,909,150	0.201	0.069	3,653	1,249										
UT	Hunter	6165	2	2014	8,621		525	76%	9,685						3,501,055	0.195	0.092	3,319	1,559	3,478,945	3.4E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
UT	Hunter	6165	2	2015	7,943			71%	9,685						3,271,270	0.202	0.091	3,210	1,448	3,250,624	3.2E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
UT	Hunter	6165	2	2016	8,345			65%	9,300						3,002,360	0.182	0.087	2,556	1,218	2,864,751	2.8E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
UT	Hunter	6165	2	2017	8,489			69%	9,624	85%	2017	2017			3,186,191	0.181	0.085	2,789	1,303	3,146,087	3.1E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
								Average HR =	9,573	3,909,150	0.181	0.085	3,381	1,590										
UT	Hunter	6165	3	2014	8,199		527	75%	9,533						3,474,798	0.288	0.072	4,857	1,187	3,398,626	3.3E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Overfire Air
UT	Hunter	6165	3	2015	8,479			78%	9,927						3,622,135	0.280	0.080	5,107	1,438	3,689,266	3.6E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Overfire Air
UT	Hunter	6165	3	2016	7,154			59%	9,597						2,746,613	0.258	0.081	3,506	1,064	2,704,415	2.6E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Overfire Air
UT	Hunter	6165	3	2017	8,667			73%	9,596	85%	2017	2017			3,371,407	0.274	0.083	4,466	1,347	3,319,459	3.2E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Overfire Air
								Average HR =	9,663	3,925,531	0.274	0.083	5,189	1,580										
UT	Huntington	8069	1	2014	7,595		541	67%	8,941						3,194,437	0.214	0.086	3,066	1,224	2,930,272	2.9E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
UT	Huntington	8069	1	2015	8,635			76%	8,877						3,607,319	0.222	0.087	3,563	1,396	3,285,650	3.2E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
UT	Huntington	8069	1	2016	7,369			59%	9,021						2,810,327	0.221	0.090	2,810	1,142	2,600,993	2.5E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
UT	Huntington	8069	1	2017	8,170			64%	9,121	85%	2017	2017			3,056,749	0.217	0.089	2,990	1,242	2,860,587	2.8E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Closed-coupled OFA
								Average HR =	8,990	4,030,520	0.217	0.089	3,928	1,614										
UT	Huntington	8069	2	2014	8,415		496	80%	9,650						3,486,311	0.224	0.075	3,798	1,254	3,451,638	3.4E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
UT	Huntington	8069	2	2015	7,246			65%	9,776						2,835,582	0.208	0.081	2,899	1,128	2,844,166	2.8E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
UT	Huntington	8069	2	2016	8,509			73%	9,609						3,162,190	0.219	0.080	3,400	1,222	3,117,461	3.0E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
UT	Huntington	8069	2	2017	8,467			65%	9,673	85%	2017	2017			2,831,505	0.208	0.076	2,940	1,040	2,810,194	2.7E+07	Pacificorp Energy Generation	Wet Lime FGD	Low NOx Burner Technology w/ Separated OFA
								Average HR =	9,677	3,693,216	0.208	0.076	3,715	1,357										
UT	Intermountain	6481	1SGA	2014	7,387										6,008,149	0.389	0.075	10,857	2,059	5,598,039	5.5E+07	Intermountain Power Service Corpo	Wet Limestone	Low NOx Burner Technology (Dry Bottom only)
UT	Intermountain	6481	1SGA	2015	8,559										6,473,758	0.377	0.068	11,322	1,996	6,038,272	5.9E+07	Intermountain Power Service Corpo	Wet Limestone	Low NOx Burner Technology (Dry Bottom only)
UT	Intermountain	6481	1SGA	2016	7,857										4,376,836	0.257	0.068	5,363	1,350	4,092,781	4.0E+07	Intermountain Power Service Corpo	Wet Limestone	Low NOx Burner Technology (Dry Bottom only)
UT	Intermountain	6481	1SGA	2017	8,109	New gas to replace									4,694,901	0.240	0.059	5,231	1,228	4,286,429	4.2E+07	Intermountain Power Service Corpo	Wet Limestone	Low NOx Burner Technology (Dry Bottom only)
UT	Intermountain	6481	2SGA	2014	8,594										7,205,470	0.378	0.070	12,759	2,310	6,784,884	6.6E+07	Intermountain Power Service Corpo	Wet Limestone	Low NOx Burner Technology (Dry Bottom only)
UT	Intermountain	6481	2SGA	2015	8,075										6,124,843	0.329	0.063	9,452	1,773	5,786,774	5.6E+07	Intermountain Power Service Corpo	Wet Limestone	Low NOx Burner Technology (Dry Bottom only)
UT	Intermountain	6481	2SGA	2016	8,634										4,663,618	0.227	0.066	5,034	1,435	4,436,062	4.3E+07	Intermountain Power Service Corpo	Wet Limestone	Low NOx Burner Technology (Dry Bottom only)
UT	Intermountain	6481	2SGA	2017	7,531	New gas to replace									4,330,608	0.211	0.063	4,378	1,256	4,096,604	4.0E+07	Intermountain Power Service Corpo	Wet Limestone	Low NOx Burner Technology (Dry Bottom only)
WY	Jim Bridger	8066	BW71	2014	7,265										3,381,707	0.185	0.154	2,997	2,424	3,305,066	3.2E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Closed-coupled OFA
WY	Jim Bridger	8066	BW71	2015	8,107										3,727,113	0.189	0.152	3,427	2,665	3,673,605	3.5E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Closed-coupled OFA
WY	Jim Bridger	8066	BW71	2016	8,245										3,347,330	0.187	0.150	3,022	2,353	3,284,320	3.1E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Closed-coupled OFA
WY	Jim Bridger	8066	BW71	2017	8,300										3,170,348	0.181	0.143	2,861	2,223	3,268,340	3.1E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Closed-coupled OFA
WY	Jim Bridger	8066	BW72	2014	8,481		617	73%	9,718						3,949,177	0.187	0.156	3,696	2,998	4,025,048	3.8E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Closed-coupled OFA
WY	Jim Bridger	8066	BW72	2015	8,521			75%	9,580						4,067,221	0.196	0.154	3,922	3,008	4,086,673	3.9E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Closed-coupled OFA
WY	Jim Bridger	8066	BW72	2016	8,553			67%	9,615						3,601,944	0.177	0.158	3,195	2,740	3,632,416	3.5E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Closed-coupled OFA
WY	Jim Bridger	8066	BW72	2017	7,113	overhaul / outage		50%	9,652	85%	2017	2017			2,713,612	0.180	0.151	2,463	1,978	2,746,879	2.6E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Closed-coupled OFA
								Average HR =	9,641	4,594,182	0.180	0.151	3,978	3,346										
WY	Jim Bridger	8066	BW73	2014	8,584		608	72%	9,824						3,834,914	0.195	0.149	3,762	2,806	3,951,360	3.8E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Closed-coupled OFA
WY	Jim Bridger	8066	BW73	2015	6,342			51%	9,872						2,728,896	0.187	0.146	2,574	1,971	2,825,458	2.7E+07	Pacificorp Energy Generation	Sodium Based	Selective Catalytic Reduction (Began Nov 25, 2015) Low NOx Burner Technology w/ Closed-coupled OFA
WY	Jim Bridger	8066	BW73	2016	6,537	scr installed		54%	9,637						2,869,464	0.052	0.150	698	2,068	2,900,368	2.8E+07	Pacificorp Energy Generation	Sodium Based	Selective Catalytic Reduction Low NOx Burner Technology w/ Closed-coupled OFA
WY	Jim Bridger	8066	BW73	2017	8,555			62%	10,008	85%	2017	2017			3,314,263	0.050	0.141	825	2,336	3,478,833	3.3E+07	Pacificorp Energy Generation	Sodium Based	Selective Catalytic Reduction Low NOx Burner Technology w/ Closed-coupled OFA
								Average HR =	9,835	4,529,402	0.050	0.141	1,116	3,137										
WY	Jim Bridger	8066	BW74	2014	8,551		608	72%	8,731						3,839,283	0.199	0.149	3,446	2,497	3,515,699	3.4E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Closed-coupled OFA
WY	Jim Bridger	8066	BW74	2015	8,551			73%	9,592						3,867,900	0.198	0.141	3,777	2,620	3,891,030	3.7E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Closed-coupled OFA
WY	Jim Bridger	8066	BW74	2016	7,092			51%	10,495						2,740,617	0.166	0.144	2,429	2,066	3,016,617	2.9E+07	Pacificorp Energy Generation	Sodium Based	Selective Catalytic Reduction (Began Nov 10, 2016) Low NOx Burner Technology w/ Closed-coupled OFA
WY	Jim Bridger	8066	BW74	2017	8,549	scr installed		63%	9,832	85%	2017	2017			3,364,727	0.049	0.144	812	2,377	3,469,649	3.3E+07	Pacificorp Energy Generation	Sodium Based	Selective Catalytic Reduction Low NOx Burner Technology w/ Closed-coupled OFA
								Average HR =	9,662	4,529,402	0.049	0.144	1,074	3,144										
WY	Laramie River	6204	1	2014	8,222		570	86%	11,013						4,297,261	0.159	0.120	3,806	2,841	4,963,597	4.7E+07	Basin Electric Power Cooperative	Wet Limestone	Overfire Air Low NOx Burner Technology (Dry Bottom only)
WY	Laramie River	6204	1	2015	5,888			56%	11,262						2,820,233	0.158	0.107	2,577	1,702	3,331,220	3.2E+07	Basin Electric Power Cooperative	Wet Limestone	Overfire Air Low NOx Burner Technology (Dry Bottom only)
WY	Laramie River	6204	1	2016	7,676			67%	11,268						3,344,522	0.151	0.089	2,915	1,669	3,952,359	3.8E+07	Basin Electric Power Cooperative	Wet Limestone	Overfire Air Low NOx Burner Technology (Dry Bottom only)
WY	Laramie River	6204	1	2017	6,736			59%	10,978	85%	permit	2017			2,962,913	0.150	0.097	2,523	1,571	3,411,356	3.3E+07	Basin Electric Power Cooperative	Wet Limestone	Overfire Air Low NOx Burner Technology (Dry Bottom only)
						SCR 2019 .06 by permit		Average HR =	11,130	4,244,220	0.060	0.097	1,417	2,281										

UTAH-WYOMING UNITS

	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Operating Time	Notes	Nameplate Capacity (MW)	Nameplate Capacity Factor	Heat Rate (mmbtu/kwhr)	Case 1 MW-h (85% or Higher)	Nox ER	SO2 ER	NOx (tons)	SO2 Tons	Gross Load (MW-h)	Avg. NOx Rate (lb/MMBtu)	SO2 ER	NOx (tons)	SO2 (tons)	CO2 (short tons)	Heat Input (MMBtu)	Operator	SO2 Control(s)	NOx Control(s)
WY	Laramie River	6204	2	2014	6,290		570	71%	9,800						3,535,264	0.161	0.126	2,801	2,179	3,633,697	3.5E+07	Basin Electric Power Cooperative	Wet Limestone	Overfire Air Low NOx Burner Technology (Dry Bottom only)
WY	Laramie River	6204	2	2015	7,813			87%	10,431						4,329,345	0.149	0.108	3,389	2,435	4,736,303	4.5E+07	Basin Electric Power Cooperative	Wet Limestone	Overfire Air Low NOx Burner Technology (Dry Bottom only)
WY	Laramie River	6204	2	2016	7,439			70%	10,053						3,479,377	0.151	0.076	2,673	1,327	3,668,636	3.5E+07	Basin Electric Power Cooperative	Wet Limestone	Overfire Air Low NOx Burner Technology (Dry Bottom only)
WY	Laramie River	6204	2	2017	8,504			86%	9,912	85%	permit	2017			4,288,107	0.155	0.101	3,301	2,150	4,457,730	4.3E+07	Basin Electric Power Cooperative	Wet Limestone	Overfire Air Low NOx Burner Technology (Dry Bottom only)
						SNCR 2018 0.15 by permit		Average HR =	10,049	4,244,220	0.150	0.101	3,199	2,158										
WY	Laramie River	6204	3	2014	5,716		570	61%	11,088						3,022,251	0.173	0.175	2,918	2,930	3,514,602	3.4E+07	Basin Electric Power Cooperative	Dry Lime FGD	Overfire Air Low NOx Burner Technology (Dry Bottom only)
WY	Laramie River	6204	3	2015	7,763			87%	11,244						4,331,628	0.148	0.165	3,611	4,014	5,108,333	4.9E+07	Basin Electric Power Cooperative	Dry Lime FGD	Overfire Air Low NOx Burner Technology (Dry Bottom only)
WY	Laramie River	6204	3	2016	8,555			86%	11,146						4,272,393	0.147	0.128	3,525	3,049	4,994,338	4.8E+07	Basin Electric Power Cooperative	Dry Lime FGD	Overfire Air Low NOx Burner Technology (Dry Bottom only)
WY	Laramie River	6204	3	2017	7,402			75%	11,348	85%	permit	2017			3,764,520	0.155	0.131	3,341	2,801	4,480,375	4.3E+07	Basin Electric Power Cooperative	Dry Lime FGD	Overfire Air Low NOx Burner Technology (Dry Bottom only)
						SNCR 2018 0.15 by permit		Average HR =	11,207	4,244,220	0.150	0.131	3,567	3,119										
WY	Naughton	4162	1	2014	8,381										1,305,929	0.192	0.140	1,339	958	1,437,489	1.4E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Separated OFA
WY	Naughton	4162	1	2015	8,532										1,376,510	0.204	0.143	1,490	1,033	1,515,826	1.4E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Separated OFA
WY	Naughton	4162	1	2016	8,599										1,375,035	0.201	0.135	1,436	959	1,494,833	1.4E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Separated OFA
WY	Naughton	4162	1	2017	7,788										1,214,124	0.188	0.131	1,224	846	1,352,943	1.3E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Separated OFA
WY	Naughton	4162	2	2014	8,415										1,664,818	0.222	0.135	1,835	1,098	1,705,009	1.6E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Separated OFA
WY	Naughton	4162	2	2015	8,576										1,761,618	0.228	0.136	2,006	1,193	1,842,881	1.8E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Separated OFA
WY	Naughton	4162	2	2016	7,487										1,557,512	0.210	0.130	1,608	992	1,595,029	1.5E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Separated OFA
WY	Naughton	4162	2	2017	8,285										1,661,014	0.207	0.132	1,732	1,101	1,742,997	1.7E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Separated OFA
WY	Naughton	4162	3	2014	8,021										2,398,534	0.248	0.359	2,882	4,090	2,387,537	2.3E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Separated OFA
WY	Naughton	4162	3	2015	7,528										2,169,541	0.238	0.235	2,583	2,508	2,237,632	2.1E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Separated OFA
WY	Naughton	4162	3	2016	8,426										2,348,885	0.208	0.175	2,545	2,119	2,540,865	2.4E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Separated OFA
WY	Naughton	4162	3	2017	8,248	gas in 2019									2,263,992	0.220	0.180	2,612	2,101	2,449,815	2.3E+07	Pacificorp Energy Generation	Sodium Based	Low NOx Burner Technology w/ Separated OFA
WY	Neil Simpson II	7504	1	2014	7,779		90	81%	11,626						635,918	0.130	0.097	488	357	775,366	7.4E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
WY	Neil Simpson II	7504	1	2015	8,237			85%	11,729						673,931	0.127	0.091	509	361	829,057	7.9E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
WY	Neil Simpson II	7504	1	2016	8,346			84%	12,025						663,087	0.135	0.097	553	386	836,247	8.0E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
WY	Neil Simpson II	7504	1	2017	7,040			76%	12,048	85%	2017	2017			601,745	0.142	0.097	526	350	760,365	7.2E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
								Average HR =	11,857	670,140	0.142	0.097	563	383										
WY	Wygen I	55479	1	2014	8,451		90	100%	11,228						785,891	0.133	0.079	589	348	925,438	8.8E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
WY	Wygen I	55479	1	2015	8,739			104%	11,150						817,684	0.131	0.068	601	311	956,230	9.1E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
WY	Wygen I	55479	1	2016	8,495			100%	11,116						788,705	0.135	0.078	592	343	919,488	8.8E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
WY	Wygen I	55479	1	2017	8,575			102%	11,405	100%	2017	2017			801,831	0.128	0.099	587	455	959,101	9.1E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
								Average HR =	11,225	788,400	0.128	0.099	565	440										
WY	Wygen II	56319	1	2014	8,694		95	92%	10,637						765,450	0.062	0.047	251	193	853,939	8.1E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
WY	Wygen II	56319	1	2015	8,001			89%	10,855						742,314	0.057	0.043	229	174	845,111	8.1E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
WY	Wygen II	56319	1	2016	8,734			97%	10,641						808,471	0.055	0.056	237	240	902,317	8.6E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
WY	Wygen II	56319	1	2017	8,410			98%	10,937	100%					819,518	0.051	0.060	228	267	940,032	9.0E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air Selective Catalytic Reduction
								Average HR =	10,768	832,200	0.051	0.060	228	267										
WY	Wygen III	56596	1	2014	8,390		116	91%	10,130						928,015	0.043	0.054	187	254	985,958	9.4E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
WY	Wygen III	56596	1	2015	7,936			85%	10,043						862,698	0.046	0.049	173	214	908,725	8.7E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
WY	Wygen III	56596	1	2016	8,161			89%	10,208						903,794	0.041	0.050	176	232	967,612	9.2E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
WY	Wygen III	56596	1	2017	7,903			84%	10,489	90%					852,169	0.043	0.063	179	280	937,422	8.9E+06	Black Hills Power, Inc	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only) Selective Catalytic Reduction
								Average HR =	10,218	1,016,160	0.043	0.063	224	326										
WY	Wyodak	6101	BW91	2014	8,549		402	82%	11,072						2,898,126	0.196	0.148	3,168	2,374	3,365,339	3.2E+07	Pacificorp Energy Generation	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
WY	Wyodak	6101	BW91	2015	8,229			82%	11,251						2,886,987	0.220	0.155	3,599	2,525	3,406,657	3.2E+07	Pacificorp Energy Generation	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
WY	Wyodak	6101	BW91	2016	6,804			66%	11,063						2,316,865	0.223	0.153	2,901	1,967	2,688,266	2.6E+07	Pacificorp Energy Generation	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
WY	Wyodak	6101	BW91	2017	8,350			82%	11,108	85%	2017	2017			2,901,325	0.226	0.152	3,661	2,450	3,380,149	3.2E+07	Pacificorp Energy Generation	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air
								Average HR =	11,124	2,995,526	0.226	0.152	3,760	2,533										

TEXAS UNITS

State	Facility Name	Facility ID (ORISPL)	Unit ID	Associated Stacks	Year	Program(s)	Operating Time	Gross Load (MW-h)	SO2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	CO2 (short tons)	Heat Input (MMBtu)	SO2 Control(s)	NOx Control(s)
TX	Big Brown	3497	1		2016	ARP	7157.1	3425424	21532.3	0.1261	2276.778	3777236	3.47E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	1		2017	ARP	8411.19	4255859	24138.15	0.1342	2845.022	4604829	4.23E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	1		2018	ARP	946.89	452952.7	3401.109	0.1725	378.81	489103.3	4492536		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	2		2016	ARP	7246.57	3325597	20937.62	0.1288	2243.173	3720802	3.42E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	2		2017	ARP	8313.61	4115184	23494.3	0.1477	2953.39	4496091	4.13E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	2		2018	ARP	1003.95	427081.6	3257.931	0.1948	394.28	470783.5	4324247		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Coleto Creek	6178	1		2018	ARP	5639.27	2887759	9198.481	0.1291	1917.508	3081848	2.94E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Coleto Creek	6178	1		2017	ARP	7577.44	4092253	12201.28	0.1275	2636.788	4325803	4.12E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Coleto Creek	6178	1		2016	ARP	5674.3	3295551	8231.219	0.1246	2049.047	3418103	3.26E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Gibbons Creek Steam Ele	6136	1		2016	ARP	6986.02	1779195	198.221	0.1143	1141.899	2024555	1.98E+07	Wet Lime	Low NOx Burner Technology w/ Closed-coupled OFA
TX	Gibbons Creek Steam Ele	6136	1		2017	ARP	6127.35	1698489	334.962	0.1073	1017.21	1905128	1.86E+07	Wet Lime	Low NOx Burner Technology w/ Closed-coupled OFA
TX	Gibbons Creek Steam Ele	6136	1		2018	ARP	2705.3	836985.4	270.858	0.1059	523.034	974388.6	9527039	Wet Lime	Low NOx Burner Technology w/ Closed-coupled OFA
TX	Harrington Station	6193	061B		2016	ARP	6780.26	1609193	3795.67	0.1448	1144.133	1621089	1.55E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Harrington Station	6193	061B		2017	ARP	5932.51	1417533	3513.534	0.1315	942.025	1434718	1.37E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Harrington Station	6193	061B		2018	ARP	6139.85	1510142	3616.701	0.176	1279.917	1499055	1.43E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Harrington Station	6193	062B		2018	ARP	8383.27	2120564	5226.341	0.1393	1518.954	2228592	2.13E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193	062B		2016	ARP	7683.75	1898746	5072.905	0.1442	1422.813	2049314	1.96E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193	062B		2017	ARP	7330.73	1792088	4763.524	0.1465	1335.093	1886623	1.80E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193	063B		2017	ARP	7089.41	1784596	4604.464	0.1411	1275.586	1830958	1.75E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193	063B		2018	ARP	5925.46	1523601	3569.268	0.1413	1180.925	1628743	1.56E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193	063B		2016	ARP	7770.44	1942860	5385.632	0.1365	1460.102	2176182	2.08E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	J K Spruce	7097	**1		2016	ARP	6977.5	2500758	466.784	0.1652	2023.975	2776093	2.71E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J K Spruce	7097	**1		2017	ARP	6909.23	2553061	592.237	0.1443	1920.653	2820587	2.75E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J K Spruce	7097	**1		2018	ARP	7934.88	3216193	823.731	0.1513	2446.174	3501951	3.41E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J K Spruce	7097	**2		2017	ARP	6677.28	3760387	147.514	0.049	892.204	3726494	3.63E+07	Wet Limes	Selective Catalytic Reduction
TX	J K Spruce	7097	**2		2018	ARP	6915.11	4400356	180.809	0.047	995.222	4370672	4.26E+07	Wet Limes	Selective Catalytic Reduction
TX	J K Spruce	7097	**2		2016	ARP	5550.25	3248413	150.835	0.0496	795.412	3293951	3.21E+07	Wet Limes	Selective Catalytic Reduction
TX	J T Deely	6181	1	CS012	2018	ARP	8078.21	2587997	8151.335	0.1079	1633.815	3155511	3.08E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	1	CS012	2017	ARP	8134.71	2051161	6103.036	0.0969	1151.921	2490794	2.43E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	1	CS012	2016	ARP	4956.75	1224239	3569.4	0.0956	643.051	1420950	1.38E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	2	CS012	2016	ARP	5875	1381507	4055.642	0.0824	637.91	1616897	1.58E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	2	CS012	2017	ARP	7360.53	1758818	5253.288	0.0849	869.499	2161662	2.11E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	2	CS012	2018	ARP	8134.87	2297785	7211.916	0.1011	1369.947	2801356	2.73E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Limestone	298	LIM1		2016	ARP	7947.3	5026723	9772.637	0.198	4350.823	4886364	4.49E+07	Wet Limes	Overfire Air
TX	Limestone	298	LIM1		2017	ARP	7306.25	4482068	4336.75	0.1662	3579.626	4707121	4.33E+07	Wet Limes	Overfire Air
TX	Limestone	298	LIM1		2018	ARP	8209.4	5117320	4156.105	0.155	3963.119	5445148	5.19E+07	Wet Limes	Overfire Air
TX	Limestone	298	LIM2		2016	ARP	7082.01	4819352	11028.43	0.1942	4446.411	4860396	4.47E+07	Wet Limes	Overfire Air
TX	Limestone	298	LIM2		2017	ARP	7667.08	5389276	5903.464	0.186	4904.547	5883471	5.40E+07	Wet Limes	Overfire Air
TX	Limestone	298	LIM2		2018	ARP	7311.39	5124353	4163.783	0.17	4167.339	5163189	4.92E+07	Wet Limes	Overfire Air
TX	Martin Lake	6146	1		2016	ARP	8447.14	5159856	11515.4	0.1571	4074.554	5608518	5.15E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	1		2017	ARP	8321.8	4634237	12559.84	0.1543	3594.205	5249546	4.82E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	1		2018	ARP	8323.94	5193391	19282.03	0.1465	3751.522	5731222	5.26E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	2		2017	ARP	8262.09	4423403	9570.985	0.1628	3492.514	4895122	4.50E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	2		2016	ARP	5326.94	3259332	5265.967	0.1526	2512.265	3606971	3.31E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	2		2018	ARP	7352.77	4543501	17166.8	0.1637	3457.159	4801149	4.41E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	3		2016	ARP	6568.09	3852017	8689.858	0.1562	2918.882	4136191	3.80E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	3		2018	ARP	8412.83	5474969	19749.35	0.1494	3787.965	5735272	5.27E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	3		2017	ARP	8104.58	4683143	14310.59	0.1548	3504.56	5102241	4.69E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Monticello	6147	1		2017	ARP	6885.02	2696357	11432.98	0.1464	2136.678	3112154	2.97E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Monticello	6147	1		2016	ARP	5260.16	2056582	8834.572	0.1398	1537.138	2426490	2.31E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Monticello	6147	2		2017	ARP	7830.71	3034838	12808.01	0.1557	2523.346	3486034	3.32E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Monticello	6147	2		2016	ARP	5248.09	2053748	8716.265	0.1385	1526.05	2345309	2.24E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Oak Grove	6180	1		2018	ARP	8314.99	7192075	4453.418	0.0735	2452.762	7477355	6.87E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
TX	Oak Grove	6180	1		2017	ARP	8450.26	7343191	4442.479	0.0717	2511.704	7612561	6.99E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
TX	Oak Grove	6180	1		2016	ARP	7387.85	6212457	3333.947	0.0745	2166.382	6658215	6.12E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
TX	Sam Seymour	6179	1		2017	ARP	8647.74	4536347	386.54	0.1124	2464.727	4877370	4.65E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	1		2018	ARP	8498.54	4479534	532.194	0.1301	2723.788	4572604	4.36E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	1		2016	ARP	7154.93	3396258	498.297	0.1092	1742.636	3607878	3.44E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	2		2017	ARP	8139.77	4403340	487.053	0.1207	2599.233	4621246	4.41E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	2		2018	ARP	7066.86	3775179	538.316	0.1254	2552.725	4288692	4.09E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	2		2016	ARP	8469.25	4255504	378.503	0.1157	2512.531	4731047	4.51E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	3		2017	ARP	8349.45	3263070	266.016	0.123	2054.243	3507916	3.34E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	3		2018	ARP	6942.01	2759367	273.44	0.1304	1857.546	3062037	2.92E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA

TEXAS UNITS

State	Facility Name	Facility ID (ORISPL)	Unit ID	Associated Stacks	Year	Program(s)	Operating Time	Gross Load (MW-h)	SO2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	CO2 (short tons)	Heat Input (MMBtu)	SO2 Control(s)	NOx Control(s)
TX	Sam Seymour	6179	3		2016	ARP	8268.82	3218149	230.992	0.1085	1876.775	3686370	3.51E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sandow	6648	4		2018	ARP	239.63	122035.8	487.424	0.0623	36.249	141589.8	1300541	Wet Limes	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
TX	Sandow	6648	4		2016	ARP	7887.82	4383004	12105.28	0.0671	1465.451	4686781	4.30E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
TX	Sandow	6648	4		2017	ARP	8063.83	4464335	17446.08	0.067	1465.917	4835292	4.44E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
TX	Tolk Station	6194	171B		2017	ARP	7587.46	2796027	6719.003	0.1237	1621.245	2652459	2.53E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Tolk Station	6194	171B		2018	ARP	7098.49	2208999	5513.121	0.1307	1386.387	2092475	2.00E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Tolk Station	6194	171B		2016	ARP	7811.06	2928015	7080.891	0.1333	1863.827	2819218	2.69E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Tolk Station	6194	172B		2017	ARP	7048.55	2657682	6907.293	0.1284	1726.475	2742397	2.62E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Tolk Station	6194	172B		2016	ARP	8148	3093955	7896.061	0.1378	2137.017	3166776	3.02E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Tolk Station	6194	172B		2018	ARP	5740.21	1818179	4446.412	0.1307	1210.072	1893840	1.81E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	W A Parish	3470	WAP7		2016	ARP	6525.49	2986930	9184.24	0.0449	603.91	2948540	2.82E+07		Selective Catalytic Reduction
TX	W A Parish	3470	WAP7		2017	ARP	7997.36	3848578	10357.6	0.0473	733.313	3523198	3.39E+07		Selective Catalytic Reduction
TX	W A Parish	3470	WAP7		2018	ARP	8246.2	4032458	10958.69	0.0487	756.118	3563273	3.41E+07		Selective Catalytic Reduction
TX	W A Parish	3470	WAP8	MS1, MS2	2016	ARP	7731.38	3792115	3111.952	0.045	855.694	4011512	3.81E+07	Sodium Ba	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection
TX	W A Parish	3470	WAP8	MS1, MS2	2017	ARP	8224.36	4297991	1929.215	0.056	1212.789	3459991	4.42E+07	Sodium Ba	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection
TX	W A Parish	3470	WAP8	MS1, MS2	2018	ARP	5039.92	2666222	1084.505	0.0489	661.656	2126266	2.81E+07	Sodium Ba	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection
TX	Big Brown	3497	1		2014	ARP	6822.27	3464103	25814.82	0.1297	2261.964	3750264	3.44E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	1		2015	ARP	8282.47	4161876	25378.96	0.1227	2625.154	4532298	4.16E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	2		2014	ARP	8225.84	4303676	31645.55	0.1316	2810.237	4598807	4.22E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Big Brown	3497	2		2015	ARP	8012.11	4002944	24458.47	0.1317	2695.691	4399654	4.04E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Coleto Creek	6178	1		2015	ARP	6370.13	3395649	8261.084	0.1229	2006.601	3430431	3.27E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Coleto Creek	6178	1		2014	ARP	8425.95	5423755	16942.22	0.1303	3271.538	5253412	5.01E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Gibbons Creek Steam Ele	6136	1		2015	ARP	8539.15	2331127	154.101	0.1129	1656.914	2929325	2.87E+07	Wet Lime	Low NOx Burner Technology w/ Closed-coupled OFA
TX	Gibbons Creek Steam Ele	6136	1		2014	ARP	7322.85	2941482	709.097	0.14	2044.178	2981204	2.91E+07	Wet Lime	Low NOx Burner Technology w/ Closed-coupled OFA
TX	Harrington Station	6193	061B		2014	ARP	8376.78	2342344	5752.961	0.1367	1610.707	2444079	2.33E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Harrington Station	6193	061B		2015	ARP	8202.21	2186567	5062.15	0.1434	1524.926	2199407	2.10E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Harrington Station	6193	062B		2015	ARP	8300.25	2169163	5161.291	0.1468	1610.419	2266125	2.16E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193	062B		2014	ARP	5985.4	1584793	4006.845	0.1451	1254.199	1727225	1.65E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193	063B		2015	ARP	6781.95	1854813	4915.292	0.1458	1461.722	2053247	1.96E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	Harrington Station	6193	063B		2014	ARP	8239.33	2229901	5708.216	0.1418	1715.56	2493491	2.38E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA Overfire Air
TX	J K Spruce	7097	**1		2014	ARP	8253	4332217	1012.108	0.1319	3021.622	4637622	4.52E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J K Spruce	7097	**1		2015	ARP	6490	2065322	397.185	0.167	1723.396	2325474	2.27E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J K Spruce	7097	**2		2014	ARP	6974.5	5406238	226.022	0.0477	1228.469	5300513	5.17E+07	Wet Limes	Selective Catalytic Reduction
TX	J K Spruce	7097	**2		2015	ARP	5842.75	2706186	84.396	0.0455	633.337	2843837	2.77E+07	Wet Limes	Selective Catalytic Reduction
TX	J T Deely	6181	1	CS012	2015	ARP	7311.25	1750091	5004.704	0.0933	905.009	2000304	1.95E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	1	CS012	2014	ARP	7544.25	2753895	7452.355	0.0747	1117.212	3036057	2.96E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	2	CS012	2014	ARP	8517.25	3139299	8441.147	0.0667	1112.756	3468363	3.38E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	J T Deely	6181	2	CS012	2015	ARP	6775	1595442	4688.803	0.0786	716.957	1880691	1.83E+07		Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Limestone	298	LIM1		2014	ARP	8185.2	6613040	14266	0.2075	6309.699	6573231	6.04E+07	Wet Limes	Overfire Air
TX	Limestone	298	LIM1		2015	ARP	6769.27	4375943	6832.679	0.1919	3898.046	4409396	4.05E+07	Wet Limes	Overfire Air
TX	Limestone	298	LIM2		2014	ARP	7387.53	6157131	13596.4	0.2076	5881.387	6125639	5.63E+07	Wet Limes	Overfire Air
TX	Limestone	298	LIM2		2015	ARP	7573.88	5454754	10385.59	0.1926	4908.483	5459967	5.02E+07	Wet Limes	Overfire Air
TX	Martin Lake	6146	1		2014	ARP	7798.26	5340338	20382.95	0.1619	4403.397	6002495	5.51E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	1		2015	ARP	7306.37	4276999	9494.243	0.1755	3786.724	4916687	4.52E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	2		2014	ARP	8263.75	5761233	19820.06	0.1619	4549.724	6199998	5.69E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	2		2015	ARP	6261.01	3707000	6959.776	0.1675	3160.556	4230206	3.89E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	3		2015	ARP	5199.21	2967721	6474.298	0.184	2702.443	3311871	3.04E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Martin Lake	6146	3		2014	ARP	5382.26	3673880	13452.57	0.1554	2799.617	4035035	3.71E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA
TX	Monticello	6147	1		2014	ARP	3452.91	1583426	6833.144	0.1268	1047.774	1804030	1.66E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Monticello	6147	1		2015	ARP	3896.69	1544949	7963.367	0.1353	1116.535	1831410	1.68E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Monticello	6147	2		2015	ARP	3098.67	1263864	6719.284	0.1347	891.547	1459200	1.34E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Monticello	6147	2		2014	ARP	3182.87	1483449	6379.853	0.1199	925.675	1703946	1.57E+07		Low NOx Burner Technology w/ Separated OFA Selective Non-catalytic Reduction
TX	Oak Grove	6180	1		2014	ARP	8248.82	7130788	3861.24	0.0714	2449.216	7329006	6.73E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
TX	Oak Grove	6180	1		2015	ARP	8011.06	6768075	2552.679	0.071	2345.943	7120485	6.54E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Ammonia Injection Selective Catalytic Reduction
TX	Sam Seymour	6179	1		2014	ARP	7130.36	3314176	237.441	0.1102	1729.419	3410696	3.25E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	1		2015	ARP	8449.88	3789126	384.431	0.1082	2008.698	4081177	3.89E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	2		2014	ARP	8199.95	3893772	392.799	0.1042	2185.561	4427802	4.22E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	2		2015	ARP	6626.84	3138641	361.804	0.1061	1775.79	3576990	3.41E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	3		2014	ARP	8284.67	2773250	173.207	0.0943	1351.49	3018623	2.88E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sam Seymour	6179	3		2015	ARP	6703.11	2426197	196.082	0.1026	1265.659	2554313	2.44E+07	Wet Limes	Low NOx Burner Technology w/ Closed-coupled/Separated OFA
TX	Sandow	6648	4		2014	ARP	7957.99	4792750	21937.65	0.0642	1466.006	5136676	4.72E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
TX	Sandow	6648	4		2015	ARP	8184.46	4516400	20924.96	0.0639	1426.61	4886940	4.49E+07	Wet Limes	Low NOx Burner Technology w/ Separated OFA Selective Catalytic Reduction
TX	Tolk Station	6194	171B		2015	ARP	6896.5	2997365	6497.793	0.1461	1989.777	2854734	2.72E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air

TEXAS UNITS

State	Facility Name	Facility ID (ORISPL)	Unit ID	Associated Stacks	Year	Program(s)	Operating Time	Gross Load (MW-h)	SO2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	CO2 (short tons)	Heat Input (MMBtu)	SO2 Control(s)	NOx Control(s)
TX	Tolk Station	6194	171B		2014	ARP	8425.14	4079809	9282.835	0.1355	2497.566	3847506	3.67E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	Tolk Station	6194	172B		2014	ARP	6390.45	2993206	7475.673	0.1441	2130.368	3029339	2.89E+07		Low NOx Burner Technology w/ Separated OFA (Began Apr 05, 2014) Overfire Air
TX	Tolk Station	6194	172B		2015	ARP	8468.35	3859455	9584.632	0.1464	2823.599	4041125	3.85E+07		Low NOx Burner Technology w/ Separated OFA Overfire Air
TX	W A Parish	3470	WAP7		2015	ARP	6823.83	3479366	11277.09	0.0417	667.875	3353369	3.20E+07		Selective Catalytic Reduction
TX	W A Parish	3470	WAP7		2014	ARP	8182.73	4143520	13606.02	0.0487	940.868	4066295	3.88E+07		Selective Catalytic Reduction
TX	W A Parish	3470	WAP8		2015	ARP	7602.69	4046576	2381.104	0.0472	887.787	3971103	3.79E+07	Wet Lime	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection
TX	W A Parish	3470	WAP8		2014	ARP	8313.04	4481612	2886.438	0.0473	1031.518	4625523	4.41E+07	Wet Lime	Low NOx Burner Technology w/ Closed-coupled/Separated OFA Selective Catalytic Reduction Ammonia Injection

Appendix G. EPA Cost Manual Cost Estimate Sheets

SCR

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Coal

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	563.42 MW
What is the higher heating value (HHV) of the fuel?	6,612 Btu/lb
What is the estimated actual annual MWhs output?	4,293,936 MWhs
Enter the net plant heat input rate (NPHR)	10.416 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 1980 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Lignite

Enter the sulfur content (%S) = 0.61 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

○ Method 1
● Method 2
○ Not applicable

SCR

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	318	days
Number of days the boiler operates (t_{plant})	318	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.13	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.04	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	3,202,636	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Gas temperature at the SCR inlet (T)	830	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	547	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	100	percent
Density of reagent as stored (ρ_{stored})	38.55	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	30	days

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia ▼

Enter the cost data for the proposed SCR:

Desired dollar-year	2018			
CEPCI for 2018	615.3	Enter the CEPCI value for 2018	541.7	2016 CEPCI
Annual Interest Rate (i)	5.25	Percent		
Reagent ($Cost_{reag}$)	1.560	$/gallon for 100% ammonia		
Electricity ($Cost_{elect}$)	0.0329	$/kWh		
Catalyst cost ($CC_{replace}$)	118.20	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		
Operator Labor Rate	71.81	$/hour (including benefits)		
Operator Hours/Day	4.00	hours/day*		

CEPCI = Chemical Engineering Plant Cost Index

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	5,869	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	4,935,559	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		4,293,936	MWhs
Heat Rate Factor (HRF) =	NPHR/10 =	1.04	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.870	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7621	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	69.2	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	528.17	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	2,012.65	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.87	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	3,202,636	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	135.19	/hour
Residence Time	1/V_{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.07	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.7	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3164	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	23,689.22	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	3,336	ft^2

Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	3,836	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	61.9	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	50	feet

SCR

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	38.55 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	205	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	205	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	40	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	28,700	gallons (storage needed to store a 30 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0669

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	3305.73	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$137,775,430	in 2018 dollars
Reagent Preparation Cost (RPC) =	$3,071,151	in 2018 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2018 dollars
Balance of Plant Costs (BPC) =	$9,657,516	in 2018 dollars
Total Capital Investment (TCI) =	$195,655,325	in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) = $137,775,430 in 2018 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564,000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564,000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) = $3,071,151 in 2018 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69,000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) = $0 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529,000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529,000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) = $9,657,516 in 2018 dollars

SCR

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$3,313,274	in 2018 dollars
Indirect Annual Costs (IDAC) =	$13,103,821	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$16,417,095	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$978,277	in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$473,567	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$828,869	in 2018 dollars
Annual Catalyst Replacement Cost =		$1,032,561	in 2018 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2 selected.	
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$3,313,274	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$14,480	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$13,089,341	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$13,103,821	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$16,417,095	per year in 2018 dollars
NOx Removed =	2,013	tons/year
Cost Effectiveness =	$8,157	per ton of NOx removed in 2018 dollars

SNCR

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility ▼

What type of fuel does the unit burn? Coal ▼

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit ▼

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 563.42 MW

What is the higher heating value (HHV) of the fuel? 6,612 Btu/lb

What is the estimated actual annual MWh output? 4,293,936 MWh

Is the boiler a fluid-bed boiler? No ▼

Enter the net plant heat input rate (NPHR) 10.416 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Lignite ▼

Enter the sulfur content (%S) = 0.61 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable ▼

Ash content (%Ash): 12.89 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

SNCR

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.13	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.1105	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	3.33	

Plant Elevation	1980	Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	50	percent
Number of days reagent is stored ($t_{storage}$)	30	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Urea ▼

Enter the cost data for the proposed SNCR:

Desired dollar-year	2018			
CEPCI for 2018	615.3	Enter the CEPCI value for 2018	541.7	2016 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)	5.25	Percent
Fuel ($Cost_{fuel}$)	1.85	\$/MMBtu*
Reagent ($Cost_{reag}$)	1.35	\$/gallon for a 50 percent solution of urea
Water ($Cost_{water}$)	0.0037	\$/gallon
Electricity ($Cost_{elect}$)	0.0329	\$/kWh
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	10.50	\$/ton

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	5,869	MMBtu/hour
Maximum Annual MWh Output =	Bmw x 8760 =	4,935,559	MWh
Estimated Actual Annual MWh Output (Boutput) =		4,293,936	MWh
Heat Rate Factor (HRF) =	NPHR/10 =	1.04	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.87	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	7621	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	15	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	114.44	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	436.08	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.07	
Atmospheric pressure at 1980 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.7	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

SNCR

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	1658	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	3,316	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	349.4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	251,600	gallons (storage needed to store a 30 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0820

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	114.6	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	1.49	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	29.1	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$4,177,101 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$5,191,356 in 2018 dollars
Total Capital Investment (TCI) =	$12,178,995 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$4,177,101 in 2018 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$5,191,356 in 2018 dollars

SNCR

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$3,828,504	in 2018 dollars
Indirect Annual Costs (IDAC) =	$1,004,158	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$4,832,662	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$182,685	in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$3,594,871	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$28,743	in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$21,041	in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$1,164	in 2018 dollars
Direct Annual Cost =		$3,828,504	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$5,481	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$998,678	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,004,158	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$4,832,662	per year in 2018 dollars
NOx Removed =	436	tons/year
Cost Effectiveness =	$11,082	per ton of NOx removed in 2018 dollars

SNCR w/MNL

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility ▼

What type of fuel does the unit burn? Coal ▼

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit ▼

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 563.42 MW

What is the higher heating value (HHV) of the fuel? 6,612 Btu/lb

What is the estimated actual annual MWh output? 4,293,936 MWh

Is the boiler a fluid-bed boiler? No ▼

Enter the net plant heat input rate (NPHR) 10.416 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Lignite ▼

Enter the sulfur content (%S) = 0.61 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable ▼

Ash content (%Ash): 12.89 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

SNCR w/MNL

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.13	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.1001	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	3.33	

Plant Elevation	1980	Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	50	percent
Number of days reagent is stored ($t_{storage}$)	30	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Urea

Enter the cost data for the proposed SNCR:

Desired dollar-year	2018			
CEPCI for 2018	615.3	Enter the CEPCI value for 2018	541.7	2016 CEPCI
Annual Interest Rate (i)	5.25	Percent		
Fuel ($Cost_{fuel}$)	1.85	\$/MMBtu*		
Reagent ($Cost_{reag}$)	1.35	\$/gallon for a 50 percent solution of urea		
Water ($Cost_{water}$)	0.0037	\$/gallon		
Electricity ($Cost_{elect}$)	0.0329	\$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	10.50	\$/ton		

CEPCI = Chemical Engineering Plant Cost Index

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	5,869	MMBtu/hour
Maximum Annual MWh Output =	Bmw x 8760 =	4,935,559	MWh
Estimated Actual Annual MWh Output (Boutput) =		4,293,936	MWh
Heat Rate Factor (HRF) =	NPHR/10 =	1.04	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.87	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	7621	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	23	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	175.47	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	668.65	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.07	
Atmospheric pressure at 1980 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.7	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

SNCR w/MNL

Reagent Data:

Type of reagent used Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole
Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	1658	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	3,316	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	349.4	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	251,600	gallons (storage needed to store a 30 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0820

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	114.6	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	1.49	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	29.1	lb/hour

SNCR w/MNL

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$4,177,101 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$5,464,586 in 2018 dollars
Total Capital Investment (TCI) =	$12,534,193 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$4,177,101 in 2018 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$5,464,586 in 2018 dollars

SNCR w/MNL

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$3,833,832 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$1,033,444 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$4,867,276 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	\$188,013 in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	\$3,594,871 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	\$28,743 in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	\$0 in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	\$21,041 in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	\$1,164 in 2018 dollars
Direct Annual Cost =		\$3,833,832 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$5,640 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$1,027,804 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$1,033,444 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$4,867,276 per year in 2018 dollars
NOx Removed =	669 tons/year
Cost Effectiveness =	\$7,279 per ton of NOx removed in 2018 dollars

Appendix H. Alstom Power MATS Tuning Report

Great River Energy

Coal Creek Station

Unit’s #1 and #2

MATS Tuning

EXECUTIVE SUMMARY REPORT

June 2015

ALSTOM

EXECUTIVE SUMMARY

Alstom Power Technical Services was on site beginning the week of 6/8/2015 to conduct a series of emissions tests under the MATS ruling. The testing/tuning consisted of monitoring flue gas emission for O_2, NOx and CO while the units were operated at full load conditions. Data was collected before, during and after all matrix parameter adjustments.

Coal Creek Units #1 and #2 are Alstom Power designed CCRRD steam generators (Controlled Circulation Radiant Reheat Divided Furnace). The MCR (Maximum Continuous Rating) of each unit is 3,730 Klbs/hr. steam flow. The unit's burn North Dakota lignite through eight (8) elevations of pulverized coal, supplied by Alstom designed 1043 RP mills. Design operating pressure is 2,620 psi.

Alstom Power Testing Services had installed a twelve (12) point sampling test grid across the furnace backpass, just after the economizer outlet for each unit tested. Vacuum pumps pulled a continuous flue gas sample through our analyzer system and this gas sample was monitored for O_2, (% dry) CO (ppm) and NOx (#/MMBtu).

Alstom followed a test matrix to affect either a positive or negative response to manipulated parameters. This test matrix included the following parameters that were adjusted with controller biases:

- WB/F ΔP
- O_2
- Burner tilts
- SOFA tilts
- SOFA dampers

ALSTOM

UNIT #2

The following data was monitored and recorded at the beginning of each parameter adjustment. The first set of data is recorded as “base load” at the start of tuning on 6/10/2015. Unit #2 was tested first.

<u>Plant Data</u>

Load	606 MW	
Throttle Press.	2520 psi	
SHO (L/R)	994/989° F	
RHO (L/R)	987/997° F	
Mills in Service	6	
Tilts (L/R)	9/19 degrees up	
O_2 Plant	2.75 %	
WB/F ΔP	5.3”	
NOx	.152 #/MMBtu	(plant CEMS)

Alstom Test Grid

O_2	3.2 %
CO	8.5 ppm
NOx	.148 #/MMBtu

Alstom began making adjustments to the WB/F ΔP controller bias. The as found output of 5.3” was incrementally increased up to 6.2” by removing the negative bias of .9” that had been installed earlier by GRE. These small step adjustments brought the NOx down to:

CEMS	.139 #/MMBtu
Alstom	.141 #/MMBtu

The following spreadsheet shows flue gas analysis of all 12 Alstom grid intersects on our point-to-point sampling. The sheet indicates the grid depth and length across the economizer outlet ducts, both Left and Right.

Great River Energy
Coal Creek #1
Economizer Outlet

ALSTOM POWER, INC.
PERFORMANCE SERVICES
WINDSOR, CONNECTICUT

TEST DATA AND RESULTS

FLUE GAS ANALYSIS - POINT BY POINT GRID DATA

Economizer Outlet Left Duct

TEST NUMBER: 1
DATE: 6/15/15
START TIME: 0857
STOP TIME: 0935
LOAD:

F FACTOR: 9860

		TEST PORT 1	TEST PORT 2	TEST PORT 3	TEST PORT 4
S =19"	O2, %	3.7	3.1	3.2	3.1
	CO, PPM	0	0	7	0
	NOX, PPM	138	154	152	152
	CO,corr 3% O2, PPM	0	0	7	0
	NOX, corr 3% O2, PPM	144	155	154	153
	NOX, Lb/Mbtu	0.197	0.213	0.211	0.210
M =57"	O2, %	2.0	2.2	2.6	2.5
	CO, PPM	20	10	7	6
	NOX, PPM	147	157	154	153
	CO,corr 3% O2, PPM	19	10	7	6
	NOX, corr 3% O2, PPM	139	150	151	149
	NOX, Lb/Mbtu	0.191	0.207	0.207	0.205
L =95"	O2, %	2.6	2.4	2.7	2.4
	CO, PPM	5	0	0	0
	NOX, PPM	136	148	146	145
	CO,corr 3% O2, PPM	5	0	0	0
	NOX, corr 3% O2, PPM	133	143	144	140
	NOX, Lb/Mbtu	0.183	0.197	0.197	0.193

Left

Right

DEPTH = 115"

129"

195"

321"

389"

WIDTH = 546"

Grid Avg. O2, % = 2.7

Grid Avg. CO, PPM = 9

Grid Avg. NOX, PPM = 149

Grid Avg. CO corr 3% O2, PPM = 9

d Avg. NOX corr 3% O2, PPM = 146

Grid Avg. NOX, LB/MBtu = 0.201

Great River Energy
Coal Creek #2
Economizer Outlet

ALSTOM POWER, INC.
PERFORMANCE SERVICES
WINDSOR, CONNECTICUT

TEST DATA AND RESULTS
FLUE GAS ANALYSIS - POINT BY POINT GRID DATA

Economizer Outlet Left Duct

TEST NUMBER: 1
DATE: 6/10/15
START TIME: 0740
STOP TIME: 0835
LOAD:

F FACTOR: 9860

		TEST PORT 1	TEST PORT 2	TEST PORT 3	TEST PORT 4
S = 19"	O2, %	2.8	2.7	2.6	2.9
	CO, PPM	0	5	5	0
	NOX, PPM	98	104	113	125
	CO,corr 3% O2, PPM	0	5	5	0
	NOX, corr 3% O2, PPM	97	102	111	124
	NOX, Lb/Mbtu	0.133	0.141	0.152	0.171
M = 57"	O2, %	2.1	2.1	2.3	2.3
	CO, PPM	32	0	0	0
	NOX, PPM	97	109	123	132
	CO,corr 3% O2, PPM	30	0	0	0
	NOX, corr 3% O2, PPM	92	104	118	127
	NOX, Lb/Mbtu	0.127	0.143	0.163	0.175
L = 95"	O2, %	2.8	3.1	2.2	3.1
	CO, PPM	0	0	0	0
	NOX, PPM	98	104	124	137
	CO,corr 3% O2, PPM	0	0	0	0
	NOX, corr 3% O2, PPM	97	105	119	138
	NOX, Lb/Mbtu	0.133	0.144	0.163	0.189

Left

Right

DEPTH = 115"

128"

244"

302"

418"

WIDTH = 546"

Grid Avg. O2, % = 2.6

Grid Avg. CO, PPM = 14

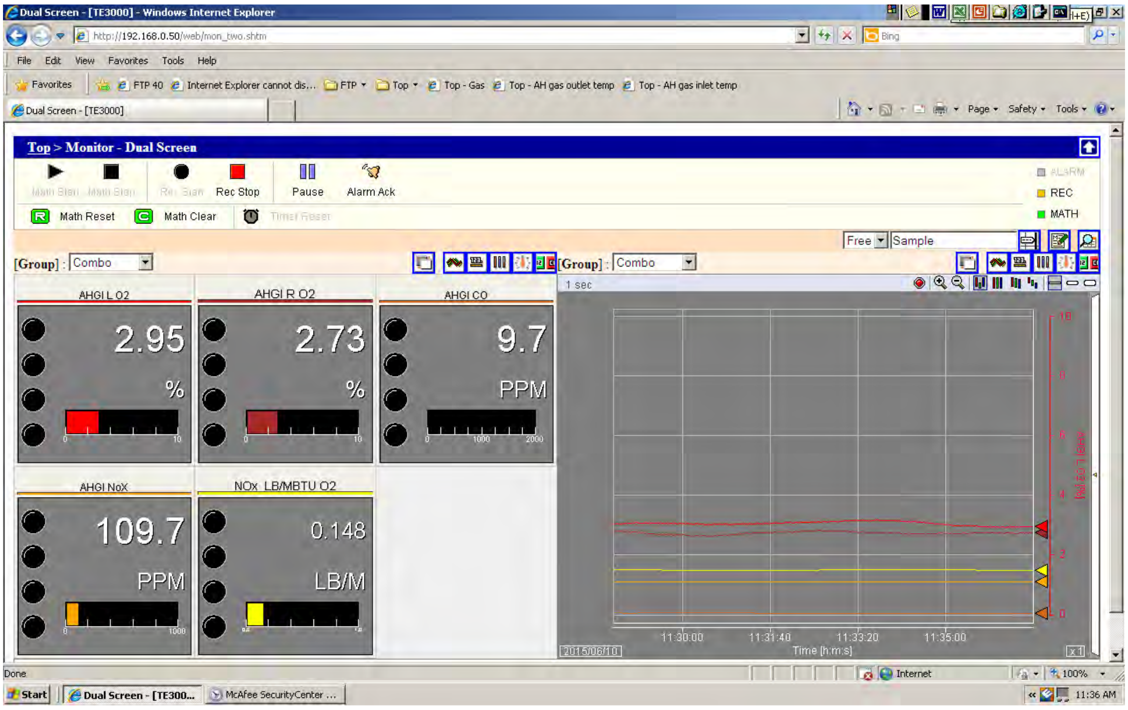
Grid Avg. NOX, PPM = 114

Grid Avg. CO corr 3% O2, PPM = 13

id Avg. NOX corr 3% O2, PPM = 111

Grid Avg. NOX, LB/MBtu = 0.153

ALSTOM



[Group] : Combo

AHGI L O2: 2.95 %

AHGI R O2: 2.73 %

AHGI CO: 9.7 PPM

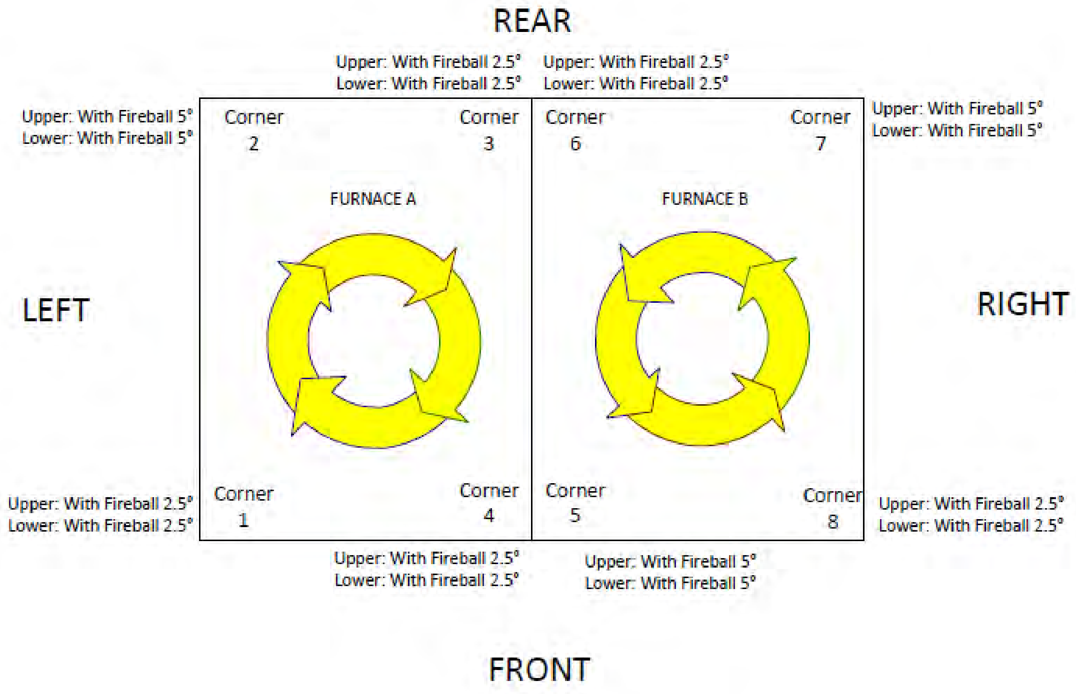
AHGI NoX: 109.7 PPM

NOx LB/MBTU O2: 0.148 LB/M

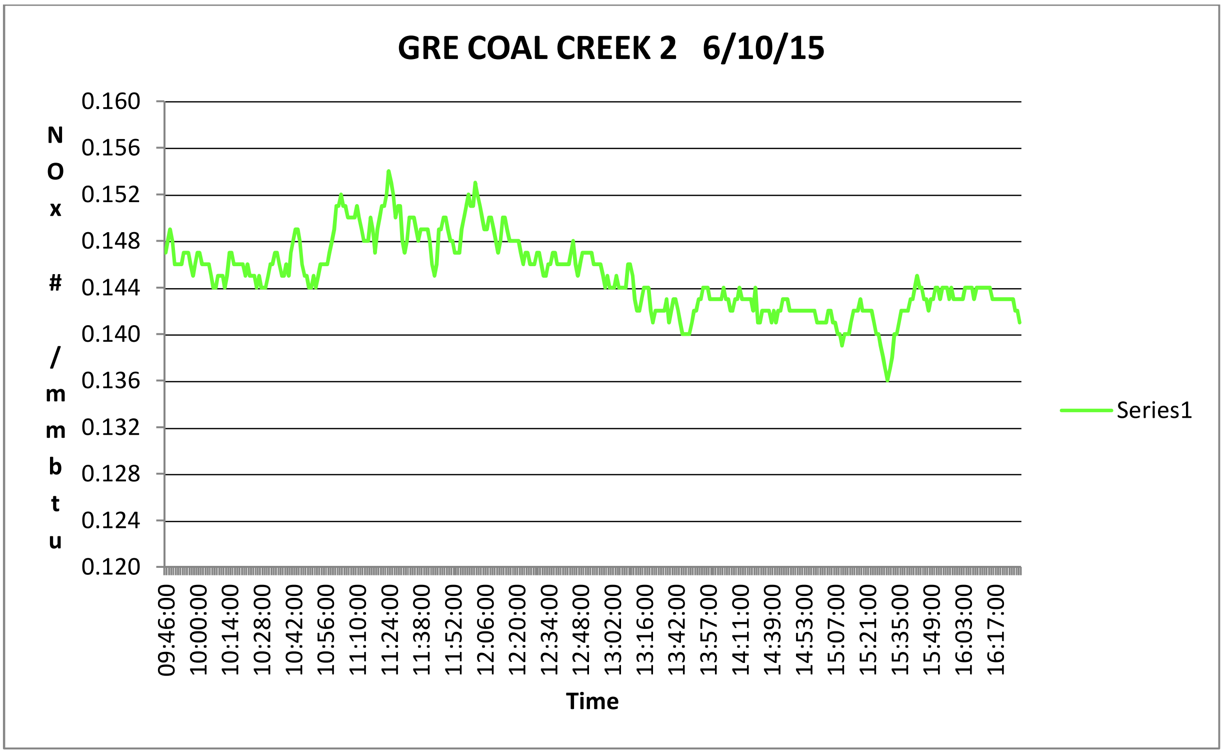
The above data shows sampling points across the economizer outlet duct on June 10th, after the unit reached a steady state of full load and prior to making a parameter adjustment. Note the low CO values and NOx ppm and #/MMBtu output.

From 6/10 through 6/12, Alstom manipulated O_2 , WB/F ΔP, Burner tilts, SOFA tilts and SOFA dampers. The O_2 adjustments were small (2.75% to 2.5% range) and did not affect the NOx output positively. WB/F ΔP adjustments accounted for the best positive effect in further reducing the already good NOx output. No amount of adjustments to the units SOFA yaw or dampers mechanisms made any positive NOx reduction. In fact, the SOFA system is so well tuned, that any all adjustments from in-place control, only made the NOx value increase.

GREAT RIVER ENERGY
COAL CREEK #2
SOFA YAW POSTIONS

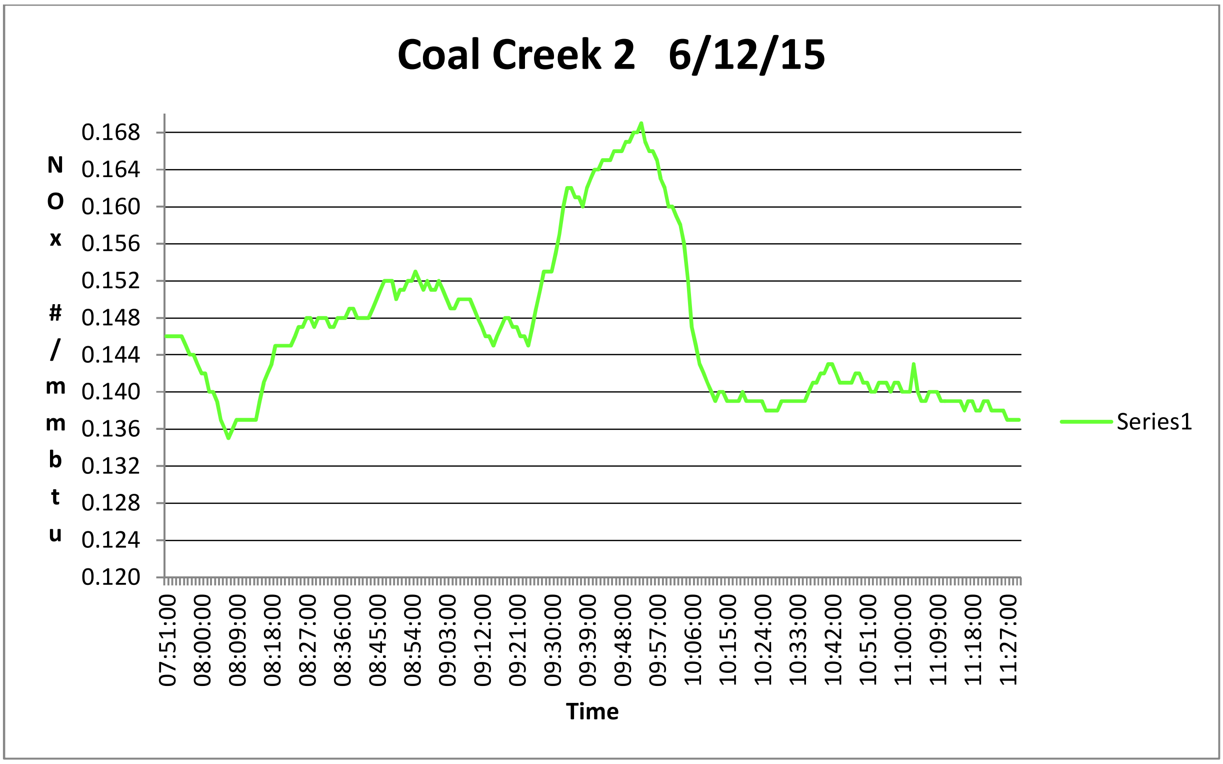


This diagram shows the optimum positioning of SOFA yaws on Unit #2, in a range of +15 to -15 degrees. These positions should not be modified. In addition, the SOFA damper control curves for the Upper and Lower SOFA compartments are working quite well and should not be modified.



The above graph shows NOx output reduction on Unit #2 after making adjustments to increase WB/F ΔP.

ALSTOM



NOx output after final parameter adjustments made to Unit #2. Ending average was .138 to .140 #/MMBtu.

Plant Data

Load	612MW
O2	2.6%
WB/FΔP	6.2”
SHO	992/985 degrees
RHO	1005/1004 degrees
CEMS	.140 #/MMBtu

Alstom Grid	.139 #/MMBtu NOx	5.1 ppm CO

ALSTOM

UNIT #1

Unit #1 was tested the week of 6/15, using the same equipment installed in the unit's economizer backpass and following the same matrix. Although this was only one week after testing was conducted on Unit #2, there were significant changes noted in operation of both units. While Unit #2 had recorded a relatively low NOx output (.139 #/MMBtu), Unit #1 was operating with a low NOx output as well. While in the Control Room, Alstom noted that Unit #1 NOx was at .181 to .183 #/MMBtu. This value is well below the permitted value of .226 #/MMBtu. However, during our week of testing on Unit #2, the NOx level had increased up to .218, with occasional spikes up to .226 #/MMBtu. We also noted that the NOx output on Unit #2 had increased as well, up to an average of .165, from our low tested point of .139 #/MMBtu average.

After discussions with GRE, we were informed that the fuel quality had changed, to the detriment of NOx increases on both units. The fuel quality change was enough that neither unit was able to achieve and maintain design SH and RH outlet temperatures. As a result, operators had raised the burner tilts to compensate for the loss of steam temperatures. Operating with burner tilts greater than 0^o (horizontal) will over-stage the Low NOx system (staging is the term associated with the total distance between the Top of the burner OFA compartments and the Bottom of the SOFA compartments).

Further discussions with GRE personnel revealed the fuel quality change was not related to a reduction of HHV (Btu content) so much, but rather a change in Sodium content. GRE stated that when burning North Dakota lignite with a Sodium content of 2.0% or less, slagging conditions within the furnace cavity is virtually non-existent. With no slag/ash build up on the units Water Walls, the heat absorption rate in the lower furnace (from Nose Arch to Lower Couton Slope) is at its maximum. This rate of heat absorption in the Water Wall circuits takes away heat that would typically be absorbed in the upper SH/RH and Back Pass areas.

As a result of this fuel change, both unit burner tilts were raised in an attempt to increase SH and RH steam outlet temperatures. Tilt positions on both units averaged from +14 / +22 degrees (Left and Right furnaces). As stated prior, raising burner tilts above the horizontal plane has a negative effect on NOx emissions.

[Group]: Combo

[Group]: DATA

AHGI L O2 2.77 %

AHGI R O2 3.01 %

AHGI CO 2.7 PPM

AHGI NoX 156.0 PPM

AHGI AVG O2 2.89 %

CO Corrected 3% 2.68 PPM

NOx Corrected3% 155.05 PPM

CO LB/M BTU O2 0.002 LB/M

NOx LB/MBTU O2 0.213 LB/M

Screen shot taken from Alstom grid On Unit #1 emissions on 6/15/2015. Note the NOx at .213 #/MMBtu. While still below its permitted level, this value is higher than the previous week with operating conditions being identical. The increased NOx output is directly related to burner tilts being elevated to obtain design SH and RH outlet steam temperatures.

The following spreadsheet shows flue gas analysis of all 12 Alstom grid intersects on our point-to-point sampling. The sheet indicates the grid depth and length across the economizer outlet ducts, both Left and Right.

Great River Energy
Coal Creek #1
Economizer Outlet

ALSTOM POWER, INC.
PERFORMANCE SERVICES
WINDSOR, CONNECTICUT

TEST DATA AND RESULTS
FLUE GAS ANALYSIS - POINT BY POINT GRID DATA

Economizer Outlet Left Duct

TEST NUMBER: 1
DATE: 6/15/15
START TIME: 0857
STOP TIME: 0935
LOAD:

F FACTOR: 9860

		TEST PORT 1	TEST PORT 2	TEST PORT 3	TEST PORT 4
S = 19"	O2, %	3.7	3.1	3.2	3.1
	CO, PPM	0	0	7	0
	NOX, PPM	138	154	152	152
	CO,corr 3% O2, PPM	0	0	7	0
	NOX, corr 3% O2, PPM	144	155	154	153
	NOX, Lb/Mbtu	0.197	0.213	0.211	0.210
M = 57"	O2, %	2.0	2.2	2.6	2.5
	CO, PPM	20	10	7	6
	NOX, PPM	147	157	154	153
	CO,corr 3% O2, PPM	19	10	7	6
	NOX, corr 3% O2, PPM	139	150	151	149
	NOX, Lb/Mbtu	0.191	0.207	0.207	0.205
L = 95"	O2, %	2.6	2.4	2.7	2.4
	CO, PPM	5	0	0	0
	NOX, PPM	136	148	146	145
	CO,corr 3% O2, PPM	5	0	0	0
	NOX, corr 3% O2, PPM	133	143	144	140
	NOX, Lb/Mbtu	0.183	0.197	0.197	0.193

Left

DEPTH = 115"

Right

129"
195"
321"
389"

WIDTH = 546"

Grid Avg. O2, % = 2.7
Grid Avg. CO, PPM = 9
Grid Avg. NOX, PPM = 149
Grid Avg. CO corr 3% O2, PPM = 9
d Avg. NOX corr 3% O2, PPM = 146
Grid Avg. NOX, LB/MBtu = 0.201

Great River Energy
Coal Creek #1
Economizer Outlet

ALSTOM POWER, INC.
PERFORMANCE SERVICES
WINDSOR, CONNECTICUT

TEST DATA AND RESULTS

FLUE GAS ANALYSIS - POINT BY POINT GRID DATA

Economizer Outlet Left Duct

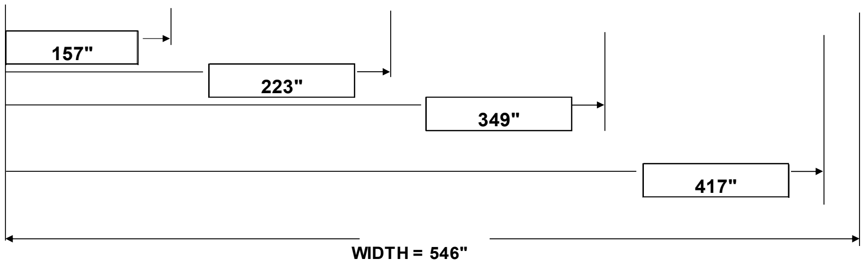
TEST NUMBER: 1
DATE: 6/15/15
START TIME: 0947
STOP TIME: 1028
LOAD:

F FACTOR: 9860

		TEST PORT 5	TEST PORT 6	TEST PORT 7	TEST PORT 8
S = 19"	O2, %	3.5	3.6	3.0	4.3
	CO, PPM	26	15	28	15
	NOX, PPM	131	160	156	140
	CO,corr 3% O2, PPM	27	16	28	16
	NOX, corr 3% O2, PPM	135	166	156	151
	NOX, Lb/Mbtu	0.185	0.228	0.214	0.208
M = 57"	O2, %	3.3	2.6	2.6	2.4
	CO, PPM	28	0	23	12
	NOX, PPM	150	150	164	151
	CO,corr 3% O2, PPM	28	0	22	12
Left	NOX, corr 3% O2, PPM	153	147	160	146
	NOX, Lb/Mbtu	0.210	0.202	0.221	0.201
L = 95"	O2, %	3.0	2.9	2.5	2.6
	CO, PPM	12	0	9	28
	NOX, PPM	147	148	141	145
	CO,corr 3% O2, PPM	12	0	9	27
	NOX, corr 3% O2, PPM	147	147	137	142
	NOX, Lb/Mbtu	0.202	0.202	0.189	0.195

DEPTH = 115"

Right



Grid Avg. O2, % = 3.0 **Grid Avg. CO, PPM = 20** **Grid Avg. NOX, PPM = 149**

Grid Avg. CO corr 3% O2, PPM = 20 **ld Avg. NOX corr 3% O2, PPM = 149**

Grid Avg. NOX, LB/MBtu = 0.205

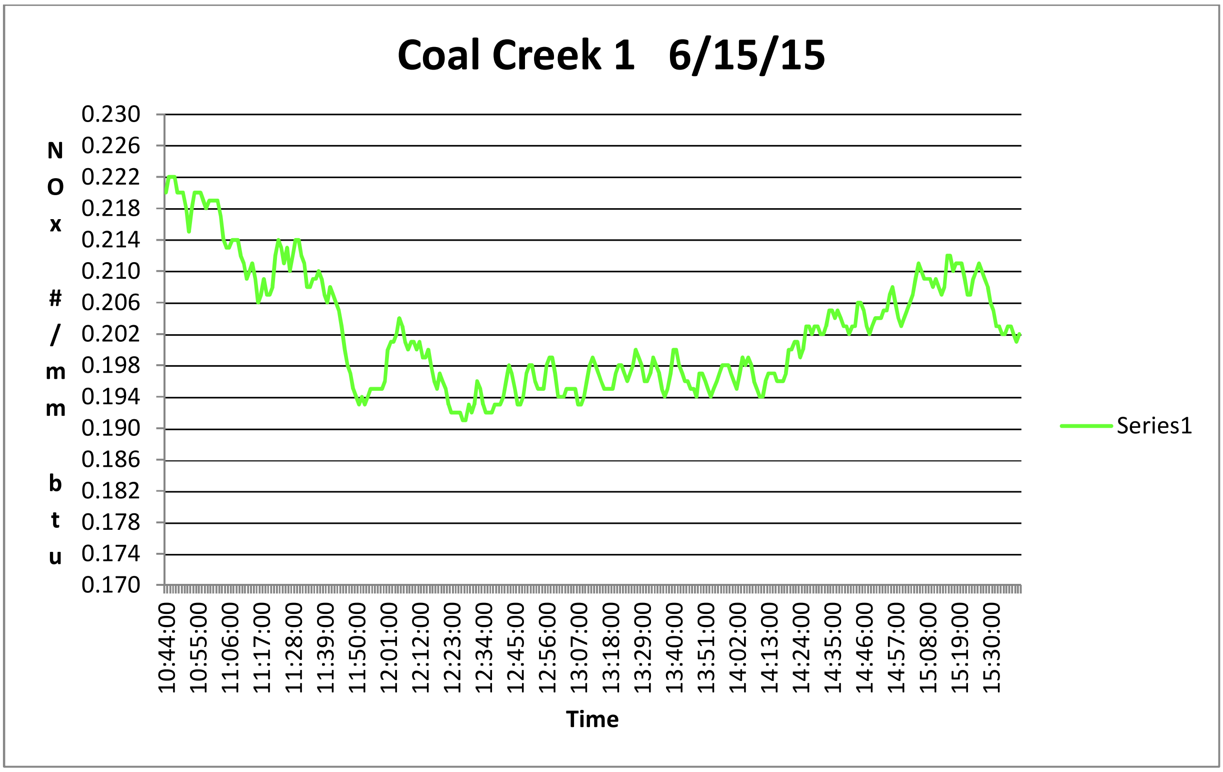
6/15/2015 Board Data (Unit #1)

Load	606 MW
Throttle Press	2522 psig
SHO	1004/995 F
RHO	1005/1002
Mills in Service	6
Burner Tilts	11/22 degrees up
O_2 plant	2.6 % set point
WB/F ΔP	5.2”
NOx	.216 #/MMBtu (CEMS)

Alstom Test Grid

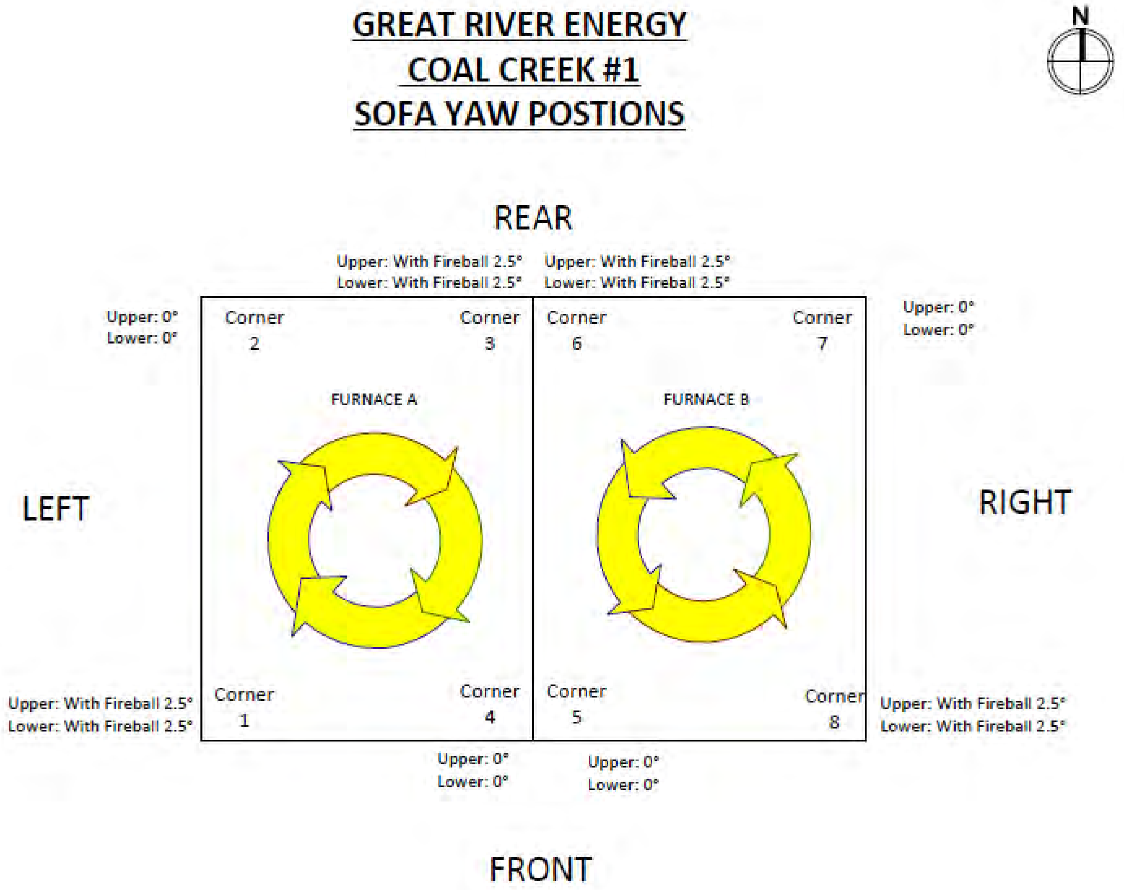
O_2	3.3 % (dry)
CO	4 ppm
NOx	.217 #/MMBtu

Alstom began testing / tuning with several changes made to WB/F dP increases to impart a greater spin to the fireball. In addition, changes were made to the CCOFA air compartments, located just above the upper elevation burner compartment (Mill #8). See graph shown on next page.



Graph showing results of parameters changes on NOx at beginning of tuning on 6/15/2015. Major change was from manual tilt decrease.

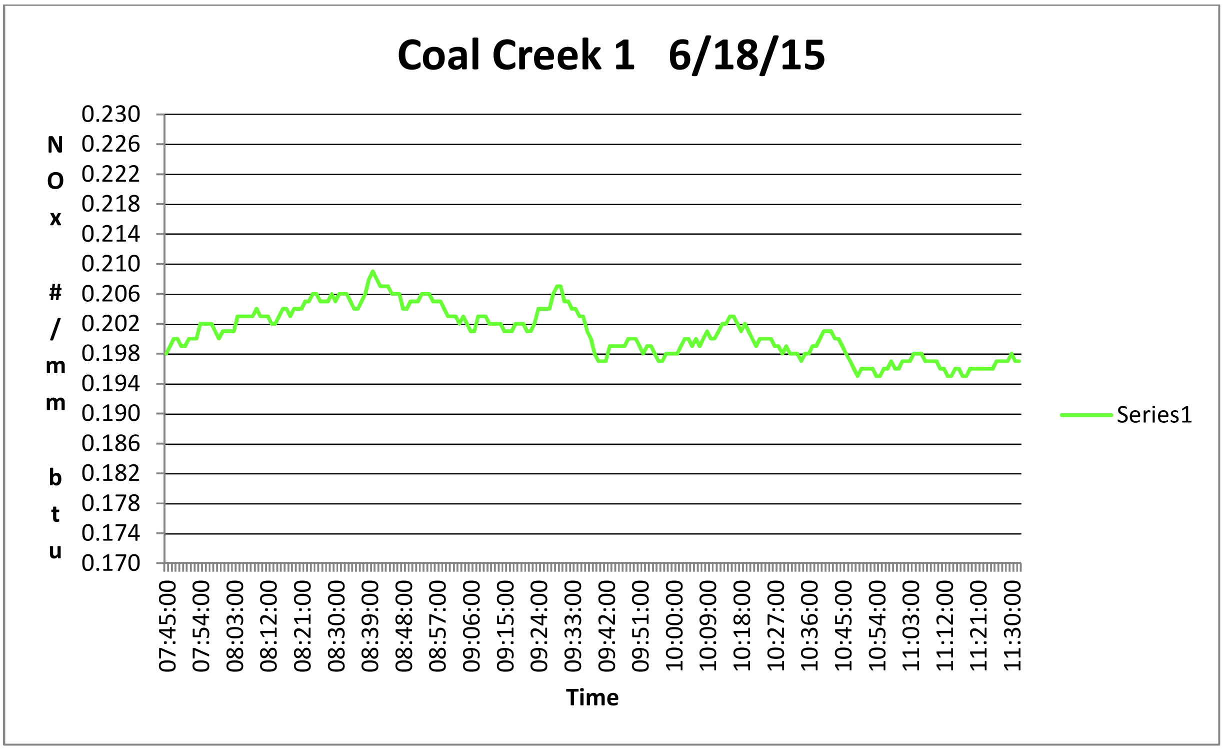
ALSTOM



GREAT RIVER ENERGY
COAL CREEK #1
SOFA YAW POSTIONS

This diagram shows the optimum positioning of SOFA yaws on Unit #1, in a range of +15 to -15 degrees. As with Unit #2, these positions should not be modified. In addition, the SOFA damper control curves for the Upper and Lower SOFA compartments are working quite well and should not be modified.

ALSTOM



The above graph indicates NOx emission on the Alstom grid after all changes / adjustments made to parameters. The low average of .198 #/MMBtu was the best NOx obtainable with the low Sodium fuel for that week. NOx at beginning of tuning was averaging .221 #/MMBtu

Parameters adjusted in matrix

- O_2
- WB/F ΔP
- Burner tilts
- SOFA dampers
- SOFA Tilts

CONCLUSIONS / RECOMMENDATIONS

GRE Coal Creek Units #1 and #2 NOx emissions were found to be below current State and Federal standards prior to Alstom making additional parameter adjustments. GRE has spent considerable effort to accomplish this goal in-house. These units are well maintained and operated. Based on our discovery during the tuning process, each unit required only minimal adjustments to certain parameters to improve overall NOx and CO emission reduction. The units SOFA system is so well tuned for full load operation that any deviance from the current in-place control curve will actually increase, rather than decrease, the NOx and CO output. Based on our testing and unit evaluation of operating controls, Coal Creek Units #1 and #2 have been optimized to its full potential for NOx and CO reduction.

To maintain the low NOx and CO output levels that GRE Coal Creek units #1 and #2 are capable of, Alstom's offers these recommendations:

- The current WB/F ΔP curves work well as it is. Do not apply a negative bias to the controllers. Alstom removed the -.9" bias at the start of the tuning on Unit #1 and changed a bias to Unit #1 (+1.1"). NOx was notably reduced.

- Alstom found a positive bias on 9 out of the 12 operating mill air flows (total for both units), ranging from 10 to 13%. It is believed that these biases were made during periods of pulverizing wet coal and were then not taken out when fuel conditions changed to dry. Excessive Primary Air through the mills typically increases the pulverized fuel ignition points and results in increased NOx and CO. If possible, limit the amount of air flow positive bias to 5 to 7%.

- During periods of low load operation, utilize the retract blowers to clean both the SH and RH pendant assemblies, including the back pass areas. The cleaner these surfaces remain, the lower the burner tilts may be operated from, which will further reduce NOx output.

- Coal fineness sampling was conducted on all mills and results showed that the % fineness through the 200 mesh screen was below design on all mills, with some as low as 54%. Design rating is 70% through the 200 mesh. GRE should continue to run performance evaluation on the mills, making adjustments where required, to obtain the design value.

- After concluding the MATS testing/tuning on Coal Creek Units 1 and 2, Alstom returned to the site to observe operating conditions on both boilers the week of 6/24. GRE informed Alstom that a higher level Sodium lignite had been delivered, with a Na content of 3.7% or higher. The operating results (NOx emissions) with this higher Sodium content fuel was significant. With all control parameter the same as the previous week, and at full load, the following data was observed on the plants CEMS.

Unit #1 NOx	Unit #2 NOx
.170 #/MMBtu	.122 #/MMBtu

  The higher Na content produced additional slag/ash build up on both units Water Wall surfaces, which resulted in somewhat less heat absorption in the lower furnace. This in turn brought higher flue gas temperatures into the SH and RH Pendant sections, which allowed for the burner tilts to be lowered from +14/+22 degrees (avg.) to +3/+8 average. This reduced staging distance was responsible for the significantly lower NOx emission. Alstom recommends burning a fuel with a Sodium content average greater than 3%, if possible.

ALSTOM

GRE Coal Creek Unit #2
MATS Testing/Tuning
Daily Report
Wednesday, 6-10-2015

Unit Status – 10:50 am

Load – 606 mw Gross   Throttle Pressure – 2510
Tilts – 15/24 degrees (L-R)   CEMS NOx - .153 #/MMBtu
SHO – 994/989   RHO – 987/997
6 mills in service (2-3-4-5-6-7). Mills 1 and 8 out.
WB/F dP – 5.3" – but has -.9" bias.
Air Flow – 97.8%
Fuel Flow – 82.5%
Stm Flow – 4024 Klbs/hr.
Alstom Test Grid   NOx - .147 #/MMBtu / 109 ppm.
CO – 8 ppm

12:55
Began removing bias from WB/F dP. -.9" to -.6".

NOx trending down. CEMS - .140   Grid - .141

13:30
Changed WB/F dP bias from -.6" to -.3"

CEMS - .138   Grid - .142

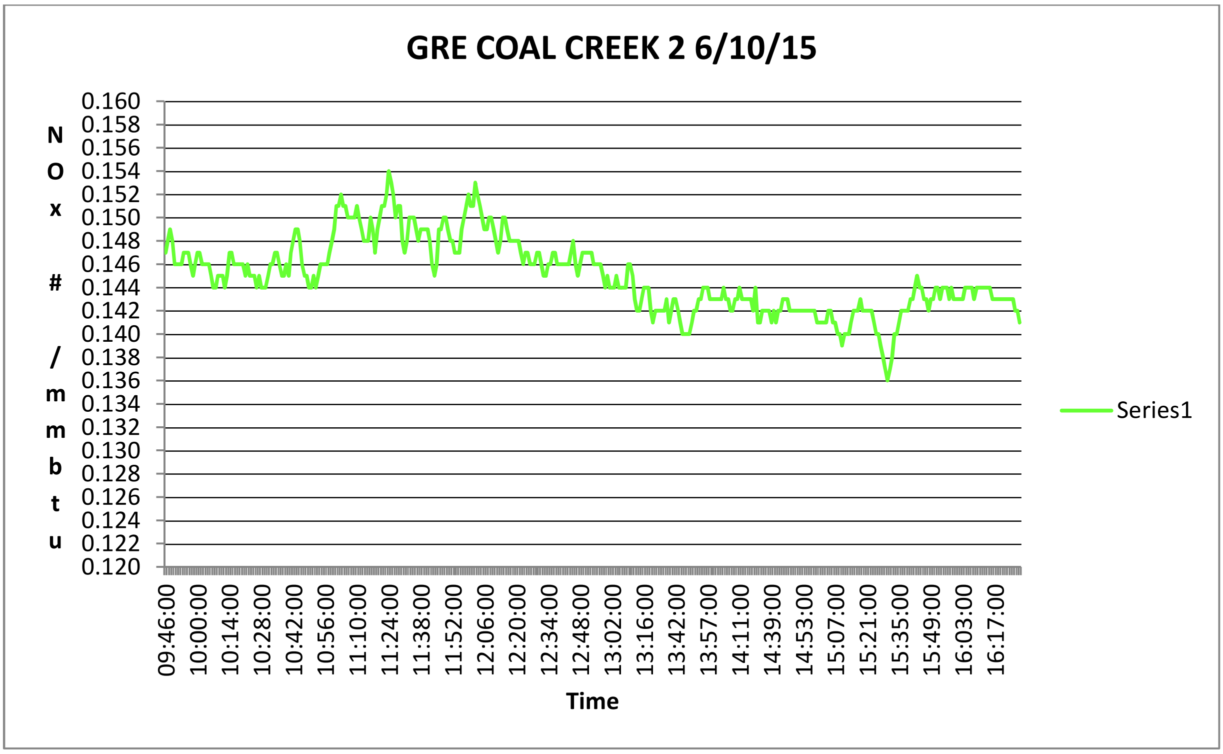
14:05
Removed all bias from WB/F dP

CEMS - .135   Grid - .141. CO still low at 4 to 6 ppm.

15:10
CEMS - .135 #/MMBtu Grid - .141 #/MMBtu

16:30 Status
Load – 611 – NOTE: Increased steam temps gave us an additional 7MW.
SHO – 996/978 RHO – 1006/1004 NOx .138 NOx -= .143

Overall NOx did decrease, primarily due to removal of all bias on WB/F dP controller.



ALSTOM

GRE Coal Creek Unit #2
MATS Testing/Tuning
Daily Report
Thursday, 6-11-2015

Load remained steady at +600 MW through the night.

7:30 Status
Load – 610 MW CEMS NOx - .149 #/MMBtu Grid - .155
Tilts – 15/25 WB/F dP – 6.2” (no bias) O2 sp at 2.6%

NOTE:
NOx higher this morning even though WB/F dP has no bias. GRE says we may have had a coal quality change. However, total TPH federate appears to be the same as 6/10. Tilts are raised more than yesterday as well and in auto, even though SH and RH temps are higher. Operator to blow some selected IK’s to raise SH and RH outlet even more. This should result in tilts lowering.

NOTE:

After blowing 4 retracts in the Reheat area, NOx decreased some, from .149 to .145 on CEMS and .155 to .149 on Alstom grid. Will continue to blow a few more IK’s.

Plan for today to remove mill air flow biases. According to GRE, these biases were placed on the mill air flow controllers when they received wet coal. Once drier fuel was provided, operators never took the biases back out. This mill air flow reduction (however slight) should decrease NOx somewhat.

09:00

Removed air flow bias from #7 mill 10% to 0.

9:35

Lowered RIGHT tilts (East) in manual from 24 to 20 degrees to lower NOx. By 9:50, had them down to 15 degrees. NOx slowly trending down.

10:00

Removed bias from #6 mill (13 to 0)

10:20

Removed bias from #5 mill (15 to 0)

11:00

Removed bias from #4 mill (10 to 0)

NOTE: #3 mill had no bias in controller.

11:20

Removed bias from #2 mill (20 to 0)

13:30

Placed LEFT tilts in manual and lowered from 11 to 8 degrees to see if NOx would decrease further.

ALSTOM

GRE Coal Creek Unit #2
MATS Testing/Tuning
Daily Report
Friday 6-12-2015

7:30 Status
Unit ran at full or near full load all night. No problems reported.
Load – 612 MW   CEMS NOx - .144 #/MMBtu
O2 - 2.6% set point   WB/F dP – 6.2”
SHO – 992/985   RHO – 1005/1004
Tilts – 9/18 degrees

8:20
Began testing by manually closing down on Lower SFA dampers from 50% to 45% open. NOx increased from .145 to .151

8:45
Closed back Lower SOFA dampers from 45% to 40% open. NOx increased again from .151 to .154

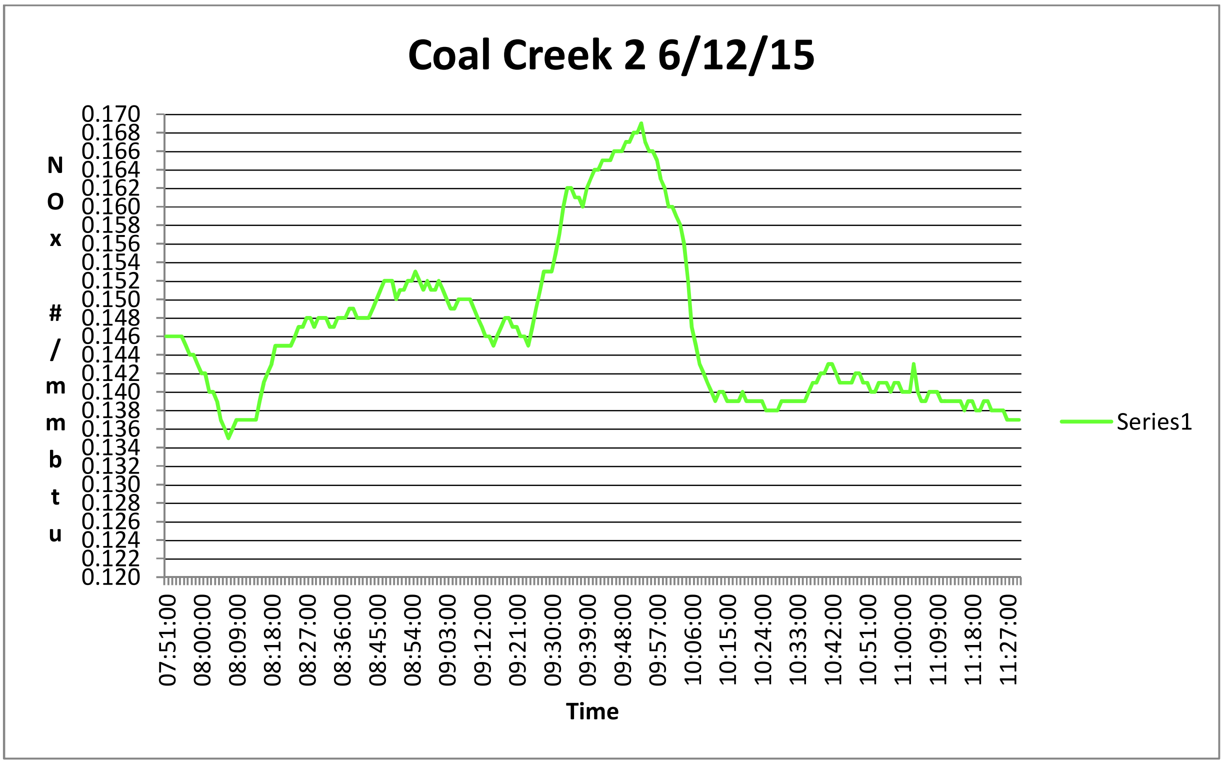
9:00
Placed lower SOFA dampers back in auto. Within 15 minutes NOx decreased back to .147/

9:05
Decreased O2 set point from 2.6 to 2.5%. NOx to .144.

9:20
Lowered SOFA tilts (manually) from +22 degree average to 10 degrees up. NOx immediately began to increase. By the time we had them all (8), NOx had increased up to .170 on CEMS and .169 on Alstom grid.

Brought all SOFA tilts to “as found” positions and NOx decreased back down to .139 to .140 #/MMBtu. No more testing conducted for day.

Began taking down test equipment from Unit #2 and moving it to Unit #1. Will pull probes and re-install on Monday.



Graph showing NOx fluctuations with small load drop in morning and then NOx increase with SOFA tilt manipulation (+22 degrees to +10 degrees up).

ALSTOM

GRE Coal Creek Unit #1
MATS Testing/Tuning
Daily Report
Monday 6-15-2015

8:00 Status

Load – 605 MW CEMS NOx .216 #/MMBtu
6 mills in service 2-3-4-5-6-7 Mills 1 and 8 off
O2 set point is 2.6%
WB/F dP - 5.2” with a +.9” bias
SHO 1004/995 RHO – 1005/1002
Tilts – 11/22 degrees.

NOTE:
NOx is higher today than last week at same load. GRE states this is due to change in coal quality. Will first work on increasing WB/F dP. Unit #1 has a plus bias installed. Unit #2 had a Minus bias installed. Difference is due to size of SOFA compartments on #2 being larger and more efficient for NOx reduction.

11:15
Increased WB/F dP bias from +.9 to +1.1”
WB/F dP now 5.4”. Slight improvement in NOx to .210

13:00
WB/F dP bias increase to +1.3”. Now reading 5.5” Do not want to go any further for now.

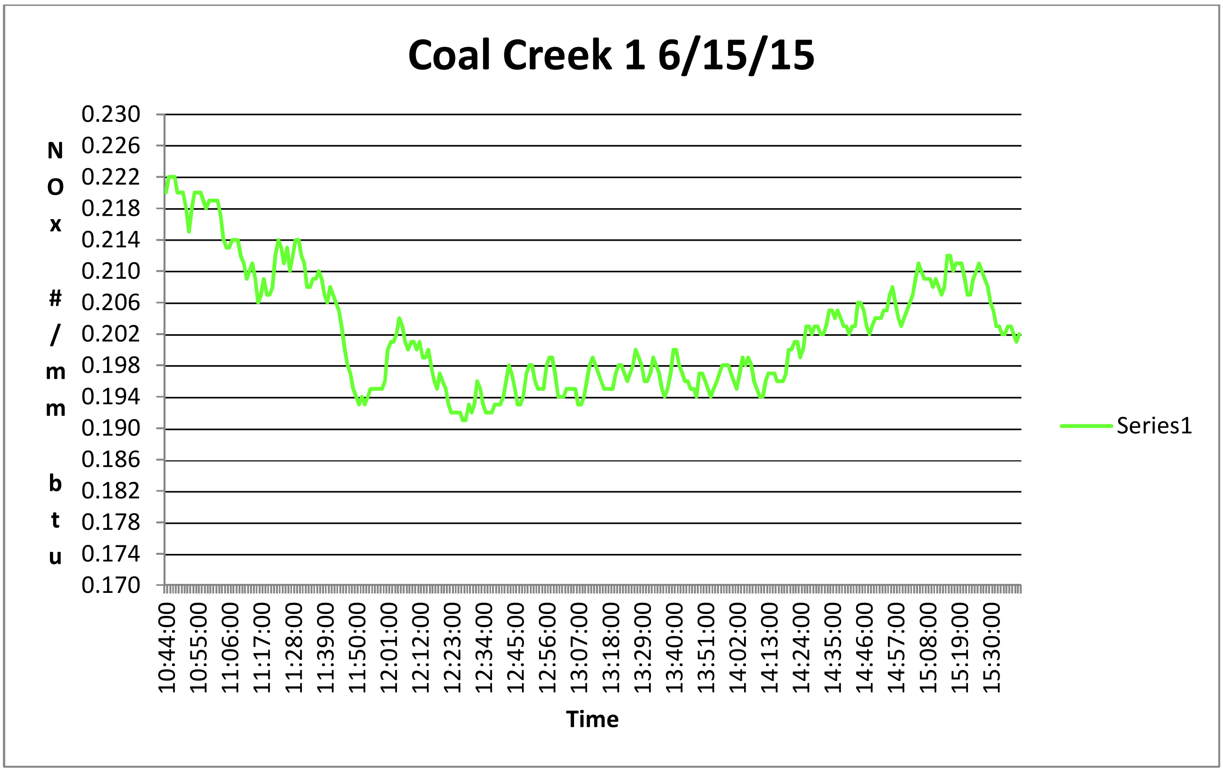
NOTE:
Mills are swinging from 84% feeder speed up to 90%. This is continuous and has been since 8:00 am. This is a significant amount of coal input change with 6 mills in service.

14:20
Lowered Lower CCOFA dampers from 50% to 45% open for NOx change

14:25
Changed Lower CCOFA dampers from 45 to 40% open . Have not seen any decrease in NOx.

14:35
Opened Lower CCOFA to 60%

15:15
Opened Lower CCOFA to 70% open. No real improvement in NOx reduction.



ALSTOM

GRE Coal Creek Unit #1
MATS Testing/Tuning
Daily Report
Tuesday 6-16-2015

7:00
Unit still down from last night load drop. 340 MW’s. Dispatch bringing load up slow.

9:50
Load now at 603 MW NOx - .229
WB/F dP – 5.2” Night shift removed 1.3” bias.
Tilts – 14/22 degrees. This is high and due to low RHO temps.
SHO – 998/1005 RHO – 1007/996

NOTE
Fuel quality down today, per GRE. 882 TPH total at 603 MW

10:15
Lowering Right side (A) tilts in manual from 22 then 18 then 15 degrees to effect NOx change.

10:30
NOx decreased from .228 to .214 #/MMBtu. Lowered Left side (B) tilts in manual from 14 to 10 degrees to effect NOx reduction.

10:40
Placed the 1.3” plus bias back into WB/F dP controller.

10:50
Now have both tilts in manual and at 11/12 degrees

SHO – 990/990
RHO – 996/977
NOx - .200 #/MMBtu
Will continue to allow SH and RH temps to drop to effect NOx reduction.

10:55
SHO – 980/986
RHO – 992/969
NOx - .194 #/MMBtu

11:00
SHO – 983/989
RHO – 991/969
NOx - .195 #/MMBtu

11:15
SHO – 984/989
RHO – 989/970
NOx - .195 #/MMBtu

11:20
Lowered O2 set point from 2.6 down to 2.5%

11:40
SHO – 980/985
RHO – 993/968
NOx - .188 #/MMBtu

11:50
SHO – 987/992
RHO – 994/973
NOx - .196 #/MMBtu

12:50
Raised Right side tilts back to 14 degrees up for additional temp
SHO – 992/995
RHO – 991/977
NOx - .199 #/MMBtu

12:55
Raising tilts back up to place in auto.

13:15
As a test, placing #8 mill in service. Hope to gain additional SH/RH temp so that tilts will come down. Even though adding an upper mill can hurt NOx, having the tilts lower is more than enough of an offset to help with total NOx.

15:50
#8 mill back off. SH and RH temps did not increase and Tilts remain high. End result was increased NOx….from .221 to .236 #/MMBtu.

GRE Coal Creek Unit #1
MATS Testing/Tuning
Daily Report
Wednesday 6-17-2015

7:30 Status
Load – 603 MW CEMS NOx - .216
Tilts – 10/21 degrees
SHO – 989-987
RHO – 992-988

NOTE
Operator had Right side (East) tilts in manual and at a lower position that auto would have driven them. Requested tilts be placed back in auto to bring SH and RH temps back up. Will attempt WB/F dP change (less) today to see if temps may go up.

09:00
Tilts – 10/21
SHO – 1001-1003
RHO – 1008-1004
NOx - .215 #/MMBtu

NOTE.
RH – SH temps up after blowing selected IK's

09:10
Increased WB/F dP from 1.3" up to 1.8" + bias.

11:30
Tilts – 12/20
SHO – 1003-996
RHO – 1002-1003
NOx - .218

12:05
Lowered Right tilts to 18 degrees in manual.

12:35
Tilts – 12/18
SHO – 1001-997
RHO – 1004-1000
NOx - .214

13:45
Tilts – 13/16
SHO – 989-1001
RHO – 1005-987
NOx - .215

13:50
Changing WB/F dP from +1.8” to .9” bias for a test to see if temps increase.

14:00
Tilts – 15/16
SHO – 993-1003
RHO – 1005-985
NOx. - .236

14:05
NOx increased with lowered WB/F dP change. Increased bias back to 1.8”

14:25
Increased WB/F dP bias again to +2.0”. WB/F dP now 6.2”

14:45
Tilts – 15/16
SHO – 992/1002
RHO – 1006/983
NOx - .225

15:35
Tilts – 12/16
SHO – 989/982
RHO – 981/969
NOx - .208 #/MMBtu

16:10
Tilts back in auto and raising back up to regain lost SH/RH temps.

ALSTOM

GRE Coal Creek Unit #1
MATS Testing/Tuning
Daily Report
Thursday 6-18-2015

7:45 Status
Load – 596 MW CEMS NOx .203 #/MMBtu
Tilts – 13-22
SHO – 978-967
RHO – 968-961 WB/F dP – 6.1”

NOTE: Placed 2.0” bias back into WB/F dP controller.

NOTE:
Fuel quality down again today on both units. Neither can make or maintain SH and RH Outlet temps, even with tilts raised up. NOx values on both 1&2 are not too bad, but no temperatures. Waterwalls on both units are very clean. They appear to be exhibiting full heat absorption in the WW circuits, where is decreasing flue gas temps in the upper furnace and backpass areas, resulting in loss of SHO and RHO steam temperatures. Each unit is also losing about 8 MW’s due to low steam temps.

09:00
Comparison of operating conditions with clean furnaces:

UNIT #1	UNIT #2
Tilts – 12/22	Tilts – 20/23
SHO – 989-979	SHO – 952-954
RHO – 971-972	RHO – 961-942
NOx - .210	NOx - .154
Load – 598 mw	Load – 598 – mw

NOx Limit .226

NOx Limit .165

Comparison indicates NOx output to be below limits on both units. However, both units cannot make or maintain SHO and RHO steam temperatures, even with tilts raised. Both units' waterwalls are very clean.

GRE has advised that fuel quality is good, but sodium content is low. This conditions results in less sticky ash and leaves the waterwall surfaces clean, allowing for better heat absorption.

11:15
Comparison

Unit #1	Unit #2
Tilts – 10-18	Tilts – 20-23
SHO – 974-963	SHO – 949-937
RHO – 956-956	RHO – 947-932
NOx - .196	NOx - .146

12:00
Complete tuning attempts on Unit #1.

Attachment B

Report “Cost Estimate for SNCR Impact to Fly Ash Disposal and Sales – Great River Energy – Coal Creek Station” March 1, 2019; Golder Associates Inc.

REPORT

Cost Estimate for SNCR Impact to Fly Ash Disposal and Sales

Great River Energy - Coal Creek Station

Submitted to:

Great River Energy
Coal Creek Station
2875 Third Street SW
Underwood, North Dakota 58576

Submitted by:

Golder Associates Inc.
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19115185

March 1, 2019

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FIGURES

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1.0 INTRODUCTION

Great River Energy (GRE) has requested that Golder Associates, Inc. (Golder) prepare a third-party cost evaluation to address the potential impact the installation of selective non-catalytic reduction (SNCR) control technology would have on the existing GRE fly ash disposal and sales at Coal Creek Station (CCS) located in Underwood, North Dakota. Evaluations were prepared in relation to the United States Environmental Protection Agency's (EPA's) approval of the North Dakota State Implementation Plan (SIP). Based on the proposed SIP, GRE is evaluating SNCR control technology to reduce nitrogen oxide (NO_x) emissions from CCS. If SNCR is installed at CCS, there is potential for unreacted ammonia in the flue gas downstream of the SNCR, called ammonia slip, as well as higher ammonia concentration in fly ash. Higher ammonia concentrations in fly ash are likely to affect beneficial use, sales, and disposal of fly ash at CCS. Due to the significant impact of ammonia concentrations in fly ash on current beneficial use and sales, GRE is evaluating a potential ammonia slip mitigation (ASM) technology patented by Boral Resources (Boral) that would allow for treatment of fly ash for beneficial use and sales.

Golder performed a third-party review and estimated costs associated with implementation of Boral's ASM technology as applied to CCS. The review includes an estimate of the capital and operating and maintenance (O&M) costs for implementation of the ASM technology at CCS, with a focus on potential impacts to ash marketing and future sales to assist GRE in determining the feasibility of the ASM technology for operations at CCS. This evaluation is limited in scope given that Boral has not conducted any field scale assessment on application of this technology to lignite-derived fly ash, nor has Boral implemented this technology commercially at a size comparable to CCS (total tons of fly ash and tons per day of fly ash). The limited experience in commercial application and lack of field trials is not adequate for Boral to be able to provide any guarantee that the process can be successfully applied to treat lignite ash at the Coal Creek.

Based on the potential impacts of ammonia concentrations to fly ash sales, and the evaluation of the ASM technology, Golder prepared a cost comparison for three fly ash management scenarios at CCS:

- Scenario A: CCS's current fly ash sale rate (approximately 80% of fly ash produced is sold);
- Scenario B: No fly ash sales;
- Scenario C: Application of ASM technology (approximately 60% of fly ash produced is sold).

The cost evaluation includes a comparison of capital and O&M costs for each scenario assuming a new facility for each scenario meets EPA Coal Combustion Residual (CCR) regulations (EPA 2015).

1.1 Qualifications

Golder Associates Corporation is a global, employee-owned organization providing consulting, design, and construction services in our specialist areas of earth, environment, and energy through technical excellence, innovative solutions, and award-winning client service. Since our founding in 1960, our more than 6,500 people operating from 165 offices worldwide deliver deep technical understanding, cross-disciplinary thinking, and a passion to help our clients succeed. The United States operating company, Golder Associates, Inc., employs approximately 1,200 people in 50 offices and 5 laboratories.

This project was conducted by a team based in our Lakewood, Colorado office. The project team was well-suited to perform the proposed services for CCS because of the experience of our technical staff on comparable projects and our familiarity with the geotechnical and engineering properties of EPA CCR Rule landfill designs.

Additionally, our team has a firm understanding of the engineering practice and regulatory environment surrounding coal-fired power plants, both in North Dakota and nationwide.

2.0 SNCR IMPACT TO FLY ASH MARKETABILITY

The potential impact to fly ash marketability is a function of the SNCR ammonia slip adsorption onto the fly ash particles and the acceptable (allowable) ammonia levels in fly ash by end users.

2.1 Ammonia Adsorption onto Fly Ash

Based on available literature, the adsorption of ammonia onto fly ash from SNCR emission controls is highly variable and dependent upon factors such as SNCR operation, fuel type/fuel mix, boiler configuration, ash content, ash mineralogy, ash alkalinity, ash sulfur content, and temperature. Limited published data are available for ammonia levels in fly ash for coal-fired power plants utilizing SNCR emissions controls, with no published information being found for energy generation facilities burning lignite coal.

In a 2007 EPRI study on the handling, disposal, and sale of ammoniated fly ash (EPRI 2007), responses from eight units utilizing SNCRs were discussed. All the units fired a PRB/eastern bituminous coal blend, were predominantly smaller units, were predominantly wall-fired, and had actual ammonia slip up to 5 parts per million (ppm). Only four units had tested levels of ammonia in the fly ash, with the measured levels ranging from less than 100 ppm to over 200 ppm. Several references attempt to relate the amount of ammonia slip to the ammonia levels in fly ash and suggest that a 2-ppm ammonia slip may result in fly ash ammonia levels from less than 50 ppm to several hundred ppm (Murarka 2003, Bittner 2001, Hinton 2012, Larrimore 2002). In addition, when explaining ash sales impacts at CCS, Sahu (2011) references a figure created by Larrimore (2002) that indicates ammonia slip levels above 2 ppm can lead to “restricted use” of fly ash and ammonia slip levels above 4 ppm may lead to “unmarketable” fly ash for use in ready mix.

GRE recently contracted with a Fuel Tech, Inc. (Fuel Tech) to evaluate the potential for implementing SNCR technology at CCS and potential ammonia slip adsorption onto the fly ash (Fuel Tech 2019). As a part of that study, Fuel Tech indicated that ammonia slip is difficult to predict but was assumed to be between 5 ppm and 10 ppm, as this range is typical for units burning coal with sulfur content below 1%. In addition, Fuel Tech stated that “…an ammonia slip of 2 ppm is not really viable, as this concentration is within instrument error” due to non-linear instrument calibration issues. Fuel Tech indicated that under steady state operation if the ammonia slip is 5 ppm, the ammonia adsorbed onto fly ash should not be expected to exceed 50 ppm. Similarly, if the ammonia slip is 10 ppm, the ammonia adsorbed onto fly ash should not be expected to exceed 100 ppm.

2.2 Allowable Ammonia Present in Fly Ash

The amount of “allowable” ammonia present in fly ash destined for beneficial use varies depending on ash marketer preferences and the ultimate end use. Higher concentrations of ammonia present in fly ash are a result of ammonia slip in SCR or SNCR systems (EPRI 2007). Fly ash impacted with elevated levels of ammonia results in ammonia being released into the air when water is added. At low levels, ammonia is a nuisance; however, at higher exposure levels, ammonia can cause irritation of the eyes, throat, and nose as well as difficulty breathing (NIOSH 2011). Strength characteristics do not appear to be affected by the presence of ammonia in fly ash (Rathbone and Robl 2001).

Elevated concentrations of ammonia in fly ash contribute to releases into the environment during placement (with the presence of water), and a reluctance of fly ash marketers and users (i.e. Boral, Lafarge, etc.) to buy fly ash for sales to the construction industry. EPRI (2007) explains that the “…industry rule-of-thumb indicates that ammonia contamination on fly ash that is destined for concrete/cement utilization must have less than 100 ppm ammonia to be useable." Headwaters Energy Services indicated (January 11, 2010) that they "…quit shipping anything over 100 ppm…" in reference to the Eastlake facility, which had an SNCR system since 2007. Eastlake has attempted to decrease ammonia content in the fly ash to less than 50 ppm using ASM to improve fly ash marketability. Lafarge (January 26, 2010) has found "…when the ammonia levels exceed 40 part per million in the fly ash that the consumer notices the ammonia and finds it to be objectionable." Additional references have generally found that 100 ppm is the approximate maximum "acceptable" ammonia level in fly ash (Bittner et al. 2001, Giampa 2000, Bittner and Gasiorowski 2005). Other sources cite 100 ppm as an acceptable allowable ammonia level in fly ash for enclosed spaces but allow a higher limit of 200 ppm in well ventilated areas (Brendel et al. 2000, Larrimore 2002).

The amount of ammonia in fly ash can be related to the ammonia off-gassed during placement. Both NIOSH and OSHA have health-based exposure limits for ammonia in the air. NIOSH has a recommended exposure limit (REL) of 25 ppm and OSHA's permissible exposure limit (PEL) is 50 ppm. A "comfortable" threshold of 10 ppm ammonia is referenced by Rathbone and Robl (2001). Rathbone and Robl (2001) evaluated the relationship between ammonia in fly ash and the corresponding amount in air using laboratory and field-scale test methods:

$$NH_{3\,ash} = \frac{(NH_{3\,water})(Water - to - Cement\ ratio)}{(Fly\ Ash\ Content)}$$

The lab and field scale testing found allowable ammonia levels in the concrete water prior to setting (for 10 ppm in the air), to be approximately 50 mg/l for non-ventilated spaces and 75 mg/l for well ventilated spaces.

Fly ash from CCS is a desirable, high quality material and has been used extensively in North Dakota, Minnesota, Colorado, and as far away as California. In a review of fly ash uses in North Dakota, the Energy & Environmental Research Center (EERC) stated:

> "NDDOT uses fly ash in almost all concrete projects at a replacement rate of 30%. A replacement rate between 15% and 30% is specified by most state DOTs (if they specify fly ash use at all), making NDDOT's specification on the higher end compared to other states. For mass pours, a replacement rate of 40% is allowed and is more typical." (EERC 2011)

Based on these uses of CCS fly ash, the above relationship was used to evaluate the maximum allowable ammonia content in fly ash for 15% and 30% fly ash mixtures, for water cement ratios between 30% and 40%, and for well-ventilated and non-ventilated areas. Results of the calculations are shown in Table 1 and Figure 1 below.

Table 1: Allowable Ammonia Content in Fly Ash

Condition	Ammonia in Air*	Water/Cement Ratio	Allowable Ammonia Content in Fly Ash (15% fly ash mixture)	Allowable Ammonia Content in Fly Ash (30% fly ash mixture)
	ppm	-	ppm	ppm
Ventilated	10	0.4	200	100
Non-Ventilated	10	0.4	133	67
Ventilated	10	0.3	150	75
Non-Ventilated	10	0.3	100	50
*Practical limit based on experience (Rathbone and Robl 2001)				

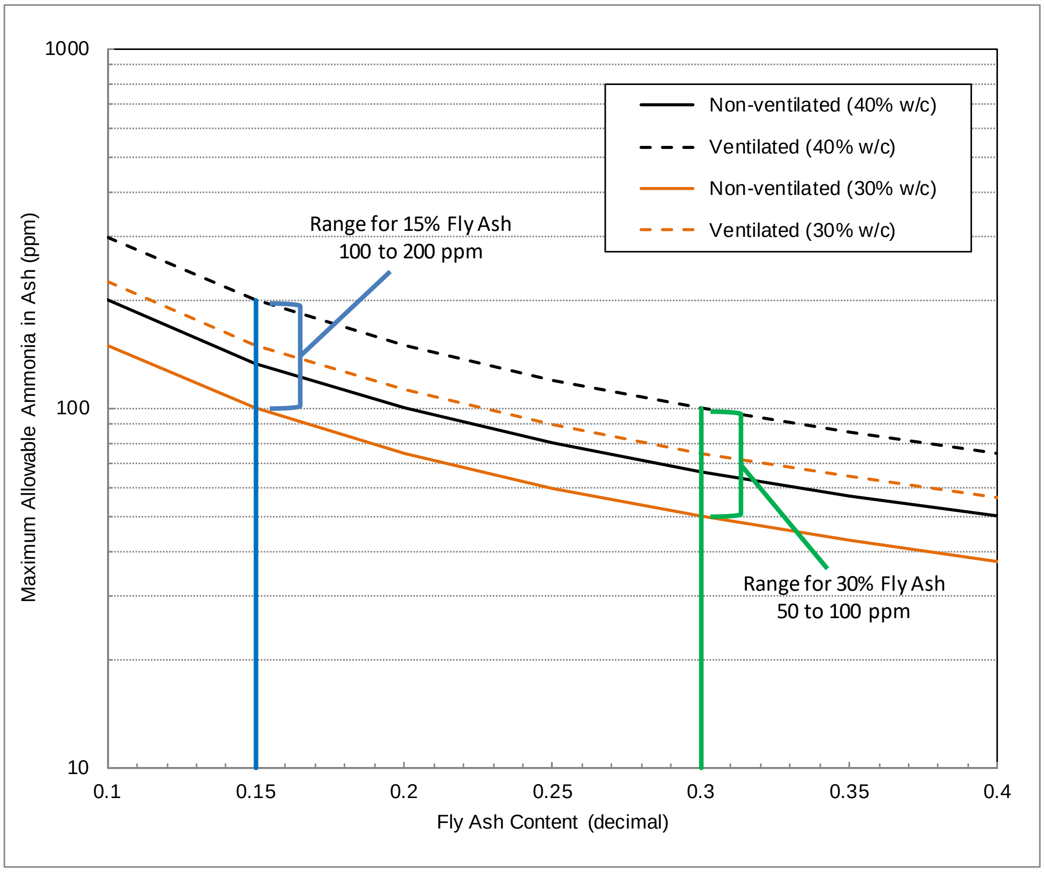

Figure 1: Allowable Ammonia Content in Fly Ash

2.3 Marketability Conclusions

When ammoniated fly ash is used in concrete, the ammonia can be released into the air during placement and may cause irritation to individuals placing the concrete. The amount of ammonia released into the air is a function of fly ash content, the water/cement ratio of the concrete batch, and the ammonia concentration in the ash. Generally, industry experience indicates that fly ash used for concrete should have less than 100 ppm ammonia to prevent handling issues from limiting the marketability of the ash. Based on the use of CCS fly ash as a high percentage cement replacement (30%), a calculated allowable ammonia level in the fly ash may range between 50 ppm and 100 ppm. When discussing ash sales impacts at CCS, Sahu (2011) cites Larrimore (2002) in concluding that 2 ppm ammonia slip can result in 100 ppm ammonia in ash. According to Larrimore (2002), 4 ppm ammonia slip can result in 200 ppm ammonia in ash, a potentially unmarketable level of ammonia for use in ready mix. As previously stated, Fuel Tech indicated that ammonia slip between 5 ppm and 10 ppm is reasonable for CCS and that the ammonia adsorbed onto fly ash may range between 50 and 100 ppm under steady state conditions (slip and ammonia adsorbed onto fly ash would be higher during load swings or upset conditions). Because the ash marketer and ready-mix user may not know the exact use of fly ash when it is purchased and placed in a silo, the practical limit for CCS fly ash is 50 ppm or less to allow its use in a wide variety of applications.

Definitive information is not available for the levels of ammonia that will be present in the fly ash at CCS due to SNCR ammonia slip. However, review of available literature indicates a reasonably high probability that ammonia concentrations would be in the range that is problematic for marketers and end users of CCS fly ash. Therefore, it is prudent for engineering cost evaluations to assume ammonia levels in CCS fly ash will be higher than the acceptable ammonia levels for CCS fly ash destined for beneficial use, and therefore to assume that CCS fly ash will be disposed or will require treatment with ASM technology to be sold for beneficial use.

3.0 AMMONIA SLIP MITIGATION

3.1 Background

Boral has developed an ASM technology to manage ammonia levels in the fly ash, allowing a portion of the fly ash produced to be sold as a concrete additive. The Boral ASM technology was initially developed in 2001 with the first US patent issued in 2004. The first commercial installation of ASM technology was completed at RG&E Russell Station in Rochester, New York, in 2004. Russell Station used an SNCR and burned eastern bituminous coal. This power plant has since been closed and deconstructed.

The second commercial installation was performed at Eastlake Station in Ohio. Eastlake Station was a 600-megawatt (MW) unit that was fired with a 50/50 blend of Powder River Basin (PRB) and eastern bituminous coal while generating approximately 100,000 tons per year of fly ash during full operation. Headwaters (acquired by Boral in 2017) was able to blend, treat, and market approximately 85% of the fly ash produced at Eastlake Station. Fly ash was not treated during periods of highly variable ammonia concentrations, typically occurring during SNCR upset or plant load swings. This power plant is currently closed.

Boral is currently in the process of installing ASM technology at the Monroe Power Plant in Michigan and anticipates ASM system startup later in 2019. Monroe Power Plant has an SCR and the ASM plant is expected to run on demand rather than full time. The plant can burn petcoke, PRB, and eastern bituminous coals. The ASM system is designed to treat fly ash with ammonia concentrations up to between 150 and 200 ppm with a treated fly ash ammonia limit of 75 ppm or lower for sales.

Currently, there are no commercial applications of ASM technology at a lignite-fired power plant, and Boral has not conducted any research on the application of the technology to lignite-derived fly ash. Due to the lack of commercial experience with lignite-derived fly ash, Boral cannot provide a guarantee that the ASM technology can be successfully applied.

3.2 Process Description

The ASM technology mixes approximately 0.5-pound (lb) calcium hypochlorite (Cal-Hypo) with approximately 3,000-lb of fly ash in a hopper. The dose of Cal-Hypo, which is fed into the hopper using a rotary screw, is based on the ammonia concentration in the fly ash. The typical ammonia range for treatment is 50 to 150 ppm with a dosage of 0.2 to 1.3 lb of Cal-Hypo, resulting in ammonia concentrations following treatment of approximately 35 to 80 ppm. The dosage is affected by other potential chemical demands for Cal-Hypo depending on fly ash chemistry. Additional testing of CCS fly ash is required to confirm the effectiveness of Cal-Hypo and the appropriate dosage.

Golder visited the commercial application of ASM technology at Eastlake Station in 2011 at a time it was operational (Figure 2). Fly ash from the electrostatic precipitator (ESP) was sent to one of two fly ash silos where the fly ash was tested daily to determine ammonia concentrations (Figure 3). If the ammonia concentrations were above 150 ppm, the fly ash was diverted for disposal. Fly ash with ammonia concentrations less than 150 ppm were sent to a third silo, after which the fly ash was “dosed” with Cal-Hypo and sent to a fourth silo (Figure 4 through Figure 6). The SNCR at Eastlake could not keep the ammonia slip consistent, and often over-treated a portion of the fly ash stream. To increase the amount of treatable and marketable fly ash, fly ash with no ammonia from other sources was regularly blended into the Eastlake fly ash to keep the initial ammonia content below 150 ppm. Through the operation of the SNCR and by blending non-ammonia-impacted fly ash with Eastlake’s ammonia-impacted fly ash, Eastlake was able to market approximately 85% of the produced fly ash as this fly ash was considered “treatable” (i.e., ammonia concentration levels were below 150 ppm). Diagrams of the Eastlake Station system provided by Headwaters (Boral) are shown in Appendix A.

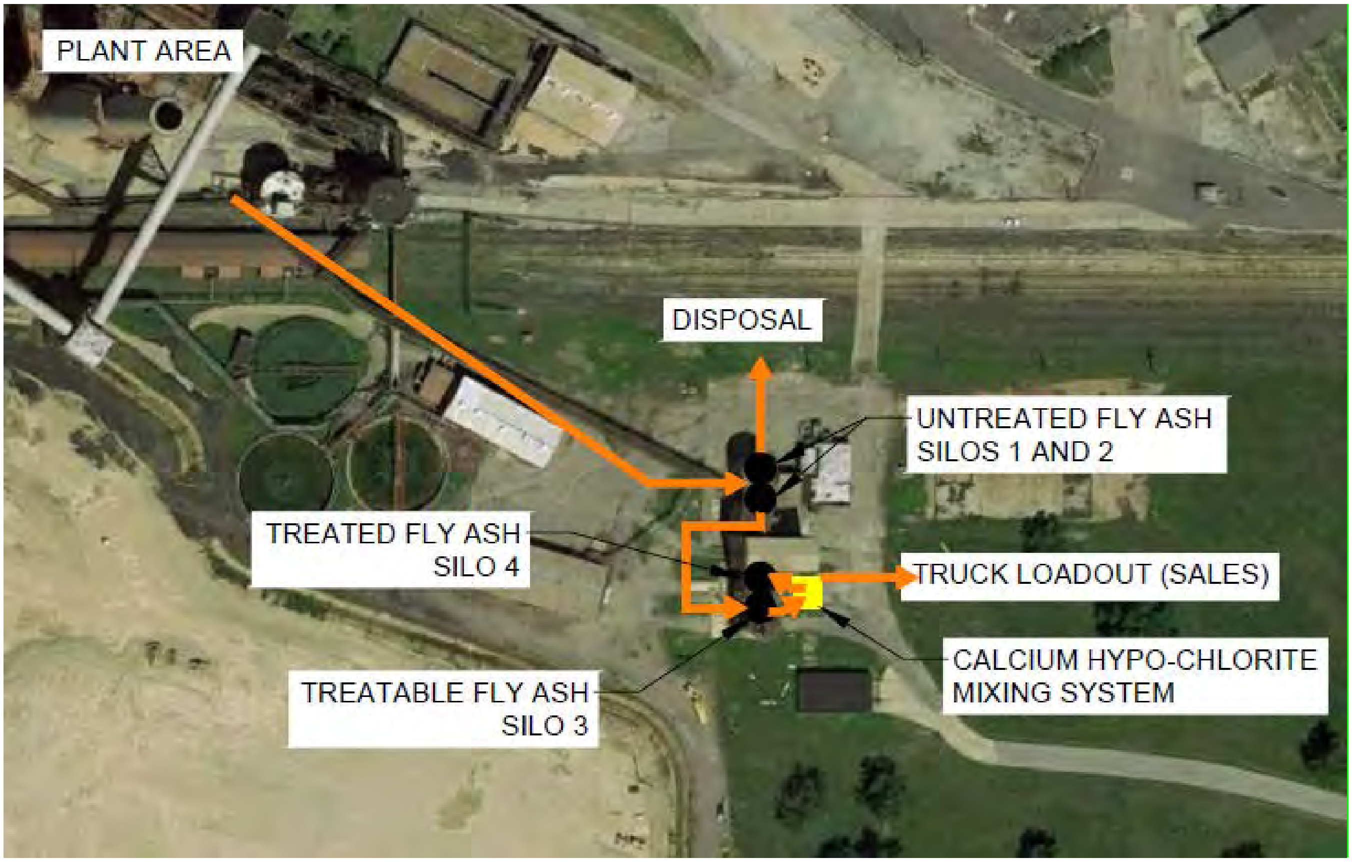

Figure 2: Eastlake Station ASM Layout

Figure 3: Eastlake Station ASM Lab

Figure 4: Eastlake Station Silo 3, Silo 4, and ASM System Location

Figure 5: Eastlake Station ASM Control Panel

Figure 6: Eastlake Station ASM Mixing Hopper

3.3 Design and Limitations

Based on the Eastlake Station application, ASM is applied to fly ash with ammonia concentration levels less than 150 ppm. Ammonia levels can fluctuate based on plant load variations and SNCR operation. Ammonia concentrations are more consistent at base load conditions and dosing levels are typically based on this condition. Therefore, during load “swings”, properly adjusting the amount of ammonia injected into the flue gas can be difficult, resulting in varying concentrations of ammonia in the fly ash. In the event of a plant upset condition, several days may pass until the fly ash is produced with ammonia concentrations at “treatable” levels. The concerns are two-fold. First, if the fly ash is not treated with enough Cal-Hypo, objectionable levels of ammonia will be released when the fly ash is mixed with water. Low concentrations of ammonia gas are an irritant, while high concentrations of ammonia gas can be dangerous to health. Second, if too much Cal-Hypo is added to the fly ash, chlorine gas will be released when the fly ash is mixed with water. Chlorine gas, even at low concentrations, is dangerous to health.

In addition to the impacts of load “swings” on the treatment effectiveness, Boral has indicated that the amount of fly ash produced at CCS may also cause issues. At Eastlake Station, the low production of fly ash allowed for significant time between fly ash being produced to fly ash being loaded for sales (fly ash could wait in silos, and trucks could wait to be loaded). This time allowed for testing of the untreated fly ash, dosage testing, and then full-scale dosage and testing. At CCS, approximately 1,500 tons of fly ash are produced daily and there are limits to fly ash storage and load-out rates for beneficial use and sales. Therefore, Boral has indicated that a robust quality assurance and quality control program would be required to understand the concentration of ammonia in the untreated fly ash, the dosage rates, and the ammonia concentrations in the treated fly ash. In addition, the rate of production and load-out may cause some treated fly ash to be disposed rather than sold.

3.4 ASM Application at CCS

The application of ASM technology at CCS is being evaluated as an option for treating ammonia slip impacted fly ash to allow continued beneficial use and sale of fly ash.

3.4.1 Potential Design at CCS

For cost estimating, a potential layout for the application of ASM at CCS is shown in Figure 7. This potential layout utilizes the existing fly ash infrastructure including the truck load-out silos (Fly Ash Silos 91 and 92), the rail load-out silo (Rail Loadout Silo 93), and the fly ash storage dome (Fly Ash Dome 94). To use ASM technology, the layout adds a new truck load-out silo south of Silos 91 and 92 and adds ASM Cal-Hypo feed systems at both the new truck load-out silo and the existing rail load-out silo (Silo 93). The general flow of material is treatable fly ash being routed to either the new truck load-out silo, Fly Ash Dome 94, or the rail load-out silo. From these locations, the fly ash is tested and then mixed with Cal-Hypo while being loaded into the trucks or rail cars. Additional testing of the resultant product would also be performed. Fly ash that is expected not to be treatable or saleable is routed to the existing truck load-out Silos (Silos 91 and 92) where the fly ash will be loaded into haul trucks and disposed at on-site disposal facilities.

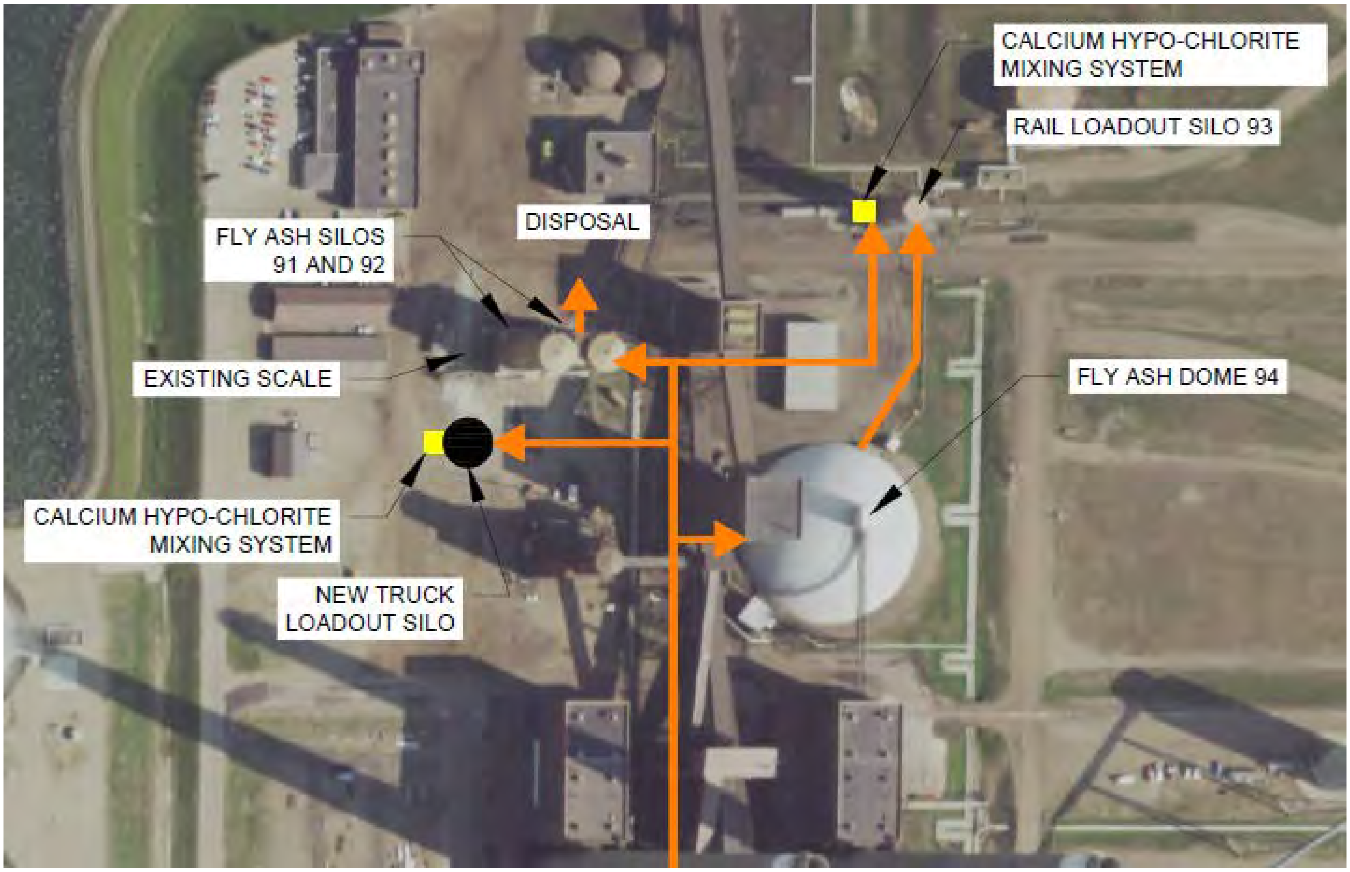

Figure 7: Coal Creek Station ASM Layout

As discussed in Section 3.2, not all fly ash coming from the precipitators is expected to have “treatable” concentrations of ammonia. Generally, when the power generation units are operating at steady load and the SNCR ammonia injection system is operating properly, the produced fly ash should be “treatable” using the ASM system and will be collected in Rail Loadout Silo 93, Fly Ash Dome 94, or the new truck loadout silo. Conditions under which the ammonia content of the produced fly ash will be questionable include:

- Unit load swings causing variations in ash ammonia concentrations (load swings may be due to regional wind penetration or variable load consistent with MISO);
- SNCR ammonia injection feed system problems; and
- Unit startup and shutdown resulting in oily ash.

Golder anticipates that when any of these conditions occur, the produced fly ash will automatically be directed to Fly Ash Silos 91 and 92 for disposal. Fly ash will not be directed to Rail Loadout Silo 93, Fly Ash Dome 94, or the new truck loadout silo for sale of the fly ash until the upset condition is over and the fly ash collected in the first two rows of the electrostatic precipitator (ESP) has been tested and proven to contain less than 150 ppm of ammonia.

Currently, approximately 80% of the fly ash produced annually at CCS is sold. The remaining 20% is disposed due to market conditions, storage/transportation issues, and unit startup and shutdown resulting in oily ash. Based on a review of the recent and anticipated load profile at CCS, and concerns described by Boral in operating ASM technology on the amount of fly ash produced at CCS, an additional 20% of the fly ash produced annually is expected to be disposed due to ammonia concentrations which will make the fly ash untreatable or unmarketable after treatment.

3.5 Cost Estimate

Included in the cost estimate are costs for the ASM infrastructure, including engineering and design, construction, and operations and maintenance. Golder used actual costs from similar projects and professional judgement to develop this cost estimate. Sources and assumptions are documented where appropriate. Some general assumptions for the cost estimate include:

- All costs are estimated in 2019 dollars.
- Capital costs are annualized based on a 20-year life and 5.25% interest rate.
- Existing fly ash sales infrastructure (silos, scales, and rail facilities) and operations and maintenance thereof are not included.

3.5.1 System Engineering and Design

Costs for system engineering, design, and permitting are estimated at 10% of the total construction costs to develop new facilities, based on Golder’s professional judgement.

3.5.2 New Truck Load-Out Silo

The costs for the new truck load-out silo include site preparation, permit application, silo and handling equipment, dust collection equipment, and feed piping. Costs for this construction are based on the construction of a similar fly ash sales terminal constructed for GRE in 2003. This silo had a 5,000-ton capacity and was used to transfer fly ash from rail cars to trucks (Figure 8). The total estimated cost for this item is $2.02 million (in 2019 dollars) and includes the following:

- Silo and truck scale similar to the Irondale, CO unit:
  - Silo slab on grade;
  - Starvrac reclaimer;
  - Truck scale beside the silo on grade;
  - Screw conveyor from discharge of the Starvrac reclaimer;
  - Bucket elevator to overhead;
  - Air slide; and
  - Building with the scale and ASM controls.
- Additional items needed at CCS:
  - Feed piping and valves from each of the four fly ash conveying lines; and
  - Higher capacity dust collectors to handle the high air flow from the ESP.

Details for this cost estimate are included in Appendix B.

Figure 8: Typical Silo used in Cost Estimate

3.5.3 Cal-Hypo Feed System

The costs for the Cal-Hypo feed systems are estimated at $680,000 (in 2019 dollars) and include:

- Rail Loadout Silo 93:
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weigh bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weigh hopper;
  - ASM system controls.
- New truck loadout silo:
  - Weigh hopper above truck loadout spot;
  - Cal-Hypo storage and conveying building;
  - Day storage hopper for Cal-Hypo on the silo weight bin floor;
  - Conveying system from the storage building to the day storage hopper;
  - Variable speed screw conveyor to feed Cal-Hypo into existing weight hopper;
  - ASM system controls.

3.5.4 GRE Internal Costs

Internal costs for GRE to manage consultants, contractors, and in-house staff is estimated at 10% of the total costs (construction, engineering, permitting, and CQA), based on GRE’s experiences with projects at CCS.

3.5.5 Project Contingency

Due to the order-of-magnitude scope of this cost estimate, a contingency of 20% on the construction costs was added to the cost estimate.

3.5.6 Operational and Maintenance Costs

ASM post-processing operations and maintenance costs are estimated as an annual cost. Operations costs include the cost of Cal-Hypo, fly ash sampling and testing costs, and labor to operate the system. Maintenance costs include labor and materials to maintain and repair the added equipment at Rail Loadout Silo 93 and the new truck loadout silo.

The estimated cost for this item, based on annual sale/processing of 308,000 tons, is approximately $1.67 million per year. Details for this cost estimate are included in Appendix B.

3.6 ASM Post-Processing Cost Summary

Using the quantities and the unit pricing described above, ASM post-processing costs are estimated as $6.40 per ton of fly ash treated.

4.0 FLY ASH DISPOSAL

Fly ash that cannot be marketed for beneficial use is disposed in engineered and permitted facilities at CCS. Golder has prepared this order-of-magnitude cost estimate to compare costs between three scenarios defined to assess the potential impact of an SNCR on fly ash sales and disposal at CCS. Summary costs and key inputs are included in Table 2 through Table 4 and Figure 9 through Figure 11, with cost estimate details provided in Appendix B.

4.1 Fly Ash Disposal Scenarios

Three scenarios were evaluated to estimate the annual cost and the cost per ton to dispose fly ash at CCS. These scenarios are as follows:

- Scenario A – This scenario is the base case, with fly ash sales equal to the average fly ash sales at CCS between 2014 and 2018 (approximately 80% of fly ash produced). The scenario assumes that fly ash will be disposed in a new landfill with a design based on EPA CCR Rules with a 20-year disposal capacity. No post-processing of the fly ash is required to make it marketable.
- Scenario B – This scenario assumes that the ammonia slip impact of an SNCR makes fly ash at CCS unsalable. The scenario also assumes that fly ash will be disposed in a new landfill with a design based on EPA CCR Rules with a 20-year disposal capacity.
- Scenario C – This scenario assumes that Boral's ASM technology will be viable for ammonia-impacted fly ash at CCS. However, sales will be reduced from current sales due to load swings, outages, ASM system upsets, market conditions, and other factors previously identified within this report (assume 60% of fly ash produced can be sold). The scenario also assumes that fly ash will be disposed in a new landfill with a design based on EPA CCR Rules with a 20-year disposal capacity.

A summary of the fly ash production, sales, and disposal annual tonnages for these scenarios is provided in Table 2.

Table 2: Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales & ASM)
Fly Ash Produced (tons/year)	513,000	513,000	513,000
Fly Ash Sold (tons/year)	400,000	0	308,000
Fly Ash Disposed (tons/year)	113,000	513,000	205,000

The total tonnage of fly ash produced is variable based on items such as plant load, plant efficiency, coal quality, and coal processing. Tonnage used in this analysis is an average of the actual tonnage produced, sold, and disposed at CCS between 2014 and 2018.

4.2 Landfill Design

For all three scenarios a 20-year disposal capacity and a design in accordance with EPA CCR Rules is assumed. Further, the landfill is assumed to be built on property not currently owned by GRE. This cost estimate assumes that property just south of the plant property would be purchased for the new facility. Figure 9 shows a potential location for these new facilities just south of the plant property and represents the approximate footprint required for Scenario C.

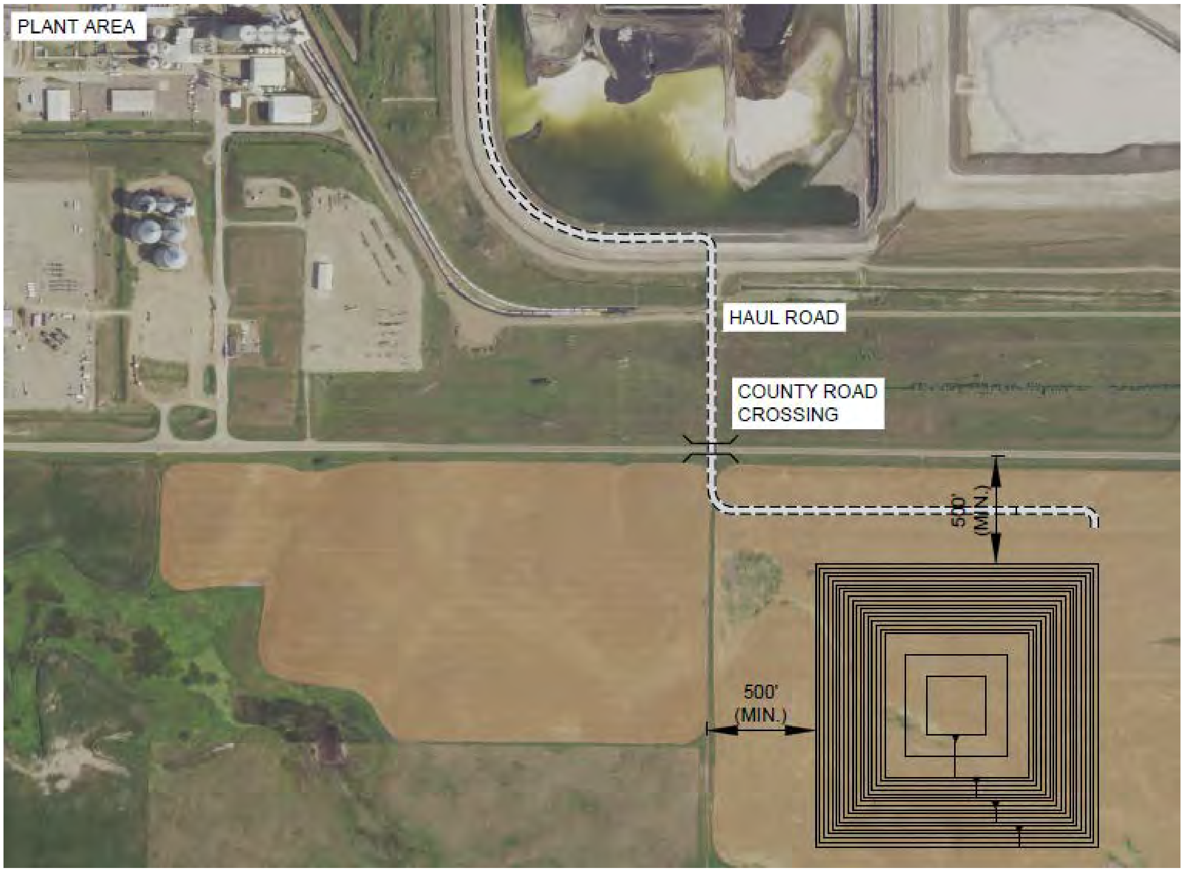

Figure 9: Potential Landfill Location (Scenario C)

4.2.1 Landfill Size

Landfill size is based on a 20-year fly ash disposal capacity. For the three scenarios, size varies between 2.3 million and 10.3 million tons of capacity. For each scenario, Golder developed a simplified landfill footprint that would provide the 20-year fly ash disposal capacity. The simplified landfill design assumes 10 feet of cut, a 12-foot high soil perimeter berm, 3H:1V soil berm slopes, and 4H:1V fly ash slopes with a 5% crown. Based on preliminary engineering, the landfill capacity ranges between 80,000 and 120,000 cubic yards (cy) per lined acre due to the increased height capacity of a larger footprint facility. Figures showing the approximate size of each scenario are included in Appendix B.

The amount of cover area in relationship to the liner area has also been estimated based on preliminary engineering as 1.1 acres of cover for every 1 acre of liner.

The amount of land required is assumed to encompass at least a 500-foot buffer beyond the lined footprint to allow for access roads, fencing, support structures, and groundwater monitoring. For the land acquisition purchase estimate, the nearest eighth section of land to the required footprint was assumed.

Table 3 provides a summary of the estimated facility liner area, cover area, and site area for the three scenarios.

Table 3: Scenario Landfill Sizes

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales & ASM)
Liner Area (acres)	24.5	72.0	36.5
Cover Area (acres)	27.0	79.0	40.0
Site Area (acres)	160	240	160

4.2.2 Infrastructure Development

Since the landfill would be constructed on new property, considerable site development is required. Such site development may include:

- Haul truck access road;
- Fencing and gates around the property;
- Power to the new site;
- Monitoring wells upgradient and downgradient of the facility; and
- Water return pipeline to allow for pumping of excess contact water from the site to the ash water tanks within the plant.

Additionally, haul trucks will be required to cross a county road to deliver fly ash from the plant to the new facility. For safety and operational flexibility, a new county road bridge should be constructed to allow haul truck traffic to pass under the county road. This bridge would include the bridge structure as well as the grading and embankment costs associated with the approach on the county road.

4.2.3 Liner

A liner design is based on EPA CCR Rules. The assumed liner system is shown in Figure 10 and consists of (from bottom to top) a compacted clay liner (1×10^{-7} centimeters per second, cm/sec, maximum permeability), a geomembrane, a leachate collection layer consisting of drainage material, piping and sumps, and a protective cover layer.

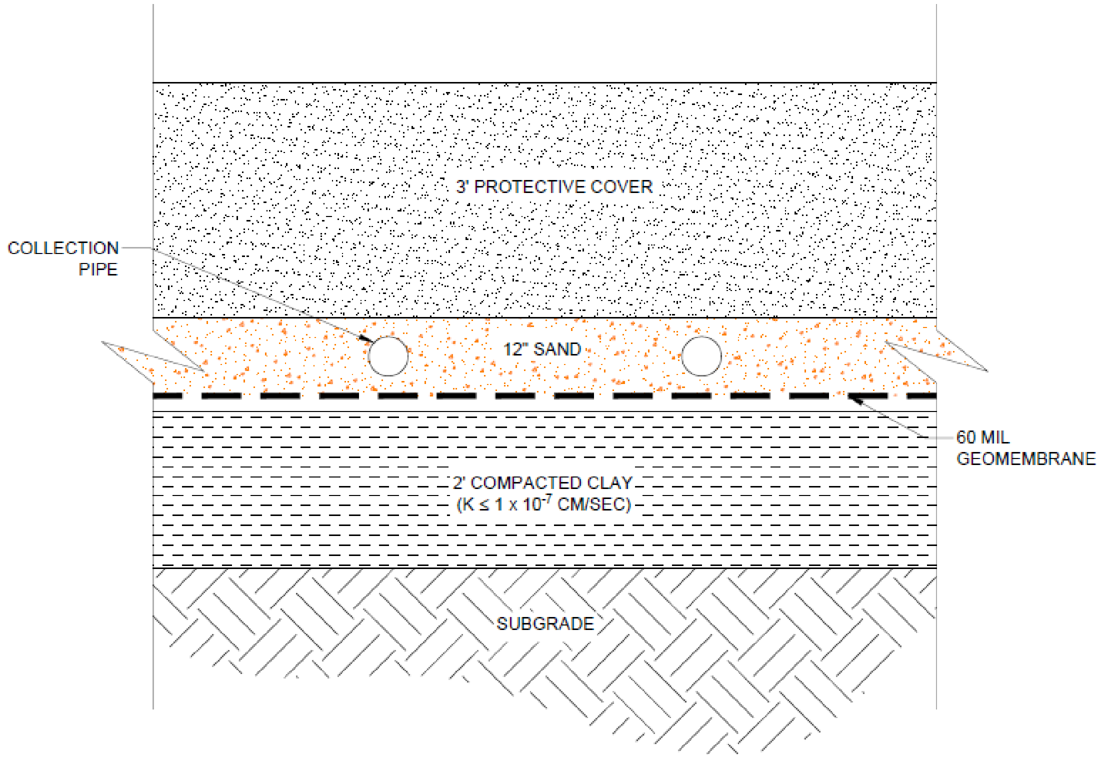

Figure 10: Composite Liner Detail

4.2.4 Cover

The final cover design is also based on EPA CCR Rules. The assumed cover system is shown in Figure 11 and consists of (from bottom to top) a leveling fill layer, a compacted clay liner ($1x10^{-7}$ cm/sec maximum permeability), a geomembrane, a drainage layer consisting of drainage material and piping, and a vegetation layer. The drainage layer over the geomembrane is required to control the head on the liner and the resulting stability of growth medium. Additionally, the cover will use terrace channels and armored down-chute channels to manage surface water runoff and reduce erosion.

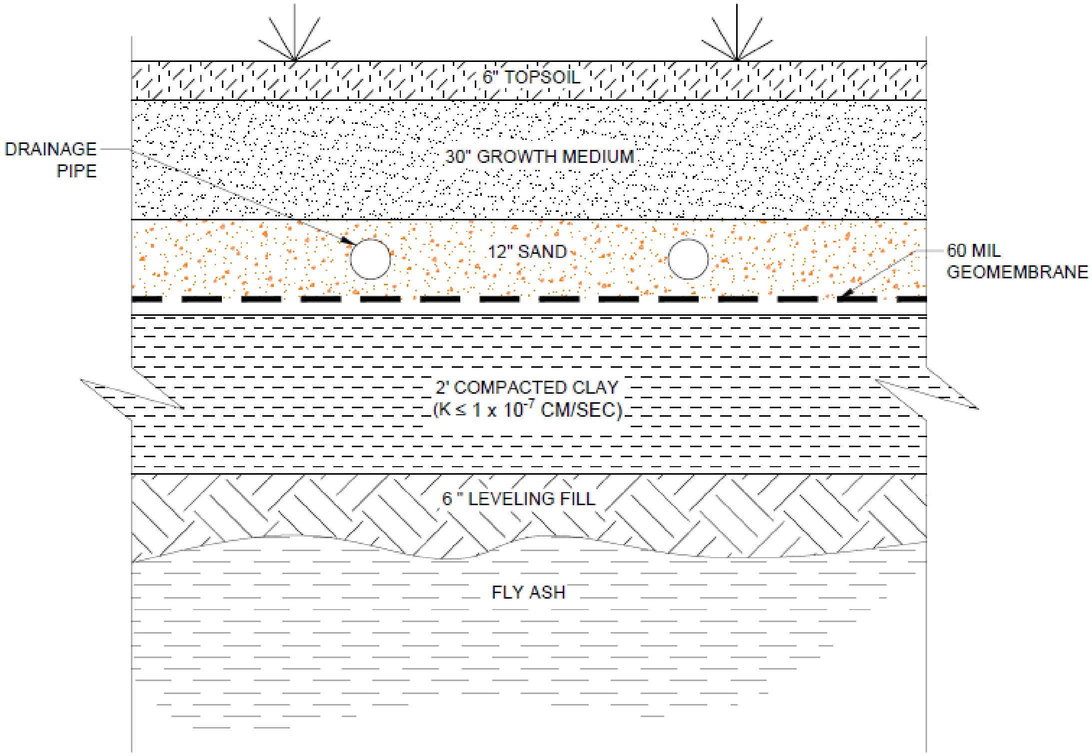

Figure 11: Composite Cover Detail

4.3 Cost Estimate

The cost estimate includes costs for the life of the disposal facility including engineering, design and permitting, construction, and operations and maintenance, including closure and post-closure care. Golder used actual costs from similar projects at CCS, crew analyses based on local contractor rates, RS Means manuals (RS Means 2019), and professional judgement to develop this cost estimate. Sources and assumptions are documented. Some general assumptions for the cost estimate include:

- All costs are estimated in 2019 dollars.
- Capital costs are annualized based on a 20-year life and 5.25% interest rate.
- Existing fly ash processing equipment (silos, unloaders, etc.) is not included. Disposal costs begin once the haul trucks are loaded with fly ash.
- Existing fly ash sales infrastructure (silos, scales, rail facilities) and operations and maintenance thereof are not included.
- Disposal costs only include fly ash disposal and not facility airspace or operations and maintenance costs for other CCRs produced at CCS.

4.3.1 Engineering, Design, and Permitting

Costs for engineering, design, and permitting are estimated at 10% of the total construction costs to develop new facilities, based on Golder's experience with coal combustion residuals facilities in the Midwest. The components included in this cost may include a facility siting evaluation, design of the facility, submittal of a solid waste landfill permit and associated permit renewals, submittal of air permits and NPDES permits, and creation of construction and bid packages for the facility.

The siting evaluation may include a hydrogeological characterization of the site, including drilling, soil testing, establishing groundwater baseline data, and preparing a hydrogeologic characterization report. Additional siting efforts may include a wetlands delineation, a site topographic survey, and other evaluations as required.

Facility design includes both landfill design and infrastructure design, including grading plans, deposition plans, contact and surface water management plans, design of haul roads, and design of the county road bridge crossing.

Permitting may include the solid waste landfill permit, air permits, and an NPDES permit, including the development of operations plans for the facility, closure plans, post-closure care plans, groundwater sampling and analysis plans, a Stormwater Pollution Prevention (SWPP) plan, and other required submittals associated with the construction and operation of a new fly ash disposal facility.

4.3.2 Land Acquisition

Land acquisition of the property required for the new facility includes site due diligence and property purchase. Site due diligence may include survey, geotechnical characterization, environmental audit, and a landfill siting suitability evaluation. The property purchase may include legal fees as well as the purchase price of the property. Currently, crop land near CCS is selling for $3,000 to $5,000 per acre. A unit cost of $4,000 per acre is used in the analysis to account for both the cost of the land and the site due diligence.

4.3.3 Infrastructure Development

The costs for infrastructure development include fencing, monitoring well installation, power from the plant to the landfill, facility access haul road, a return water pipeline, and a county road bridge crossing. The costs for this construction are estimated to be between $2,740,000 and $2,910,000 for the various scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.4 Liner Construction

Liner construction includes several elements as described above, including a compacted clay liner, a geomembrane layer, a leachate collection system, and protective cover. Additionally, the construction effort will include clearing and grubbing, topsoil stripping and stockpiling, construction of temporary roads, soil excavation and stockpiling to be used for perimeter berms, compaction of the liner and cover, and application of site controls such as erosion controls. The costs for construction are estimated to be between $239,000 and $243,000 per acre for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.5 Final Cover Construction

Final cover construction includes leveling fill, a compacted soil layer, a geomembrane liner, a drainage collection system, growth medium, topsoil, armored down-chute channels, and vegetation of the site. Costs for this construction are estimated to be between $183,000 and $201,000 per acre for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.6 Post-Closure Care

Post-closure care includes groundwater monitoring and reporting (for the state and the EPA CCR Rule), annual site inspections, additional compliance requirements associated with the EPA CCR Rule, repair and maintenance of the final cover (soil, seeding, mowing, surface water structures), maintenance of the facility access roads and fencing, and permit-required record keeping. Post-closure care will occur for 30 years following the closure of the facility and is included in the capital/direct costs for this cost analysis. Costs for post-closure care are estimated to be between $106,000 and $154,000 per year for the different scenarios. Details for the quantities and unit rates applied to this work are included in Appendix B.

4.3.7 Construction Management and Construction Quality Assurance

Throughout the construction effort, a construction manager will be on-site to communicate between the contractors and the design engineer. In addition to the construction manager, one or several construction quality assurance (CQA) monitors will be on-site during the construction. Costs for construction management and construction quality assurance are estimated as 10% of the total construction costs to develop the facility, based on Golder's experience with coal combustion residuals facilities in the Midwest.

4.3.8 GRE Internal Costs

Internal costs for GRE to manage consultants, contractors, and in-house staff are estimated at 10% of the total costs (construction, engineering, permitting, CQA), based on GRE's experience with projects at CCS.

4.3.9 Project Contingency

Due to the order-of-magnitude scope of this cost estimate and the associated engineering and unit rate development, a contingency of 20% on the construction and land acquisition costs was added.

4.3.10 Operational Costs

Landfill operations and maintenance costs are estimated as an annual cost and include both engineering support and site operations. Engineering support includes design support, permit support, an annual inspection, groundwater monitoring and reporting (for the state and the EPA CCR Rule), additional compliance requirements associated with the EPA CCR Rule, and an annual survey. Site operations include the ownership and operation of site haul and placement equipment, full-time site staff, and material expenses. Since ammonia concentrations in the fly ash to be contained in site landfills may be an irritant, operational modifications may be required to handling and placement methods. Costs associated with these potential operational changes have not been included.

Estimated costs for this work are broken into haul costs, placement costs, and site management and maintenance costs.

Haul costs were estimated at $3.30 per ton based on haul distance, equipment capacity, operator costs, and equipment costs. Placement costs were estimated at $2.30 per ton based on dozer spreading with minimal compaction. Details on the haul and placement costs are included in Appendix B.

Site management and maintenance costs were estimated between $196,000 and $396,000 per year for the different scenarios. Details on the annual site management and maintenance costs are included in Appendix B.

4.4 Disposal Cost Summary

Using the quantities and the unit pricing described above, disposal costs were estimated for the three scenarios and are summarized in Table 4.

Table 4: Disposal Cost Summary

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales & ASM)
Fly Ash Disposal (ton/year)	113,000	513,000	205,000
Disposal Cost ($/ton)	$26.00	$15.80	$20.60
Annual Disposal Cost ($/year)	$2,940,000	$8,100,000	$4,220,000
Annual Increase in Disposal Cost Compared to Scenario A ($/year)	-	$5,160,000	$1,280,000

The disposal cost per ton is reduced with increased disposal quantity due to the efficiency of the landfill footprint (a larger landfill can be built higher and has larger capacity), and the distribution of fixed costs (roads, bridge, fence) across a larger amount of disposed fly ash.

Based on the annual disposal cost estimate, the potential impact of an SNCR to the fly ash disposal costs at CCS may be an additional $5.2 million per year if fly ash is no longer marketable or an additional $1.3 million per year if the ASM technology proves successful.

4.5 Industry Ranges for CCR Disposal

Disposal costs of $16 to $26 per ton were estimated based on site-specific designs for the disposal of fly ash at CCS. These disposal costs were based on a detailed engineering cost estimate for CCS including costs from landfill development to post-closure care.

In 2010, the EPA estimated baseline (i.e. current) CCR disposal costs in their Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residuals Generated by the Electric Utility Industry (EPA 2010). In Chapter 3 of that report, the EPA provided a cost estimate for the management of CCRs and estimated a range of $2 per ton to $80 per ton with an average of $59 per ton. In discussion of these results, the report indicates that $2 per ton is reflective of unlined, near-plant impoundments in states with low regulatory requirements, and the high end of $80 per ton is reflective of off-site commercial disposal in landfills. The proposed fly ash disposal facilities at CCS are composite-lined (per EPA rule requirements), engineered landfills located at varying distances from the plant.

The EPA report further references information from the American Coal Ash Association (ACAA) to validate its cost estimate. The ACAA routinely collects ash disposal and beneficial use information from its members and has developed estimates for the disposal of CCPs. From the ACAA website and referenced in the EPA report:

> “As one can see, a variety of factors enter into determining disposal costs. The lowest cost occurs when a disposal site is located near the power plant and the material being disposed can be easily handled. If the material can be piped, rather than trucked, costs are usually lower. In these types of situations, cost may be as low as $3.00 to $5.00 per ton. In other areas, when distance is far away and the material must be handled several times due to its moisture content or volume, costs could range from $20.00 to $40.00 a ton. In some areas, the costs are even higher. If new sites are required and extensive permitting processes take place, the total cost of the facility may be increased, resulting in higher disposal costs over time.” (ACAA 2012)

The disposal of fly ash at CCS does not fall at either cost extreme (unlined impoundment or off-site commercial disposal), and the engineering estimate of $16 to $26 per ton appears well within the EPA’s cost estimate and industry practice (particularly when accounting for inflation and new regulatory requirements since the 2010 estimates).

5.0 COST IMPACT

The total cost impact of an SNCR on fly ash management at CCS requires the aggregation of the post-processing costs (ASM), the disposal costs, and the loss in revenue generated from the sale of fly ash. This total cost impact was evaluated for the three Scenarios discussed previously. As a basis for the cost comparison, Table 5 provides a summary of the annual tons of fly ash produced, sold, disposed, and the loss in fly ash sales in comparison to Scenario A (current sales).

Table 5: Fly Ash Sales and Disposal Tons

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales & ASM)
Fly Ash Produced (tons/year)	513,000	513,000	513,000
Fly Ash Sold (tons/year)	400,000	0	308,000
Fly Ash Disposed (tons/year)	113,000	513,000	205,000
Lost Fly Ash Sales (tons/year)	0	400,000	92,000

5.1 Ammonia Slip Mitigation

Post-processing of ammonia slip impacted fly ash by Boral’s ASM technology is proposed as an option to maintain fly ash sales. This post-processing is only being applied to the sold fly ash tonnage in Scenario C. Depending on the plant power profile and how the fly ash distribution system is set up, additional tons of fly ash will likely be treated and disposed, but these potential cost impacts are not included. The cost impact for ASM post-processing is shown in Table 6.

Table 6: ASM Post-Processing Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales & ASM)
ASM Unit Rate Capital and O&M ($/ton sold)	$0.00	$0.00	$6.40
ASM Annual Capital and O&M ($/year)	$0	$0	$1,980,000

5.2 Fly Ash Disposal

Disposal costs vary between the scenarios with the per ton cost being reduced by disposal volume. The cost impact for fly ash disposal is shown in Table 7.

Table 7: Fly Ash Disposal Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales & ASM)
Unit Rate Capital and O&M ($/ton disposed)	$26.00	$15.80	$20.60
Annual Capital and O&M ($/year)	$2,940,000	$8,100,000	$4,220,000

5.3 Lost Sales

The current fly ash sales are supported by a large investment in capital infrastructure as well as a large operations and management contingency. Changes to the quantity of fly ash marketed and sold will have a direct impact on fly ash management costs, as the revenue currently used to offset fly ash management will be lost. The lost fly ash sales revenue to GRE is based on the 2014 to 2018 average revenue per ton of $12.40. The cost impact of the potential loss in fly ash sales is shown in Table 8.

Table 8: Cost Impact of Lost Fly Ash Sales

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales & ASM)
Lost Fly Ash Sales Revenue ($/ton lost sales)	$12.40	$12.40	$12.40
Annual Lost Fly Ash Sales Revenue ($/year)	$0	$4,960,000	$1,140,000

5.4 Combined Impact to Fly Ash Management

The combination of the ASM post-processing, fly ash disposal, and lost fly ash sales revenue is shown in Table 9. This table also shows the additional cost impact of Scenario B and Scenario C in comparison with the current sales (Scenario A).

Table 9: Total Fly Ash Management Costs

	Scenario A (Current Sales)	Scenario B (No Sales)	Scenario C (Reduced Sales & ASM)
Total (Disposal + Post-Processing + Lost Sales)			
Annual Cost ($/year)	$2,940,000	$13,060,000	$7,340,000
Unit Cost ($/ton produced)	$5.70	$25.50	$14.30
Additional Cost (Scenario B/C – Scenario A)			
Fly Ash Management Cost ($/year)	-	$10,120,000	$4,400,000
Fly Ash Management Cost ($/ton produced)	-	$19.70	$8.60

The total additional cost impact to fly ash management as a result of an SNCR is estimated between $4.4 and $10.1 million per year.

6.0 CLOSING

We appreciate the opportunity to provide this third-party review of Boral's ASM technology, and an estimate of the potential impact of SNCR on fly ash management costs including disposal and sales. Please contact us if you have any questions about the information provided.

Signature Page

Golder Associates Inc.

Todd Stong

Craig Schuettpelz, PE
Senior Project Engineer

Todd Stong, PE
Associate and Senior Consultant

TJS/CCS/cm

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https://golderassociates.sharepoint.com/sites/102406/deliverables/reports/rpt_fly_ash_sncr_01mar19/19115185_flyashevaluation_fnl_01mar19.docx

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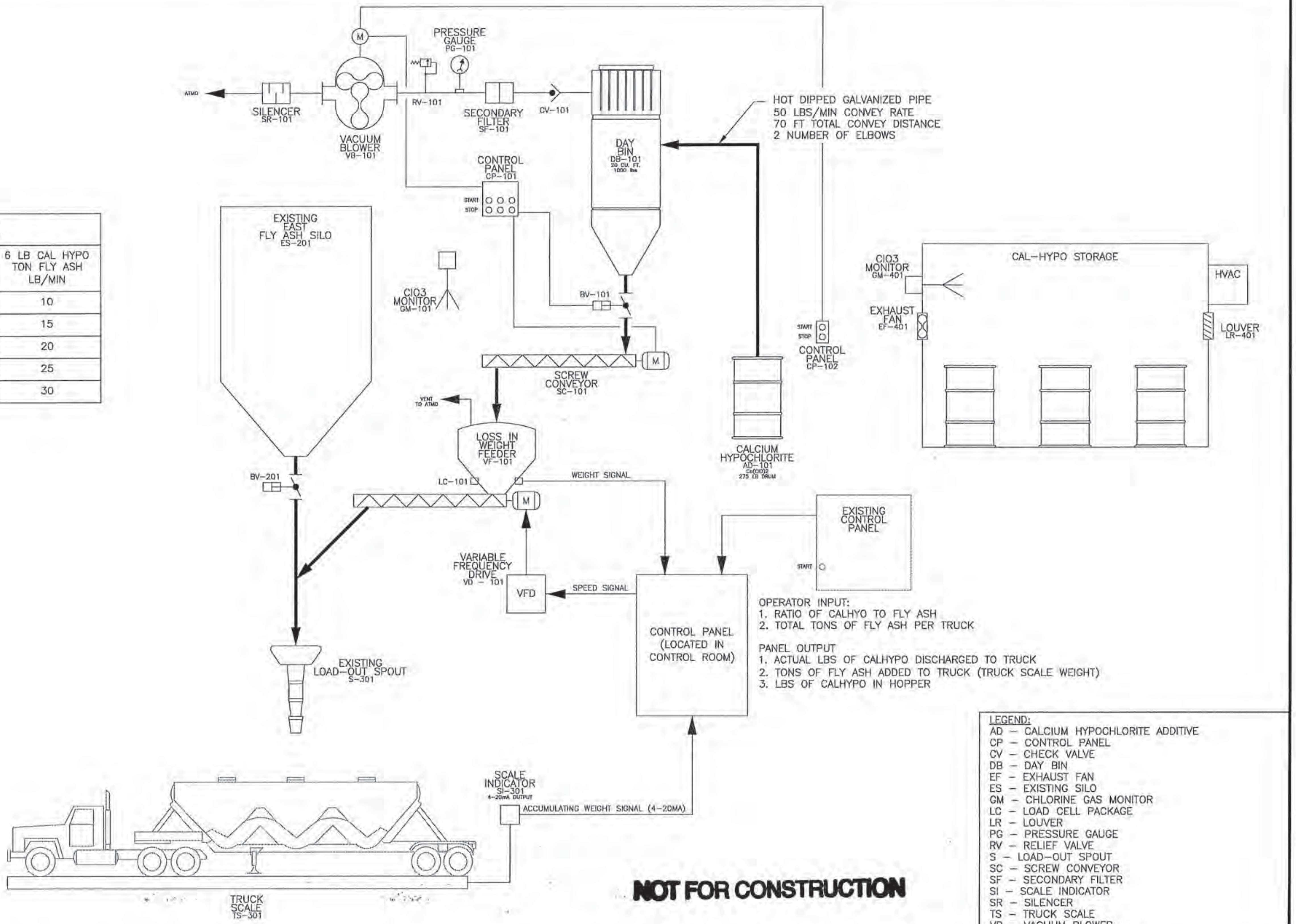
APPENDIX A

EASTLAKE ASM DESIGN DRAWINGS (HEADWATERS RESOURCES)

NOTES:
1. APPROXIMATELY 1½ TO 6 LBS CALCIUM HYPOCHLORITE/TON FLY ASH OR 38 LBS (1½*25) TO 150 LBS (6*25)/TRUCK
2. 30 TRUCKS MAX PER DAY. 1140 LBS (38*30) TO 4500 LBS (150*30) PER DAY
3. FLY ASH FEED RATE 300 TONS/HR TO 150 TONS/HR
4. CALCIUM HYPOCHLORITE FEED RATE 2.5 LBS/MIN TO 30 LBS/MIN
5. TRUCK LOAD TIME BETWEEN 5 AND 10 MINUTES
6. FLY ASH PH BETWEEN 11.5 TO 12
7. FLY ASH DENSITY 70 LBS LOOSE 100 LBS VIBRATED
8. CALHYPO APPROX. 50 LBS/FT^3
9. CALHYPO DRUM 275 LBS

LOSS IN WEIGHT FEEDER RATES

FLY ASH LOAD-OUT TON/HR	1.5 LB CAL HYPO TON FLY ASH LB/MIN	2 LB CAL HYPO TON FLY ASH LB/MIN	4 LB CAL HYPO TON FLY ASH LB/MIN	6 LB CAL HYPO TON FLY ASH LB/MIN
100	2.5	3.3	6.7	10
150	3.75	5.0	10.0	15
200	5	6.7	13.3	20
250	6.25	8.3	16.7	25
300	7.5	10.0	20.0	30



OPERATOR INPUT:
1. RATIO OF CALHYO TO FLY ASH
2. TOTAL TONS OF FLY ASH PER TRUCK

PANEL OUTPUT
1. ACTUAL LBS OF CALHYPO DISCHARGED TO TRUCK
2. TONS OF FLY ASH ADDED TO TRUCK (TRUCK SCALE WEIGHT)
3. LBS OF CALHYPO IN HOPPER

NOT FOR CONSTRUCTION

LEGEND:
AD – CALCIUM HYPOCHLORITE ADDITIVE
CP – CONTROL PANEL
CV – CHECK VALVE
DB – DAY BIN
EF – EXHAUST FAN
ES – EXISTING SILO
GM – CHLORINE GAS MONITOR
LC – LOAD CELL PACKAGE
LR – LOUVER
PG – PRESSURE GAUGE
RV – RELIEF VALVE
S – LOAD-OUT SPOUT
SC – SCREW CONVEYOR
SF – SECONDARY FILTER
SI – SCALE INDICATOR
SR – SILENCER
TS – TRUCK SCALE
VB – VACUUM BLOWER
VD – VARIABLE SPEED DRIVE
VF – VIBRATORY FEEDER

HEADWATERS
RESOURCES

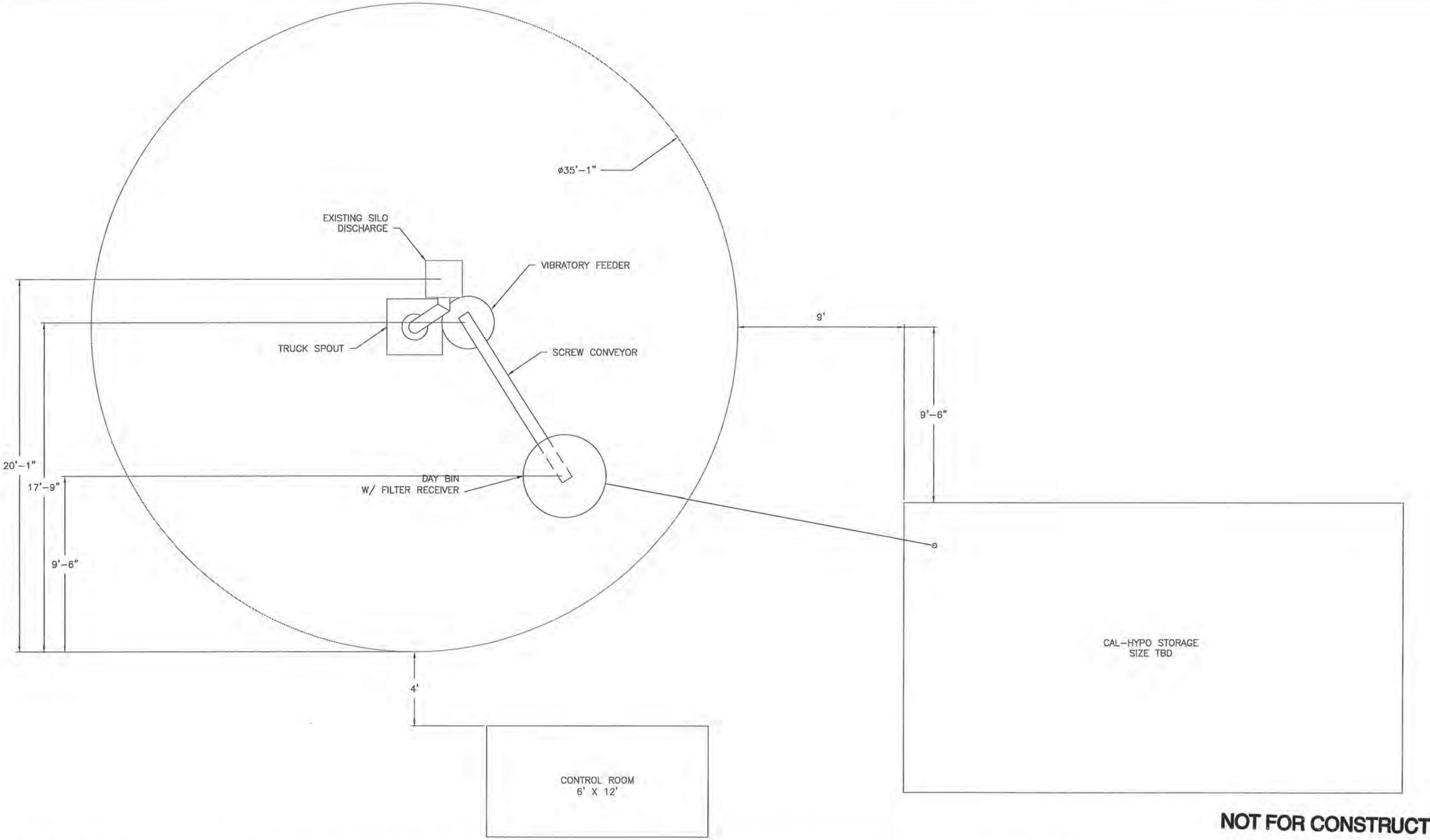
HEADWATERS RESOURCES, INC.
10653 S. RIVER FRONT PARKWAY
SUITE 300
SOUTH JORDAN, UT 84095
(801) 984-9400
FAX (801) 984-9419
www.headwaters.com

DATE	NO.	REVISION DESCRIPTION	BY
8/13/07	G	ADDED EXHAUST FAN & LOUVER	DCB
8/2/07	F	ADDED CONTROL PANELS	DCB
7/16/07	E	ADDED GAS MONITORS AND STORAGE BUILDING	DCB
5/21/07	B	GENERAL REV.	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
PROCESS FLOW DIAGRAM
EAST LAKE, OH

SCALE: NO SCALE
DATE: 05-18-07
DESIGN BY: LS
DRAWN BY: DCB
CHECKED BY:
APPROVED BY:

SHEET NO.
PF100
REVISION NO.
G
PROJECT NO.
R070H0



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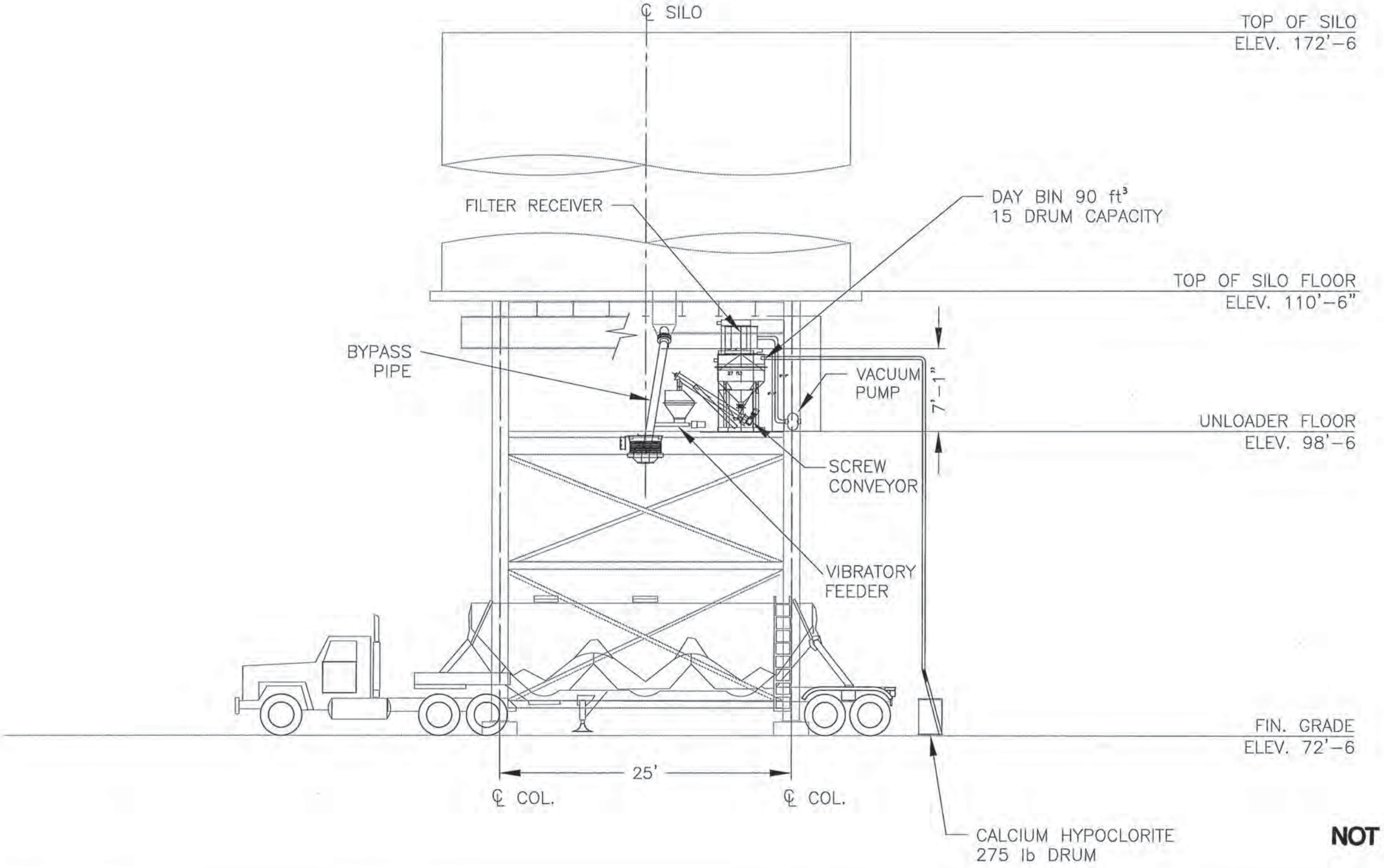
DATE	NO.	REVISION DESCRIPTION	BY
7/18/07	A	DRAWING CREATED	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
PLAN VIEW
EAST LAKE, OH

SCALE: 3/16" = 1'
DATE: 07-18-07

DESIGN BY:	LAS
DRAWN BY:	DCB
CHECKED BY:	
APPROVED BY:	

SHEET NO.
M100
REVISION NO.
A
PROJECT NO.
R07OH0



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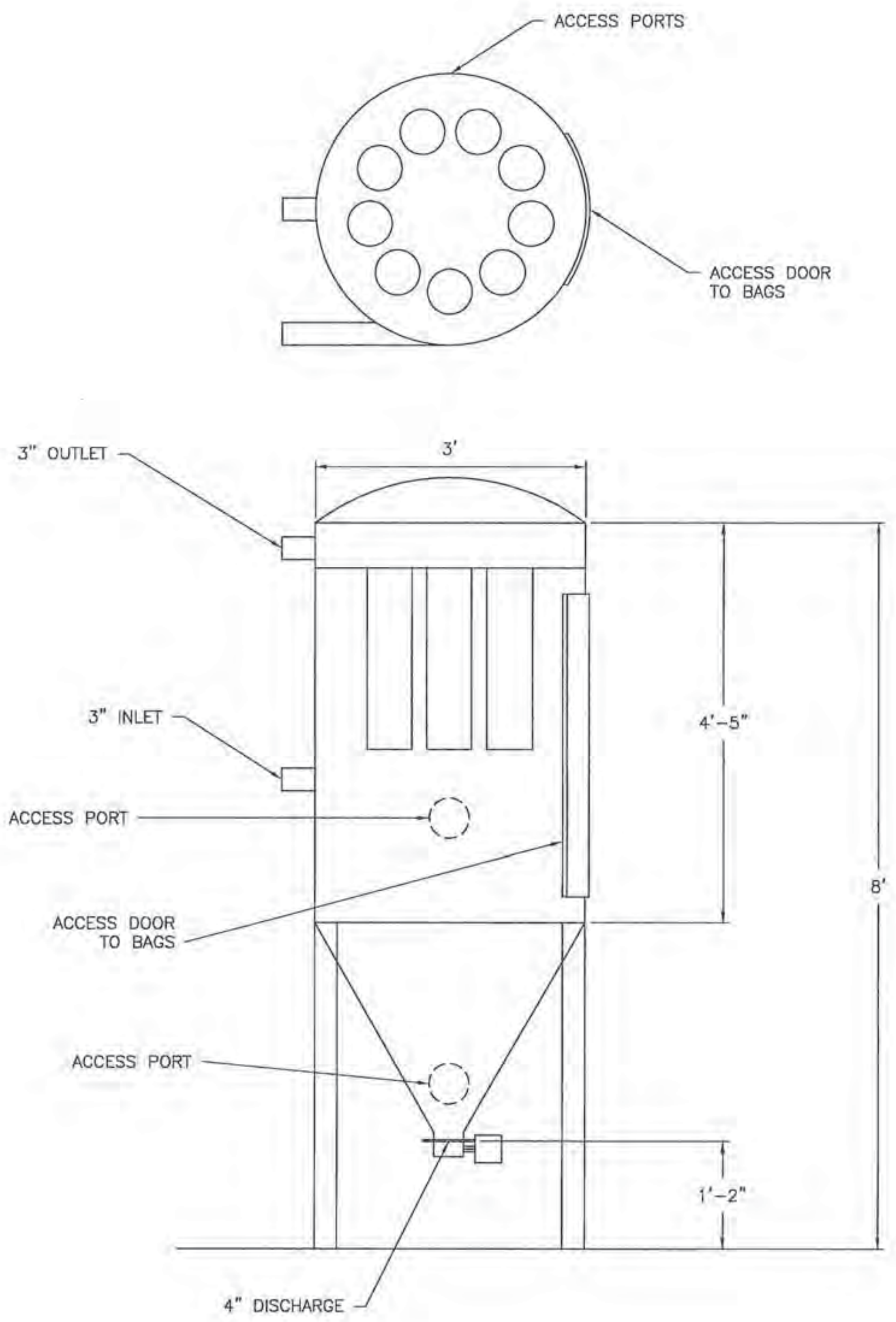
DATE	NO.	REVISION DESCRIPTION	BY
7/18/07	A	DRAWING CREATED	DCB

EAST LAKE
AMMONIA SLIP MITIGATION
ELEVATION
EAST LAKE, OH

SCALE: 1"=10'
DATE: 07-18-07
DESIGN BY: LAS
DRAWN BY: DCB
CHECKED BY:
APPROVED BY:

SHEET NO.
M101
REVISION NO.
A
PROJECT NO.
R07OHO



NOTE:
1. EPOXY PAINT INSIDE AND OUT
2. TOTAL CAPACITY – 17 FT^3
3. USE 2' TEFLON–COATED BAGS

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FAX (801) 984-9419
www.headwaters.com

DATE	NO.	REVISION DESCRIPTION	BY
8/6/07	B	RELOCATED ACCESS PORTS	DCB
8/3/07	A	DRAWING CREATED	DCB

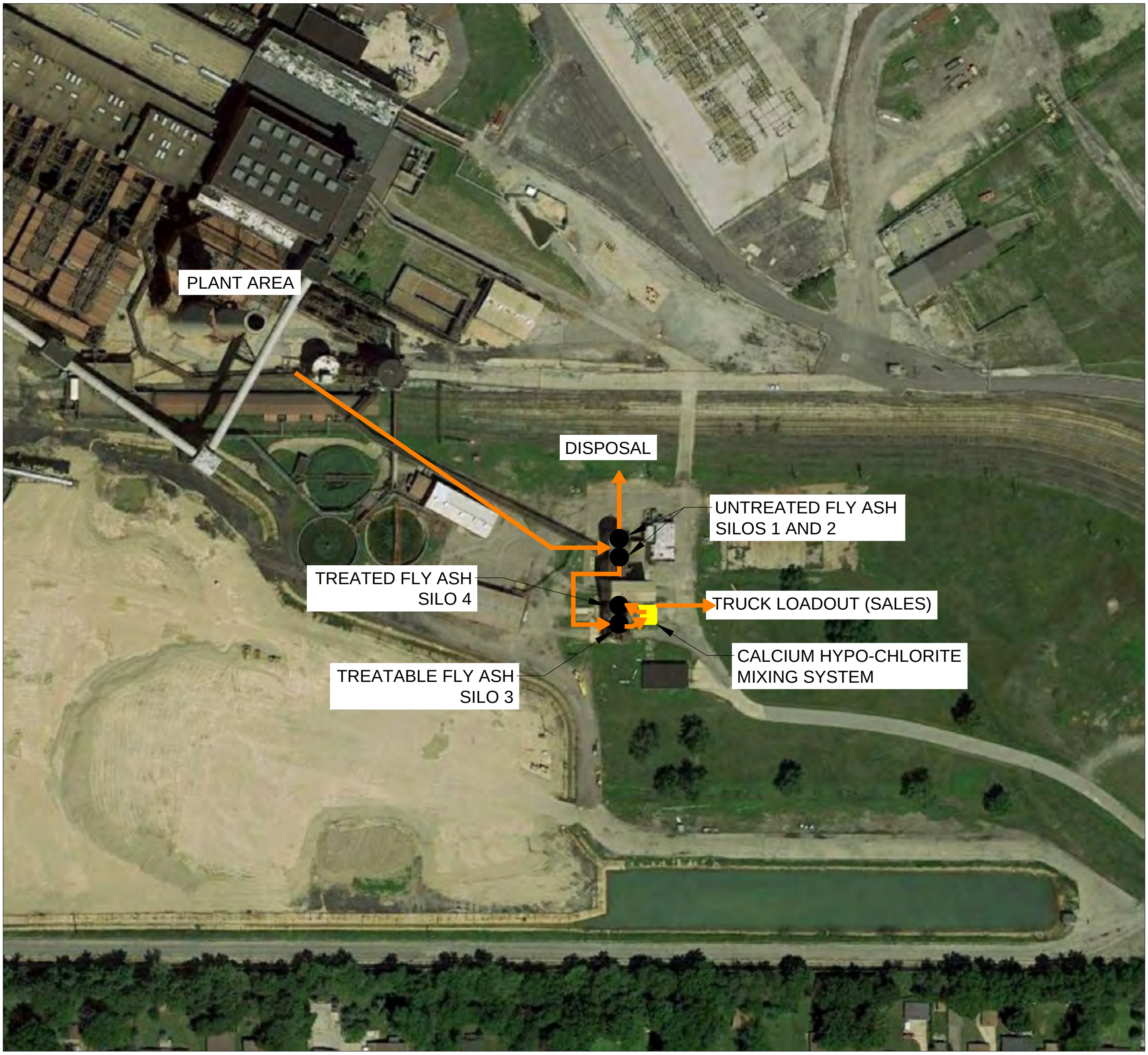
EAST LAKE
AMMONIA SLIP MITIGATION
FILTER RECEIVER
EAST LAKE, OH

SCALE: 1/2" = 1'
DATE: 08-03-07
DESIGN BY: LAS
DRAWN BY: DCB
CHECKED BY:
APPROVED BY:

SHEET NO. M200
REVISION NO. B
PROJECT NO. R070H0

APPENDIX B

COST ESTIMATE DETAILS

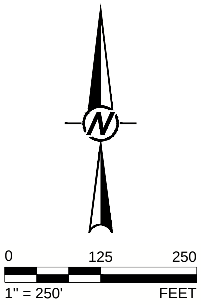


LEGEND

→	FLY ASH STREAM
🟨	CALCIUM HYPO-CHLORITE MIXING SYSTEM

NOTE(S)

1. EASTLAKE GENERATING PLANT HAS A TRUCK LOADOUT FOR BOTH UNTREATABLE FLY ASH DESTINED FOR DISPOSAL (SILOS 1 AND 2) AND TREATED FLY ASH (SILO 4).



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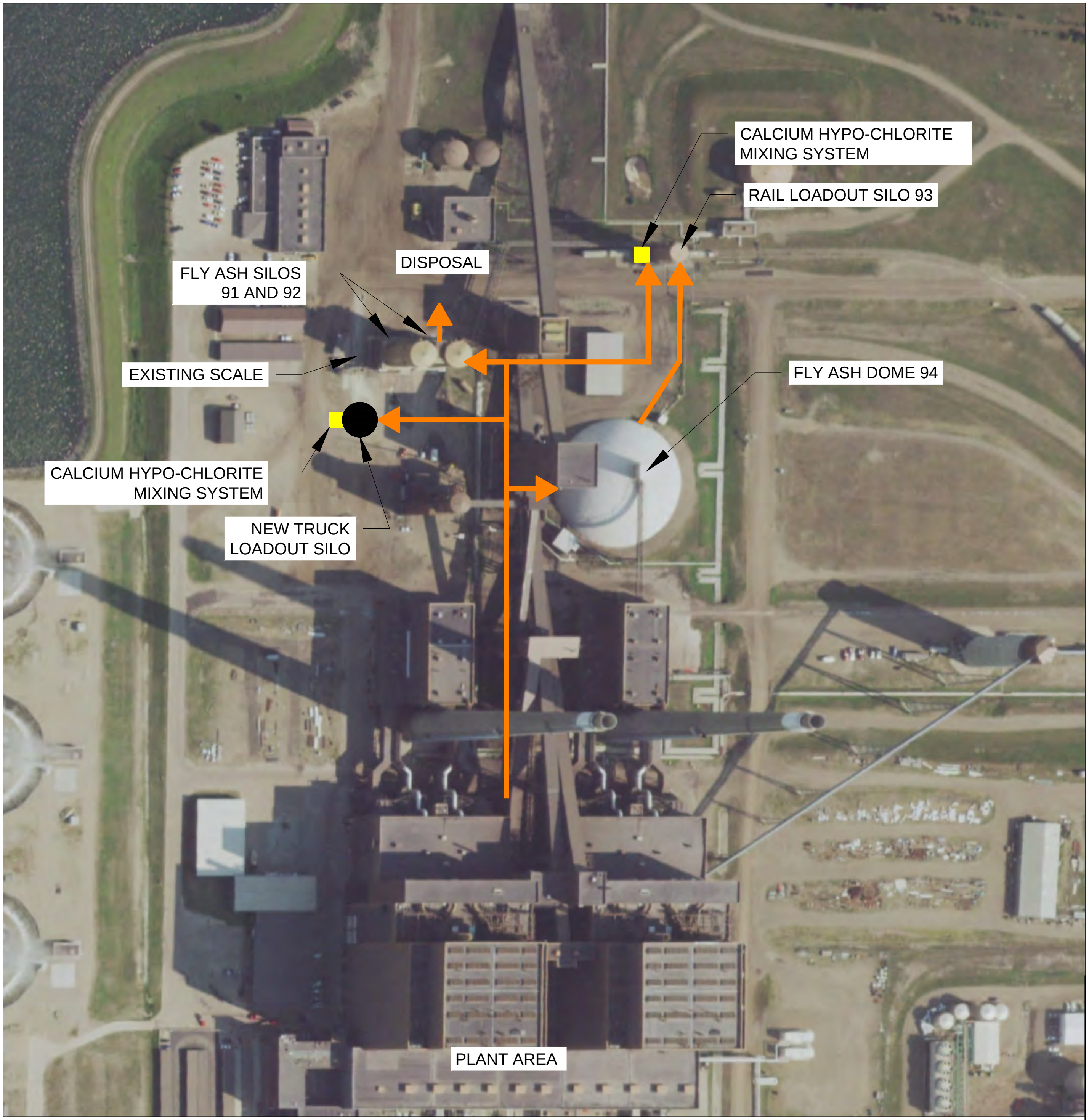
GOLDER

FLY ASH LOADOUT LAYOUT
EASTLAKE GENERATING PLANT

FIGURE 1



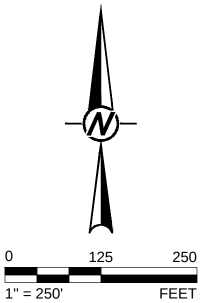
LEGEND

→ FLY ASH STREAM

🟨 CALCIUM HYPO-CHLORITE MIXING SYSTEM

NOTE(S)

1. NEW TRUCK LOADOUT SILO AND SCALE ARE REQUIRED TO STORE TREATABLE FLY ASH FOR SALE.
2. TWO CALCIUM HYPO-CHLORITE MIXING SYSTEMS WOULD BE REQUIRED NEAR THE NEW TRUCK LOADOUT SILO AND THE RAIL LOADOUT SILO (93) FOR TREATING FLY ASH AVAILABLE FOR SALE.
3. THE EXISTING FLY ASH SILOS (91 AND 92) ARE AVAILABLE TO STORE UNTREATABLE FLY ASH FOR DISPOSAL.
4. THE EXISTING FLY ASH DOME (94) IS AVAILABLE TO STORE TREATABLE FLY ASH FOR RAIL SALE.



GOLDER

FLY ASH LOADOUT LAYOUT
COAL CREEK STATION

FIGURE 2

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LEGEND

═══ TOP OF CONTAINMENT FACILITY CONTOURS

▭ ▭ ▭ HAUL ROAD TO BE CONSTRUCTED

)(COUNTY ROAD CROSSING TO BE CONSTRUCTED

N

0 400 800

1" = 800' FEET

SCENARIO A
FLY ASH CONTAINMENT FACILITY

GOLDER

FIGURE 3

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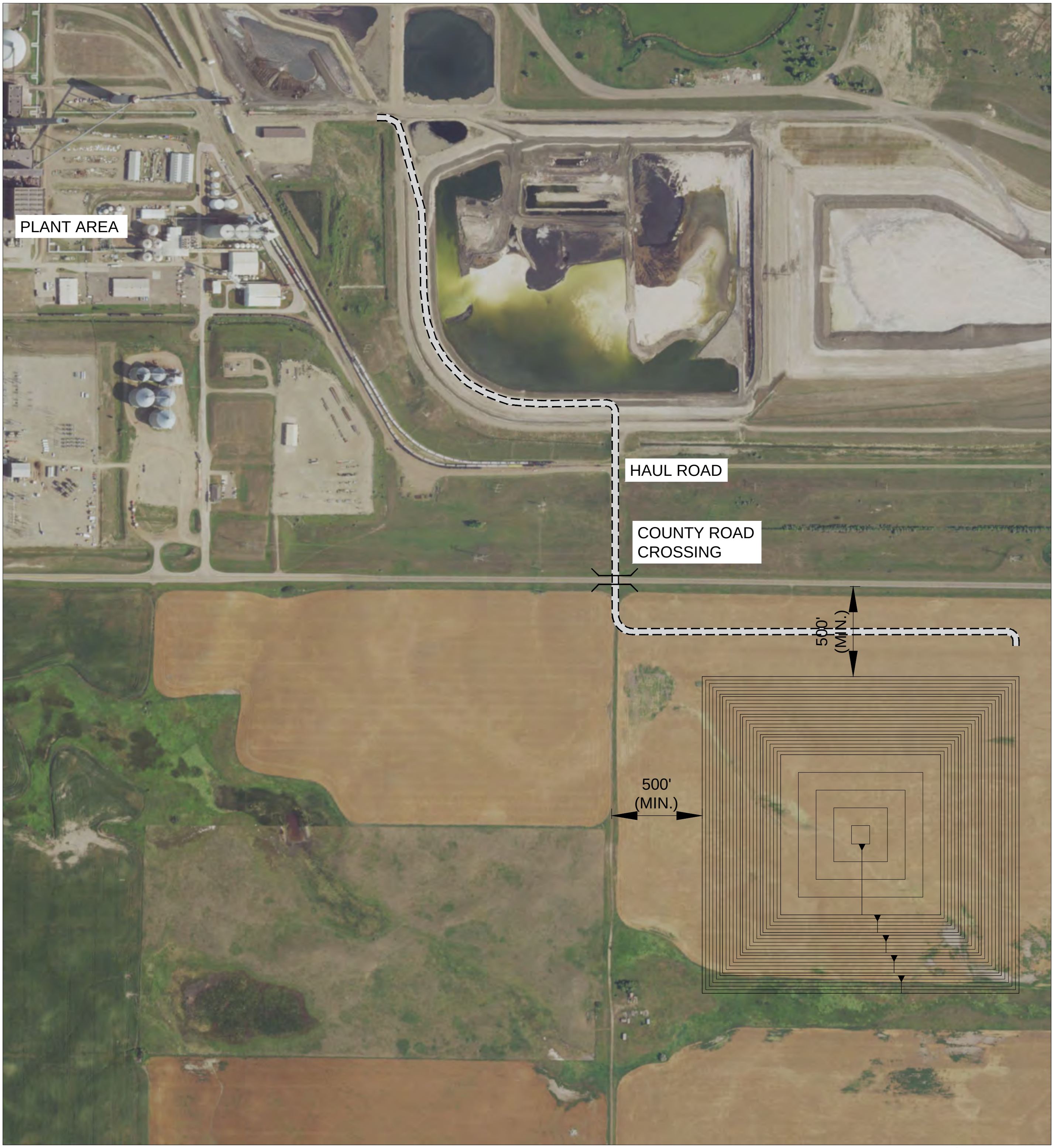

LEGEND

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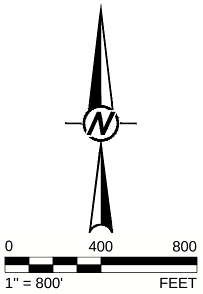
┅ HAUL ROAD TO BE CONSTRUCTED

)(COUNTY ROAD CROSSING TO BE CONSTRUCTED



SCENARIO B
FLY ASH CONTAINMENT FACILITY

GOLDER

FIGURE 4

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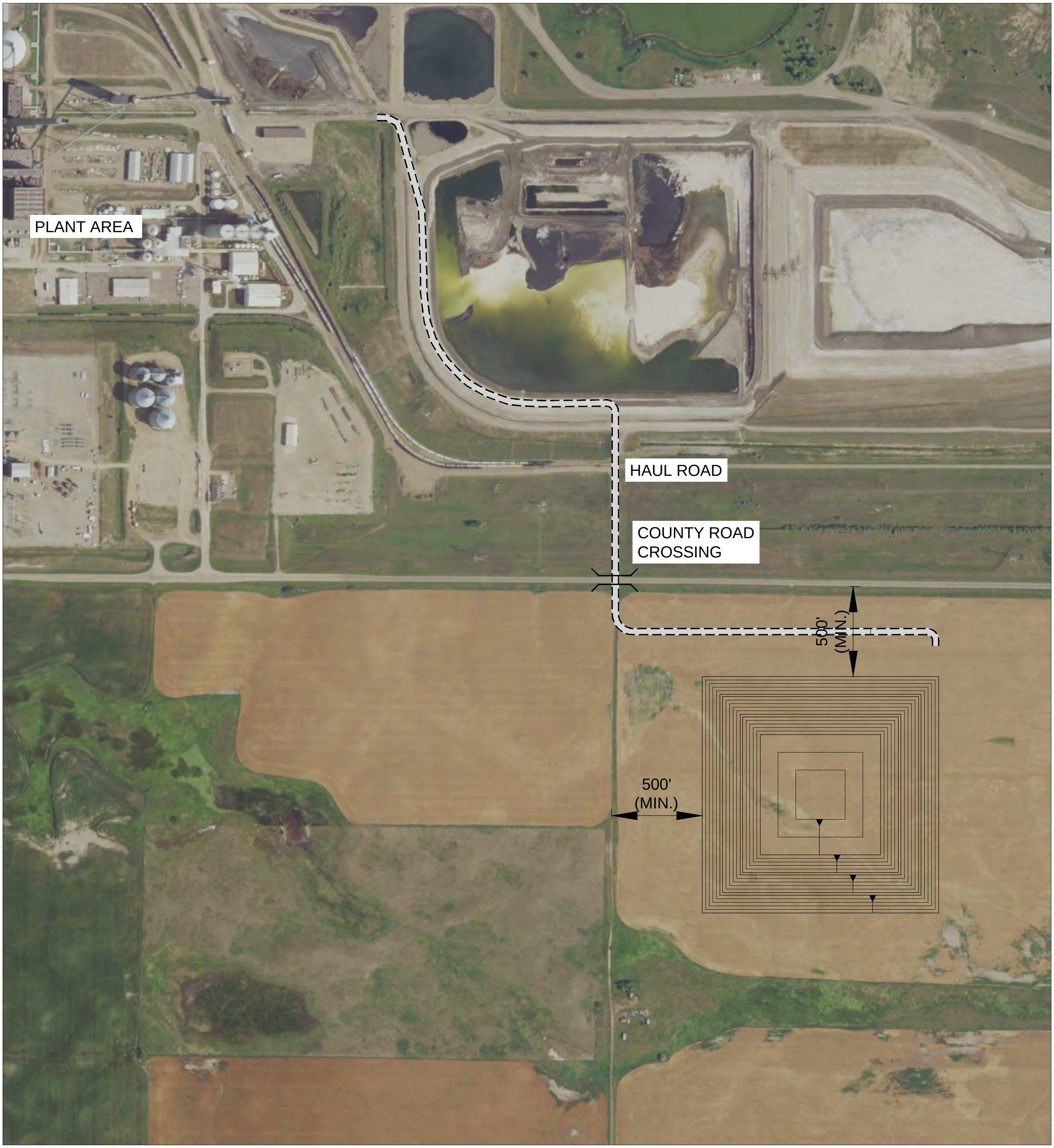
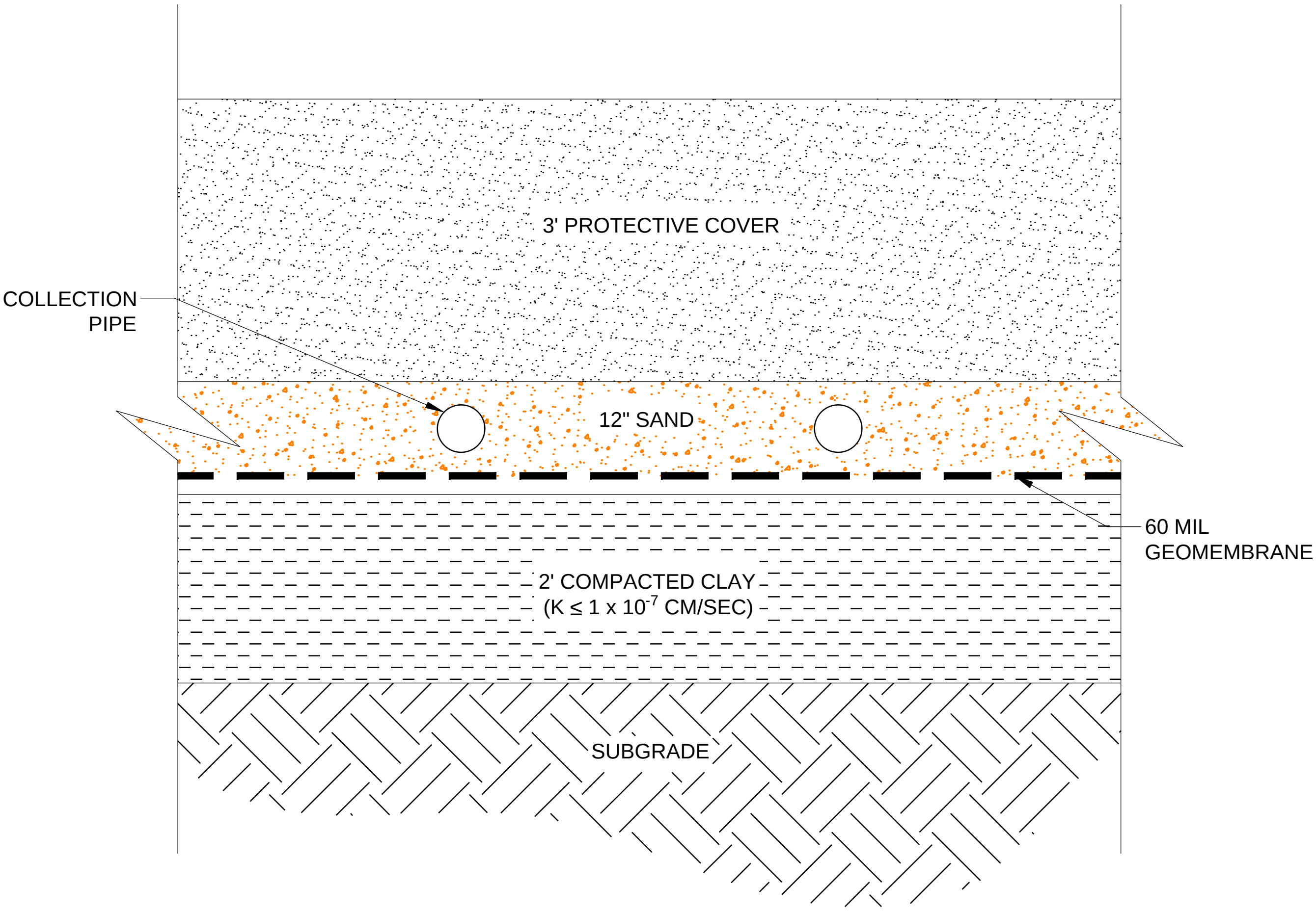


LEGEND

☰	TOP OF CONTAINMENT FACILITY CONTOURS
▭	HAUL ROAD TO BE CONSTRUCTED
⨯	COUNTY ROAD CROSSING TO BE CONSTRUCTED

SCENARIO C
FLY ASH CONTAINMENT FACILITY

FIGURE 5



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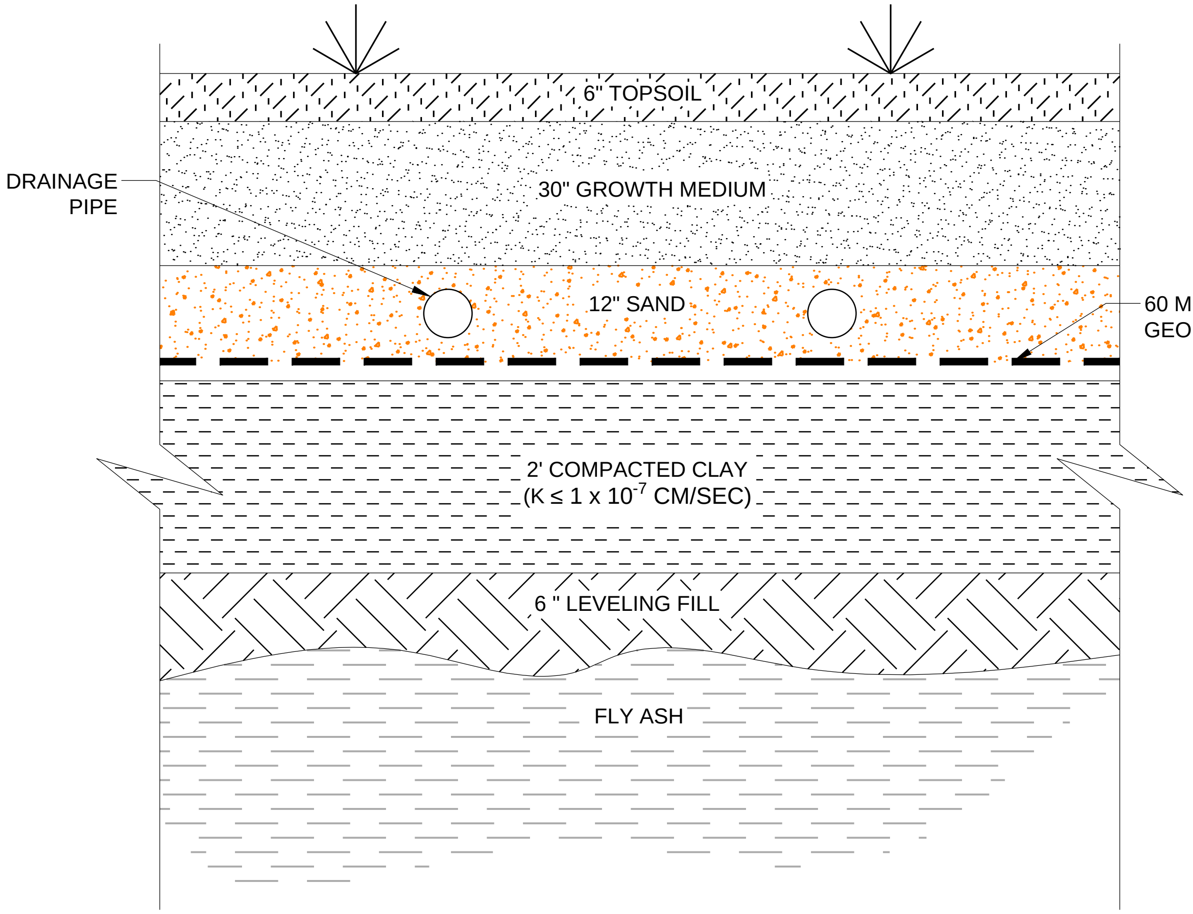
GOLDER

COMPOSITE LINER DETAIL

FIGURE 6



GOLDER

COMPOSITE COVER DETAIL

FIGURE 7

Fly Ash Management Impact Evaluation Summary (March 1, 2019)

	Scenario A	Scenario B	Scenario C
	Current fly ash sales with new EPA CCR Rule landfill	No fly ash sales with new EPA CCR Rule landfill	ASM technology to allow reduced fly ash sales with new EPA CCR Rule landfill
Fly Ash Quantities			
Fly Ash production (ton/yr)	513,000	513,000	513,000
Fly Ash Sales (ton/yr)	400,000	0	308,000
Fly Ash Disposal (ton/yr)	113,000	513,000	205,000
Lost Fly Ash Sales (ton/yr)	0	400,000	92,000
ASM Fly Ash Post Processing			
ASM Unit Rate Capital and O&M ($/ton sold)	$ -	$ -	$ 6.40
ASM Annual Capital and O&M ($/yr)	$ -	$ -	$ 1,980,000
Fly Ash Disposal			
Lined Footprint (acres)	24.5	72.0	36.5
Unit Rate Capital and O&M ($/ton disposed)	$ 26.00	$ 15.80	$ 20.60
Annual Capital and O&M ($/yr)	$ 2,940,000	$ 8,100,000	$ 4,220,000
Lost Fly Ash Sales			
Lost Fly Ash Sales Revenue ($/ton lost sales)	$ 12.40	$ 12.40	$ 12.40
Annual Lost Fly Ash Sales Revenue ($/yr)	$ -	$ 4,960,000	$ 1,140,000
Total (Disposal + Post Processing + Lost Sales)			
Annual Cost ($/yr)	$ 2,940,000	$ 13,060,000	$ 7,340,000
Unit Cost ($/ton produced)	$ 5.70	$ 25.50	$ 14.30
Additional Cost (Scenario B/C - Scenario A)			
Fly Ash Management Cost ($/yr)	-	$ 10,120,000	$ 4,400,000
Fly Ash Management Cost ($/ton produced)	-	$ 19.70	$ 8.60

<u>Notes:</u>

Capital costs annualized based on 20-year life and 5.25% interest rate.

Disposal costs based on new facility built across county road from Coal Creek Station with 20-year life.

EPA CCR Rule compliant facility (composite liner, leachate collection system, and composite cover).

Disposal costs only include fly ash disposal and not facility airspace or O&M for other CCPs.

Ammonia slip mitigation costs based on existing facility site visit and historic costs for fly ash infrastructure.

All costs are in 2019 dollars.

Lost fly ash sales revenue based on average per ton revenue to GRE between 2014 and 2018.

Existing fly ash sales infrastructure and O&M costs are not included.

Scenario A - Current Sales

Project	19115185
Date	3/1/2019
By	PDS
Checked	CCS

Sizing Information

Annual Fly Ash Disposal	113,000	tn	
20yr Fly Ash Disposal	2,260,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	1,860,000	cy	
Lined Footprint	24.5	ac	80,000 cy/ac
Disturbance Footprint	35.0	ac	100' offset on liner footprint
Berm Length	4,300	ft	20' offset on liner footprint
Total Footprint	160	ac	500' offset on liner footprint, nearest 1/8 section
Total Cover Area	27.0	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	**Rate**		**#**		**Total Cost**	
Land Acquisition	$ 4,000	/ac	160.0	ac	$ 640,000	
Infrastructure Development	$ 851,000	ea	1.0	LS	$ 850,000	
County Road Crossing	$ 1,887,000	ea	1.0	LS	$ 1,890,000	
Liner Construction	$ 243,000	/ac	24.5	ac	$ 5,950,000	
Final Cover Construction	$ 201,000	/ac	27.0	ac	$ 5,430,000	
Post-Closure Care	$ 106,000	/yr	30.0	yr	$ 3,180,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 14,120,000	LS	$ 1,410,000	
Construction Quality Assurance (on construction)	10.0%	-	$ 14,120,000	LS	$ 1,410,000	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 20,760,000	-	$ 2,080,000	
Project Contingency (on construction & land)	20.0%	-	$ 14,760,000	-	$ 2,950,000	
			Total Direct/Capital Costs		$ 25,790,000	
			Annualized Capital Cost*		$ 2,110,000	/yr
			Capital Costs		$ 18.70	/tn

Operational Costs

Hauling Costs	$ 3.30	/tn	113,000	tn/yr	$ 370,000	/yr
Placement Costs	$ 2.30	/tn	113,000	tn/yr	$ 260,000	/yr
Maintenance Costs	$ 196,000	/yr	1	yr	$ 200,000	/yr
			Annual Operational Costs		$ 830,000	/yr
			Operational Costs		$ 7.30	/tn

TOTAL DISPOSAL COSTS

Annual Costs	$ 2,940,000	/yr
20-Year Total Costs	$ 58,800,000	
Per Ton Cost	$ 26.00	/tn

Notes:

*Annualized capital cost based on 20-year life and 5.25% interest rate.

All costs are in 2019 dollars.

Scenario B - No Fly Ash Sales

Project	19115185
Date	3/1/2019
By	PDS
Checked	CCS

Sizing Information

Annual Fly Ash Disposal	513,000	tn	
20yr Fly Ash Disposal	10,260,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	8,444,000	cy	
Lined Footprint	72.0	ac	120,000 cy/ac
Disturbance Footprint	89.0	ac	100' offset on liner footprint
Berm Length	7,240	ft	20' offset on liner footprint
Total Footprint	240	ac	500' offset on liner footprint, nearest 1/8 section
Total Cover Area	79.0	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	**Rate**		**#**		**Total Cost**	
Land Acquisition	$ 4,000	/ac	240.0	ac	$ 960,000	
Infrastructure Development	$ 1,020,000	ea	1.0	LS	$ 1,020,000	
County Road Crossing	$ 1,887,000	ea	1.0	LS	$ 1,890,000	
Liner Construction	$ 239,000	/ac	72.0	ac	$ 17,210,000	
Final Cover Construction	$ 183,000	/ac	79.0	ac	$ 14,460,000	
Post-Closure Care	$ 154,000	/yr	30.0	yr	$ 4,620,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 34,580,000	LS	$ 3,460,000	
Construction Quality Assurance (on construction)	10.0%	-	$ 34,580,000	LS	$ 3,460,000	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 47,080,000	-	$ 4,710,000	
Project Contingency (on construction & land)	20.0%	-	$ 35,540,000	-	$ 7,110,000	
			Total Direct/Capital Costs		$ 58,900,000	
			Annualized Capital Cost*		$ 4,830,000	/yr
			Capital Costs		$ 9.40	/tn

Operational Costs

Hauling Costs	$ 3.30	/tn	513,000	tn/yr	$ 1,690,000	/yr
Placement Costs	$ 2.30	/tn	513,000	tn/yr	$ 1,180,000	/yr
Maintenance Costs	$ 396,000	/yr	1	yr	$ 400,000	/yr
			An. Operational Costs		$ 3,270,000	/yr
			Operational Costs		$ 6.40	/tn

TOTAL DISPOSAL COSTS

Annual Costs	$ 8,100,000	/yr
20-Year Total Costs	$ 162,000,000	
Per Ton Cost	$ 15.80	/tn

Notes:

*Annualized capital cost based on 20-year life and 5.25% interest rate.

All costs are in 2019 dollars.

Scenario C - Partial Fly Ash Sales with ASM

Project	19115185
Date	3/1/2019
By	PDS
Checked	CCS

Sizing Information

Annual Fly Ash Disposal	205,000	tn	
20yr Fly Ash Disposal	4,100,000	tn	
Fly Ash Dry Density (in-situ)	90	pcf	
20yr Fly Ash Quantity	3,374,000	cy	
Lined Footprint	36.5	ac	90,000 cy/ac
Disturbance Footprint	49.0	ac	100' offset on liner footprint
Berm Length	5,200	ft	20' offset on liner footprint
Total Footprint	160	ac	500' offset on liner footprint, nearest 1/8 section
Total Cover Area	40.0	ac	1.1 ration of cover area to liner area

Direct/Capital Costs

Item	**Rate**		**#**		**Total Cost**	
Land Acquisition	$ 4,000	/ac	160.0	ac	$ 640,000	
Infrastructure Development	$ 865,000	ea	1.0	LS	$ 870,000	
County Road Crossing	$ 1,887,000	ea	1.0	LS	$ 1,890,000	
Liner Construction	$ 241,000	/ac	36.5	ac	$ 8,800,000	
Final Cover Construction	$ 198,000	/ac	40.0	ac	$ 7,920,000	
Post-Closure Care	$ 120,000	/yr	30.0	yr	$ 3,600,000	
Facility Design & Permitting (on construction)	10.0%	-	$ 19,480,000	LS	$ 1,950,000	
Construction Quality Assurance (on construction)	10.0%	-	$ 19,480,000	LS	$ 1,950,000	
GRE Internal Costs (on construction, design, CQA, & land purchase)	10.0%	-	$ 27,620,000	-	$ 2,760,000	
Project Contingency (on construction & land)	20.0%	-	$ 20,120,000	-	$ 4,020,000	
				Total Direct/Capital Costs	$ 34,400,000	
				Annualized Capital Cost*	$ 2,820,000	/yr
				Capital Costs	$ 13.80	/tn

Operational Costs

Hauling Costs	$ 3.30	/tn	205,000	tn/yr	$ 680,000	/yr
Placement Costs	$ 2.30	/tn	205,000	tn/yr	$ 470,000	/yr
Maintenance Costs	$ 246,000	/yr	1	yr	$ 250,000	/yr
				An. Operational Costs	$ 1,400,000	/yr
				Operational Costs	$ 6.80	/tn

TOTAL DISPOSAL COSTS

Annual Costs	$ 4,220,000	/yr
20-Year Total Costs	$ 84,400,000	
Per Ton Cost	$ 20.60	/tn

Notes:

*Annualized capital cost based on 20-year life and 5.25% interest rate.

All costs are in 2019 dollars.

ASM Post-Processing

Project	19115185
Date	3/1/2019
By	PDS
Checked	TJS

Sizing Information

Annual Fly Ash Sales	308,000	tn

Direct/Capital Costs

Item	**Rate**		**#**		**Total Cost**	
New Truck Load-out Silo	$ 2,021,000	ea	1.0	LS	$ 2,020,000	
Cal-Hypo Feed Systems (Rail silo)	$ 288,000	ea	1.0	LS	$ 290,000	
Cal-Hypo Feed Systems (New silo)	$ 385,000	ea	1.0	LS	$ 390,000	
System Design & Engineering (on construction)	10.0%	-	$ 2,700,000	-	$ 270,000	
GRE Internal Costs (on all)	10.0%	-	$ 2,970,000	-	$ 300,000	
Project Contingency (on construction)	20.0%	-	$ 2,700,000	-	$ 540,000	
				Total Direct/Capital Costs	$ 3,810,000	
				Annualized Capital Cost*	$ 310,000	/yr
				Capital Costs	$ 1.00	/tn

Operational Costs

Maintenance	$ 90.00	$/hr	4,600	hr	$ 410,000	/yr
Maintenance Materials	50%	-	$ 410,000	-	$ 210,000	/yr
Operations Materials	$ 90.00	$/hr	5,750	hr	$ 520,000	/yr
Operations Materials (Cal-Hypo)	$ 0.70	/tn	308,000	tn/yr	$ 220,000	/yr
Technology Royalty	$ 1.00	/tn	308,000	tn/yr	$ 310,000	/yr
				An. Operational Costs	$ 1,670,000	/yr
				Operational Costs	$ 5.40	/tn

TOTAL ASM COSTS

Annual Costs	$ 1,980,000	/yr
20-Year Total Costs	$ 39,600,000	
Per Ton Cost	$ 6.40	/tn

Notes:

*Annualized capital cost based on 20-year life and 5.25% interest rate.

Capital costs based on previous silo construction and discussions with Headwaters.

Assumed calcium hypo-chlorite cost of $1.25/lb.

Calcium hypo-chlorite mix rate is estimated between 0.3 and 1.3 lbs per 3,000 lbs of fly ash.

Scenario A (Current Sales) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development			Total	$ 850,500	**$ 851,000**	
General						
Mobilize/Demobilize	5%	%	$ -	$ 38,659.11		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 38,659.11		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Road Topsoil Stripping and Stockpiling	3,200	CY	$ 2.64	$ 8,448	Crew analysis, dozer work	18" topsoil
Access Road Construction	186,200	SF	$ 1.47	$ 273,714	32 11 23.23 RS Means 2019 Bismarck	8" thick, Crushed 1-1/2"stone base, compacted to 4" deep, 5,320' x 35'
Return Water Pipeline						
Trench Excavation	8,300	CY	$ 2.94	$ 24,439	Crew analysis	
6" Pipeline	5,600	LF	$ 12.00	$ 67,200	33 14 13.35 RS Means 2019 Bismarck	DR25 PVC
Misc. Appurtenances	1	EA	$ 10,000.00	$ 10,000		
Pipe Bedding & Embedment	1,700	CY	$ 4.99	$ 8,475	Crew analysis	
Trench Backfill	5,700	CY	$ 3.59	$ 20,485	Crew analysis	
Topsoil	900	CY	$ 3.52	$ 3,168	Crew analysis	
Marking Tape	5,600	LF	$ 0.10	$ 560	Underground Warning tape - via web search	
Tracer Wire	5,600	LF	$ 0.20	$ 1,120	14 gauge burial wire - via web search	
Fence	8,132	LF	$ 28.23	$ 229,574	32 31 13.20 RS Means 2019 Bismarck	6' Chain link fence, 3 strands barb wire
Overhead Power (Plant to Landfill)	1	EA	$ 90,000	$ 90,000	RS Means 2019 Bismarck 33.71.39.13.0150 33.71.16.33.5060	Pipeline length + 20% One utility pole every 200 feet
Monitoring Well Installation	6	EA	$ 6,000	$ 36,000	Golder Estimate	
County Road Crossing			Total	$ 1,886,520	**$ 1,887,000**	
General						
Mobilize/Demobilize	5%	%	$ -	$ 85,751		
Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 85,751		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Topsoil Stripping and Stockpiling	4,577	CY	$ 2.64	$ 12,083	Crew analysis, dozer work	18" topsoil
Embankment Fill	5,776	CY	$ 6.49	$ 37,510	Crew analysis	
County Road Base Course	32,200	SF	$ 2.13	$ 68,586	32 11 23.23 RS Means 2019 Bismarck	12" Gravel base course Crushed 1-1/2"stone base, compacted to 4" deep
County Road Asphalt Pavement	3,578	SY	$ 35.45	$ 126,838	RSMeans 2019, Bismarck 32 12 16.13.1595 32.12.16.13.1460 31.23.23.20.1114	2" Binder Course 4" Wearing Course
Bridge Deck Construction	4,900	SF	$ 300	$ 1,470,000	2016 California DOT cost range	140 ft bridge deck, 35 ft wide
Liner Construction			Total	$ 5,962,218	Cost Per Acre of Liner	**$ 243,000**
General						
Mobilize/Demobilize	5%	%	$ -	$ 271,010		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 271,010		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Clearing and Grubbing	35	AC	$ 4,500.00	$ 157,500	31 11 10.10 RS Means 2019 Bismarck	Clear & grub brush including stumps
Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.64		Crew analysis	
	35	AC	$ 6,389	$ 223,608		
Subgrade Cut to Stockpile	297,800	CY	$ 5.62	$ 1,674,165	Crew analysis	10' deep cut across liner area: for liner, berms and cover
Subgrade Cut/Embankment Fill	97,467	CY	$ 6.49	$ 632,930	Crew analysis	612 ft2 cross section area
Low Permeability Soil Liner (24")	-	CY	$ 6.56		Crew analysis	
	25	AC	$ 21,161	$ 518,456		
60-mil HDPE Liner	-	SF	$ 0.75		Recent construction	Materials, waste, conformance testing, installation
	25	AC	$ 32,670	$ 800,415		
Leachate Collection Layer, Sand (12")		CY	$ 29.70		Crew analysis for haul/place from Bismarck	
	25	AC	$ 47,916	$ 1,173,942		
Protective Cover (3')	-	CY	$ 6.33		Crew analysis	Fly ash as protective cover
	6	AC	$ 30,626	$ 187,584		Contractor place 25% of liner area (side slopes, haul routes)
Piping						
LCS 4" Piping	4,570	LF	$ 3.92	$ 17,914	33 42 11.50 RS Means 2019 Bismarck	4" Corrugated HDPE
LCS 8" Piping	910	LF	$ 7.78	$ 7,080	33 42 11.50 RS Means 2019 Bismarck	8" Corrugated HDPE
LCS Sump/Riser	1	EA	$ 20,000	$ 20,000	Golder Estimate	
Equipment and Electrical						
Power Posts at Pumps/Sumps	1	EA	$ 1,605	$ 1,605	26 24 16.30-0150 RS Means 2019 Bismarck	Panelboard/utility box with outlets
Collection pump	1	EA	$ 5,000	$ 5,000	Golder Estimate	

Scenario A (Current Sales) Unit Rate Details

PROJECT COMPONENT		QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover				Total	$ 5,415,669	Cost Per Acre of Cover	$ 201,000
General							
	Mobilize/Demobilize	5%	%	$ -	$ 246,167		
	Miscellaneous Site Work & Materials	5%	%	$ -	$ 246,167		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil							
	Leveling Fill (6")	-	CY	$ 6.49		Crew analysis	Stockpile cut to embankment fill
		27	AC	$ 5,238	$ 141,435		
	Compacted Low Permeability Soil Liner (24")	-	CY	$ 6.56		Crew analysis	Stockpile cut to embankment fill
		27	AC	$ 21,161	$ 571,360		
	60-mil HDPE Liner	-	SF	$ 0.75		Recent construction	Materials, waste, conformance testing, installation
		27	AC	$ 32,670	$ 882,090		
	Drainage Layer, Sand (12")		CY	$ 29.70		Crew analysis for haul/place from Bismarck	
		27	AC	$ 47,916	$ 1,293,732		
	Growth Medium (30")		CY	$ 6.34		Crew analysis	
		27	AC	$ 25,578	$ 690,599		
	Topsoil (6")		CY	$ 6.34		Crew analysis	
		27	AC	$ 5,116	$ 138,120		
	Downchute Channels	57,600	SF	$ 20.00	$ 1,152,000	Golder Estimate	36' wide, 4 downchutes
	Seed and Mulch	27	AC	$ 2,000	$ 54,000	32 92 19.14-4600 RS Means 2019 Bismarck	Seed, mulch & fertilizer, hydro or air seeding
Post Closure Care				Total	$ 105,500	$ 106,000	
	CCR Groundwater Monitoring & Reporting	1	EA	$ 25,000	$ 25,000	Golder Estimate	
	Update CCR Baseline, Network Cert., and Statistical Method Cert. As Needed	1	EA	$ 24,000	$ 24,000	Golder Estimate	
	Annual Site Inspection	1	EA	$ 10,000	$ 10,000	Golder Estimate	
	Annual Dust Control Report	1	EA	$ 2,000	$ 2,000	Golder Estimate	
	Other CCR Requirements	1	EA	$ 4,600	$ 4,600	Golder Estimate	
	Final Cover Repair	1	EA	$ 5,500	$ 5,500	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
	Seeding Repair	1	EA	$ 5,400	$ 5,400	Golder Estimate	10% of cover area
	Mowing and/or rodent, weed, & tree control	1	EA	$ 2,200	$ 2,200	Golder Estimate	$2,000 per 25 acres
	Surface Water Controls Maintenance	1	EA	$ 17,500	$ 17,500	Golder Estimate	1% of armored channel replaced + other repairs
	Gate and/or fence Maintenance	1	EA	$ 2,300	$ 2,300	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 1,600	$ 1,600	Golder Estimate	$1,500 per 25 acres
	Direct Expenses	1	EA	$ 5,400	$ 5,400	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)				Total	$ 195,800	$ 196,000	
	CCR Groundwater Monitoring & Reporting	1	EA	$ 25,000	$ 25,000	Golder Estimate	
	Update CCR Baseline, Network Cert., and Statistical Method Cert. As Needed	1	EA	$ 24,000	$ 24,000	Golder Estimate	
	Annual Site Inspection	1	EA	$ 10,000	$ 10,000	Golder Estimate	
	Annual Dust Control Report	1	EA	$ 2,000	$ 2,000	Golder Estimate	
	Other CCR Requirements	1	EA	$ 4,600	$ 4,600	Golder Estimate	
	Engineering Support	1	EA	$ 49,000	$ 49,000	Golder Estimate	$50,000 per 25 acres of liner
	Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
	Gate and/or fence Maintenance	1	EA	$ 2,300	$ 2,300	Golder Estimate	1% of fence
	Recordkeeping	1	EA	$ 4,900	$ 4,900	Golder Estimate	$5,000 per 25 acres
	Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 49,000	$ 49,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs							
	Haul Cost	1	CY	$ 3.30	$ 3.30	31 23 23.20-8180 RSMeans 2019 Bismarck	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
	Haul Cost	1	TON	$ 3.30	$ 3.30	Golder Estimate	75pcf haul density (1 ton/cy)
	Place Cost	1	CY	$ 1.90	$ 1.90	31 23 23.17-0020 RSMeans 2019 Bismarck	Dozer, no compaction
	Place Cost	1	TON	$ 2.30	$ 2.30	Golder Estimate	90pcf placed density (1.2 ton/cy)

Scenario B (No Sales) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development			Total	$ 1,019,878	$ 1,020,000	
General						
Mobilize/Demobilize	5%	%	$ -	$ 46,358		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 46,358		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Road Topsoil Stripping and Stockpiling	4,700	CY	$ 2.64	$ 12,408	Crew analysis, dozer work	18" topsoil
Access Road Construction	213,500	SF	$ 1.47	$ 313,845	32 11 23.23 RS Means 2019 Bismarck	8" thick, Crushed 1-1/2"stone base, compacted to 4" deep, 6,100' x 35'
Return Water Pipeline						
Trench Excavation	9,400	CY	$ 2.94	$ 27,677	Crew analysis	
6" Pipeline	6,340	LF	$ 12.00	$ 76,080	33 14 13.35 RS Means 2019 Bismarck	
Misc. Appurtenances	1	EA	$ 10,000.00	$ 10,000		
Pipe Bedding & Embedment	1,900	CY	$ 4.99	$ 9,472	Crew analysis	
Trench Backfill	6,500	CY	$ 3.59	$ 23,360	Crew analysis	
Topsoil	1,000	CY	$ 3.52	$ 3,520	Crew analysis	
Marking Tape	6,340	LF	$ 0.10	$ 634	Underground Warning tape - via web search	
Tracer Wire	6,340	LF	$ 0.20	$ 1,268	14 gauge burial wire - via web search	
Fence	11,084	LF	$ 28.23	$ 312,897	32 31 13.20 RS Means 2019 Bismarck	6' Chain link fence, 3 strands barb wire
Overhead Power (Plant to Landfill)	1	EA	$ 100,000	$ 100,000	RS Means 2019 Bismarck 33.71.39.13.0150 33.71.16.33.5060	Pipeline length + 20% One utility pole every 200 feet
Monitoring Well Installation	6	EA	$ 6,000	$ 36,000	Golder Estimate	
County Road Crossing			Total	$ 1,886,520	$ 1,887,000	
General						
Mobilize/Demobilize	5%	%	$ -	$ 85,751		
Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 85,751		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Topsoil Stripping and Stockpiling	4,577	CY	$ 2.64	$ 12,083	Crew analysis, dozer work	18" topsoil
Embankment Fill	5,776	CY	$ 6.49	$ 37,510	Crew analysis	
County Road Base Course	32,200	SF	$ 2.13	$ 68,586	32 11 23.23 RS Means 2019 Bismarck	12" Gravel base course Crushed 1-1/2"stone base, compacted to 4" deep
County Road Asphalt Pavement	3,578	SY	$ 35.45	$ 126,838	RSMeans 2019, Bismarck 32 12 16.13.1595 32.12.16.13.1460 31.23.23.20.1114	2" Binder Course 4" Wearing Course
Bridge Deck Construction	4,900	SF	$ 300	$ 1,470,000	2016 California DOT cost range	140 ft bridge deck, 35 ft wide
Liner Construction			Total	$ 17,224,249	Cost Per Acre of Liner	$ 239,000
General						
Mobilize/Demobilize	5%	%	$ -	$ 782,920.39		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 782,920.39		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Clearing and Grubbing	89	AC	$ 4,500.00	$ 400,500	31 11 10.10 RS Means 2019 Bismarck	Clear & grub brush including stumps
Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.64		Crew analysis	
	89	AC	$ 6,389	$ 568,603		
Subgrade Cut to Stockpile	997,493	CY	$ 5.62	$ 5,607,683	Crew analysis	10' deep cut across liner area: for liner, berms and cover
Subgrade Cut/Embankment Fill	164,107	CY	$ 6.49	$ 1,065,677	Crew analysis	612 ft2 cross section area
Low Permeability Soil Liner (24")	-	CY	$ 6.56		Crew analysis	
	72	AC	$ 21,161	$ 1,523,626		
60-mil HDPE Liner	-	SF	$ 0.75		Recent construction	Materials, waste, conformance testing, installation
	72	AC	$ 32,670	$ 2,352,240		
Leachate Collection Layer, Sand (12")		CY	$ 29.70		Crew analysis for haul/place from Bismarck	
	72	AC	$ 47,916	$ 3,449,952		
Protective Cover (3')	-	CY	$ 6.33		Crew analysis	Fly ash as protective cover
	18	AC	$ 30,626	$ 551,267		Contractor place 25% of liner area (side slopes, haul routes)
Piping						
LCS 4" Piping	15,280	LF	$ 3.92	$ 59,898	33 42 11.50 RS Means 2019 Bismarck	4" Corrugated HDPE
LCS 8" Piping	3,310	LF	$ 7.78	$ 25,752	33 42 11.50 RS Means 2019 Bismarck	8" Corrugated HDPE
LCS Sump/Riser	2	EA	$ 20,000	$ 40,000	Golder Estimate	
Equipment and Electrical						
Power Posts at Pumps/Sumps	2	EA	$ 1,605	$ 3,210	26 24 16.30-0150 RS Means 2019 Bismarck	Panelboard/utility box with outlets
Collection pump	2	EA	$ 5,000	$ 10,000	Golder Estimate	

Scenario B (No Sales) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover			Total	$ 14,419,074	Cost Per Acre of Cover	$ 183,000
General						
Mobilize/Demobilize	5%	%	$ -	$ 655,412		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 655,412		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Leveling Fill (6")	-	CY	$ 6.49		Crew analysis	Stockpile cut to embankment fill
	79	AC	$ 5,238	$ 413,828.74		
Compacted Low Permeability Soil Liner (24")		CY	$ 6.56		Crew analysis	Stockpile cut to embankment fill
	79	AC	$ 21,161	$ 1,671,756		
60-mil HDPE Liner	-	SF	$ 0.75		Recent construction	Materials, waste, conformance testing, installation
	79	AC	$ 32,670	$ 2,580,930		
Drainage Layer, Sand (12")		CY	$ 29.70		Crew analysis for haul/place from Bismarck	
	79	AC	$ 47,916	$ 3,785,364		
Growth Medium (30")		CY	$ 6.34		Crew analysis	
	79	AC	$ 25,578	$ 2,020,642		
Topsoil (6")		CY	$ 6.34		Crew analysis	
	79	AC	$ 5,116	$ 404,128		
Downchute Channels	103,680	SF	$ 20.00	$ 2,073,600	Golder Estimate	36' wide, 4 downchutes
Seed and Mulch	79	AC	$ 2,000	$ 158,000	32 92 19.14-4600 RS Means 2019 Bismarck	Seed, mulch & fertilizer, hydro or air seeding
Post Closure Care			Total	$ 154,200	$ 154,000	
CCR Groundwater Monitoring & Reporting	1	EA	$ 25,000	$ 25,000	Golder Estimate	
Update CCR Baseline, Network Cert., and Statistical Method Cert. As Needed	1	EA	$ 24,000	$ 24,000	Golder Estimate	
Annual Site Inspection	1	EA	$ 10,000	$ 10,000	Golder Estimate	
Annual Dust Control Report	1	EA	$ 2,000	$ 2,000	Golder Estimate	
Other Potential CCR Reporting Requirements/Updates	1	EA	$ 4,600	$ 4,600	Golder Estimate	
Final Cover Repair	1	EA	$ 16,200	$ 16,200	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
Seeding Repair	1	EA	$ 15,800	$ 15,800	Golder Estimate	10% of cover area
Mowing and/or rodent, weed, & tree control	1	EA	$ 6,300	$ 6,300	Golder Estimate	$2,000 per 25 acres
Surface Water Controls Maintenance	1	EA	$ 26,700	$ 26,700	Golder Estimate	1% of armored channel replaced + other repairs
Gate and/or fence Maintenance	1	EA	$ 3,100	$ 3,100	Golder Estimate	1% of fence
Recordkeeping	1	EA	$ 4,700	$ 4,700	Golder Estimate	$1,500 per 25 acres
Direct Expenses	1	EA	$ 15,800	$ 15,800	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)			Total	$ 396,130	$ 396,000	
CCR Groundwater Monitoring & Reporting	1	EA	$ 25,000	$ 25,000	Golder Estimate	
Update CCR Baseline, Network Cert., and Statistical Method Cert. As Needed	1	EA	$ 24,000	$ 24,000	Golder Estimate	
Annual Site Inspection	1	EA	$ 10,000	$ 10,000	Golder Estimate	
Annual Dust Control Report	1	EA	$ 2,000	$ 2,000	Golder Estimate	
Other Potential CCR Reporting Requirements/Updates	1	EA	$ 4,600	$ 4,600	Golder Estimate	
Engineering Support	1	EA	$ 144,000	$ 144,000	Golder Estimate	$50,000 per 25 acres of liner
Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
Gate and/or fence Maintenance	1	EA	$ 3,130	$ 3,130	Golder Estimate	1% of fence
Recordkeeping	1	EA	$ 14,400	$ 14,400	Golder Estimate	$5,000 per 25 acres
Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 144,000	$ 144,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs						
Haul Cost	1	CY	$ 3.30	$ 3.30	31 23 23.20-8180 RSMeans 2019 Bismarck	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
Haul Cost	1	TON	$ 3.30	$ 3.30	Golder Estimate	75pcf haul density (1 ton/cy)
Place Cost	1	CY	$ 1.90	$ 1.90	31 23 23.17-0020 RSMeans 2019 Bismarck	Dozer, no compaction
Place Cost	1	TON	$ 2.30	$ 2.30	Golder Estimate	90pcf placed density (1.2 ton/cy)

Scenario C (Reduced Sales with ASM) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Infrastructure Development			Total	$ 864,616	**$ 865,000**	
General						
Mobilize/Demobilize	5%	%	$ -	$ 20,340		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 20,340		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Road Topsoil Stripping and Stockpiling	3,800	CY	$ 2.64	$ 10,032	Crew analysis, dozer work	18" topsoil
Access Road Construction	197,400	SF	$ 1.47	$ 290,178	32 11 23.23 RS Means 2019 Bismarck	8" thick, Crushed 1-1/2"stone base, compacted to 4" deep, 5,640' x 35'
Return Water Pipeline						
Trench Excavation	8,800	CY	$ 2.94	$ 25,911	Crew analysis	
6" Pipeline	5,890	LF	$ 12.00	$ 70,680	33 14 13.35 RS Means 2019 Bismarck	
Misc. Appurtenances	1	EA	$ 10,000.00	$ 10,000		
Pipe Bedding & Embedment	1,800	CY	$ 4.99	$ 8,974	Crew analysis	
Trench Backfill	6,100	CY	$ 3.59	$ 21,922	Crew analysis	
Topsoil	900	CY	$ 3.52	$ 3,168	Crew analysis	
Marking Tape	5,890	LF	$ 0.10	$ 589	Underground Warning tape - via web search	
Tracer Wire	5,890	LF	$ 0.20	$ 1,178	14 gauge burial wire - via web search	
Fence	9,044	LF	$ 28.23	$ 255,304	32 31 13.20 RS Means 2019 Bismarck	6' Chain link fence, 3 strands barb wire
Overhead Power (Plant to Landfill)	1	EA	$ 90,000	$ 90,000	RS Means 2019 Bismarck 33.71.39.13.0150 33.71.16.33.5060	Pipeline length + 20% One utility pole every 200 feet
Monitoring Well Installation	6	EA	$ 6,000	$ 36,000	Golder Estimate	
County Road Crossing			Total	$ 1,886,520	**$ 1,887,000**	
General						
Mobilize/Demobilize	5%	%	$ -	$ 85,751		
Misc. (erosion controls, toilets, etc)	5%	%	$ -	$ 85,751		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Topsoil Stripping and Stockpiling	4,577	CY	$ 2.64	$ 12,083	Crew analysis, dozer work	18" topsoil
Embankment Fill	5,776	CY	$ 6.49	$ 37,510	Crew analysis	
County Road Base Course	32,200	SF	$ 2.13	$ 68,586	32 11 23.23 RS Means 2019 Bismarck	12" Gravel base course Crushed 1-1/2"stone base, compacted to 4" deep
County Road Asphalt Pavement	3,578	SY	$ 35.45	$ 126,838	RSMeans 2019, Bismarck 32 12 16.13.1595 32.12.16.13.1460 31.23.23.20.1114	2" Binder Course 4" Wearing Course
Bridge Deck Construction	4,900	SF	$ 300	$ 1,470,000	2016 California DOT cost range	140 ft bridge deck, 35 ft wide
Liner Construction			Total	$ 8,803,611	Cost Per Acre of Liner	**$ 241,000**
General						
Mobilize/Demobilize	5%	%	$ -	$ 400,164		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 400,164		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Clearing and Grubbing	49	AC	$ 4,500.00	$ 220,500	31 11 10.10 RS Means 2019 Bismarck	Clear & grub brush including stumps
Topsoil Stripping & Stockpiling (18")	-	CY	$ 2.64		Crew analysis	
	49	AC	$ 6,389	$ 313,051		
Subgrade Cut to Stockpile	471,000	CY	$ 5.62	$ 2,647,856	Crew analysis	10' deep cut across liner area: for liner, berms and cover
Subgrade Cut/Embankment Fill	117,867	CY	$ 6.49	$ 765,404	Crew analysis	612 ft2 cross section area
Low Permeability Soil Liner (24")	-	CY	$ 6.56		Crew analysis	
	37	AC	$ 21,161	$ 772,394		
60-mil HDPE Liner	-	SF	$ 0.75		Recent construction	Materials, waste, conformance testing, installation
	37	AC	$ 32,670	$ 1,192,455		
Leachate Collection Layer, Sand (12")		CY	$ 29.70		Crew analysis for haul/place from Bismarck	
	37	AC	$ 47,916	$ 1,748,934		
Protective Cover (3')	-	CY	$ 6.33		Crew analysis	Fly ash as protective cover
	9	AC	$ 30,626	$ 279,462		Contractor place 25% of liner area (side slopes, haul routes)
Piping						
LCS 4" Piping	7,060	LF	$ 3.92	$ 27,675	33 42 11.50 RS Means 2019 Bismarck	4" Corrugated HDPE
LCS 8" Piping	1,150	LF	$ 7.78	$ 8,947	33 42 11.50 RS Means 2019 Bismarck	8" Corrugated HDPE
LCS Sump/Riser	1	EA	$ 20,000	$ 20,000	Golder Estimate	
Equipment and Electrical						
Power Posts at Pumps/Sumps	1	EA	$ 1,605	$ 1,605	26 24 16.30-0150 RS Means 2019 Bismarck	Panelboard/utility box with outlets
Collection pump	1	EA	$ 5,000	$ 5,000	Golder Estimate	

Scenario C (Reduced Sales with ASM) Unit Rate Details

PROJECT COMPONENT	QTY	UNIT	UNIT PRICE	TOTAL	Source	NOTES
Final Cover			Total	$ 7,919,961	Cost Per Acre of Cover	$ 198,000
General						
Mobilize/Demobilize	5%	%	$ -	$ 359,998		
Miscellaneous Site Work & Materials	5%	%	$ -	$ 359,998		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Civil						
Leveling Fill (6")	-	CY	$ 6.49		Crew analysis	Stockpile cut to embankment fill
	40	AC	$ 5,238	$ 209,534		
Compacted Low Permeability Soil Liner (24")	-	CY	$ 6.56		Crew analysis	Stockpile cut to embankment fill
	40	AC	$ 21,161	$ 846,459		
60-mil HDPE Liner	-	SF	$ 0.75		Recent construction	Materials, waste, conformance testing, installation
	40	AC	$ 32,670	$ 1,306,800		
Drainage Layer, Sand (12")		CY	$ 29.70		Crew analysis for haul/place from Bismarck	
	40	AC	$ 47,916	$ 1,916,640		
Growth Medium (30")		CY	$ 6.34		Crew analysis	
	40	AC	$ 25,578	$ 1,023,110		
Topsoil (6")		CY	$ 6.34		Crew analysis	
	40	AC	$ 5,116	$ 204,622		
Downchute Channels	80,640	SF	$ 20.00	$ 1,612,800	Golder Estimate	36' wide, 4 downchutes
Seed and Mulch	40	AC	$ 2,000	$ 80,000	32 92 19.14-4600 RS Means 2019 Bismarck	Seed, mulch & fertilizer, hydro or air seeding
Post Closure Care			Total	$ 120,100	$ 120,000	
CCR Groundwater Monitoring & Reporting	1	EA	$ 25,000	$ 25,000	Golder Estimate	
Update CCR Baseline, Network Cert., and Statistical Method Cert. As Needed	1	EA	$ 24,000	$ 24,000	Golder Estimate	
Annual Site Inspection	1	EA	$ 10,000	$ 10,000	Golder Estimate	
Annual Dust Control Report	1	EA	$ 2,000	$ 2,000	Golder Estimate	
Other Potential CCR Reporting Requirements/Updates	1	EA	$ 4,600	$ 4,600	Golder Estimate	
Final Cover Repair	1	EA	$ 8,200	$ 8,200	Golder Estimate	2% of cover area, 12" growth medium/topsoil fill
Seeding Repair	1	EA	$ 8,000	$ 8,000	Golder Estimate	10% of cover area
Mowing and/or rodent, weed, & tree control	1	EA	$ 3,200	$ 3,200	Golder Estimate	$2,000 per 25 acres
Surface Water Controls Maintenance	1	EA	$ 22,100	$ 22,100	Golder Estimate	1% of armored channel replaced + other repairs
Gate and/or fence Maintenance	1	EA	$ 2,600	$ 2,600	Golder Estimate	1% of fence
Recordkeeping	1	EA	$ 2,400	$ 2,400	Golder Estimate	$1,500 per 25 acres
Direct Expenses	1	EA	$ 8,000	$ 8,000	Golder Estimate	$5,000 per 25 acres
Annual Operations & Maintenance Costs (not haul and place)			Total	$ 246,450	$ 246,000	
CCR Groundwater Monitoring & Reporting	1	EA	$ 25,000	$ 25,000	Golder Estimate	
Update CCR Baseline, Network Cert., and Statistical Method Cert. As Needed	1	EA	$ 24,000	$ 24,000	Golder Estimate	
Annual Site Inspection	1	EA	$ 10,000	$ 10,000	Golder Estimate	
Annual Dust Control Report	1	EA	$ 2,000	$ 2,000	Golder Estimate	
Other Potential CCR Reporting Requirements/Updates	1	EA	$ 4,600	$ 4,600	Golder Estimate	
Engineering Support	1	EA	$ 73,000	$ 73,000	Golder Estimate	$50,000 per 25 acres of liner
Survey Control	1	EA	$ 25,000	$ 25,000	Golder Estimate	GPS unit(s), $25,000 per year
Gate and/or fence Maintenance	1	EA	$ 2,550	$ 2,550	Golder Estimate	1% of fence
Recordkeeping	1	EA	$ 7,300	$ 7,300	Golder Estimate	$5,000 per 25 acres
Misc Work (contact water, dust, erosion, grading, etc)	1	EA	$ 73,000	$ 73,000	Golder Estimate	$50,000 per 25 acres
Haul & Place Costs						
Haul Cost	1	CY	$ 3.30	$ 3.30	31 23 23.20-8180 RSMeans 2019 Bismarck	60cy Off-road, 20 min wait, 15 mph, 2 mile cycle
Haul Cost	1	TON	$ 3.30	$ 3.30	Golder Estimate	75pcf haul density (1 ton/cy)
Place Cost	1	CY	$ 1.90	$ 1.90	31 23 23.17-0020 RSMeans 2019 Bismarck	Dozer, no compaction
Place Cost	1	TON	$ 2.30	$ 2.30	Golder Estimate	90pcf placed density (1.2 ton/cy)

ASM Unit Rate Details

PROJECT COMPONENT	QTY	UNIT OF MEASURE	UNIT PRICE	TOTAL	Source	NOTES
New Silo			Total	$ 2,021,053	**$ 2,021,000**	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 183,732		Erosion controls, offices, toilets, temporary roads, survey control, etc.
Silo slab on grade	1	EA	$ 827,470	$ 827,470	2003 Irondale CO Unit less RR & land	Site prep, silo & handling equipment, permit
Starvac reclaimer	1	EA	$ 90,439	$ 90,439		
Truck scale	1	EA	$ 88,293	$ 88,293		Beside the silo on grade
Screw conveyor	1	EA	$ 26,687	$ 26,687		From Starvac reclaimer to bucket elevator
Bucket Elevator	1	EA	$ 96,370	$ 96,370		From screw conveyor to overhead airslide
Air Slide	1	EA	$ 29,158	$ 29,158		From bucket elevator to new weigh hopper
Truck load-out spout	1	EA	$ 49,420	$ 49,420		From new weigh hopper to truck
Building	1	EA	$ 12,355	$ 12,355		With scales and ASM controls
Feed piping & valves	1	EA	$ 385,713	$ 385,713	Golder Estimate	From each of the four fly ash conveying lines
Dust collectors	1	EA	$ 231,417	$ 231,417	Golder Estimate	Higher capacity to handle high air flow from ESP
Cal-Hypo Feed System (Rail Load-out Silo)			Total	$ 288,181	**$ 288,000**	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 26,198		
Storage & Conveying Building	1,000	SF	$ 58.58	$ 58,583	GRE 2009 Construction Project	$35/sf for large insulated bldg, use $50/sf
Building Foundation	62	CY	$ 351.50	$ 21,793	Worley Parsons Jul09	12' x 40' x 1' thick plus 1' x 5' perimeter
Day Storage Hopper	1	EA	$ 17,575	$ 17,575	Golder Estimate	On the silo weigh bin floor
Conveying System	1	EA	$ 23,433	$ 23,433	Golder Estimate	From storage building to the day storage hopper
Variable speed conveyor	1	EA	$ 23,433	$ 23,433	Golder Estimate	To feed cal-hypo into the existing weigh hopper
ASM System Controls	1	EA	$ 117,166	$ 117,166	Golder Estimate	
Cal-Hypo Feed System (New Truck Load-out Silo)			Total	$ 384,843	**$ 385,000**	
Miscellaneous Site Work & Materials	10%	%	$ -	$ 34,986		
Weigh Hopper	1	EA	$ 87,874	$ 87,874	Golder Estimate	Above truck load-out spout
Storage & Conveying Building	1,000	SF	$ 58.58	$ 58,583	GRE 2009 Construction Project	$35/sf for large insulated bldg, use $50/sf for 25'x40'
Building Foundation	62	CY	$ 351.50	$ 21,793	Worley Parsons Jul09	25' x 40' x 1' thick plus 1' x 5' perimeter
Day Storage Hopper	1	EA	$ 17,575	$ 17,575	Golder Estimate	On the silo weigh bin floor
Conveying System	1	EA	$ 23,433	$ 23,433	Golder Estimate	From storage building to the day storage hopper
Variable speed conveyor	1	EA	$ 23,433	$ 23,433	Golder Estimate	To feed cal-hypo into the existing weigh hopper
ASM System Controls	1	EA	$ 117,166	$ 117,166	Golder Estimate	

Historic prices have been escalated 2% per year from original price date to 2019.

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Attachment C

Report “Ammonia Slip Mitigation for SNCR Impacted Ash at the Coal Creek Station” March 22, 2019; Boral Resources

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March 22, 2019

Ammonia Slip Mitigation for SNCR Impacted Ash at the Coal Creek Station

Introduction

The contamination of fly ash with ammonia is a major concern for the marketability of ash for beneficial use in concrete. Although, ammoniated fly ash causes no detrimental effects to the durability of concrete, it poses safety concerns for workers pouring, placing and finishing fresh concrete. When placed in the high alkaline concrete slurry, ammoniated fly ash creates unpleasant and noxious ammonia gas odor that impacts the workers handling fresh concrete and concrete products. Exposure to ammonia in high concentrations is considered a health hazard to concrete workers as it can irritate or burn skin, mouth, throat, lungs and eyes. In very high dosages, ammonia gas can damage lungs or cause death. The presence of ammonia in ash at coal-fired plants and their disposal facilities can also create the potential for exposing power plant workers to this noxious gas. It also creates the potential for its release to air and water.

Ammonia in Ash from SNCR Systems

Ammonia-based environmental control technologies such as SCR and SNCR's are used to reduce NOx emissions from coal-fired power units. Ammonia/NOx redox reactions are not 100% complete and result in excess ammonia in flue gas. The excess ammonia gas, known as ammonia slip, reacts with other flue gas species, primarily SO_3, to form an ammonium salt solid deposit (NH_4SO_3) that is collected with the fly ash. The ammonium salt content of the ash depends on the ammonia slip, the SO_3 levels and other flue gas parameters such as acidity, temperature, etc. Typically, SNCR units have resulted in higher levels of ammonia in ash than SCR units.

A study performed by EPRI in 2007 reviewed eight units fueled with PRB/eastern bituminous coal blends where SNCRs systems had been installed and were in operation. The units were small and had ammonia slip up to 5 ppm. Four of the units had ammonia in the fly ash data ranging from less than 100 ppm to over 200 ppm. (EPRI 2007). Other studies suggest that 2 ppm ammonia slip may result in fly ash ammonia levels from less than 50 to several hundred mg/kg (Murarka 2003, Bittner 2001, Hinton 2012, Larrimore 2002). There is no published information for SNCR ammonia gas slip levels from lignite powered units.

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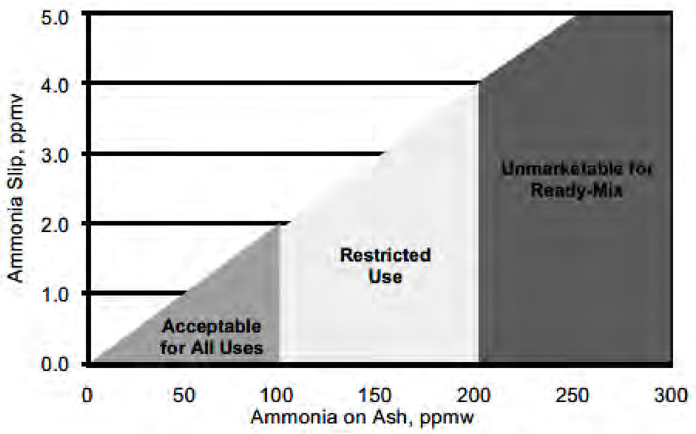
For the Coal Creek units, Fuel Tech is quoting ammonia in ash levels at less than 20 mg/kg for 2 ppm slip and less than 100 mg/kg for 10 ppm slip for full load steady state operations. These estimated ammonia-in-ash levels relative to slip in flue gas do not correspond to literature values. In fact, the chart included herein, created by Larrimore (2002) and based on literature reviews and operating plant data, indicates that ammonia slip levels of 2 ppm can lead up to 100 mg/kg of ammonia in ash while a slip of 10 ppm could lead up to 500 mg/kg making the ash “unmarketable” for use in ready mix concrete.

The ammonia slip level from SNCR systems is highly dependent on the ammonia injection rate, NOx reduction efficiency, plant load, reaction zone temperature and other unit specific flue gas parameters. Although the coal fired units at the Coal Creek station were designed for baseload service, they are expected to cycle depending on electric power demand and economic dispatch. Load cycling which includes ramping up or down and heat-up and cool-down of the units impart significant variability to the performance of the reaction-temperature sensitive SNCR. Load cycling is expected to result in significant variability in ammonia slip and ammonia in ash levels. Accurate and reliable ammonia slip and ash contamination levels can only be determined by a full scale SNCR demonstration and modeling of the specific fuel/unit.



Acceptable Levels of Ammonia in Ash

The ammonium salt present in the ash is rapidly converted to ammonia gas once the ash is exposed to the high pH concrete mixture. Ammonium salts are converted to ammonia gas at high pH (>10). Concrete mixtures can easily reach a pH of 12-13 within seconds of adding water to hydrate the cement. Mixing of concrete containing ammoniated ash will result in ammonia gas evolution from the mixer and during concrete pouring, placing and finishing. Ammonia gas evolution continues after placement of fresh concrete. Undesirable ammonia odor can linger after the hardening of concrete products in enclosed applications.

Exposure to ammonia gas evolving from concrete mixers or job sites is a health and safety risk. Exposure to mild levels of ammonia odors can generate unpleasant conditions for concrete workers that can result in undesirable finish and poor workmanship. The presence of even milder ammonia odor in residential/commercial concrete (indoor walls or slabs) would expose concrete producers, contractors, fly ash marketers and source utilities to potential product quality and health risk claims. Such claims of “poor” quality or potential long risk exposure from mild unpleasant odors would significantly impact ash sales in residential concrete markets.

There is no <u>definitive</u> ammonia limit for fly ash used in concrete since the factors affecting workers exposure are highly dependent on the amount of ash used in concrete and the environment where fly ash concrete is produced, placed and finished. When ammoniated fly ash concrete is placed in an open environment, personnel are rarely subjected to a time-weighted-average-permissible exposure limit exceeding 50 ppm if the ammonia in ash is less than 100 mg/kg. However, in a closed environment with restricted ventilation the same ammonia in ash level can results in exceeding both OSHA and NIOSH time-weighted-average-permissible exposure limits 50 ppm/20 ppm respectively. (Schert 2013)

Based on studies from the University of Kentucky funded by DOE, Electric Power Research Institute (EPRI) suggests the recommended limit of NH_3 is 200 mg/kg for fly ash used in concrete placed in well vented areas, in non-vented areas, the recommended limit is 100 mg/kg (Rathbone 2003). These limits are based on <u>15% ash replacement</u> of cement, which is typical for ash derived from the combustion of eastern bituminous coal. When doubling the fly ash replacement to 30%, which is common with high quality ash such as the Coal Creek ash, the allowable ammonia content in fly ash will need to be reduced by 50% to 100 mg/kg and 50 mg/kg, respectively.

FDOT and other state agencies have concluded, if specifications are needed, an upper limit of 100 mg/kg would be protective of human health for most situations, and achievable under most circumstances (Schert 2012). It is Boral Resources policy to reject fly ash containing more than 100 mg/kg. However, fly ash products are marketed for use in various concrete products and applications. The amount of ash used in a concrete mixture also varies depending on the ash pozzolanic reactivity, specified concrete mixture, ambient temperature and other concrete product parameters.

Boral Resources and its concrete-producing customers do not know the intended application of all concrete products or the environment where the concrete is placed. Ammonia in ash contents of less than 100 mg/kg are sometimes requested by customers for the purpose of protecting their workers environment or to reduce the risk of customers’ claims. Boral Resources complies with special customers request and periodically notifies customers with NH_3 in ash tests results. Although, the 100 mg/kg threshold has been established based on research and general practice, in some ash markets such as MI/OH, Boral had to lower acceptable ammonia concentration to 75 mg/kg based on market feedback and customers' requests (concrete producers).

Rejected fly ash contaminated with unacceptable levels of ammonia is typically discarded in the landfill. Risks associated with the release and exposure at the utility fly ash landfill and handling systems are discussed elsewhere.

Economic impact of ammoniated ash

The direct cost Impacts resulting from ammoniated ash include: lost revenue to GRE from fly ash sales by Boral, incremental ash disposal costs and the costs of long-term monitoring associated with the disposed ash. The direct cost impacts are discussed elsewhere. Other economic impacts include externalities of lost opportunity values related to; carbon emissions offset, additional sustainability benefits of reduced cement content Concrete durability benefits for using fly ash.

The Environmental impact of carbon emissions offset equal to 0.72 metric tons of avoided CO_2 equivalent emissions per ton of ash replacing cement in concrete. This is based on U.S. Environmental Protection Agency Report to Congress EPA530-R-08-007, June 3, 2008, page 3-11. Assuming potential future adoption of an accessible carbon tax or cap and trade program, the monetary value of carbon offsets is $16.30 per ton. This value is based on California Carbon Allowance Futures pricing on January 15, 2019, for 2018 vintage offsets deliverable December 2019. Based on the same EPA Report to Congress, the other sustainability benefits of using fly ash to replace cement in concrete include; reduced water use by 379 liters per ton of ash and reduced energy consumption by 4,695 megajoules per ton of ash.

The benefits of fly ash use in concrete include; increasing higher ultimate strength, reducing permeability and corrosion of embedded steel, mitigating deleterious alkali aggregate reactions and increase concrete resistance to sulfate and other chemical attacks.

The Economic Impacts of Prohibiting Coal Fly Ash Use in Transportation Infrastructure Construction was evaluated by the American Road and Transportation Builders Association. Based on their September 2011 report, the economic impact of durability was estimated at $478 per ton of ash replacing cement in concrete for transportation projects.

Beneficiation of ammoniated fly ash

Boral has a chemical treatment technology that was developed to address moderate levels (<200 mg/kg) of ammonia in ash. The chemical treatment process, known as Ammonia Slip Mitigation (ASM), has been deployed at two power plants 1) the eastern bituminous fired units (4@ 253 MW total nameplate capacity) of Rochester Gas & Electric Russell Station – in this plant, ASM was used to treat an average of 3 truck-loads of ash per day with a total annual marketable ash production of about 10,000 tons; and 2) The East Lake station in Ohio - ASM was deployed to treat fly ash generated from a 600 MW unit burning a 50/50 blend of powder River Basin and Eastern Bituminous Coals. These plants used ASM to lower the ammonia in ash levels from up to 150 ppm to less than 50 ppm. Ammonia concentrations over 150 ppm were diverted to disposal. Higher levels of ammonia were also accompanied by wide variability, an issue that could not be solved by ASM.

The ASM technology requires robust quality control efforts to frequently test the ammonia in ash level to assure adequate treatment. Heightened quality control efforts were relatively simple to deploy at the above referenced small plants with low ash load-out rates.

ASM consists of adding a strong oxidizer, calcium hypochlorite, in powder form to the ash during load-out from the silo into a truck. The reagent is used to neutralize (oxidize) the ammonia once the ash gets wet in a concrete mixer. This approach works well with consistent and moderate ammonia levels. Higher ammonia levels and associated high reagent additions would lead to high levels of chlorides in concrete which is limited by many specifications. The ASM technology has not been demonstrated to deal with ammoniated ash at large power plant units requiring potentially complex quality control program.

Another commercially proven approach was developed by STI. It consists of wetting the ash and adding $Ca(OH)_2$ to rapidly raise the pH to strip the ammonia then dry the ash. This approach has been deployed for low CaO eastern bituminous derived ash at a powerplant in Tampa. However, this chemical stripping of ammonia is not feasible for Coal Creek ash since it would increase the ash CaO content limiting its use in the market. It would require about 10% of lime by weight of ash to raise the pH to 12 for effective stripping. The 10% lime addition will drive the CaO content of the Coal Creek above 20%, making it not suitable for use in DOT specified projects to enhance durability of concrete.

Inconsistent and high levels of ammonia in ash from SNCR units can be thermally removed from the ash to maintain an effectively safe program for the beneficial use of ash in concrete. The state-of-the art thermal removal of ammonia from ash has not been commercially demonstrated. It requires a significant capital investment for the thermal reactor, cooler, bag house and other ancillary equipment. Energy from the boiler or natural gas will be needed to raise the ash temperature for effective striping of ammonia. The operating temperature will depend the ammonium salt species found in the ash. Temperatures ranging from 800 to 1400 °F have been cited as effective to remove ammonia from fly ash. Pilot scale testing will be required to confirm ammonia stripping temperature and retention time. The stripped ammonia can be returned to the boiler or scrubbed. Balance of plant issues much also be evaluated.

The costs to deploy the Ammonia Slip Mitigation technology at GRE Coal Creek Station was developed by Golder Associates in 2011 and updated in March 2019. The estimates were based on their review of the East Lake installation scaled up for deployment at the Coal Creek Station. The 2019 updates adequately cover the costs of ASM system installations and ancillary equipment such as a new truck load out silo dedicated for the ASM system and installing a second ASM system at the existing rail loadout silo. The ASM system at Coal Creek would be used to treat ash containing less than 150 mg/kg. Fly ash containing more than 150 mg/kg would be diverted to disposal via existing silos. The Golder 2019 updated study also includes the operating and maintenance costs associated with the use of the ASM technology to treat the ash.

It's very difficult to estimate the annual quantity of fly ash that would contain less than 150 mg/kg of ammonia and be suitable for treatment using ASM. This is due to the inherent site-specific performance capabilities of SNCR and variabilities expected by load cycling.

References

L. Larrimore, "Effects of ammonia from post-combustionNOx control on ash handling and use," Southern Company, Birmingham, 2002.

J. Schert, "Emerging worker safety concerns associated with the recycling of fly ash from coal-fired power plant in concrete mixtures," Transportation Research Information Services, 29 01 2013. [Online]. Available: https://rns.trb.org/details/dproject.aspx?n=33398.

R. Rathbone and T. Robl, "A study of the effects of post-combustion ammonia injection on fly ash quality: Characterization of ammonia release from concrete and mortars containing fly ash as a pozzolanic admixture," University of Kentucky Center for Applied Energy Research, Lexington, 2003.

J. Schert, T. Townsend and W. Chang-Yu, "Identification of potential concerns associated with FDOT use of ammoniated fly ash," Department of Environmental Engineering Science University of Florida, Gainesville, 2012.

ESI Inc of Tennesse, PMI Ash Technology Ammonia Reduction Facility. 2010

Rafic Minkara, Ph.D., P.E.

Attachment D

Letter “Coal Creek Station Unit 2 NOx Emissions” March 5 2018 from GRE to the NDDEQ

12300 Elm Creek Boulevard
Maple Grove, Minnesota 55369-4718
763-445-5000
greatriverenergy.com

GREAT
RIVER
ENERGY™

March 5, 2018

VIA ELECTRONIC
AND U.S. MAIL

Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Ave, 2nd Floor
Bismarck, ND 58501-1947

RE: Coal Creek Station Unit 2 NOx Emissions

Dear Mr. O'Clair:

We understand that you have been working with the U.S. Environmental Protection Agency ("EPA") to finalize the phase I regional haze state implementation plan ("SIP") for North Dakota. In connection with these efforts, you asked Great River Energy to discuss the NOx emission rates at Coal Creek Station, Unit 2 ("CCS2"), particularly the relatively lower NOx emission rates that CCS2 has achieved in the last 12-24 months. This letter responds to that request.

In its amended SIP, the North Dakota Department of Health ("NDDH") proposed a best available retrofit technology ("BART") limit of 0.17 lbs/mmBtu on a 30-day rolling average for NOx at CCS2. This limit was based on Great River Energy's use of our DryFining™ process for the coal and the installation of LNC3+ low NOx burners on CCS2. Great River Energy is pleased with the performance of CCS2 following the application of these technologies. These technologies allowed us to appreciably reduce our NOx emission rate.

Great River Energy continues to believe that NDDH's proposed BART limit is appropriate for CCS2 and hopes that EPA will concur with NDDH's determination. Based on our experience with these technologies and expectations of future operation, we are concerned that NOx emission rates will continue to have high variability and increase in the future.

There are two primary factors that affect the NOx emission rate at CCS2: the sodium content of the coal and the load variability of the boiler. In recent months, the NOx emission rate has benefitted from higher sodium coal and relatively steady-state generation. As discussed in detail below, Great River Energy cannot depend on the continuation of these trends because we have little control over coal sodium content or load variability. Thus, the proposed NOx emission rate, 0.17 lbs/mmBtu over 30 days, remains appropriate for CCS2.

Lignite Sodium Content

Lignite sodium content is a key variable that affects boiler operation and, as a result, NOx performance. CCS2 was designed for the use of local lignite coal. The design anticipated a certain amount of slagging on the boiler walls which affects the rate of heat absorption by the boiler walls in the area of the main fireball. The quantity of sodium in the coal has a pronounced impact on the amount of slagging: as sodium levels drop, less slagging occurs. When CCS2 burns low-sodium coal and less slagging occurs, there is much greater heat absorption in the lower zone of the boiler and less heat reaches the upper reheat and superheat zones of the boiler. This lowers unit efficiency and raises the heat rate. As a result, CCS2 must burn more coal to produce the same amount of electricity.

Great River Energy has little ability to counter the loss of efficiency caused by the combustion of lower sodium coal. First, Great River Energy cannot dictate different coal specifications because CCS2 is a mine-mouth facility and designed to burn the coal from that mine. The mine's ability to blend coal for various constituents is limited because it typically operates only one or two pits. While the sodium content varies across the seam, it is logistically impractical for the mine to stockpile coal from the same mine to achieve a consistently higher sodium content. Second, because CCS2 is designed to maximize efficiency, the burners automatically adjust in response to an imbalance in the heat distribution. Low temperatures in the super heat section of the boiler automatically cause the burners to tilt upwards to move more heat to the upper sections of the boiler. When this happens, the fireball is extended upwards within the boiler, changing the fuel-air mixture in that section of the boiler and increasing NOx emissions. The boiler operators have little ability to limit these automatic adjustments. Efforts to override the burner tilt controls adversely affect unit efficiency and emissions of NOx and other pollutants.

Figure 1, attached, demonstrates the impact of sodium on the NOx emission rate at CCS2. Figure 1 shows the sodium content of coal and the NOx emissions over a four-year period (2014-2017). The green line shows short-term sodium concentration; the blue line shows the long-term average sodium concentration; and the red line reflects the 30-day rolling average NOx emission rate. When sodium levels were low, particularly in the 2014-2015 time frame, the NOx emission rate was significantly higher, with several periods exceeding 0.17 lbs/mmBtu. As sodium levels increased starting in early 2016, the NOx emission rate began trending lower.

Even during periods when the average sodium levels were relatively high – above 3 percent – Great River Energy still observed significant short-term NOx variability, including several very high NOx spikes. This is because even short-term sodium variability impacts NOx emissions; even a one- or two-week pocket of low-sodium coal will drive up the NOx emission rate.

Load Variability

Load variability also is a key factor that affects NOx rates at CCS2. CCS2 was designed as a baseload generating unit, operating in a steady-state, high-capacity mode. At a constant load, it is easier to manage and minimize NOx emissions. NOx emissions increase when CCS2 is required to ramp up and down based on demands from our independent system operator, Midcontinent Independent System Operator ("MISO").

When Great River Energy proposed the CCS2 BART limit to NDDH, we did not envision CCS2 becoming a load-following unit. However, the last decade has seen dramatic increases in renewable energy penetration in the MISO region. As a result, MISO has been increasingly requiring CCS2 to "chase load" over extended periods. As an example, between 2012 and 2014 CCS2 operated in "low load" mode (30 - 40 percent of maximum capacity) less than 10 hours per year. In 2016, that increased to 249 hours. The amount of planned and announced wind development in the MISO region promises to increase this trend.

The impact of load shifts on NOx emission rates, particularly low-load and ramping operation, is demonstrated in Figures 2 and 3, also attached. Figure 2 depicts the direct, inverse relationship between load levels and NOx emission rates over a five-day period when sodium levels in the coal were low (<2 percent). The red line shows the hourly load levels; the dark blue line shows the hourly NOx emission rate; and the light blue line shows the 24-hr rolling average NOx rate over the period. The NOx emission rates (hourly and 24-hr average) were consistently above 0.2 lbs/mmBtu over this five-day period due to the combination of low sodium and high load variability.

Figure 3 shows a different period when the sodium levels were above 3 percent, where we would have expected NOx rates to be correspondingly lower. Instead, CCS2 experienced higher than expected NOx emission rates because of the highly variable load demands, with the 24-hr average rate hovering at or above 0.17 lbs/mmBtu. It takes only a few periods like that reflected in Figure 3 to drive the 30-day rolling average NOx emission rate above 0.17 lbs/mmBtu.

Conclusion

CCS2 has achieved significant improvement in its NOx performance as a result of Great River Energy's DryFining^{TM} process and the installation of LNC3+ burners. As Great River Energy works to ensure that we can achieve the proposed BART emission rate of 0.17 lbs/mmBtu, two variables – sodium content and load variability – will continue to be impediments and these variables are largely out of Great River Energy's control. Accordingly, Great River Energy hopes that EPA will concur with NDDH's determination that 0.17 lbs/mmBtu is an appropriate BART limit.

Please contact me at (763-445-5212) if you have any questions or wish to discuss any of the above.

Sincerely,

Great River Energy

Mary Jo Roth
Manager, Environmental Services

Attachments

Figure 1 - NOx vs. Sodium

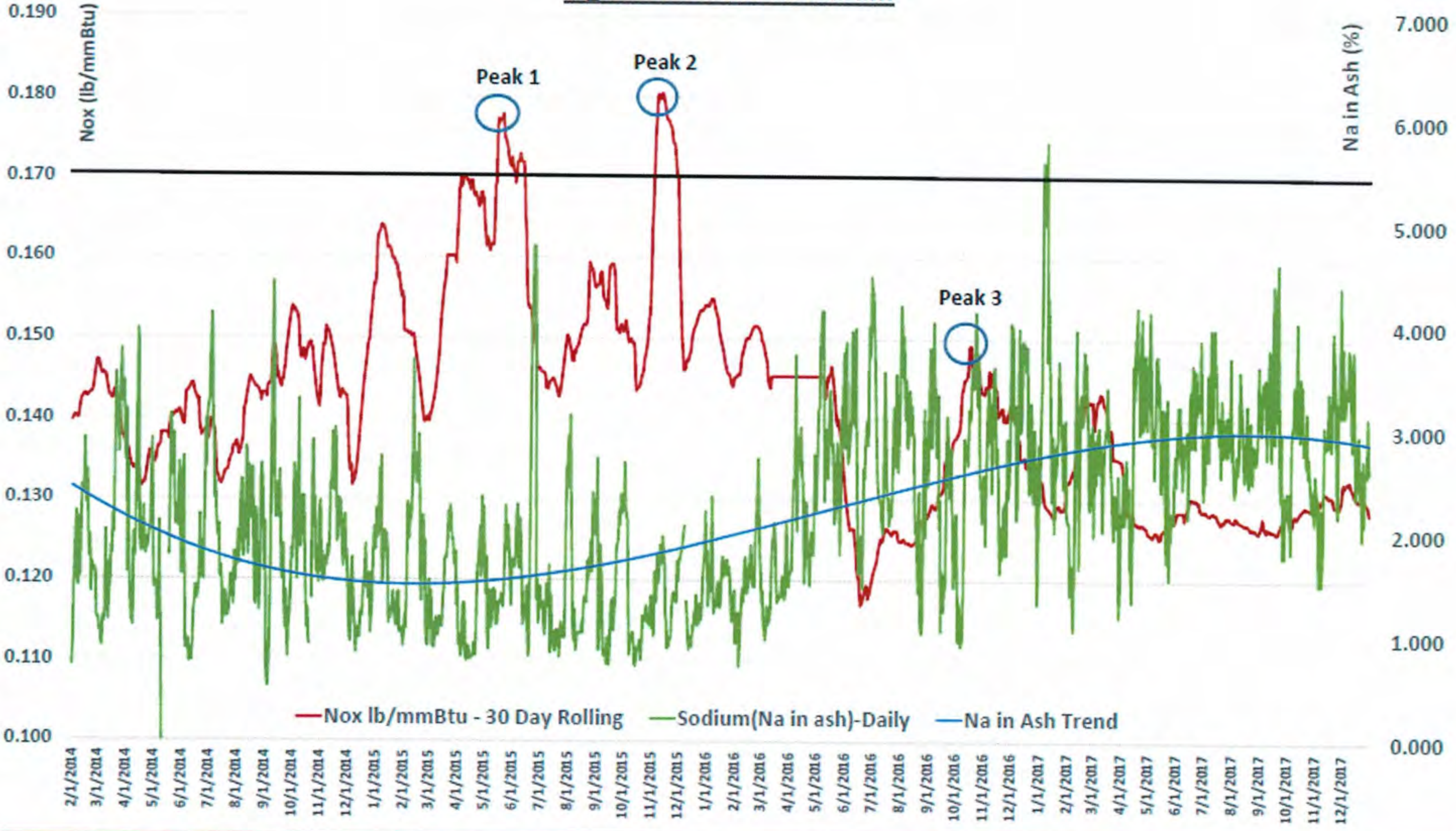
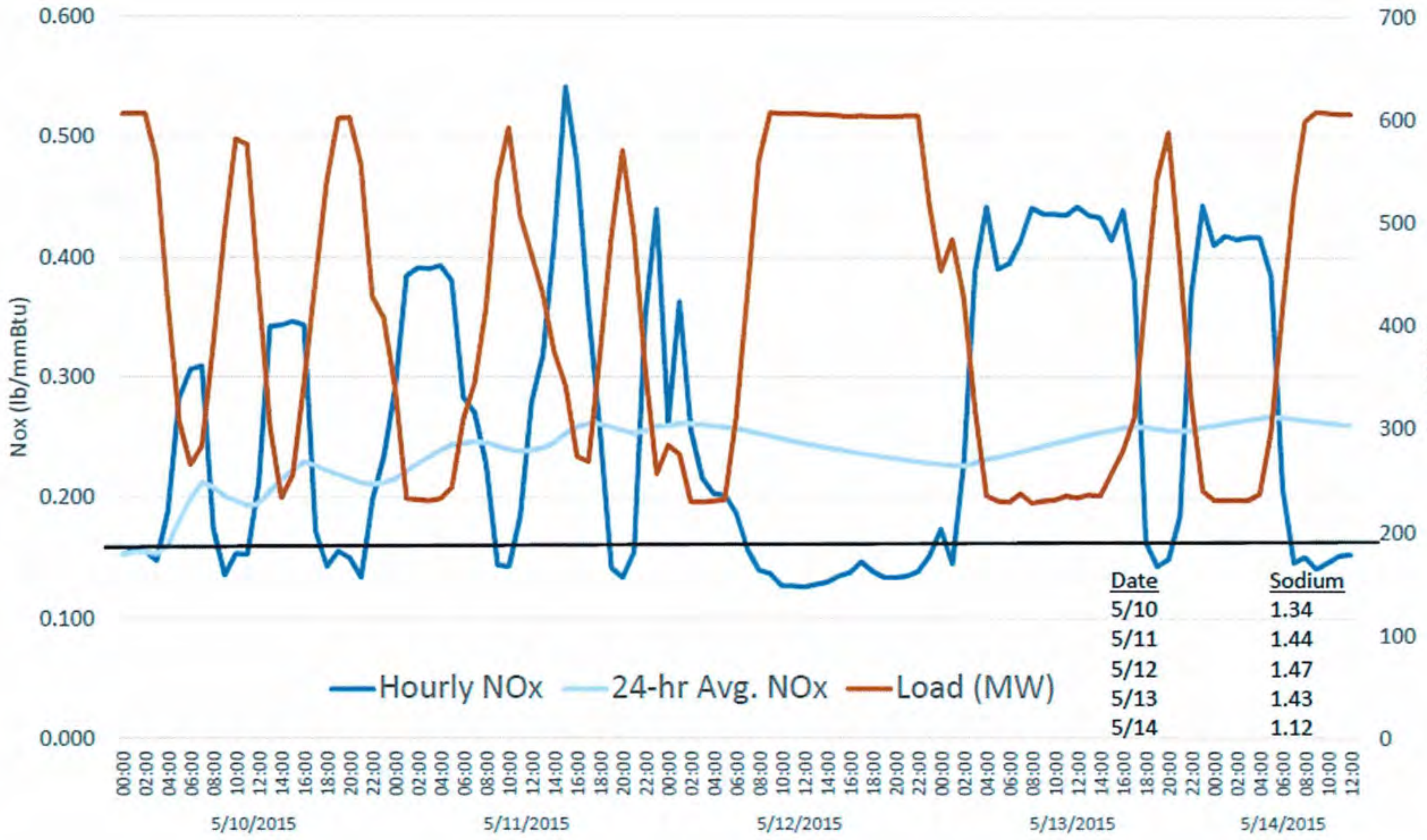


Figure 2

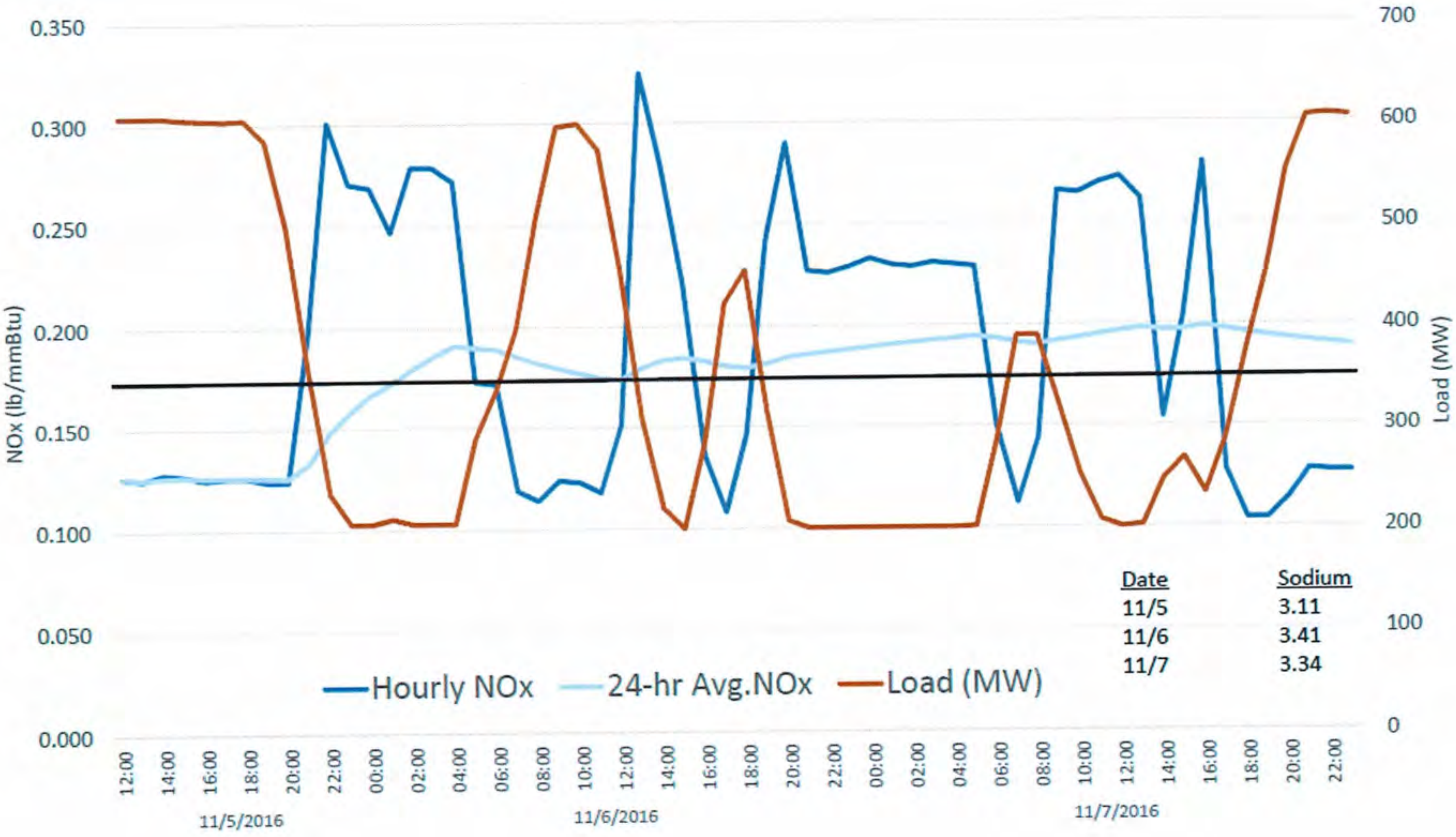
Peak 1 - NOx vs. Variable Load

Low Sodium Coal



Date	Sodium
5/10	1.34
5/11	1.44
5/12	1.47
5/13	1.43
5/14	1.12

Figure 3
Peak 3 - NOx vs. Variable Load
High Sodium Coal



Date	Sodium
11/5	3.11
11/6	3.41
11/7	3.34

Attachment E-1

Report “Protocol for BART-Related Visibility Impairment Modeling Analysis – Great River Energy – Coal Creek Station” July 2019; Barr Engineering Company

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone 800-227-8917
www.epa.gov/region8

Ref: 8ARD-PM

Mr. James L. Semerad
Director, Division of Air Quality
North Dakota Department of Environmental Quality
918 E. Divide Avenue, 2nd Floor
Bismarck, North Dakota 58501–1947

Dear Mr. Semerad:

On March 21, 2019, the North Dakota Department of Environmental Quality (NDDEQ) shared the *Protocol for BART-Related Visibility Impairment Modeling Analysis, Great River Energy Coal Creek Station (March 2019)* with the Environmental Protection Agency (EPA) by email for our review. The EPA provided comments on the protocol to NDDEQ in our letter dated April 8, 2019. Subsequently, on July 8, 2019, NDDEQ provided a revised protocol that addressed the concerns raised by the EPA, with the exception of the modeled scenarios and several other items detailed in the email sent by Aaron Worstell, of my staff, on July 10, 2019. On July 26, 2019, after further coordination between Great River Energy, NDDEQ, and the EPA, a final protocol was submitted to the EPA addressing these remaining concerns. With this letter, the EPA is approving the modeling methods and assumptions contained in the final modeling protocol.

In our comments of April 8, 2019, the EPA stated that the protocol did not provide enough detail to explain how the emission units and control scenarios will be combined in POSTUTIL and subsequently in CALPUFF (see item 31). The final protocol has largely addressed this concern. To ensure that the concern is fully addressed during implementation, we request that NDDEQ provide us with sample POSTUTIL input files prior to running the module to ensure that the configuration aligns with our preferred approach.

We understand that the protocol is intended to support a future State Implementation Plan (SIP) revision addressing Best Available Retrofit Technology requirements for nitrogen oxides at Coal Creek Station. Please note that we will only reach a final conclusion regarding the adequacy of the SIP revision when we act on the SIP submittal through notice and comment rulemaking.

We appreciate the opportunity to provide input on the modeling protocol. If you have any additional questions, please contact Aaron Worstell, of my staff, at 303-312-6073 or worstell.aaron@epa.gov.

Sincerely,

8/7/2019

X Carl Daly

Signed by: CARL DALY

Carl Daly
Acting Director
Air and Radiation Division

Attachment E-2

Approval Correspondence from US EPA Region 8 and NDDEQ for the BART Modeling Protocol; August 7 and 8, 2019

From: Stroh, David E. <deStroh@nd.gov>
Sent: Thursday, August 8, 2019 7:23 AM
To: Archer, Gregory GRE-MG <garcher@GREnergy.com>
Cc: Roth, Mary Jo GRE-MG <mjroth@GREnergy.com>; Nelson, Debra GRE-MG <dnelson@grenergy.com>; Semerad, Jim L. <jsemerad@nd.gov>; Bachman, Tom A. <tbachman@nd.gov>; Seligman, Angela N. <aseligman@nd.gov>; Thorton, Rhannon T. <rThorton@nd.gov>
Subject: FW: Coal Creek Modeling Protocol

EXTERNAL
Morning Greg,

Attached you will find EPA's approval of the modeling protocol for the revised NOx BART analysis.

GRE CCS can proceed forward with the modeling as outlined. Let me know if you have any questions or comments.

Thanks,

David Stroh
Environmental Engineer

701-328-5188 • destroh@nd.gov

NORTH Dakota | Environmental Quality
Be Legendary.™

918 E. Divide Ave. • Bismarck, ND 58501

From: Daly, Carl <Daly.Carl@epa.gov>
Sent: Wednesday, August 7, 2019 4:40 PM
To: Semerad, Jim L. <jsemerad@nd.gov>
Cc: Worstell, Aaron <Worstell.Aaron@epa.gov>; Morales, Monica <Morales.Monica@epa.gov>
Subject: Coal Creek Modeling Protocol

Jim

Please see attached, our letter approving the July 26, 2019 CALPUFF modeling protocol for the Coal Creek station.

Regards

Carl Daly, Acting Director
Air and Radiation Division
303-312-6416

Attachment F

EPA RBLC Database Tables

Coal Creek Station Updated BART Review
EPA RACT BACT LAER Clearinghouse Data Jan 2000 - Aug 2019
NOx Controls on Large Coal Fired Boilers (>250 MMBtu/hr)
NOx limts in lb/MMBtu

Highlighting Key	Average	Max	Min	Count
No Emission Controls Specified				
Comb Cont, LNB,OFA, etc	0.22	0.30	0.15	6
SNCR (PC Boiler)	0.36	0.36	0.35	2
CFB w SNCR	0.09	0.16	0.07	15
All SNCR	0.12	0.36	0.07	17
SCR	0.07	0.12	0.05	24

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLC ID	Facility Name	Corporate or Company Name	Facility State	Permit Number	NAICS Code	Permit Date	Facility Description	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	Case-by-Case Basis	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AR-0074	PLUM POINT ENERGY	PLUM POINT ASSOCIATES, LLC	AR	1995-AOP-R0	221112	08/20/2003 ACT		BOILER , UNIT 1 - SN-01	SUB-BITUMINOUS COAL	800	MW	Nitrogen Oxides (NOx)	LOW NOX BURNERS + SCR (SCR not listed in RBLC, but specified in permit for facility 0.09 lb/MMBtu specified with SCR)	0.09	LB/MMBTU		BACT-PSD	0			0.09	LB/MMBTU	
AR-0079	PLUM POINT ENERGY	PLUM POINT ASSOCIATES, LLC	AR	1995-AOP-R0	221112	08/20/2003 ACT	PLUM POINT ENERGY ASSOCIATES, LLC (PERMITTEE) PROPOSES TO CONSTRUCT AND OPERATE A NOMINAL 550-800 MW COAL FIRED GENERATING STATION	BOILER - SN-01	SUB-BITUMINOUS COAL	800	MW	Nitrogen Oxides (NOx)	LOW NOX BURNERS + SCR (SCR not listed in RBLC, but specified in permit for facility 0.09 lb/MMBtu specified with SCR)	0.09	LB/MMBTU		BACT-PSD	0.09	LB/MMBTU		0		
AR-0094	JOHN W. TURK JR. POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY	AR	2123-AOP-R0	221112	11/05/2008 ACT	600 MW POWDER RIVER BASIN SUB-BITUMINOUS PULVERIZED COAL FIRED POWER PLANT	PC BOILER	PRB SUB-BIT COAL	6000	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION (SCR)	0.067	LB/MMBTU	24 HOUR ROLLING	BACT-PSD	0.05	LB/MMBTU	12 MONTH ROLLING	0		
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ	AZ 08-01	221112	02/06/2012 ACT	2,250 MW COAL FIRED POWER PLANT	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.24	LB/MMBTU	30-DAY ROLLING AVG	BACT-PSD	0			0		
IA-0067	WALTER SCOTT JR. ENERGY CENTER	MIDAMERICAN ENERGY COMPANY	IA	PROJECT 02-528	221112	06/17/2003 ACT	utility	CBEC 4 BOILER	PRB COAL	7675	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS, OVERFIRE AIR, AND SELECTIVE CATALYTIC REDUCTION	0.07	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	2353	T/YR		0.07	LB/MMBTU	30 DAY ROLLING AVERAGE
KS-0026	HOLCOMB UNIT #2	SAND SAGE POWER, LLC	KS	0550087/C-3855	221112	10/08/2002 ACT		BOILER, PULVERIZED COAL	COAL	660	MW	Nitrogen Oxides (NOx)	SCR, LOW NOX BURNERS, SEPARATED OVERFIRE AIR (SOFA)	0.12	LB/MMBTU	initial 18 months	Other Case-by-Case	0.08	LB/MMBTU	after initial 18 months	0.08	LB/MMBTU	
KY-0079	KENTUCKY MOUNTAIN POWER, LLC	KENTUCKY MOUNTAIN POWER, LLC	KY	V-00-045	221112	05/04/2001 ACT	ELECTRIC GENERATING STATION	BOILER, CIRCULATING FLUIDIZED BED UNITS 1 & 2	COAL	2550	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.07	LB/MMBTU		Other Case-by-Case	0			0.07	LB/MMBTU	
KY-0084	THOROUGHBRED GENERATING STATION	THOROUGHBRED GENERATING COMPANY, LLC	KY	V-02-001	221112	10/11/2002 ACT	POWER PLANT	BOILER, COAL, (2)	COAL	7446	MMBTU/H	Nitrogen Oxides (NOx)	PROPER BOILER DESIGN, LOW NOX BURNERS, AND SCR	0.08	LB/MMBTU	30 day rolling avg	BACT-PSD	0			0.08	LB/MMBTU	
KY-0086	EAST KENTUCKY POWER COOP., INC./SPURLOCK POWER STA	EAST KENTUCKY POWER COOP., INC.	KY	V-97-050 (REVISION 1)	221112	08/04/2002 ACT	POWER PLANT	BOILER, CFB, COAL	COAL	2500	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON CATALYTIC REDUCTION (SNCR) SYSTEM	0.07	LB/MMBTU	30 day rolling avg	BACT-PSD	0			0.07	LB/MMBTU	
MI-0389	KARN WEADOCK GENERATING COMPLEX	CONSUMERS ENERGY	MI	341-07	221112	12/29/2009 ACT	ELECTRICITY GENERATING FACILITY, EXISTING CAPACITY GREATER THAN 2,000 MW.	BOILER	PRB COAL OR 50/50 BLEND	8190	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNER, OVER-FIRED AIR, SELECTIVE CATALYTIC REDUCTION.	0.05	LB/MMBTU	30-DAY ROLLING	BACT-PSD	409.5	LB/H	24-HOUR ROLLING	0		
MI-0399	DETROIT EDISON--MONROE	DETROIT EDISON	MI	93-09A	221112	12/21/2010 ACT	Utility--Coal fired power plant	Boiler Units 1, 2, 3 and 4	Coal	7624	MMBTU/H	Nitrogen Oxides (NOx)	Staged combustion, low-NOx burners, overfire air, and SCR.	0.08	LB/MMBTU	EACH, 12-MONTH ROLLING AVG.	BACT-PSD	222.6	T/MO	EACH, 12-MONTH ROLLING AVG.	0		
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2) -	Petcoke/coal	3030	MMBTU/H each	Nitrogen Oxides (NOx)	SNCR (Selective Non-Catalytic Reduction)	0.07	LB/MMBTU	EACH, 30 D ROLLING AVG; BACT	BACT-PSD	0			0		
MO-0060	CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	CITY UTILITIES OF SPRINGFIELD	MO	122004-007	221111	12/15/2004 ACT	CITY UTILITIES OF SPRINGFIELD HAS APPLIED FOR THE AUTHORITY TO INSTALL A 275 MW (2,724 MMBTU/H) PULVERIZED COAL BOILER AND ASSOCIATED MATERIAL HANDLING EQUIPMENT AT THEIR EXISTING SOUTHWEST POWER STATION. THE EXISTING	PULVERIZED COAL FIRED BOILER	COAL	2724	MMBTU/H	Nitrogen Oxides (NOx)	IT WAS DETERMINED THAT THE BACT FOR NOX FROM THE PULVERIZED COAL FIRED BOILER IS GOOD COMBUSTION PRACTICES ALONG WITH SCR HAVING A NOX EMISSION	0.08	LB/MMBTU	30-DAYS ROLLING AVERAGE	BACT-PSD	0			0		NOT AVAILABLE-*SEE NOTES
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	GREAT PLAINS ENERGY	MO	012006-019	221112	01/27/2006 ACT	KCPL HAS APPLIED FOR THE AUTHORITY TO INSTALL A PULVERIZED COAL BOILER, AN AUXILLIARY BOILER, ASSOCIATED STORAGE, HANDELING AND POLLUTION CONTROL EQUIPMENT, A FUEL OIL STORAGE TANK AND A LANDFILL, ALL ADJACENT TO THE EXISTING	PULVERIZED COAL BOILER - UNIT 2	PULVERIZED COAL	4000	T/H	Nitrogen Oxides (NOx)	KCPL SHALL INSTALL SCR UNIT FOR THE UNIT 2 BOILER TO REDUCE NOX EMISSIONS AND ALSO SHALL INSTALL WET SCRUBBER TO REDUCE SOX EMISSIONS. BOTH CONTROLS	0.08	LB/MMBTU	30 DAYS ROLLING AVERAGE	BACT-PSD	0			0		
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	GREAT PLAINS ENERGY	MO	012006-019	221112	01/27/2006 ACT	KCPL HAS APPLIED FOR THE AUTHORITY TO INSTALL A PULVERIZED COAL BOILER, AN AUXILLIARY BOILER, ASSOCIATED STORAGE, HANDELING AND POLLUTION CONTROL EQUIPMENT, A FUEL OIL STORAGE TANK AND A LANDFILL, ALL ADJACENT TO THE EXISTING	PULVERIZED COAL BOILER - UNIT 1	COAL	4000	T/H	Nitrogen Oxides (NOx)		0.1	LB/MMBTU	30 DAYS ROLLING AVERAGE	N/A	0			0		
MO-0077	NORBORNE POWER PLANT	ASSOCIATED ELECTRIC COOPERATIVE, INC	MO	022008-010	221121	02/22/2008 ACT	TO CONSTRUCT A NEW SUPERCRITICAL PULVERIZED COAL-FIRED BOILER WITH RELATED MATERIAL HANDLING AND POLLUTION CONTROL EQUIPMENT AND A STEAM TURBINE GENERATOR WITH A NET ELECTRICAL OUTPUT OF 689 MEGAWATTS (780 MW GROSS	MAIN BOILER	COAL	3762420	T/YR	Nitrogen Oxides (NOx)	SCR - SELECTIVE CATALYTIC REDUCTION LNB - LOW NOX BURNERS OFA - OVERFIRE AIR	0.065	LB/MMBTU	30 DAYS ROLLING AVERAGE	BACT-PSD	0.05	LB/MMBTU	12 MONTH ROLLING AVERAGE	0		
MT-0027	HARDIN GENERATOR PROJECT	ROCKY MOUNTAIN POWER, INC.	MT	3185-00	221112	06/11/2002 ACT	COAL-FIRED POWER PLANT	BOILER, PULVERIZED COAL-FIRED	COAL	1304	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION	0.09	LB/MMBTU	30-day rolling average	Other Case-by-Case	0			0.09	LB/MMBTU	30-day rolling average
ND-0024	SPIRITWOOD STATION	GREAT RIVER ENERGY	ND	PTC07026	221112	09/14/2007 ACT	LIGNITE FIRED COMBINED HEAT AND POWER PLANT RATED AT A NOMINAL 99 MWE (NET) AND A MAXIMUM OF 112 MWE (GROSS). BOILER IS RATED AT 1280.	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	LIGNITE	1280	MMBTU/H	Nitrogen Oxides (NOx)	FLUIDIZED BED COMBUSTION AND SELECTIVE NON-CATALYTIC REDUCTION	0.09	LB/MMBTU	30 D ROLLING	BACT-PSD	114.9	LB/H	24 H BLOCK	0		
ND-0026	M.R. YOUNG STATION	MINNKOTA POWER COOPERATIVE	ND	PTC12003	221112	03/08/2012 ACT	Two lignite fired cyclone boilers.	Cyclone Boilers, Unit 2	Lignite	6300	MMBTU/H	Nitrogen Oxides (NOx)	SNCR plus separated over fire air	0.35	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	3995.6	LB/H	24 HOUR AV DURING STARTUP	0		
ND-0026	M.R. YOUNG STATION	MINNKOTA POWER COOPERATIVE	ND	PTC12003	221112	03/08/2012 ACT	Two lignite fired cyclone boilers.	Cyclone Boilers, Unit 1	Lignite	3200	MMBTU/H	Nitrogen Oxides (NOx)	SNCR plus separated over fire air	0.36	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	2070.2	LB/H	24 HOUR AV DURING STARTUP	0		
NE-0018	WHELAN ENERGY CENTER	HASTINGS UTILITIES	NE	58048	221112	03/30/2004 ACT	ADDITION OF A 220 MW COAL-FIRED UTILITY BOILER & 75 MMBTU/HR AUX BOILER TO AN EXISTING 80 MW FACILITY	BOILER, UNIT 2 UTILITY	SUBBITUMINOUS COAL	2210	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION	0.08	LB/MMBTU	30-day rolling ave.	BACT-PSD	0			0.08	LB/MMBTU	
NE-0031	OPPD - NEBRASKA CITY STATION	OMAHA PUBLIC POWER DISTRICT	NE	58343C01	221112	03/09/2005 ACT	EXISTING ELECTRICAL GENERATING PLANT, CONSTRUCTING A NEW 660 (NET) MW UNIT.	UNIT 2 BOILER	SUBBITUMINOUS COAL			Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION (SCR)	0.07	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	0			0.07	LB/MMBTU	
NE-0049	OPPD NEBRASKA CITY STATION	OMAHA PUBLIC POWER DISTRICT	NE	CP07-0049	221112	02/26/2009 ACT	COAL-FIRED POWER PLANT CONSISTING OF TWO ~650MW ELECTRIC STEAM GENERATING UNITS. UNIT 1 INSTALLED IN THE 1970S, UNIT 2 CONSTRUCTED/OPERATIONAL IN 2009.	NCS UNIT 1	POWDER RIVER BASIN COAL	370	T/YR	Nitrogen Oxides (NOx)	LNB W/OVERFIRE AIR PORT SYSTEM	0.23	LB/MMBTU	30-DAY ROLLING AV	BACT-PSD	0			0		

Coal Creek Station Updated BART Review
EPA RACT BACT LAER Clearinghouse Data Jan 2000 - Aug 2019
NOx Controls on Large Coal Fired Boilers (>250 MMBtu/hr)
NOx limts in lb/MMBtu

Highlighting Key	Average	Max	Min	Count
No Emission Controls Specified				
Comb Cont, LNB,OFA, etc	0.22	0.30	0.15	6
SNCR (PC Boiler)	0.36	0.36	0.35	2
CFB w SNCR	0.09	0.16	0.07	15
All SNCR	0.12	0.36	0.07	17
SCR	0.07	0.12	0.05	24

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLC ID	Facility Name	Corporate or Company Name	Facility State	Permit Number	NAICS Code	Permit Date	Facility Description	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	Case-by-Case Basis	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
NV-0036	TS POWER PLANT	NEWMONT NEVADA ENERGY INVESTMENT, LLC	NV	AP4911-1349	221112	05/05/2005 ACT	200 MW PC COAL FIRED ELECTRICAL GENERATION UNIT	200 MW PC COAL BOILER	POWDER RIVER BASIN COAL	2030	MMBTU/H	Nitrogen Oxides (NOx)	SCR & LOW NOX BURNERS	0.067	LB/MMBTU	24-HOUR ROLLING	BACT-PSD	0			0.067	LB/MMBTU	24-HOUR ROLLING
OK-0118	HUGO GENERATING STA	WESTERN FARMERS ELECTRIC COOP	OK	97-058-C M-2 PSD	335999	02/09/2007 ACT	GENERATING STATION	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)		750	MW	Nitrogen Oxides (NOx)	LOW NOX BURNERS (LNB) W/ OVERFIRE AIR (OFA) AND SELECTIVE CATALYTIC REDUCTION (SCR)	0.07	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	0.05	LB/MMBTU	12 MONTH ROLLING AVERAGE	0		
OK-0151	SOONER GENERATING STATION	O G AND E	OK	2010-338-C(M-1)PSD	221112	01/17/2013 ACT	The facility is an electricity generation plant (SIC Code 4911) located in an attainment area. The facility is currently operating under Permit No. 2010-338-TVR2 issued November 21, 2011.	COAL-FIRED BOILERS	COAL	550	MW	Nitrogen Oxides (NOx)	LOW-NOx BURNERS AND OVERFIRE AIR.	0.15	LB/MMBTU	30-DAY AVG	BART	0			0		
OK-0152	MUSKOGEE GENERATING STATION	O G AND E	OK	2005-271-C(M-5)PSD	221112	01/30/2013 ACT	The Muskogee Generating Station utilizes sub-bituminous coal, natural gas, and some waste products (used oil-sorb, used antifreeze, used solvents, used oil, chemical cleaning wastes, hazardous waste fuel, activated carbon, demineralizer resin, and waste water	COAL-FIRED BOILER	COAL	550	MW	Nitrogen Oxides (NOx)	LOW-NOx BURNERS AND OVERFIRE AIR	0.15	LB/MMBTU	30-DAY AVG	BART	0			0		
PA-0182	RELIANT ENERGY SEWARD POWER	RELIANT ENERGY	PA	PA-32-040B	221112	08/26/2003 ACT	ELECTRIC GENERATING FACILITY	BOILER, CIRCULATING FLUIDIZED BED, (2)	COAL	2532	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON CATALYTIC REDUCTION (SNCR)	0.15	LB/MMBTU		BACT-PSD	0			0.15	LB/MMBTU	
PA-0247	BEECH HOLLOW POWER PROJECT	ROBINSON POWER COMPANY LLC	PA	63-00922A	221112	04/01/2005 ACT	PA FOR INSTALLATION OF 272 (NET) MEGAWATT WASTE COAL FIRED CFB AND ASSOCIATED AIR SOURCES CONTROLLED BY A LIMESTONE INJECTION ,SNCR AND BAGHOUSE.	COAL FIRED CFB	WASTE COAL			Nitrogen Oxides (NOx)	SNCR EMPLOYED TO MINIMIZE NOX EMISSIONS. FACILITY WILL BE EQUIPPED WITH NOX CEM TO MONITOR EXHAUST GAS STREAM.	0.08	LB/MMBTU		LAER	972	T/YR		0.08	LB/MMBTU	
PA-0248	GREENE ENERGY RESOURCE RECOVERY PROJECT	WELLINGTON DEV/GREENE ENERGY	PA	30-00150A	221119	07/08/2005 ACT	THIS PA IS FOR THE CONSTRUCTION OF A NEW 525 NET MW (580 GROSS) ELECTRIC GENERATING FACILITY. THE FACILITY CONSISTS OF 2 WASTE COAL FIRED CFB BOILERS, EACH RATED AT 2756 MMBTU/HR, CFB'S WILL DRIVE A SINGLE TURBINE/GENERATOR.	2 CFB BOILERS	WASTE COAL	358	T/H (each)	Nitrogen Oxides (NOx)	SNCR, NOX CEM	0.08	LB/MMBTU	30 DAY ROLLING AVERAGE	LAER	0.1	LB/MMBTU	24 HR AVERAGE	0		
PA-0257	SUNNYSIDE ETHANOL,LLC	SUNNYSIDE ETHANOL,LLC	PA	17-313-001	325193	05/07/2007 ACT	THIS PA IS FOR A 88 MILLION GALLON PER YEAR ETHANOL PRODUCTION PLANT POWERED BY A 24.7 MW COAL FIRED COGENERATION PLANT. THE PLANT IS LOCATED AT CURWENSVILLE BOROUGH IN CLEARFIELD COUNTY.	CFB BOILER	COAL	496.8	MMBTU/H	Nitrogen Oxides (NOx)	SNCR	0.1	LB/MMBTU	24 HR AVERAGE	LAER	34.78	LB/H		0		
SC-0104	SANTEE COOPER CROSS GENERATING STATION	SANTEE COOPER	SC	0420-0030-CI	221112	02/05/2004 ACT	ELECTRIC UTILITY	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	5700	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS AND SCR	0.08	LB/MMBTU		Other Case-by-Case	2278	T/YR	Each Boiler	0.08	LB/MMBTU	
TX-0489	SOUTHWESTERN PUBLIC SERVICE COMPANY-HARRINGTON STATION	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	P017M1	221112	10/17/2006 ACT	COAL-FIRED ELECTICAL GENERATING FACILITY	UNIT 3 BOILER	PBR COAL	3870	MMBtu/h	Nitrogen Oxides (NOx)	LOW NOX BURNERS, SEPARATED OVERFIRE AIR WINDBOX, WITH ADDITIONAL YAW CONTROL OF THE BURNERS FOR ADDITIONAL NOX CONTROL	0.3	LB/MMBTU		Other Case-by-Case	0			0		
TX-0554	COLETO CREEK UNIT 2	COLETO CREEK	TX	PSDTX1118	221112	05/03/2010 ACT	Coal-fired boiler	Coal-fired Boiler Unit 2	PRB coal	6670	MMBTU/H	Nitrogen Oxides (NOx)	low-NOx burners with OFA, Selective Catalytic Reduction	0.06	LB/MMBTU	ROLLING 30 DAY AVG	BACT-PSD	0.05	LB/MMBTU	ROLLING 12 MONTH AVG	0		
TX-0557	LIMESTONE ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	TX	PSDTX371M4	221112	02/01/2010 ACT	NRG Texas Power LLC (NRG) operates two coal and petroleum coke-fired steam/electric units, otherwise known as Limestone Units 1 and 2, which were originally permitted to operate in September 1981. These units are Combustion Engineering tangentially-fired, controlled	LMS Units 1 and 2	Coal	9061	MMBtu/H	Nitrogen Oxides (NOx)	Tuning of existing low-NOx firing system to induce deeper state combustion.	0.25	LB/MMBTU	30-DAY	BACT-PSD	0			0		
TX-0577	WHITE STALLION ENERGY CENTER	WHITE STALLION ENERGY CENTER, LLC	TX	86088	221112	12/16/2010 ACT	WSEC proposes to construct and operate new steam-electric utility generating facilities using four circulating fluidized bed (CFB) boilers, each with a design maximum heat input of 3,300 million British thermal units per hour (MMBtu/hr) and 300 MW net electric output.	CFB BOILER	COAL & PET COKE	3300	MMBTU/H	Nitrogen Oxides (NOx)	CFB AND SNCR	0.07	LB NOX/MMBTU	30-DAY ROLLING	BACT-PSD	0.1	LB NOX/MMBTU	1-HR	0		
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	TENASKA TRAILBLAZER PARTNERS LLC	TX	PSDTX1123	221112	12/30/2010 ACT	Coal-fired electric generating facility	Coal-fired Boiler	Sub-bituminous coal	8307	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	0.05	LB/MMBTU	12-MONTH ROLLING	BACT-PSD	0.06	LB/MMBTU	30-DAY ROLLING	0		
UT-0064	SEVIER POWER COMPANY	NEVCO - SEVIER POWER COMPANY	UT	DAQE-AN2529001-04	221112	10/12/2004 ACT	270 MW COAL-FIRED CIRCULATING FLUIDIZED BED STEAM ELECTRIC PLANT (BOILER). USES LOW-NOX BURNERS (DRY LOW NOX), LIMESTONE INJECTION SNCR, AMMONIS INJECTION, DRY LIME SCRUBBER, BAGHOUSE ALL AS CONTROLS	LOW-NOX BURNERS WITH SNCR (SELECTIVE NON-CATALYTIC	WESTERN COAL	270	MW	Nitrogen Oxides (NOx)	LOW NOX BURNERS WITH SNCR WITH AMMONIA INJECTION	0.1	LB/MMBTU	24-HOUR ROLLING	BACT-PSD	0			0.1	LB/MMBTU	
UT-0065	INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	INTERMOUNTAIN POWER SERVICE CORPORATION	UT	DAQE-AN0327010-04	221112	10/15/2004 ACT	NEW PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT #3, DESIGNED AT 950-GROSS MW (900-NETMW) WITH A DRY BOTTOM, TANGENTIALLY FIRED OR WALL-FIRED BOILER. UNIT #3 BOILER WILL BE EQUIPPED WITH WET FLUE GAS DESULPHURIZATION, LNB, OVER	PULVERIZED COAL FIRED ELECTRIC GENERATING	BITUMINOUS OR BLEND	950	MW-gross	Nitrogen Oxides (NOx)	LOW NOX BURNERS, OVER FIRE AIR, SCR	0.07	LB/MMBTU	30-DAY ROLLING AVERAGE	BACT-PSD	633.5	LB/H	24-BLOCK AVERAGE	0.07	LB/MMBTU	
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	DESERET POWER ELECTRIC COOPERATIVE	UT	PSD-OU-0002-04.00	221112	08/30/2007 ACT	110 MW WASTE COAL FIRED UNIT	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR	WASTE COAL/BITUMINOUS BLEND			Nitrogen Oxides (NOx)	SNCR	0.088	LB/MMBTU	30-DAY ROLLING	BACT-PSD	0			0		
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	DESERET POWER ELECTRIC COOPERATIVE	UT	PSD-OU-0002-04.00	221112	08/30/2007 ACT	110 MW WASTE COAL FIRED UNIT	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR	WASTE COAL/BITUMINOUS BLEND			Nitrogen Oxides (NOx)	SNCR	0.08	LB/MMBTU	30-DAY ROLLING	BACT-PSD	0			0		
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	VIRGINIA ELECTRIC AND POWER CO	VA	11526	221112	06/30/2008 ACT	ELECTRIC POWER GENERATING FACILITY	2 CIRCULATING FLUIDIZED BED BOILERS	COAL AND COAL REFUSE	3132	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE NON-CATALYTIC REDUCTION AND GOOD COMBUSTION PRACTICES AND CEM SYSTEM	0.07	LB/MMBTU	30 DAY ROLLING AVERAGE	BACT-PSD	0.07	LB/MMBTU	30 DAY ROLLING AVERAGE	0		
WI-0225	MANITOWOC PUBLIC UTILITIES	MANITOWOC PUBLIC UTILITIES	WI	02-RV-147	22	12/03/2003 ACT	PUBLIC ELECTRIC UTILITY	CIRCULATING FLUIDIZED BED BOILER (ELECTRIC	COAL / PET COKE	650	MMBTU/H	Nitrogen Oxides (NOx)	SNCR NETTED OUT OF PSD BACT BY ELIMINATING COAL FROM BOILER #5	0.155	LB/MMBTU		N/A	24.62	T/MO	12 MO. ROLLING AVERAGE	0		
WI-0228	WPS - WESTON PLANT	WISCONSIN PUBLIC SERVICE	WI	04-RV-248	22	10/19/2004 ACT	ELECTRICAL UTILITY	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER	PRB COAL	5173.07	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS, GOOD COMBUSTION PRACTICES SELECTIVE CATALYTIC REDUCTION (SCR)	0.07	LB/MMBTU	30 DAY AVG. EXCL. STARTUP/SHUTDOWN	BACT-PSD	0.06	LB/MMBTU	12 MO. AVG. INCL. STARTUP / SHUTDOWN	0		
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	WESTERN GREENBRIER CO-GENERATION, LLC	WV	R14-0028	221112	04/26/2006 ACT	NOMINAL 98 NET MEGAWATT WASTE COAL-FIRED STEAM ELECTRIC CO-GENERATION FACILITY. BOILER IS CFB TECHNOLOGY. FACILITY INCLUDES KILN TO PRODUCE CEMENTITIOUS MATERIAL FROM ASH GENERATED IN BOILER.	CIRCULATING FLUIDIZED BED BOILER (CFB)	WASTE COAL	1070	mmbtu/h	Nitrogen Oxides (NOx)	SNCR	0.1	LB/MMBTU	30-DAY	BACT-PSD	0			0.1	LB/MMBTU	30-DAY
WY-0057	WYGEN 2	BLACK HILLS CORPORATION	WY	CT-3030	221112	09/25/2002 ACT	500 MW PC POWER PLANT	BOILER, 500 MW PC	SUBBITUMINOUS COAL	5145.7	MMBTU/H	Nitrogen Oxides (NOx)	LOW NOX BURNERS/SCR	0.07	LB/MMBTU	30 DAY ROLLING	BACT-PSD	0			0.07	LB/MMBTU	
WY-0063	WYGEN 3	BLACK HILLS CORPORATION	WY	CT-4517	221112	02/05/2007 ACT	100 MW PULVERIZED COAL FIRED ELECTRIC UTILITY	PC BOILER	SUBBITUMINOUS COAL	1300	MMBTU/H	Nitrogen Oxides (NOx)	SCR/LNB/OVERFIRE AIR	0.05	LB/MMBTU	12 MONTH ROLLING	BACT-PSD	65	LB/H	30 DAY ROLLING	0		
WY-0064	DRY FORK STATION	BASIN ELECTRIC POWER COOPERATIVE	WY	CT-4631	237130	10/15/2007 ACT	ONE PC BOILER RATED A 385 MW (NET)	PC BOILER (ES1-01)	COAL			Nitrogen Oxides (NOx)	LOW NOX BURNERS AND SCR	0.05	LB/MMBTU	12 MONTH ROLLING	BACT-PSD	190.1	LB/H	30-DAY ROLLING	832.4	T/YR	ANNUAL

Attachment G

EPA Control Cost Manual SCR and SNCR Spreadsheets for Units 1 and 2

Data Inputs

Coal Creek SCR Cost Estimate for 2019 BART - 0.06 lb NOx/MMBtu EPA calculations for flue gas flow and catalyst volume. Use anhydrous ammonia Meth 2 Cat Rep Cost EPA Default Cat Cost.

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Coal

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

EPA default value used

Site specific data entered

What is the MW rating at full load capacity (Bmw)?	605	MW
What is the higher heating value (HHV) of the fuel?	6,685	Btu/lb
What is the estimated actual annual MWhs output?	4,610,826	MWhs
		87% capacity factor
Enter the net plant heat input rate (NPHR)	10	MMBtu/MW
Plant Elevation	1980	Feet above sea level

*HHV value of 6685 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Lignite

Enter the sulfur content (%S) = 0.82 percent by weight

CCS data sulfur content

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

○ Method 1
● Method 2
○ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.13	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.06	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	Replace all catalyst every 3 years
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet (confidential)
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Gas temperature at the SCR inlet (T)	650	^{o}F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	547	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used Ammonia ▼

Enter the cost data for the proposed SCR:

Desired dollar-year	2018				
CEPCI for 2018	615.3	Enter the CEPCI value for 2018	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.25	Percent			
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0361	$/kWh			* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Percent sulfur content for Coal (% weight)	0.82	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	6,685	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate Use 5.25 per ND Dept of Health Guidance	

SCR Design Parameters

Coal Creek SCR Cost Estimate for 2019 BART - 0.06 lb NOx/MMBtu EPA calculations for flue gas flow and catalyst volume. Use anhydrous ammonia Meth 2 Cat Rep Cost EPA Default Cat Cost.

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	6,050	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	5,299,800	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		4,610,826	MWhs
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.870	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7621	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	53.8	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	423.50	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1,613.79	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.67	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	3,166,706	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	181.21	/hour
Residence Time	1/V_{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.07	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.7	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3164	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	17,475.38	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	3,299	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	3,793	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	61.6	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	48	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	165	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	568	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	76	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	25,500	gallons (storage needed to store a 14 day reagent supply rounded to the ne

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0669

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	3488.02	kW

Cost Estimate

Coal Creek SCR Cost Estimate for 2019 BART - 0.06 lb NOx/MMBtu EPA calculations for flue gas flow and catalyst volume. Use anhydrous ammonia Meth 2 Cat Rep Cost EPA Default Cat Cost.

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost})** =	$134,743,323	in 2018 dollars
Reagent Preparation Cost (RPC) =	$2,906,167	in 2018 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2018 dollars
Balance of Plant Costs (BPC) =	$9,781,799	in 2018 dollars
Total Capital Investment (TCI) =	$191,660,675	in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

** **Cost estímate for SCR Reactor from Version 10 spreadsheet at 0.04 lb NOx/MMBtu was $141.8M.** Size and cost of reactor is not reduced at performance rating of 0.06 lb NOx/MMBtu. A 0.06 lb NOx/MMBtu performance rating reflects an optomistic estimate of the 3-year average performace of the SCR catalyst in this service based actual performance of the best performing power plant of two plants firing Texas Lignite. Actual performance could be lower based on the higher sodium content of North Dakota lignite versus Texas lignite

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$134,743,323 in 2018 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$2,906,167 in 2018 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$9,781,799 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$3,868,611 in 2018 dollars
Indirect Annual Costs (IDAC) =	$12,836,227 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$16,704,838 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$958,303 in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$169,294 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$959,641 in 2018 dollars
Annual Catalyst Replacement Cost =		$1,781,373 in 2018 dollars

For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.

Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2 selected.
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3	
Direct Annual Cost =		$3,868,611 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$14,128 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$12,822,099 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$12,836,227 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$16,704,838 per year in 2018 dollars
NOx Removed =	1,614 tons/year
Cost Effectiveness =	$10,351 per ton of NOx removed in 2018 dollars

Data Inputs

Coal Creek SCR Cost Estimate for 2019 BART - 0.08 lb NOx/MMBtu EPA calculations for flue gas flow and catalyst volume. Use anhydrous ammonia Meth 2 Cat Rep Cost EPA Default Cat Cost.

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility ▼

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit ▼

What type of fuel does the unit burn? Coal ▼

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

EPA default value used

Site specific data entered

What is the MW rating at full load capacity (Bmw)? 605 MW

What is the higher heating value (HHV) of the fuel? 6,685 Btu/lb

*HHV value of 6685 Btu/lb is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MWhs output? 4,610,826 MWhs

87% capacity factor

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 1980 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: Lignite ▼

Enter the sulfur content (%S) = 0.82 percent by weight

CCS data sulfur content and HHV

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

○ Method 1
● Method 2
○ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.13	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.08	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	Replace all catalyst every 3 years
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet (confidential)
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Gas temperature at the SCR inlet (T)	650	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	547	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used	Ammonia ▼

Enter the cost data for the proposed SCR:

Desired dollar-year	2018		
CEPCI for 2018	615.3	Enter the CEPCI value for 2018 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.25	Percent	
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*	* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0361	$/kWh	* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*	* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Percent sulfur content for Coal (% weight)	0.82	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	6,685	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate Use 5.25 per ND Dept of Health Guidance	

SCR Design Parameters

Coal Creek SCR Cost Estimate for 2019 BART - 0.08 lb NOx/MMBtu EPA calculations for flue gas flow and catalyst volume. Use anhydrous ammonia Meth 2 Cat Rep Cost EPA Default Cat Cost.

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	6,050	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	5,299,800	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		4,610,826	MWhs
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.870	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	7621	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	38.5	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	302.50	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	1,152.71	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.48	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	3,166,706	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	223.72	/hour
Residence Time	$1/V_{space}$	0.00	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.07	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.7	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^{Y} -1) , where Y = H$_{catalyts}$/(t$_{SCR}$ x 24 hours) rounded to the nearest integer	0.3164	Fraction
Catalyst volume (Vol$_{catalyst}$) =	2.81 x Q$_{B}$ x EF $_{adj}$ x Slipadj x NOx$_{adj}$ x S$_{adj}$ x (T$_{adj}$/N$_{scr}$)	14,154.71	Cubic feet
Cross sectional area of the catalyst (A$_{catalyst}$) =	q$_{flue\ gas}$ /(16ft/sec x 60 sec/min)	3,299	ft^{2}
Height of each catalyst layer (H$_{layer}$) =	(Vol$_{catalyst}$/(R$_{layer}$ x A$_{catalyst}$)) + 1 (rounded to next highest integer)	2	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A$_{SCR}$) =	1.15 x A$_{catalyst}$	3,793	ft^{2}
Reactor length and width dimensions for a square reactor =	(A$_{SCR}$)$^{0.5}$	61.6	feet
Reactor height =	(R$_{layer}$ + R$_{empty}$) x (7ft + h$_{layer}$) + 9ft	47	feet

Reagent Data:

Type of reagent used Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^{3}

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m$_{reagent}$) =	(NOx$_{in}$ x Q$_{B}$ x EF x SRF x MW$_{R}$)/MW$_{NOx}$ =	118	lb/hour
Reagent Usage Rate (m$_{sol}$) =	m$_{reagent}$/Csol =	405	lb/hour
	(m$_{sol}$ x 7.4805)/Reagent Density	54	gal/hour
Estimated tank volume for reagent storage =	(m$_{sol}$ x 7.4805 x t$_{storage}$ x 24)/Reagent Density =	18,200	gallons (storage needed to store a 14 day reagent supply rounded to the ne

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^{n}/(1+ i)^{n} - 1 = Where n = Equipment Life and i= Interest Rate	0.0669

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	3488.02	kW

Cost Estimate

Coal Creek SCR Cost Estimate for 2019 BART - 0.08 lb NOx/MMBtu EPA calculations for flue gas flow and catalyst volume. Use anhydrous ammonia Meth 2 Cat Rep Cost EPA Default Cat Cost.

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$125,974,211	in 2018 dollars
Reagent Preparation Cost (RPC) =	$2,671,705	in 2018 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2018 dollars
Balance of Plant Costs (BPC) =	$9,781,799	in 2018 dollars
Total Capital Investment (TCI) =	$179,956,029	in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) = $125,974,211 in 2018 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) = $2,671,705 in 2018 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) = $0 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) = $9,781,799 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$3,383,172 in 2018 dollars
Indirect Annual Costs (IDAC) =	$12,052,484 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$15,435,656 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$899,780 in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$120,924 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$959,641 in 2018 dollars
Annual Catalyst Replacement Cost =		$1,402,826 in 2018 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2 selected.
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3	
Direct Annual Cost =		$3,383,172 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$13,425 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$12,039,058 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$12,052,484 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$15,435,656 per year in 2018 dollars
NOx Removed =	1,153 tons/year
Cost Effectiveness =	$13,391 per ton of NOx removed in 2018 dollars

Data Inputs

Coal Creek SNCR w MNL Cost Estimate for 2019 BART - 0.10 lb NOx/MMBtu

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility ▼

What type of fuel does the unit burn? Coal ▼

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit ▼

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

EPA default value used

Site specific data entered

What is the MW rating at full load capacity (Bmw)? 605 MW

What is the higher heating value (HHV) of the fuel? 6,626 Btu/lb

What is the estimated actual annual MWh output? 4,610,826 MWh

87% capacity factor

Is the boiler a fluid-bed boiler? No ▼

Enter the net plant heat input rate (NPHR) 10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Lignite ▼

Enter the sulfur content (%S) = 0.82 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable ▼

*The sulfur content of 0.82% is a default value. See below for data source. Enter actual value, if known.

Ash content (%Ash): 13.6 percent by weight

*The ash content of 13.6% is a default value. See below for data source. Enter actual value, if known.

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.13	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.10	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	3.00	

Plant Elevation	1980	Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	50	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

<u>Densities of typical SNCR reagents:</u>

50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Urea ▼

Enter the cost data for the proposed SNCR:

Desired dollar-year	2018			
CEPCI for 2018	615.3	Enter the CEPCI value for 2018	541.7	2016 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)	5.25	Percent
Fuel ($Cost_{fuel}$)	1.74	$/MMBtu*
Reagent ($Cost_{reag}$)	1.66	$/gallon for a 50 percent solution of urea*
Water ($Cost_{water}$)	0.0042	$/gallon*
Electricity ($Cost_{elect}$)	0.0361	$/kWh*
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	$/ton*

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Fuel Cost ($/MMBtu)	1.74	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.82	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	13.60	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	6,685	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate (%)	5.5	Default bank prime rate	

SNCR Design Parameters

Coal Creek SNCR w MNL Cost Estimate for 2019 BART - 0.10 lb NOx/MMBtu

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	6,050	MMBtu/hour
Maximum Annual MWh Output =	Bmw x 8760 =	5,299,800	MWh
Estimated Actual Annual MWh Output (Boutput) =		4,610,826	MWh
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.87	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	7621	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	23	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	181.50	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	691.62	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.07	
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.07	
Atmospheric pressure at 1980 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.7	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	1540	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	3,080	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	324.5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	109,100	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0820

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	110.9	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	1.39	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	28.4	lb/hour

Cost Estimate

Coal Creek SNCR w MNL Cost Estimate for 2019 BART - 0.10 lb NOx/MMBtu

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$4,230,857	in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$5,617,234	in 2018 dollars
Total Capital Investment (TCI) =	$12,802,518	in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$4,230,857	in 2018 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$5,617,234	in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$4,351,631	in 2018 dollars
Indirect Annual Costs (IDAC) =	$1,055,568	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$5,407,198	in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$192,038	in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$4,105,413	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$30,510	in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$18,380	in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$5,290	in 2018 dollars
Direct Annual Cost =		$4,351,631	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$5,761	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,049,806	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,055,568	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$5,407,198	per year in 2018 dollars
NOx Removed =	692	tons/year
Cost Effectiveness =	$7,818	per ton of NOx removed in 2018 dollars

Attachment H-1

Report “Estimating Total Sulfuric Acid Emissions from Stationary Power Plants” 2018 Update; Electric Power Research Institute

Estimating Total Sulfuric Acid Emissions from Stationary Power Plants

2018 Update

3002012398

Estimating Total Sulfuric Acid Emissions from Stationary Power Plants

2018 Update

3002012398

Technical Update, March 2018

EPRI Project Manager

N. Goodman

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ACKNOWLEDGMENTS

The following organization, under contract to the Electric Power Research Institute (EPRI), prepared this report:

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This report describes research sponsored by EPRI.

The methodology described in this document was developed by Southern Company Services and modified, with permission, by EPRI. Individuals responsible for the development of the original Southern Company sulfuric acid model are Keith E. Harrison and Larry S. Monroe, Ph.D. of the Southern Company.

This publication is a corporate document that should be cited in the literature in the following manner:

Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update. EPRI, Palo Alto, CA: 2018. 3002012398.

ABSTRACT

The U. S. Environmental Protection Agency's (EPA's) Toxics Release Inventory (TRI) program requires electric utilities to estimate and report annual emissions of 682 chemicals and chemical categories. Sulfuric acid (H_2SO_4) is one of the chemicals included in the TRI reporting requirement, when it is present in an aerosol form. The EPA defines sulfuric acid aerosols as "includ[ing] mists, vapors, gas, fog, and other airborne forms of any particle size." The objective of this report is to provide a method for predicting the sulfuric acid manufactured during fuel combustion, removed by air pollution control equipment or flue gas treatment, and released to the environment in stack gases. The estimation method is an empirical model, whereby emissions are predicted from factors derived from sulfuric acid measurements at full-scale power plants. The power generation units considered in the report include coal, oil and natural gas-fired boilers, as well as both simple and combined cycle gas turbines. The procedures presented here can be used to estimate sulfuric acid manufacture from combustion, operation of nitrogen oxide reduction control equipment and flue gas conditioning, and the removal of SO_3 or H_2SO_4 from the flue gas stream by air heaters, particulate control devices such as electrostatic precipitators (ESPs) and fabric filters, sulfur dioxide control equipment, and nitrogen oxide control equipment.

Keywords
Air emissions
Coal combustion
Natural gas combustion
Sulfuric acid
Toxics Release Inventory (TRI)

EXECUTIVE SUMMARY

Deliverable Number: 3002012398

Product Type: Technical Update

Product Title: Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update

PRIMARY AUDIENCE: Power company environmental staff responsible for Toxics Release Inventory reporting and air permitting.

SECONDARY AUDIENCE: Air quality agencies and other organizations with an interest in power plant emissions.

KEY RESEARCH QUESTION

The U. S. Environmental Protection Agency's (EPA's) Toxics Release Inventory (TRI) program requires owners of some coal-, oil-, and natural gas-fired power plants to estimate and report annual emissions of 682 chemicals and chemical categories. Sulfuric acid (H_2SO_4) is one of the chemicals included in the TRI reporting requirement, when it is present in an aerosol form. The objective of this report is to provide a method for predicting the sulfuric acid manufactured during fuel combustion, removed by air pollution control equipment or flue gas treatment, and released to the environment in stack gases.

RESEARCH OVERVIEW

The sulfuric acid estimation method is an empirical model, whereby emissions are predicted from factors derived from sulfuric acid measurements at full-scale power plants. The power generation units considered in the report include coal, oil, and natural gas-fired boilers, as well as both simple and combined cycle gas turbines. The procedures presented here can be used to estimate sulfuric acid manufacture from combustion, operation of nitrogen oxide reduction control equipment and flue gas conditioning, and the removal of SO_3 or H_2SO_4 from the flue gas stream by air heaters, particulate control devices such as electrostatic precipitators (ESPs) and fabric filters, sulfur dioxide control equipment, and nitrogen oxide control equipment. The 2018 update to this report incorporates modifications to the methodology for estimating emissions from coal plants with hot-side electrostatic precipitators (ESPs), and plants that add magnesium oxide to inhibit conversion of sulfur dioxide to sulfur trioxide.

KEY FINDINGS

- The principal sources of sulfuric acid emissions from fossil fuel-fired power plants are 1) oxidation of sulfur during fuel combustion, 2) injection of sulfur trioxide for flue gas conditioning to improve the efficiency of ESPs, and 3) increased conversion of sulfur dioxide to sulfur trioxide when flue gas passes through selective catalytic reduction (SCR) NOx control equipment.
- Sulfuric acid is removed from flue gas when it reacts with ammonia to form solids that are not reportable to TRI, and are also removed when the flue gas passes through wet or dry scrubber equipment.
- Measurements of sulfuric acid before and after power plant process equipment were used to develop factors representing the impact of fuel type and pollution control devices on formation and removal of sulfuric acid.

EXECUTIVE SUMMARY

WHY THIS MATTERS

Sulfuric acid is emitted from power plants that burn coal, and to a lesser extent, those that burn oil or natural gas for electricity production. For some U.S. power plants, the quantities emitted must be reported annually to the Environmental Protection Agency TRI program, as well as to state agencies. This report provides power plant owners with a methodology to estimate the impact of fuel changes or new equipment on sulfuric acid emissions.

HOW TO APPLY RESULTS

The equations in this report provide a complete methodology for estimating emissions from most common fossil fuel-fired power plant configurations. The equations may be calculated by entering them into a spreadsheet. The Electric Power Research Institute (EPRI) also incorporates the equations into the Toxics Release Inventory for Power Plants software, designed to assist power plant owners with annual TRI reporting.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- Toxics Release Inventory for Power Plants User's Group

EPRI CONTACTS: Naomi Goodman, Senior Technical Leader, ngoodman@epri.com

PROGRAM: Program 59: Power Plant Multimedia Emissions Characterization

ACRONYMS AND ABBREVIATIONS

APH	air preheater
ABS	ammonium bisulfate
AS	ammonium sulfate
Btu	British thermal units
CCS	controlled condensation system
CEMS	continuous emissions monitoring system
EDTA	ethylenediamine tetraacetic acid
EGU	electric generation unit
EPA	U.S. Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-To-Know Act
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
FGC	flue gas conditioning
FGD	flue gas desulfurization
lb	pound
HV	heating value
MBtu	million Btu
Mcf	thousand cubic feet (of natural gas)
mmBtu	million Btu (of natural gas)
mol	mole
MW	molecular weight
PCD	pollution control device
ppm	parts per million
ppmv	parts per million by volume
PRB	Powder River Basin
scf	standard cubic feet
SBS	sodium bisulfate
SCR	selective catalytic reduction
SCS	Southern Company Services
SNCR	selective non-catalytic reduction

TRI	Toxics Release Inventory
TSAM	total sulfuric acid manufactured
TSAR	total sulfuric acid release
WAF	wall adjustment factor
yr	year

SI CONVERSION FACTORS

	English (US) units	X	Factor	=	SI units
Area:	1 ft^2	X	9.29×10^{-2}	=	m^2
Flow Rate:	1 gal/min	X	6.31×10^{-5}	=	m^3/s
	1 gal/min	X	6.31×10^{-2}	=	L/s
Length:	1 ft	X	0.3048	=	m
	1 in	X	2.54	=	cm
	1 yd	X	0.9144	=	m
Mass:	1 lb	X	454	=	g
	1 lb	X	0.454	=	kg
	1 gr	X	0.0648	=	g
	1 ton	X	0.907		tonne
Volume:	1 ft^3	X	28.3	=	L
	1 ft^3	X	0.0283	=	m^3
	1 gal	X	3.785	=	L
	1 gal	X	3.785×10^{-3}	=	m^3
Temperature:	°F-32	X	0.556	=	°C
Energy:	Btu	X	1055.1	=	joule

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1

INTRODUCTION

Background

Estimation of sulfuric acid emissions from power plants is a topic of increasing importance to the U.S. electric utility industry. Most significantly, Section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA), also known as the Toxics Release Inventory (TRI), requires facilities that "manufacture," "process," or "otherwise use" a listed chemical above certain threshold amounts to report their annual releases of the chemical to EPA and state agencies. For sulfuric acid, the TRI reporting requirements are triggered if a facility "manufactures" or "processes" more than 25,000 pounds of this chemical or "otherwise uses" more than 10,000 pounds of it in a given calendar year.

In June 1995, the U. S. Environmental Protection Agency (EPA) modified the list of chemicals subject to the EPCRA § 313 reporting requirements so that only aerosol forms of sulfuric acid would be subject to the TRI reporting requirements (EPA, 1995a). EPA defines sulfuric acid aerosols as "includ[ing] mists, vapors, gas, fog, and other airborne forms of any particle size." Although initially it appeared that only liquid droplets of sulfuric acid needed to be reported, the present method estimates the sulfuric acid emissions regardless of the physical state of the molecules.

Beginning on July 1, 1999, certain coal- and oil-fired electric power plants have been required to report annual releases of TRI chemicals that they manufacture, process or otherwise use above threshold amounts. Under EPA's EPCRA § 313 regulations, coal- and oil-fired electric utilities are deemed to "manufacture" sulfuric acid. Thus, electric utilities have to submit TRI reports on sulfuric acid aerosol releases if they "manufacture" more than 25,000 pounds of the chemical in a given reporting year (EPA, 1997).

Emissions of sulfuric acid received considerable attention in with the broad application of selective catalytic reduction (SCR) NOx control technology. The use of SCR unavoidably contributes to production of sulfur trioxide (SO_3), the precursor of sulfuric acid. Several notable incidents have been witnessed where an increase in sulfuric acid emissions, as manifested by an increase in stack plume visibility, was attributed to the addition of SCR process equipment to an existing power plant. The deployment of approximately 115 GW of selective catalytic reduction (SCR) from 1997 through 2009 prompted power plant owners to conduct extensive measurements documenting the fate of SO_3 and sulfuric acid in power plants.

The methodology described in this report was developed by Southern Company Services (SCS). Between 2000 and 2005, SCS developed several versions of the estimation methodology and released draft reports informally (Hardman, 1998; Hardman, 1999; Monroe, 2001, Harrison, 2004, and Harrison, 2005**)**. The SCS model was widely used in the electrical power generation industry for TRI reporting and other emissions estimation purposes. In 2007, EPRI received permission from Southern Company Services to modify the SCS estimation method to include additional data and improvements, and to publish this method under EPRI sponsorship. The 2008 version of the model added the ability to estimate emissions based on a specified sulfuric acid flue gas concentration at the stack, which can be used when alkali injection is employed to reduce sulfuric acid emissions. The 2010 version updated several of the “technology impact factors” (F2 factors, used to reflect the impact of pollution control devices on sulfuric acid releases) with new SO_3 measurements. The 2012 version of the model (EPRI, 2012) made minor changes to the calculation procedure to more accurately represent flow through from the boiler and control devices, changed the approach used to account for sulfuric acid from flue gas conditioning (FGC), and made several corrections and clarifications to technology factors, including a new technology factor for units with a wet electrostatic precipitator (ESP) and the addition of a new sulfuric acid source through the oxidation of sulfur dioxide across a carbon monoxide catalyst in combined cycle units.

The current version of the model makes minor changes to the application of the sulfuric acid removal factors (Technology Impact Factors, F2) for configurations that include a hot-side ESP or magnesium oxide addition to the fuel or furnace. This version also incorporates methodology for the calculation of releases when SCR or SCNR is only injected on a partial-year basis (previously published in 2014 as an erratum to the 2012 report).

Objective

The objective of this report is to present a methodology for estimating sulfuric acid emissions from power generating facilities, for use in Toxics Release Inventory reporting and other applications. The scope of units considered includes coal- and oil-fired steam generating units, as well as simple cycle and combined cycle natural gas- and oil-fired combustion turbines. To date, the most authoritative and documented data describe sulfuric acid emissions from coal-fired steam generators. The focus on this category of units is due to the increased availability of measurements describing the fate of sulfuric acid attributable to the retrofit of SCR process equipment on coal-fired steam generators.

Report Organization

Section 2 of this report addresses the uncertainty in measuring SO_3 concentration using the preferred controlled condensation system (CCS) method, and the accuracy and representativeness of the available data. Section 3 outlines the general methodology adopted in this model while Section 4 describes the details of the methodology, focusing on data that can be used to predict sulfuric acid manufacture by combustion. This section also summarizes data describing the removal of sulfuric acid across air heaters, ESPs, and wet flue gas desulfurization (FGD) process equipment. Section 5 outlines how to conduct the calculation for steam boilers firing a mixture of fuels. Section 6 addresses simple cycle and combined cycle combustion turbine applications. Example calculations for various power plant configurations are presented in Appendix A. A chronology of changes to the sulfuric acid model is presented in Appendix B.

2

MEASUREMENT UNCERTAINTY

A predictive method for sulfuric acid emissions requires knowledge of sulfuric acid production and the fate of emissions from specific boilers and combustion turbines, to an acceptable degree of measurement accuracy. In addition, a large database of measurements from many electric generating units (EGUs) is desired to obtain a robust predictive method. Both the size and the representativeness of the measurement database are critical to the accuracy of a predictive method.

The predictive correlations presented in this report are based on data obtained from field tests conducted predominantly within the last 10 years, with some estimates conducted in the 1990s. The quality of the data is thought to vary widely. It was not possible to obtain quality control information for all of the available measurements; thus, it was not possible to critically review all data used in this model.

The technique used to measure SO_3/H_2SO_4 is not known for all data sources, but most measurements were conducted using the controlled condensate system (CCS), a widely used technique that is generally considered the most accurate method for measuring SO_3/H_2SO_4 in stack gases from stationary combustion sources. EPA Method 8 is sometimes used for this purpose, but that method has a known positive bias from oxidation of SO_2 to SO_3 in the impinger solution.

CCS Measurement Uncertainty

A series of field and laboratory trials conducted by EPRI evaluated the measurement bias of the CCS technique by comparing results from both laboratory tests and field trials (EPRI, 2001). SO_3/H_2SO_4 measurements at similar gas compositions were compared in a 1) clean, ash-free laboratory environment; 2) simulated ash environment, and 3) actual field duty. The findings of the EPRI tests conducted under high-ash conditions are applicable to much of the field data used to derive removal factors in the current estimation model. The results showed that, when fly ash was present in the flue gas stream, the technique imposed a low bias (e.g., indicated lower SO_3/H_2SO_4 than measured in the ash-free laboratory environment), due to reactions of SO_3 or sulfuric acid with fly ash in the filter thimble holder upstream of the CCS condenser. Conversely, the EPRI tests indicated that use of CCS downstream of the particulate control device produces unbiased measurements, as long as appropriate procedures are followed.

The extent of bias observed in the EPRI study depended on the sampling location, which could be the air heater inlet, air heater outlet, or flue gas desulfurization outlet. Furthermore, the bias depended on the quantity of ash collected, the alkalinity of the ash, and the coal sulfur content (e.g., SO_2 content in the sample gas). Measurement bias in the simulated ash environment was observed for both high sulfur coal and low sulfur Powder River Basin (PRB) coal; however biasing in the PRB coal tests can generally be considered non-significant in light of already low SO_3 concentrations and the expected absorption of sulfuric acid with the alkaline ash in actual field tests. Data for high sulfur coal suggested a low bias of 20-25% could occur in measurement locations upstream of a particulate control device with typical ash loadings, and no significant bias downstream of the particulate control device.

The precision of the CCS data used in this estimation model can be estimated from the variability among duplicate measurements believed to be conducted under the same process conditions. Data from recent field trials with experienced test crews suggest a precision of up to ± 20% is realistic for most conditions. The repeatability of the CCS measurements depends on avoiding stratification within the gas stream (traversing is very difficult), maintaining correct temperatures in the sampling train, and having well trained sampling personnel. Therefore, the precision of the entire data set used in this model, which includes data from older studies of unknown quality, is expected to be closer to ± 50%.

Representativeness

The accuracy of the correlations presented in this report depends on the representativeness of the constituent data points. For some power plant configurations, only a few measurements are available, and the correlations provide only rough approximations of the flue gas SO_3/H_2SO_4 releases for similar units. The category with the largest number of data points is dry-bottom boilers, firing low sulfur, eastern bituminous coal. In general, the number of SO_3 measurements for various power plant configurations are proportional to the occurrence of those configurations among the total population of U.S. EGUs. The number of measurements in each power plant category should be considered when applying this model; factors based on one measurement have much higher uncertainty than factors based on dozens of measurements.

As a consequence of the uncertainty in SO_3/H_2SO_4 measurements and the limited number of data points that comprise the relevant correlations, the predictive technique should be assumed to provide estimates within a ± 50% relative accuracy.

3

BACKGROUND AND METHODOLOGY OVERVIEW

This section provides a brief overview of sulfuric acid production mechanisms in power plants and presents the basic equations for estimating sulfuric acid releases. A detailed review of this topic has been provided by Srivastava (2004) and more recently by Monroe (2006).

The production or manufacture of SO_3, and ultimately sulfuric acid, is determined initially by processes occurring directly within the flame zone of a boiler, the convective heat transfer sections, or environmental control components. These production or manufacturing processes can be gas phase or can be induced by catalysis on the surface of fly ash particles or heat removal surfaces.

Mechanisms that remove sulfuric acid from the flue gas also can occur both in the gas phase and on heat transfer surfaces, usually promoted by ash-derived deposits. The amount of sulfuric acid released from the stack is the aggregate result of production mechanisms, generally occurring at temperatures above 650°F, and removal mechanisms, including alkali-based sorbent injection, occurring at lower temperatures.

Description of General Methodology

The method estimates the manufacture and the subsequent release of sulfuric acid from the power generation process. The ***manufacture*** of sulfuric acid is defined as any process step that increases the flue gas content of sulfuric acid, regardless of its ultimate fate. To estimate the ***release*** of sulfuric acid, the manufacture estimate is corrected by a factor or series of factors to account for sulfuric acid removal within the system.

Three process steps ultimately lead to the manufacture of sulfuric acid in a fossil fuel-fired electricity generation unit: the combustion process, selective catalytic reduction (SCR) for NOx control, and flue gas conditioning. All remaining steps in the power generation process reduce sulfuric acid. Therefore, the total sulfuric acid released (TSAR) is the cumulative sum of the total sulfuric acid manufactured (TSAM), adjusted by sulfuric acid losses.

Sulfuric Acid Manufacture from Combustion

A detailed analytical study by Senior (2002) explored details of SO_2 oxidation to SO_3. Specifically, the author modeled the relevant reaction sets employing the temperature-time history of a typical utility boiler, considering gas phase events only and ignoring catalytic effects. The results showed that insignificant SO_3 formed in the early stage of the flame, but SO_3 production increased as the gases exited the flame zone and cooled. The author reported production of SO_3 to be essentially complete prior to flue gas entering the economizer section. The observation that most SO_3 forms during cooling from post-flame temperatures (2,900-3,100°F) to temperatures typical of the economizer entrance was also noted by Buckley (2002). Senior further quantified the relationship between coal sulfur content, excess air, and SO_3 production that has been empirically observed by previous investigators. Specifically, the results showed that after four seconds of residence time, SO_3 production could range from between 0.3 - 0.6% of the flue gas SO_2 concentration.

In the absence of SCR NOx control or FGC, the boiler or turbine combustion process comprises the only source of sulfuric acid. The sulfuric acid manufacture by the combustion process (EM_{Comb}) is expressed as follows:

$$EM_{Comb} = K \bullet F1 \bullet E2 \qquad \text{Eq. 3-1}$$

Where K is a constant, F1 is a Fuel Impact Factor describing the SO_3 production associated with combustion for a specific fuel type, and E2 is the annual rate of SO_2 production. Further details of this relationship and the derivation of constants and other terms are presented in Section 4. There are two situations where the TSAR equations must be modified to reflect reduction or removal of sulfuric acid from combustion: 1) the use of a hot-side ESP and 2) magnesium oxide (Mag-Ox) addition to the boiler or fuel. All other sources of sulfuric acid (SCR or FGC) are manufactured downstream of these two technologies and require no modifications. The derivation and use of technology impact factors for hot-side ESP and Mag-Ox addition are discussed in Section 4.

Sulfuric Acid Manufacture from SCR/SNCR NOx Control

The SCR process increases the production of SO_3, and therefore, H_2SO_4, as a percentage of SO_2. SO_3 production can range from as low as 0.3%, for the most recent catalyst technology, to as high as 3% of the SO_2 concentration.

The production of SO_3 from SO_2 is a well-known consequence of SCR, and the degree of SO_2 oxidation is a performance variable that should be part of catalyst procurement specifications. To a degree, SO_3 production can be mitigated by reducing the content of vanadium pentoxide and compensating with other catalyst oxides such as tungsten or molybdenum, which offer improved selectivity (e.g., lower SO_2 oxidation) but also lower activity for NOx removal. Alternatively, advanced catalyst formulations can be used that concentrate the vanadium-containing active ingredients on the catalyst surface and minimize content within the substrate, lowering SO_2 oxidation. To achieve an equivalent level of NOx and residual ammonia slip, a low SO_2 oxidation catalyst may require a larger volume of catalyst than one for which SO_2 conversion is not constrained. In general, the degree of SO_2 oxidation ranges from about 0.2% to 1.5% for most SCR process reactors designed for bituminous coals. If SCR is applied to extremely low sulfur, high alkalinity coals such as PRB, higher SO_2 oxidation is acceptable. Depending on how the measurement of SO_2 oxidation is performed, the oxidation can be 3% or higher.

In many instances, owners and catalyst suppliers prefer that measurements to quantify SO_2 oxidation for the purpose of commercial guarantees be conducted not with authentic flue gas but in a laboratory-scale test facility, without fly ash present. This approach has the advantage of improved accuracy and repeatability of the SO_3 concentration. The measurements are generally conducted using CCS. However, particularly for PRB coals, this method will over-predict SO_3 manufactured by the SCR, as the mitigating role of high fly ash alkalinity is not considered. Consequently, the role of fly ash alkalinity must be considered in predicting SO_3 manufactured by SCR.

The observation that calculated laboratory-scale SO_3 values at the exit of an SCR reactor exceed measurements in the field has been witnessed on numerous occasions. Specifically, Lindenhoff (2004) reported that the measured SO_2 oxidation rate for PRB-generated flue gas of 1.25% was below the 1.6% value predicted based on the boiler and SCR catalyst specifications. Further, tests conducted by this catalyst manufacturer noted significant absorption of SO_3 generated within the SCR reactor prior to the air heater. Sufficient data was accumulated to derive both a mathematical model and to project a graphical relationship describing SO_3 removal within an SCR reactor as a function of both ash content and the number of alkaline sites available in the flue gas stream.

An alternative NOx control process, selective non-catalytic reduction (SNCR), does not use a catalyst and does not promote the oxidation of SO_2 to SO_3. Accordingly, there is no manufacture of sulfuric acid attributable to SNCR.

The following relationship describes the total H_2SO_4 manufactured from an SCR equipped utility boiler or steam generator:

$$EM_{SCR} = K \bullet S2 \bullet f_{sops} \bullet E2 \bullet F3_{SCR} \qquad \text{Eq. 3-2}$$

Where K is a constant, S2 is the catalyst SO_2 oxidation rate, f_{sops} is the fraction of the coal burn in which flue gas is directed through the SCR, E2 is the annual rate of SO_2 production, and $F3_{SCR}$ is the Technology Impact Factor for SCR used to adjust for the presence of alkaline fly ash. Further details of this relationship and the derivation of constants and other terms are presented in Section 4.

Sulfuric Acid Manufacture from Flue Gas Conditioning

Flue gas conditioning (FGC) is a process that is typically used in power plants to assist in particulate control in an ESP or baghouse. The conditioning additives can be any of the following: SO_3, SO_3 plus NH_3, or NH_3 alone. In SO_3-based FGC, SO_3 is introduced into the flue gas either preceding or following the air heater. The SO_3 is typically produced on-site from sulfurous fuel that is burned to produce SO_2, which is then catalytically oxidized to SO_3 with a conversion rate typically exceeding 95%. When injected into the flue gas, the SO_3 immediately reacts with water vapor to create sulfuric acid, thus resulting in the manufacture of sulfuric acid. Estimating the manufacture source requires knowledge of the concentration of SO_3 injected and the associated oxygen content of the flue gas.

Equation 3-3 estimates the manufacture of sulfuric acid from FGC, where K_e is a constant, B is the coal burn, f_e is the FGC operating factor, and I_s the SO_3 injection rate. $F3_{FGC}$ is the Technology Impact Factor for FGC that is used to adjust for the presence of alkaline fly ash in PRB coals. Further details and derivation of the constant are provided in Section 4.

$$EM_{FGC} = K_e \bullet B \bullet f_e \bullet I_s \bullet F3_{FGC} \qquad \text{Eq. 3-3}$$

Methodology to Estimate Release

Sources of sulfuric acid manufactured upstream of the air preheater are calculated separately (modified for hot-side ESP or Mag-Ox if necessary), then summed. The combined SO_3 is modified to reflect reactions of SO_3 with residual equivalent NH_3 slip from SCR/SNCR equipment and/or FGC ammonia injection to form ABS, and then adjusted by removal in applicable downstream equipment such as the air preheater, electrostatic precipitator or other particulate control device (PCD) and flue gas desulfurization (FGD) equipment. In the calculations to determine the amount of ABS formation, ammonia slip is subtracted from sulfuric acid. However, the 1:1 ratio of H_2SO_4 to NH_3 is on a molar basis. Therefore, all the following calculations of ammonia slip are actually the amount of ammonia slip that is equivalent to sulfuric acid based on a 1:1 molar ratio, as determined through the use of the constant K. The adjustments are made using Technology Impact Factors (F2) which describe the fraction of sulfuric acid that penetrates each component.

The methodology employs the follow steps, combined into a single release equation, which is shown in Equation 3-4, and illustrated schematically in Figure 3-1:

1. Calculate the sources of sulfuric acid upstream of the APH from combustion, SCR and FGC
2. If applicable, apply the technology factor for sulfuric acid removal to the sulfuric acid manufactured from combustion only, for hot-side ESP and/or Mag-Ox addition
3. Sum the resulting sources of sulfuric acid upstream of the APH from combustion, SCR and FGC
4. Calculate residual equivalent ammonia slip from the SCR/SNCR and FGC and subtract this ammonia from the sum of the sources upstream of the APH to account for ABS formation which is not reportable
5. If the result of Steps 1) and 2) is a positive value, apply the technology factor for APH removal of SO_3 ($F2_{APH}$)
6. Add downstream sources of sulfuric acid (from FGC, if injected downstream), and subtract downstream ammonia injection (from FGC, if injected downstream) to account for ABS, which is not reportable
7. Apply all remaining relevant downstream technology factors

In equation form, the methodology is expressed as shown in Equation 3-4.

$$\mathbf{TSAR} = \{[((EM_{Comb} * F2_{Hotside\_ESP} * F2_{Mag\text{-}ox}) + EM_{SCR/SNCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] \bullet F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} \bullet F2_{x} \qquad \textbf{Eq. 3-4}$$

where,

TSAR = Total sulfuric acid released

EM_{Comb} = Sulfuric acid manufactured through combustion

$EM_{SCR/SNCR}$ = Sulfuric acid manufactured from SCR or SNCR

$EM_{FGC\_beforeAPH}$ = Sulfuric acid manufactured from FGC injected upstream of the air preheater (APH)

$EM_{FGC\_afterAPH}$ = Sulfuric acid manufactured from FGC injected downstream of the APH

NH_3Slip = Calculated equivalent ammonia slip that reacts with H_2SO_4 to form ammonium bisulfate (ABS) from SCR/SNCR and/or FGC

$F2_{APH}$ = Technology Impact Factor for APH

$F2_{Hotside\_ESP}$ = Technology Impact Factor for hot-side ESP

= 0.63 if hot-side ESP is present

= 1.0 if hot-side ESP is <u>not</u> present (optional)

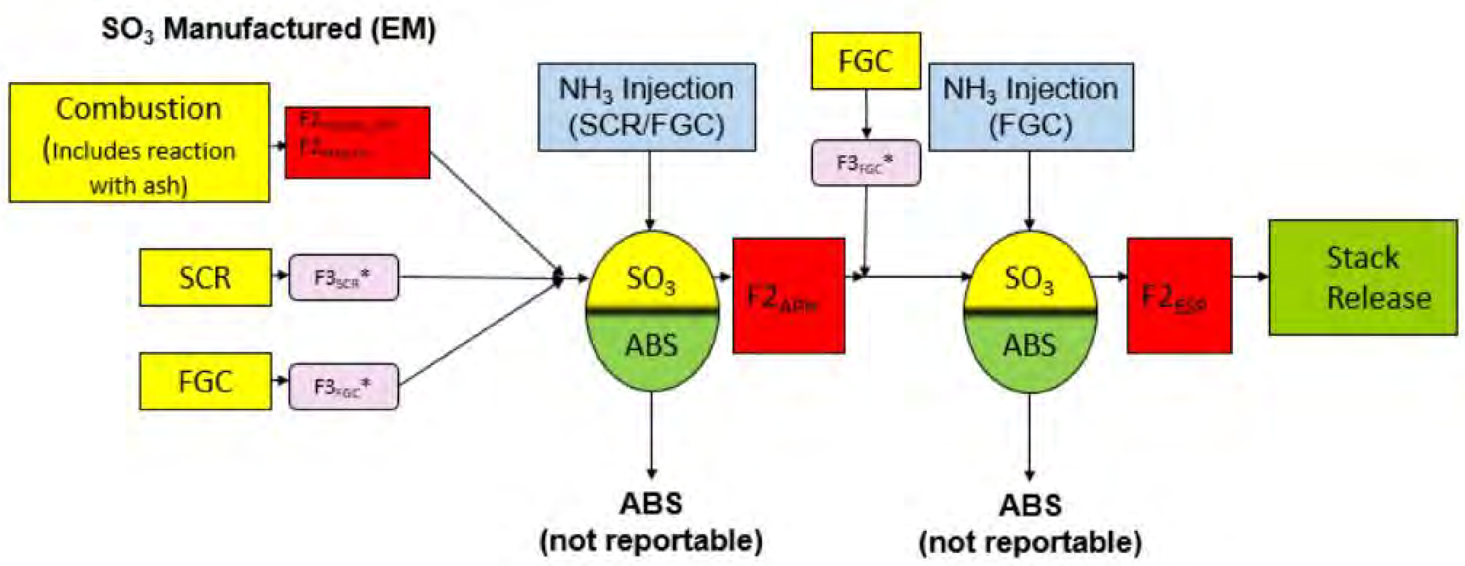
$F2_{Mag\text{-}Ox}$ = Technology Impact Factor for magnesium oxide addition in fuel or furnace

= 0.25 (or custom) if Mag-Ox is sprayed into furnace

= 0.50 (or custom) if Mag-Ox is mixed with fuel

= 1.0 if Mag-Ox is <u>not</u> applied (optional)

$F2_x$ = Technology Impact Factors, all others that apply (downstream of APH)



*F3 factor accounting for alkalinity of PRB ash

Figure 3-1
Schematic of Methodology Used to Estimate Sulfuric Acid Releases

Ammonia from SCR/SNCR NOx Control

Both SCR and SNCR can introduce residual ammonia (NH_3), also called ammonia slip, into the flue gas. This residual ammonia can react with SO_3 or sulfuric acid to form ammonium sulfate and/or ammonium bisulfate, thereby removing from the flue gas some of the SO_3 that is a precursor to sulfuric acid, and reducing the amount released.

For an SCR, ammonia slip is expected to usually range between 0 and 2 parts per million (ppm) for bituminous coal cases. Higher values of ammonia slip are possible if the unit has not been recently tuned, the boiler or SCR process operates under upset, or as the catalyst ages. Higher ammonia slip may be tolerable in PRB coal applications, since ammonia is not readily absorbed by the highly alkaline PRB ash and adverse operational impacts (air preheater pluggage and ash contamination by ammonia) are avoided. Reactions between the residual ammonia and SO_3 or H_2SO_4 occur in the air preheater and result in a solid product that may deposit or accumulate on the surface of the fly ash. Any SO_3 or H_2SO_4 that participates in these reactions is no longer present as sulfuric acid and is not required to be reported to the EPA TRI program as a release of sulfuric acid.

SNCR employs ammonia or urea injection in the upper furnace for NOx reduction. The higher temperatures characteristic of the upper furnace zone (1,800 to 2,400°F, as compared to 700°F for SCR) do not require reduction catalyst so there is no additional manufacture of SO_3 or sulfuric acid. Typically, SNCR systems operate with higher levels of residual ammonia (5 to 10 ppm), so any sulfuric acid that is present from combustion is reduced through reaction with the ammonia. Consequently, SNCR systems will always *reduce* the overall amount of sulfuric acid released, while SCR systems can *reduce* but will likely *increase* the amount of sulfuric acid released.

The reactions between SO_3 and/or H_2SO_4 and ammonia produce ammonium sulfate [$(NH_4)_2SO_4$] and/or ammonium bisulfate (NH_4HSO_4). While both chemicals are solids, the bisulfate pairs one molecule of ammonia with one of sulfuric acid, while the sulfate requires two ammonia molecules for each sulfuric acid. Which reaction product is present is usually determined by the stoichiometry, or the relative amount of each substance on a mole basis, that is present in the flue gas. When ammonia is present in an amount over twice the mole content of sulfuric acid, the reaction product will always be ammonium sulfate (AS). Conversely, when sulfuric acid is present in an amount on a mole basis greater than ammonia, the product will be ammonium bisulfate (ABS). Between these two extremes, a mixture of ammonium sulfate and bisulfate is produced.

A SCR-equipped unit firing bituminous coals with low-to-medium sulfur content will always produce an excess of sulfuric acid over ammonia slip. Accordingly, ammonium bisulfate is the primary byproduct anticipated. For subbituminous and lignite coals, any sulfuric acid produced is typically adsorbed by the ash and it is likely that residual ammonia will exceed sulfuric acid content on a mole basis. Under these conditions, ammonium sulfate is the likely product.

For SNCR-equipped units, ammonia slip levels of 5 ppm and possibly higher will favor ammonium sulfate, particularly for western U.S. coals where the alkaline fly ash will reduce the SO_3 content. For eastern bituminous coals, which have generally higher sulfur content and lower ash alkalinity, ammonium bisulfate will likely predominate.

For the purpose of predicting sulfuric acid emissions, these distinctions are not important. A single molecule of sulfuric acid will capture a single molecule of ammonia, producing ammonium bisulfate. If additional ammonia is available, the ammonium bisulfate can react with another ammonia molecule to form ammonium sulfate. It can be assumed that all sulfuric acid forms ammonium bisulfate before any further reaction to the ammonium sulfate form occurs. This assumption leads to the calculation strategy that ammonia captures all of the sulfuric acid it can as ammonium bisulfate, and since the bisulfate form is no longer reportable, the sulfuric acid disappears from the release calculation. Additional ammonia reacting with the ammonium bisulfate is of no consequence to the sulfuric acid calculation – although this reaction is important when estimating ammonia releases.

The total sulfuric acid released is reduced by the residual equivalent ammonia, or ammonia slip, from SCR or SNCR. This equivalent ammonia slip is calculated as follows, and is added to any ammonia injection from FGC before it is subtracted from the sum of the sulfuric acid manufactured.

$$\mathbf{NH3_{SCR} = K_s \bullet B \bullet f_{sreagent} \bullet S_{NH3}} \qquad \textbf{Eq. 3-5}$$

Where K_S is a constant, B is the coal burn in TBtu/yr, $f_{sreagent}$ is the fraction of SCR operation with reagent injection, and S_{NH3} is the NH_3 slip for the SCR/SCNR. This calculation and factors are described further in Section 4.

Ammonia from Flue Gas Conditioning

Flue gas conditioning may involve injection of NH_3 alone or NH_3 with SO_3. Thus, FGC can result in sulfuric acid manufacture or may result in sulfuric acid removal, if NH_3 is injected alone or in quantities greater than the sulfuric acid. The following equation describes the calculation of equivalent ammonia that is used to reduce sulfuric acid. If ammonia is injected upstream of the APH, this value would be added to the residual ammonia from SCR/SNCR. If added downstream of the APH, the value would be subtracted from any downstream SO_3 injection introduced by FGC.

$$\mathbf{NH3_{FGC} = K_e \bullet B \bullet f_e \bullet I_{NH3}} \qquad \textbf{Eq. 3-6}$$

Where K_e is a constant, B is the coal burn in TBtu/yr, f_e is the fraction of coal burn with FGC operation, and I_{NH3} is the NH_3 injected. This calculation and factors are described further in Section 4.

Estimating Release with Alkali Injection

Many utility operators inject alkali into the flue gas to control SO_3. A wide variety of alkali materials based on calcium, sodium, or in some cases magnesium compounds, have been used with varying degrees of effectiveness to remove SO_3. These alkali materials include sodium bisulfate, trona, and various types of lime (conventional, hydrated, and magnesium enhanced).

Sodium bisulfate (SBS) is the most widely used reagent for control of SO_3. SBS is introduced into the flue gas, usually at the air heater exit, but in some units at the air heater inlet, to maximize residence time and improve SO_3 removal. SBS can be highly effective in removing SO_3. Additional sodium can be added to the flue gas to compensate for any compromise in ESP performance due to increased ash resistivity associated with SO_3 reduction. A detailed summary of experience with SBS usage has recently been published (Moser, 2007).

Trona is another sodium-containing reagent that is used to control SO_3. Trona can be injected at several locations within the boiler, but most applications introduce trona at the air heater exit, prior to the particulate collector (Ritzenthaler, 2006). As with SBS, additional sodium introduced into flue gas is advantageous to compensate for the reduction in ESP performance.

Several forms of calcium-based sorbents can be utilized. These are injected at various locations in the flue gas, including the economizer inlet, economizer outlet (e.g., air heater inlet), and the air heater outlet. A survey of recent experience with lime-derived sorbents addressed the advantages of this approach (Benson, 2006a). Hydrated lime has been shown to be an effective calcium-based reagent for SO_3 control (Gale, 2006), as has lime supplemented with magnesium hydroxide (Benson, 2006b). Calcium–based sorbents can be very effective in reducing SO_3, but may compromise ESP performance, as the reduced SO_3 content in flue gas increases the electrical resistivity of the ash on the collecting plate. For this reason, some operators have proposed using both calcium- and sodium-based sorbents, the latter to both augment SO_3 removal and promote ESP performance. In summary, any of several alkali materials can be used to control SO_3, with the least cost solution depending on the plant and access to low cost sorbent.

Plant units that deploy alkali injection will generally have conducted field tests to determine the SO_3 concentration in flue gas for a specified sorbent injection rate. In most cases, these tests will be conducted at the stack. The alkali injection system usually is operated to reduce SO_3 emissions to between 5 and 15 ppm, an optimal range to prevent formation of a visible plume. A procedure to convert measured sulfuric acid concentration in flue gas to a mass emission rate is summarized below and described in more detail in Section 4. An example application of this procedure is provided in Appendix A.

$$\mathbf{ER_{ALKINJ} = K_{alkali} \bullet B \bullet S_{SO3} \bullet F2_x \bullet F_{alkali}} \qquad \textbf{Eq. 3-7}$$

Where K_{alkali} is a constant, B is the coal burn, S_{SO3} is the measured SO_3 content with injection, F_{alkali} is the fraction of time alkali injection is in operation, and F2 are any applicable downstream Technology Impact Factors.

Users of this approach should be cautioned that the current EPA-approved test method for SO_3 (EPA Method 8) has a significant positive bias, and that corrections for this bias may be needed to accurately assess flue gas concentrations. A more accurate method is the controlled condensate system (CCS). Although no general-purpose, EPA-approved CCS method is currently available, it is widely used by stack test contractors for sulfuric acid measurement and is more accurate than Method 8, if performed correctly.

Some units will not have measured stack emissions. This version of the model adds an alternate approach to estimate releases with alkali injection if stack SO_3 measurements are not available. Instead of using Equation 3-7 for ER_{ALKINJ}, the total sulfuric acid release is calculated by estimating total releases using Equation 3-4. An alkali injection factor, $F3_{ALKINJ}$, is then applied to the total release as shown in Equation 3-8. This $F3_{ALKINJ}$ is either the expected fractional reduction in SO_3 (generally as guaranteed by the vendor) or a default of 0.2. The basis of the 0.2 value is test results indicating that 80% removal is easily achievable (EPRI, 2010b). This method is explained in further detail in Section 4.

$$\mathbf{TSAR_{ALKINJ} = (TSAR_{Comb+SCR+FGC}) \bullet F3_{ALKINJ}} \qquad \textbf{Eq. 3-8}$$

To estimate SO_3 manufacture with alkali injection, plant owners should use the standard approaches given in Section 4 for the appropriate plant configuration. At this time, EPRI does not have sufficient information to estimate the impact on SO_3 formation of adding alkali at various points in the fuel combustion and stack gas treatment process. Assuming that there is no reduction of SO_3 formation is conservative for a threshold determination for TRI reporting purposes.

Estimating Sulfuric Acid with Partial-Year SNCR or SCR Operation

When ammonia or urea is employed in SCR or SNCR during only part of a year, the methodology outlined in this report may not provide an accurate estimate of total sulfuric acid released through the stack. The reason is that the model calculates the pounds of ammonia injected on an annual basis, and uses that quantity to subtract an equivalent quantity of sulfuric acid as non-reportable ammonia salt. However, if there is an excess of ammonia slip present during SCR/SNCR operation above the amount of SO_3 available to react, the model is in effect borrowing SO_3 from periods when the SCR/SNCR is not operating. As a result, the annual release of sulfuric acid will be underestimated for that unit. Underestimation of sulfuric acid releases is most likely to when the following conditions are met:

- SNCR (more likely) or SCR (less likely) operated partial-year
- Sulfuric acid emissions are calculated from fuel sulfur, not CEMS
- The operating factor for reagent addition in the SCR/SNCR system ($f_{sreagent}$) is small
- The unit burns a fuel that inherently manufactures low levels of SO_3 from combustion, such as PRB coal
- The unit has high ammonia slip levels when ammonia is injected

To determine whether the model is underestimating releases for a unit with SCR or SNCR partial-year operation, the user should perform separate calculations for the SCR/SNCR "Ammonia On" condition and SCR/SNCR "Ammonia Off" condition, allocating the amount of fuel burned during the two conditions appropriately. If the sum of the sulfuric acid releases for these two conditions is greater than for the full-year calculation, separate calculations should be employed going forward.

4

ESTIMATING GUIDELINE: STEAM BOILERS

This section describes an estimation procedure for calculating the manufacture and release of sulfuric acid from coal-fired steam generators. The topics addressed are (a) formation within the furnace; (b) the role of SCR, (c) flue gas conditioning (FGC), and (d) alkali injection; and (e) removal by downstream equipment such as air heaters, ESPs or other particulate control devices, and FGD process equipment. Each of the subsequent sections in this chapter provides the information to conduct this stepwise calculation.

Sulfuric Acid Manufacture

Sulfuric Acid Manufactured by Combustion (EM_{Comb})

The premise of the methodology is that the amount of sulfuric acid manufactured by the boiler is a function of the amount of SO_2 produced – which may be determined either from coal usage (amount burned and sulfur content) or from continuous emission monitoring system (CEMS) output. Units equipped with FGD equipment or other methods of SO_2 control are required to estimate emissions either from coal data or from the output of a CEMS positioned ahead of the scrubber. As described below, it may be necessary to correct SO_2 CEMS data for non-ideal stack flow conditions.

The following relationship is used to estimate the sulfuric acid manufactured from combustion in utility sources:

$$\mathbf{EM_{Comb} = K \bullet F1 \bullet E2} \qquad \textbf{Eq. 4-1}$$

where,

EM_{Comb} = total H_2SO_4 manufactured from combustion, lbs/yr

K = Molecular weight and units conversion constant
= $98.07 / 64.04 \bullet 2000 = 3{,}063$

98.07 = Molecular weight of H_2SO_4

64.04 = Molecular weight of SO_2

2000 = Conversion from tons per year to pounds per year.

F1 = Fuel Impact Factor

E2 = Sulfur dioxide (SO_2) emissions, either: (1) recorded by a continuous emissions monitor, tons/yr, or (2) calculated from coal burn data, tons/yr.

The Fuel Impact Factor (F1) is a numerical value or a mathematical relationship reflecting the conversion of SO_2 to SO_3 in the boiler for a specific coal type and boiler type. In the derivation of Equation 4-1, the following assumptions are made:

- SO_3 concentrations are proportional to SO_2 concentrations.
- The grade of coal being burned impacts the rate of conversion from SO_2 to SO_3.
- All SO_3 that forms is converted to H_2SO_4.
- The rate of SO_3 formation is independent of the boiler firing rate (unit load).

The estimates of sulfur dioxide emissions (E2) and F1 factors are further described in the following sections.

Sulfur dioxide (SO2) Emissions from Combustion (E2)

Estimating the sulfuric acid production from Equation 4-1 requires knowledge of the mass rate of SO_2 generated. This rate is designated as E2 in Equation 4-1. As noted previously, the value of E2 can be estimated from either (a) the EPA CEMS data, or (b) calculated from the coal burn data (EPA, 1995a).

If the CEMs data are used to directly quantify the annual SO2 production rate in tons/year of SO_2, it may be necessary to correct for stack geometry, depending on the measurement method used. The user should check with their CEMs operator to obtain the bias correction factors, or the bias corrections may already be taken care of in the instrument software.

If a facility used EPA Methods 1 and 2 for CEM flow monitor setup and validation under the guidelines described in 40 CFR Part 60, Appendix A, flow bias and wall effects corrections should be made to the CEMs SO2 measurements to accurately estimate sulfuric acid releases. This correction can be made using one of the following two equations:

$$\mathbf{E2 = E\left[1 - \frac{\left(C1 \bullet R^2 + C2 \bullet R + C3\right)}{100}\right]} \qquad \textbf{Eq. 4-2}$$

where,

E2 = Corrected SO_2 mass rate, tons per year

E = CEMS-derived SO_2 mass rate, tons per year

C1 = 0.0264 (non-axial flow bias factor)

C2 = 0.183 (non-axial flow bias factor)

C3 = 1.5 (wall effects bias factor) – default value for cylindrical stacks

R = Stack/duct average resultant angle (or swirl angle) from site verification tests, degrees

The average resultant angle, R, is determined using Method 1. The wall effects bias factor, C3, is the percent difference between flow rates calculated using standard Method 1 sampling and flow rates calculated using measured near-wall velocity data. Many utilities do not have bias data available, and as such, an average default value of 1.5, derived from actual data, can be used. Measured bias factors were within the range of 0.9 to 2.2% (Noble, 1998).

If a facility used EPA Method 2H (EPA, 1999) for round stacks, or CTM-041 (EPA, 2003) for rectangular stacks to determine a Wall Adjustment Factor (WAF), then this value can be used instead and the correction equation can be simplified to the following:

$$E2 = E \bullet WAF \qquad \textbf{Eq. 4-3}$$

where,

E2 = Corrected SO_2 mass rate, tons per year

E = CEMS-derived SO_2 mass rate, tons per year

WAF= Wall Adjustment Factor, determined from Method 2H

The WAF correction factor determined by Method 2H is applicable to stack flow rates determined by Methods 2, 2F and 2G. A default value of 0.995 can be used, although actual data should be used if available.

As an alternative to using CEMS data, the following relationship based on coal burn data can be used to estimate the rate of SO_2 emissions:

$$E2 = K1 \bullet K2 \bullet C1 \bullet S1 \qquad \textbf{Eq. 4-4}$$

where,

E2 = SO_2 mass rate, tons/yr

C1 = Dry coal burn, tons/yr. The dry coal can be calculated from wet coal through the following relationship:
Dry coal (tons/yr) = wet coal (tons/yr) • (1-moisture(%)/100%)

S1 = Coal sulfur weighted average, %, dry

K1 = Molecular weight and units conversion constant
= (64.04)/(100 • 32.06) = 0.02
64.04 = molecular weight of SO_2
32.06 = molecular weight of S
100 = conversion of % S to a fraction

K2 = Sulfur conversion to SO_2, implicit from EPA AP-42 (EPA, 1995b)

= 0.95 for bituminous coals

= 0.875 for subbituminous coals

= 0.55 to 0.85 for lignite, based on the Na content

= 1.0 for oil

When any source uses FGD equipment or another technology to control SO_2 emissions, either the fuel basis must be used for the manufacturing and release calculations, or CEMS data can be used, but only when the CEMS precedes the FGD or SO_2 control equipment. Data from a CEMS located after a flue gas desulfurization system cannot be used, because the measured SO_2 has already been decreased by the control equipment, and therefore is not an accurate predictor of the SO_3 emissions rate.

Fuel Impact Factor (F1). Figure 4-1 depicts the fraction of H_2SO_4 produced as a function of flue gas SO_2 content for several coal sources and boiler types. The coal ranks and boiler types consist of (a) high sulfur (>2.5%) eastern bituminous coal, fired in a dry bottom boiler (wall-fired or cell-fired), (b) low sulfur eastern bituminous coal, fired in a dry bottom boiler, (c) PRB coal, fired in both a cyclone and dry bottom boilers. Data are also shown for one unit that fires 75% lignite with the balance PRB and one unit that fires 100% lignite.

Figure 4-1 shows that a wide range in SO_3 production is observed for all coals and boiler types. This range exceeds the theoretical predictions by Senior (2000), suggesting that the role of ash in either catalyzing SO_3 production or absorbing/neutralizing SO_3 is not fully accounted for. The only consistent results in Figure 4-1 are for SO_3 from PRB-fired units, regardless of boiler type, in that less than 1 ppm was observed.

The current model uses a linear relationship to estimate SO_3 production for all eastern bituminous, dry bottom boiler data, as shown in Figure 4-1. The equation expressing this relationship is shown in Equation 4-5. This relationship is significant at the 95% confidence level, although the correlation coefficient (R2) is low (0.13) due to scatter in the data. The current model retains F1 factors based on average fraction of SO_2 converted to SO_3 for all other coal types.

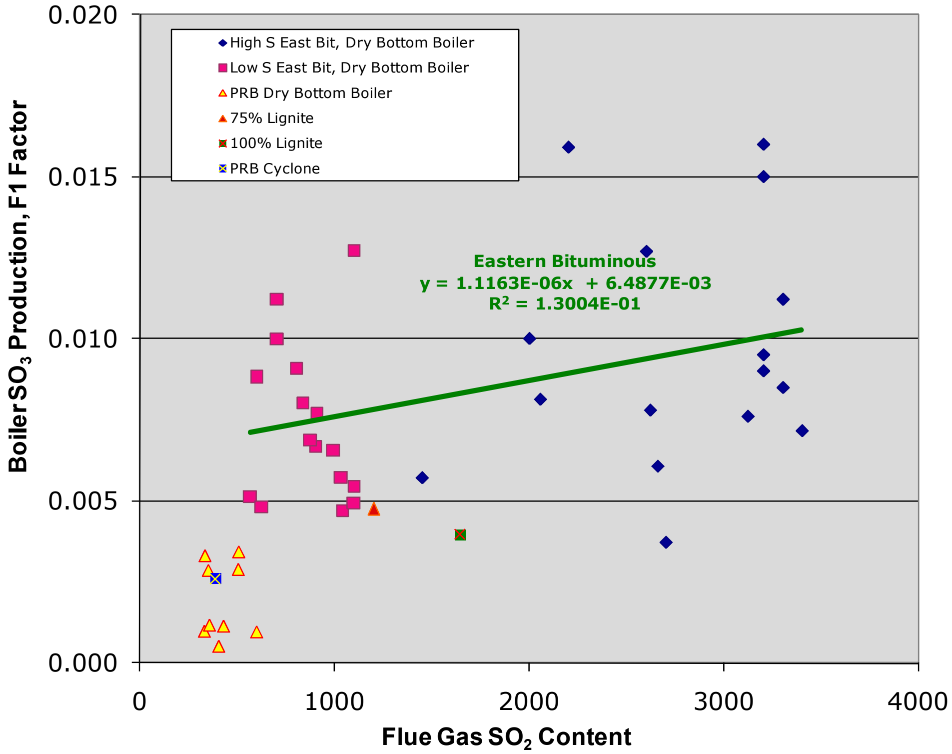


Figure 4-1
Relationship between Boiler SO_3 Production and Flue Gas SO_2 (corrected to 3% O_2)

$$\mathbf{F1_{ebit} = 1.12E\text{-}6 \bullet SO_2 + 0.0065} \qquad \textbf{Eq. 4-5}$$

where,

$F1_{ebit}$ = Fuel Impact Factor for all Eastern Bituminous coals burned in a dry-bottom boiler

SO_2 = Boiler SO_2 concentration (ppm), derived from fuel sulfur content (%)

In order to use this approach, it is necessary to relate coal sulfur (%) to the SO_2 concentration in the boiler. Equation 4-6 is used to calculate that relationship:

$$SO_2 = S1 \bullet \frac{K_{F1}}{HV} \qquad \textbf{Eq. 4-6}$$

where,

SO_2 = Boiler SO_2 concentration (ppmvd, 3% O_2, dry) derived from fuel sulfur content (%)

S1 = Coal sulfur weighted average, %, dry

K_{F1} = Conversion factor = 10,003,602

HV = Coal heating value, Btu/lb, dry

The conversion factor K_{F1} considers all relevant constants to yield the result in ppm of SO_2. The derivation of this constant is presented in Text Box A.

Text Box A: Derivation of Conversion Factor, K_{F1}. The U.S. Code of Federal Regulations 40, Part 60, Table 19-1 “F Factors for Various Fuels” states that 1 million Btu of heat input for bituminous or subbituminous coal will produce 10,640 wet standard cubic feet of flue gas, defined at 0% oxygen and on a wet basis at 20ºC and 760 mm Hg. Correcting this volume to 3% O_2 on a dry basis (typical of the SO_2 measurement data used in the Fuel Impact Factors correlation) yields a volume of 11,419 scf. The standard volume of one pound mole of any gas is 359 scf, defined at 0ºC and 760 mm Hg. Converting this to the English units standard of 20C (68°F), one pound mole occupies 385.5 standard cubic feet. The value 0.95 is the AP-42 (EPA, 1995b) K2 factor for sulfur conversion to SO_2 for a bituminous coal.

Equation 4-4 above can then be expanded as follows:

S1%	0.95	385.5 scf S	1 lb mol S	1 MBtu	1 lb fuel	10^6 Btu	10^6 ppm
	100%	1 lb mol S	32.06 lbs S	11,419 scf	HV Btu	1 MBtu	

Grouping terms,

SO_2 = S1 • 10,003,602 / HV

Therefore, the value of K_{F1} is equal to 10,003,602 [ppmvd SO_2 (3% O_2, dry) • Btu/lb]/%S.

Table 4-1 summarizes the F1 factors. There are no changes to these factors from the previous version of the model (EPRI, 2012).

Table 4-1
Summary of Fuel Impact (F1) Factors for Steam Generating Units

Fuel	Equipment	F1	Comment
E. Bituminous (all)1	Dry Bottom Boiler	Slope: 1.1163E-6 Intercept: 0.0064877	F1 = slope SO2 + intercept 32 data points
Med-High S Eastern Bituminous (>2.5%)	Cyclone	0.016	One data point.
W. Bituminous	Dry Bottom Boiler	0.00111	One data point.
W. Bituminous	Cyclone	0.0022	One data point.
Subbituminous/PRB	All Boilers	0.0019	Average of 8 units
Lignite	Dry Bottom Boiler	0.0044	Two data points.
Lignite	Cyclone	0.00112	One data point.
Petroleum coke	Boiler	0.04	One data point.
Natural gas	Boiler	0.01	
#2 Fuel oil	Boiler	0.01	
#6 Fuel oil	Boiler	0.025	
Used oil	Boiler	0.0175	
Natural gas	CT	See Table 6-1	
#2 Fuel oil	CT	See Table 6-1	
Natural gas	CC	0.0555	
#2 Fuel oil	CC	0.0555	
Other Alternative Fuels	Any	0.04	
Other Alternative Fuels, co-fired w/coal, >75% heat throughput	NA		Use Coal F1, in absence of any applicable data.

[1] For eastern bituminous coal, a linear relationship between SO_2 and SO_3 is used instead of an average F1 factor.

Sulfuric Acid Manufactured from SCR (EM_{SCR})

This section describes a method to estimate impacts of SCR on sulfuric acid emissions. As discussed in Section 3, SCR produces SO_3 (and ultimately sulfuric acid), while SNCR removes or reduces it due to the reaction with residual ammonia. As such, only the SCR process will be addressed in this section. The removal equations will be discussed in subsequent sections, and will address both SCR and SCNR, as residual ammonia from either process contributes to sulfuric acid removal.

The following relationship estimates the total H_2SO_4 manufactured from an SCR equipped utility boiler or steam generator:

$$EM_{SCR} = K \bullet S2 \bullet f_{sops} \bullet E2 \bullet F3_{SCR} \qquad \textbf{Eq. 4-7}$$

where,

EM_{SCR} = Total H_2SO_4 manufactured from SCR, lbs per year

K = Molecular weight and units conversion constant
= 98.07 / 64.04 • 2000 = 3,063

98.07 = Molecular weight of H_2SO_4

64.04 = Molecular weight of SO_2

2000 = Conversion from tons per year to pounds per year.

S2 = SCR catalyst SO_2 oxidation rate (specified as a fraction, typically from 0.001- 0.03)

f_{sops} = Operating factor of SCR system, or the fraction of coal burn when the flue gas is directed through the SCR, whether NH_3 reagent is injected to derive NOx reduction or not. This value should reflect the hours the SCR reactor processed flue gas, which will be site-specific but can be approximated by generally 0.8 for year-round peaking operation, 0.98 for year-round base-loaded operation, or 0.43 for seasonal operation

E2 = SO_2 produced, tons per year

$F3_{SCR}$ = Technology Impact Factor, for SCR

The Technology Impact Factor for SCR ($F3_{SCR}$) is required to adjust SO_3 content for the presence of alkaline fly ash, as described in Section 3, unless direct measurements exist for the subject unit documenting SO_3 increase across the SCR reactor.

It is important to select the correct SO_2 oxidation rate, S2, for use in Equation 4-7. Typically, the SO_2 oxidation rate from SCR catalysts can range from as low as 0.3% of flue gas SO_2 content, up to 3% for low sulfur, highly alkaline coals (e.g., PRB). There are two means by which SO_2 oxidation is specified and measured for SCR process equipment, and each has significantly different implications for SO_3 produced. One method – based on actual field tests in commercial units – does not require adjustment and can be used as reported to predict sulfuric acid. The other method is based on laboratory tests of catalyst samples in the absence of ash and alkaline materials, and must be adjusted to account for these latter factors. The consequences of each of these methods on estimates of sulfuric acid emissions are described as follows:

Full-Scale Catalyst Performance Tests. Ideally, SO_2 conversion data will be determined with commercial testing of full-scale equipment. These data – measured on commercial plants under actual operating conditions – are the most authentic in reflecting actual SO_3 content, as the impact of ash alkalinity is taken into account. This approach reflects commercial process operation, and the resulting fractional oxidation rate can be used as the S2 value in Equation 4-7 without adjustment by the $F3_{SCR}$ Technology Impact Factor.

Laboratory Bench-Scale Tests. Some owners and process suppliers prefer to specify and conduct guarantee measurements for SO_2 oxidation on laboratory-scale equipment using synthetic flue gases without fly ash. There are good reasons to select this methodology; evidence suggests SO_3 measurements in the environment of the test laboratory are more accurate and reproducible than field tests. However, this method does not expose the catalyst being tested to ash, so there is no alkaline component to mitigate or absorb any SO_3 generated. Accordingly, SO_2 oxidation reported by this method exceeds that measured in commercial practice, particularly for PRB coals. SO_2 oxidation data from bench-scale tests can be used, but must be adjusted for the role of ash alkalinity. This adjustment is provided by the Technology Impact factor $F3_{SCR}$.

Table 4-2 shows the $F3_{SCR}$ factors. It should be noted that the 0.17 factor for PRB coals when using laboratory-scale SO_2 conversion (S2) data without fly ash is based on measurements at two PRB-fired units. SO_3 emitted from these units was lower than specified in the catalyst guarantee, which was based on laboratory test data. At present, there are no data to support $F3_{SCR}$ factors for other coals, so a factor of 1 (full penetration) is recommended. Additionally, if full-scale catalyst performance SO_2 conversion data is used, the $F3_{SCR}$ factor is 1 for all coal types.

Table 4-2
$F3_{SCR}$ Technology Impact Factors for SCR

Coal Type	$F3_{SCR}$
Using Laboratory-Scale SO_2 Conversion Data (S2), Without Fly Ash	
PRB	0.17 (n = 2)
Other Coals	1 (no data available)
Using Full-Scale Catalyst Performance SO_2 Conversion Data (S2)	
All Coals	1

SNCR does not result in the manufacture of sulfuric acid; thus, EM_{SNCR} for SNCR is by definition zero.

Sulfuric Acid Manufactured from FGC (EM_{FGC})

In order to moderate ash resistivity, most SO_3–based FGC systems attempt to maintain a fixed concentration of SO_3 in the flue gas, typically between 5 and 7 ppm by volume (ppmv). Calculations to estimate the sulfuric acid manufactured during FGC use the setpoint of the FGC system as the key input. The FGC system is assumed to operate during most of the plant's duty, except for perhaps startup and low load operation. The sulfuric acid manufactured by SO_3-based FGC equipment (EM_{FGC}) is calculated as follows:

$$EM_{FGC} = K_e \bullet B \bullet f_e \bullet I_s \bullet F3_{FGC} \qquad \textbf{Eq. 4-8}$$

where,

EM_{FGC} = Total H_2SO_4 manufactured from FGC, lbs per year, either upstream of APH ($EM_{FGC\_beforeAPH}$) and/or downstream of APH ($EM_{FGC\_afterAPH}$)

K_e = Conversion factor = 3,799, see Text Box B.

B = Coal burn in TBtu/yr

f_e = Operating factor of FGC system: the fraction of coal burn when the FGC system operates. This value is site-specific, must be determined for each unit, but generally will be about 0.8.

I_s = SO_3 injection rate in ppmv at 6% O_2, wet; generally,

= 7 ppmv if before the APH

= 5 ppmv if after the APH

$F3_{FGC}$ = Technology Impact Factor for FGC

= 0.17 for PRB coal

= 1 for all other coals

A Technology Impact Factor for FGC ($F3_{FGC}$) is used to adjust the flue gas SO_3 manufacture from FGC injection to account for the presence of alkaline fly ash. The principle is the same as for the $F3_{SCR}$ factor that is used to adjust the flue gas SO_3 produced by SO_2 oxidation rate on the SCR catalyst.

The method first reduces the SO_3 that is injected into a PRB-fired boiler using the $F3_{FGC}$ factor to account for sorption by the alkaline fly ash. Subsequently, SO_3 from FGC is treated the same as all other sources of sulfuric acid with respect to ABS formation or reduction through control devices. The $F3_{FGC}$ factor (0.17) is assumed to be equal to the $F3_{SCR}$ factor. A $F3_{SCR}$ of 1.0 is used for eastern bituminous coals (zero reduction), as those coals produce an acidic ash that does not adsorb appreciable amounts of SO_3.

The conversion factor Ke, equal to 3,799, considers all relevant constants to yield the result in pounds per year of sulfuric acid. The derivation of this constant, for the case where residual SO_3 is reported in terms of 6% oxygen and “wet” flue gas at 8.1% H_2O, is presented in Text Box B.

Text Box B: Derivation of Conversion Factor, K_e. The U.S. Code of Federal Regulations 40, Part 60, Table 19-1 “F Factors for Various Fuels” lists that 1 million Btu of heat input for bituminous or subbituminous coal will produce 10,640 wet standard cubic feet of flue gas, defined at 0% oxygen and on a wet basis at 20°C and 760 mm Hg. Correcting this volume to 6% O_2 (typical at ESP conditions) yields a volume of 14,925 scf. The standard volume of one pound mole of any gas is 359 scf, defined at 0°C and 760 mm Hg. Converting this to the English units standard of 20°C (68°F), one pound mole occupies 385 standard cubic feet. Using these in the equation above,

$(K_e \bullet B \bullet f_e \bullet I_S)$ = lbs H_2SO_4 per yr =

B TBtu	***$I_S(S_{NH3})$*** scf NH_3	1 lb mol SO_3	1 lb mol H_2SO_4	98 lbs H_2SO_4	14925 scf fg	10^6 MBtu
year	10^6 scf flue gas	385 scf SO_3	1 lb mol NH_3	1 lb mol H_2SO_4	1 MBtu	TBtu

Grouping terms,

$= B \bullet f_e \bullet I_S \bullet 3{,}799$

Therefore, the value of K_e is equal to 3,799 lbs H_2SO_4/(TBtu • ppmv SO_3 @ 6% O_2 and wet).

Equation 4-8 specifies the concentration of SO_3 in flue gas (I_S) in terms of ppmv at 6% O_2, wet flue gas basis. If the concentration of SO_3 is reported at different conditions, the value of the constant K_e will change. The following formula is used to adjust the value of the constant K_e:

$$\mathbf{K_e\ (O_2, H_2O) = 3{,}799\ (6\%\ O_2, 8.1\%\ H_2O) \bullet [(100-8.1)/(100-\text{new } H_2O)] \bullet [(20.9 - 6.0)/(20.9 - \text{new } O_2)]} \qquad \textbf{Eq. 4-9}$$

For example, if the SO_3 concentration is quantified at a value (in ppm) that is defined at 0% oxygen and a dry basis, the value of K_e that should be used is:

$$\mathbf{K_e\ (O_2, H_2O) = 3{,}799\ (6\%\ O_2, 8.1\%\ H_2O) \bullet [(100-8.1)/(100-0)] \square [(20.9 - 6.0)/(20.9 - 0)]}$$

$$\mathbf{K_e = 2{,}489}$$

The sulfuric acid manufacture from FGC should be noted as either upstream of the APH, $EM_{FGC\_beforeAPH}$, or downstream of the APH, $EM_{FGC\_afterAPH}$. These values must be kept separate for the release equations.

FGC equipment that employs NH_3 injection alone does not manufacture sulfuric acid and therefore this amount, EM_{FGC}, would be zero. However, the injected NH_3 will reduce the total release of sulfuric acid by reacting with SO_3 or the resultant H_2SO_4, and therefore should be used in the release equation, as discussed in subsequent sections.

Total Manufacture from All Sources

The total manufacture of sulfuric acid is the sum of the individual manufacture estimates, prior to any adjustments or modifications due to fuel conditioning or particulate deices. Therefore, if a site burns coal and uses both SCR and FGC, the amount of sulfuric acid manufactured – by combustion, SCR, and/or FGC – is summed to determine the total amount.

Accordingly, total sulfuric acid manufacture (TSAM) is estimated for a generating unit equipped with SCR and flue gas conditioning by the following equation:

Total Sulfuric Acid Manufacture (TSAM) is described by the following equation:

$$\mathbf{TSAM = EM_{Comb} + EM_{SCR} + (EM_{FGC\_beforeAPH} + EM_{FGC\_afterAPH})} \qquad \textbf{Eq. 4-10}$$

Sulfuric Acid Release

Both SCR and/or ammonia-based FGC may have a negative effect on sulfuric acid release, as the ammonia slip can combine with some or all of the sulfuric acid generated from combustion to form a non-reportable ammonia salt (ABS or AS). Under these conditions, ammonia-based FGC can serve to only reduce the release of sulfuric acid. Therefore, sources of ammonia are calculated in terms that are equivalent on a 1:1 molar basis as sulfuric acid, summed in relation to the APH, and used to adjust the sulfuric acid manufactured. Once adjusted by the equivalent ammonia, the remaining sulfuric acid is then adjusted by the removals in applicable downstream equipment such as the APH, ESP or other particulate control device and FGD equipment by applying Technology Impact Factors (F2) which describe the fraction of sulfuric acid that penetrates each component.

Total Sulfuric Acid Release (TSAR) is described by the following equation:

$$\begin{aligned}\mathbf{TSAR} &= \mathbf{\{[((EM_{Comb} * \mathit{F2_{Hotside\_ESP}} * \mathit{F2_{Mag\text{-}ox}}) + EM_{SCR} + EM_{FGC\_beforeAPH}) -} \\ &\mathbf{(NH3_{SCR} + NH3_{FGC\_beforeAPH})] \bullet F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} \bullet F2_{x}} \qquad \textbf{Eq. 4-11}\end{aligned}$$

where,

TSAR = Total Sulfuric Acid Release, lbs per year

EM_{Comb} = Total sulfuric acid manufactured from combustion, lbs per year

$F2_{Hotside\_ESP}$ = Technology Impact Factor for hot-side ESP

= 0.63 if hot-side ESP is present

= 1.0 if hot-side ESP is <u>not</u> present (optional)

$F2_{Mag\text{-}Ox}$ = Technology Impact Factor for magnesium oxide addition in fuel or furnace

= 0.25 (or custom) if Mag-Ox is sprayed into furnace

= 0.50 (or custom) if Mag-Ox is mixed with fuel

= 1.0 if Mag-Ox is not applied (optional)EM_{SCR} = Total sulfuric acid manufactured from SCR, lbs per year

$EM_{FGC\_beforeAPH}$ = Total sulfuric acid manufactured from FGC upstream of the APH

$EM_{FGC\_afterAPH}$ = Total sulfuric acid manufactured from FGC downstream of the APH

$NH3_{SCR}$ = Total equivalent ammonia slip produced from SCR/SNCR, lbs per year

$NH3_{FGC\_beforeAPH}$ = Total equivalent ammonia produced from FGC upstream of the APH, lbs per year

$NH3_{FGC\_afterAPH}$ = Total equivalent ammonia produced from FGC downstream of the APH, lbs per year

$F2_{APH}$ = Technology Impact Factor for APH, applied only if subtotal for releases upstream of the APH is non-negative

$F2_{x}$ = Technology Impact Factors for processes downstream of the APH, all that apply

Examples in Appendix A detail the use of these calculations. Ammonia produced from SCR/SNCR and FGC are calculated using equations from the sections below.

The application of the hot-side ESP and Mag-Ox F2 factors to the sulfuric acid manufactured from combustion are a change from all previous versions of the report where these factors were applied to the total sulfuric acid release, which also included sulfuric acid from flue gas conditioning and SCR/SNCR. However, as a hot-side ESP removes sulfuric acid upstream of the APH, and therefore prior to any subsequent manufacture of sulfuric acid via SCR or FGC, the hot-side ESP F2 factor should only be applied to EM_{COMB}. Furthermore, application of magnesium oxide compounds into the furnace or fuel has been shown to only affect sulfuric acid produced from combustion, and does not affect any downstream formation due to SCR oxidation (Blythe, 2004). These two factors are discussed in more detail in subsequent sections, but it should be noted that as with other devices, these F2 factors only need to be included if the technology or device is present, and are optional (i.e. equal to 1.0) if the technology is not present.

The F2 factor for the APH ($F2_{APH}$) should only be applied if the subtotal of the sum of the sulfuric acid manufactured minus the ammonia slip upstream of the APH $[((EM_{Comb} * F2_{Hotside\_ESP} * F2_{Mag\text{-}ox}) + EM_{SCR} + EM_{FGC\_beforeAPH}) – (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is a positive value. If this subtotal is negative, this would indicate that excess ammonia slip is still present after all the sulfuric acid from combustion, SCR and FGC has been consumed to form ABS. In this instance, the resulting ammonia slip should not be reduced by the $F2_{APH}$ factor, as all the ammonia is expected to penetrate the APH. This negative ammonia slip value can then be added to any downstream FGC injection, as summarized in Equation 4-12:

$$\mathbf{TSAR_{ExcessNH3} = \{[((EM_{Comb} * \mathit{F2_{Hotside\_ESP}} * \mathit{F2_{Mag\text{-}ox}}) + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} \bullet F2_{x}} \qquad \textbf{Eq. 4-12}$$

Text Box C summarizes calculations for a unit equipped with a FGD process that employs partial flue gas bypass, to account for the fact that the entire flue gas flow is not subject to sulfuric acid removal by the FGD process. This bypass factor is pertinent only to units that employ flue gas bypass.

Text Box C: Flue Gas Desulfurization Bypass Calculation. Those units equipped with scrubbers where some of the flue gas bypasses the scrubber should take this into account in their total release calculations. No credit for sulfuric acid removal should be taken for the fraction of the flue gas that bypasses the scrubber. Therefore, this amount of the flue gas should not be multiplied by the F2 factor for the scrubber. However, the flue gas volume should still be multiplied by the F2 factors for the other control devices.

Modified equations considering partial scrubber bypass are given below and should be used where appropriate.

$$TSAR_{bypass} = \{[(EM_{Comb} + EM_{SCR/SNCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] \bullet F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} \bullet F2_{x}$$

$$TSAR = [SB_f + (1 - SB_f) \bullet F2_s] \bullet TSAR_{bypass}$$

where, SB_f = fraction of scrubber bypass, as a decimal

$F2_s$ = F2 for scrubber

$F2_x$ = All other applicable F2 factors except for scrubber.

Ammonia Slip from SCR and SNCR ($NH3_{SCR}$)

A key assumption in the calculation methodology is that residual ammonia from either a SCR or SNCR captures all available sulfuric acid in the (ammonium) bisulfate form. The bisulfate form is not reportable under the Toxics Release Inventory rules and thus is not part of the manufacture calculation. If any additional ammonia reacts with bisulfate to form ammonium sulfate, that reaction is of no consequence to the sulfuric acid calculation – although it needs to be taken into account when estimating ammonia releases.

The total sulfuric acid released from combustion, SCR, and FGC is determined by subtracting from the sulfuric acid manufactured the amount removed by the residual ammonia, or equivalent ammonia slip, as calculated on a 1:1 molar basis with sulfuric acid. For SCR/SNCR, the ammonia slip is calculated using the following:

$$NH3_{SCR} = K_s \bullet B \bullet f_{sreagent} \bullet S_{NH3} \qquad \textbf{Eq. 4-13}$$

where,

$NH3_{SCR}$ = Total equivalent ammonia slip produced from SCR/SNCR, lbs per year

K_s = Conversion factor = 3799, which is equivalent to K_e (See Text Box B)

B = Coal burn in TBtu/yr

$f_{sreagent}$ = fraction of SCR operation with reagent injection, when residual NH_3 is produced that will remove SO_3. The value of $f_{sreagent}$ will be similar to, but slightly less than, the value of f_{sops}, defined for Equation 4-6.

S_{NH3} = NH_3 slip from SCR/SNCR, ppmv at 6% O_2, wet:

- SCR averages 0.75 ppmv over catalyst guarantee period
- SNCR averages 5 ppmv
- Note: actual NH_3 slip data should be used if available

The conversion factor K_s, equal to 3,799, is equivalent to the factor K_e used for SO_3 injected from FGC, and considers all relevant constants to yield the result in pounds per year of equivalent ammonia. The derivation of this constant, in the form of K_e, was presented previously in Text Box B.

Equation 4-13 specifies the concentration of NH_3 in flue gas (S_{NH3}) in terms of ppmv at 6% O_2, wet flue gas basis. If the concentration of NH_3 is reported at different conditions, the value of the constant K_s will change. As with K_e, Equation 4-9, described previously and repeated again below for reference, is used to adjust the value of the constant K_s:

$$K_s (O_2, H_2O) = 3799 (6\% O_2, 8.1\% H_2O) \bullet [(100-8.1)/(100-\text{new } H_2O)] \bullet [(20.9 - 6.0)/(20.9 - \text{new } O_2)] \qquad \textbf{Eq. 4-9}$$

The operating factor of the SCR describes the portion of the coal burn that reflects the period of SCR operation, based on whether the unit operates seasonally (0.43), annually in a base-load duty (0.98), or annually in peaking duty (0.80).

The coal burn rate in TBtu/yr can be obtained from coal use records, such as those reported to EIA in Form 767, or can be calculated from the annual coal burn (tons/yr) and the heating value of the coal, as described in the equation below:

$$B = C1 \bullet HV \bullet K_B \qquad \textbf{Eq. 4-14}$$

where,

B = Coal burn in TBtu/yr

C1 = Dry coal burn, tons/yr. The dry coal can be calculated from wet coal through the following relationship:
Dry coal (tons/yr) = wet coal (tons/yr) • (1-moisture(%)/100%)

HV = Coal heating value, Btu/lb, dry

K_B = Conversion factor = 2E-9. The factor is calculated from the conversion of tons per year to pounds per year and Btu to TBtu ($2000/10^{12}$ = 2E-9)

Ammonia Injection from FGC ($NH3_{FGC}$)

Similar to reactions with ammonia slip from SCR or SNCR, any ammonia injected from FGC will react with sulfuric acid manufactured to form ABS. The following equation is used to calculate equivalent ammonia from FGC. Care must be taken to note the location of the ammonia injection, upstream or downstream of the APH, such that the ammonia can be utilized correctly in the release equation.

$$NH3_{FGC} = K_e \bullet B \bullet f_e \bullet I_{NH3} \qquad \textbf{Eq. 4-15}$$

where,

$NH3_{FGC}$ = Total equivalent ammonia produced from FGC, lbs per year, either upstream of APH, $NH3_{FGD\_beforeAPH}$, or downstream of APH, $NH3_{FGC\_afterAPH}$

K_e = Conversion factor = 3,799, as described in Text Box B

B = Coal burn in TBtu/yr

f_e = Operating factor of FGC system, or the fraction of fuel burn when the FGC system operates. This value will be the same as f_e described previously and in many cases can be approximated by 0.8.

I_{NH3} = NH_3 injection for dual flue gas conditioning, ppmv at 6% O_2, wet; generally 3 ppmv NH_3 if operating, or zero (0) if no ammonia is used.

Total Release Calculation for Sources Employing Alkali Injection

As described in Section 3, sources that employ alkali injection to mitigate stack opacity or a visible plume will typically have access to field measurements describing SO_3 concentration in flue gas, most likely at the stack. The concentration of SO_3 measured at the stack can be converted to a mass emission rate using Equation 4-16.

$$ER_{ALKINJ} = K_{alkali} \bullet B \bullet S_{SO3} \bullet F2_x \bullet F_{alkali} \qquad \textbf{Eq. 4-16}$$

where,

ER_{ALKINJ} = Total H_2SO_4 released from unit equipped with alkali injection, lbs per year

K_{alkali} = Constant, equal to 3,799, which is equivalent to K_e, as described in Text Box B.

B = Coal burn in TBtu/yr

S_{SO3} = SO_3 content, as measured in the stack or particulate collector exit, ppmv at 6% O_2, wet

F_{alkali} = Operating factor for the alkali injection system, fraction of coal burn when unit is operated with alkali addition to remove SO_3

$F2_x$ = Technology Impact Factors, to be applied only if SO_3 measurements are conducted at a location preceding the stack. The value of $F2_x$ is 1 if measurements are conducted at the stack, and there are no control components downstream of the measurement location. If the control device is an SO_2 scrubber, F2x is denoted as F2s, but is handled the same way.

If the SO_3 content (S_{SO3}) is known at conditions other than 6% O_2 and wet, Equation 4-8 can be used to calculate a new value K_{alkali} at the new conditions.

The Technology Impact Factors selected should represent the control equipment between the point of SO_3 measurement and the stack. For example, if a unit is equipped with only an ESP, and the SO_3 measurement is conducted at the ESP inlet, then the F2 factor for an ESP (Table 4-5, below) should be selected.

If the utility employing alkali injection does not have access to measured data, the total sulfuric acid releases may be calculated as described by Equation 4-11 (i.e., by estimating and summing the manufacture and applying the technology Impact Factors), and an alkali injection factor, $F3_{ALKINJ}$, is then applied to the total release. This $F3_{ALKINJ}$ is either the expected fractional reduction in SO_3 (generally as guaranteed by the vendor), a default value of 0.2, as available data indicates 80% removal is easily achievable (EPRI, 2010b).

$$\mathbf{ER_{ALKINJ} = (TSAR_{Comb+SCR+FGC}) \bullet F_{alkali}\ F3_{ALKINJ}} \qquad \textbf{Eq. 4-17}$$

where,

ER_{ALKINJ} = Total H_2SO_4 released from unit equipped with alkali injection, lbs per year

$TSAR_{Comb+SCR+FGC}$ = Total H_2SO_4 released from combustion, SCR and FGC, as calculated using Equation 4-10.

F_{alkali} = Operating factor for the alkali injection system, fraction of coal burn when unit is operated with alkali addition to remove SO_3

$F3_{ALKINJ}$ = Technology Impact Factor for alkali injection; the expected fractional reduction in SO_3 (generally as guaranteed by the vender). If no vendor information is available, use a default value of 0.2.

Partial Year Injection

If alkali injection is not utilized for the entire operating year (F_{alkali} does not equal 1), then Equation 4-16 (or Equation 4-17) must be added to the fraction of the total sulfuric acid release (TSAR) calculated from combustion, SCR/SNCR and/or FGC for the remainder of the operating time (Equation 4-11). Furthermore, in the calculation of TSAR for partial-year alkali injection, if SO_3 measurements also exist for operation without alkali injection, these data should be used with Equation 4-16 instead of the standard estimation equations, as shown below:

$$\mathbf{ER_{NOINJ} = K_{alkali} \bullet B \bullet S_{SO3} \bullet F2_x \bullet (1-F_{alkali})} \qquad \textbf{Eq. 4-18}$$

where,

ER_{NOINJ} = Total H_2SO_4 released from unit without alkali injection, lbs per year

K_{alkali} = Constant, equal to 3,799, which is equivalent to K_e, as described in Text Box B.

B = Coal burn in TBtu/yr

S_{SO3} = SO_3 content without alkali injection, as measured in the stack or particulate collector exit, ppmv at 6% O_2, wet

F_{alkali} = Operating factor for the alkali injection system, fraction of coal burn when unit is operated with alkali addition to remove SO_3

$F2_x$ = Technology Impact Factors, to be applied only if SO_3 measurements are conducted at a location preceding the stack. The value of $F2_x$ is 1 if measurements are conducted at the stack, and there are no control components downstream of the measurement location. If the control device is an SO_2 scrubber, F2x is denoted as F2s, but is handled the same way.

Accordingly, total sulfuric acid release (TSAR) for a unit employing partial-year alkali injection is estimated by one of the following equations:

$$\mathbf{TSAR = ER_{ALKINJ} + (TSAR_{Comb+SCR+FGC}) \bullet (1\text{-}F_{alkali})} \qquad \textbf{Eq. 4-19}$$

$$\mathbf{TSAR = ER_{ALKINJ} + ER_{NOINJ}} \qquad \textbf{Eq. 4-20}$$

Technology Impact Factors (F2)

The sulfuric acid estimating methodology employs empirically-derived Technology Impact Factors (F2). These F2 factors describe sulfate removal observed over the air heater, the ESP or other particulate control device, and FGD process equipment. Background information on these processes and the derivation of these F2 factors are addressed in this section.

Air Heater

The removal of SO_3 and/or H_2SO_4 within the air heater is due to the condensation of sulfuric acid and its removal as discrete individual particles (along with the fly ash) on the surface of this heat exchanger. The conventional Ljungstrom-type air heater has been documented to provide a removal sink for sulfuric acid (Saranuc, 1999). In fact, the largest supplier of Ljungstrom air heaters has evaluated the feasibility of employing the air heater process environment in conjunction with limestone injection as a proactive sulfuric acid control strategy (Hamel, 2003, and Bowes, 2006).

Air heater surfaces follow a pattern of alternately heating and cooling as the heat exchange elements move from the relatively hot flue gas to the cooler combustion air. As reported during field tests of commercial equipment (Saranuc, 1999), this temperature profile introduces a strong gradient in sulfuric acid concentration across the exit plane of the air heater. The cyclic thermal conditions as described by Hamel (2003) reveal that a significant portion of the air heater basket surface metal is exposed to flue gas temperature below the sulfuric acid dewpoint. This phenomenon may promote sulfuric acid deposition on the heat exchanger metal surface, compared to a tube-type heat exchanger in which the metal temperature is always above the sulfuric acid dewpoint.

Figure 4-2 presents data obtained from a survey of power plant operators and general literature sources describing SO_3/H_2SO_4 removal (and the corresponding F2 factors) across commercial, Ljungstrom-type air heaters. These data are presented as a function of SO_2 content of the flue gas for the host unit. Most data shown are for low sulfur eastern bituminous coal, for which air heater H_2SO_4 removal varies significantly between 0% and 69%, averaging 50% as indicated by the horizontal line. Two high sulfur (>2.5%) eastern cases are shown, along with limited data for PRB coal.

The data point showing 0% removal at approximately 600 ppm SO_2 is believed suspect, as an identical companion unit firing the same coal exhibited sulfuric acid capture of 38%. This measurement was not included in the F2 calculation.

Figure 4-2 presents two points reported by Hamel (2003) based on a low sulfur eastern bituminous-fired unit where SO_3 was "spiked" into the flue gas to elevate the concentration entering the air heater to 80 and 122 ppm. These two points are plotted separately on Figure 4-2 versus an estimated flue gas SO_2 content that could generate such values (using the average SO_2 oxidation rate for high sulfur, eastern bituminous coal in Figure 4-1. It should be noted these values measured for the "spiked" flue gas significantly exceed those measured for the two high sulfur eastern coal cases.

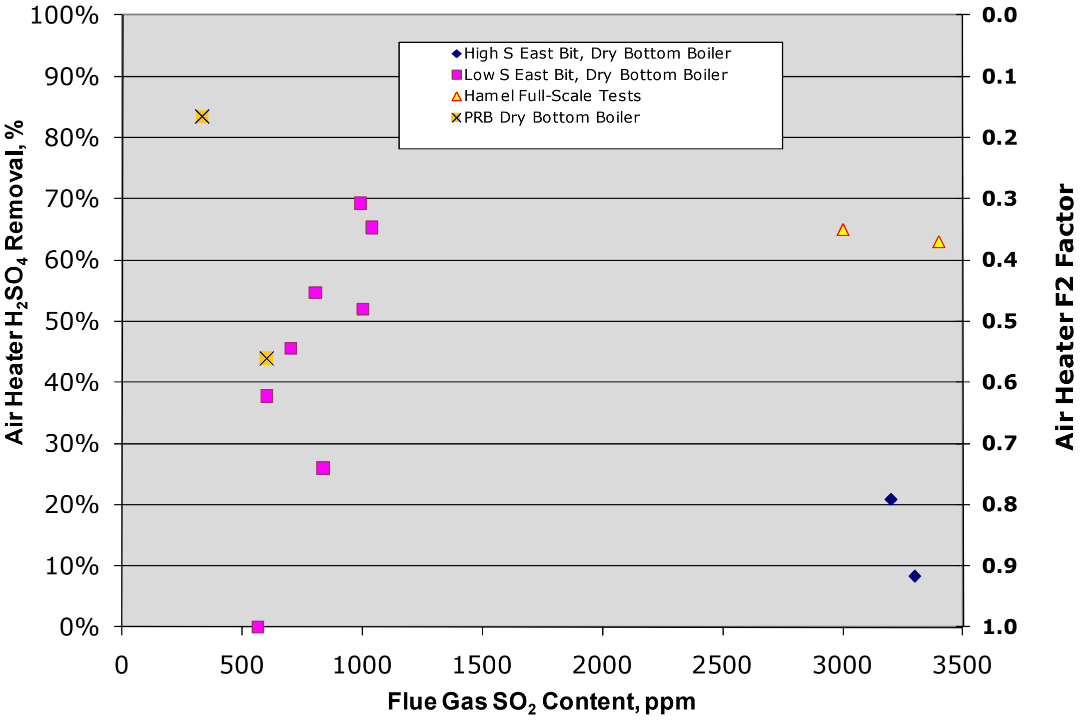


Figure 4-2
Removal of Sulfuric Acid by Ljungstrom-Type Air Heaters

The F2 factor for the air heater, calculated as [1 – Percent Removal], is estimated excluding the "spiked" SO_3 and suspect 0% removal measurement. The F2 factors for the air heater for low sulfur eastern bituminous, medium-high sulfur eastern bituminous, and PRB coals are shown in Table 4-4. Data are not currently available for other coal types. For those coals, as well as fuel oils, the model user could consider adopting the F2 factor for PRB if the ash is strongly alkaline and the low sulfur, eastern bituminous value if the ash is acidic.

Table 4-3
Summary of F2 Factors for Air Heater Removal of Sulfuric Acid

Boiler Type	Fuel	F2	Standard Deviation	Comment
All Boilers	Low S Eastern Bit	0.50	0.15	Average of measurements at 7 units.
All Boilers	Med-High S Eastern Bit (S >2.5%)	0.85	n/a	Based on two data points.
All Boilers	PRB	0.36	n/a	Based on two data points.

The standard deviation of the reported measurements for low sulfur eastern bituminous coal is about one third of the average measurement. Inadequate data prevent calculating a standard deviation for F2 factors for the other fuels.

Particulate and SO_3 Control Processes

This section discusses the available data on removal of SO_3 by ESPs, FGDs, and alkali injection.

ESPs and Baghouses

An ESP provides extended residence time at relatively low temperatures, allowing contact between sulfuric acid and fly ash particles, as well as having collecting plates that can retain sulfuric acid particles. These features contribute to the removal of sulfuric acid. The ESP is the flue gas contacting device with perhaps the longest residence time; for large units, usually 10 seconds and in some cases, up to 15 seconds. Given the low flue gas velocities of 2 to 4 actual feet per second (0.6 – 1.2 meters per second), and the opportunity for heat loss at or near the walls, sulfuric acid condensation can be significant.

Figure 4-3 plots sulfuric acid removal by the ESP and the corresponding F2 factors as a function of the SO_2 content of the flue gas for the host unit, from a survey of plant operators. Most data shown are for a cold–side ESP and low sulfur eastern bituminous coal; three data points are shown for high sulfur coal (>2.5%). Also shown is a single data point for a hot-side ESP and four data points for low sulfur eastern bituminous coal. Similar to the case for the air heater, the 0% sulfuric acid removal at approximately 800 ppm SO_2 is suspect, as a companion unit at the same site firing the identical coal had 50% sulfuric acid removal. Accordingly, this “zero” removal datum, although shown in Figure 4-3, is not used in the analysis.

The F2 factor for the cold-side ESP, calculated as [1- Percent Removal], is estimated using all data except the 0% removal point. The F2 factors for ESP capture for low sulfur eastern bituminous, medium-high sulfur eastern bituminous, and PRB coals are listed in Table 4-5. Data are not currently available for other coal types. Western subbituminous coals (e.g., non-PRB) could consider adopting the F2 factor for PRB if the ash is strongly alkaline; western coals with acidic ash (e.g., bituminous) may consider adopting the low sulfur, eastern bituminous value. This guidance also applies to for fuel oils or any other coal that is not listed in the table.

Data describing the reduced H_2SO_4 penetration for one hot-side ESP (ESPh) is based on only a single test series. It should be noted that although this F2 factor is used for all coals, the measurement is from a power plant burning a low-sulfur, eastern bituminous coal. Comparison of F2 factors for a cold-side ESP burning low and high sulfur eastern bituminous coals show a significant difference between the two coal types. As a result, total H_2SO_4 releases for hot-side ESP configurations may have a low bias; however, there is insufficient data to recommend alternate values.

Wet ESP's operate in much the same manner as a traditional ESP; however, due to the lower operating temperature and saturated environment, higher power levels are achievable, resulting in higher collection efficiency for sulfuric acid mists. Data describing sulfuric acid removal for a Wet ESP is based on two sets of paired measurements, both of which demonstrated 88% removal. One data point was from a high sulfur, eastern bituminous, coal-fired boiler and the other from a petroleum-coke fired boiler. Flue gas SO_2 was not reported for these tests; therefore, the data points are not included in Figure 4-3. Until further data are available, EPRI recommends using a wet ESP F2 factor of 0.12 for all fuels.

Baghouses show high H_2SO_4 removal based on very limited data. The average of two data points is 90% removal.

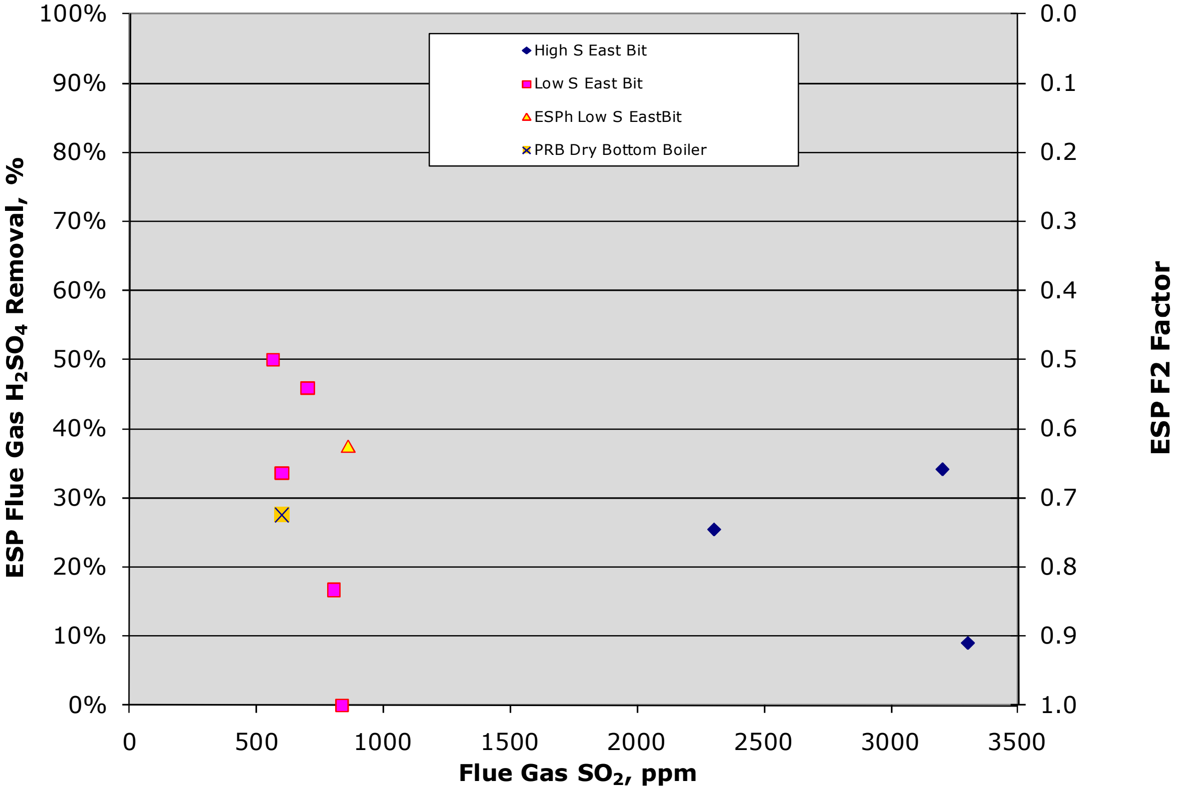


Figure 4-3
Removal of Sulfuric Acid by Cold-Side ESPs and One Hot-Side ESP

Table 4-4
Summary of F2 Factors for Particulate Control Devices (ESP, Baghouse)

Equipment Type	Coal Type	F2 Factor	Standard Deviation	Comment or Observation
Cold-side ESP	Low S Eastern Bit	0.63	0.15	Average of measurements at 4 units.
Cold-side ESP	High S Eastern Bit (>2.5%)	0.77	0.13	Average of measurements at 3 units.
Cold-side ESP	Subbituminous (PRB)	0.72	n/a	Based on one measurement at one unit.
Hot-side ESP	All	0.63	n/a	Based on one measurement at one unit.
Wet ESP	All	0.12	n/a	Average of measurements at two units
Baghouse	Subbituminous coal	0.10	n/a	Two data points.

n/a – not applicable – too few points to calculate.

The standard deviation of the reported measurements for low sulfur eastern bituminous coal is about one fourth of the average measurement, while the standard deviation of the measurements for the high sulfur eastern bituminous coal is about one sixth of the average. Inadequate data prevent calculating a standard deviation for F2 factors for the other fuels.

FGD

FGD process equipment rapidly cools or quenches flue gas, condensing a significant portion of the sulfuric acid into submicron droplets that can escape the process environment, confounding capture. Buckley (2002) notes that for condensation to occur, sulfuric acid generally must be supersaturated. However, fly ash particles can provide a nucleus for condensation of sulfuric acid, even at conditions that are not thermodynamically supersaturated. Buckley also projects sulfuric acid condensation on surfaces where equipment walls are lower in temperature than the flue gas (common in commercial equipment). However, the thin laminar boundary layer at the wall limits mass transfer, and for FGD equipment this mechanism provides no appreciable removal. Ironically, it is the high saturation conditions in this laminar layer near surfaces that are key to producing fine sulfuric acid mist.

Srivastava (2004) suggests that the condensed submicron droplets, once formed, are sufficiently small so that they follow the flow streamlines and avoid contact with the remaining wetted walls, liquid sheets, and droplets in the flow path. Although some degree of sulfuric acid removal is observed in FGD equipment, the amount is highly variable and depends on the design of the system. Buckley (2002) estimates FGD equipment removes 40-70% of the sulfuric acid, and Srivastava an average of 50%.

Figure 4-4 summarizes data reported in the public domain and from utility-specific tests describing FGD removal (and corresponding F2 factors) of sulfuric acid. The percent of sulfuric acid removal is depicted as a function of FGD inlet SO_2 concentration. Removals range from 14% to 78%, with an average of about 50%. The shaded portion of Figure 4-4 represents the upper and lower bounds of the data reported by Buckley (2002), while the solid horizontal line reflects the average reported by Srivastava (2004).

Table 4-6 summarizes the F2 factors for FGD process equipment, including results for a wet spray tower burning bituminous coal, and also one burning a blend of PRB/lignite. Given the limited data, the latter is assumed to serve as the basis of an F2-factor for 100% firing of PRB or lignite. Data for a wet venturi -type combined particulate/FGD process is also available, but only for a bituminous coal. Similar to the case for a wet spray tower, the lack of data merits assuming sulfuric acid removal for all coals is described by that measured for bituminous coal.

F2 factors for the use of magnesium-based additives in oil-fired boilers are also included in Table 4-6. These additives are used to control furnace slagging caused by the vanadium in the oil or to control sulfuric acid emissions or both. The fuel oil vanadium can also catalyze SO_2 to SO_3 oxidation, but the additive, when added to the oil, tends to effectively bind up the vanadium, partially reducing its catalytic effect. Addition of magnesium-based additives in the fuel oil tend to be less effective in controlling the emissions of sulfuric acid than the same additive sprayed into the furnace downstream of the flame zone. The factors for Mag-Ox addition are derived from a single data point; as such, it is recommended to use measured facility data if available

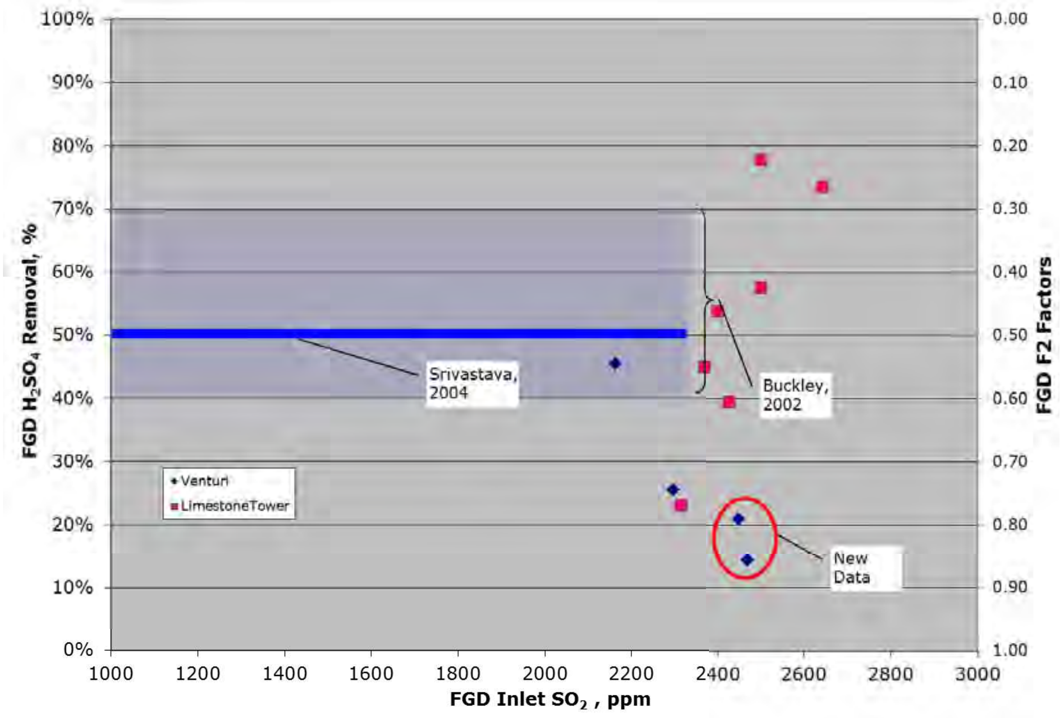


Figure 4-4
Removal of Sulfuric Acid by Flue Gas Desulfurization Equipment: Various FGD Designs, Coals

Table 4-5
Summary of F2 Factors for Wet and Dry FGD Equipment and Additives

FGD Type	Coal Type	F2 Factor	Standard Deviation	Comment or Observation
Wet: Spray Tower	E. Bituminous	0.47	0.17	Seven data points.
Wet: Spray Tower	PRB or Lignite	0.40	n/a	Two data points.
Wet: Venturi Tower	All coals	0.73	0.13	Four data points from three units, bituminous coal only; limited data merit assigning same factor for other coals.
Dry FGD and baghouse	All coals	0.01	n/a	Two data points.
Mg-Ox mixed w/fuel oil	All fuel	0.50	n/a	One data point.
Mg-Ox into furnace	All fuel	0.25	n/a	One data point.

5

ESTIMATING GUIDELINE: MULTIPLE FUEL OR BLENDED FUEL BOILERS

Estimating sulfuric acid production of steam boilers firing multiple or blended fuels – such as natural gas, fuel oil, and perhaps coal – uses the same approach as for single fuels. This will consist of determining the contribution of each source (combustion, SCR or SNCR NOx control, and FGC) for each different fuel, and adjusting for loss or removal. It is assumed for multiple fuel boilers that the contribution of each fuel can be separated and treated individually. The same approach is to be used for boilers that fire a blended coal. This assumption is particularly important when considering blends of PRB with low or high sulfur eastern bituminous coal, as this approach accounts for the role of alkalinity in PRB ash in mitigating SO_3.

This approach of treating blends of coal as separate fuels in proportion to the mass burn rate is believed to be conservative with regard to SO_3 emissions when considering PRB coal, in that it will likely project H_2SO_4 emissions higher than actual. The ability of PRB coal to neutralize SO_3 by an amount that is greater than a direct proportion of the coal blend is due to the extremely high content of alkaline material, particularly CaO. However, data to quantify this impact with any reasonable degree of confidence are not available at present. Accordingly, the conservative approach is to presume an impact in direct proportion to the coal blend until a database can be developed.

The sequence of calculations is performed for the first component of the blend, including calculations for SCR and FGC, if applicable. The sequence is repeated for each component. When complete, the total manufacture of sulfuric acid is calculated by adding all of the manufacture totals for all fuels from all processes. Likewise, the release is summed over all processes and fuels.

As an example, if a unit with an SCR and FGC burns mostly coal, but uses natural gas in a NOx reburn process and also disposes of used oil by combustion in the furnace, then the following sequence of calculations would be required:

1. Coal fuel
    a. Combustion manufacture
    b. Combustion release
    c. SCR manufacture
    d. SCR release
    e. FGC manufacture
    f. FGC release
2. Natural gas
    a. Combustion manufacture
    b. Combustion release
    c. SCR manufacture

   - d. SCR release
   - e. FGC manufacture
   - f. FGC release
3. Used oil
   - a. Combustion manufacture
   - b. Combustion release
   - c. SCR manufacture
   - d. SCR release
   - e. FGC manufacture
   - f. FGC release
4. Sum manufacture and releases
   - a. Manufacture
     - = 1a + 1c + 1e + 2a + 2c + 2e + 3a + 3c + 3e
   - b. Release
     - = 1b + 1d + 1f + 2b + 2d + 2f + 3b + 3d + 3f

All of the manufactured results would be summed together and the releases summed also to give the final result. Example 8 in Appendix A details this calculation procedure.

6

ESTIMATING GUIDELINE: COMBUSTION TURBINES

Natural gas-fired sources typically have negligible content of sulfur in the fuel, thus sulfuric acid production is negligible. Facilities that burn only natural gas are not required to participate in the TRI reporting program. However, sources that are co-located with coal units will need to be included in the estimates for total sulfuric acid release for the site. The calculation described in this section can also be used to estimate sulfuric acid emissions for Prevention of Significant Deterioration (PSD) review of new natural gas-fired generation sites.

The calculations for gas-fired units are structured very much the same as for coal- and oil-fired sources. For simple cycle combustion turbines, the only source of sulfuric acid is the sulfur in the fuel. The EPA AP-42 emissions factor suggests a value of 2000 grains of sulfur per million cubic feet of natural gas as a default sulfur content value. This value is equivalent to approximately 3.5 ppm of sulfur in the raw natural gas.

A methodology to estimate manufacture and release of sulfuric acid for simple cycle and combined cycle units is provided below.

Manufacture and Release for Simple Cycle Units

Given the current configuration of simple cycle units, any sulfuric acid ***manufactured*** is ***released***; thus, the estimates of sulfuric acid are the same. This is because there is no equipment located following the simple cycle arrangement that removes sulfuric acid. Even though simple cycle units can be equipped with SCR, and the use of SCR with sulfur-containing fuels will manufacture SO_3, the exit gas temperature is too high to allow condensation of SO_3 or reaction with ammonia slip. Selective non-catalytic reduction is not applied to simple cycle or combined cycle combustion turbines; therefore, no estimation procedure is provided for that configuration.

Accordingly, the equations for formation of sulfuric acid from natural gas (NG) combustion are:

$$\mathbf{EM_{SC} = K \bullet F1 \bullet E2_{NG}} \qquad \textbf{Eq. 6-1}$$

where,

EM_{SC} = total H_2SO_4 *manufactured* from combustion, lbs/yr

K = Molecular weight and units conversion constant

= 98.07 / 64.04 • 2000 = 3,063

98.07 = Molecular weight of H_2SO_4

64.04 = Molecular weight of SO_2

2,000 = Conversion from tons per year to pounds per year.

F1 = Fuel Impact Factor for NG

$E2_{NG}$ = Sulfur dioxide (SO_2) emissions either: (1) recorded by a continuous emissions monitor, tons/yr, or (2) calculated from fuel burn data, tons/yr.

SO_2 emissions can be obtained through a calculation using the heat input of natural gas.

$$\mathbf{E2_{NG} = K_b \bullet B_{NG} \bullet S} \qquad \textbf{Eq. 6-2}$$

where,

$E2_{NG}$ = Total SO_2 production from NG combustion, tons/yr

K_b = Molecular weight and units conversion constant = 0.0001359

B_{NG} = Burn of NG in Tbtu/yr

S = Sulfur content of natural gas, in grains per million standard cubic feet (Mscf), typically 2000 gr/10^6 scf per EPA AP-42.

The derivation of constant K_b is presented in Text Box D.

Text Box D: Derivation of Molecular Weight and Units Conversion Constant, K_b

K_b is determined from the following equation.

($K_b \bullet B_{NG} \bullet S$) = tons SO_2 per yr =

B_{NG} TBtu	**S** gr S	1 scf nat gas	10^{12} Btu	lb S	1 ton S	1 ton mol S	1 ton mole SO_2	64 tons SO_2
Year	10^6 scf nat gas	1050 Btu	TBtu	7000 gr S	2000 lbs S	32 tons S	1 ton mol S	1 ton mole SO_2

Grouping terms,

= ($B_{NG} \bullet S$) • 64 / (1050 • 32 • 14) = ($B_{NG} \bullet S$) • 0.0001359

Therefore, the value of K_b is equal to 0.0001359 tons SO_2/(TBtu • grains S/million SCF NG).

The SO_2 emissions can also be calculated from the volume of natural gas burned:

$$\mathbf{E2_{NG} = K_{NG} \bullet N1 \bullet S} \qquad \textbf{Eq. 6-3}$$

where,

$E2_{NG}$ = total SO_2 production from NG combustion, tons/yr

K_{NG} = Molecular weight and units conversion constant = $1.427 \bullet 10^{-7}$

N1 = NG burn in million standard cubic feet (Mscf) per year

S = NG sulfur content in grains per million standard cubic feet; use EPA's value of 2000 gr/10^6 scf as default

The derivation of constant K_{NG} is presented in Text Box E.

Text Box E: Derivation of Molecular Weight and Units Conversion Constant, K_{NG}

(K_{NG} • N1 • S) = tons SO_2 per yr =

N1 10^6 scf	**S** gr S	lb S	1 ton S	1 ton mol S	1 ton mole SO_2	64 tons SO_2
Year	10^6 scf nat gas	7000 gr S	2000 lbs S	32 tons S	1 ton mol S	1 ton mole SO_2

Grouping terms,

(N1 • S) • 64 / (7000 • 2000 • 32) = (N1 • S) • 1.427 • 10^{-7}

Therefore, the value of K_{NG} is equal to 1.427 • 10^{-7} tons SO_2/(grains S)

Table 6-1 presents the F1 factors for simple cycle units as a function of stack temperature, as sulfuric acid vapor is related to the temperature of the exhaust. As simple cycle combustion turbines (CT) exhaust is usually around 1000°F, and TRI rules require the reporting of sulfuric acid (not of SO_3), the amount manufactured and released depends on stack temperature. Table 6-1 combines the temperature-based SO_3 to H_2SO_4 conversion with the SO_2 to SO_3 conversion to give the Fuel Impact Factor, F1.

Table 6-1
Fuel Impact (F1) Factors for a Simple CT

Stack T, °F	F1
300	0.055
400	0.055
500	0.047
600	0.022
700	0.0055
750	0.0027
800	0.0013
850	0.00071
900	0.00039
950	0.00022
1000	0.00013
1050	0.00008
1100	0.00005
1150	0.00003
1200	0.00002

Combined Cycle Units

Sulfuric Acid Manufactured

For combined cycle units, sources of *manufacture* of sulfuric acid are combustion, oxidation of SO_2 across catalyst used for NOx control and recently, oxidation of SO_2 across catalyst used for CO control.

For combustion, the manufacture of sulfuric acid for combined-cycle units is described by Equation 6-4.

$$EM_{CCcom} = K \bullet F1 \bullet E2_{NG} \qquad \textbf{Eq. 6-4}$$

where,

EM_{CCcom} = Total H_2SO_4 *manufactured* from combustion, lbs/yr

K = Molecular weight and units conversion constant

= 98.07/64.04 • 2000 = 3,063

98.07 = Molecular weight of H_2SO_4;

64.04 = Molecular weight of SO_2;

2,000 = Conversion from tons per year to pounds per year.

F1 = Fuel Impact Factor for NG (See Table 4-1)

$E2_{NG}$ = Sulfur dioxide (SO_2) emissions either: (1) recorded by a continuous emissions monitor, tons/yr, or (2) calculated from fuel burn data, tons/yr.

Recently, it has been shown that CO catalysts in combined cycle units can oxidize SO_2 to SO_3 in a manner similar to SCRs. Equation 6-5 describes the manufacture of sulfuric acid across the CO catalyst. For the case of combined cycle combustion turbines, the CO catalyst SO_2 oxidation rate (S3) will be approximately 0.1. This value is an estimate based on data from a prominent catalyst vendor. A more accurate value can be obtained from field measurements of SO_2 oxidation, or from the vendor's specification of the CO catalyst.

$$EM_{CC\_CO} = K \bullet S3 \bullet f_{COops} \bullet E2 \qquad \textbf{Eq. 6-5}$$

where,

EM_{CC_CO} = Total H_2SO_4 manufactured from the CO catalyst, lbs per year

K = Molecular weight and units conversion constant

= 98.07/64.04 • 2000 = 3,063

98.07 = Molecular weight of H_2SO_4

64.04 = Molecular weight of SO_2

2000 = Conversion from tons per year to pounds per year

S3 = CO catalyst SO_2 oxidation rate (specified as a decimal, typically from 0.1-0.6)

f_{COops} = Operating factor of CO catalyst system, or the fraction of fuel burn when the flue gas is directed through the CO catalyst. This value should reflect the fraction of hours that the CO catalyst processed flue gas. This value will be site-specific but can be approximated as 0.8 for year-round peaking operation, 0.98 for year-round base-loaded operation, or 0.43 for seasonal operation.

E2 = SO_2 produced, tons per year

Equation 6-6 describes the manufacture of sulfuric acid in an SCR. The amount of sulfuric acid manufactured due to SO_2 oxidation across the CO catalyst (EM_{CC_CO}) must be subtracted from the total amount of SO_2 produced (E2), because the CO catalyst will reduce the amount available for conversion by the SCR catalyst. For the case of combined cycle combustion turbines, the SCR catalyst SO_2 oxidation rate (S2) will be approximately 0.03. A more precise value can be obtained from either field test reports of SO_2 oxidation, or from the vendor's specification of the SCR catalyst or process. The Technology Impact Factor for SCR, $F3_{SCR}$, will be 1.0.

$$EM_{CCSCR} = [(K \bullet E2) - EM_{CC\text{-}CO}] \bullet f_{sops} \bullet S2 \bullet F3_{SCR} \quad \textbf{Eq. 6-6}$$

where,

EM_{CCSCR} = Total H_2SO_4 manufactured from SCR, lbs per year

K = Molecular weight and units conversion constant

= 98.07/64.04 • 2000 = 3,063

98.07 = Molecular weight of H_2SO_4;

64.04 = Molecular weight of SO_2;

2,000 = Conversion from tons per year to pounds per year

E2 = SO_2 produced, tons per year

EM_{CC_CO} = Total H_2SO_4 manufactured from the CO catalyst, lbs per year

S2 = SCR catalyst SO_2 oxidation rate (specified as a decimal, typically from 0.001- 0.03)

f_{sops} = Operating factor of SCR system, or the fraction of coal burn when the flue gas is directed through the SCR, whether NH_3 reagent is injected to derive NOx reduction or not. This value should reflect the hours the SCR reactor processed flue gas, which will be site-specific but can be approximated by generally 0.8 for year-round peaking operation, 0.98 for year-round base-loaded operation, or 0.43 for seasonal operation

$F3_{SCR}$ = Technology Impact Factor, for SCR (equal to 1.0, refer to Table 4-2)

The total sulfuric acid *manufacture* (TSAM) for a combined cycle unit is estimated using the equation below:

$$\mathbf{TSAM_{CC} = EM_{CCcom} + EM_{CC\_CO} + EM_{CCSCR}} \qquad \textbf{Eq. 6-7}$$

Sulfuric Acid Released

The sulfuric acid released by all sources in combined cycle units is estimated as shown in Equation 6-8. This equation takes into account the reducing effect of ammonia slip from the SCR equipment in a similar method as described in Section 4:

$$\mathbf{TSAR_{CC} = [TSAM_{CC} - (K_s \bullet B \bullet f_{sreagent} \bullet S_{NH3})] \bullet F2_{cc}} \qquad \textbf{Eq. 6-8}$$

where,

$TSAR_{CC}$ = Total H_2SO_4 released, lbs per year

$TSAM_{CC}$ = Total H_2SO_4 manufactured from all sources, lbs per year

K_s = Conversion factor = 3,799 (see Text Box B)

B = Fuel burn in Tbtu/yr

$f_{sreagent}$ = Fraction of SCR operation with reagent injection, when residual NH_3 is produced that will remove SO_3.

S_{NH3} = NH_3 slip from SCR, ppmv at 6% O_2, wet (averages 0.75 ppmv over catalyst guarantee period. Actual NH_3 slip data should be used if available)

$F2_{CC}$ = Technology Impact Factor for the combined cycle heat exchanger, equal to a value of 0.5.

Examples 9 and 10 of Appendix A illustrates a gas-fired combined cycle plant calculation.

7
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A

EXAMPLE CALCULATIONS

Example 1: Conventional Coal-Fired Boiler with an ESP

A 500 MW pulverized coal-fired (PC) boiler, equipped with a cold-side electrostatic precipitator, burns an Eastern bituminous coal. The coal used in the reporting year is 1,126,938 tons with a weighted average sulfur concentration of 2.0% and a heating value of 12,000 Btu/lb.

Solution

Manufactured

$$E2 = K1 \bullet K2 \bullet C1 \bullet S1$$

$$E2 = 0.02 \bullet 0.95 \bullet 1{,}126{,}938 \bullet 2.0 = 42{,}824 \text{ tons } SO_2/\text{yr}$$

$$EM_{Comb} = K \bullet F1 \bullet E2$$

$$F1_{eastbit} = 1.1163\text{E-}6 \bullet SO2 + 0.0064876$$

$$SO_2 = S1 \bullet \frac{K_{F1}}{HV} = 2.0 \bullet \frac{10{,}003{,}602}{12{,}000} = 1667\ ppm$$

$$F1_{eastbit} = 1.1163\text{E-}6 \bullet + 0.0064876 = 0.0083$$

$$EM_{Comb} = 3063 \bullet 0.0083 \bullet 42{,}824 = 1{,}088{,}710 \text{ lbs } H_2SO_4/\text{yr}$$

The 25,000 lbs/yr threshold has been exceeded; therefore, a release estimate must be made and the result reported on Form R.

Released

$$TSAR = EM_{Comb} \bullet F2_{APH} \bullet F2_{ESP}$$

$$TSAR = 1{,}088{,}710 \bullet 0.50 \bullet 0.63 = 342{,}944 \text{ lbs } H_2SO_4/\text{yr}$$

Example 2: SCR Added to Example 1

A 500 MW PC boiler, equipped with a cold-side electrostatic precipitator, burns an Eastern bituminous coal. The plant is equipped with an SCR process that operates during the ozone season only, so that 0.43 of the coal burn occurred with the SCR operating. The remaining time that the SCR is not in service the flue gas is bypassed around the SCR. The SCR catalyst SO_2 oxidation rate specified in the design is 0.75%, and the ammonia slip is estimated to be 0.75 ppmv. The coal used in the reporting year is 1,126,938 tons with a weighted average sulfur concentration of 2.0% and a heating value of 12,000 Btu/lb.

Solution

Manufactured

$$E2 = K1 \bullet K2 \bullet C1 \bullet S1$$

$$E2 = 0.02 \bullet 0.95 \bullet 1{,}126{,}938 \bullet 2.0 = 42{,}824 \text{ tons } SO_2/\text{yr}$$

Combustion

$$EM_{comb} = K \bullet F1 \bullet E2$$

$$F1_{eastbit} = 1.1163E\text{-}6 \bullet SO2 + 0.0064877$$

$$SO_2 = S1 \bullet \frac{K_{F1}}{HV} = 2.0 \bullet \frac{10{,}003{,}602}{12{,}000} = 1667\ ppm$$

$$F1_{eastbit} = 1.1163E\text{-}6 \bullet + 0.0064877 = 0.0083$$

$$EM_{Comb} = 3063 \bullet 0.0083 \bullet 42{,}824 = 1{,}088{,}710 \text{ lbs } H_2SO_4/\text{yr}$$

SCR

$$EM_{SCR} = K \bullet S2 \bullet f_s \bullet E2$$

$$EM_{SCR} = 3063 \bullet 0.0075 \bullet 0.43 \bullet 42{,}824 = 423{,}023 \text{ lbs } H_2SO_4/\text{yr}$$

Total

$$TSAM = EM_{comb} + EM_{SCR}$$

$$TSAM = 1{,}088{,}710 + 423{,}023 \text{ lbs } H_2SO_4/\text{yr}$$

$$TSAM = 1{,}511{,}733 \text{ lbs } H_2SO_4/\text{yr}$$

The 25,000 lbs/yr threshold has been exceeded; therefore, a release estimate must be made and the result reported on Form R.

Released

Coal Burn

$$B = C1 \bullet HV \bullet K_B$$

$$B = 1{,}126{,}938 \text{ tons/yr} \bullet 2000 \text{ lbs/ton} \bullet 12{,}000 \text{ Btu/lb} \bullet 1 \text{ Tbtu}/10^{12} \text{ Btu}$$

$B = 27.05$ Tbtu/yr

Ammonia Slip

$NH3_{SCR} = K_s \bullet B \bullet f_{sreagent} \bullet S_{NH3}$

$NH3_{SCR} = 3799 \bullet 27.05 \bullet 0.43 \bullet 0.75 = 33{,}141$ lbs NH_3/yr

Total Releases

$TSAR = [(EM_{Comb} + EM_{SCR/SNCR}) - (NH3_{SCR})] \bullet F2_{APH} \bullet F2_{ESP}$

$TSAR = [(1{,}088{,}710 + 423{,}023) - (33{,}141)] \bullet 0.50 \bullet 0.63$

$TSAR = 465{,}756$ lbs H_2SO_4/yr

Example 3: Alkali Injection Added to Example 2

A 500 MW PC boiler, equipped with a cold-side electrostatic precipitator, burns an Eastern bituminous coal. The plant is equipped with an SCR process that operates during the ozone season only, so that 0.43 of the coal burn occurred with the SCR operating. The remaining time that the SCR is not in service the flue gas is bypassed around the SCR. The SCR catalyst SO_2 oxidation rate specified in the design is 0.75%, and the ammonia slip is estimated to be 0.75 ppmv.

The plant employs injection of alkali material (e.g., lime, sodium bicarbonate, sodium bisulfate, etc.) to control SO_3 emissions at the stack. The plant operator has conducted a series of field tests to determine the amount of alkali material that must be injected to limit flue gas SO_3 concentration at the stack. The test contractor has issued a report defining the amount of alkali that should be added to limit the stack SO_3 to 5 ppm, as measured in the flue gas at 6.6% O_2, and 8.8% moisture. The alkali injection system will be operated throughout the entire year, so that no more than 5 ppm of SO_3 at the stated conditions of excess O_2 and moisture exist in the stack.

The coal burn rate in the reporting year is 1,126,938 tons, with a weighted average sulfur concentration of 2.0%, and a heating value of 12,000 Btu/lb.

The calculation of manufactured sulfuric acid is the same as Example 1, and is repeated here:

Solution

Manufactured

$$E2 = K1 \bullet K2 \bullet C1 \bullet S1$$

$$E2 = 0.02 \bullet 0.95 \bullet 1{,}126{,}938 \bullet 2.0 = 42{,}824 \text{ tons } SO_2/\text{yr}$$

Combustion

$$EM_{comb} = K \bullet F1 \bullet E2$$

$$F1_{eastbit} = 1.1163E\text{-}6 \bullet SO_2 + 0.0064877$$

$$SO2 = S1 \bullet \frac{K_{F1}}{HV} = 2.0 \bullet \frac{10{,}003{,}602}{12{,}000} = 1667 \text{ ppm}$$

$$F1_{eastbit} = 1.1163E\text{-}6 \bullet + 0.0064877 = 0.0083$$

$$EM_{Comb} = 3063 \bullet 0.0083 \bullet 42{,}824 = 1{,}088{,}710 \text{ lbs } H_2SO_4/\text{yr}$$

SCR

$$EM_{SCR} = K \bullet S2 \bullet f_s \bullet E2$$

$$EM_{SCR} = 3063 \bullet 0.0075 \bullet 0.43 \bullet 42{,}824 = 423{,}023 \text{ lbs } H_2SO_4/\text{yr}$$

Total

$$TSAM = EM_{comb} + EM_{SCR}$$

$$TSAM = 1{,}088{,}710 + 423{,}023 \text{ lbs } H_2SO_4/\text{yr}$$

TSAM = 1,511,733 lbs H_2SO_4/yr

The 25,000 lbs/yr threshold has been exceeded; therefore, a release estimate must be made and the result reported on Form R.

Released

The total sulfuric acid released is based on the maximum value allowed by alkali injection, as measured in the stack, and the volume flow rate of combustion products processed.

The concentration of SO_3 measured at the stack can be converted to a mass emission rate, as described by Equation 4-15

$ER_{ALKINJ} = K_{alkali} \bullet B \bullet S_{SO3} \bullet F_{alkali} \bullet F2_x$

where,

ER_{ALKINJ} = Total H_2SO_4 released from unit equipped with alkali injection, lbs per year

K_{alkali} = Constant, equal to 3,799, with units of lbs H_2SO_4/(Tbtu ppmv SO_3) (SO_3 measured at @ 6% O_2 and 8.1% H_2O)

B = 27.05 Tbtu/yr, for the specific case of Example 1

S_{SO3} = SO_3 content as measured in the stack or particulate collector exit, corrected to a concentration basis of ppmv at 6% O_2, 8.1% moisture

F_{alkali} = fraction of operation with alkali addition to remove SO_3.

$F2_x$ = 1 (as the SO_3 measurement is in the stack, there are no control technology components downstream of the measurement)

The conversion factor K_{alkali} is equal to 3,799 (see Text Box B). This constant is derived for the case where flue gas SO_3 is reported in terms of 6% oxygen and wet flue gas at 8.1% H_2O. However, the SO_3 concentration of 5 ppm in the stack is measured at slightly different conditions of excess O_2 and moisture (6.6% oxygen and 8.8% moisture and therefore, a new value of K_{alkali} must be calculated:

K_{alkali} (O_2, H_2O) = 3799 (6% O_2, 8.1% H_2O) • [(100-8.1)/(100-new H_2O)] • [(20.9 – 6.0)/(20.9 – new O_2)]

K_{alkali} (O_2, H_2O) = 3799 (6% O_2, 8.1% H_2O) • [(100-8.1)/(100-8.8)] • [(20.9 – 6.0)/(20.9 – 6.6)]

K_{alkali} (6.6%, 8.8%) = 3799 • [1.0077] • [1.034]

K_{alkali} (6.6%, 8.8%) =3958

Total sulfuric acid release is then calculated as follows:

ER_{ALKINJ} = [3,958] • [27.05] •[5.0] • [1] • [1]

ER_{ALKINJ} = 535,320 lbs/yr

TSAR = ER_{ALKINJ}

TSAR = 535,320 lbs/yr

Example 4: 500 MW PRB-fired Boiler with ESP, SCR

A 500 MW PC boiler, equipped with a cold-side electrostatic precipitator, burns a PRB coal. The plant is equipped with an SCR process that operates during the ozone season only, so that 0.43 of the coal burn occurred with the SCR operating. The SCR is bypassed when not in use. The SCR catalyst SO_2 oxidation rate specified in the design is 2%, and the ammonia slip is estimated to be 0.75 ppmv. The coal used in the reporting year is 1,384,552 tons with a weighted average sulfur concentration of 0.40% and a heating value of 8,500 Btu/lb.

Solution

Manufactured

$$E2 = K1 \bullet K2 \bullet C1 \bullet S1$$

$$E2 = 0.02 \bullet 0.875 \bullet 1{,}384{,}552 \bullet 0.40 = 9{,}692 \text{ tons } SO_2/\text{yr}$$

Combustion

$$EM_{comb} = K \bullet F1 \bullet E2$$

$$EM_{comb} = 3063 \bullet 0.0019 \bullet 9{,}692 = 56{,}405 \text{ lbs } H_2SO_4/\text{yr}$$

SCR

$$EM_{SCR} = K \bullet S2 \bullet f_s \bullet f_{3SCR} \bullet E2$$

$$EM_{SCR} = 3063 \bullet 0.020 \bullet 0.43 \bullet 0.17 \bullet 9{,}692 = 43{,}402 \text{ lbs } H_2SO_4/\text{yr}$$

Total

$$TSAM = EM_{comb} + EM_{SCR}$$

$$TSAM = 56{,}404 + 43{,}402 \text{ lbs } H_2SO_4/\text{yr}$$

$$TSAM = 99{,}806 \text{ lbs } H_2SO_4/\text{yr}$$

The 25,000 lbs/yr threshold has been exceeded; therefore, a release estimate must be made and the result reported on Form R.

Released

Coal Burn

$$B = C1 \bullet HV \bullet K_B$$

$$B = 1{,}384{,}552 \text{ tons/yr} \bullet 2000 \text{ lbs/ton} \bullet 8{,}500 \text{ Btu/lb} \bullet 1 \text{ Tbtu}/10^{12} \text{ Btu}$$

$$B = 23.54 \text{ Tbtu/yr}$$

Ammonia Slip

$$NH3_{SCR} = K_s \bullet B \bullet f_{sreagent} \bullet S_{NH3}$$

$$NH3_{SCR} = 3799 \bullet 23.54 \bullet 0.43 \bullet 0.75 = 28{,}841 \text{ lbs } NH_3/\text{yr}$$

Total Releases

$TSAR = [(EM_{Comb} + EM_{SCR/SNCR}) - (NH3_{SCR})] \bullet F2_{APH} \bullet F2_{ESP}$

$TSAR = [(56{,}404 + 43{,}402) - (28{,}841)] \bullet 0.36 \bullet 0.72$

TSAR = 18,394 lbs H_2SO_4/yr

Example 5: FGC Added to Example 1

A 500 MW PC boiler, equipped with a cold-side electrostatic precipitator, burns an Eastern bituminous coal. The plant is equipped with a FGC process that injects both SO3 and NH3 upstream of the air preheater. The SO3 is injected at 7 ppmv at 6% O2 wet, and the ammonia at 3 ppmv also at 6% O2 wet. The FGC system operates whenever the plant is on, except during startup and shutdown, with an operating factor estimated at 0.9. The coal used in the reporting year is 1,126,938 tons with a weighted average sulfur concentration of 2.0% and a heating value of 12,000 Btu/lb.

Solution

Manufactured

$$E2 = K1 \bullet K2 \bullet C1 \bullet S1$$

$$E2 = 0.02 \bullet 0.95 \bullet 1{,}126{,}938 \bullet 2.0 = 42{,}824 \text{ tons } SO_2\text{/yr}$$

Combustion

$$EM_{Comb} = K \bullet F1 \bullet E2$$

$$F1_{eastbit} = 1.1163E\text{-}6 \bullet SO_2 + 0.0064877$$

$$SO_2 = S1 \bullet \frac{K_{F1}}{HV} = 2.0 \bullet \frac{10{,}003{,}602}{12{,}000} = 1667\ ppm$$

$$F1_{eastbit} = 1.1163E\text{-}6 \bullet + 0.0064877 = 0.0083$$

$$EM_{Comb} = 3063 \bullet 0.0083 \bullet 42{,}824 = 1{,}088{,}710 \text{ lbs } H_2SO_4\text{/yr}$$

FGC

$$B = 1{,}126{,}938 \text{ tons/yr} \bullet 2000 \text{ lbs/ton} \bullet 12000 \text{ Btu/lb} \bullet 1 \text{ Tbtu}/10^{12} \text{ Btu}$$

$$B = 27.05 \text{ Tbtu/yr}$$

$$EM_{FGC} = K_e \bullet B \bullet f_e \bullet I_s \bullet F3_{FGC}$$

$$EM_{FGC} = 3799 \bullet 27.05 \bullet 0.9 \bullet 7 \bullet 1 = 647{,}407 \text{ lbs } H_2SO_4\text{/yr}$$

Total

$$TSAM = EM_{Comb} + EM_{FGC}$$

$$TSAM = 1{,}088{,}710 + 647{,}407 \text{ lbs } H_2SO_4\text{/yr}$$

$$TSAM = 1{,}736{,}117 \text{ lbs } H_2SO_4\text{/yr}$$

The 25,000 lbs/yr threshold has been exceeded; therefore, a release estimate must be made and the result reported on Form R.

Released

Coal Burn

$B = C1 \bullet HV \bullet K_B$

$B = 1{,}126{,}938 \text{ tons/yr} \bullet 2000 \text{ lbs/ton} \bullet 12000 \text{ Btu/lb} \bullet 1 \text{ Tbtu}/10^{12} \text{ Btu}$

$B = 27.05 \text{ Tbtu/yr}$

FGC Ammonia Injection

$NH3_{FGC} = K_e \bullet B \bullet f_e \bullet I_{NH3}$

$NH3_{FGC} = 3799 \bullet 27.05 \bullet 0.9 \bullet 3.0 = 277{,}460 \text{ lbs } NH_3\text{/yr}$

Total Releases

$TSAR = [(EM_{Comb} + EM_{FGC}) – (NH3_{FGC})] \bullet F2_{APH} \bullet F2_{ESP}$

$TSAR = [(1{,}088{,}710 + 647{,}407) – (277{,}460)] \bullet 0.50 \bullet 0.63$

$TSAR = 459{,}477 \text{ lbs } H_2SO_4\text{/yr}$

Example 6: SCR and FGC Added to Example 1

A 500 MW PC boiler, equipped with a cold-side electrostatic precipitator, burns an Eastern bituminous coal. The plant is equipped with an SCR process that operates during the ozone season only, so that 0.43 of the coal burn occurred with the SCR operating. The SCR is bypassed when not in operation. The SCR catalyst SO_2 oxidation rate specified in the design is 0.75%, and the ammonia slip is estimated to be 0.75 ppmv. The plant is also equipped with a FGC process that injects both SO_3 and NH_3 upstream of the air preheater. The SO_3 is injected at 7 ppmv at 6% O_2 wet, and the ammonia at 3 ppmv also at 6% O_2 wet. The FGC system operates whenever the plant is on, except during startup and shutdown, with an operating factor estimated at 0.9. The coal used in the reporting year is 1,126,938 tons with a weighted average sulfur concentration of 2.0% and a heating value of 12,000 Btu/lb.

Solution

Manufactured

Total (from previous examples)

$$TSAM = EM_{Comb} + EM_{SCR} + EM_{FGC}$$

$$TSAM = 1{,}088{,}710 + 423{,}023 + 647{,}407 \text{ lbs } H_2SO_4/yr$$

$$TSAM = 2{,}159{,}140 \text{ lbs } H_2SO_4/yr$$

The 25,000 lbs/yr threshold has been exceeded; therefore, a release estimate must be made and the result reported on Form R.

Released

Total Releases (from previous examples)

$$TSAR = [(EM_{Comb} + EM_{SCR} + EM_{FGC}) - (NH3_{SCR} + NH3_{FGC})] \bullet F2_{APH} \bullet F2_{ESP}$$

$$TSAR = [(1{,}088{,}710 + 423{,}023 + 647{,}407) - (33{,}141 + 277{,}460)] \bullet 0.50 \bullet 0.63$$

$$TSAR = 582{,}290 \text{ lbs } H_2SO_4/yr$$

Example 7: SCR and Downstream FGC Added to Example 1

A 500 MW PC boiler, equipped with a cold-side electrostatic precipitator, burns an Eastern bituminous coal. The plant is equipped with an SCR process that operates during the ozone season only, so that 0.43 of the coal burn occurred with the SCR operating. The SCR is bypassed when not operating. The SCR catalyst SO_2 oxidation rate specified in the design is 0.75%, and the ammonia slip is estimated to be 0.75 ppmv. The plant is also equipped with a FGC process that injects both SO_3 and NH_3 downstream of the air preheater. The SO_3 is injected at 7 ppmv at 6% O_2 wet, and the ammonia at 3 ppmv also at 6% O_2 wet. The FGC system operates whenever the plant is on, except during startup and shutdown, with an operating factor estimated at 0.9. The coal used in the reporting year is 1,126,938 tons with a weighted average sulfur concentration of 2.0% and a heating value of 12,000 Btu/lb.

Solution

Manufactured

Total (from previous examples)

$$TSAM = EM_{Comb} + EM_{SCR} + EM_{FGC}$$

$$TSAM = 1{,}088{,}710 + 423{,}023 + 647{,}407 \text{ lbs } H_2SO_4/\text{yr}$$

$$TSAM = 2{,}159{,}140 \text{ lbs } H_2SO_4/\text{yr}$$

The 25,000 lbs/yr threshold has been exceeded; therefore, a release estimate must be made and the result reported on Form R.

Released

Total Releases (from previous examples)

$$TSAR = \{[(EM_{Comb} + EM_{SCR}) - NH3_{SCR}] \bullet F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} \bullet F2_{ESP}$$

Check that subtotal from upstream sources is positive:

$$TSAR_{upstream} = [(1{,}088{,}710 + 423{,}023) - 33{,}141] = 1{,}478{,}592 > 0$$

$$TSAR = [(1{,}088{,}710 + 423{,}023) - 33{,}141] \bullet 0.50 + (647{,}407 - 277{,}460)\} \bullet 0.63$$

$$TSAR = 698{,}823 \text{ lbs } H_2SO_4/\text{yr}$$

Example 8: Coal-Fired Boiler with FGC, NG Startup Fuel, and Used Oil Co-Firing

A 500 MW PC boiler, equipped with a cold-side electrostatic precipitator, burns an Eastern bituminous coal as the main fuel. The plant is equipped with an SCR process that operates during the ozone season only, so that 0.43 of the coal burn occurred with the SCR operating. The SCR is bypassed when not in operation. The SCR catalyst SO_2 oxidation rate specified in the design is 0.75%, and the ammonia slip is estimated to be 0.75 ppmv. The plant is also equipped with a FGC process that injects both SO_3 and NH_3 upstream of the air preheater. The SO_3 is injected at 7 ppmv at 6% O_2 wet, and the ammonia at 3 ppmv also at 6% O_2 wet. The FGC system operates whenever the plant is on, except during startup and shutdown, with an operating factor estimated at 0.9.

The coal used in the reporting year is 1,126,938 tons with a weighted average sulfur concentration of 2.0% and a heating value of 12,000 Btu/lb.

Natural gas is used as a startup fuel, with 0.5 Tbtu per year. During startup, neither the SCR nor the FGC system is used. Used oil is also burned, with 483.2 tons burned (0.0185 Tbtu/yr) in the year. Since the used oil is burned when the unit is at full load, it is burned while the SCR and FGC are both operating. The used oil has a sulfur content of 0.1% from analysis.

Solution

Coal fuel calculations

Manufactured from coal

Total (from previous examples)

$$TSAM = EM_{Comb} + EM_{SCR} + EM_{FGC}$$

$$TSAM= 1,088,710 + 423,023 + 647,407 \text{ lbs } H_2SO_4/yr$$

$$TSAM = 2,159,140 \text{ lbs } H_2SO_4/yr$$

Released from coal

Total Releases (from previous examples)

$$TSAR_{coal} = 582,290 \text{ lbs } H_2SO_4/yr$$

Natural gas fuel calculations

Manufactured from natural gas

Combustion

$$E2_{NG} = K_b \bullet B_{NG} \bullet S$$

$$E2_{NG} = 0.0001359 \bullet 0.5 \text{ Tbtu/yr} \bullet 2000 \text{ gr}/10^6 \text{ scf}$$

$$E2_{NG} = 0.136 \text{ tons } SO_2/\text{year}$$

$$EM_{Comb} = K \bullet F1 \bullet E2_{NG}$$

$EM_{Comb} = 3063 \bullet 0.01 \bullet 0.136$

$EM_{Comb} = 4.17$ lbs H_2SO_4 manufactured

No sulfuric acid is manufactured in either the SCR or FGC.

Released from natural gas

Total Releases

$TSAR_{NG} = EM_{Comb} \bullet F2_{APH} \bullet F2_{ESP}$

$TSAR_{NG} = 4.17 \bullet 0.50 \bullet 0.63$

$TSAR_{NG} = 1.31$ lbs H_2SO_4/yr

F2 is taken to be equal to 0.50 for the air heater and 0.63 for the ESP.

Used oil fuel calculations

Manufactured from used oil

Combustion

$E2 = K1 \bullet K2 \bullet C1 \bullet S1$

$E2 = 0.02 \bullet 1.0 \bullet 483.2 \bullet 0.1$

$E2 = 0.966$ tons SO_2/year

$EM_{Comb} = K \bullet F1 \bullet E2$

$EM_{Comb} = 3063 \bullet 0.0175 \bullet 0.966$

$EM_{Comb} = 51.8$ lbs H_2SO_4 manufactured

SCR

$EM_{SCR} = K \bullet S2 \bullet f_s \bullet E2$

$EM_{SCR} = 3063 \bullet 0.0075 \bullet 1.0 \bullet 0.966$

$EM_{SCR} = 22.2$ lbs H_2SO_4 manufactured

FGC

$EM_{FGC} = K_e \bullet B \bullet f_e \bullet I_s \bullet F3_{FGC}$

$EM_{FGC} = 3799 \bullet 0.0185 \bullet 1.0 \bullet 7.0 \bullet 1$

$EM_{FGC} = 492$ lbs H_2SO_4 manufactured

Total Manufactured

$TSAM = EM_{Comb} + EM_{SCR} + EM_{FGC}$

$TSAM = 51.8 + 22.2 + 492$ lbs H_2SO_4/yr

$TSAM = 566$ lbs H_2SO_4/yr

Released from used oil

Ammonia Slip

$NH3_{SCR} = K_s \bullet B \bullet f_{sreagent} \bullet S_{NH3}$

$NH3_{SCR} = 3799 \bullet 0.0185 \bullet 1.0 \bullet 0.75 = 52.7$ lbs NH_3/yr

FGC Ammonia Injection

$NH3_{FGC} = K_e \bullet B \bullet f_e \bullet I_{NH3}$

$NH3_{FGC} = 3799 \bullet 0.0185 \bullet 1.0 \bullet 3.0 = 211$ lbs NH_3/yr

Total Releases

$TSAR_{oil} = [(EM_{Comb} + EM_{SCR} + EM_{FGC}) – (NH3_{SCR} + NH3_{FGC})] \bullet F2_{APH} \bullet F2_{ESP}$

$TSAR_{oil} = [(51.8 + 22.2 + 492) – (52.7 + 211)] \bullet 0.5 \bullet 0.63$

$TSAR_{oil} = 95$ lbs H_2SO_4/yr

F2 is taken to be equal to 0.50 for the air heater and 0.63 for the ESP

Grand totals for all fuels

Manufactured

$TSAM = TSAM_{coal} + TSAM_{NG} + TSAM_{oil}$

$TSAM = 2,159,140 + 4.17 + 566$ lbs H_2SO_4/yr

$TSAM = 2,159,710$ lbs H_2SO_4/yr

Released

$TSAR = TSAR_{coal} + TSAR_{NG} + TSAR_{oil}$

$TSAR = 582,290 + 1.31 + 95$ lbs H_2SO_4/yr

$TSAR = 582,386$ lbs H_2SO_4/yr

Example 9: Natural Gas Combined Cycle Plant

A natural gas-fired combined-cycle unit uses 12.3 Tbtu/yr. of natural gas, with the standard sulfur content.

Solution

Manufactured

$E2_{NG} = K_b \bullet B_{NG} \bullet S$

$E2_{NG} = 0.0001359 \bullet 12.3 \bullet 2000$

$E2_{NG} = 3.343$ tons SO_2/yr□

Combustion

$EM_{CC} = K \bullet F1 \bullet E2_{NG}$

$EM_{CC} = 3063 \bullet 0.0555 \bullet 3.343$

$EM_{CC} = 568$ lbs H_2SO_4/yr

Released

$TSAR_{NG} = EM_{Comb} \bullet F2_{CC}$

$TSAR_{NG} = 568 \bullet 0.5$

$TSAR_{NG} = 284$ lbs H_2SO_4/yr

$F2_{CC} = 0.5$ because the low temperature of the back-end tubes of the HRSG act like an air heater.

Example 10: SCR and CO catalyst added to Example 9

A natural gas-fired combined-cycle unit uses 12.3 Tbtu/yr. of natural gas, with the standard sulfur content. The plant is equipped with an SCR process that operates continually (operating factor of 1.0). The SCR catalyst SO_2 oxidation rate specified in the design is 2.0%, and the ammonia slip is estimated to be 0.75 ppmv. The plant is also equipped with a CO catalyst, which also is in continuous operation, and has an estimated SO_2 oxidation rate of 10%.

Solution

Manufactured

$E2_{NG} = K_b \bullet B_{NG} \bullet S$

$E2_{NG} = 0.0001359 \bullet 12.3 \bullet 2000$

$E2_{NG} = 3.343$ tons SO_2/yr□

Combustion

$EM_{CC} = K \bullet F1 \bullet E2_{NG}$

$EM_{CC} = 3063 \bullet 0.0555 \bullet 3.343$

$EM_{CC} = 568$ lbs H_2SO_4/yr

CO Catalyst

$EM_{CC\_CO} = K \bullet S3 \bullet f_{COops} \bullet E2$

$EM_{CC\_CO} = 3063 \bullet 0.1 \bullet 1.0 \bullet 3.343$

$EM_{CC\_CO} = 1024$ lbs H_2SO_4/yr

SCR

$EM_{CCSCR} = [(K \bullet E2) - EM_{CC\text{-}CO}] \bullet f_{sops} \bullet S2 \bullet F3_{SCR}$

$EM_{CCSCR} = [(3063 \bullet 3.343) – 1024] \bullet 1.0 \bullet 0.02 \bullet 1.0$

$EM_{CCSCR} = 184$ lbs H_2SO_4/yr

Total

$TSAM_{CC} = EM_{Comb} + EM_{CC\_CO} + EM_{SCR}$

$TSAM_{CC} = 568 + 1024 + 184$

$TSAM_{CC} = 1776$ lbs H_2SO_4/yr

Released

$TSAR_{CC} = [TSAM – (K_s \bullet B \bullet f_{sreagent} \bullet S_{NH3})] \bullet F2_{cc}$

$TSAR_{CC} = [1776 – (3799 \bullet 12.3 \bullet 1.0 \bullet 0.75)] \bullet 0.5$

$TSAR_{CC} = -16{,}635 = 0$ lbs H_2SO_4/yr

The total releases are zero because the actual result is a negative value, indicating that the ammonia slip is greater than the sulfuric acid, thereby forming ABS, which is not reportable.

$F2_{CC}$ = 0.5 because the low temperature of the back-end tubes of the HRSG act like an air heater.

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CHRONOLOGY OF CHANGES TO THE EPRI SULFURIC ACID ESTIMATION MODEL

EPRI, 2018 (EPRI Report 3002012398)

Modification	Description
Stack correction for CEMs SO_2 measurements	Added equation using wall affects factor (WAF) for CEMs measurements in conjunction with Method 2H.
Total Sulfuric Acid Release Methodology (TSAR)	Changed application location of $F2_{Hotside\_ESP}$ and $F2_{Mag\text{-}Ox}$ such that they apply only to EM_{COMB}.
Partial-Year SCR/SNCR	Added methodology to calculate the Total Sulfuric Acid Release if injection for SCR/SNCR is partial-year.

EPRI, 2012 (EPRI Report 1023790)

Modification	Description
SCR Factor ($F3_{SCR}$)	Changes made to Table 4-2 to clarify proper use of the $F3_{SCR}$ factor.
Alkali Injection	Changed description of F_{alkali} such that it is fraction of coal burn instead of fraction of operating year, to be consistent with other operating factors Added alternate approach for calculating releases with alkali injection to be used if the utility does not have measured data. $F3_{ALKINJ}$ factor is introduced.
Total Sulfuric Acid Release Methodology (TSAR)	Reorganized release equations such that sources are summed upstream of the APH and ammonia from SCR/SNCR is applied to reduce releases based on ABS formation, then the F2 factor for the APH is applied. Then, any downstream source of SO_3 or ammonia from downstream FGC is added, followed by application of all remaining F2 factors.
FGC Factor ($F3_{FGC}$)	Corrected the $F3_{FGC}$ factor. The $F3_{FGC}$ factor was introduced in the 2001 version of the report, but as actual data has become available to update the F2 factors, the $F3_{FGC}$ factor has become outdated. $F3_{FGC}$ will now account only for alkalinity in PRB coal, and be applied directly to the manufacture equation.

EPRI, 2012 (EPRI Report 1023790), continued

Combined Cycle	Introduced a potential third source of sulfuric acid manufacture and release from oxidation across CO catalysts.
Technology Factors (F2)	Added Wet ESP, all fuels: 0.1. Changed FGD, venturi, all coals from 0.65 to 0.73 (2 new data points). Updated and corrected Figure 4-4 to reflect two new data points, change the shaded area to reflect the proper data range, and deleted an inaccurate PRB/lignite data point Changed the F2 factor in Table 4-6 for Mg-Ox into furnace from 0.5 to 0.25 to rectify an error introduced in the 2004 version of the report.
Examples	Updated examples to account for new release equation methodology.

EPRI, 2010a (EPRI Report 1020636)

Modification	Description
Fuel Impact Factor (F1)	Combined low and high-sulfur eastern bituminous coals into a single category with a linear curve fit. F1 factor based on fuel SO_2 content calculated from fuel sulfur content: $F1_{ebit} = 1.1163E\text{-}6 \bullet SO_2 + 0.0065$ Changed the following F1 factors based on additional data: Subbit/PRB – changed from 0.0018 to 0.0019 Lignite – changed from 0.0048 to 0.0044
Technology Factors (F2)	Changed factors for APH and ESP due to addition and re-evaluation of data: APH, low-sulfur east. bit. – changed from 0.49 to 0.50 APH, PRB – changed from 0.56 to 0.36 ESP, low-sulfur east. bit – changed from 0.49 to 0.63 ESP, PRB – changed from 0.73 to 0.72

EPRI, 2010a (EPRI Report 1020636) (continued)

Alkali Injection	Added a procedure to determine total releases from partial year injection. Incorporated correction to alkali injection conversion factor, K_{alkali}.
Report Organization	Moved F2 Factors from Section 3 to Section 4.
Examples	Updated examples to account for new F1 and F2 factors.

EPRI, 2008 (EPRI Report 1016384)

Modification	Description
Alkali Injection	Added a procedure to estimate a stack release using a measured or specified stack gas SO_3 concentration, to support estimates on units with alkali injection. Errata page published to correct error in alkali injection conversion factor, K_{alkali}.
Combustion Turbines	Clarified procedures for estimating emissions from simple and combined cycle CTs.
Blended Coals	New method calculates SO_3 manufacture by calculating the SO_3 emission rate separately for each of the component coals, and proportioning the contribution of SO_3 from each. The prior method assumed the SO_3 production was the same as that of the major coal component.
Examples	Provided new example calculations for alkali injection and blended coal.

EPRI, 2007 (Report 1014773) changes from Harrison, 2005

Modification	Description
Formatting	Adapted Southern Company paper (Harrison, 2005) to EPRI format.
Fuel (F1) Factors	Changed the following F1 factors based on additional data: Low S E. Bit, Dry Boiler – from 0.0080 to 0.0082 Subbit. (including PRB), Dry Boiler – from 0.0014 to 0.0018 Subbit. (including PRB), Cyclone – from 0.003 to 0.0018

EPRI, 2007 (Report 1014773) changes from Harrison, 2005 (continued)

Technology (F2) Factors	Added new F2 Factors: Air Preheater, PRB fuel - 0.56 Cold-side ESP, PRB fuel – 0.73
SCR	Added a Technology Impact Factor for SCR, $F3_{SCR}$.

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3002012398

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Attachment H-2

Sulfuric Acid Mist Emissions Calculations at Coal Creek Station Due to Selective Catalytic Reduction using EPRI Guidance

GRE Coal Creek Station 2019 BART Review
Sulfuric Acid Mist Generation from SCR Operation
Basis EPRI publication 300201298: "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, 2018 Update"

The EPRI document describes an emissions estimation procedure for the manufacture and release of sulfuric acid from formation within the boiler and the SCR, and the effects of flue gas conditioning (FGC), alkali injection, and removal by downstream equipment such as air preheaters (APH), electrostatic precipitators (ESPs) and flue gas desulfurization (FGD) equipment.

This analysis only includes formation of sulfuric acid from the SCR, the effects of ammonia slip produced by the SCR, and removal by downstream pollution control equipment. Sulfuric acid manufactured by the boiler is not included in the calculations.

Sulfuric acid manufactured from SCR is estimated using the following equation.

Eq. 4-7: EMSCR = K • S2 • fsops • E2 • F3SCR

where,

EMSCR = Total H_2SO_4 manufactured from SCR, lbs per year

K = Molecular weight and units conversion constant = 98.07 / 64.04 • 2000 = 3,063

98.07 = Molecular weight of H_2SO_4

64.04 = Molecular weight of SO_2

2000 = Conversion from tons per year to pounds per year.

S2 = SCR catalyst SO_2 oxidation rate (specified as a fraction, typically from 0.001- 0.03), Catalyst Manufacturer's suggested oxidation rate for the proposed catalyst is 0.05.

fsops = Operating factor of SCR system, or the fraction of coal burn when the flue gas is directed through the SCR, whether NH_3 reagent is injected to derive NOx reduction or not. This value should reflect the hours the SCR reactor processed flue gas, which will be site-specific but can be approximated by generally 0.8 for year-round peaking operation, 0.98 for year-round base- loaded operation, or 0.43 for seasonal operation.

E2 = SO_2 produced, tons per year

F3SCR = Technology Impact Factor, for SCR. Table 4-2 recommends a factor of 1 for all coals except PRB.

K	S2	fsops	E2	F3SCR	EMSCR			
			tons/year		lb/hour	lb/year	ton/year	lb H_2SO_4/ ton SO_2
3,063	0.05	0.98	40,500	1	796	6,078,524	3,039	150

The Total Sulfuric Acid Release accounts for sulfuric acid manufactured from the SCR, the amount removed by ammonia slip, and the amount captured by downstream emission control equipment. Ammonia slip from the SCR can combine with some or all of the sulfuric acid generated to reduce the amount released.

Total Sulfuric Acid Release (TSAR) is described by the following equation:

Eq. 4-11 TSAR = {[((~~EMComb* F2Hotside_ESP * F2Mag-ox~~) + EMSCR + ~~EMFGC_beforeAPH~~) – (NH3SCR + ~~NH3FGC_beforeAPH~~)]
• F2APH + (EMFGC_afterAPH – NH3FGC_afterAPH)} • F2x

where,

TSAR = Total Sulfuric Acid Release, lbs per year

EMComb = Total sulfuric acid manufactured from combustion, lbs per year. Only H_2SO_4 manufactured by the SCR is addressed in this analysis.

F2Hotside_ESP = Technology Impact Factor for hot-side ESP. Only H_2SO_4 manufactured by the SCR is addressed in this analysis so this factor is not applicable.

F2Mag-Ox = Technology Impact Factor for magnesium oxide addition in fuel or furnace. Only H_2SO_4 manufactured by the SCR is addressed in this analysis so this factor is not applicable.

EMSCR = Total sulfuric acid manufactured from SCR, lbs per year. See equation 4-7 above.

EMFGC_beforeAPH = Total sulfuric acid manufactured from FGC upstream of the air preheater (APH). Not Applicable.

NH3SCR = Total equivalent ammonia slip produced from SCR/SNCR, lbs per year. See equation 4-13 below.

NH3FGC_beforeAPH = Total equivalent ammonia produced from FGC upstream of the APH, lbs per year.

F2APH = Technology Impact Factor for APH, applied only if subtotal for releases upstream of the APH is non-negative
= 0.5, average measurement for air preheater, Table 4-3.

EMFGC_afterAPH = Total sulfuric acid manufactured from FGC downstream of the APH. Not Applicable.

NH3FGC_afterAPH = Total equivalent ammonia produced from FGC downstream of the APH, lbs per year

F2x = Technology Impact Factors for processes downstream of the APH, all that apply

Cold Side ESP F2 Factor	0.65	equivalent to 35% eff
Spray Tower FGD F2 Factor	0.45	equivalent to 55% eff
Control Equip F2 Factor $F2_X$	0.29	equivalent to 71% eff

The following equation calculates the amount of ammonia slip from SCR.

Eq. 4-13 NH3SCR = Ks • B • fsreagent • SNH3

where,

NH3SCR = Total equivalent ammonia slip produced from SCR/SNCR, lbs per year

Ks = Conversion factor = 3,799 lb H_2SO_4/(TBtu * ppmv SO_3 @ 6% O2 and wet)

B = Coal burn in TBtu/yr See calculations below.

fsreagent = Fraction of SCR operation with reagent injection, when residual NH3 is produced that will remove SO_3. The value of fsreagent will be similar to, but slightly less than, the value of fsops, defined for Equation 4-6. 0.98 is used in the analysis.

SNH3 = NH_3 slip from SCR/SNCR, ppmv at 6% O2, wet. Performance guarantee = 2 PPM.

Ks	B	fsreagent	SNH3	NH3SCR		
	TBTU/yr			lb/hour	lb/year	ton/year
3,799	44.8	0.98	2	44	333,506	167

Coal data based on Black & Veatch BART report, Appendix A.

Coal Input	Operating hours	Coal Energy	Coal Burn
ton/hour	hour/year	Btu/lb	TBtu/year
443.79	7,632	6,612	44.8

EMSCR	NH3SCR	F2APH	F2x	TSAR		
lb/year	lb/year			lb/hour	lb/year	ton/year
6,078,524	333,506	0.5	0.29	109	833,027	417

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December 23, 2019

VIA ELECTRONIC MAIL

Jim Semerad
Director, Division of Air Quality
North Dakota Department of Environmental Quality
918 E. Divide Ave., 2nd Floor
Bismarck, ND 58501-1947

RE: Regional Haze Four-factor Analysis for SO_2 and NOx Emissions at Coal Creek Station Units 1 and 2

Dear Mr. Semerad:

This letter and attachment serve to respond to the North Dakota Department of Environmental Quality's (NDDEQ) May 2, 2018 request for Great River Energy (GRE) to prepare a "four factors" analysis (herein termed a four-factor analysis) of SO_2 and NOx emissions control measures for Coal Creek Station Units 1 and 2.[1] The NDDEQ had requested that this analysis be submitted by January 31, 2019. In follow-up conversations with NDDEQ staff during 2018 and 2019, GRE agreed to focus first on completing an updated best available retrofit technology (BART) analysis of NOx emissions for the phase 1 State Implementation Plan (SIP). The updated NOx BART analysis was submitted to the NDDEQ on September 12, 2019. We understand that submission of this SO_2 four-factor analysis before the end of 2019 is timely for the NDDEQ's preparations on the phase 2 SIP (RHR2), due to the U.S. Environmental Protection Agency (EPA) by July 31, 2021.

Under RHR2, the NDDEQ four-factor analysis request is specific to SO_2 and NOx emissions because "sulfate and nitrates continue to be the largest contributors to visibility impairment" at North Dakota's Class I areas. For informational purposes, actual annual SO_2 emissions in the last decade from GRE's electric generating units in North Dakota – Coal Creek Station, Stanton Station, and Spiritwood Station – have decreased from nearly 31,000 tons in 2009 to less than 6,900 tons in 2018, representing a 78 percent reduction. In this same time frame, actual annual NOx emissions have decreased 44 percent from nearly 13,000 tons in 2009 to 7,300 tons in 2018.

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[1] May 2, 2018 letter from Terry O'Clair of the North Dakota Department of Health (now the North Dakota Department of Environmental Quality) to Mary Jo Roth of Great River Energy. Pursuant to a June 1, 2018 teleconference between GRE and NDDEQ staff, the NDDEQ confirmed that the four-factor analysis is to be completed only for the two electricity generating units, Unit 1 and Unit 2, which together constitute the vast majority of the actual SO_2 and NOx emissions at Coal Creek Station. Other emissions units at Coal Creek Station are not subject to the four-factor analysis.

SO_2 Four-factor Analysis

The enclosed technical report (SO_2 four-factor report) provides a detailed analysis of SO_2 emissions control measures at Units 1 and 2. This report is based on and references EPA's final regional haze SIP guidance[2] issued on August 20, 2019 (2019 RH SIP Guidance), per verbal communication with NDDEQ staff, instead of earlier draft guidance issued in 2016 that was referenced in the May 2, 2018 NDDEQ letter.

The SO_2 four-factor report describes existing operations and SO_2 emissions performance at Units 1 and 2. As a result of GRE's work in recent years to better understand the opportunities and implications of reducing SO_2 emissions with its existing infrastructure (i.e., wet scrubber system, flue gas reheat technology, and dry stack design), GRE determined its baseline annualized SO_2 emissions performance level to be 626 lb/hr at each unit, which is equivalent to 0.104 lb/MMBtu at full load conditions.[3] Setting this emissions rate for the baseline control scenario is consistent with the 2019 RH SIP Guidance. It is also notably less than the current 0.15 lb/MMBtu BART limit on a 30-day rolling average. The SO_2 performance level is consistent with operation of multiple emissions control measures in place, namely the wet scrubber system, DryFining^{TM} technology, and flue gas reheat applications.

An assessment of additional SO_2 emissions control measures was conducted relative to this baseline control scenario. Upon review of potentially available control technologies, the two technically feasible measures that were further evaluated in the four-factor analysis are both intended to increase the amount of flue gas to the existing wet scrubbers by either: 1) replacing the current stack with a wet stack design, or 2) installing a natural gas-fired flue gas reheat system to maintain dry stack operating temperature. GRE estimates that the annual SO_2 emissions performance level from either of these measures is 0.080 lb/MMBtu compared to the baseline control scenario of 0.104 lb/MMBtu.

The costs of compliance for these two control measures have been determined with a screening-level engineering cost estimate. The cost effectiveness analysis of either control measure is summarized in the following table and is compared to the cost effectiveness threshold of $4,630/ton represented in today's dollars. The cost of either control measure is significantly greater than this threshold. GRE believes the screening-level costs provided in Appendix A of this report are conservatively low and that a more detailed cost estimate is likely to increase the costs for installing and implementing either of the projects.

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[2] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

[3] 626 lb/hr = 0.104 lb/MMBtu x 6,015 or 6,022 MMBtu/hr rated capacities for Unit 1 and 2 listed in the Title V operating permit.

SO_2 Emissions Control Measure	Installed Capital Cost ($)	Annualized Capital Cost ($/yr)	Annual Operating Costs ($/yr)	Total Annualized Costs ($/yr)	Annual SO_2 Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
New Wet Stack	$38.8 million	$3.2 million	$0.8 million	$4.0 million	550	7,200
Natural Gas Reheat System	$14.5 million	$1.2 million	$2.2 million	$3.4 million	550	6,200

Additionally, the observations of energy and environmental burden from installation of these measures (i.e., demolition and disposal of the existing stacks, natural gas combustion NOx emissions from the flue gas reheat system) leads to the conclusion that these additional emissions control measures are not reasonably supported at Units 1 or 2.

In consultation with the NDDEQ, GRE proposes a federally enforceable SO_2 emissions rate limit of 626 lb/hr as an annualized average (365-boiler-operating-day rolling average) limit for each unit, with plant averaging between the two units. GRE proposes to implement operational practices summarized in Section 2.5 of the report in order to comply with the proposed SO_2 emissions rate limit, effective upon approval of a federally enforceable permit to construct (PTC) issued by the NDDEQ. This new performance level further reduces annual SO_2 emissions at each unit by an estimated 1,050 tpy in comparison to the BART limit.[4]

NOx Four-factor Analysis

GRE submitted to the NDDEQ an updated NOx BART report for Units 1 and 2 on September 12, 2019. This updated report follows the same evaluation steps as the SO_2 four-factor report summarized above with respect to the following two key elements:

- The annual NOx emissions performance level is updated to reflect current and expected conditions, as was done for the SO_2 four-factor analysis, in order to appropriately evaluate the effectiveness of additional future control measures.
- The analysis of additional available NOx emissions control measures follows the same four statutory factors (costs of compliance, energy and non-air environmental impacts, pollution control equipment in use at the source, and remaining useful life of the source) that are used in the SO_2 four-factor analysis, in addition to the visibility impacts analysis.

With respect to the first bullet, Unit 2 is currently operating at an annual NOx emissions performance level of 0.13 lb/MMBtu. Unit 1 is scheduled to install the same LNC3+ NOx control technology in the first half of 2020 and will therefore have equivalent NOx performance. Using the same methodology as in the

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[4] Comparing the two SO_2 performance levels and applying the 87% annual capacity factor equals an emissions reduction of 1,054 tpy at each unit. (0.15 lb/MMBtu BART limit 30-day rolling average - 0.104 lb/MMBtu expected level 365-day rolling average) x (6,015 or 6,022 MMBtu/hr rated capacities for Unit 1 and 2) x (87% annual capacity factor), converted to tpy basis.

SO_2 four-factor report for full-load operation, the corresponding annualized baseline NOx emissions level is 782 lb/hr for each unit.[5]

A thorough evaluation of potentially available control measures was completed in the updated BART analysis that resulted in two technologies, selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR), that were examined against the same four statutory factors as in the SO_2 report. Significant technical feasibility concerns were noted in the BART report of implementing either of these controls at Coal Creek Station, but both controls were conservatively carried forward into the more detailed, cost of compliance evaluation.

The costs of compliance for these two measures were determined in the BART report by third-party engineering firms. The cost effectiveness of either measure is summarized in the following table excerpted from the updated BART report and is compared to the same cost effectiveness threshold of $4,630/ton as in the SO_2 four-factor report. The cost of either NOx control measure is significantly greater than this threshold.

NO_X Emissions Control	Installed Capital Cost ($)	Annualized Capital Cost ($/yr)	Annual Operating Costs ($/yr)	Total Annualized Costs ($/yr)	Annual NOx Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
SNCR	$12.8 million	$1.1 million	$4.4 million	$5.4 million	692	7,818
SCR	$180 million	$12.1 million	$3.4 million	$15.4 million	1,153	13,391

Additionally, the BART report describes other environmental impacts and implementation issues if SCR or SNCR were to be applied at Coal Creek Station, leading to the conclusion that these SNCR or SCR emissions control measures are not reasonably supported at Units 1 or 2.

In consultation with the NDDEQ for RHR2, GRE proposes a federally enforceable NOx emissions rate limit of 782 lb/hr as an annualized average (365-boiler-operating-day rolling average) limit for each unit, with plant averaging between the two units. This is consistent with the updated NOx BART report that establishes 0.13 lb/MMBtu as the baseline. GRE proposes to implement operational practices summarized in Section 2.1 of the updated BART report, specifically DryFining^{TM} and LNC3+ technologies, in order to comply with the proposed NOx mass emissions limit. The NOx limit shall be effective after both approval of a federally enforceable PTC issued by the NDDEQ and startup of LNC3+ technology at Unit 1.

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[5] 782 lb/hr = 0.13 lb/MMBtu x 6015 or 6022 MMBtu/hr rated capacities for Unit 1 and 2 listed in the Title V operating permit.

Please contact me at 763-445-5212 if you have any questions regarding the SO_2 four-factor analysis or wish to discuss any of the above.

Sincerely,

GREAT RIVER ENERGY

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services

c: David Stroh, NDDEQ
John Bauer, Great River Energy

Attachment

Coal Creek Station Units 1 and 2

Regional Haze Four-Factor Analysis for SO_2 Emissions Control

Prepared for
Great River Energy

GREAT
RIVER
ENERGY®

December 2019

Coal Creek Station Units 1 and 2

Regional Haze Four-Factor Analysis for SO_2 Emissions Control

Prepared for
Great River Energy

December 2019

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Coal Creek Station Units 1 and 2 Regional Haze Four-Factor Analysis for SO_2 Emissions Control

December 2019

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1 Introduction

The Regional Haze Rule (RHR),[1] published on July 15, 2005 by the U.S. Environmental Protection Agency (EPA), defines regional haze as “visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources.” The RHR requires state regulatory agencies to submit a series of state implementation plans (SIPs) in ten-year increments to protect visibility in certain national parks and wilderness areas, known as mandatory federal Class I areas. The original state SIPs were due on December 17, 2007 and included milestones for establishing reasonable progress towards the visibility improvement goals, with the ultimate goal to achieve natural background visibility by 2064. The original SIP was informed by best available retrofit technology (BART) analyses that were completed on all subject-to-BART sources. The second RHR planning period requires development and submittal of updated state SIPs by July 31, 2021.

On May 2, 2018, the North Dakota Department of Environmental Quality (NDDEQ), formerly known as the North Dakota Department of Health, requested that Great River Energy (GRE) complete a “four factors” analysis (herein termed a four-factor analysis), for Coal Creek Station (CCS) Units 1 and 2 as part of the state’s regional haze reasonable progress.[2] The analysis considers the following four statutory factors:

1. The cost of compliance;
2. The time necessary to achieve compliance;
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements.

The NDDEQ’s May 2018 letter to GRE specified that the “… analysis should be prepared using the draft EPA guidance,” referring to a draft EPA regional haze SIP guidance document issued in July 2016.[3] Since

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[1] The EPA also refers to this regulation as the Clean Air Visibility Rule. The regional haze program requirements are promulgated at 40 CFR 51.308. The SIP requirements for this implementation period are specified in §51.308(f).

[2] May 2, 2018 letter from Terry O’Clair of NDDEQ to Mary Jo Roth of GRE. Pursuant to a June 1, 2018 teleconference between GRE and NDDEQ staff, the NDDEQ confirmed that the four-factor analysis is to be completed only for the two electricity generating units, Unit 1 and Unit 2, which together constitute the vast majority of the actual SO_2 and NOx emissions at Coal Creek Station. Other emissions units at Coal Creek Station are not subject to the four-factor analysis.

[3] US EPA, “Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,” July 2016, EPA-457/P-16-001.

then, EPA has issued final regional haze SIP guidance[4] on August 20, 2019 (2019 RH SIP Guidance) that replaces the 2016 draft guidance. Pursuant to verbal communications with NDDEQ, the four-factor analysis is conducted in accordance with the four statutory factors described in the 2019 RH SIP Guidance.

This report describes the background and analysis for conducting a four-factor analysis for sulfur dioxide (SO_2) as applied to the review of emissions controls at GRE CCS.[5] Coal Creek Station consists of two coal-fired electric generating units. Both boilers are tangentially-fired boilers manufactured by Combustion Engineering (CE, now a part of General Electric, or GE), and each unit produces about 605 megawatts (MW) of power on a gross basis. Coal Creek Station is a mine-mouth facility located near Underwood, North Dakota and burns lignite coal from the co-located Falkirk Mine.

For informational purposes, actual SO_2 emissions in the last decade from GRE's electric generating units (EGUs) located in North Dakota – Coal Creek Station, Stanton Station, and Spiritwood Station – have decreased from nearly 31,000 tons in 2009 to less than 6,900 tons in 2018, representing a 78 percent reduction in SO_2 emissions. The aggregated actual annual SO_2 emissions for the last 10 calendar years from GRE's North Dakota EGUs are illustrated in Figure 1-1. During this period:

- GRE commenced operation of its combined heat and power plant, Spiritwood Station, located on the east side of North Dakota. Given its best available emission controls (BACT), Spiritwood Station does not cause or contribute to regional haze at Class 1 areas based on a screening "Q/D" determination made by the North Dakota Department of Environmental Quality (NDDEQ).[6]

- GRE has permanently ceased operations of its 180 MW coal-fired power plant located just outside of Stanton (Stanton Station). Stanton Station's retirement results in an SO_2 actual emissions reduction of approximately 2,500 tons annually.

- GRE implemented DryFining™ and flue gas reheat technology at CCS, as described in more detail below, which are novel multi-pollutant emission controls that do not exist anywhere else in the world.

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[4] US EPA, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," August 20, 2019, EPA-457/B-19-003.

[5] As described in the cover letter, the regional haze four-factor analysis for NOx emissions was provided in separate correspondence and is effectively the updated BART report dated September 12, 2019.

[6] Information on Spiritwood Station's screening analysis provided by NDDEQ staff during teleconference between GRE and NDDEQ staff on June 1, 2018.

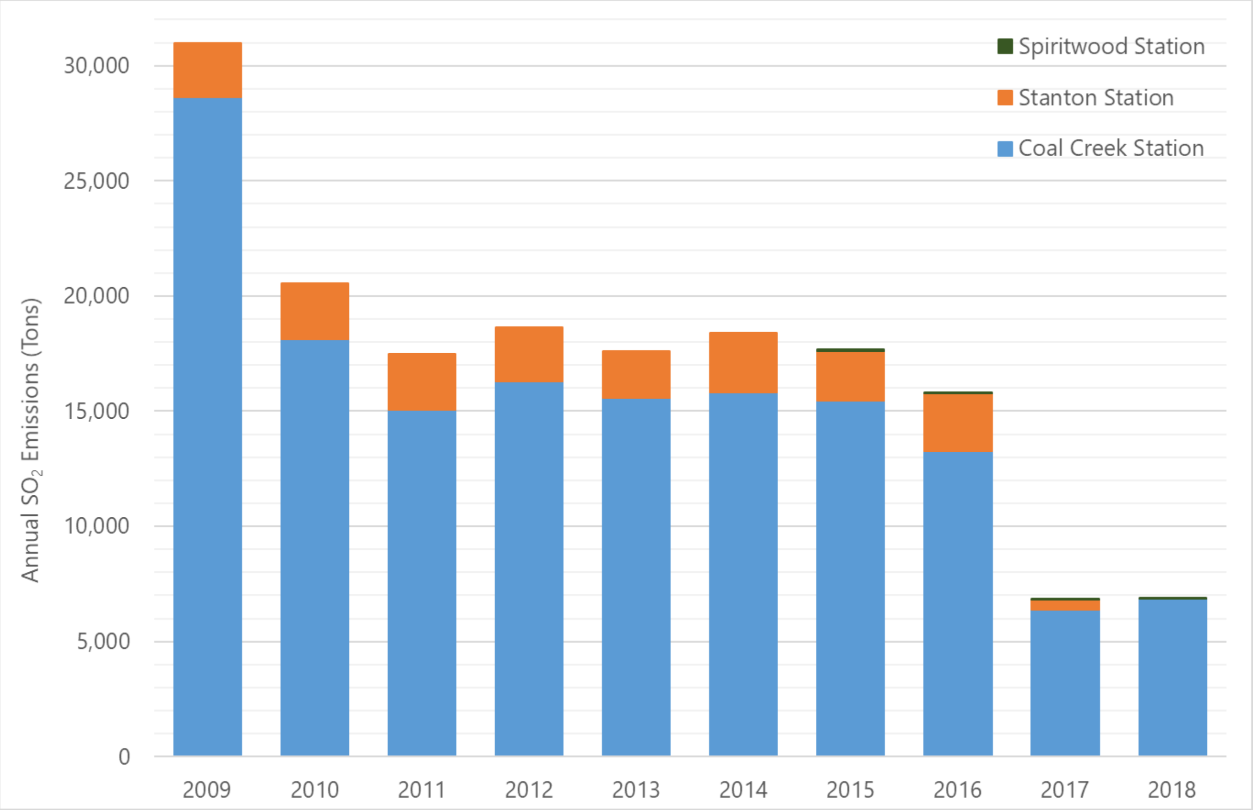

Figure 1-1: Annual SO_2 Emissions from GRE Electric Generating Units in North Dakota

2 Existing Operations and SO_2 Emissions Performance

In 2007, GRE submitted its BART analysis that evaluated SO_2 control strategies, in addition to particulate matter (PM), and oxides of nitrogen (NOx).[7] For SO_2, this BART analysis determined that EPA's presumptive emissions level of 0.15 pounds per million British thermal units (lb/MMBtu), as a 30-day rolling average, appropriately met BART requirements. GRE proceeded with installation and operation of DryFining™ in conjunction with additional work on scrubber modifications and conversion to a "wet stack" design in order to meet the presumptive emissions level.[8,9]

DryFining™ technology was installed and became operational on January 1, 2010 as further described in Section 2.1. However, as GRE was making preparations to convert its existing stacks to a wet stack design pursuant to Electric Power Research Institute (EPRI) guidance currently available at that time (1996 EPRI Guide),[10] EPRI issued new guidance (2012 EPRI Guide) based on additional day-to-day operational observations and information gathered from wet stacks.[11] Specifically, EPRI lowered the allowable exit velocity for a wet stack, which caused the GRE design stack velocity to be higher than the new specifications. Thus, GRE's wet stack conversion project was discontinued. See Section 2.2 for additional details.

Subsequently, in 2017, GRE designed and implemented a novel stack flue gas reheat system, which increases the exhaust temperature in order to allow each unit to operate with a dry stack and with improved capture of the flue gas to the existing wet gas scrubber (i.e., reduced use of the scrubber bypass). See Section 2.3 for a description of this system.

GRE currently operates the DryFining™ system, the existing four-module wet flue gas desulfurization (FGD) scrubbers, and the newly installed novel reheat system in order to comply with the SO_2 presumptive BART limit, which became effective May 2017. Together, the DryFining™ technology and the novel reheat system are a unique emissions control design, requiring a site-specific evaluation for consideration of

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[7] GRE, "Coal Creek Station Units 1 and 2 Best Available Retrofit Technology Analysis," revised December 12, 2007.

[8] DryFining™ is referred to in Section 5.2.1 of the GRE December 2007 BART Analysis Report as "coal drying." This pre-combustion emissions control project was later implemented and trademarked as DryFining™.

[9] A "wet stack" is designed to exhaust saturated (i.e., 100% relative humidity) flue gas downstream from a wet flue gas desulfurization system without causing problems such as stack liquid discharge, plume downwash and icing, and corrosion/chemical attack. The Unit 1 and 2 stacks were originally designed as "dry stacks," meaning that the inner metallurgy and other physical characteristics of the stacks are not meant to carry a saturated exhaust stream.

[10] EPRI, "Wet Stacks Design Guide," November 1996, EPRI Technical Report No. TR-107099.

[11] EPRI, "Revised Wet Stack Design Guide," December 2012, EPRI Technical Report No. TR-1026742.

further SO_2 emission reductions. In Section 3.3.4, GRE evaluates opportunities to optimize scrubber performence for all operating modes.

2.1 DryFining™ Technology

In collaboration with many project participants, including the Department of Energy (DOE), the Lignite Research Council (LRC), Lehigh University, and EPRI, among others, GRE developed, tested, and commercialized the DryFining™ technology. DryFining™ is a multi-pollutant control technology, and Coal Creek Station represents the first full-scale, commercial installation of this technology. In short, this technology reduces coal moisture to increase the heat content of Fort Union lignite, which has the highest moisture content of any coal in the US. The DryFining™ process is also designed to segregate dense material (pyritic sulfur) from the coal prior to combustion to support SO_2 reductions.

DryFining™ was fully operational on January 1, 2010 and has since demonstrated a heat input reduction of approximately 2 to 3 percent for the same level of output. This heat input reduction correspondingly decreased the amount of flue gas created by the combustion process, which in turn has allowed for an additional proportion of gas to be routed to the wet scrubber instead of bypassing the scrubber. The corresponding SO_2 emissions rate on a lb/MMBtu decreased upon operation of DryFining™. For illustrative purposes, Figure 2-1 summarizes the calendar-year SO_2 emissions on a lb/MMBtu basis prior to, and after implementation of, DryFining™ at Unit 1. Unit 2 has a similar SO_2 emissions reduction trend.

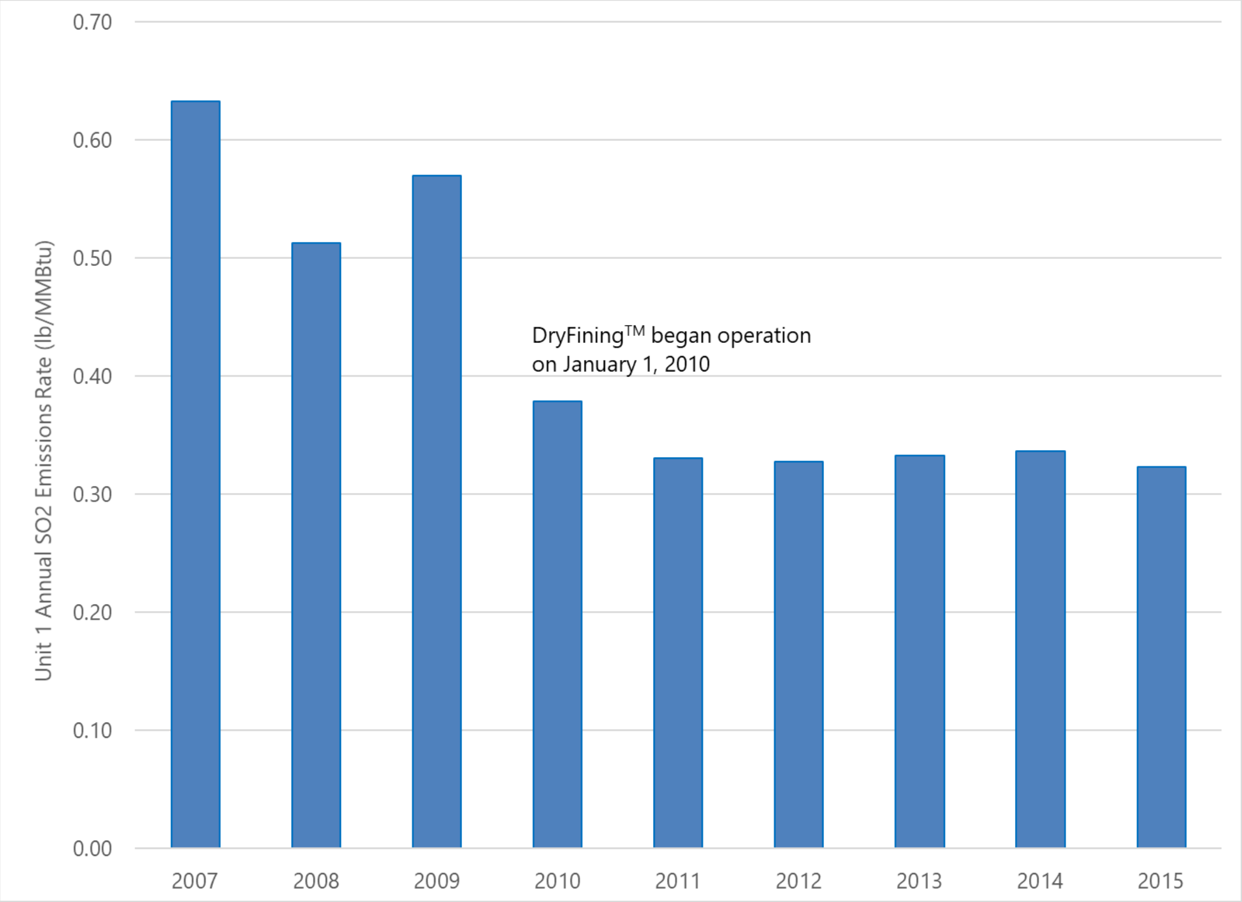

Figure 2-1: Unit 1 Annual SO_2 Emissions Prior to and After DryFining™

2.2 Wet Stack Conversion Efforts

Consistent with its 2007 SO_2 BART assessment and report, GRE also began implementation of its wet stack conversion project which, in conjunction with DryFining™, was intended to improve the amount of exhaust gas to the wet scrubber. The wet stack conversion project at both stacks was planned to occur over 3-year outage increments and would have been completed by 2017. However, during conversion to wet stack as mentioned, EPRI revised its wet stack guide, which caused the planned design velocities for Units 1 and 2 stacks to be higher than the new specification, potentially resulting in stack liquid discharge, also known as stack rainout. This section describes the history of GRE's wet stack conversion efforts as related to EPRI's design guide.

In 1996, EPRI issued a design guide for wet stacks.[12] The 1996 EPRI Guide was prepared in order to address problems that were being caused by the presence of liquid water in electric utility chimneys

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[12] EPRI, "Wet Stacks Design Guide," November 1996, EPRI Technical Report No. TR-107099.

downstream of wet flue gas desulfurization systems. The liquid water originates from water droplets passing through wet scrubber mist eliminator systems and from water condensation in the chimney. Most of the liquid water accumulates on the chimney walls and can be captured by water collection systems in a properly designed "wet stack." In order for the wet stacks to function properly, the chimney design must limit flue gas velocities to less than the recommended values as identified by EPRI's wet stack design guidelines. If stack velocities are higher than the guidelines, water droplets have the potential to form in the gas/liquid interface at the stack wall. These droplets will then become entrained in the exhaust gas and carried out of the stack, which causes liquid discharge conditions. Additionally, the water droplets carried out the chimneys create an acidic precipitation and deposition of liquid droplets from the stack plume onto the surrounding area. This condition is generally called "stack rainout." Winter operations at CCS further complicate the issue due to downwash at the chimney exit and the potential for ice buildup.

Based on the 1996 EPRI Guide, GRE commissioned three technical studies to evaluate the potential for mitigating these adverse impacts:

1. In 2004, the CCS wet stack design included a dual liner with brick liner in the lower portion of the stack and alloy liner in the top portion of the stack. The velocities in the brick liner were expected to exceed the EPRI recommendation of 55 feet per second (fps) for approximately 70 lineal feet of the stack. The alloy velocities were limited to the EPRI recommendation of 70 fps.
2. In 2005, URS Corporation performed computational flow dynamic modeling of the CCS stacks to address flue gas downwash and icing potentials at the stack exit.
3. In 2006, Alden Research Laboratory, Inc. constructed a scale model of the CCS chimneys to evaluate wet stack operation and concluded that the velocities in the brick liner would be consistent with the 1996 EPRI Guide with modifications made to the liner.

Based on these three studies, GRE began to implement the wet stack conversion changes.

During the course of making these stack improvements, industry began to report that stack rainout events were occurring while operating in accordance with the 1996 EPRI Guide. In response to these industry observations, EPRI revised its wet stack design guide (2012 EPRI Guide).[13] The new maximum gas velocity in the 2012 EPRI Guide was lowered to be approximately 45 fps for brick liners and approximately 55 fps for alloy liners.

At full load, CCS stack velocities average 65 to 70 fps in both units based on 40 CFR Part 75 stack monitoring, which has been verified by independent stack testing firms. Although conforming with the 1996 EPRI Guide, both CCS Unit 1 and 2 greatly exceeded the 2012 EPRI recommended maximum gas flow velocities for both the lower brick portion and upper alloy portion of the stacks. Calculated inner diameters needed to avoid stack rainout is 32 feet for the brick portion and 30 feet for the alloy portion of

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[13] EPRI, "Revised Wet Stack Design Guide," December 2012, EPRI Technical Report No. TR-1026742. EPRI notes that, "A limited number of units, although designed within the recommendation of the original Wet Stack Design Guide, experienced "stack liquid discharge" (SLD), or rainout, from the start. It was found that most of these units had been designed for the higher end of the recommended liner-gas velocity range…"

the stacks. The concrete shell of both Unit 1 and 2 stacks has exit inner diameters of 29 feet, making it impossible to expand liners inside the shell to a diameter large enough to achieve velocities consistent with the 2012 EPRI Guide. In summary, the current design of the stacks prevents their conversion to wet stacks, so a complete replacement of the two stacks would be necessary if the stack gas temperature were to be at saturated conditions.[14]

To confirm the 2012 EPRI values for maximum gas velocities, GRE conducted a test in 2013 to evaluate the impacts of closing the bypass damper as much as physically possible in order to route the boiler flue gas through the wet scrubbing systems. Only a portion of the stack liner upgrade had been completed at the time of the test. During the tests GRE observed the following conditions:

- Stack liquid discharge and rainout, confirming that 1996 EPRI Guide values were not protective.
- Scrubbing water break-through onto the mist eliminators at a lower flue gas velocity than predicted due to improper design.
- Actual stack velocity data that are higher than the predicted design.

In 2014, an additional test was completed in order to reflect a state of maximizing the flue gas to the wet scrubber. This test did not experience stack liquid discharge and rainout. However, it was determined that the scrubber bypass leakage was approximately 6 percent during the test. The plant was unable to completely close/blind the bypass, so some bypass flue gas leaked through to the scrubbed gas, effectively reheating it to maintain a dry stack condition.

Following these tests, GRE replaced the wet scrubber mist eliminators in order to minimize water carryover from the wet scrubbers. Nevertheless, water accumulation on chimney walls due to condensation could not be eliminated when GRE maximized the proportion of flue gas to the wet scrubber. Therefore, a different solution was needed.

The technical conclusions and subsequent testing results described above were driving factors to cease work on the wet stack conversion project, resulting in abandoned costs of approximately $20 million. Instead, GRE designed and implemented a novel flue gas reheat system as described in Section 2.3 so that the stacks could operate in a dry (non-saturated) state to comply with the SO_2 BART limit of 0.15 lb/MMBtu.

2.3 Flue Gas Reheat Technology

To maintain dry stack conditions while increasing the proportion of flue gas to the wet scrubber, GRE designed and installed a novel flue gas reheat system in late spring and early summer of 2017. The design

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[14] Saturation conditions or saturation temperature refers to the stack temperature at which a wet stack occurs, thus creating potential for stack liquid discharge, rainout, and icing, as described in this report. Generally, the minimum saturation temperature value used at the plant is 132°F. However, due to variability in conditions that create a saturated environment (i.e., relative humidity) as well as the significant consequences of a wet stack operation at CCS, GRE attempts to apply an operating safety margin above the minimum saturated temperature target at the stack (referred to as dry stack operating temperature) such that the gas temperature at the absorber outlets is sufficiently warm.

of the reheat system is to pull ambient air from within the boiler house building, which contains residual heat from all plant processes. The reheat inlet temperature typically runs a steady state of about 80 degrees Fahrenheit (°F) throughout the year. This reheat air is ducted across the outer surface of the economizer ductwork by new fans. The economizer area increases the reheat air temperature. From the reheat fan discharge, the ductwork then passes between the two precipitators gaining more heat before being routed to the scrubber building. Once in the scrubber building, this reheat air is injected into the flue stream immediately downstream of the absorber outlet. (See Figure 2-4.)

For illustrative purposes, Figure 2-2 provides a basic profile view of the flue gas reheat ductwork and corresponding tie-ins in the boiler house building and the scrubber building.

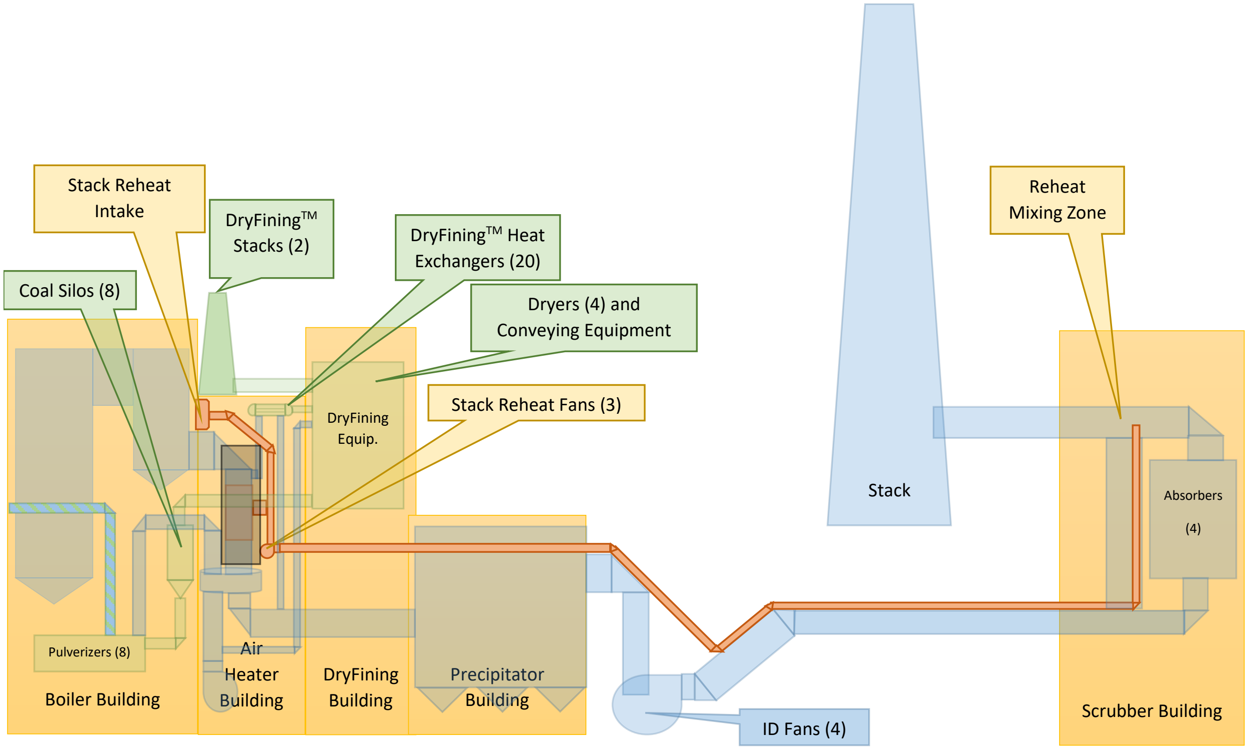

Figure 2-2: Illustration of CCS Flue Gas Reheat System

In 2014, the NDDEQ approved installation of the flue gas reheat systems for Units 1 and 2.[15] In 2017, the flue gas reheat systems began operation. Use of this reheat system in concert with DryFining™ has allowed GRE to maintain compliance with the SO_2 BART limit of 0.15 lb/MMBtu on a 30-day rolling average basis. Figure 2-3 provides an illustration of Unit 1 SO_2 emissions on a lb/MMBtu basis before and

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[15] December 1, 2014 letter from Terry O'Clair of the NDDEQ to Deb Nelson of GRE.

after installation of the flue gas reheat design. Unit 2's SO_2 emissions reduction trend is consistent with Unit 1.

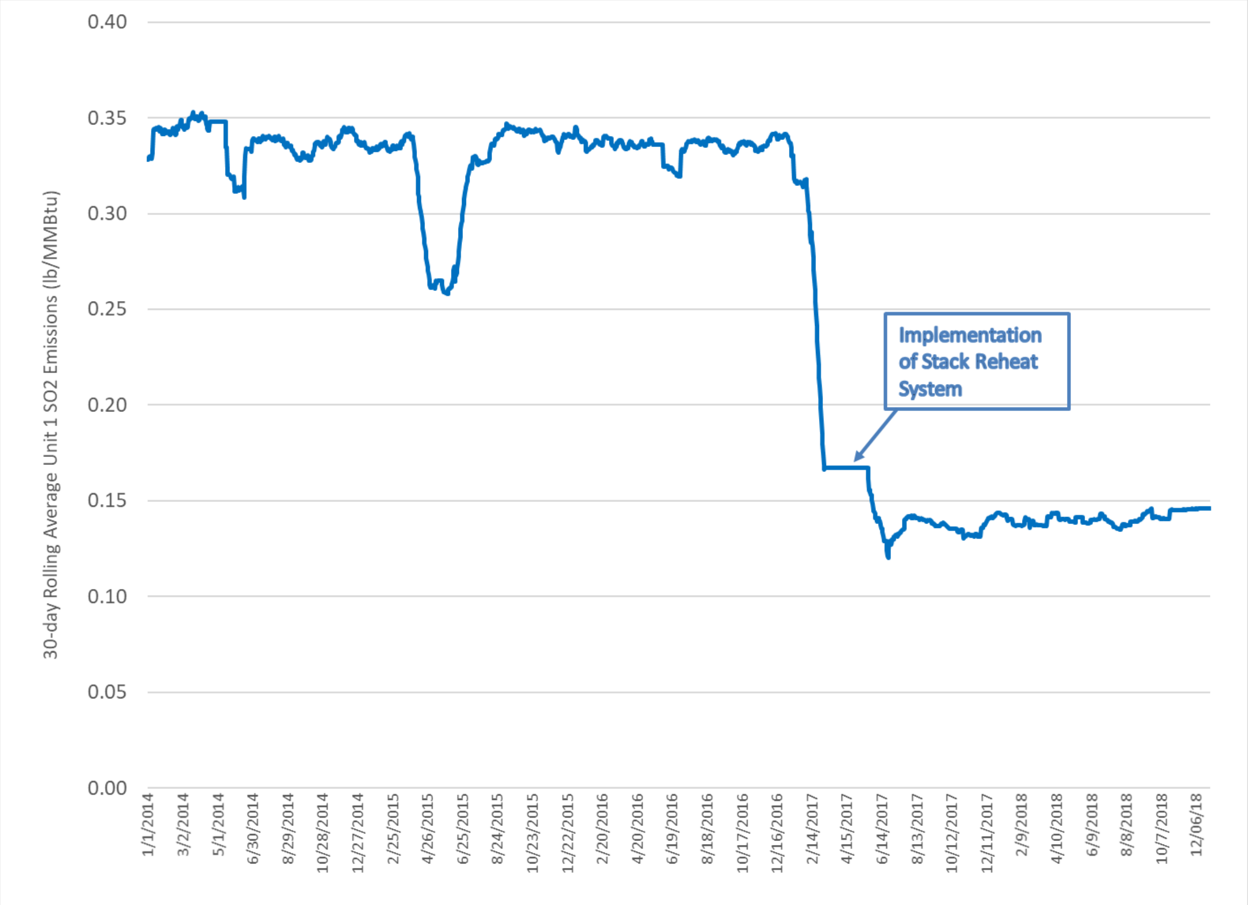

Figure 2-3: Unit 1 SO_2 Emissions Reductions After Implementation of the Flue Gas Reheat System

However, upon completion of the flue gas reheat installation, GRE observed that the reheat system did not meet design criteria. Specifically, the reheated air provided only ~200°F to the reheat mixing zone, rather than the 300°F design. This was due to an error in the modeling in which the surface of the economizer duct was assumed to have minimal temperature losses and would remain at approximately 780°F. The actual temperature loss of the economizer ductwork with the reheat system was found to decrease the economizer side walls to roughly 320°F, significantly less than the 780°F design value. The net effect was lower-temperature reheat mixing air. The resulting stack temperature could not be maintained at 10°F to 12°F above saturation temperature[16] at full unit load, which was the minimum

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[16] See footnote 15, which describes saturation temperature.

design specification. This target flue gas temperature range is generally referred to herein as dry stack operation.

The installed flue gas reheat system only increases stack temperature by approximately 2°F above the saturation temperature at full load. GRE also observed that the volume of dry reheat mixing air decreases the adiabatic saturation temperature by roughly 3°F, thus resulting in a total reheat system benefit of approximately 5°F above saturation at full load. This is a very narrow margin for dry stack operation given the inherent variability and dynamic nature of functional and meteorological parameters for all operating conditions.

During non-cold weather and at full unit load with all coal dryers in operation, the stack reheat system is capable of maintaining dry stack operation such that the proportion of boiler flue gas to the wet scrubber may be maximized. However, by increasing flue gas volume to the scrubber, less of un-scrubbed hotter gas is bypassed, thus consuming the margin in the system needed to maintain a dry stack. As a result, in the following circumstances, the scrubber bypass may need to be opened to a certain degree to maintain dry stack conditions:

1. At reduced unit load, flue gas temperature cannot be sustained above the saturation point, since the plant is producing less thermal energy for the reheat system. As the available level of heat degrades, the temperature of the reheat air is reduced, increasing the risk that the stack will become wet.
2. During extended cold weather periods, the stack temperature cannot be sustained above the saturation point due to both heat losses throughout the reheat ductwork and denser ambient air to the boilers.[17]

For example, during a recent winter test case, GRE staff confirmed that at mid-load (~350 MW) operation, the heat absorbed by the equipment and duct work dissipated, which significantly degraded the effectiveness of the reheat system. Had the test continued for a prolonged period, plant staff anticipated a wet stack condition. The test ended prior to observing a wet stack condition, but this example demonstrates the need to have the scrubber bypass available to increase stack temperature safely above the saturation level.

In these aforementioned circumstances, the scrubber bypass must be opened slightly to allow hotter, drier gases to increase the gas temperature at the absorber outlets to the stack. Figure 2-4 provides a basic cutaway illustration of the interface between the scrubber bypass dampers and flue gas reheat ductwork at the outlet of the four scrubber (absorber) modules.

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[17] "Cold" is used to describe weather conditions that create the need for additional reheat, requiring more flue gas to bypass the scrubber to maintain dry stack operation. Cold weather is a function of temperature, wind speed, and other weather factors that cause significant cooling of the power plant equipment and flue gases.

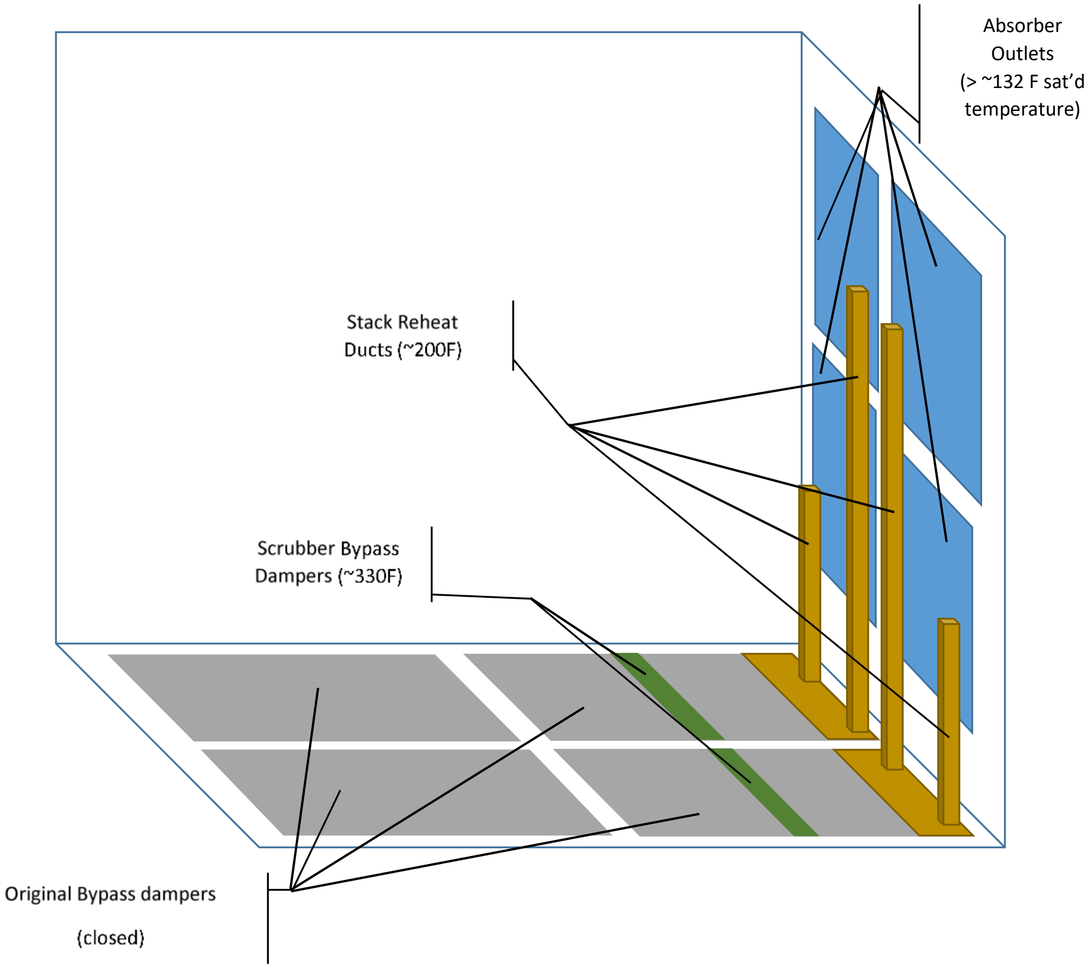

Figure 2-4: Cutaway Illustration of Interface between Scrubber Bypass Dampers and Flue Gas Reheat Ducts at the Absorber Module Outlets

2.4 Recent Reheat Optimization Assessments

Given that the novel flue gas reheat system was commissioned in 2017, GRE has had relatively limited operational experience with it over the full range of operation. Since the commissioning of this system, GRE has conducted two optimization assessments to better understand and identify the limits of its operation, specifically to test the level of SO_2 control performance at high load and non-cold weather conditions and during variable load and colder weather operation. These optimization assessments are detailed in this section as the 2017 and 2019 winter test cases.

2.4.1 2017 Winter Test Case

The 2017 winter test case was performed in February and March 2017 at Unit 2 to better understand the optimal level of SO_2 control performance (i.e., maximum proportion of flue gas routed to the wet scrubber) below 0.15 lb/MMBtu that could be achieved for short periods and at varying loads and weather conditions.

Throughout the duration of this first test, GRE observed several periods when the stack temperature dropped to lower than the saturation point, indicating high potential for wet stack conditions. Figure 2-5 provides the hourly Unit 2 SO_2 emissions data on a lb/MMBtu basis for the period February 4 through March 8 at Unit 2. The hourly Unit 2 load (MW) during this period is shown on the secondary axis. The green-filled areas demonstrate periods when the stack temperature was less than 130°F. At other times, SO_2 emissions increased for short periods due to low unit load or absorber cleaning.

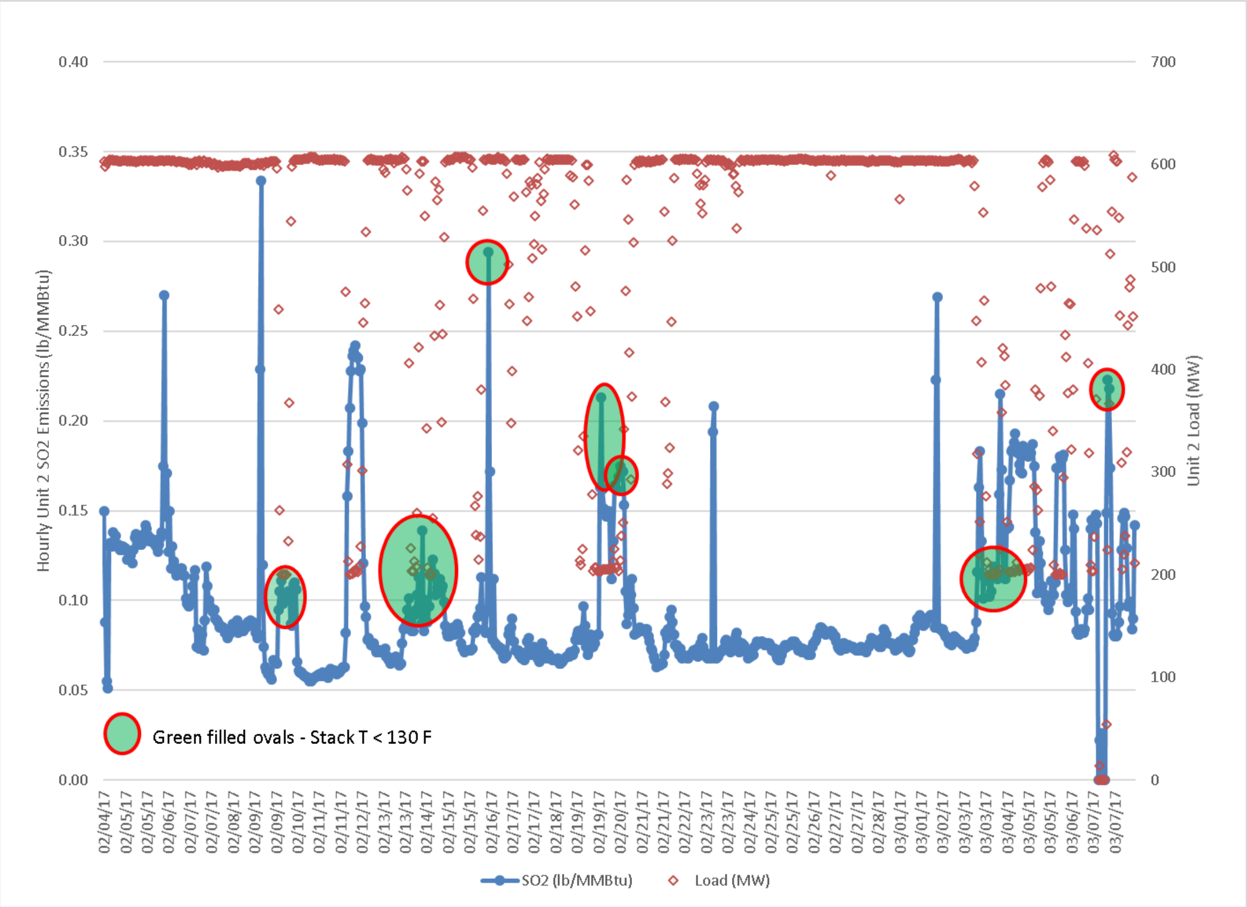

Figure 2-5: Winter 2017 Test Case Results of Unit 2 SO_2 Emissions v. Load

GRE observed a correlation between low load and decreased stack temperature, unless the scrubber bypass damper is opened to allow hot, unsaturated flue gas to mix with the scrubbed gas. Figure 2-6 compares the Unit 2 load with stack temperature. In every instance that the unit load was reduced by at least half of its maximum capacity, the stack temperature rapidly decreased to levels that approached or reached saturation levels. As in the previous figure, the green shaded areas demarcate generally when the stack temperature was less than 130°F.

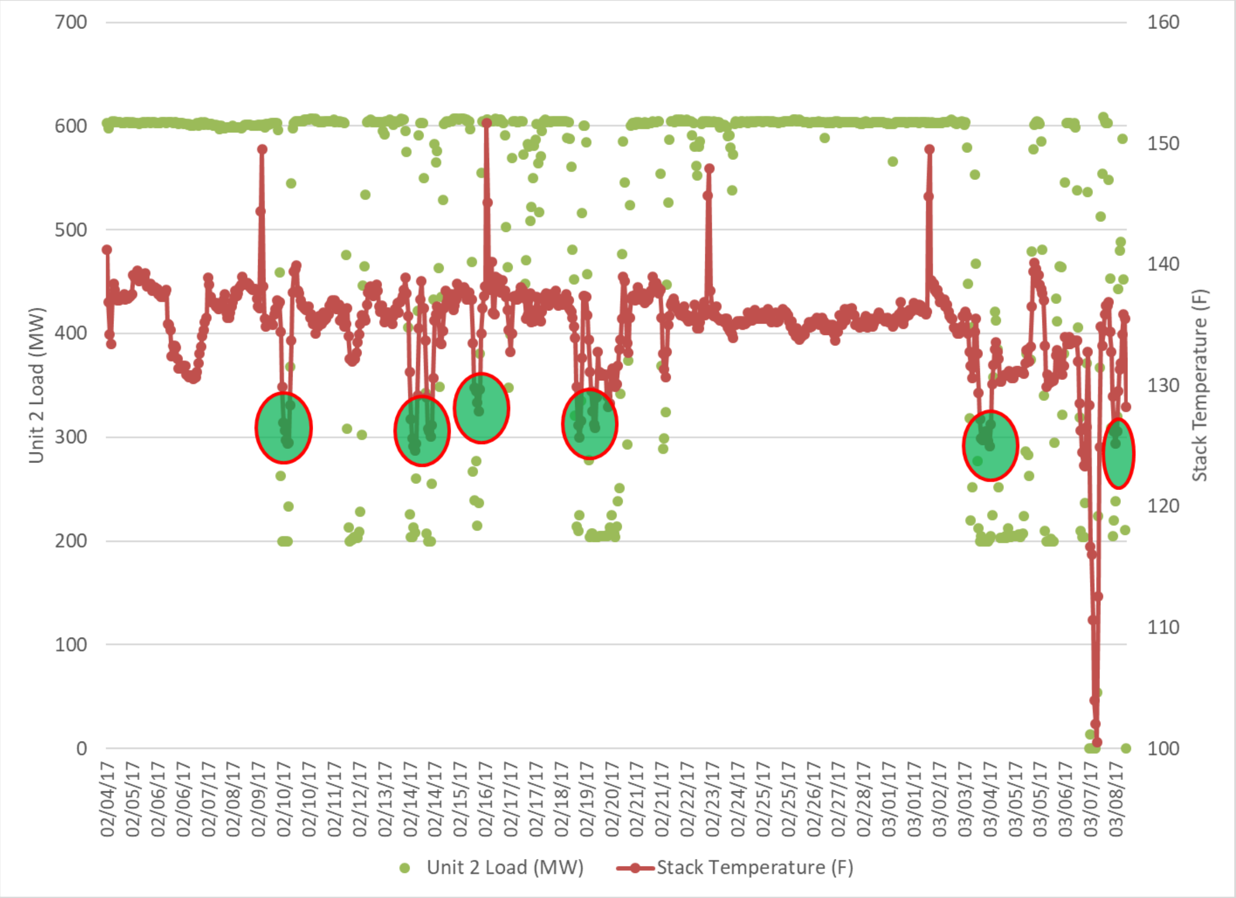

Figure 2-6: Winter 2017 Test Case Results of Unit 2 Load v. Stack Temperature

2.4.2 2019 Winter Test Case

GRE conducted a second assessment during winter to both optimize scrubber performance and to gather additional data on flue gas reheat at high unit load averaging 595 MW while maintaining dry stack. Over approximately a four-week period, GRE attempted to operate Unit 2 at an SO_2 emissions performance level of approximately 0.10 lb/MMBtu while monitoring for wet stack conditions and any other operational issues. The test concluded with a unit outage to inspect the physical characteristics of the emissions control system. Figure 2-7 illustrates the daily average SO_2 emissions performance and the corresponding stack temperature measured during the test with certain days shaded for emphasis as follows:

- The days with green-shaded areas indicate that an absorber cleaning event occurred, so one of the four scrubber modules was out of service for a few hours on those days.
- The two days (March 1 and 2) encircled in the blue shaded area demarcate a significant reduction in daily ambient temperature that occurred during the test. The daily average temperature dropped 22°F between February 28 and March 2, with the single-day decline of 17°F (from 9°F

to -8°F) between March 1 and 2 being the most significant single-day ambient temperature decrease.

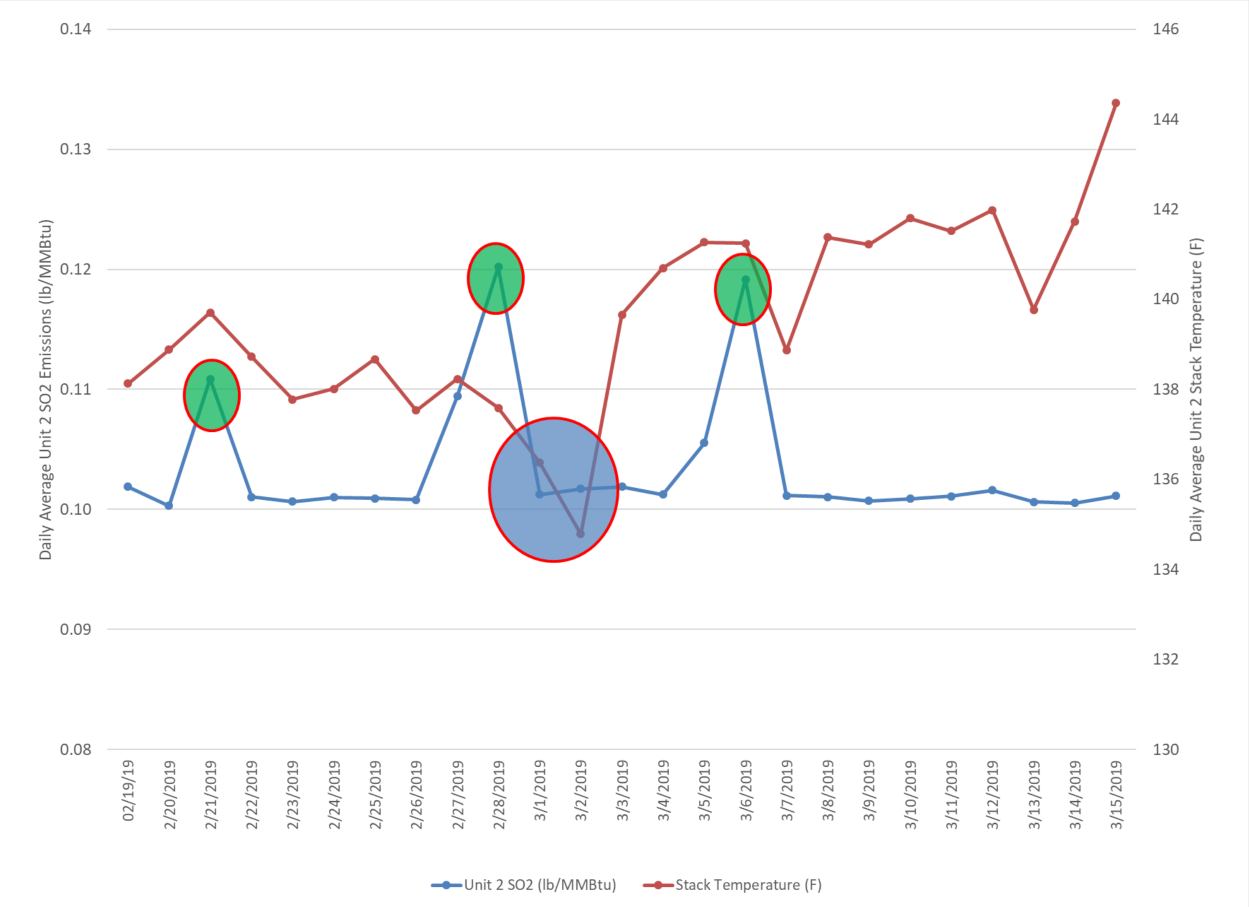

Figure 2-7: Winter 2019 Test Case Results of Daily Unit 2 SO_2 Emissions v. Stack Temperature

GRE made the following key observations during this second test:

1. The lowest stack temperature recorded of 133.8°F on March 2 corresponded to the most significant day-to-day decline in ambient temperature and one of the lowest daily ambient temperature readings during the test of -9°F. However, ambient temperatures observed during the test did not reach the level of extreme cold that CCS experiences each winter, with the lowest hourly temperature of -15°F occurring on March 3. The lowest recorded stack temperature during the test was within 2°F of what is generally considered the saturation temperature of 132°F and is less than the targeted dry stack operating temperature.
2. Broken and cracked duct stiffeners were observed during the outage. An inspection of the broken stiffeners revealed heavy corrosion. Upon more detailed cleaning and inspection, corrosion was present on all stiffeners with the worst conditions on the downstream airflow side. It is suspected

that moisture collected on the front of the stiffeners was blown to the back where it resided, which may explain more corrosion on the back of the stiffeners. Although this area historically has required some patch repairs, the extent of corrosion and damage was unexpected in this outage. Without a detailed history of inspections and corrosion rates, it is difficult to causally relate the increased scrubbing during the four-week test to the evidence of accelerated damage in this area.

3. The stack drains did not have any liquid and there were no stack opacity spikes. An opacity spike can be an indication of excessive moisture in the stack. However, evidence of moisture was observed on new stack view ports in the mid-level area of the stack. Additionally, the entire breeching area was moist, and two of the four stack drains were plugged with solid material or precipitate, indicating moisture was potentially present.

In summary, Unit 2 SO_2 emissions performance averaged ~0.10 lb/MMBtu (0.104 lb/MMBtu) for this short duration test, understanding that longer term effects are difficult to assess from this test, especially given the unfavorable observations made with respect to the integrity of the equipment internals observed during the outage.

2.4.3 Low Load Reheat Augmentation System

These two optimization assessments in 2017 and 2019 indicate that the emissions control systems are capable of improved SO_2 emissions performance levels for short periods of time, while fully understanding that there are potential long-term operational risks. As a measure to potentially mitigate or better manage the risk of a wet stack, especially at low load conditions, GRE is in the process of installing an emergency heat source, termed Low Load Reheat Augmentation System, that is expected to be ready for use as needed in 2020. The design of this system is to temporarily reroute some air from an existing forced draft fan to the existing reheat system. The additional air flow and thermal energy is intended to maintain a stack temperature safely above the saturation temperature.

The system is designed as a contingency to be used during low load operating conditions and when there is potential for wet stack (i.e., increased opacity levels, measured stack temperature approaching possible saturation conditions, presence of liquid in stack drains) in order to maintain a dry stack operating temperature. Accordingly, use of this system only in these infrequent situations to support an incremental level of additional flue gas to the wet scrubber is expected to not appreciably affect annualized SO_2 emissions on a mass basis.

2.5 Updated Baseline SO_2 Emissions Performance Level

As a result of GRE's test efforts in the last two years to better understand the opportunities and implications of improved SO_2 emissions performance, GRE proposes to adjust its annual SO_2 emissions to be reflective of a performance level less than the current BART limit of 0.15 lb/MMBtu. Specifically, through a permitting action to be completed via the NDDEQ's permit to construct regulatory program at NDAC 33.1-15-14, GRE seeks an annual-average mass emissions limit of 626 lb/hr that is equivalent to

0.104 lb/MMBtu at full load, as described in Section 3.8.[18] This performance level is consistent with operation of multiple emissions control measures, namely the wet scrubber system, DryFining™ technology, and flue gas reheat applications at Units 1 and 2.

This baseline emissions update is in alignment with the 2019 RH SIP Guidance with respect to evaluating a projected scenario for baseline emissions. At page 29 in the section entitled "Baseline control scenario for the analysis," excerpted below, EPA considers the projected 2028 emissions scenario as a "reasonable and convenient choice" for the baseline control scenario:

> "Typically, a state will not consider the total air pollution control costs being incurred by a source or the overall visibility conditions that would result after applying a control measure to a source but would rather consider the incremental cost and the change in visibility associated with the measure relative to a baseline control scenario. The projected 2028 (or the current) scenario can be a reasonable and convenient choice for use as the baseline control scenario for measuring the incremental effects of potential reasonable progress control measures on emissions, costs, visibility, and other factors. A state may choose a different emission control scenario as the analytical baseline scenario. Generally, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions during a representative historical period. However, there may be circumstances under which it is reasonable to project that 2028 operations will differ significantly from historical emissions. Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes may be another. A state considering using assumptions about future operating parameters that are significantly different than historical operating parameters should consult with its EPA Regional office."

Section 3.8 provides additional detail on the proposed mass emissions rate limit for SO_2 at Units 1 and 2 following the four-factor analysis of additional emissions control measures.

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[18] 626 lb/hr = 0.104 lb/MMBtu x 6,015 or 6,022 MMBtu/hr rated capacities for Unit 1 and 2 listed in the Title V operating permit.

3 Sulfur Dioxide (SO_2) Four-Factor Analysis

GRE has completed a four-factor analysis of additional SO_2 emissions control technologies and optimizations at CCS Units 1 and 2 above and beyond those described in Section 2.

Section 3.1 summarizes the four-factor analysis approach with respect to the regional haze program detailed in the 2019 RH SIP Guidance. Sections 3.2 and 3.3 identify and describe various SO_2 control measures. Sections 3.4 through 3.7 evaluate the four statutory factors to CCS Units 1 and 2. Section 3.8 proposes an SO_2 emissions limit and control measures.

3.1 Four-Factor Analysis Approach

Consistent with EPA's guidance and NDDEQ direction, GRE has completed a four-factor analysis as summarized in Sections 3.1.1 to 3.1.5.

3.1.1 Identify all Emission Control Options

Prior to completing a four-factor analysis of each emissions control technology, all commercially available and technically feasible emission control options for CCS Units 1 and 2 must first be identified. Potentially available emission control options include both add-on control equipment and process improvement applications. All control options identified as available and technically feasible are then evaluated against the "four factors."

In order to be considered available and technically feasible, an emissions control must have been previously installed and operated successfully on a similar source under similar physical and operating conditions. Novel controls that have not been demonstrated on full-scale, coal-fired utilities are not considered as part of this analysis. Instead, this evaluation focuses on commercially demonstrated control options.

The control effectiveness of currently available retrofit technologies ranges from 40% to 98+%. For purposes of this analysis, GRE evaluated only those technologies that have the potential to achieve an overall SO_2 reduction greater than the performance of the existing systems, including optimizations.

Sulfur emissions from coal combustion consist primarily of SO_2, with a much lower quantity of SO_3 and gaseous sulfates. These compounds form in the coal as organic and pyritic sulfur. Either form is oxidized during the combustion process. For permitting and design purposes, it is assumed that 100% of the fuel sulfur will convert to SO_2 during the combustion process, and that 1% of the uncontrolled SO_2 will oxidize to SO_3. Theoretically, several techniques can be used to reduce SO_2 emissions from coal combustion sources and they are grouped into pre-combustion controls and post combustion controls, which further subdivide into wet and dry technologies, as summarized in Table 3-1.

Table 3-1: Additional SO_2 Control Measures with Potential Application at CCS Units 1 and 2

Control Technology
Pre-Combustion Controls (operational improvements) • DryFining™ Optimization
Post-Combustion SO_2 Control Technologies
• Dry Flue Gas Desulfurization - Add Dry Sorbent Injection - Add Spray Dry Absorption • Wet Flue Gas Desulfurization - Replace Wet Lime/Limestone Scrubber - Increase Proportion of Flue Gas to Existing Wet Scrubber ○ Install Replacement Wet Stacks ○ Install Natural Gas Fired Reheat System

An evaluation of additional pre-combustion and post-combustion SO_2 emissions control measures to CCS Units 1 and 2 are described in Sections 3.2 and 3.3, respectively.

3.1.2 Factor #1 – Cost of Compliance

Factor #1 considers and estimates, as needed, the capital and annual operating and maintenance (O&M) costs of the control measure. As directed by the 2019 RH SIP Guidance at page 21, costs of emissions controls follow the accounting principles and generic factors from the EPA Air Pollution Control Cost Manual (EPA Control Cost Manual)[19] unless more refined site-specific estimates are available. Under this step, the annualized cost of installation and operation on a dollars per ton of pollutant removed ($/ton) of the control measure, referred to as "average cost effectiveness," is compared to a cost effectiveness threshold that is estimated by the NDDEQ.

Generally, if the average cost effectiveness is greater than the threshold, the cost is considered to not be reasonable, pending an evaluation of other factors. Conversely, if the average cost effectiveness is less than the threshold, then the cost is considered reasonable for purposes of Factor #1, pending an evaluation of whether the absolute cost of control (i.e., costs in absolute dollars, not normalized to $/ton) is unreasonable. This situation is particularly applicable to a source with existing emissions controls with

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[19] US EPA, "EPA Air Pollution Control Cost Manual, Sixth Edition," January 2002, EPA/452/B-02-001. The EPA has updated certain sections and chapters of the manual since January 2002. These individual sections and chapters may be accessed at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution as of the date of this report.

an intermediate or high degree of effectiveness, as is the case at CCS Units 1 and 2 due to its existing SO_2 emissions controls.

The cost of an emissions control measure is derived using capital and annual operation and maintenance (O&M) costs. Capital costs generally refer to the money required to design and build the system. This includes direct costs, such as equipment purchases, and installation costs. Indirect costs, such as engineering and construction field expenses and lost revenue due to additional unit downtime in order to install the additional control measure(s), are considered as part of the capital calculation. Annual O&M costs include labor, supplies, utilities, etc., as used to determine the annualized cost in the numerator of the cost effectiveness value. The denominator of the cost effectiveness value (tons of pollutant removed) is derived as the difference in: 1) projected emissions using the current emissions control measures (baseline emissions), as described in Section 2.5, in tons per year (tpy), and 2) expected annual emissions performance through installation of the additional control measure (controlled emissions), also in tpy.

For purposes of calculating cost effectiveness, GRE uses the updated baseline emissions value of 626 lb/hr, as described in Section 2.5, in conjunction with projected utilization (also called annual capacity factor or ACF) of the unit to determine an annual tpy value.[20] Over the past 10 years, CCS averages 87% plant utilization, as shown in Table 3-2. GRE considers this value representative of projected operations for purposes of determining annualized emissions. The product of the 626 lb/hr value and 87 percent ACF converted to a tpy basis is 2,385 tpy SO_2 for each unit as the baseline annual emissions rate to be used for purposes of determining annual emissions reductions for a given additional control measure.

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[20] Annual capacity factor is defined by EPA (40 CFR 60 Subpart Dc) as "… the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity…" Because the proposed mass SO_2 emissions limit is based on the maximum rated heat input capacity to the boiler, the annual capacity factor is a reasonable representation to determine projected annual heat input duty for purposes of this analysis. Unit outages are considered in the annual capacity factor calculation.

Table 3-2: Annual Average Capacity Factors at CCS Unit 1 and Unit 2

Year	Annual Capacity Factor	
	Unit 1	Unit 2
2009	94.2%	92.7%
2010	93.8%	79.6%
2011	81.6%	89.0%
2012	92.4%	90.9%
2013	92.4%	83.3%
2014	87.8%	88.2%
2015	89.3%	87.3%
2016	86.3%	72.9%
2017	70.8%	85.0%
2018	91.6%	90.5%
10 yr Average	**88%**	**86%**
Plant Average	**87%**	

The calculated cost effectiveness value for each control measure is compared to a cost effectiveness threshold established by the NDDEQ. The NDDEQ's original BART cost thresholds were based on the "high cost" value of $3,000 per ton listed in the June 1999 WRAP Annex to Grand Canyon Visibility Transport Commission (GCVTC) Report.[21] This 1999 value is scaled to today's dollars using the Chemical Engineering Plant Cost Index (CEPCI).[22] The CEPCI is an industrial plant index that is considered more representative for purposes of this analysis than general cost indices such as the Consumer Price Index (CPI). The average cost effectiveness threshold in current dollars is calculated to be $4,630 per ton.[23]

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[21] Cited by EPA in the "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations" proposed rule; 69 FR 25198; May 5, 2004.

[22] More information on CEPCI may be found at this link: https://www.chemengonline.com/pci-home. The CEPCI is accessible by subscription through "Chemical Engineering" magazine. The CEPCI scaling factors for this analysis compare 1999 values to December 2018 values.

[23] The NDDEQ also calculated an incremental cost effectiveness (cost effectiveness between two control measures) threshold in addition to the average cost effectiveness threshold for the BART evaluations. Pursuant to a June 1, 2018 teleconference between GRE and NDDEQ staff, the NDDEQ stated that the average cost effectiveness and absolute costs of an additional control measure will be considered, but incremental cost effectiveness will not be evaluated for purposes of the screening level analysis.

3.1.3 Factor #2 – Time Necessary for Compliance

Factor #2 is considered by NDDEQ in setting reasonable deadlines for the selected control. This includes the planning, installation and commissioning of the selected control.

For purposes of this analysis and if a given SO_2 control measure requires a unit outage as part of its installation, GRE considers the forecasted outage schedule for Units 1 and 2 in conjunction with the expected timeframe for engineering and equipment procurement following NDDEQ and EPA approval of the given control measure.

3.1.4 Factor #3 – Energy and Non-air Environmental Impacts:

Factor #3 involves consideration of the energy and non-air environmental impacts of each control measure. Non-air quality impacts may include solid or hazardous waste generation, wastewater discharges from a control device, increased water consumption, and land use. The environmental impact analysis is conducted based on consideration of site-specific circumstances.

The energy impact analysis considers whether use of an emissions control technology results in any significant or unusual energy penalties or benefits. Energy use may be evaluated on an energy used per unit of production basis, energy used per ton of pollutant controlled, or total annual energy use.

3.1.5 Factor #4 – Remaining Useful Life of the Source

Factor #4 is the remaining useful life of the source, which is the difference between the date that additional emissions controls will be put in place and the date that the facility permanently ceases operation. Generally, the remaining useful life of the source is assumed to be longer than the useful life of the emissions control measure unless there is an enforceable cease-operation requirement. In the presence of an enforceable end date, the cost calculation can use a shorter period to amortize the capital cost.

For the purpose of this evaluation, the remaining useful life of both Unit 1 and Unit 2 is assumed to be longer than the useful life of the additional emission controls measures. Therefore, the expected useful life of the control measure is used to calculate the emissions reductions, amortized costs, and the resulting cost per ton ($/ton).

3.2 Identification of Pre-Combustion Controls

As introduced in Section 2.1, GRE developed and commercialized a novel multipollutant control technology, described as DryFining™. At issue is the question of whether there is any opportunity to further optimize this pre-combustion technology. In theory, either more high-density segregation could be achieved to remove pyritic sulfur, or more moisture could be removed in order to increase the proportion of flue gas that may be routed to the wet scrubber instead of the scrubber bypass.

For purposes of SO_2 emissions control, DryFining™ is a two-stage process, beginning with an air jig that separates higher density coal, containing some pyritic sulfur, before routing the coal to the next stage.

GRE’s plant engineering staff have reviewed alternative techniques for improving pyritic segregation but have not found anything to impact SO_2 at the stack.

With respect to stage 2 after the air jig, the coal is moved through fluid bed dryers using plant waste heat to reduce its moisture content. This dried coal provides many benefits, including that it improves plant heat rate, which reduces plant energy use and, with respect to SO2, reduces flue gas volume thus allowing more of the flue gas to be scrubbed.

There is a limit to the effectiveness of the coal drying stage without causing negative environmental consequences.[24] Each CCS unit was designed with four dryers, so eight total dryers are installed. The plant can produce enough dried coal to operate at full load with seven dryers in service. Therefore, one dryer can be out of service for maintenance while still maintaining emission rates. In theory, this extra dryer could be used to process (i.e., dry) coal to a lower moisture content; however, in practice, this would be environmentally detrimental.

When the dryers are operating properly, the plant can decrease coal moisture by 10% to 12%. As removal approaches 12%, the plant begins to experience significant operational issues such as auto-ignition of coal in bunkers in addition to difficulties maintaining steam temperature. Specifically, DryFining^{TM} increases the heat content of coal from ~6,300 to ~6,700 Btu/lb. When the coal reaches very high Btu values for the design of Units 1 and 2, the fireball becomes too hot at a lower location in the boiler. The water walls absorb most of the heat and it thus does not reach the upper area of the boiler necessary to maintain steam temperature. To combat this, the burner tilts are changed to raise the fireball higher to get better heat transfer in the upper part of the boiler and to maintain steam temperature to the turbine. Changing the burner tilts in this way will, in and of itself, negatively impact NOx emissions performance.

In summary, after almost a decade of operating DryFining™ technology at Units 1 and 2, GRE has fully optimized its ability to reduce SO_2 as a pre-combustion control measure.

3.3 Identification of Post-Combustion Controls

The flue gas desulfurization (FGD) systems commonly used to control SO_2 emissions can be classified as either dry or wet systems. As implied by the name, dry scrubbers require less water than wet systems but also require higher temperatures to ensure that all moisture has been evaporated before leaving the scrubber. Wet systems are generally capable of achieving higher removal efficiencies than dry systems because it is easier to mix a gas with a liquid than a solid.

FGD systems require the use of an alkali powder of slurry. Lime (or limestone) is the most widely used compound for acid gas absorption. Wet FGD systems may discard all the waste by-product streams or

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[24] DryFining™ is a multipollutant technology that, in part, reduces mercury, SO_2 and NOx emissions. While this evaluation is focused on SO_2, drier coal beyond that currently targeted will negatively impact NOx emissions.

regenerate and reuse them. Wet systems generally require more extensive networks of pumps and piping than dry systems to recirculate, collect and treat the scrubbing liquid.

There are three main FGD systems including wet scrubbing, spray dryer absorption, and dry sorbent injection. CCS Units 1 and 2 currently operate with a wet scrubber.

3.3.1 Dry Sorbent Injection

Dry sorbent injection involves the injection of a lime, limestone or even sodium powder into the exhaust gas stream. The flue gas is then routed through a baghouse or electrostatic precipitators to remove the sorbent and entrained SO_2. The process was developed as a lower cost FGD option because the mixing occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time and gas stream temperature, sorbent injection control efficiency is typically between 50% and 70%. While dry sorbent injection is a technically feasible retrofit option, given that the maximum expected removal efficiency of this technology is approximately 70%, it will not provide improvement over CCS's existing SO_2 emissions control system and is therefore not evaluated further for this analysis.

3.3.2 Spray Dry Absorption

Spray dry absorption is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO_2 is absorbed by the droplets. The absorption of the SO_2 leads to the formation of calcium sulfite ($CaSO_3 \cdot 2H_2O$) and calcium sulfate ($CaSO_4$) within the droplets as illustrated by equations 1 and 2 below.

$$SO_2 + CaO + 1/2\ H_2O \rightarrow CaSO_3 \cdot 1/2\ H_2O \qquad (1)$$

$$CaSO_3 + \tfrac{1}{2}O_2 + 2H_2O \rightarrow CaSO_4 \cdot 2H_2O \qquad (2)$$

The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder that is collected with a fabric filter. Spray dryer absorption control efficiency is typically in the 70% to 90% range. A spray dry scrubber is a technically feasible control option, but it will not provide improvement over the existing removal efficiency and is therefore not evaluated further as part of this analysis.

3.3.3 Wet Lime/Limestone Scrubbing

Wet lime/limestone scrubbing involves scrubbing the exhaust gas stream with a slurry comprised of lime (CaO) or limestone ($CaCO_3$) in suspension. The process takes place in a wet scrubbing tower located downstream of a particulate matter control device. Similar to the chemistry illustrated above for spray dry absorption, the SO_2 in the flue gas reacts with the lime or limestone slurry to form calcium sulfite ($CaSO_3 \cdot 2H_2O$) and calcium sulfate ($CaSO_4$).

There are two basic types of wet scrubber technologies: natural oxidation and forced oxidation. For new installations, forced oxidized scrubbers are capable of achieving 98+% control. Both Coal Creek units have natural oxidation scrubbers. GRE estimates that the existing wet scrubbers control SO_2 to approximately 94% to 95%, based on the proposed permitted mass emissions limit that is calculated from a 0.104 lb SO_2/MMBtu performance level as well as some bypass leakage as provided in the analysis from a third-party engineering firm.[25,26] Theoretically, with a completely closed and sealed flue gas system and a new "wet" stack, the existing scrubber performance would improve only to approximately 96%. This estimate is specific to the scrubber/absorber proper and does not include upstream SO_2 emissions control that results from DryFining™ air jig operations.

As described in GRE's CCS BART report,[27] several wet scrubber modifications were assessed. These included the addition of a fifth scrubber module and expansion of the existing absorber towers to scrub all the flue gas. With the implementation of DryFining™, the flue gas volume was reduced such that the existing scrubber modules could handle 100% of the flue gas, notwithstanding that the current stacks are designed as dry stacks, as detailed in Sections 2.2 through 2.4. Therefore, the fifth absorber module and/or expanded absorber towers are no longer needed. Further, conducting a four-factor evaluation to replace the existing wet scrubber system with a new design for a possible incremental level of improved SO_2 performance (and which would also require one of the two projects described in Section 3.3.4) will inherently result in unreasonable costs on absolute cost and average cost effectiveness bases.

3.3.4 Increase Amount of Flue Gas to Existing Wet Scrubbers

As a potential method to reduce SO_2, a greater proportion of the unit's flue gas could be routed to the existing wet scrubbers if additional control measures are taken. As detailed in Sections 2.2 through 2.4, a relatively minor bypass is currently needed in limited situations to maintain dry stack conditions. If new wet stacks are installed or if a natural gas-fired reheat system is implemented, as considered in Sections 3.3.4.1 and 3.3.4.2, then theoretically there would no longer be a need to bypass the scrubbers. In this scenario, some un-scrubbed flue gas would still leak through the scrubber bypass dampers, which are not designed to be completely sealed and are estimated to add approximately 0.007 lb SO_2/MMBtu to the total SO_2 emissions rate.

In total, based on testing with scrubber bypass closed and accounting for future variability in operations, GRE estimates that the annual emissions from either technology will improve SO_2 performance to a level of 0.08 lb/MMBtu, representing an approximately 20% improvement from the proposed permit level that

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[25] The SO_2 emissions rate is not directly measured in the flue gas to the wet scrubbers. Because DryFining™ serves as a pre-combustion SO_2 control and due to the minor proportion of flue gas that is required to bypass the scrubber to maintain a dry stack, it is incorrect to conclude that the difference in SO_2 at the stack versus the sulfur in the incoming coal is solely a function of wet scrubber performance.

[26] URS Corporation, "GRE Coal Creek Units 1 & 2 Review of Options to Reduce SO_2 Emissions," October 26, 2004. This slide deck was included in the December 2007 GRE CCS BART Report.

[27] GRE, "Coal Creek Station Units 1 and 2 Best Available Retrofit Technology Analysis," revised December 12, 2007.

is based on 0.10 lb/MMBtu. The resulting average annual expected emissions reduction for each unit is 550 tpy, calculated as the difference in the baseline emissions of 2,385 tpy calculated in Section 3.1.2 and the controlled emissions rate of 1,835 tpy, calculated as the product of 6,019 MMBtu/hr (average of the two rated heat input capacities for Units 1 and 2), 0.080 lb SO_2/MMBtu performance, and 87% ACF.

3.3.4.1 Replace Current Stack with Wet Stack

As detailed in Section 2.2, Coal Creek has a unique emission control configuration, coupling a wet scrubber with a dry stack and novel flue gas reheat system. It is not possible to convert the existing stack to a wet stack design. Instead, a new wet stack would need be installed and the current stack would be abandoned for each unit.

A screening-level four-factor analysis is provided for the project to replace the Unit 1 and 2 stacks in their entirety with wet stacks. For this evaluation, Hamon Custodis, Inc. (Custodis) was engaged to provide a budgetary quote for a new wet stack, excluding foundation and tie-ins. Custodis provided an initial high-level concept to effectively replace the two existing stacks with a "rough budget price."[28] GRE has added to this price a high-level and conservatively low set of cost estimates to convert the Custodis cost to an appropriate diameter and to include foundations, duct work, and continuous emissions monitoring systems (CEMS).

3.3.4.2 Natural Gas Reheat System

As detailed in Section 2.3, the novel flue gas reheat system is capable of maintaining a dry stack under most, but not all, operational situations, while maximizing the proportion of flue gas to the wet scrubber. During low load and cold weather operation, the existing reheat system does not provide enough thermal energy to reheat the stack gas to a dry state. There is no significant additional heat in the buildings or equipment that can be scavenged to be used for the current flue gas reheat system; therefore, GRE has considered the additional control measure of a natural gas-fired reheat system. A screening-level four-factor analysis is provided for the project to replace the existing flue gas reheat system with a natural gas-fired reheat system.

In order to maintain dry stack operation, GRE estimates approximately 31.5 MMBtu/hr of additional heat would be required. For reference, the existing reheat system adds approximately 11 MMBtu/hr, which would be abandoned at an estimated $12 million/unit loss. Therefore, the new natural gas reheat system is sized at 31.5 MMBtu/hr per unit. The most logical location for a natural gas fired duct burner is adjacent to the current reheat mixing zone. See Figure 2-2 and Figure 2-4 for illustrations of the current flue gas reheat system.

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[28] April 5, 2019 email from David Durham of Custodis to Loren Loritz of GRE.

Two companies were engaged to provide estimates to support this evaluation. Given that Coal Creek does not currently have a gas supply, WBI Energy (WBI) provided a cost estimate for a new gas line with firm (non-interruptible) gas supply up to Coal Creek's fence line.[29] The cost for installation of the natural gas pipeline is split between Unit 1 and Unit 2, because the same pipeline could be used for both sources. GRE plant staff estimated a connecting gas line from the WBI fence line point to the duct burner locations. Barr Engineering (Barr) was engaged to provide an estimate for the natural gas-fired duct burner system. Its high-level (Class 5) estimate of the system was provided with additional consideration for site-specific installation factors.[30]

3.4 Factor 1 Evaluation – Costs of Compliance

GRE has completed a high-level screening-level cost estimate for the replacement wet stack and natural gas-fired reheat system projects. The capital cost estimates are considered by GRE's plant engineering staff, based on their considerable experience with projects at CCS and their informal conversations with other companies that have completed similar types of projects at power plants, to be conservatively low. A more detailed cost estimate is likely to increase the costs for installing and implementing either of the projects. Importantly, this initial set of cost estimates does not include additional outage time that will very likely be necessary, especially for the replacement wet stack. Cost summary spreadsheets for these two are provided in Appendix A.

The cost effectiveness analysis compares the annualized cost of the technology per ton of pollutant removed and is evaluated on dollar per ton basis using the annual cost (annualized capital cost plus annual operating costs) divided by the annual emissions reduction (tons) achieved by the control device. For purposes of this screening evaluation, a 20-year life (before new and extensive capital is needed to maintain and repair the equipment) at 5.25% interest is assumed in annualizing capital costs.

The resulting cost effectiveness calculations are summarized in Table 3-3.

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[29] March 20, 2019 email from David Dahms of WBI to Richard Garman of GRE.

[30] March 21, 2019 email from Joel Trinkle of Barr to several staff at GRE, forwarding a March 20, 2019 email quote prepared by William Mullinix of Barr.

Table 3-3: SO_2 Control Cost Summary, per Unit Basis

Additional Emissions Control Measure	Installed Capital Cost ($)	Annualized Capital Cost ($/yr)	Annual Operating Costs ($/yr)	Total Annualized Costs ($/yr)	Annual Emissions Reduction (tpy)	Pollution Control Cost Effectiveness ($/ton)
New Wet Stack	$38.8 million	$3.2 million	$0.8 million	$4.0 million	550	7,200
Natural Gas Reheat System	$14.5 million	$1.2 million	$2.2 million	$3.4 million	550	6,200

The cost effectiveness values of both projects are substantially greater than the cost effectiveness threshold of $4,630 derived in Section 3.1.2. Therefore, the costs for either retrofit option to replace the current stack with a wet stack or to implement a natural gas-fired reheat system are not reasonable.

Sections 3.5 through 3.7 provide a screening-level summary of the remaining three factors evaluated for the replacement wet stack and natural gas-fired reheat system, understanding that these projects represent substantial capital investments that are not justified on a cost per ton or absolute cost basis.

3.5 Factor 2 Evaluation – Time Necessary for Compliance

Factor #2 estimates the amount of time needed for full implementation of different control measures, which in this case is the replacement wet stack or the natural gas-fired reheat system. Typically, time for compliance includes the time needed to develop and approve the new emissions limit into the state implementation plan (SIP) by state and federal action, then to implement the project necessary to meet the SIP limit via installation and tie-in of equipment for the emissions control measure.

Either projects would require significant resources and time of at least two to three years to engineer, permit, and install the equipment, whether it be a 675-foot-high, 30-foot-inner-diameter chimney or a 10-mile-long, 6-inch-diameter natural gas pipeline with an integrated duct burner system. Subsequently, the new stacks would need to be tied-in to the existing scrubber building, which will likely require several additional days beyond the standard extended outage duration of approximately seven weeks. Similarly, the duct burner systems would need to be tied-in during a subsequent outage after the equipment is built before it can begin operation.

Assuming that a SIP is approved in 2022, then the next set of extended outages for the two units are scheduled to occur in 2025 and 2026 for potentially installing the required technology.

3.6 Factor 3 Evaluation – Energy and Non-Air Quality Environmental Impacts

The energy and non-air environmental impacts associated with implementation of the two technologies are summarized herein.

For the replacement wet stack, the current stacks would be abandoned, resulting in demolition and disposal of a significant amount of materials with associated use of demolition equipment and portable engines to accommodate these activities. Additionally, it is not clear where the new stacks would be located because the property surrounding this area is already being used. Significant planning and logistical issues will need to be addressed in order to locate and tie in these stacks.

The natural gas-fired reheat system creates additional non-SO_2 pollutant emissions associated with combustion of natural gas onsite. Based on an estimated range of emission factors (0.1 to 0.2 lb/MMBtu) and assuming year-round operation of the burner, potential NOx emissions from each unit range from between 14 and 27 tpy. Combustion emissions from the duct burners will require a permit to construct from NDDEQ.

3.7 Factor 4 Evaluation – Remaining Useful Life

Because CCS will operate for the foreseeable future, a 20-year life is used for each control measure, as described in Section 3.4, to calculate emission reductions, amortized costs and cost effectiveness on a dollar per ton basis.

3.8 Proposed SO_2 Controls and Emissions Rates

This analysis does not support the installation of additional SO_2 control technologies at CCS Unit 1 or Unit 2 beyond those described in Section 2. The two identified control strategies of a replacement wet stack or a natural gas-fired reheat system are not cost effective and have significant implementation concerns.

In consultation with NDDEQ, GRE proposes a federally enforceable SO_2 emissions rate limit of 626 lb/hr as an annualized average (365-boiler-operating-day rolling average) limit for each unit, with plant averaging between the two units.[31] GRE proposes to implement operational practices consistent with those summarized in Section 2.5 in order to comply with the proposed SO_2 emissions rate limit, effective upon approval of a federally enforceable permit to construct issued by NDDEQ. This new performance level

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[31] 626 lb/hr = 0.104 lb/MMBtu x 6,015 or 6,022 MMBtu/hr rated capacities for Unit 1 and 2 listed in the Title V operating permit.

further reduces annual SO_2 emissions at each unit by an estimated 1,050 tpy in comparison to the BART limit.[32]

In the 2019 RH SIP Guidance (p. 44), there is the section entitled "Averaging period and units," which prescribes the options for the form of a limit being taken pursuant to this regional haze implementation period. EPA states that the "… Regional Haze Rule also allows SIPs to contain limits on mass emissions during a particular time period (e.g., a cap on 30-operating day mass emissions)." The proposed SO_2 limit is on a mass rate basis instead of a lb/MMBtu basis for the following reasons:

1. It is consistent with a mass emissions rate used in the dispersion modeling analysis to determine the visibility benefits at Class I areas due to application of control measures.
2. It is consistent with a mass emissions rate needed for control cost evaluation purposes, such as when considering other emissions control options and improvements with respect to conducting a regional haze four-factor analysis.
3. As described above, low load conditions may cause higher lb/MMBtu levels due to the lack of available heat to maintain the stack temperature safely above saturation. The lb/hr emission rate is inclusive of these higher lb/MMBtu levels during low load operation.
4. The proposed 626 lb/hr SO_2 limit on a 365-day rolling average in the permit to construct shall be inclusive of all expected operations throughout the year, including low load, planned startups and shutdowns, and maintenance activities such as routine absorber cleanings. An annual average limit that is inclusive of startups and shutdowns aligns EPA's current startup, shutdown, and malfunction (SSM) state implementation plan (SIP) policy.[33]

For purposes of clarifying compliance demonstration with this limit, GRE uses the same framework as in 40 CFR 60 Subpart Da for which Units 1 and 2 are already subject. The definition of "boiler operating day" in Subpart Da for a newer boiler is a "24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit." Compliance with the proposed SO_2 limit will be demonstrated using the existing continuous emissions monitoring system (CEMS) by averaging all hourly SO_2 emissions data over each 365-boiler-operating-day rolling average with the first compliance date occurring after 365 boiler operating days of the limit becoming effective when the permit to construct is issued.

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[32] Comparing the two SO_2 performance levels and applying the 87% annual capacity factor equals an emissions reduction of 1,054 tpy at each unit. (0.15 lb/MMBtu BART limit - 0.104 lb/MMBtu expected level) x (6,015 or 6,022 MMBtu/hr rated capacities for Unit 1 and Unit 2) x (87% annual capacity factor), converted to tpy basis.

[33] EPA's current SSM policy for SIPs is found at 80 FR 33840, June 12, 2015, "State Implementation Plans: Response to Petition for Rulemaking; Restatement and Update of EPA's SSM Policy Applicable to SIPs; Findings of Substantial Inadequacy; and SIP Calls To Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown and Malfunction," Final Rule.

Appendix A

Unit Specific Screening Level Cost Summary for SO_2 Control Measures

Great River Energy Coal Creek Station: Unit Specific Screening Level Cost Summary

Appendix A

New Wet Stack

Cost Item	$		Comments
CAPITAL COST			
Direct Capital Costs			
Purchased Equipment Cost			Custodis, GRE, and Barr engineering estimates
Concrete Chimney	$20,663,265		Estimate for 30' diameter, 675' tall concrete chimney; includes exterior
Foundation	$8,000,000		Estimate based on recent area builds; costs are considered minimum estimates; actual costs would increase based on height and geotechnical data
Elevated Ductwork	$8,352,000		
Electrical Equipment	$1,000,000		
Misc. Equipment			
CEMS shelter	$250,000		
CEMS equipment	$500,000		
Total Capital Investment	**$38,765,265**		
ANNUAL COSTS			
Utilities, Supplies, Replacements & Waste Management			
Electricity	$533,000		Cost for increased fan power to support additional flue gas scrubbing plus
Load Reduction/Absorber Washe	$150,000	$ 30.0	$/MWH; 100 MW (total plant) load reduction for 100 hours annually due to increased absorber cleaning requirements
Lime	$104,608	$ 217.5	$/ton; 481 tons annual incremental lime usage to support additional scrubbing
Solid Waste Disposal	$10,826	$ 10.5	$/ton; 1,031 tons waste generated annually as a result of additional scrubbing
Total Indirect Annual Costs	$798,433		
Indirect Annual Operating Costs			
Capital Recovery	$3,176,902	0.0820	for a 20-year equipment life and a 5.25% interest rate
Total Indirect Annual Costs	**$3,176,902**		
Total Annual Cost	**$3,975,335**		Screening-level cost estimate is considered to be conservatively low and does not include all items that would typically be included as part of a more detailed cost evaluation
	$7,228		**$/ton SO2 removed at 550 tpy SO2 reduced due to the new control measure**

Great River Energy Coal Creek Station: Unit Specific Screening Level Cost Summary

Appendix A

Natural Gas Fired Reheat System

Cost Item	$	Comments	
CAPITAL COST			
Direct Capital Costs			
Purchased Equipment Cost		GRE and Barr engineering estimates	
Natural Gas Fired 2-duct Burner	$10,267,500		
Natural Gas Pipeline		Estimated costs for natural gas pipeline inside CCS fenceline	
6" high pressure pipe	$1,312,000		
2" high pressure pipe	$80,000		
buried length	$2,050,000		
boring length	$480,000		
flow meters (2x)	$30,000		
gas heaters (2x)	$300,000		
Total Capital Investment	**$14,519,500**		
ANNUAL COSTS			
Direct Annual Costs			
Utilities, Supplies, Replacements & Waste Management			
Natural Gas	$840,237	$ 3.5	$/MMBtu; 31.5 MMBtu/hr gas required to achieve design stack temp
Electricity	$200,000	Cost for increased fan power to support additional flue gas scrubbing	
Load Reduction/Absorber Washe	$150,000	$ 30.0	$/MWH; 100 MW (total plant) load reduction for 100 hours annually due to increased absorber cleaning requirements
Lime	$104,608	$ 217.5	$/ton; 481 tons annual incremental lime usage to support additional scrubbing
Solid Waste Disposal	$10,826	$ 10.5	$/ton; 1,031 tons waste generated annually as a result of additional scrubbing
Firm Natural Gas Pipeline Fee	$930,000	Pipeline fee for new pipeline from existing WBI line to CCS fenceline and reservation for firm gas supply	
Total Indirect Annual Costs	$2,235,671		
Indirect Annual Operating Costs			
Capital Recovery	$1,189,906	0.0820	for a 20-year equipment life and a 5.25% interest rate
Total Indirect Annual Costs	**$1,189,906**		
Total Annual Cost	**$3,425,577**	Screening-level cost estimate is considered to be conservatively low and does not include all items that would typically be included as part of a more detailed cost evaluation	
	$6,228	**$/ton SO2 removed at 550 tpy SO2 reduced due to the new control measure**	

B.4.c – Communications

Stroh, David E.

From: Roth, Mary Jo GRE-MG <mjroth@GREnergy.com>
Sent: Tuesday, December 18, 2018 3:08 PM
To: Stroh, David E.
Cc: O'Clair, Terry L.; Bachman, Tom A.
Subject: RE: RH2 4 Factor Letter - GRE CCS

David,

I concur that it makes sense to focus on the BART analysis since it is a precursor to round 2. Following our updated round 1 submittal, we will work diligently on the round 2 analysis. Thanks.

MJ

Mary Jo Roth
Manager, Environmental Services
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369-4718
office: 763.445.5212 // cell: 612.810.4677
www.GreatRiverEnergy.com

From: Stroh, David E. <deStroh@nd.gov>
Sent: Tuesday, December 18, 2018 2:46 PM
To: Roth, Mary Jo GRE-MG <mjroth@GREnergy.com>
Cc: O'Clair, Terry L. <toclair@nd.gov>; Bachman, Tom A. <tbachman@nd.gov>
Subject: RH2 4 Factor Letter - GRE CCS

Mary Jo,

Based on the tentatively established timeline for Great River Energy's Regional Haze Round 1 report submittal (March 2019), the Department would like GRE to focus their efforts on completing the updated BART analysis associated with Round 1.

This means GRE may delay efforts to complete the analysis required by the May 2, 2018 Regional Haze Second Planning Period letter (due 1/31/19) until further notified by the Department.

Should you have any questions, please let me know. Thanks.

David Stroh
Environmental Engineer
North Dakota Department of Health
Division of Air Quality
918 E. Divide Ave. 2nd Floor
Bismarck, ND 58501-1947

701.328.5188
destroh@nd.gov
Division Website:
www.deq.nd.gov/aq/

Major power supply changes to reduce costs to member-owner cooperatives (https://greatriverenergy.com/mc power-supply-changes-to-reduce-costs-to-member-owner-cooperatives/)

May 7, 2020

Great River Energy plans to replace coal with low cost renewables and market energy purchases

Great River Energy announced plans today to transform its portfolio of power supply resources in the coming years, significantly reducing member-owner wholesale power costs. The electric cooperative plans to phase out remaining coal resources, add significant renewable energy and explore critical grid-scale battery technology.

Great River Energy plans to take the following actions:

Keeping power reliable and affordable

Continuing to reduce carbon dioxide emissions

Adding cleaner electricity sources

- Retire the 1,151-megawatt (MW) Coal Creek Station in the second half of 2022
- Add 1,100 MW of wind energy purchases by the end of 2023
- Modify the 99-MW, coal and natural gas-based Spiritwood Station power plant to be fueled by natural gas
- Install a 1-MW, long-duration battery demonstration system
- Support the repowering of the Blue Flint biorefinery with natural gas

"We are building a power supply portfolio that will serve our member-owner cooperatives for decades," Great River Energy President and Chief Executive Officer David Saggau said. "We are taking advantage of cost-competitive renewables and reliable access to market energy while fostering innovation as the technology of our industry evolves."

Today's announcement follows several changes Great River Energy has made in recent years to seek economic efficiencies in its power supply portfolio. Past analysis has led to decisions to exit a contract for half the output of a Wisconsin coal plant in 2015, retire the coal-based Stanton Station power plant in 2017, close the waste-to-energy Elk River Resource Recovery Project in 2019 and purchase the output of several wind energy projects.

The portfolio changes announced today will significantly reduce Great River Energy's member-owner power supply costs. In addition, the cooperative's power supply resources will be more than 95% carbon dioxide-free, virtually eliminating carbon risk.

"Our power supply plans deliver on our member-owners' three highest priorities: affordability, reliability and environmental stewardship," Saggau said. "Electric cooperatives have a bright future in Minnesota."

Great River Energy plans to purchase more than 1,100 MW from new wind energy projects. This amounts to a more than $1.2 billion investment in the Midwest's abundant clean energy resources. Great River Energy's renewable capacity is projected to grow from approximately 660 MW in 2020 to more than 1,760 MW by the end of 2023. The Great River Energy board of directors today approved 600 MW of wind energy projects, most of which will be located in Minnesota.

Great River Energy plans to add energy and capacity as needed through upgrades at its fleet of modern, natural gas peaking plants and purchases from the MISO energy market.

Coal Creek Station has been a critical part of Great River Energy's power supply portfolio for decades, but it has lost value compared to other alternatives in recent years. Great River Energy plans to shut down both units of Coal Creek Station during the second half of 2022, although the cooperative is willing to consider opportunities to sell the plant. Coal Creek Station began operations in 1979 in Underwood, North Dakota, and employs 260 people.

"Like all of Great River Energy's decisions, these changes are made in the best interests of our member-owner cooperatives," Saggau said. "Coal Creek Station is operated efficiently, safely and with pride by a dedicated and talented staff. We will make every effort to minimize impacts on our employees and the communities through this transition."

To assist local communities during the upcoming transition, Great River Energy plans to make voluntary annual payments of the local government share of the plant's taxes for five years after the plant's closure.

Great River Energy plans to negotiate an agreement to terminate its steam and water supply contract with Blue Flint, an ethanol biorefinery fueled by process steam from Coal Creek Station. Blue Flint's owner, Midwest AgEnergy, is considering using the contract termination payment from Great River Energy to reinvest in an economical alternate source for its process heat, thereby benefitting area farmers by continuing to support the local market for corn.

Located near Jamestown, North Dakota, Spiritwood Station is a combined heat and power plant fueled by a combination of DryFineTM lignite coal and natural gas. Great River Energy plans to modify the plant to be fueled with natural gas. The plant generates electricity for the regional electric grid and supplies steam to a nearby ethanol biorefinery.

Great River Energy is working with Form Energy, a battery storage technology developer based in Somerville, Massachusetts, on a first-of-its-kind demonstration of Form's unique long-duration storage technology. The battery project will be a 1-MW, grid-connected storage system capable of delivering its rated power continuously for 150 hours, far longer than the four-hour usage period common among lithium ion batteries. Long-duration storage will help maintain grid reliability in the future during extreme conditions, such as a heat wave or polar vortex. The battery system will be located in Cambridge, Minnesota, and completed in late 2023.

The projects announced today will create hundreds of high-quality construction jobs. "We look forward to partnering with local labor and industry on our projects," Saggau said.

Categories: Company news (https://greatriverenergy.com/category/company-news/), Power generation resources (https://greatriverenergy.com/category/power-generation-resources/), Power plants (https://greatriverenergy.com/category/power-generation-resources/power-plants/), Renewable energy (https://greatriverenergy.com/category/power-generation-resources/renewable-energy/)

← Great River Energy to be conservative in returning to normal work arrangements (https://greatriverenergy.com/great-river-energy-to-be-conservative-in-returning-to-normal-work-arrangements/)

B.5 – Minnkota MRY

B.5.a – Department Request

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

May 2, 2018

FILE

Mr. Craig Bleth
Minnkota Power Cooperative
5301 – 32nd Avenue S
Grand Forks, ND 58203

Re: Regional Haze
Second Planning Period

Dear Mr. Bleth:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:
1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
Division of Municipal Facilities 701.328.5211
Division of Waste Management 701.328.5166
Division of Water Quality 701.328.5210

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair
Director
Division of Air Quality

TLO/TB:saj
xc: Kevin Thomas, Minnkota Power Cooperative

B.5.b – Facility Response

Minnkota Power
COOPERATIVE
A Touchstone Energy® Cooperative

5301 32nd Avenue South
Grand Forks, ND 58201

Phone 701.795.4000
www.minnkota.com

JAN 2019
Received
Air Quality

January 31, 2019

Mr. Terry L. O'Clair, Director
Division of Air Quality
North Dakota Department of Health
918 East Divide Avenue
Bismarck, ND 58501-1947

RE: Milton R. Young Station Regional Haze Control Study
Second Planning Period

Dear Mr. O'Clair:

As requested in your May 2, 2018 correspondence, I am enclosing three copies of the Regional Haze Control Study (Four Factor Analysis) for Unit 1 and Unit 2 at the Milton R. Young Station.

If you have any questions regarding this study, please contact me at 701-794-8711.

Sincerely,

MINNKOTA POWER COOPERATIVE, INC.

Craig J. Bleth

Craig J. Bleth
Senior Manager of Power Production

Cc: Gerad Paul
Dan Laudal
Kevin Thomas
Jon Madison
Station File

BURNS McDONNELL

JAN 2019
Received
Air Quality

Regional Haze Control Study

Minnkota Power
COOPERATIVE
A Touchstone Energy® Cooperative

Minnkota Power Cooperative, Inc.

Milton R. Young Station Unit 1 and Unit 2
Project No. 107926

Revision 0
1/29/2019

Regional Haze Control Study

prepared for

Minnkota Power Cooperative, Inc.
Milton R. Young Station Unit 1 and Unit 2
Center, North Dakota

Project No. 107926

Revision 0
1/29/2019

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

INDEX AND CERTIFICATION

Minnkota Power Cooperative, Inc.
Regional Haze Control Study

Project No. 107926

Report Index

Certification

I hereby certify, as a Professional Engineer in the state of North Dakota, that the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by the Minnkota Power Cooperative, Inc. or others without specific verification or adaptation by the Engineer.

CHRISTOPHER J.
MARKS
PE-9703
DATE 1-29-19

Jan 29 2019 6:38 PM

Insert Engineer's Name, P.E., state, & license

Date: Insert Date

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LIST OF TABLES

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
ASOFA	Advanced separated over fire air
B&W	Babcock & Wilcox
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BOP	Balance of plant
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CD	Consent decree
CDS	Circulating dry scrubber
CFD	Computational fluid dynamics
CO	Carbon monoxide
CO_2	Carbon dioxide
CRF	Capital recovery factor
EPA	United States Environmental Protection Agency
ESP	Electrostatic precipitator
FDA	Flash dryer absorber
FGD	Flue gas desulfurization
LACC	Levelized annual capital cost
LAOMC	Levelized annual O&M cost
LTAC	Levelized total annual cost
Minnkota	Minnkota Power Cooperative, Inc.
MRYS	Milton R. Young Station

Abbreviation	**Term/Phrase/Name**
NDDH	North Dakota Department of Health
NOx	Nitrogen oxides
NPV	Net present value
O&M	Operation & maintenance
OEM	Original equipment manufacturer
OMLF	O&M levelization factor
RBLC	RACT/BACT/LAER Clearinghouse
RHCT	Regional Haze Control Technology
RHR	Regional Haze Regulations
RRI	Rich reagent injection
RO	Reverse Osmosis
SCR	Selective catalytic reduction
SDA	Spray dryer absorber
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
Square Butte	Square Butte Electric Cooperative
TPI	Total plant investment
URGE	Ultimate short-term maximum gross output
VOCs	Volatile organic compounds
WRAP	Western Regional Air Partnership

EXECUTIVE SUMMARY

This report presents the Regional Haze Control Technology (RHCT) analysis for nitrogen oxides (NO_X), and sulfur dioxide (SO_2) for Minnkota Power Cooperative, Inc.'s (Minnkota's) Unit 1 and Square Butte Electric Cooperative's (Square Butte's) Unit 2 at the Milton R. Young Station (MRYS) located near Center, North Dakota. On July 6, 2005, the United States Environmental Protection Agency (U.S. EPA or EPA) finalized the Regional Haze Regulations (RHR) and Guidelines for BART Determinations. In July of 2016, the EPA issued draft guidance for the second implementation period of the regional haze regulations. The guidance document requires a "four factor analysis" to be conducted for sources that have the potential to impair visibility in Class 1 areas. The four statutory factors are:

- The cost of compliance
- The time necessary for compliance
- The energy and non-air quality environmental impacts of compliance, and
- The remaining useful life of the source

This report presents the required "four factor analysis" for MRYS. Note that for MRYS, Minnkota has determined that the "remaining useful life of the source" is not a relevant factor in the analysis. The term "RHCT analysis" is used throughout this report to refer to the analysis that has been conducted in compliance with the requirements of EPA's July 2016 draft guidance.

The guidance document, in general, indicates that the goal of the second implementation period is to look at all sources for incremental visibility improvement including all sources that were previously determined to be Best Available Retrofit Technologies (BART) eligible. Milton R. Young Station Unit 1 and Unit 2 were previously determined to be BART-eligible by the North Dakota Department of Health (NDDH). This evaluation is intended to inform NDDH of the future potential to reduce emissions at Milton R. Young Station and the cost associated with these reductions. This evaluation is based on a top down evaluation of control technologies and will provide NDDH an emission rate for visibility impairment modeling.

There are five predefined steps for conducting a RHCT analysis. Steps 1 through 3 include identifying control technologies, evaluating feasibility, and ranking feasible options by control effectiveness. Step 4 involves a technical evaluation of various impacts related to each feasible control technology. The evaluation reviews include economics, energy, and non-air environmental impacts. This evaluation addresses these first four steps, resulting in an emission rate for the Step 5 Class 1 area visibility impairment impact analysis.

Unlike the previous BART analysis, this analysis reviews technologies on a 'Top Down' basis. The best (lowest emitting) feasible technology that is acceptable (considering economic, energy and non-air impacts) will be evaluated by NDDH for visibility impact reduction. The results of conducting the first four step analysis will provide a recommendation to NDDH of a potential RHCT and the associated emission rate.

This analysis used several reference works, including the RACT/BACT/LAER Clearinghouse (RBLC), to identify which control technologies to evaluate. The technologies were reviewed for feasibility and those deemed infeasible were eliminated from further study. The feasible control technologies were ranked by control efficiency and estimates of costs to implement, operate, and maintain such technologies were developed for the top ranked technologies. Evaluating the top ranked technology based upon the average cost (dollars per ton removed) and other impacts determined if the top ranked technology was acceptable. The final RHCT results are summarized in the tables below. The RHCT emission rates are presented as a 30-day rolling average to account for variations in boiler operation and variations in fuel quality (including sulfur content).

MRYS Unit 1 RHCT 30-Day Rolling Average

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Existing Selective Non-Catalytic Reduction (SNCR) and Advanced Separated Over Fire Air (ASOFA) [1]	0.36
SO_2	Modify the existing Wet Flue Gas Desulfurization (FGD) system [2]	0.10

1: Excludes startups. See referenced BACT analysis for a detailed discussion.

MRYS Unit 2 RHCT 30-Day Rolling Average

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Existing Selective Non-Catalytic Reduction (SNCR) and Advanced Separated Over Fire Air (ASOFA) [1]	0.35
SO_2	Modify the existing Wet Flue Gas Desulfurization (FGD) system [2]	0.10

1: Excludes startups. See referenced BACT analysis for a detailed discussion.

The four factor analysis was completed based on a request by the North Dakota Department of Health (NDDH) while utilizing the EPA 2016 Guidance document. The NDDH has requested this information for the purpose of WRAP modeling. As EPA has indicated, the Regional Haze Roadmap may be updated, and the results of the WRAP modeling will provide new information to be considered, Minnkota reserves the right to modify the 4 Factor analysis once the Regional Haze Roadmap, any additional guidance and the results of the WRAP modeling are available. In addition, Minnkota reserves the right to conduct a 5th Factor based on visibility modeling once the results of the WRAP modeling are available. This analysis is provided to assist the NDDH in the WRAP modeling and is not intended to serve as an agreement by Minnkota to any changes in permitted emission limits or permit conditions.

1.0 INTRODUCTION

The United States Environmental Protection Agency (U.S. EPA or EPA) finalized the Regional Haze Regulations (RHR) and Guidelines for Best Available Retrofit Technology (BART) Determinations[1] in the Federal Register on July 6, 2005 (70 FR 39104). In July, 2016, the EPA issued draft guidance for the second implementation period of the regional haze regulations[2]. The draft guidance for the second implementation period retains many aspects of the BART guidelines.

The guidance documents, in general, indicate the goal of the second implementation period is to look at all sources for incremental visibility improvement including all sources that were previously Best Available Retrofit Technologies (BART) eligible. Milton R. Young Station Unit 1 and Unit 2 were previously determined to be BART-eligible by the NDDH. BART is defined as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by a BART-eligible source. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology" (70 FR 39163). Note that for MRYS, Minnkota has determined that the "remaining useful life of the source" is not a relevant factor in the analysis.

The second implementation guidance indicates a similar review to BART should be performed but in the second round the technology evaluation should be based on a 'top down' approach. The evaluation criteria are the same as the previous BART analysis; case-by-case basis considering availability, cost, energy and non-air quality impacts. However, in a 'top down' analysis the highest ranked technology that meets the acceptable criteria in the first four steps is the selected technology. The final determination of what top ranked technologies across the utility fleet will be accepted, if any, as RHCT is dependent on Step 5 (visibility modeling) and will be based on the modeling performed by the Western Regional Air Partnership (WRAP). This RHCT evaluation will be used by the NDDH as a tool to evaluate the potential to reduce emissions at Minnkota Power Cooperative, Inc.'s (Minnkota's) Unit 1 and Square

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[1] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations"; Environmental Protection Agency; Federal Register, Volume 70, No. 128; July 6, 2005.

[2] "Draft Guidance on Progress Tracking Metrics, Long-Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period", Environmental Protection Agency; Federal Register, Volume 81, No. 131; July 8, 2016.

Butte Electric Cooperative's (Square Butte's) Unit 2 at the Milton R. Young Station (MRYS) located near Center, North Dakota and the cost associated with these reductions.

1.1 RCHT Analysis Process

The general steps for determining RHCT for each pollutant are virtually the same as the previous BART steps (70 FR 39164) and are as follows:

STEP 1 - Identify all available retrofit control technologies.
STEP 2 - Eliminate technically infeasible options.
STEP 3 - Evaluate control effectiveness of remaining control technologies.
STEP 4 - Evaluate the following impacts for each feasible control technology and document results:
    The cost of compliance.
    The time required for compliance.
    The energy and non-air quality environmental impacts of compliance.
    The remaining useful life of the source.
STEP 5 – Evaluate the visibility impacts.

Unlike the previous BART analysis where all five steps were performed at once, NDDH's approach for the second implementation of the regional haze program is breaking the first four steps apart from the fifth step. The first four steps are performed on a 'top down' basis to determine the top ranked control technology that is applicable to each source. The fifth step is then taken by NDDH to determine which of the sources top down technologies are selected as RHCT.

Minnkota Power Cooperative, Inc. retained Burns & McDonnell to assist in the completion of the first four steps of the RHCT analysis for Milton R. Young Station. Burns & McDonnell is a full service engineering, architectural, construction and environmental firm. The company plans, designs and constructs electric generating facilities and has been providing environmental services to the power industry since the 1970s. As a result of their long history providing these services, Burns & McDonnell has extensive experience in permitting, Best Available Control Technology (BACT) studies, BART studies and control technology analysis similar to a RHCT analysis.

1.1.1 Identification of Retrofit Control Technologies

The initial step in the RHCT determination is the identification of retrofit control technologies. In order to identify the applicable control technologies, several reference works are consulted. A preliminary list of control technologies and their estimated capabilities is developed.

1.1.2 Feasibility Analysis

The second step of the RHCT process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible. The BART guidelines are also applicable for the RHCT analysis and discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the "availability" and "applicability" of each control technology.

A control technology is considered available, "if the source owner may obtain it through commercial channels, or it is otherwise available in the common sense meaning of the term" or "if it has reached the stage of licensing and commercial availability." On the contrary, a control technology is not considered available, "in the pilot scale testing stages of development." (70 FR 39165) When considering a source's applicability, technical judgment must be exercised to determine "if it can reasonably be installed and operated on the source type." The EPA also does not "expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type." (70 FR 39165) "A technology that is available and applicable is technically feasible." (70 FR 39165)

1.1.3 Evaluate Technically Feasible Control Option by Effectiveness

The third step in the RHCT analysis is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the analysis, the control efficiency is reviewed and presented with the description of each technology. The evaluation of the technically feasible alternatives concludes with the alternatives ranked in descending order of control effectiveness.

1.1.4 Impact Analysis

Step four in the analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) and the draft guidelines for the second implementation period (81 FR 44608) each list four factors to be considered in the impact analysis. The RHCT evaluation will consider the following four factors in the impact analysis:

- The costs of compliance
- The time required for compliance
- The energy and non-air quality environmental impacts of compliance
- The remaining useful life of the source.

The first three of the four factors considered in the impact analysis are discussed in the associated pollutant section. The remaining useful life of the source is included as part of the cost of compliance.

In the second implementation period the impact analysis is performed on a 'top down' basis. The highest ranked (lowest emitting) technology is evaluated on the above factors for acceptability. If the top-ranked control technology is unacceptable, then the next highest ranked control technology is evaluated. This process continues until the highest ranked acceptable technology is identified.

1.1.5 Baseline Emissions

The cost of compliance evaluation is typically performed on a levelized dollars per tons of pollutant removed basis. In determining the tons removed, a baseline emission rate must be determined. The MRYS units both have existing SO_2 and NO_x pollution control systems that are part of the baseline. The baseline emission rate was developed by evaluating the 2014-2018 daily emissions data. A 30-day rolling average emission rate for all boiler operating days was developed and the highest 30-day value was determined. The highest 30-day emission rate for Unit 1 was 0.35 lbs/MMBtu NO_x and 0.14 lbs/MMBtu SO_2. The highest 30-day emission rate for Unit 2 was 0.35 lbs/MMBtu NO_x and 0.15 lbs/MMBtu SO_2. The highest 30-day rate is selected to reflect an emission rate the existing system would have maintained on a continuous basis during 2014-2018. Potential reductions from higher removal options will be evaluated from this baseline rate to evaluate the average/actual and incremental cost of control.

1.1.6 Methodology for Estimated Costs

The cost summary of each alternative is presented in the section for each pollutant. Installed capital and annual O&M cost estimates for each alternative are presented individually. The Levelized Total Annual Cost (LTAC) represents the levelized annual cost of procurement, construction and operation over a 20 year design life, in 2021 dollars. The LTAC represents an annual payment in current day dollars sufficient to finance the project over its entire life.

In determining the LTAC, a Capital Recovery Factor was calculated from the project economic conditions and then applied separately to the estimated capital costs. The equation used is shown below.

$$LACC\ /\ NPV = \left(\frac{i_d(1+i_d)^n}{(1+i_d)^n - 1} \right) = CRF$$

Where,
LACC = Levelized Annual Capital Cost
NPV = Net Present Value of the capital investments required.
i_d = discount rate
n = design life in years
CRF = Capital Recovery Factor

Therefore:

$$\text{LACC} = \text{CRF} \times \text{NPV}$$

For the economic conditions described in Table 1-1, the Capital Recovery Factor was calculated to be 0.08368.

The O&M cost used is the first year costs, in 2021 dollars. The O&M cost was not further inflated or otherwise levelized.

The Levelized Total Annual Cost, or LTAC is the sum of the levelized capital cost and the first year O&M cost. Therefore:

$$\text{LTAC} = \text{LACC} + 1^{st}\text{ Year O\&M} = (\text{CRF} \times \text{NPV}) + 1^{st}\text{ Year O\&M} = 0.08368 \times \text{NPV} + 1^{st}\text{ Year O\&M}$$

The economic analyses presented in this report not only include the estimated capital and annual O&M costs for each top ranked control technology, but also the LTAC for economic comparison.

Table 1-1: Economic Factors

Factor	Value
Total Possible Operating Hours per Year	8,760
Plant Capacity Factor	85%
Amortization Life, Years	20
Allowance for Funds Used During Construction	Not Included
Property Taxes, Insurance, %	NA
Amortization Rate for APC Capital Costs	0%
Discount Rate	5.5%
Construction Cost Escalation	3%
Maintenance Material and Labor Cost, % of Direct Capital	3%
Non-Fuel O&M Escalation	1.5%
Fuel (coal and natural gas) Escalation	1.5%
Auxiliary Electric Power Cost, $/MW-hr	$52.28
Reverse Osmosis Water, $/kgal	$9.44
Condensate water, $/kgal	$10.30
Urea 70% Solution, $/ton	$438.14
Lime, $/ton	$200.77
FGD Byproduct Disposal, $/ton	$6.27

(1) All costs are in 2021 dollars unless noted otherwise.

1.2 RHCT Analysis Approach

The purpose of the Regional Haze Rule (RHR) is to address visibility impairment in mandatory Class 1 areas. Before the actual RHCT analysis can begin the approach used to conduct the analysis should be addressed. The following sections present specific subjects related to MRYS's background, which warrant mention due to their effects on the contents of the report.

1.2.1 Background

Minnkota Power Cooperative, Inc. operates the Milton R. Young Station near Center, North Dakota. MRYS is a steam electric generating plant with two units. Unit No. 1 is a Babcock & Wilcox (B&W) cyclone-type coal-fired boiler burning lignite coal, serving a turbine generator with a nameplate rating of 257 MW.[3] Unit 1 employs advanced separated over fire air (ASOFA) and selective non-catalytic reduction (SNCR) for NO_x control achieving 59% NO_x reduction. Particulate control is provided by a Research-Cottrell Electrostatic Precipitator rated at approximately 99% control. Unit 1 has a wet scrubber provided by Marsulex Environmental Technologies achieving compliance with a 30-day rolling average 95% SO_2 removal efficiency and exhausts to a 544 foot tall stack.

Unit No. 2 is a B&W cyclone-fired unit burning lignite coal, with a turbine-generator nameplate rating of 477 MW.[4] Unit 2 employs ASOFA and SNCR for NO_x control achieving 60% NO_x reduction. Particulate control for Unit 2 is provided by a Wheelabrator-Lurgi precipitator rated at approximately 99% control. Unit 2 has a Combustion Equipment Associates wet flue gas desulfurization (FGD) system (modified by Combustion Engineering) achieving compliance with a 30-day rolling average 90% SO_2 removal efficiency and a 30-day rolling average 0.15 lb/MMBtu emission rate, and exhausts to a 550 foot tall stack.

Unit 1 began commercial operation on November 20, 1970 and Unit 2 on May 11, 1977.

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[3] "Generator Nameplate Data"; Emissions & Generation Resource Integrated Database (eGRID); U.S. Environmental Protection Agency; April, 2003.

[4] Ibid footnote 3 reference.

2.0 NOx RHCT EVALUATION

The RHCT analyses for NO_X emissions from MRYS Unit 1 and Unit 2 are described in this section. Technical descriptions of MRYS Unit 1 and Unit 2 boilers and existing air pollution control equipment are provided. Minnkota previously entered into a Consent Decree (CD) that required MRYS to install BACT for NO_X, which was determined to be Selective Non-Catalytic Reduction (SNCR) systems with Advanced Separated Overfire Air (ASOFA) on both units. These technologies are the current baseline condition for the two units.

2.1 NOx Evaluation Basis

Milton R. Young Station Unit 1 includes a B&W steam generator installed in 1970. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation. Original unit design steam generating capacity is 1.714 million lbs/hr at 1,920 psi with a fuel heat input of 2,510 MMBtu/hr. The boiler is fired by seven ten-foot diameter cyclone burners, arranged "three over four" across the front wall of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the electrostatic precipitator (ESP). Unit 1's boiler serves a turbine generator with a nameplate rating of 257 MW[5]. The Unit 1 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a mine located adjacent to the site.

Milton R. Young Unit 2 is a B&W steam generator installed in 1977. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation assisted with circulation pumps. Original unit design steam generating capacity is 3.20 million lbs/hr at 2,620 psi with a fuel heat input of 4,696 MMBtu/hr. The boiler is fired by twelve ten-foot diameter cyclone burners, arranged "three over three" across the front and rear walls of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Unit 2's boiler serves a turbine-generator with a nameplate rating of 477 MW[6]. The Unit 2 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a mine located adjacent to the site.

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[5] Ibid EPA's eGRID database; April, 2003.

[6] Ibid EPA's eGRID database; April, 2003.

2.2 Identification of Retrofit NOx Control Technologies

The initial step in the RHCT determination is the identification of retrofit NOx control technologies. In order to identify the applicable NOx control technologies, several reference works were consulted, including the RACT/BACT/LAER Clearinghouse (RLBC). From this and other literature sources, a preliminary list of control technologies and their estimated capabilities for potential application to MRYS was developed. However, as discussed in the introduction, Minnkota already has ASOFA and SNCR systems installed on both units to achieve 30-day rolling average removal rates of approximately 60% on Unit 1 and Unit 2. Thus, the control technologies included in the RHCT analysis either meet this minimum level of control or have more stringent removal efficiency. Table 2-1 contains the results of this effort.

Table 2-1: NOx Control Technologies Identified for RHCT Analysis

Control Technology	Approximate Control Efficiency*
Selective Catalytic Reduction and Advanced Separated Over Fire Air (ASOFA)	90%
Rich Reagent Injection and Selective Non-Catalytic Reduction and Advanced Separated Over Fire Air (ASOFA)	66-67%
Optimized Selective Non-Catalytic Reduction and Advanced Separated Over Fire Air (ASOFA)	61-62%
Existing Selective Non-Catalytic Reduction* and Advanced Separated Over Fire Air (ASOFA)	Baseline 59-60%

*Based on pre SNCR/ASOFA baseline of 0.884/0.874 lb NOx/MMBtu for Units 1 and 2, respectively.

2.3 Technical Description and Feasibility Analysis

The second step in the RHCT analysis procedure is a technical feasibility analysis of the options identified in Step 1. The RHCT guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the "availability" and "applicability" of each control technology. A control technology is considered available, "if it has reached the stage of licensing and commercial availability." (70 FR 39165) On the contrary, a control technology is not considered available, "if it is in the pilot scale testing stages of development." (70 FR 39165) When considering a source's applicability, technical judgment must be exercised to determine "if it can reasonably be installed and operated on the source type." (70 FR 39165) The technical and feasibility analysis is presented below for each identified option.

2.3.1 Selective Catalytic Reduction

The lowest NOx emission levels from coal-fired utility boilers are typically achieved by installing and operating selective catalytic reduction (SCR) technology. In the SCR process, the gas stream is passed through a catalyst bed in the presence of ammonia to reduce NOx to molecular nitrogen and water. The process is termed “selective” because the ammonia preferentially reacts with the NO_X rather than with the oxygen in the flue gas. A large reactor containing catalyst is used to enhance NO_X reduction and ammonia utilization at lower flue gas temperatures than required by a SNCR system. SCR is usually applied to flue gas in the 600°F to 750°F temperature range. There are variations in the SCR process for coal-fired boilers that mostly involve locations in the flue gas path where the catalyst is placed in order to promote the desired NO_X emission reduction effect. This technology was reviewed in the previous BART and BACT analysis (2008-2010) and it was concluded by NDDH that SCR systems (of all types) are not technically feasible at the Milton R Young facility. No new information or experience has occurred since 2010 to change the result of this analysis and this technology remains not technically feasible.

2.3.2 Rich Reagent Injection & Selective Non-Catalytic Reduction

Rich Reagent Injection (RRI) has been demonstrated and placed in continuous operation on multiple cyclone-fired boilers. RRI is specifically intended for NOx emissions control on cyclone boilers. RRI adds dilute urea reagent to the hot furnace gases near the cyclones, which must be devoid of free oxygen in order to avoid oxidation of the urea. This system is combined with a SNCR system to further reduce NOx emissions within the boiler. However, the RRI injection location is limited to the lower portion of the furnace and requires an oxygen deprived environment. RRI is considered technically feasible for application on the Unit 1 and Unit 2 cyclone boilers at the Milton R. Young Station.

2.3.3 Optimized Selective Non-Catalytic Reduction

Taking into consideration the past operating experience of the existing system and vendor experience since the original installation, there is potential to reduce the emission rate further with enhancements to the existing design. These enhancements could include changing the nozzles on existing lances, replacing the existing lances, and adding lances in new locations. Additionally, allowing for higher ammonia slip rates than originally designed will allow for higher levels of urea injection which has the potential to further reduce NOx emission rates. Optimized SNCR is considered technically feasible for application on the Unit 1 and Unit 2 cyclone boilers at the Milton R. Young Station.

2.3.4 Results of Feasibility Analysis

The evaluations of the identified RHCT alternatives following the feasibility analysis are summarized in Table 2-2.

Table 2-2: MRYS RHCT NOx Control Feasibility Analysis Results

Control Technology	In full-scale service on Existing Utility Boilers	In Service on Other Combustion Sources	Commercially Available	Technically Applicable To Milton R. Young Station
SCR	Yes	Yes	No*	No
RRI + SNCR	Yes	Yes	Yes	Yes
Optimized SNCR	Yes	Yes	Yes	Yes
Existing SNCR	Yes	Yes	Yes	Yes

*Not available on cyclone fired units firing North Dakota lignite.

2.4 Evaluate the Technically Feasible NOx Control Options by Effectiveness

The third step in the RHCT analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the RHCT analysis, the NOx control efficiency was reviewed and presented as part of the technical description for each technology. The evaluations of the remaining RHCT alternatives following the feasibility analysis are summarized in Table 2-3. The alternatives are ranked in 'top down' descending order according to their effectiveness in NOx control.

Table 2-3: Feasible NOx Control Technologies Identified for RHCT Analysis

Control Technology	Unit 1 lb/MMBtu	Unit 2 lb/MMBtu
RRI + SNCR	0.30	0.29
Optimized SNCR	0.345	0.335
Existing SNCR	0.36	0.35

The emission rates identified above were developed as continuously achievable 30-day emission rates taking into account vendor supplied information, variations in load, experience in the long-term variation of boiler NOx control technologies, and the variable quality associated with the supply of mine mouth lignite. The vendor information is based on MRYS unit-specific boiler mapping data and CFD modeling results to determine the equipment, approximate injection locations, and subsequent emission rate. The emission rates take into account that the rates must be continuously achievable on a 30-day period including the impacts of changing unit loads, control equipment limitations, and variability in coal quality.

Load variations must be considered because at lower loads the ability to control NOx is reduced. The RRI and SNCR systems are designed to inject dilute ammonia/urea into the correct temperature zones in the boiler for NOx control. The maximum NOx reductions from both RRI and SNCR systems occur when the boiler is at or near full load. At other conditions the ability to control NOx can be significantly impacted. RRI operation depends on oxygen-deprived conditions, and without this (such as with a single cyclone out of service and/or at lower loads), using the RRI system could increase NOx emissions. Multiple levels of injection are included to introduce reagent into the correct temperature zone at multiple loads. However, even with multiple injection levels, emission reductions are reduced at lower loads.

The Milton R. Young facility is a mine-mouth plant that utilizes run-of-mine fuel, resulting in significant coal quality variability. Within a 30-day period, the plant can, and has, experienced multiple days of lower quality coal that in turn, creates conditions that make NOx harder to control (such as burning fuel oil to control cyclone fouling), increasing emissions and reagent usage rates.

These factors, along with unit-specific vendor information, were considered in developing the continuously achievable 30-day emission rates. The emission rates guaranteed by vendors are based on stable, steady state operating conditions, and do not reflect the varying conditions that occur over the life of the equipment or even in a 30-day operating period. A 30-day emission rate must account for operating during periods such as the transition period between two planned stable load conditions, and other unplanned operating variations such as changing coal quality.

2.5 Evaluation of Impacts for Feasible NOx Controls

Step four in the RHCT analysis procedure is the impact analysis. The draft Guidelines (81 FR 44608) lists four factors to be considered in the impact analysis.

- The costs of compliance
- The time required for compliance
- The energy and non-air quality environmental impacts of compliance
- The remaining useful life of the source

Three of the four impacts required by the RHCT Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the RHCT determination for MRYS.

2.5.1 Cost Estimates

Cost estimates for the RRI + SNCR control technology were developed based on vendor budgetary quotes, and installation estimates were based upon Burns & McDonnell's in-house experience. The vendor has utilized MRYS unit–specific boiler mapping data and CFD modeling results to determine the equipment and approximate injection locations. Economic information utilized as inputs to the model are provided in Table 1-1.

2.5.1.1 RRI + SNCR Capital Cost Estimate

The vendor equipment cost estimate for the RRI and SNCR system includes new RRI injectors for the lowest level of the boiler, a new RRI distribution module, and modifications to the existing SNCR system to provide load-following flexibility. The remaining capital cost estimate includes installation of the vendor equipment, supply and installation of necessary equipment access, and balance of plant (BOP) costs. The NOx control system cost is representative of a typical furnish and erect contract.

Table 2-4: Capital Cost Estimate for MRYS Unit 1 & 2 RRI + SNCR System

DIRECT COSTS	**Unit 1 Estimated Cost ($)**	**Unit 2 Estimated Cost ($)**
RRI and SNCR System		
Equipment Cost	$4,283,000	$5,507,000
BOP Costs		
Mechanical Contract	$1,611,000	$4,709,000
Foundations and Steel	$559,000	$900,000
Electrical and Controls	$131,000	$179,000
BOP Total Direct Cost =	$2,301,000	$5,788,000
Total Direct Cost =	$6,584,000	$11,295,000
INDIRECT COSTS		
Engineering 10% of DC	$647,000	$1,129,000
Escalation to 2021	$611,000	$1,048,000
Indirect Cost Subtotal	$1,258,000	$2,177,000
Contingency (20% of DC)	$784,000	$1,348,000
Prime Contractor's Fee (3% of DC)	$604,000	$1,038,000
Total Capital Requirement	**$9,230,000**	**$15,858,000**

The total estimated capital cost estimate to upgrade the existing Unit 1 SNCR system to a RRI + SNCR system is $9,230,000, or $35.9/kW. The total estimated capital cost estimate to upgrade the existing Unit 2 SNCR system to a RRI + SNCR system is $15,858,000, or $33.2/kW.

2.5.1.2 Optimized SNCR Capital Cost Estimate

The vendor equipment cost estimate for optimizing the SNCR system is based on vendor estimates and may include changing the nozzles on the existing lances, replacing the existing lances, adding lances in new locations, and/or boiler modifications for the additional lances. The NOx control system cost is representative of a typical furnish and erect contract.

Table 2-5: Capital Cost Estimate for MRYS Unit 1 & 2 Optimized SNCR System

DIRECT COSTS	**Unit 1 Estimated Cost ($)**	**Unit 2 Estimated Cost ($)**
Optimized SNCR System		
SNCR Equipment Cost	$628,000	$748,000
BOP Costs		
Mechanical Contract	$311,000	$932,000
Foundations and Steel	$100,000	$250,000
Electrical and Controls	$15,000	$25,000
BOP Total Direct Cost =	$425,000	$1,207,000
Total Direct Cost =	$1,054,000	$1,955,000
INDIRECT COSTS		
Engineering 10% of DC	$105,000	$195,000
Escalation to 2021	$98,000	$181,000
Indirect Cost Subtotal	$203,000	$376,000
Contingency (20% of DC)	$126,000	$233,000
Prime Contractor's Fee (3% of DC)	$97,000	$180,000
Total Capital Requirement	**$1,479,000**	**$2,744,000**

The total estimated capital cost estimate to optimize the Unit 1 SNCR system is $1,479,000 or $5.8/kW. The total estimated capital cost estimate to optimize the Unit 2 SNCR system is $2,744,000, or $5.8/kW.

2.5.1.3 RRI + SNCR O&M Cost Estimate

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The fixed costs include operating labor, administrative and support labor and the maintenance material and labor costs. No change in administrative, support and operating labor cost was assumed. The maintenance material and labor cost was estimated at approximately 3% of the system direct capital cost in Table 2-4. Table 2-6 summarizes the O&M cost estimates for the RRI + SNCR system.

Variable costs include reagent, cooling water, auxiliary power costs and increased coal consumption. The estimated annual costs for these consumables are the estimated change from the baseline conditions based on vendor provided consumption rates, unit operating assumptions and the unit cost information provided in Table 1-1. The coal consumption cost increases because of the significant quantity of water that is introduced to the boiler with increased dilute urea injection. This additional water is evaporated and negatively impacts the unit efficiency.

Table 2-6: O&M Cost Estimate for MRYS Unit 1 & 2 RRI + SNCR System

Fixed Costs	Unit 1	Unit 2
Operating Labor	$0	$0
Admin and Support labor	$0	$0
Maintenance Material and Labor	$47,000	$54,000
Total Fixed O&M Costs =	**$47,000**	**$54,000**
Variable Costs		
Dilute Urea Reagent	$4,977,000	$4,348,000
Water	$296,000	$696,000
Auxiliary Power	$52,000	$52,000
Increased Coal Usage	$289,000	$687,000
Total Variable O&M Costs =	**$5,614,000**	**$5,783,000**
Total Annual O&M Costs	**$5,661,000**	**$5,837,000**
Net Annual O&M Cost ($/MWh)	2.96	1.64

O&M Cost represent costs above the baseline (existing system)

2.5.1.4 Optimized SNCR O&M Cost Estimate

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The fixed costs include operating labor, administrative and support labor and the maintenance material and labor costs. The maintenance material and labor cost was estimated at approximately 3% of the new direct capital cost in Table 2-5. No change in administrative, support and operating labor cost was assumed. Table 2-7 summarizes the O&M cost estimates for the RRI + SNCR system.

Variable costs include reagent, cooling water, auxiliary power costs and increased coal consumption. The estimated annual costs for these consumables are the estimated change from the baseline conditions based on vendor provided consumption rates, unit operating assumptions and the unit cost information provided in Table 1-1 Economic Design Criteria. The coal consumption cost increases because of the significant quantity of water that is introduced to the boiler with increased dilute urea injection. This additional water is evaporated and impacts the unit efficiency.

Table 2-7: O&M Cost Estimate for MRYS Unit 1 & 2 Optimized SNCR System

Fixed Costs	Unit 1	Unit 2
Operating Labor	$0	$0
Admin and Support labor	$0	$0
Maintenance Material and Labor	$19,000	$22,000
Total Fixed O&M Costs =	**$19,000**	**$22,000**
Variable Costs		
Dilute Urea Reagent	$1,820,000	$717,000
Water	$85,000	$296,000
Auxiliary Power	$26,000	$26,000
Increased Coal Usage	$57,000	$253,000
Total Variable O&M Costs =	**$1,988,000**	**$1,292,000**
Total Annual O&M Costs	**$2,007,000**	**$1,314,000**
Net Annual O&M Cost ($/MWh)	1.05	0.37

O&M Cost represent costs above the baseline (existing system)

2.5.1.5 Levelized Total Annual Cost

In order to effectively compare the cost of installing, operating and maintaining the NOx control systems, capital and O&M costs can be evaluated on a levelized basis.

The Levelized Total Annual Cost (LTAC) for NOx control systems was calculated based on a 20-year project life and are presented in Table 2-8 and Table 2-9 along with the emissions reduction, resultant emissions rate and the Unit Control Cost. No salvage value was assumed at the end of the service life. The Unit Control Cost is the LTAC divided by the annual tons of NOx emissions that would be controlled by implementation of the respective alternative. The Levelized Total Annual Cost and Unit Control Cost are used to evaluate the technology alternatives on a cost effectiveness basis.

Table 2-8: Levelized Total Annual Cost of MRYS Unit 1 NOx Control Technologies

NO$_x$ Control Alternative	Emission Rate lb/10^6 Btu	Annual Emissions (tpy)[1]	Annual Emission Reduction (tpy)[1]	Installed Capital Cost ($2021)[2]	Annual O&M Cost ($2021)	Levelized Total Annual Cost ($2021)[3]	Actual Unit Control Cost ($/ton)[4]	Incremental Unit Control Cost ($/ton)
RRI+SNCR/ASOFA	0.30	2,803	467	9,230,000	5,661,000	6,433,360	13,769	10,232
Optimized SNCR/ASOFA	0.345	3,224	47	1,479,000	2,007,000	2,130,762	45,603	
Existing SNCR/ASOFA[5]	0.35	3,271	Baseline					

1. Based on 2,510 MMBtu/hr and 85% capacity factor.
2. All Costs in 2021 dollars.
3. For LTAC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.
4. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.
5. Baseline emission rate based on maximum 30-day emission rate between 2014-2018.

Table 2-9: Levelized Total Annual Cost of MRYS Unit 2 NOx Control Technologies

NO$_x$ Control Alternative	Emission Rate lb/10^6 Btu	Annual Emissions (tpy)[1]	Annual Emission Reduction (tpy)[1]	Installed Capital Cost ($2021)[2]	Annual O&M Cost ($2021)	Levelized Total Annual Cost ($2021)[3]	Actual Unit Control Cost ($/ton)[4]	Incremental Unit Control Cost ($/ton)
RRI+SNCR/ASOFA	0.29	5,070	1049	15,858,000	5,837,000	7,163,987	6,829	7,144
Optimized SNCR/ASOFA	0.335	5,857	262	2,744,000	1,314,000	1,543,644	5,886	
Existing SNCR/ASOFA[5]	0.35	6,119	Baseline					

1. Based on 4,696 MMBtu/hr and 85% capacity factor.
2. All Costs in 2021 dollars.
3. For LTAC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.
4. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.
5. Baseline emission rate based on maximum 30-day emission rate between 2014-2018.

2.5.1.6 Cost Estimate Conclusion

In the RHCT guidelines, EPA does not provide definition, or even discussion of what Unit Control Costs are considered reasonable or unreasonable. NDDH has indicated that costs below $5,000 per ton may be considered to be reasonable.

The cost analysis portion of the RHCT determination for MRYS Unit 1 and 2 indicates that Actual Unit Control Costs for the top ranked RRI + SNCR for Unit 1 is more than double $5,000 per ton and the Unit 2 cost is well above $5,000 per ton. The incremental rate (cost of removal between two options) of controlling NOx with RRI + SNCR is also over $5,000 per ton on both Units. From an economic analysis viewpoint, the RRI+SNCR system, although the top ranked technology, is not an economically effective NOx control alternative for either Unit 1 or Unit 2.

The Actual Unit Control Costs for the next top ranked control technology, optimized SNCR system, is above $5,000 per ton on Unit 1 and Unit 2. From an economic analysis viewpoint, optimized SNCR system is not an economically effective NOx control alternative for Unit 1 or Unit 2.

2.5.2 Energy Impacts

The primary energy impact of the RRI + SNCR and Optimized SNCR systems is reduced boiler efficiency due to evaporation of large amounts of dilute urea. For Unit 1, the equivalent of an additional 39 tons of coal per day will be required to evaporate the expected amount of dilute urea to be injected into the boiler. For Unit 2, the equivalent of an additional 93 tons of coal per day will be required to evaporate the expected amount of dilute urea to be injected into the boiler. Increasing heat input to maintain present unit production capacity may have PSD implications that could add significant cost and significant permitting considerations.

Other energy impacts include an incremental increase in water consumption due to the need for additional cooling water, and an incremental increase in energy related to providing more compressed air for reagent atomization. The impact of these items is negligible.

Table 2-10: Energy Requirement of MRYS Unit 1 NOx Control Technologies

RHCT Alternative	Energy Demand (kW)	Percent of Nominal Generation
Existing SNCR	200	0.09%
Optimized SNCR	266	0.11%
RRI + SNCR	332	0.14%

Table 2-11: Energy Requirement of MRYS Unit 2 NOx Control Technologies

RHCT Alternative	Energy Demand (kW)	Percent of Nominal Generation
Existing SNCR	300	0.07%
Optimized SNCR	366	0.08%
RRI + SNCR	432	0.10%

2.5.3 Non-Air Quality Environmental Impacts

The addition of the RRI system to the SNCR system is not expected to significantly impact emissions of CO or volatile organic compounds (VOCs).

Operation of the existing SNCR-related system creates a small amount of unreacted ammonia to be emitted. In the future, the settings for the new RRI+SNCR or Optimized SNCR system may increase the amount of ammonia slip produced. Higher NOx reduction performance involves greater amounts of reagent usage and consequently, the increased ammonia slip. This is typically controlled to less than 10 ppmvd, especially when the possible formation of sulfates such as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium bisulfate [NH_4HSO_4] will be more problematic at higher slip levels. Sulfur trioxide (SO_3) formed during combustion in the boiler can combine with ammonia during passage through the flue gas ductwork to form the sulfates.

Some of the unreacted ammonia (ammonia slip) will be collected with the flyash in the ESP. Any remaining ammonia slip that is not collected or condensed in the air pollution control system will collected in the wet scrubber or emitted from the stack as an aerosol or condensable particulate. Increasing the ammonia slip has the potential to increase atmospheric visibility impairment downwind of the facility compared with a pristine condition. Although the predicted amount of such potential impact from ammonia slip emissions has not been determined, it is expected to be small in comparison with the significant anticipated reduction in far-field ozone and improvement in atmospheric visibility as a result of the overall NOx emission reduction.

One mole of carbon dioxide (CO_2) will be created and emitted for every mole of urea injected for reaction with NOx. The consumption rate of urea will significantly increase with the use of RRI+SNCR or optimized SNCR and thus the CO_2 rate will also increase. However, this is a relatively small increase in the total amount of CO_2 produced as part of the combustion of carbon-based fossil fuel in the form of lignite.

Delivery of the urea reagent to the MRYS and storage of aqueous urea reagent on-site creates the potential for accidents, leaks, and subsequent releases to air, ground, and surface water immediately surrounding the facility. Urea is much less volatile than anhydrous or aqueous ammonia, and these risks are expected to be manageable. Emergency planning and community communications are already part of the management plan requirements for such reagent usage.

Increased dilution water and urea usage rates will require the production of greater volumes of Reverse Osmosis (RO)/condensate quality water for dilution of concentrated urea deliveries and injection into the boiler. The production of RO/condensate quality water results in a discharge of a concentrated brine solution, which is ultimately discharged under the requirements of the facility NDPDES permit. This waste stream typically represents 20% of the RO product volume produced. This would result in millions of gallons of additional water treatment wastewaters being discharged from the MRYS facility on an annual basis.

3.0 SO_2 RHCT EVALUATION

The RHCT determination process has five predefined steps as described in Section 1. In this section, steps 1 through 4 of the RHCT determination for Milton R. Young Station (MRYS) are described for SO_2 and a presentation is made of the results. Potentially applicable SO_2 control technologies are first identified. A brief description of the processes and their capabilities are reviewed for availability and feasibility. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal SO_2 control capability. The impacts analysis then reviews the estimated capital and O&M costs for each alternative. Following the cost determination, the energy impacts and non-air quality impacts are reviewed for each technology. The impact based on the remaining useful life of the source is reviewed as part of the cost analysis. The results of the impact analyses are tabulated and potential RHCT options are listed.

3.1 Identification of Retrofit SO_2 Control Technologies

The initial step in the RHCT determination is the identification of retrofit SO_2 control technologies. In order to identify the applicable SO_2 control technologies, several reference works were consulted, including "Controlling SO_2 Emissions: A Review of Technologies (EPA-600/R-00-093, October 2000) and the RACT/BACT/LAER Clearinghouse (RLBC). From these and other literature sources, a preliminary list of control technologies and their estimated capabilities for potential application to MRYS was developed. However, Minnkota already has wet FGD systems installed on both units to achieve 30-day rolling average removal rates of 95% and 90% on Unit 1 and 2, respectively. Additionally, Unit 2 complies with a 0.15 lb/MMBtu 30-day rolling average emission rate. Thus, the control technologies included in the RHCT analysis either meet this minimum level of control or have more stringent removal efficiency. Table 3-1 contains the results of this effort.

Table 3-1: SO_2 Control Technologies Identified for RHCT Analysis

Control Technology	Approximate Control Efficiency
ReACT Scrubber	92-98%
New Wet Flue Gas Desulfurization (FGD)	98%
Modify Existing Wet FGD	96-97%
Circulating Semi-Dry FGD	90-97%
Semi-Dry FGD	90-95%

3.2 Technical Description and Feasibility Analysis

The second step in the RHCT analysis procedure is a technical feasibility analysis of the options identified in Step 1. The RHCT guidelines, which reference the prior BART Guidelines, discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the "availability" and "applicability" of each control technology. A control technology is considered available "if it has reached the stage of licensing and commercial availability" (70 FR 39165). On the contrary, a control technology is not considered available "if it is in the pilot scale testing stages of development" (70 FR 39165). When considering a source's applicability, technical judgment must be exercised to determine "if it can reasonably be installed and operated on the source type" (70 FR 39165). The technical and feasibility analysis is presented below for each identified option.

3.2.1 Wet Flue Gas Desulfurization

Wet FGD technology utilizing lime or limestone as the reagent is commonly applied to coal-fired boilers. Wet FGD utilizes an absorber, such as an open spray tower or a spray tower with a perforated plate contactor, to expose flue gas to the neutralizing slurry. Absorbed SO_2 is converted to calcium sulfite and then may be oxidized to calcium sulfate dihydrate (gypsum) which is filtered from the scrubber solution and either disposed of in a permitted disposal facility, or possibly sold for either wallboard or cement production. Lime is utilized as the reagent in the wet FGD technology analysis, because the plant currently uses lime in the FGD processes and has existing lime reagent preparation equipment. Lime, rather than limestone, is used at the plant because it is the most cost-effective reagent to truck to the plant. The MRYS is not equipped with rail service.

An alternative reagent to lime or limestone is ammonia. The scrubbing technology is similar to other wet FGD systems; however, the byproduct handling is significantly different. The advantage of utilizing ammonia is the production of a high value fertilizer byproduct (ammonium sulfate). This byproduct is a commodity that can be sold worldwide all year. The disadvantage of utilizing ammonia reagent is the byproduct requires significant handling/treatment. This handling/treatment includes concentration, crystallization, drying, prilling and storage. Because ammonium sulfate is highly soluble in water, landfilling the byproduct is not feasible so the product must be stored and sold. As fertilizer is generally seasonal demand in a given part of the country, therefore access to the world market is necessary.

Historically, wet FGD systems have operated with SO_2 control efficiency anywhere from 70% to 98%. New coal-fired power plant SO_2 control projects have achieved coal to stack SO_2 control efficiency of ≥ 99 percent. However, considering a reasonable degree of margin is appropriate to allow for continuous

compliance including upsets, fuel variability, and operational variability, 98% removal on a 30-day rolling average basis is considered an appropriate removal rate for a new state of the art scrubber.
For the purposes of this analysis, a new wet FGD performance was evaluated at 98% SO_2 removal. Due to the relative ages of Unit 1 and Unit 2 scrubbers, a new wet scrubber was considered only for Unit 2, as the Unit 1 wet scrubber was placed in service relatively recently, in 2011. Based on the ability of a new wet FGD system to achieve 98% percent SO_2 removal efficiency and considering the commercial availability and applicability, a new wet FGD system was found to be an acceptable RHCT alternative for MRYS Unit 2 SO_2 emission control.

This report also evaluates the modification of the existing wet FGD process currently operating on Unit 1 and Unit 2 as a possible RHCT alternative. The original equipment manufacturer (OEM) of the Unit 1 scrubber was engaged to evaluate modifications required to increase the removal efficiency of the existing wet FGD processes. The same OEM has previously studied upgrading the Unit 2 scrubber to achieve higher removal efficiency, and was engaged to update and confirm the results of that study. Through this evaluation it was determined modifications can be made to achieve 95-98% removal in each of the two existing scrubbing systems. Upgrades include increasing the liquid-to-gas ratio, installation of new types of spray nozzles, running additional pumps, and adjusting the operating conditions of the scrubber.

The range of removal is dependent on both mechanical upgrades and a range of potential chemistry changes. The potential operating condition changes were evaluated with the Owner's experience with these different operating conditions and considering the impacts they have on reliability and BOP impacts (scaling, nozzle plugging, byproduct settling/removal). Considering these potential impacts/risks, this evaluation assumes 97% removal from the maximum future sulfur fuel (3.2 lb SO_2/MMBtu) to set a not to exceed emission rate. Because the 10 year mining plan indicates the sulfur content of the coal will vary by 40% (generally increasing in the future) a minimum removal rate of 96% is also included.

3.2.2 Semi-Dry Flue Gas Desulfurization

As an alternative to wet FGD technology, the control of SO_2 emissions can be accomplished using semi-dry FGD technology. The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a fabric filter for downstream particulate collection. There are several variations of the semi-dry process in use today. Two other variations, the Flash Dryer Absorber (FDA) and Circulating Dry Scrubber (CDS) are similar in nature. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling. This section addresses the SDA process and the CDS process.

No SDA process has clearly demonstrated the ability to achieve SO_2 removal levels similar to wet FGD systems in the U.S. The application of high SO_2 removal SDA system for high sulfur coal have been limited in the industry due to multiple factors. For purposes of completeness an SDA system is assumed to be able to achieve 93% removal in this application.

The CDS system can increase the lime injection rate independent of the water injection, higher removal rates can be achieved. The CDS system removal is assumed to be equivalent to the retrofit wet FGD system achieving 95-97% removal.

3.2.3 ReACT Dry Scrubbing Process

ReACT (Regenerative Activated Coke Technology) is a multipollutant control system that utilizes activated coke to remove SO_2, NOx and mercury. The process is divided into three main processes; 1) adsorption, 2) regeneration, 3) recovery. In the first step ammonia is injected into the flue gas and the flue gas is passed through an adsorber filled with a moving bed of activated coke pellets where the SO_2 and mercury are adsorbed and the NOx is reduced to N_2. In the second step the activated coke pellets are transferred to a second vessel to be regenerated for recycle/reuse through thermal desorption. The captured mercury is concentrated in the lower portion of the regenerator vessel. The resulting gas from the regeneration step is a concentrated stream of SO_2 that must be further treated in a separate acid recovery plant to produce a sellable sulfuric acid byproduct. Sulfuric acid is a worldwide commodity that, with access, can be sold year-round. This ReACT process is installed and operating on multiple low sulfur coal fired units achieving ≥98% SO_2 removal. Burns & McDonnell contacted the supplier of the ReACT process and discussed the application of the technology to an application like MRYS. It was determined that MRYS is 'not a good application' for the technology, however, the technology could be applied and would work. Factors in this application at MRYS that would impact performance and cost of ReACT include that the inlet temperature is too high, higher oxidation of the activated coke can be expected, and the sulfuric acid production rates would be very high. This technology is still considered a viable alternative and previous ReACT pilot tests on high sulfur coals have shown ReACT can achieve 92-98% SO_2 removal rates.

3.2.4 Results of Feasibility Analysis

The evaluations of the identified RHCT alternatives following the feasibility analysis are summarized in Table 3-2.

Table 3-2: MRYS RHCT SO_2 Control Feasibility Analysis Results

Control Technology	In full-scale service on Existing Utility Boilers	In Service on Other Combustion Sources	Commercially Available	Technically Applicable To Milton R. Young Station
ReACT Scrubber	Yes	Yes	Yes	Yes
Wet FGD	Yes	Yes	Yes	Yes
CDS Dry FGD	Yes	Yes	Yes	Yes
SDA Dry FGD	Yes	Yes	Yes	Yes

3.3 Evaluate Technically Feasible SO_2 Control Options by Effectiveness

The third step in the RHCT analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the RHCT analysis, the SO_2 control efficiency was reviewed and presented as part of the technical description for each technology. The evaluations of the remaining RHCT alternatives following the feasibility analysis are summarized in Table 3-3. The alternatives are ranked in descending order according to their effectiveness in SO_2 control.

Table 3-3: Feasible SO_2 Control Technologies Identified for RHCT Analysis

Control Technology	Unit 1	Unit 2
New Wet FGD	Not Reviewed*	98% Control
ReACT	98% Control	98% Control
Retrofit Existing Wet FGD	97% Control	97% Control
CDS Semi-Dry FGD	NA**	NA**
SDA FGD	NA**	NA**

*Existing system was installed in 2011, so replacement with a like-kind system was not reviewed.

**SDA semi-dry FGD is not evaluated for Unit 1 or 2 because the existing wet FGD can be used to achieve equivalent removal efficiency while using existing equipment.

3.4 Evaluation of Impacts for Feasible SO_2 Controls

Step four in the RHCT analysis procedure is the impact analysis. The draft Guidelines (81 FR 44608) lists four factors to be considered in the impact analysis.

- The costs of compliance;
- The time required for compliance;
- Energy and non-air quality environmental impacts of compliance; and
- The remaining useful life of the source.

Three of the four impacts required by the RHCT Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the

EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the RHCT determination for MRYS.

Unlike the Best Available Retrofit Technology (BART) evaluation performed in the last round for the RHCT evaluation, the technologies in the second implementation period are evaluated on a 'Top Down' down basis similar to a Best Available Control Technology (BACT) approach. Where multiple technologies achieve similar removal rates, a single technology is evaluated to represent that level of performance. The top rated SO_2 removal rate is 98% removal and can be achieved by replacing the existing wet FGD system with either a new wet FGD system or a ReACT system. As a wet FGD system is a well demonstrated technology for high sulfur fuel and ReACT has only been applied on low sulfur fuel this evaluation will focus on the new wet FGD option to evaluate the top rated option. As shown in Table 3-3, ReACT is not expected to have better performance than wet FGD in operating conditions encountered at MRYS.

3.4.1 Cost Evaluation

The following sections evaluate the top two ranked control options for Unit 2, replacing the existing wet FGD system with a new wet FGD system, and upgrading the Unit 2 scrubber. A new wet FGD was not considered for Unit 1, as the existing wet FGD began operations in 2011 as part of the previous BART/BACT analysis and is within the previously evaluated useful life. The top ranked control option for Unit 1, modify the existing wet FGD, is evaluated.

3.4.1.1 New Wet FGD Capital Cost Estimate

Cost estimates for the new wet FGD SO_2 control technologies were completed utilizing the 'IPM Model – Updates to Cost and Performance for APC Technologies Wet FGD Cost Development Methodology' available from the U.S. Environmental Protection Agency and supplemented with engineering estimates based upon Burns & McDonnell's in-house experience. The IPM Model Update is a formula-based report that was specifically developed to estimate the cost of wet FGD technologies for utility power plants. The report was prepared for the EPA in January 2017. The report is available for download from the U.S. EPA website at www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.

As a conservative (lowest cost) approach, this evaluation only considered the 'Absorber Island' portion of the new scrubber cost at a retrofit factor of 1.0 and supplemented this with engineering estimates for new duct work, connecting piping and space modifications required to fit the absorber. This approach assumes all of the existing balance of plant (BOP) systems are capable of supporting the new system with no upgrades. Further, it is assumed there is no change in operating staff and only a proportional change in the variable operating cost. These conservative assumptions minimize the overall project cost resulting in a conservatively low dollars per ton control cost.

For the addition of a new wet FGD absorber, Unit 2 will require new ductwork to connect to the new wet FGD system, modifications to the coal pile to create space for the new system and electrical replacement/upgrades for the new scrubber or a significantly extended outage to allow for the existing wet FGD system to be shut down while the new system is tied in, commissioned and started up. The SO_2 control system cost is representative of a typical furnish and erect contract by a wet FGD system supplier. Economic information utilized as input into the model is given in Table 1-1. The results of the capital cost estimates are given in Table 3-4.

Table 3-4: Capital Cost Estimate for MRYS Unit 2 Wet Lime FGD System

DIRECT COSTS	**Unit 2 Estimated Cost ($)**
New FGD Absorber	
FGD Island	$51,586,000
BOP Costs	
Mechanical Contract	$54,000,000
Foundations and Steel	$4,461,000
BOP Total Direct Cost =	$58,461,000
Total Direct Cost =	$110,047,000
INDIRECT COSTS	
Engineering 10% of DC	$11,005,000
Escalation to 2021	$10,204,000
Indirect Cost Subtotal	$21,209,000
Contingency (20% of DC)	$13,126,000
Prime Contractor's Fee (3% of DC)	$10,107,000
Total Capital Requirement	**$154,489,000**

The total estimated capital cost estimate for a complete new wet FGD absorber is $154,489,000 or $324kW.

3.4.1.2 Wet FGD Modification Capital Cost Estimate

Cost estimates for retrofitting the existing wet FGD systems were based on the equipment modification and associated pricing provided by the OEM and supplemented with engineering estimates for installation based upon Burns & McDonnell's in-house experience.

This evaluation assumes all of the existing balance of plant (BOP) systems are capable of supporting the new system with no further upgrades. Further, it is assumed there is no change in operating staff and only a proportional change in the variable operating cost. These conservative assumptions minimize the overall project cost resulting in a conservatively low dollars per ton control cost.

The capital cost estimate for the Unit 1 wet FGD system modification includes the OEM recommendation to replace three out of the four recirculation pump motors to increase the liquid to gas ratio in the scrubber. During this investigation the existing electrical system and foundation associated with the pump was reviewed and is believed to be sufficient to support this upgrade with no further modifications.

The capital cost estimate for the Unit 2 wet FGD system modification includes the OEM recommendation to replace all of the absorber spray nozzles with dual flow nozzles. The OEM did not recommend upgrading the pumps on Unit 2 due to velocity limitations in the riser pipe and headers and did not recommend upgrading the riser headers and spray headers to accommodate more flow as these upgrades could compromise or complicate the conditions of the existing towers. The results of the capital cost estimates for the FGD system modifications are given in Table 3-5.

Table 3-5: Capital Cost Estimate for MRYS Unit 1 Wet FGD System Modification

DIRECT COSTS	**Unit 1 Estimated Cost ($)**	**Unit 2 Estimated Cost ($)**
Modified FGD System		
FGD Modification Equipment Cost	$569,000	$1,011,000
BOP Costs		
Mechanical Contract	$0	$280,000
Electrical and Controls	$16,000	$0
BOP Total Direct Cost =	$16,000	$280,000
Total Direct Cost =	$585,000	$1,291,000
INDIRECT COSTS		
Engineering 10% of DC	$58,000	$129,000
Escalation to 2021	$54,000	$120,000
Indirect Cost Subtotal	$112,000	$249,000
Contingency (20% of DC)	$70,000	$154,000
Prime Contractor's Fee (3% of DC)	$54,000	$119,000
Total Capital Requirement	**$821,000**	**$1,813,000**

The total estimated capital cost for a upgrades to the Unit 1 wet FGD system is $821,000, or $3.2/kW. The total estimated capital cost for upgrades to the Unit 2 wet FGD system is $1,813,000, or $3.8/kW.

3.4.1.3 New Wet FGD O&M Cost Estimate

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The operating and maintenance costs are evaluated as additional costs beyond the existing wet FGD system as the current costs are part of the baseline operating conditions. The operating labor cost of a new system is not expected to be significantly different than the existing system over the life of the equipment. No additional operating labor has been assumed.

Variable costs include reagent, makeup water, FGD byproduct disposal and auxiliary power costs. The estimated annual costs for these consumables are based on the incremental consumption rates change between the existing removal rate and the new removal rate and the unit cost information provided in Table 1-1 Economic Design Criteria.

Table 3-6: O&M Cost Estimate for a New MRYS Unit 2 Wet Lime FGD System

Fixed Costs	
Operating Labor	$0
Admin and Support labor	$0
Maintenance Material and Labor	$3,301,000
Total Fixed O&M Costs =	**$3,301,000**
Variable Costs	
Lime Reagent	$29,000
Byproduct Disposal	$323,000
Auxiliary Power	$854,000
Total Variable O&M Costs =	**$1,206,000**
Total Annual O&M Costs	**$4,507,000**
Net Annual O&M Cost ($/MWh)	**1.27**

3.4.1.4 Wet FGD Modification O&M Cost Estimate

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The operating and maintenance costs are evaluated as additional costs beyond the existing wet FGD system as the current costs are part of the baseline operating conditions. The operating labor cost of a new system is not expected to be significantly different than the existing system over the life of the equipment. No additional operating labor has been assumed.

Variable costs include reagent, makeup water, FGD byproduct disposal and auxiliary power costs. The estimated annual costs for these consumables are based on the incremental consumption rates change between the existing removal rate and the new removal rate and the unit cost information provided in Table 1-1 Economic Design Criteria.

Table 3-7: O&M Cost Estimate for MRYS Unit 1 and 2 Wet Lime FGD System Modification

Fixed Costs	Unit 1	Unit 2
Operating Labor	$0	$0
Admin and Support labor	$0	$0
Maintenance Material and Labor	$18,000	$39,000
Total Fixed O&M Costs =	**$18,000**	**$39,000**
Variable Costs		
Lime Reagent	$86,000	$162,000
Byproduct Disposal	$8,000	$15,000
Auxiliary Power	$228,000	$376,000
Total Variable O&M Costs =	**$322,000**	**$553,000**
Total Annual O&M Costs	**$340,000**	**$592,000**
Net Annual O&M Cost ($/MWh)	0.18	0.17

O&M Cost represent costs above the baseline (existing system)

3.4.1.5 Levelized Total Annual Cost

In order to effectively compare the cost of installing, operating, and maintaining the SO_2 control systems, capital and O&M costs should be evaluated on a levelized basis.

The Levelized Total Annual Cost (LTAC) for SO_2 control systems was calculated based on overnight construction period (2021), followed by a 20 year service life ending December 31, 2041. O&M costs were based on first year (2021) cost. No salvage value was assumed at the end of the service life for any of the alternatives. The results are presented in Table 3-8 and Table 3-9 along with the emissions reduction, resultant emissions rate and the Unit Control Cost. The Unit Control Cost is the LTAC divided by the annual tons of additional SO_2 emissions that would be controlled by implementation of the respective alternative.

Table 3-8: MRYS Unit 1 SO_2 Control System Levelized Total Annual Cost

SO_2 Control Alternative	**Emission Rate lb/10^6 Btu**	**Annual Emission (tpy) [1]**	**Annual Emission Reduction (tpy) [1]**	**Installed Capital Cost ($2021) [2]**	**Annual O&M Cost ($2021)**	**Levelized Total Annual Cost ($2021) [3]**	**Actual Unit Control Cost ($/ton) [4]**
Modified Wet FGD[5]	0.10	934	374	821,000	340,000	408,701	1,093
Baseline	0.14	1,308	Baseline				

1. Based on baseline heat input of 2,510 MMBtu/hr at 85% capacity factor
2. All Costs in 2021 dollars.
3. For LTAC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.
4. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.
5. Emission rate based on future higher sulfur coal (96% removal).

Table 3-9: MRYS Unit 2 SO_2 Control System Levelized Total Annual Cost

SO_2 Control Alternative	Emission Rate lb/10^6 Btu	Annual Emission (tpy) [1]	Annual Emission Reduction (tpy) [1]	Installed Capital Cost ($2021) [2]	Annual O&M Cost ($2021) [2]	Levelized Total Annual Cost ($2021) [3]	Actual Unit Control Cost ($/ton) [4]	Incremental Unit Control Cost ($/ton)
New Wet FGD	0.065	1,136	1,486	154,489,000	6,133,196	19,060,732	12,826	29,934
Modified Wet FGD[5]	0.10	1,748	874	1,813,000	592,000	743,684	851	
Baseline	0.15	2,622	Baseline					

1. Based on baseline heat input of 4,696 MMBtu/hr at 85% capacity factor
2. All Costs in 2021 dollars.
3. For LTAC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.
4. Overall control cost is LTAC divided by actual annual emissions reduction of each alternative.
5. Emission rate based on future higher sulfur coal (96% removal).

The annual tons of SO_2 reduction in this RHCT analysis are calculated as the difference between the baseline emission rate and the controlled emissions assumed to be at the same heat input and unit operating time.

3.4.1.6 Cost Estimate Conclusion

In the RHCT guidelines, EPA does not provide definition, or even discussion of what Unit Control Costs are considered reasonable or unreasonable. NDDH has indicated that costs below $5,000 per ton may be considered to be reasonable.

The Actual Unit Control Cost are used to evaluate the technology alternatives on a cost effectiveness basis. As can be seen from a review of Table 3-9, the cost of the new Unit 2 wet FGD alternative is excessively high with an actual and incremental control cost far greater than $5,000 dollars per ton.

As can be seen from a review of Table 3-8 and Table 3-9, the wet FGD modification alternatives for both units are not high, with a Actual Unit Control Cost of $851-$1,093 per ton.

3.4.2 Energy Impacts

The energy impacts of replacing the existing U2 wet FGD with a new wet FGD, or of upgrades to the existing wet FGD in the case of Unit 1, in terms of both estimated kW of energy usage and the percent of total generation, are given in Table 3-10 and Table 3-11. The primary energy impacts of the wet FGD alternative consists of the additional electrical load resulting from pumps and reagent preparation. Building HVAC and interior and exterior lighting loads are considered minimal.

Table 3-10: Energy Requirement of MRYS Unit 1 FGD Upgrades

RHCT Alternative	Energy Demand (kW)	Percent of Nominal Generation
Existing Wet FGD	5,170	2.2%
Upgraded Wet FGD	5,756	2.5%

Table 3-11: Energy Requirement of MRYS Unit 2 New FGD

RHCT Alternative	Energy Demand (kW)	Percent of Nominal Generation
Existing Wet FGD	9,658	2.2%
UpgradedWet FGD	10,623	2.4%
New Wet FGD	11,853	2.7%

3.4.3 Non-Air Quality Environmental Impacts

Non-air quality environmental impacts of replacing the existing wet FGD with a new wet FGD or retrofitting the existing FGD systems are expected to be very similar to the impacts of the existing system. These may include hazardous waste generation, solid and aqueous waste streams. The primary change anticipated due to the use of a new wet FGD or modifying the existing FGD systems will be an incremental increase in the solids disposal rate as additional removal of SO_2 will result in increased byproduct.

While the economic evaluation of a new wet FGD system assumes overnight installation, the actual process to bid, design, purchase, and install a retrofitted new wet FGD system can take five years to implement. The actual process to bid, design, purchase, and install a retrofits to an existing wet FGD system can take two to three years to implement.

3.4.4 SO_2 Control Technology Evaluation Conclusion

The energy impacts of a new wet FGD system are only incrementally higher than the existing system and are primarily driven by the increase in SO_2 removal. These incremental increases are acceptable.

The time period to install a new wet FGD system is significantly longer than the second ranked option (retrofitting the existing wet FGD) and would result in years of higher emission rates to achieve only a marginal increased removal rate. This would result in years of higher emissions before the RHCT would be installed.

Considering the existing systems are being replaced with like systems, there could be years of implementation delay with a new system for marginal removal improvement, and the high dollars per ton control cost includes low capital cost assumptions this evaluation rejects the top ranked control technology for Unit 2 (new wet FGD) as RHCT.

While this is not used as the reason for the rejection of this top ranked option, comparison to the second ranked option [an upgrade to the existing wet FGD] shows that the high levelized cost differential and low differential removal rate of the new FGD option result in an excessive incremental dollars per ton removed of almost $30,000 per ton.

The time period to modify the existing wet FGD systems is significantly shorter than installing other new systems and would result in lower emission rates sooner than other options. The average control cost to modify the existing wet FGD systems is well below $5,000 per ton. This evaluation results in modification of the wet FGD systems as RHCT.

4.0 REGIONAL HAZE CONTROL TECHNOLOGY RESULTS

This report presents the analysis of control technologies for nitrogen oxides (NO_X), and sulfur dioxide (SO_2) for Minnkota Power Cooperative Inc.'s (Minnkota's) Milton R. Young Station (MRYS) Units 1 and 2. The final result of this analysis is a Regional Haze Control Technology (RHCT) emission rate for each unit based upon "the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source..." (70 FR 39163). The presented emission rates in this section are the RHCT results.

The first four steps of RHCT are usually used to identify technologies, determine feasibility and evaluate cost, energy, non-air quality and useful life impacts. This analysis reviewed technologies on these factors starting from the baseline of the existing units that include ASOFA/SNCR and wet scrubbers. The RHCT analysis does not review technologies that do not achieve at least the baseline level of performance.

As stated in previous sections of the report, the first four steps of the technology evaluation provided for in the Guidelines were completed for both Units. Each pollutant required a different approach in order to determine RHCT emission rate. This section provides a brief description of the approach used for each pollutant and summarizes the results.

For NOx emissions, the top ranked technically feasible control technology for both units is the use of Rich Reagent Injection (RRI) in combination with Selective Non-Catalytic Reduction (SNCR) and Advanced Separated Overfire Air (ASOFA). However, the RRI+SNCR system is not an economically effective NOx control alternative for either Unit 1 or Unit 2 with average control cost of $6,829 – $13,769.

The Unit Control Costs for the next top ranked control technology, Optimized SNCR system, is above $5,000 per ton on Unit 1 ($45,603 per ton) and Unit 2 ($5,886). From an economic analysis viewpoint, optimized SNCR systems are not economically effective NOx control alternative for either unit.

This evaluation results show the existing SNCR system as the top ranked alternative.

For SO_2 emissions, the top ranked technology for Unit 2 was to replace the existing wet scrubber with a new wet scrubber. This technology was evaluated and rejected primarily because it was determined to be excessively costly on an actual dollars per ton removed basis ($12,826 per ton). Furthermore this top ranked control technology provided only limited additional removal for an order of magnitude additional costs compared to the second ranked control technology.

The next highest ranked control technology (and also top ranked for Unit 1) is to retrofit the existing wet scrubbers to increase removal. The OEM of the Unit 1 scrubber was engaged to evaluate how to increase the Unit 1 scrubber removal and re-evaluate a previous study they performed to increase removal in the Unit 2 scrubber. The mechanical upgrades the OEM included are replacing pump motors and changing nozzle designs. The various changes to operating conditions were evaluated based on the plant's previous operating history and experience to consider which conditions will improve removal, working with the existing system and not impact reliability. There are no sufficient economic or energy reasons to reject modifying the existing scrubbers. There are non-environmental reasons taking are into consideration associated with scrubber operational changes due to long term impact to the scrubber ponds. Based upon this analysis modifying the existing scrubbers is a RHCT option for SO_2 emissions.

Table 4-1 and Table 4-2 summarize the control technologies and associated emission rates for each pollutant and for each unit. The RHCT emission rates are presented as a 30-day rolling average to account for variations in boiler operation, and fuel sulfur content.

Table 4-1: RHCT 30-Day Rolling Average Emission Rate, MRYS Unit 1

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Existing Selective Non-Catalytic Reduction (SNCR) and Advanced Separated Over Fire Air (ASOFA) [1]	0.36
SO_2	Modify the existing Wet Flue Gas Desulfurization (FGD) system [2]	0.10

1: Excludes startups. See referenced BACT analysis for a detailed discussion.

Table 4-2: RHCT 30-Day Rolling Average Emission Rate, MRYS Unit 2

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Existing Selective Non-Catalytic Reduction (SNCR) and Advanced Separated Over Fire Air (ASOFA) [1]	0.35
SO_2	Modify the existing Wet Flue Gas Desulfurization (FGD) system [2]	0.10

1: Excludes startups. See referenced BACT analysis for a detailed discussion.

The four factor analysis was completed based on a request by the North Dakota Department of Health (NDDH) while utilizing the EPA 2016 Guidance document. The NDDH has requested this information for the purpose of WRAP modeling. As EPA has indicated the Regional Haze Roadmap may be updated, and the results of the WRAP modeling will provide new information to be considered, Minnkota reserves the right to modify the 4 Factor analysis once the Regional Haze Roadmap, any additional guidance and the results of the WRAP modeling are available. In addition, Minnkota reserves the right to conduct a 5th Factor based on visibility modeling once the results of the WRAP modeling are available. This analysis is provided to assist the NDDH in the WRAP modeling and is not intended to serve as an agreement by Minnkota to any changes in permitted emission limits or permit conditions.

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May 29, 2019

Mr. Jim Semerad
Director, Division of Air Quality
North Dakota Department of Environmental Quality
Gold Seal Center, 918 East Divide Ave
Bismarck, ND 58501-1947

Dear Mr. Semerad:

Re: Four-Factor Analysis – Milton R. Young Station Unit 1 and Unit 2

Minnkota appreciates the North Dakota Department of Environmental Quality's (NDDEQ) review of the Milton R. Young Station (MRYS) four-factor analysis submitted for the second implementation period of the Regional Haze Rule. As a part of NDDEQ's review, six comments were provided to Minnkota (dated March 18, 2019) as the basis for revising our first report, which was submitted on January 31, 2019. The following provides Minnkota's responses to each of these six comments. Additionally, two hardcopies of Minnkota's revised four-factor analysis report are enclosed.

1) Summary of NDDEQ Comment: *"All estimates of costs should be based on current (2019) dollars not 2021 dollars…All estimates of capital costs must be consistent with [EPA's] Control Cost Manual."*

   Minnkota Response: The revised report reflects 2019 dollars and all capital costs are now consistent with the Control Cost Manual. (Updates appear throughout report impacting cost values.)

2) Summary of NDDEQ Comment: *"…baseline emission rates were based on the maximum 30-day rolling average from 2014-2018. Baseline emissions should represent expected future* ***annual emissions****…"*

   Minnkota Response: Per our discussion with NDDEQ, baseline emissions for both Unit 1 and Unit 2 have been revised and are now based on a 3-year annual average from 2016-2018. For each unit, this baseline period represents two non-major outage years and one major outage year. Emissions data submitted as required by 40 CFR Part 75 were used to determine the baseline emissions. (Discussed in section 1.1.5.)

3) Summary of NDDEQ Comment: *"The costs of Rich Reagent Injection (RRI) appears to be excessive…Please revise the estimates for both units or provide a detailed explanation for the high cost."*

   Minnkota Response: The cost estimates for RRI used in the first draft report were determined using: (1) computational fluid dynamics modeling, boiler mapping and RRI system design in conjunction with advanced separated overfire air (ASOFA) and selective non-catalytic reduction (SNCR) by technology vendor Fuel Tech, and (2) installation and balance of plant (BOP) costs determined by Burns & McDonnell (BMcD) with input from Minnkota. The enclosed revised report, as well as the separately submitted (through confidentiality) Fuel Tech vendor proposals, provide complete details. Minnkota firmly believes that the costs used in the first report are accurate and represent actual costs for installation of RRI with ASOFA and SNCR at MRYS. As such, these costs have not been changed in the revised report. (Discussed in Sections 2.5.1.1, 2.5.1.2 and the addition of Appendices A & B.)

4) Summary of NDDEQ Comment: *"Many cost estimates throughout the analysis are based on vendor budgetary quotes or engineering estimates. When cost estimates are not based on EPA's Control Cost Manual, evidence for the estimate must be provided…"*

   Minnkota Response: As requested, the revised report contains discussion and evidence of vendor budgetary quotes and engineering estimates where used. BMcD has prepared a more detailed breakdown of installation and BOP costs based on a combination of vendor quotations and engineering estimates; this is included as appendices to the revised report. Additionally, confidential vendor proposals from Fuel Tech (NOx control systems) and Marsulex Environmental Technologies (SO_2 control systems) have been submitted separately via confidential avenues. Minnkota is confident that the costs used accurately represent the actual costs for installing the emissions control systems at MRYS. (Discussed in Sections 2.5.1.1, 2.5.1.2, 3.5.1.2 and the addition of Appendices A & B.)

5) Summary of NDDEQ Comment: *"…"levelizing" of costs using the normal electric utility industry method is not acceptable…The costs must be revised to be consistent with the Control Cost Manual."*

   Minnkota Response: The actual cost estimating methods used in the first report were consistent with the Control Cost Manual. However, the nomenclature was not consistent. Therefore, in the revised report, the nomenclature has been updated to be consistent with the Control Cost Manual. The "annualized total cost" (ATC) represents the annual cost of procurement, construction and operation over a 20-year design life, in current day dollars. The ATC represents an annual payment in current day dollars sufficient to finance the project over its entire life. The ATC is the sum of the annualized capital cost and the first year operating & maintenance cost. (Revised Section 1.1.6.)

6) Summary of NDDEQ Comment: *"…the projected emissions (tpy) for a "Modified Wet FGD" were based on future higher sulfur coal. It appears the baseline emission rates were also based on future higher sulfur coal. …the high baseline emission rates should be explained."*

   Minnkota Response: The projected emissions have been modified to reflect a common wet FGD inlet condition. The common/baseline wet FGD inlet condition is the average continuous emissions monitor readings for the 2016-2018 baseline years. (Discussed in section 1.1.5.)

In addition to Minnkota's above responses to the NDDEQ comments and our enclosed revised four-factor analysis report, a separate submission containing confidential documents has also been provided.

Thank you for the attention given to the MRYS four-factor analysis report. If you have any further questions regarding this revised report, please contact me by email at dlaudal@minnkota.com or by phone at (701) 795-4216.

Sincerely,

MINNKOTA POWER COOPERATIVE, INC.

Daniel A. Laudal, Ph.D.
Environmental Manager

Enclosure

c: Gerad Paul
Craig Bleth
Tim Hagerott
Kevin Thomas
Jon Madison
Young Station File

Regional Haze Control Study

Minnkota Power Cooperative, Inc.

Milton R. Young Station Unit 1 and Unit 2
Project No. 107926

Revision 1
5/28/2019

Regional Haze Control Study

prepared for

Minnkota Power Cooperative, Inc.
Milton R. Young Station Unit 1 and Unit 2
Center, North Dakota

Project No. 107926

Revision 1
5/28/2019

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

INDEX AND CERTIFICATION

Minnkota Power Cooperative, Inc.
Regional Haze Control Study

Project No. 107926

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Certification

I hereby certify, as a Professional Engineer in the state of North Dakota, that the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by the Minnkota Power Cooperative, Inc. or others without specific verification or adaptation by the Engineer.

Christopher J. Marks, PE; ND #PE-9703
Insert Engineer's Name, P.E., state, & license

Date: Insert Date

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
ASOFA	Advanced separated over fire air
ATC	Annualized Total Cost
B&W	Babcock & Wilcox
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BOP	Balance of plant
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CD	Consent decree
CDS	Circulating dry scrubber
CFD	Computational fluid dynamics
CO	Carbon monoxide
CO_2	Carbon dioxide
CRF	Capital recovery factor
EPA	United States Environmental Protection Agency
ESP	Electrostatic precipitator
FDA	Flash dryer absorber
FGD	Flue gas desulfurization
Minnkota	Minnkota Power Cooperative, Inc.
MRYS	Milton R. Young Station
NDDEQ	North Dakota Department of Environmental Quality
NOx	Nitrogen oxides

Abbreviation	**Term/Phrase/Name**
NPV	Net present value
O&M	Operation & maintenance
OEM	Original equipment manufacturer
RBLC	RACT/BACT/LAER Clearinghouse
RHCT	Regional Haze Control Technology
RHR	Regional Haze Regulations
RRI	Rich reagent injection
RO	Reverse Osmosis
SCR	Selective catalytic reduction
SDA	Spray dryer absorber
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
Square Butte	Square Butte Electric Cooperative
TPI	Total plant investment
URGE	Ultimate short-term maximum gross output
VOCs	Volatile organic compounds
WRAP	Western Regional Air Partnership

EXECUTIVE SUMMARY

This report presents the Regional Haze Control Technology (RHCT) analysis for nitrogen oxides (NO_x), and sulfur dioxide (SO_2) for Minnkota Power Cooperative, Inc.'s Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station (MRYS)

The MRYS is a two-unit station, located near Center, North Dakota. Unit 1 (257 MWg) commenced commercial operation in 1970, and Unit 2 (477 MWg) commenced operation in 1977. Both units employ Babcock and Wilcox cyclone boilers, and both boilers fire North Dakota lignite supplied from BNI Coal, Ltd's Center Mine. Each unit is equipped with Advanced Separated Over Fire Air (ASOFA) and selective non-catalytic reduction (SNCR) for NO_x control. Each unit is equipped with wet flue gas desulfurization (FGD) for SO_2 control. Each unit employs an electrostatic precipitator (ESP) for particulate control. Each unit employs halide injection and activated carbon injection for the control of mercury.

On July 6, 2005, the United States Environmental Protection Agency (U.S. EPA or EPA) finalized the Regional Haze Regulations (RHR) and Guidelines for BART Determinations. In July of 2016, the EPA issued draft guidance for the second implementation period of the RHR. The guidance document requires a "four factor analysis" to be conducted for sources that have the potential to impair visibility in Class 1 areas. The four statutory factors are:

- The cost of compliance
- The time necessary for compliance
- The energy and non-air quality environmental impacts of compliance
- The remaining useful life of the source

This report presents the required "four factor analysis" for MRYS. Note that for MRYS, Minnkota has determined that the "remaining useful life of the source" is not a relevant factor in the analysis. The term "RHCT analysis" is used throughout this report to refer to the analysis that has been conducted in compliance with the requirements of EPA's July 2016 draft guidance.

The guidance document, in general, indicates that the goal of the second implementation period is to evaluate all sources for incremental visibility improvement, including those sources that were previously determined to be Best Available Retrofit Technologies (BART)-eligible. MRYS Unit 1 and Unit 2 were previously determined to be BART-eligible by the North Dakota Department of Environmental Quality (NDDEQ).

This RHCT evaluation is intended to inform NDDEQ of the future potential to reduce emissions at MRYS and the cost associated with these reductions. This evaluation is based on a top down evaluation of control technologies and will provide NDDEQ an emission rate for visibility impairment modeling.

There are five predefined steps for conducting a RHCT analysis. Steps 1 through 3 include identifying control technologies, evaluating feasibility, and ranking feasible options by control effectiveness. Step 4 involves a technical evaluation of economic, energy, and non-air environmental impacts related to each feasible control technology. This evaluation addresses these first four steps, resulting in an emission rate for the Step 5 Class 1 area visibility impairment impact analysis.

Unlike the previous BART analysis, this analysis reviews technologies on a ‘Top Down’ basis. The best (lowest emitting) feasible technology that is acceptable (considering economic, energy and non-air impacts) will be evaluated by NDDEQ for visibility impact reduction. The results of conducting the four step analysis will provide a recommendation to NDDEQ of a potential RHCT and the associated emission rate.

This analysis used several reference works, including the RACT/BACT/LAER Clearinghouse (RBLC), to identify which control technologies to evaluate. The technologies were reviewed for feasibility and those deemed infeasible were eliminated from further study. The feasible control technologies were then ranked by control efficiency with estimates of costs necessary to implement, operate, and maintain such technologies. The top ranked technology was evaluated based upon the average cost (dollars per ton removed) to determine if it was acceptable. The final RHCT results are summarized in the tables below. The RHCT emission rates are presented as annual average emission rates to account for variations in boiler operation, and fuel quality (including sulfur content). These are the emission rates utilized in the economic evaluation.

MRYS Unit 1 RHCT Annual Average Emission Rates

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_x	Existing Selective Non-Catalytic Reduction and Advanced Separated Over Fire Air	0.332
SO_2	Modify the existing Wet Flue Gas Desulfurization system	0.061

MRYS Unit 2 RHCT Annual Average Emission Rates

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_x	Existing Selective Non-Catalytic Reduction and Advanced Separated Over Fire Air	0.334
SO_2	Modify the existing Wet Flue Gas Desulfurization system	0.057

The four factor analysis was completed based on a request by NDDEQ while utilizing the EPA 2016 Guidance document. The NDDEQ has requested this information for the purpose of Western Regional Air Partnership (WRAP) modeling, and potentially for emissions reductions for the second implementation period. The emission rates in this report are for WRAP modeling and are not proposed permit emission limits. As EPA has indicated, the Regional Haze Roadmap may be updated, and the results of the WRAP modeling will provide new information to be considered. Minnkota reserves the right to modify the four factor analysis once the Regional Haze Roadmap, any additional guidance and the results of the WRAP modeling are available. In addition, Minnkota reserves the right to conduct a 5th factor analysis based on visibility modeling once the results of the WRAP modeling are available.

This analysis is provided to assist the NDDEQ in the WRAP modeling and is not intended to serve as an agreement by Minnkota to any changes in permitted emission limits or permit conditions.

1.0 INTRODUCTION

This report presents the Regional Haze Control Technology (RHCT) analysis for nitrogen oxides (NO_x), and sulfur dioxide (SO_2) for Minnkota Power Cooperative, Inc.'s Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station (MRYS)

The MRYS is a two-unit station, located near Center, North Dakota. Unit 1 (257 MWg) commenced commercial operation in 1970, and Unit 2 (477 MWg) commenced operation in 1977. Both units employ Babcock and Wilcox cyclone boilers, and both boilers fire North Dakota lignite supplied from BNI Coal, Ltd's Center Mine. Each unit is equipped with Advanced Separated Over Fire Air (ASOFA) and selective non-catalytic reduction (SNCR) for NO_x control. Each unit is equipped with wet flue gas desulfurization (FGD) for SO_2 control. Each unit employs an electrostatic precipitator (ESP) for particulate control. Each unit employs halide injection and activated carbon injection for the control of mercury.

The United States Environmental Protection Agency (U.S. EPA or EPA) finalized the Regional Haze Regulations (RHR) and Guidelines for Best Available Retrofit Technology (BART) Determinations[1] in the Federal Register on July 6, 2005 (70 FR 39104). In July 2016, the EPA issued draft guidance for the second implementation period of the RHR[2]. The draft guidance for the second implementation period retains many aspects of the BART guidelines.

The guidance documents, in general, indicate the goal of the second implementation period is to evaluate all sources for incremental visibility improvement including those sources that were previously BART-eligible. Both units at MRYS were previously determined to be BART-eligible by the North Dakota Department of Environmental Quality (NDDEQ). BART is defined as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by a BART-eligible source. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in

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[1] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations"; Environmental Protection Agency; Federal Register, Volume 70, No. 128; July 6, 2005.
[2] "Draft Guidance on Progress Tracking Metrics, Long-Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period", Environmental Protection Agency; Federal Register, Volume 81, No. 131; July 8, 2016.

visibility which may reasonably be anticipated to result from the use of such technology” (70 FR 39163). Note that for MRYS, Minnkota has determined that the “remaining useful life of the source” is not a relevant factor in the analysis.

The second implementation period guidance indicates a similar review to BART should be performed but in the second round the technology evaluation should be based on a ‘top down’ approach. The evaluation criteria are the same as the previous BART analysis, which is on a case-by-case basis considering availability, cost, energy and non-air quality impacts. However, in a ‘top down’ analysis the highest ranked technology that meets the acceptable criteria in the first four steps is the selected technology. The final determination of what top ranked technologies across the utility fleet will be accepted, if any, as the Regional Haze Control Technology (RHCT) is dependent on Step 5 (visibility modeling) and will be based on the modeling performed by the Western Regional Air Partnership (WRAP). This RHCT evaluation will be used by the NDDEQ as a tool to evaluate the potential to reduce emissions at MRYS and the cost associated with these reductions.

1.1 RHCT Analysis Process

The general steps for determining RHCT for each pollutant are virtually the same as the previous BART steps (70 FR 39164) and are as follows:

STEP 1 - Identify all available retrofit control technologies.
STEP 2 - Eliminate technically infeasible options.
STEP 3 - Evaluate control effectiveness of remaining control technologies.
STEP 4 - Evaluate the following impacts for each feasible control technology and document results:
    The cost of compliance.
    The time required for compliance.
    The energy and non-air quality environmental impacts of compliance.
    The remaining useful life of the source.
STEP 5 – Evaluate the visibility impacts.

Unlike the previous BART analysis where all five steps were performed at once, the 2016 EPA Draft Guidance’s approach for the second implementation period of the regional haze program is breaking the first four steps apart from the fifth step. The first four steps are performed on a ‘top down’ basis to determine the top ranked control technology that is applicable to each source. The fifth step, evaluation of visibility impacts, is being conducted by WRAP. The WRAP evaluation of visibility impacts will then be used by the State (as part of the development of the State Implementation Plan) to determine which sources, if any, are needed to fulfill the Reasonable Progress Goals required by the RHR.

Minnkota retained Burns & McDonnell to assist in the completion of the first four steps of the RHCT analysis for MRYS. Burns & McDonnell is a full service engineering, architectural, construction and environmental firm. The company plans, designs and constructs electric generating facilities and has been providing environmental services to the power industry since the 1970s. As a result of their long history providing these services, Burns & McDonnell has extensive experience in permitting, Best Available Control Technology (BACT) studies, BART studies and control technology analysis similar to a RHCT analysis.

1.1.1 Identification of Available Retrofit Control Technologies

The initial step in the RHCT determination is the identification of available retrofit control technologies. In order to identify the available control technologies, several reference works are consulted. A preliminary list of control technologies and their estimated capabilities is then developed.

1.1.2 Elimination of Technically Infeasible Options

The second step of the RHCT process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible. The BART guidelines are applicable to this RHCT analysis. These guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the “availability” and “applicability” of each control technology.

A control technology is considered available “if the source owner may obtain it through commercial channels, or it is otherwise available in the common sense meaning of the term,” or “if it has reached the stage of licensing and commercial availability.” On the contrary, a control technology is not considered available, “in the pilot scale testing stages of development.” (70 FR 39165) When considering a source’s applicability, technical judgment must be exercised to determine “if it can reasonably be installed and operated on the source type.” The EPA also does not “expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type.” (70 FR 39165) “A technology that is available and applicable is technically feasible.” (70 FR 39165)

A control technology is considered technically infeasible if physical, chemical or engineering principles conclude that technical difficulties would preclude use of the control option on the emission unit under review.

1.1.3 Evaluate Technically Feasible Control Option by Effectiveness

The third step in the RHCT analysis is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the analysis, the control efficiency is reviewed and presented with the description of each technology. The evaluation of the technically feasible alternatives concludes with the alternatives ranked in descending order of control effectiveness.

1.1.4 Four Factor Impact Analysis

Step four in the analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) and the draft guidelines for the second implementation period (81 FR 44608) each list four factors to be considered in the impact analysis. The RHCT evaluation will consider the following four factors in the impact analysis:

- The costs of compliance
- The time required for compliance
- The energy and non-air quality environmental impacts of compliance
- The remaining useful life of the source.

The first three of the four factors considered in the impact analysis are discussed in the associated pollutant section. The remaining useful life of the source would have been included as part of the cost of compliance, however for MRYS, Minnkota has determined that the “remaining useful life of the source” is not a relevant factor in the analysis.

In the second implementation period, the impact analysis is performed on a ‘top down’ basis. The highest ranked (lowest emitting) technology is evaluated on the above factors for acceptability. If the top-ranked control technology is unacceptable, then the next highest ranked control technology is evaluated. This process continues until the highest ranked acceptable technology is identified.

1.1.5 Baseline Emissions

The cost of compliance evaluation is typically performed on an annualized dollars per ton of pollutant removed basis. In order to determine the tons removed by a proposed technology, a baseline emission rate must be determined as a basis for the comparison. The MRYS units both have existing SO_2 and NO_x pollution control systems in service, and the baseline is calculated with those systems in operation. Since the control costs are based on annual costs, the baseline emission rates need to be based on a similar long-term basis.

The baseline emission rates were developed by evaluating the three most recent years (2016-2018) for Unit 1 and for Unit 2. This baseline was established in consultation with the NDDEQ. The baseline period, for each unit, contains two non-major outage years and one major outage year. Previously submitted emissions data as required by 40 CFR Part 75 were used to determine the baseline emissions. A summary of the baseline emission rates and annual tons of emissions is provided in Table 1-1 and Table 1-2 for Unit 1 and Unit 2, respectively.

The scrubber inlet SO_2 conditions for each unit at MRYS are measured using continuous emissions monitors (CEMS). These inlet conditions during the baseline period for Unit 1 (2.327 lb/MMBtu) and Unit 2 (2.487 lb/MMBtu) will be used as the basis for future sulfur content at the inlet of each scrubber.

Table 1-1: MRYS Unit 1 Baseline Emissions (2016-2018)

Pollutant	Control Technology	Emissions, lb/MMBtu	Emissions, tpy	Heat Input, MMBtu/year
SO_2	Wet FGD	0.0739	777	20,726,417
NO_x	ASOFA/SNCR	0.332	3,435	20,726,417

Table 1-2: MRYS Unit 2 Baseline Emissions (2016-2018)

Pollutant	Control Technology	Emissions, lb/MMBtu	Emissions, tpy	Heat Input, MMBtu/year
SO_2	Wet FGD	0.126	2165	34,354,956
NO_x	ASOFA/SNCR	0.334	5,735	34,354,956

1.1.6 Methodology for Estimated Costs

The cost summary of each control technology alternative is presented in the section for each pollutant. Installed capital and annual operating and maintenance (O&M) cost estimates for each alternative are presented individually. The Annualized Total Cost (ATC) represents the annual cost of procurement, construction and operation over a 20-year design life, in current day dollars. The ATC is the sum of the annualized capital cost and the first year O&M cost and represents an annual payment in current day dollars sufficient to finance the project over its entire life.

In determining the ATC, a Capital Recovery Cost (CRC) is calculated to annualize the ‘overnight’ capital cost. The CRC is determined by multiplying the Net Present Value (NPV) by a Capital Recovery Factor (CRF). The CRF was calculated from the project economic conditions and then applied separately to the estimated capital costs. The equations used are shown below.

$$CRF = \left(\frac{i\,(1 + i)^n}{(1 + i)^n - 1} \right)$$

$$CRC = CRF \times NPV$$

Where,
CRF = Capital Recovery Factor
CRC = Capital Recovery Cost
NPV = Net Present Value of the capital investments required (overnight cost).
i = discount rate
n = design life in years

For the economic conditions described in Table 1-3, the CRF was calculated to be 0.08368.

Table 1-3: Economic Factors

Factor	Value
Total Possible Operating Hours per Year	8,760
Unit 1 Plant Capacity Factor, 2016-2018 baseline average	79.9%
Unit 2 Plant Capacity Factor, 2016-2018 baseline average	78.7%
Amortization Life, Years	20
Allowance for Funds Used During Construction	Not Included
Property Taxes, Insurance, %	Not Included
Amortization Rate for APC Capital Costs	Not Included
Interest Rate used in Capital Recovery Cost calculation	5.5%
Construction Cost Escalation	Not Included
Maintenance Material and Labor Cost, % of Direct Capital	3%
Non-Fuel O&M Escalation	Not Included
Fuel (coal and natural gas) Escalation	Not Included
Lost Electrical Generation Cost, $/MW-hr	$22.00
Auxiliary Electric Power Cost, $/MW-hr	$48.07
Reverse Osmosis Water, $/kgal	$9.03
Condensate water, $/kgal	$9.85
Urea 70% Solution, $/ton	$419.00
Lime, $/ton	$192.00
FGD Byproduct Disposal, $/ton	$6.00

(1) All costs are in 2019 dollars unless noted otherwise.

The capital cost (NPV in the equation above) is an ‘overnight’ installed cost for the equipment, in current day dollars, that does not include income tax effects, owners’ costs, escalation during construction, or interest costs from financing. The O&M cost used is the first-year costs, in 2019 dollars. The O&M cost was not further inflated or otherwise annualized. The ATC is the sum of the annualized capital cost and the first year O&M cost. Therefore:

$$\text{ATC} = \text{CRC} + 1^{st}\text{ Year O\&M} = (\text{CRF x NPV}) + 1^{st}\text{ Year O\&M} = 0.08368\text{ x NPV} + 1^{st}\text{ Year O\&M}$$

The economic analyses presented in this report not only includes the estimated capital and annual O&M costs for each top ranked control technology, but also the ATC for economic comparison.

1.2 Background

MRYS is a steam electric generating plant with two units. Unit 1 employs ASOFA + SNCR for NO_x control, achieving 59% NO_x reduction. Particulate control is provided by a Research-Cottrell Electrostatic Precipitator (ESP) rated at approximately 99% control. Unit 1 has a Wet Flue Gas Desulfurization (FGD) system provided by Marsulex Environmental Technologies achieving compliance with a 30-day rolling average 95% SO_2 removal efficiency, based on inlet and outlet SO_2 CEMS, and exhausts to a 564-foot-tall chimney.

Unit 2 employs ASOFA + SNCR for NO_x control, achieving 60% NO_x reduction. Particulate control for Unit 2 is provided by a Wheelabrator-Lurgi ESP rated at approximately 99% control. Unit 2 has a Combustion Equipment Associates wet FGD system (modified by Combustion Engineering) achieving compliance with a 30-day rolling average 90% SO_2 removal efficiency, based on inlet and outlet SO_2 CEMS, and a 30-day rolling average 0.15 lb/MMBtu emission rate, and exhausts to a 550-foot-tall chimney.

Unit 1 began commercial operation on November 20, 1970 and Unit 2 on May 11, 1977.

2.0 NO_X RHCT EVALUATION

The RHCT analyses for NO_x emissions from MRYS Unit 1 and Unit 2 are described in this section. Technical descriptions of MRYS Unit 1 and Unit 2 boilers and existing air pollution control equipment are provided. Minnkota previously entered into a Consent Decree (CD) that required MRYS to install BACT for NO_x, which was determined to be SNCR systems with ASOFA on both units. These technologies are the current baseline condition for the two units.

2.1 NO_x Evaluation Basis

MRYS Unit 1 includes a B&W steam generator installed in 1970. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation. The boiler is fired by seven ten-foot diameter cyclone furnaces, arranged “three over four” across the front wall of the lower boiler. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Unit 1’s boiler serves a turbine generator with a nameplate rating of 257 MWg[3]. The Unit 1 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from the Center Mine, operated by BNI Coal, LTD, located adjacent to the site. The baseline emission rate of the Unit 1 boiler using the existing ASOFA/SNCR system is 0.332 lb NO_x/MMBtu, as described previously in Section 1.1.5.

MRYS Unit 2 is a B&W steam generator installed in 1977. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation assisted with circulation pumps. The boiler is fired by twelve ten-foot diameter cyclone furnaces, arranged “three over three” across the front and rear walls of the lower boiler. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Unit 2’s boiler serves a turbine-generator with a nameplate rating of 477 MWg[4]. The Unit 2 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from the Center Mine located adjacent to the site. The baseline emission rate of the Unit 2 boiler using the existing ASOFA/SNCR system is 0.334 lb NO_x/MMBtu, as described previously in Section 1.1.5.

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[3] Ibid EPA’s eGRID database; April 2003.
[4] Ibid EPA’s eGRID database; April, 2003.

2.2 Identification of Retrofit NO_x Control Technologies

The initial step in the RHCT determination is the identification of retrofit NO_x control technologies. In order to identify the applicable NO_x control technologies, several reference works were consulted, including the RACT/BACT/LAER Clearinghouse (RLBC). From this and other literature sources, a preliminary list of control technologies and their estimated capabilities for potential application to MRYS was developed. However, as discussed in the introduction, Minnkota already has ASOFA and SNCR systems installed on both units to achieve 30-day rolling average removal rates of 60% and 59% on Unit 1 and Unit 2, respectively. Thus, the control technologies included in the RHCT analysis either meet this minimum level of control or have more stringent removal efficiency. Table 2-1 contains the results of this effort.

Table 2-1: NO_x Control Technologies Identified for RHCT Analysis

Control Technology	Approximate Annual Control Efficiency*
Selective Catalytic Reduction and ASOFA	90%
Rich Reagent Injection and SNCR and ASOFA	66-68%
Optimized SNCR and ASOFA	60-61%
Existing SNCR* and ASOFA	Baseline 59-60%

*Based on pre SNCR/ASOFA baseline of 0.820/0.817 lb NO_x/MMBtu for Units 1 and 2, respectively.

2.3 Technical Description and Feasibility Analysis

The second step in the RHCT analysis procedure is a technical feasibility analysis of the options identified in Step 1. The RHCT guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the “availability” and “applicability” of each control technology. A control technology is considered available, “if it has reached the stage of licensing and commercial availability.” (70 FR 39165) On the contrary, a control technology is not considered available, “if it is in the pilot scale testing stages of development.” (70 FR 39165) When considering a control technology’s applicability, technical judgment must be exercised to determine “if it can reasonably be installed and operated on the source type.” (70 FR 39165) The technical feasibility analysis is presented below for each identified option.

2.3.1 Selective Catalytic Reduction

The lowest NO_x emission levels from coal-fired utility boilers are typically achieved by installing and operating selective catalytic reduction (SCR) technology. In the SCR process, the gas stream is passed through a catalyst bed in the presence of ammonia to reduce NO_x to molecular nitrogen and water. The process is termed “selective” because the ammonia preferentially reacts with the NO_x rather than with the oxygen in the flue gas. A large reactor containing catalyst is used to enhance NO_x reduction and ammonia utilization at lower flue gas temperatures than required by an SNCR system. SCR is usually applied to flue gas in the 600°F to 750°F temperature range. There are variations in the SCR process for coal-fired boilers that mostly involve locations in the flue gas path where the catalyst is placed in order to promote the desired NO_x emission reduction effect. This technology was reviewed in the previous BART and BACT analysis (2008-2010) and it was concluded by NDDEQ that SCR systems (of all types) are technically infeasible at MRYS. No new information or experience has occurred since 2010 to change the conclusion of this analysis and this technology remains technically infeasible.

2.3.2 Rich Reagent Injection & Selective Non-Catalytic Reduction

Rich Reagent Injection (RRI) has been demonstrated and placed in continuous operation on multiple cyclone boilers. RRI is specifically intended for NO_x emissions control on cyclone boilers. RRI adds dilute urea reagent to the hot boiler gases near the cyclones, which must be devoid of free oxygen in order to avoid oxidation of the urea and formation of additional NO_x. This system is combined with SNCR to further reduce NO_x emissions within the boiler. The ASOFA system would be operated in conjunction with the RRI and SNCR systems. RRI is considered technically feasible under limited conditions for application on the Unit 1 and Unit 2 cyclone boilers at MRYS.

2.3.3 Optimized Selective Non-Catalytic Reduction

Taking into consideration the past operating experience of the existing system and vendor experience since the original installation, there is potential to reduce the emission rate further with enhancements to the existing system. These enhancements could include changing the nozzles on existing lances, replacing the existing lances, and adding lances in new locations. Additionally, allowing for higher ammonia slip rates than originally designed (i.e., 10 ppm vs. 5 ppm) will allow for higher levels of urea injection, which has the potential to further reduce NO_x emission rates. The ASOFA system would be operated in conjunction with the optimized SNCR system. Optimized SNCR is considered technically feasible for application on the Unit 1 and Unit 2 cyclone boilers at MRYS.

2.3.4 Results of Feasibility Analysis

The evaluations of the identified RHCT alternatives following the feasibility analysis are summarized in Table 2-2.

Table 2-2: MRYS RHCT NO_x Control Feasibility Analysis Results

Control Technology	In full-scale service on Existing Utility Boilers	In Service on Other Combustion Sources	Commercially Available	Technically Applicable to MRYS
SCR	Yes	Yes	No*	No
RRI + SNCR	Yes	Yes	Yes	Yes**
Optimized SNCR	Yes	Yes	Yes	Yes
Existing SNCR	Yes	Yes	Yes	Yes

*Not available on cyclone fired units firing North Dakota lignite.
**Under limited operating conditions

2.4 Evaluate the Technically Feasible NO_x Control Options by Effectiveness

The third step in the RHCT analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives. In step 2 of the RHCT analysis, the NO_x control efficiency was reviewed and presented as part of the technical description for each technology. The evaluations of the remaining RHCT alternatives following the feasibility analysis are summarized in Table 2-3. The alternatives are ranked in 'top down' descending order according to their annual effectiveness in NO_x control.

Table 2-3: Feasible NO_x Control Technologies Identified for RHCT Analysis

Control Technology	Unit 1 Annual lb/MMBtu	Unit 2 Annual lb/MMBtu
Applied RRI + SNCR/ASOFA	0.28	0.26
Applied Optimized SNCR/ASOFA	0.33	0.32
Existing SNCR/ASOFA	0.332	0.334

The 'applied' emission rates identified in Table 2-3 were developed as annual emission rates taking into account vendor supplied information, variations in load, variations in boiler operating conditions, and experience in the long-term variations in effectiveness of boiler NO_x control technologies. The variable quality of mine-mouth lignite coal is responsible for most of the operating variation experienced. The vendor information is based on MRYS unit-specific measured data of boiler temperature and species of NO_x, CO and O_2. This data was mapped and used to perform computational fluid dynamics (CFD) modeling to determine the equipment, approximate injection locations, and subsequent emission rate able to be achieved. The 'applied' emission rates take into account that the rates must be continuously achievable on an annual basis including the impacts of changing unit loads, control equipment limitations, and variability in coal quality.

Load variation must be considered because at lower loads the ability to control NO_x is reduced. The RRI and SNCR systems are designed to inject dilute urea into the correct temperature zones in the boiler for NO_x control. The maximum NO_x reductions from both RRI and SNCR systems occur when steady-state conditions are achieved when the boiler is at or near full load. At all other conditions, the ability to control NO_x can be significantly impacted. RRI operation depends on oxygen-deprived conditions, and without this (such as with one or more cyclones out of service and/or at lower loads), using the RRI system will increase NO_x emissions. Multiple levels of injection are included to introduce reagent into the correct temperature zone at varying unit loads. However, even with multiple injection levels, emission reductions are reduced at lower loads.

MRYS is a mine-mouth plant that utilizes run-of-mine fuel, which results in significant coal quality variability. Within any 30-day period, the plant can, and has, experienced multiple days of lower quality coal that in turn, creates conditions that make NO_x harder to control, increasing emissions and reagent usage rates.

These factors, along with unit-specific vendor information, were considered in developing the ‘applied’ annual evaluation rate. The emission rates stated by vendors are based on stable, steady state operating conditions, and do not reflect the varying conditions that occur over the life of the equipment, or even in a 30-day or annual operating period. An emission rate must account for operating during periods such as the transition period between two planned stable load conditions, and other unplanned operating variations described above.

During normal high load operations at MRYS, the lower portions of the Unit 1 and Unit 2 boiler are in an oxygen deficient, fuel rich environment. These conditions in the boiler reduce the amount of thermal NO_x being produced as the fuel is combusted. These are the conditions required for optimal use of RRI. As the stoichiometric ratio (oxygen to fuel ratio) in the lower portion of the boiler increases, the performance of a RRI system decreases, with the urea becoming oxidized to create additional NO_x in the presence of oxygen. Several operating conditions can cause lower boiler stoichiometric ratio to increase. Some of these conditions, which are frequently experienced at MRYS, are discussed below:

- Cyclone(s) out of service - Both Unit 1 and Unit 2 boilers are designed to operate with one cyclone out of service and still achieve full load. It is not unusual for single cyclones to be out of service for routine maintenance. Air leaking through the combustion air dampers of an out-of-service cyclone will increase NOx formation due to addition of oxygen in the fuel-rich zone.
- Main fuel oil in service – Due to variations in coal quality, cyclone(s) may become fouled, meaning that insufficient temperature exists for the slag to flow properly from the cyclone. During these times, it becomes necessary to co-burn fuel oil in the fouled cyclone(s), which

results in increased oxygen in the fuel-rich zone and the formation of additional NOx. When main fuel oil is in service, the ASOFA system for the cyclone(s) is deactivated because it is ineffective. The deactivation of the ASOFA for the cyclone(s) will increase the stoichiometric ratio in the lower boiler.

- Fuel Variability - With the variability of the coal that is being combusted, the carbon content of the coal also changes. Because the carbon content of the fuel is not known in real-time, the oxygen to fuel carbon ratio continuously changes as the coal composition naturally varies with deliveries from the mine.

As described above, the ‘applied’ annual emission rates established in Table 2-3, for both the RRI + SNCR/ASOFA and Optimized SNCR/ASOFA control technologies, have been determined based on MRYS unit-specific operations and represent annual average emission rates. Note that these projected emission rates do not equate to achievable annual emission permit limits, however.

2.5 Evaluation of Impacts for Feasible NO_x Controls

Step four in the RHCT analysis procedure is the impact analysis. The draft Guidelines (81 FR 44608) lists four factors to be considered in the impact analysis.

- The costs of compliance
- The time required for compliance
- The energy and non-air quality environmental impacts of compliance
- The remaining useful life of the source

Three of the four impacts required by the RHCT Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA’s OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the RHCT determination for MRYS.

2.5.1 Cost Estimates

The following sections evaluate the top two ranked NO_x control options on Unit 1 and Unit 2: replacing the existing SNCR systems with new RRI + SNCR systems and optimizing the existing SNCR systems (with both units maintaining the existing ASOFA systems). Cost estimates for the RRI + SNCR control technology were developed based on proposals from an RRI + SNCR vendor, and installation estimates were based upon Burns & McDonnell’s in-house experience for additional water treatment, compressed air, balance of plant (BOP) piping, access, and installation. The RRI + SNCR vendor utilized CFD modeling results completed by another vendor as well as conducted on-site data measurement of boiler temperature and species of NO_x, CO and O_2. The measured data was mapped and used to perform additional CFD modeling to determine the equipment and optimum injection locations. The data collected by these vendors and the proposal of the RRI + SNCR technology vendor provide good assurance that the application of these technologies, and their associated costs, are well understood for the boilers at MRYS. Economic information utilized as inputs to the model are provided in Table 1-3.

2.5.1.1 RRI + SNCR Capital Cost Estimate

The vendor equipment cost estimate for the RRI + SNCR system is based on the vendor proposal and includes new RRI injectors and associated equipment as well as equipment necessary to modify the existing SNCR system. A proposal from the vendor has been submitted to NDDEQ under separate cover to protect confidential business information. The remaining capital cost estimate includes installation of the vendor equipment, supply and installation of necessary equipment access, and BOP costs.

Because boiler testing, data from CFD modeling, and detailed RRI injection analysis was performed by the vendors as part of the RRI + SNCR system evaluation, it is known that the necessary injection locations are not in easily accessible locations on either unit. Because of the detailed evaluation by the vendor, the proposed system is specific to MRYS and identified the need for significant BOP modifications. The BOP design accounted for the new recommended RRI + SNCR injection locations by including: new platforms and stairs to access the new injection elevations/locations; significant new piping for increased urea, cooling water, dilution water and atomization air; expansion of the microfiltration and reverse osmosis water system due to the increased dilution water usage; and supply and installation of the boiler bent tube openings for the new RRI + SNCR injectors, including the necessary boiler scaffolding. Appendix A includes a breakdown of major cost categories.

The NO_x control system cost (Table 2-4) is representative of a typical furnish and erect contract.

Table 2-4: **Capital Cost Estimate for MRYS Unit 1 & 2 RRI + SNCR System**

DIRECT COSTS	Unit 1 Estimated Cost ($)	Unit 2 Estimated Cost ($)
RRI and SNCR System		
Equipment Cost	$4,283,000	$5,507,000
BOP Costs		
Mechanical Contract	$1,611,000	$4,709,000
Foundations and Steel	$559,000	$900,000
Electrical and Controls	$131,000	$179,000
BOP Total Direct Cost	$2,301,000	$5,788,000
Total Direct Cost	$6,584,000	$11,295,000
INDIRECT COSTS		
Engineering 10% of DC	$647,000	$1,129,000
Escalation	Not Included	Not Included
Indirect Cost Subtotal	$647,000	$1,129,000
Contingency (20% of DC)	$723,000	$1,242,000
Prime Contractor's Fee (3% of DC)	$557,000	$957,000
Total Capital Requirement	**$8,511,000**	**$14,623,000**

The total estimated capital cost estimate to upgrade the existing Unit 1 SNCR system to a RRI + SNCR system is $8,511,000, or $33.1/kW. The total estimated capital cost estimate to upgrade the existing Unit 2 SNCR system to a RRI + SNCR system is $14,623,000, or $30.7/kW.

2.5.1.2 Optimized SNCR Capital Cost Estimate

The vendor equipment cost estimate for optimizing the SNCR system is based on the vendor proposal and includes equipment necessary to modify the existing SNCR system. Because of the detailed evaluation by the vendor, the proposed system is specific to the MRYS and identified the need for additional modifications. The design accounted for the new recommended SNCR injection locations by including the supply and installation of the boiler bent tube openings for the new SNCR injectors including the necessary boiler work platforms. The NO_x control system cost (Table 2-5) is representative of a typical furnish and erect contract. Appendix B includes a breakdown of major cost categories.

Table 2-5: Capital Cost Estimate for MRYS Unit 1 & 2 Optimized SNCR System

DIRECT COSTS	Unit 1 Estimated Cost ($)	Unit 2 Estimated Cost ($)
Optimized SNCR System		
Equipment Cost	$1,238,000	$1,265,000
BOP Costs		
Mechanical Contract	$321,000	$958,000
Foundations and Steel	$259,000	$409,000
Electrical and Controls	$38,000	$48,000
BOP Total Direct Cost	$618,000	$1,415,000
Total Direct Cost	$1,857,000	$2,680,000
INDIRECT COSTS		
Engineering 10% of DC	$183,000	$268,000
Escalation	Not Included	Not Included
Indirect Cost Subtotal	$183,000	$268,000
Contingency (20% of DC)	$204,000	$295,000
Prime Contractor's Fee (3% of DC)	$157,000	$227,000
Total Capital Requirement	**$2,400,000**	**$3,470,000**

The total estimated capital cost estimate to optimize the Unit 1 SNCR system is $2,400,000 or $9.3/kW. The total estimated capital cost estimate to optimize the Unit 2 SNCR system is $3,470,000 or $7.3/kW.

2.5.1.3 RRI + SNCR O&M Cost Estimate

The annual O&M costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The fixed costs include operating labor, administrative and support labor, and the maintenance material and labor costs. No change in administrative, support and operating labor cost was assumed. The maintenance material and labor cost is estimated at 3% of the system direct capital costs in Table 2-4. Table 2-6 summarizes the O&M cost estimates for the RRI + SNCR systems.

Variable costs include reagent, cooling water, dilution water, auxiliary power costs and the loss of electrical generation revenues. The estimated annual costs for these consumables are the estimated change from the baseline conditions based on vendor provided consumption rates, unit operating assumptions and the unit cost information provided in Table 1-3. The costs associated with loss of electrical generation capacity (i.e. revenue lost) are because of the significant quantity of urea and water that is introduced to the boiler with increased dilute urea injection. This additional urea and water is evaporated and negatively impacts the unit efficiency. Since the assumption of this RHCT analysis is that heat input is the same in the baseline case as for the future control alternatives, the loss in unit efficiency equates to a decrease in generation. While lost electricity sales revenues are not in actuality an O&M expense, they represent an opportunity cost of installing RRI + SNCR and are thus important to include for the purposes of this analysis.

Table 2-6: O&M Cost Estimate for MRYS Unit 1 & 2 RRI + SNCR System

Fixed Costs	Unit 1	Unit 2
Operating Labor	$0	$0
Admin and Support labor	$0	$0
Maintenance Material and Labor	$47,000	$54,000
Total Fixed O&M Costs	**$47,000**	**$54,000**
Variable Costs		
Urea Reagent	$4,522,000	$4,590,000
Water	$209,000	$471,000
Auxiliary Power	$45,000	$44,000
Lost Generation	$469,000	$1,119,000
Total Variable O&M Costs	**$5,245,000**	**$6,224,000**
Total Annual O&M Costs	**$5,292,000**	**$6,278,000**
Net Annual O&M Cost ($/MWh)	**2.94**	**1.91**

O&M Cost represent costs above the baseline (existing system)

2.5.1.4 Optimized SNCR O&M Cost Estimate

The annual O&M costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The fixed costs include operating labor, administrative and support labor and the maintenance material and labor costs. The maintenance material and labor cost is estimated at 3% of the new direct capital costs in Table 2-5. No change in administrative, support and operating labor cost was assumed. Table 2-7 summarizes the O&M cost estimates for the Optimized SNCR system.

Variable costs include reagent, dilution water, auxiliary power costs and loss of electrical generation revenues. The estimated annual costs for these consumables are the estimated change from the baseline conditions based on vendor provided consumption rates, unit operating assumptions and the unit cost information provided in Table 1-3. The costs associated with loss of electrical generation capacity (i.e. revenue lost) are because of the significant quantity of urea and water that is introduced to the boiler with increased urea injection. This additional urea and water is evaporated and negatively impacts the unit efficiency. Since the assumption of this RHCT analysis is that heat input is the same in the baseline case as for the future control alternatives, the loss in unit efficiency equates to a decrease in power generation.

Table 2-7: O&M Cost Estimate for MRYS Unit 1 & 2 Optimized SNCR System

Fixed Costs	Unit 1	Unit 2
Operating Labor	$0	$0
Admin and Support labor	$0	$0
Maintenance Material and Labor	$35,000	$36,000
Total Fixed O&M Costs	$35,000	$36,000
Variable Costs		
Urea Reagent	$1,661,000	$909,000
Water	$19,000	$116,000
Auxiliary Power	$23,000	$22,000
Lost Generation	$95,000	$414,000
Total Variable O&M Costs	**$1,798,000**	**$1,461,000**
Total Annual O&M Costs	**$1,833,000**	**$1,497,000**
Net Annual O&M Cost ($/MWh)	**1.02**	**0.46**

O&M Cost represent costs above the baseline (existing system)

2.5.1.5 Annualized Total Cost

In order to effectively compare the cost of installing, operating and maintaining the NO_x control systems, capital and O&M costs can be evaluated on an annualized basis.

The Annualized Total Cost (ATC) for NO_x control systems was calculated based on a 20-year project life and is presented in Table 2-8 and Table 2-9, for Unit 1 and Unit 2, respectively, along with the emissions reduction, resultant emissions rate and the Unit Control Cost. No salvage value was assumed at the end of the service life. The Unit Control Cost is the ATC divided by the annual tons of NO_x emissions that would be controlled by implementation of the respective control technology. The ATC and Unit Control Cost are used to evaluate the control technologies on a cost effectiveness basis.

Table 2-8: Annualized Total Cost of MRYS Unit 1 NO_x Control Technologies

NO_x Control Alternative	Emission Rate lb/10^6 Btu	Annual Emissions (tpy) [1]	Annual Emission Reduction (tpy) [1]	Installed Capital Cost ($) [2]	Annual O&M Cost ($)	Annualized Total Cost ($) [3]	Actual Unit Control Cost ($/ton) [4]	Incremental Unit Control Cost ($/ton)
Applied RRI+SNCR/ASOFA	0.28	2,902	539	8,500,000	5,300,000	6,000,000	11,100	7,700
Applied Optimized SNCR/ASOFA	0.33	3,420	21	2,400,000	1,800,000	2,000,000	96,500	
Existing SNCR/ASOFA[5]	0.332	3,441	Baseline					

1. Based on baseline heat input of 20,726,417 MMBtu/yr
2. All Costs in 2019 dollars.
3. For ATC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.
4. Overall control cost is ATC divided by actual annual emissions reduction of each alternative.
5. Baseline emission rate based on average emission rate between 2016-2018.

Table 2-9: Annualized Total Cost of MRYS Unit 2 NO_x Control Technologies

NO_x Control Alternative	Emission Rate lb/10^6 Btu	Annual Emissions (tpy) [1]	Annual Emission Reduction (tpy) [1]	Installed Capital Cost ($) [2]	Annual O&M Cost ($)	Annualized Total Cost ($) [3]	Actual Unit Control Cost ($/ton) [4]	Incremental Unit Control Cost ($/ton)
Applied RRI+SNCR/ASOFA	0.26	4,466	1271	14,600,000	6,300,000	7,500,000	5,900	5,500
Applied Optimized SNCR/ASOFA	0.32	5,497	240	3,500,000	1,500,000	1,800,000	7,500	
Existing SNCR/ASOFA[5]	0.334	5,737	Baseline					

1. Based on baseline heat input of 34,354,956 MMBtu/yr
2. All Costs in 2019 dollars.
3. For ATC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.
4. Overall control cost is ATC divided by actual annual emissions reduction of each alternative.
5. Baseline emission rate based on average emission rate between 2016-2018.

2.5.1.6 Cost Estimate Conclusion

In the RHCT guidelines, EPA does not provide definition, or even discussion of what Unit Control Costs are considered reasonable or unreasonable. NDDEQ has indicated that costs below $4,500 per ton may be considered to be reasonable.

The cost analysis portion of the RHCT determination for MRYS Unit 1 and 2 indicates that Actual Unit Control Costs for the top ranked RRI + SNCR for Unit 1 is more than double $4,500 per ton and the Unit 2 cost is almost $6,000 per ton. The incremental rate (cost of removal between two options) of controlling NO_x with RRI + SNCR is also over $4,500 per ton on both Units. From an economic analysis viewpoint, the RRI+SNCR system, although the top ranked technology, is not an economically feasible NO_x control alternative for either Unit 1 or Unit 2.

The Actual Unit Control Costs for the next top ranked control technology, optimized SNCR system, for Unit 1 is more than an order of magnitude greater than $4,500 per ton and the Unit 2 cost is over $7,000 per ton. From an economic analysis viewpoint, the optimized SNCR system is not an economically feasible NO_x control alternative for Unit 1 or Unit 2.

2.5.2 Energy Impacts

The primary energy impact of the RRI + SNCR and Optimized SNCR systems is reduced boiler efficiency due to evaporation of large amounts of dilute urea. For the purposes of this RHCT analysis, it was assumed that the heat input rate (MMBtu/yr) for the baseline and each control technology case were the same. Therefore, no additional coal usage was assumed; rather, it was assumed that a loss of electrical generation capacity would occur for the control cases. However, for the Optimized SNCR for Unit 1, the equivalent of an additional 8 tons of coal per day would be required to evaporate the expected amount of dilute urea to be injected into the boiler. For Optimized SNCR for Unit 2, the equivalent of an additional 34 tons of coal per day would be required to evaporate the expected amount of dilute urea to be injected into the boiler. For the RRI + SNCR for Unit 1, the equivalent of an additional 39 tons of coal per day would be required to evaporate the expected amount of dilute urea to be injected into the boiler. For RRI + SNCR for Unit 2, the equivalent of an additional 94 tons of coal per day would be required to evaporate the expected amount of dilute urea to be injected into the boiler. Increasing heat input to maintain present unit production capacity may have New Source Review, Prevention of Significant Deterioration implications that could add significant cost and permitting considerations. Without a heat input increase, electrical generation would decrease, meaning that generation from another unit, with unknown environmental profile, would be required to make up for the loss.

Other energy impacts include an incremental increase in water consumption due to the need for additional cooling water, and an incremental increase in energy related to providing more compressed air for reagent atomization. Auxiliary power requirements for each of the control technologies are presented in Table 2-10 and Table 2-11 for Unit 1 and Unit 2, respectively.

Table 2-10: Auxiliary Energy Requirement of MRYS Unit 1 NO_x Control Technologies

RHCT Alternative	Energy Demand (kW)	Percent of Nominal Generation
Existing SNCR	200	0.09%
Optimized SNCR	266	0.11%
RRI + SNCR	332	0.14%

Table 2-11: Auxiliary Energy Requirement of MRYS Unit 2 NO_x Control Technologies

RHCT Alternative	Energy Demand (kW)	Percent of Nominal Generation
Existing SNCR	300	0.07%
Optimized SNCR	366	0.08%
RRI + SNCR	432	0.10%

2.5.3 Non-Air Quality Environmental Impacts

The addition of the RRI system to the SNCR system is not expected to significantly impact emissions of CO or volatile organic compounds (VOCs).

Operation of the existing SNCR system creates a small amount of unreacted ammonia to be emitted. In the future, the settings for the new RRI+SNCR or Optimized SNCR system may increase the amount of ammonia slip produced. Higher NO_x reduction performance involves greater amounts of reagent usage and consequently, the increased ammonia slip. This is typically controlled to less than 10 ppmvd, especially when the possible formation of sulfates such as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium bisulfate [NH_4HSO_4] will be more problematic at higher slip levels. Sulfur trioxide (SO_3) formed during combustion in the boiler can combine with ammonia during passage through the flue gas ductwork to form the sulfates.

Some of the unreacted ammonia (ammonia slip) will be collected with the fly ash in the ESP. Any remaining ammonia slip that is not collected or condensed in the air pollution control system will be collected in the wet scrubber or emitted from the chimney as an aerosol or condensable particulate. Increasing the ammonia slip has the potential to increase atmospheric visibility impairment downwind of the facility compared with a pristine condition. Although the predicted amount of such potential impact from ammonia slip emissions has not been determined, it is expected to be small in comparison with the significant anticipated reduction in far-field ozone and improvement in atmospheric visibility as a result of the overall NO_x emission reduction.

One mole of carbon dioxide (CO_2) will be created and emitted for every mole of urea injected for reaction with NO_x. The consumption rate of urea will significantly increase with the use of RRI + SNCR or optimized SNCR and thus the CO_2 rate will also increase. However, this is a relatively small increase in the total amount of CO_2 produced as part of the combustion of carbon-based fossil fuel in the form of lignite.

Delivery of the urea reagent to the MRYS and storage of aqueous urea reagent on-site creates the potential for accidents, leaks, and subsequent releases to air, ground, and surface water immediately surrounding the facility. Urea is much less volatile than anhydrous or aqueous ammonia, and these risks are expected to be manageable.

Increased dilution water and urea usage rates will require the production of greater volumes of microfiltration/reverse osmosis (MF/RO) and condensate quality water for dilution of concentrated urea deliveries and injection into the boiler. The production of MF/RO and condensate quality water results in a discharge of a concentrated brine solution, which is ultimately discharged under the requirements of the MRYS facility NDPDES permit. This waste stream typically represents 20% of the RO product volume produced. This would result in millions of gallons of additional water treatment wastewaters being discharged from the MRYS facility on an annual basis.

2.5.4 NO_x Control Technology Evaluation Conclusion

The energy impacts of a new RRI + SNCR system or an optimized SNCR system are only incrementally higher than the existing system. These incremental increases are acceptable.

The non-air quality impacts of a new RRI + SNCR system or an optimized SNCR system are very similar to the impacts of the existing SNCR system. There will be an increase in the ammonia carry over from the systems but a majority of that will be captured in the wet FGD system. There will be insignificant increases in CO_2 due the increased consumption of urea. There will be additional RO/condensate waste due to the increase in demand from the systems. All of these non-air quality impacts are considered acceptable.

The average control cost to add an RRI system or to optimize the SNCR system is above $4,500 per ton. This evaluation results in the determination that maintaining operation of the existing SNCR system is the RHCT top ranked control technology.

This evaluation determined maintaining the existing annual emission rates of 0.332 lb NO_x/MMBtu and 0.334 lb NO_x/MMBtu for Unit 1 and Unit 2, respectively, should be modeled by WRAP as appropriate annual emission rates for the Step 5 review. Maintaining the existing 30-day emission limits of 0.36 lb NO_x/MMBtu and 0.35 lb NO_x/MMBtu for Unit 1 and Unit 2, respectively, are appropriate permit limits.

The emission rates in this report are for WRAP modeling and are not proposed permit emission limit. As EPA has indicated, the Regional Haze Roadmap may be updated, and the results of the WRAP modeling will provide new information to be considered. Minnkota reserves the right to modify the four factor analysis once the Regional Haze Roadmap, any additional guidance and the results of the WRAP modeling are available. In addition, Minnkota reserves the right to conduct a 5th factor analysis based on visibility modeling once the results of the WRAP modeling are available.

This analysis is provided to assist the NDDEQ in the WRAP modeling and is not intended to serve as an agreement by Minnkota to any changes in permitted emission limits or permit conditions.

3.0 SO_2 RHCT EVALUATION

The RHCT determination process has five predefined steps as described in Section 1. In this section, steps 1 through 4 of the RHCT determination for MRYS are described for SO_2 and a presentation is made of the results. Potentially applicable SO_2 control technologies are first identified. A brief description of the processes and their capabilities are reviewed for availability and feasibility. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal SO_2 control capability. The impacts analysis then reviews the estimated capital and O&M costs for each alternative. Following the cost determination, the energy impacts and non-air quality impacts are reviewed for each technology. The impact based on the remaining useful life of the source is reviewed as part of the cost analysis. The results of the impact analyses are tabulated and potential RHCT options are listed.

3.1 SO_2 Evaluation Basis

MRYS Unit 1 includes a B&W steam generator installed in 1970. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation. The boiler is fired by seven ten-foot diameter cyclone furnaces, arranged “three over four” across the front wall of the lower boiler. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Unit 1’s boiler serves a turbine generator with a nameplate rating of 257 MW[5]. The Unit 1 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a mine located adjacent to the site. The baseline emission rate of the Unit 1 boiler using the existing wet FGD system is 0.0739 lb SO_2/MMBtu, as described previously in Section 1.1.5.

MRYS Unit 2 is a B&W steam generator installed in 1977. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation assisted with circulation pumps. The boiler is fired by twelve ten-foot diameter cyclone furnaces, arranged “three over three” across the front and rear walls of the lower boiler. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Unit 2’s boiler serves a turbine-generator with a nameplate rating of 477 MW[6]. The Unit 2 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid

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[5] Ibid EPA’s eGRID database; April, 2003.
[6] Ibid EPA’s eGRID database; April, 2003.

in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a mine located adjacent to the site. The baseline emission rate of the Unit 2 boiler using the existing wet FGD system is 0.126 lb SO_2/MMBtu, as described previously in Section 1.1.5.

3.2 Identification of Retrofit SO_2 Control Technologies

The initial step in the RHCT determination is the identification of retrofit SO_2 control technologies. In order to identify the applicable SO_2 control technologies, several reference works were consulted, including "Controlling SO_2 Emissions: A Review of Technologies (EPA-600/R-00-093, October 2000) and the RACT/BACT/LAER Clearinghouse (RLBC). From these and other literature sources, a preliminary list of control technologies and their estimated capabilities for potential application to MRYS was developed. However, Minnkota already has wet FGD systems installed on both units to achieve annual average removal rates of 96.8% and 94.9% on Unit 1 and 2, respectively (based on 3-year average baseline emissions). Additionally, Unit 2 complies with a 0.15 lb/MMBtu 30-day rolling average emission limit. Thus, the control technologies included in the RHCT analysis either meet this minimum level of control or have more stringent removal efficiency. Table 3-1 contains the results of this effort.

Table 3-1: SO_2 Control Technologies Identified for RHCT Analysis

Control Technology	Approximate Annual Control Efficiency
ReACT Scrubber	92-98%
New Wet FGD	98%
Modify Existing Wet FGD	96-98%
Circulating Semi-Dry FGD	90-97%
Semi-Dry FGD	90-95%

3.3 Technical Description and Feasibility Analysis

The second step in the RHCT analysis procedure is a technical feasibility analysis of the options identified in Step 1. The RHCT guidelines, which reference the prior BART Guidelines, discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the "availability" and "applicability" of each control technology. A control technology is considered available "if it has reached the stage of licensing and commercial availability" (70 FR 39165). On the contrary, a control technology is not considered available "if it is in the pilot scale testing stages of development" (70 FR 39165). When considering a source's applicability, technical judgment must be exercised to determine "if it can reasonably be installed and operated on the source type" (70 FR 39165). The technical and feasibility analysis is presented below for each identified option.

3.3.1 Wet Flue Gas Desulfurization

Wet FGD technology utilizing lime or limestone as the reagent is commonly applied to coal-fired boilers. Wet FGD utilizes an absorber, such as an open spray tower or a spray tower with a perforated plate contactor, to expose flue gas to the neutralizing slurry. Absorbed SO_2 is converted to calcium sulfite and then may be oxidized to calcium sulfate dihydrate (gypsum) which is filtered from the scrubber solution and either disposed of in a permitted disposal facility, or possibly sold for either wallboard or cement production. Lime is utilized as the reagent in the wet FGD technology analysis because the plant currently uses lime in the FGD processes and has existing lime reagent preparation equipment. Lime, rather than limestone, is used at the plant because it is the most cost-effective reagent to truck to the plant. The MRYS is not equipped with rail service.

An alternative reagent to lime or limestone is ammonia. The scrubbing technology is similar to other wet FGD systems; however, the byproduct handling is significantly different. The advantage of utilizing ammonia is the production of a high value fertilizer byproduct (ammonium sulfate). This byproduct is a commodity that can be sold worldwide all year. The byproduct, if sold in liquid form, may not require any treatment and limited handling. A potential disadvantage of utilizing ammonia reagent is if the byproduct is not sold in liquid form, it could require significant handling/treatment depending on the final product requirements (delivery, target clients, etc). This handling/treatment could include some or all of the following steps; concentration, crystallization, drying, prilling and storage. As fertilizer demand near MRYS is seasonal, the product will need to be shipped to other parts of the United States or the world market.

Historically, wet FGD systems have operated with SO_2 control efficiency anywhere from 70% to 98%. New coal-fired power plant SO_2 control projects have achieved coal to chimney SO_2 control efficiency of ≥99 percent. However, considering a reasonable degree of margin is appropriate to allow for continuous compliance including upsets, fuel variability, and operational variability, 98% removal is evaluated as an appropriate removal rate for a new state of the art scrubber.

For the purposes of this analysis, new wet FGD performance was evaluated at 98% SO_2 removal. Due to the relative ages of Unit 1 and Unit 2 scrubbers, a new wet scrubber was considered only for Unit 2, as the Unit 1 wet scrubber was placed in service relatively recently, in 2011. Based on the ability of a new wet FGD system to achieve 98% percent SO_2 removal efficiency and considering the commercial availability and applicability, a new wet FGD system was found to be a technically feasible RHCT alternative for MRYS Unit 2 SO_2 emission control.

This report also evaluates the modification of the existing wet FGD process currently operating on Unit 1 and Unit 2 as a possible RHCT alternative. The original equipment manufacturer (OEM) of the Unit 1 scrubber was engaged to evaluate modifications required to increase the removal efficiency of the existing wet FGD processes. The same OEM has previously studied upgrading the Unit 2 scrubber to achieve higher removal efficiency, and was engaged to update and confirm the results of that study. Upgrades evaluated include increasing the liquid-to-gas ratio, installation of new types of spray nozzles, running additional pumps, and adjusting the operating conditions of the scrubber. The OEM study evaluated the scrubbers based on the highest sulfur coal (3.16 lb SO_2/MMBtu) identified by core samples collected and analyzed by the mine that supplies MRYS. The high sulfur fuel is utilized in this evaluation to ensure the updated scrubber is capable of the necessary long-term fuel flexibility associated with a mine mouth plant. The removal rates referenced in the confidential vendor proposal (submitted separately under confidentiality) are coal to chimney short term (test period) removal rates reflective of vendor determined performance. This RHCT evaluation, however, has applied selected removal rates across the scrubber.

The selected rates applied across the scrubber is considered a reasonable balance of the difference between: the baseline scrubber inlet SO_2 and the studied sulfur content of the coal, consideration of the need for margin between a guarantee and long term continuously achievable performance, and long term (annual performance) basis of this evaluation. Optimizing Unit 1 is assumed to increase removal across the scrubber to 97.4% by increasing stoichiometry (Ca/S) to 1.025. Upgrading Unit 2 is assumed to increase removal across the scrubber to 97.6% utilizing the recommended nozzle changes, additional spray header, and increasing the stoichiometry to 1.020. MRYS did not increase the stoichiometry in Unit 2 to the same level as Unit 1 because MRYS experience on Unit 2 is that operating at higher pH (associated with higher stoichiometry) will cause increased scaling and plugging of the suctions screens to the spray recycle pumps that will reduce the liquid to gas ratios, and hence lower SO_2 removal.

3.3.2 Semi-Dry Flue Gas Desulfurization

As an alternative to wet FGD technology, the control of SO_2 emissions can be accomplished using semi-dry FGD technology. The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a fabric filter for downstream particulate collection. There are several variations of the semi-dry process in use today. Two other variations, the Flash Dryer Absorber (FDA) and Circulating Dry Scrubber (CDS) are similar in nature. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling. This section addresses the SDA process and the CDS process.

No SDA process has clearly demonstrated the ability to achieve SO_2 removal levels similar to wet FGD systems in the U.S. The application of high SO_2 removal SDA system for high sulfur coal have been limited in the industry due to multiple factors. For purposes of completeness an SDA system is assumed to be able to achieve 93% removal in this application.

The CDS system can increase the lime injection rate independent of the water injection and higher removal rates can be achieved. The CDS system removal is assumed to be equivalent to the retrofit wet FGD system achieving 95-97% removal.

3.3.3 ReACT Dry Scrubbing Process

ReACT (Regenerative Activated Coke Technology) is a multipollutant control system that utilizes activated coke to remove SO_2, NO_x and mercury. The process is divided into three main processes: 1) adsorption, 2) regeneration, and 3) recovery. In the first step, ammonia is injected into the flue gas and the flue gas is passed through an adsorber filled with a moving bed of activated coke pellets where the SO_2 and mercury are adsorbed and the NO_x is reduced to N_2. In the second step, the activated coke pellets are transferred to a second vessel to be regenerated for recycle/reuse through thermal desorption. The captured mercury is concentrated in the lower portion of the regenerator vessel. The resulting gas from the regeneration step is a concentrated stream of SO_2 that must be further treated in a separate acid recovery plant to produce a sellable sulfuric acid byproduct. Sulfuric acid is a worldwide commodity that, with access, can be sold year-round. This ReACT process is installed and operating on multiple low sulfur coal fired units achieving $\geq 99\%$ SO_2 removal. Burns & McDonnell contacted the supplier of the ReACT process and discussed the application of the technology to an application like MRYS. It was determined that MRYS is ‘not a good application’ for the technology, however, the technology could be applied and would work. Factors in this application at MRYS that would impact performance and cost of ReACT include that the inlet temperature is too high, higher oxidation of the activated coke can be expected, and the sulfuric acid production rates would be very high. This technology is still considered a viable alternative and previous ReACT pilot tests on high sulfur coals have shown ReACT can achieve 92-98% SO_2 removal rates.

3.3.4 Results of Feasibility Analysis

The evaluations of the identified RHCT alternatives following the feasibility analysis are summarized in Table 3-2.

Table 3-2: MRYS RHCT SO_2 Control Feasibility Analysis Results

Control Technology	In full-scale service on Existing Utility Boilers	In Service on Other Combustion Sources	Commercially Available	Technically Applicable To MRYS
ReACT Scrubber	Yes	Yes	Yes	Yes
Wet FGD	Yes	Yes	Yes	Yes
CDS Dry FGD	Yes	Yes	Yes	Yes
SDA Dry FGD	Yes	Yes	Yes	Yes

3.4 Evaluate Technically Feasible SO_2 Control Options by Effectiveness

The third step in the RHCT analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the RHCT analysis, the SO_2 control efficiency was reviewed and presented as part of the technical description for each technology. The evaluations of the remaining RHCT alternatives following the feasibility analysis are summarized in Table 3-3. The alternatives are ranked in descending order according to their effectiveness in SO_2 control. The control efficiencies listed in Table 3-3 are representative of annual average removal rates and do not represent a permit limit that would be continuously achievable over a 30-day rolling average.

Table 3-3: Feasible SO_2 Control Technologies Identified for RHCT Analysis

Control Technology	Unit 1[1]	Unit 2[1]
New Wet FGD	Not Reviewed[2]	98% Control
ReACT	98% Control	98% Control
Retrofit Existing Wet FGD	97.4% Control	97.6% Control
CDS Semi-Dry FGD	NA[3]	NA[3]
SDA FGD	NA[3]	NA[3]

1. Control rates are reflective of conservative (high) annual removal rates and do not reflect maintainable/guaranteed 30-day rates.
2. Existing system was installed in 2011, so replacement with a like-kind system was not reviewed.
3. SDA and semi-dry FGDs are not evaluated for Unit 1 or 2 because the existing wet FGD can be used to achieve equivalent removal efficiency while using existing equipment.

3.5 Evaluation of Impacts for Feasible SO_2 Controls

Step four in the RHCT analysis procedure is the impact analysis. The draft Guidelines (81 FR 44608) lists four factors to be considered in the impact analysis.

- The costs of compliance;
- The time required for compliance;
- Energy and non-air quality environmental impacts of compliance
- The remaining useful life of the source.

Three of the four impacts required by the RHCT Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the

EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the RHCT determination for MRYS.

Unlike the Best Available Retrofit Technology (BART) evaluation performed in the last round for the RHCT evaluation, the technologies in the second implementation period are evaluated on a 'Top Down' down basis similar to a Best Available Control Technology (BACT) approach. Where multiple technologies achieve similar removal rates, a single technology is evaluated to represent that level of performance. The top rated SO_2 removal rate is 98% removal and can be achieved by replacing the existing wet FGD system with either a new wet FGD system or a ReACT system. As a wet FGD system is a well demonstrated technology for high sulfur fuel and ReACT has only been applied on low sulfur fuel, this evaluation will focus on the new wet FGD option to evaluate the top-rated option. As shown in Table 3-3, ReACT is not expected to have better performance than wet FGD in operating conditions encountered at MRYS.

3.5.1 Cost Evaluation

The following sections evaluate the top two ranked control options for Unit 2, replacing the existing wet FGD system with a new wet FGD system, and upgrading the Unit 2 scrubber. A new wet FGD was not considered for Unit 1, as the existing wet FGD began operations in 2011 as part of the previous BART/BACT analysis and is within the previously evaluated useful life. The top ranked control option for Unit 1, modify the existing wet FGD, is evaluated.

3.5.1.1 New Wet FGD Capital Cost Estimate

Cost estimates for the new wet FGD SO_2 control technologies were completed utilizing the 'IPM Model – Updates to Cost and Performance for APC Technologies Wet FGD Cost Development Methodology' available from the U.S. Environmental Protection Agency and supplemented with engineering estimates based upon Burns & McDonnell's in-house experience. The IPM Model Update is a formula-based report that was specifically developed to estimate the cost of wet FGD technologies for utility power plants. The report was prepared for the EPA in January 2017. The report is available for download from the U.S. EPA website[7].

As a conservative (lowest cost) approach, this evaluation only considered the 'Absorber Island' portion of the new scrubber cost at a retrofit factor of 1.0 and supplemented this with engineering estimates for new duct work, connecting piping and space modifications required to fit the absorber. This approach

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[7] www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6

assumes all of the existing balance of plant (BOP) systems are capable of supporting the new system with no upgrades. Further, it is assumed there is no change in operating staff and only a proportional change in the variable operating cost. These conservative assumptions minimize the overall project cost resulting in a conservatively low dollars per ton control cost.

For the addition of a new wet FGD, Unit 2 will require new ductwork to connect to the new wet FGD system, modifications to the coal pile to create space for the new system and electrical replacement/ upgrades for the new scrubber or a significantly extended outage to allow for the existing wet FGD system to be shut down while the new system is tied in, commissioned and started up. The SO_2 control system cost is representative of a typical furnish and erect contract by a wet FGD system supplier. Economic information utilized as input into the model is given in Table 1-3. The results of the capital cost estimates are given in Table 3-4.

Table 3-4: Capital Cost Estimate for MRYS Unit 2 New Wet Lime FGD System

DIRECT COSTS	**Unit 2 Estimated Cost ($)**
New FGD Absorber	
FGD Island Equipment Cost	$51,586,000
BOP Costs	
Mechanical Contract	$54,000,000
Foundations and Steel	$4,461,000
BOP Total Direct Cost	$58,461,000
Total Direct Cost	$110,047,000
INDIRECT COSTS	
Engineering 10% of DC	$11,005,000
Escalation	Not Included
Indirect Cost Subtotal	$11,005,000
Contingency (20% of DC)	$12,105,000
Prime Contractor's Fee (3% of DC)	$9,321,000
Owners Cost	Not Included
Total Capital Requirement	**$142,478,000**

The total estimated capital cost estimate for a complete new wet FGD absorber is $142,478,000 or $299/kW.

3.5.1.2 Wet FGD Modification Capital Cost Estimate

Cost estimates for retrofitting the existing wet FGD systems were based on the equipment modification and associated pricing provided by the OEM (provided separately under confidentiality) and supplemented with engineering estimates for installation based upon Burns & McDonnell's in-house experience.

This evaluation assumes all of the existing BOP systems are capable of supporting the new system with no further upgrades. Further, it is assumed there is no change in operating staff and only a proportional change in the variable operating cost. These conservative assumptions minimize the overall project cost resulting in a conservatively low dollars per ton control cost.

The capital cost estimate for the Unit 1 wet FGD system modification includes the OEM recommendation to replace three out of the four recirculation pump motors to increase the liquid to gas ratio in the scrubber. During this investigation, the existing electrical system and foundation associated with the pump was reviewed and is believed to be sufficient to support this upgrade with no further modifications.

The capital cost estimate for the Unit 2 wet FGD system modification includes the OEM recommendation to replace all of the absorber spray nozzles with dual flow nozzles. The OEM did not recommend upgrading the pumps on Unit 2 due to velocity limitations in the riser pipe and headers and did not recommend upgrading the riser headers and spray headers to accommodate more flow as these upgrades could compromise or complicate the conditions of the existing towers. The results of the capital cost estimates for the FGD system modifications are given in Table 3-5.

Table 3-5: Capital Cost Estimate for MRYS Unit 1 Wet FGD System Modification

DIRECT COSTS	Unit 1 Estimated Cost ($)	Unit 2 Estimated Cost ($)
Modified FGD System		
Equipment Cost	$569,000	$1,011,000
BOP Costs		
Mechanical Contract	$0	$280,000
Electrical and Controls	$16,000	$0
BOP Total Direct Cost	$16,000	$280,000
Total Direct Cost	$585,000	$1,291,000
INDIRECT COSTS		
Engineering 10% of DC	$58,000	$129,000
Escalation	Not Included	Not Included
Indirect Cost Subtotal	$58,000	$129,000
Contingency (20% of DC)	$64,000	$142,000
Prime Contractor's Fee (3% of DC)	$50,000	$109,000
Total Capital Requirement	**$757,000**	**$1,671,000**

The total estimated capital cost for upgrades to the Unit 1 wet FGD system is $757,000, or $3.00/kW. The total estimated capital cost for upgrades to the Unit 2 wet FGD system is $1,671,000, or $3.50/kW.

3.5.1.3 New Wet FGD O&M Cost Estimate

The annual O&M costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The O&M costs are evaluated as additional costs beyond the existing wet FGD system as the current costs are part of the baseline operating conditions. The operating labor cost of a new system is not expected to be significantly different than the existing system over the life of the equipment. No additional operating labor has been assumed.

Variable costs include reagent, makeup water, FGD byproduct disposal and auxiliary power costs. The estimated annual costs for these consumables are based on the incremental consumption rates change between the existing removal rate and the new removal rate and the unit cost information provided in Table 1-3. Table 3-6 provides the O&M cost estimate.

Table 3-6: O&M Cost Estimate for a New MRYS Unit 2 Wet Lime FGD System

Fixed Costs	**Unit 2**
Operating Labor	$0
Admin and Support labor	$0
Maintenance Material and Labor	$3,301,000
Total Fixed O&M Costs	**$3,301,000**
Variable Costs	
Lime Reagent	$21,000
Byproduct Disposal	$233,000
Auxiliary Power	$727,000
Total Variable O&M Costs	**$981,000**
Total Annual O&M Costs	**$4,282,000**
Net Annual O&M Cost ($/MWh)	**1.30**

3.5.1.4 Wet FGD Modification O&M Cost Estimate

The annual O&M costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). The O&M costs are evaluated as additional costs beyond the existing wet FGD system as the current costs are part of the baseline operating conditions. The operating labor cost of a new system is not expected to be significantly different than the existing system over the life of the equipment. No additional operating labor has been assumed.

Variable costs include reagent, FGD byproduct disposal and auxiliary power costs. The estimated annual costs for these consumables are based on the incremental consumption rates change between the existing removal rate and the new removal rate and the unit cost information provided in Table 1-3. Table 3-7 provides the O&M cost estimate.

Table 3-7: O&M Cost Estimate for MRYS Unit 1 and 2 Wet Lime FGD System Modification

Fixed Costs	Unit 1	Unit 2
Operating Labor	$0	$0
Admin and Support labor	$0	$0
Maintenance Material and Labor	$18,000	$39,000
Total Fixed O&M Costs	**$18,000**	**$39,000**
Variable Costs		
Lime Reagent	$108,000	$286,000
Byproduct Disposal	$2,000	$19,000
Auxiliary Power	$197,000	$320,000
Total Variable O&M Costs	**$307,000**	**$625,000**
Total Annual O&M Costs	**$325,000**	**$664,000**
Net Annual O&M Cost ($/MWh)	0.18	0.20

O&M Cost represent costs above the baseline (existing system)

3.5.1.5 Annualized Total Cost

In order to effectively compare the cost of installing, operating, and maintaining the SO_2 control systems, capital and O&M costs should be evaluated on an annualized basis. The Annualized Total Cost (ATC) for SO_2 control systems was calculated based on overnight construction period (2019), followed by a 20-year service life. O&M costs were based on first year (2019) cost. No salvage value was assumed at the end of the service life for any of the control technology alternatives. The results are presented in Table 3-8 and Table 3-9 for Unit 1 and Unit 2, respectively, along with the emissions reduction, resultant emissions rate and the Unit Control Cost. The Unit Control Cost is the ATC divided by the annual tons of additional SO_2 emissions that would be controlled by implementation of the respective alternative.

Table 3-8: MRYS Unit 1 SO_2 Control System Annualized Total Cost

SO_2 Control Alternative	Percent Removal	Emission Rate lb/10^6 Btu	Annual Emission (tpy) [1]	Annual Emission Reduction (tpy) [1]	Installed Capital Cost ($) [2]	Annual O&M Cost ($)	Annualized Total Cost ($) [3]	Actual Unit Control Cost ($/ton) [4]
Modified Wet FGD	97.4%	0.061	632	145	800,000	300,000	400,000	2,800
Baseline	96.8%	0.075	777	Baseline				

1. Based on baseline heat input of 20,726,417 MMBtu/yr
2. All Costs in 2019 dollars.
3. For ATC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.
4. Overall control cost is ATC divided by actual annual emissions reduction of each alternative.

Table 3-9: MRYS Unit 2 SO_2 Control System Annualized Total Cost

SO_2 Control Alternative	Percent Removal	Emission Rate lb/10^6 Btu	Annual Emission (tpy) [1]	Annual Emission Reduction (tpy) [1]	Installed Capital Cost ($) [2]	Annual O&M Cost ($) [2]	Annualized Total Cost ($) [3]	Actual Unit Control Cost ($/ton) [4]	Incremental Unit Control Cost ($/ton)
New Wet FGD	98.0%	0.050	859	1,305	142,500,000	4,300,000	16,200,000	12,400	128,000
Modified Wet FGD	97.7%	0.057	979	1,185	1,700,000	700,000	800,000	700	
Baseline	94.9%	0.126	2,164	Baseline					

1. Based on baseline heat input of 34,354,956 MMBtu/yr
2. All Costs in 2019 dollars.
3. For ATC calculation, Capital Recovery Factor = 0.08368 and first year O&M Cost.
4. Overall control cost is ATC divided by actual annual emissions reduction of each alternative.

The annual tons of SO_2 reduction in this RHCT analysis are calculated as the difference between the baseline emission rate and the controlled emissions and are assumed to be at the same heat input and unit operating time.

3.5.1.6 Cost Estimate Conclusion

In the RHCT guidelines, EPA does not provide definition, or even discussion of what Unit Control Costs are considered reasonable or unreasonable. NDDEQ has indicated that costs below $4,500 per ton may be considered to be reasonable.

The Actual Unit Control Cost are used to evaluate the technology alternatives on a cost effectiveness basis. As can be seen from a review of Table 3-9, the cost of the new Unit 2 wet FGD alternative is excessively high with an actual and incremental control cost far greater than $4,500 dollars per ton.

As can be seen from a review of Table 3-8 and Table 3-9, the wet FGD modification alternatives for both units are considered reasonable, with an Actual Unit Control Cost of $2,800 and $700 per ton for Unit 1 and Unit 2, respectively.

3.5.2 Energy Impacts

The energy impacts of replacing the existing Unit 2 wet FGD with a new wet FGD, or of upgrades to the existing wet FGD in the case of Unit 1, in terms of auxiliary power requirements, are given in Table 3-10 and Table 3-11. The primary energy impacts of the wet FGD alternative consists of the additional electrical load resulting from pumps and reagent preparation. Building HVAC and interior and exterior lighting loads are considered minimal.

Table 3-10: Auxiliary Energy Requirement of MRYS Unit 1 FGD Upgrades

RHCT Alternative	Energy Demand (kW)	Percent of Nominal Generation
Existing Wet FGD	5,170	2.2%
Upgraded Wet FGD	5,756	2.5%

Table 3-11: Auxiliary Energy Requirement of MRYS Unit 2 New FGD

RHCT Alternative	Energy Demand (kW)	Percent of Nominal Generation
Existing Wet FGD	9,658	2.2%
Upgraded Wet FGD	10,623	2.4%
New Wet FGD	11,853	2.7%

3.5.3 Non-Air Quality Environmental Impacts

Non-air quality environmental impacts of replacing the existing wet FGD with a new wet FGD or retrofitting the existing FGD systems are expected to be very similar to the impacts of the existing system. These may include hazardous waste generation, solid and aqueous waste streams. The primary change anticipated due to the use of a new wet FGD or modifying the existing FGD systems will be an incremental increase in the solids disposal rate as additional removal of SO_2 will result in increased byproduct.

While the economic evaluation of a new wet FGD system assumes overnight installation, the actual process to bid, design, purchase, and install a retrofitted new wet FGD system can take five years to implement. The actual process to bid, design, purchase, and install retrofits to an existing wet FGD system can take two to three years to implement.

3.5.4 SO_2 Control Technology Evaluation Conclusion

The energy impacts of a new wet FGD system are only incrementally higher than the existing system and are primarily driven by the increase in SO_2 removal. These incremental increases are acceptable.

The time period to install a new wet FGD system is significantly longer than the second ranked option (modifying the existing wet FGD) and would result in years of higher emission rates to achieve only a marginal increased removal rate. This would result in years of higher emissions before the RHCT would be installed.

Considering the existing systems are being replaced with like systems, there could be years of implementation delay with a new system for marginal removal improvement, and the high dollars per ton control cost includes low capital cost assumptions. This evaluation rejects the top ranked control technology for Unit 2 (new wet FGD) as RHCT.

While this is not used as the reason for the rejection of this top ranked option, comparison to the second ranked option (an upgrade to the existing wet FGD) indicates that the high annualized cost differential and low differential removal rate of the new FGD option result in an excessive incremental dollars per ton removed greater than $128,000 per ton.

The time period to modify the existing wet FGD systems is significantly shorter than installing other new systems and would result in lower emission rates sooner than other options. The average control cost to modify the existing wet FGD systems is well below $4,500 per ton. This evaluation results in the determination that modification of the Unit 1 and 2 wet FGD systems is RHCT.

This evaluation determined that 97.4% removal for Unit 1 and 97.7% removal on Unit 2 resulting in annual emission rates of 0.061 lb SO_2/MMBtu and 0.057 lb SO_2/MMBtu, respectively, should be modeled by WRAP as appropriate emission rates for the Step 5 review. The emission rates in this report are for WRAP modeling and are not proposed permit emission limits. As EPA has indicated, the Regional Haze Roadmap may be updated, and the results of the WRAP modeling will provide new information to be considered. Minnkota reserves the right to modify the four factor analysis once the Regional Haze Roadmap, any additional guidance and the results of the WRAP modeling are available. In addition, Minnkota reserves the right to conduct a 5th factor analysis based on visibility modeling once the results of the WRAP modeling are available.

This analysis is provided to assist the NDDEQ in the WRAP modeling and is not intended to serve as an agreement by Minnkota to any changes in permitted emission limits or permit conditions.

4.0 REGIONAL HAZE CONTROL TECHNOLOGY RESULTS

This report presents the analysis of control technologies for nitrogen oxides (NO_x), and sulfur dioxide (SO_2) for Minnkota Power Cooperative Inc.'s Milton R. Young Station (MRYS) Units 1 and 2. The final result of this analysis is a Regional Haze Control Technology (RHCT) for each unit based upon "the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source…" (70 FR 39163). The presented emission rates in this section are the RHCT recommended rates for evaluation in Step 5 of a RHCT evaluation.

The first four steps of RHCT are used to identify technologies, determine feasibility and evaluate cost, energy, non-air quality and useful life impacts. This analysis reviewed technologies on these factors starting from the baseline of the existing units that include ASOFA/SNCR for NO_x control and wet FGDs for SO_2 control. The RHCT analysis does not review technologies that do not achieve at least the baseline level of performance.

As stated in previous sections of the report, the first four steps of the technology evaluation provided for in the Guidelines were completed for both Units. Each pollutant required a different approach in order to determine RHCT emission rate. This section provides a brief description of the approach used for each pollutant and summarizes the results.

For NO_x emissions, the top ranked technically feasible control technology for both units is the use of RRI in combination with SNCR and ASOFA. However, the RRI+SNCR system is not an economically effective NO_x control alternative for either Unit 1 or Unit 2 with control cost of $11,100 and $5,900 per ton of NO_x removed, respectively.

The Unit Control Costs for the next top ranked control technology, optimized SNCR system, is above $4,500 per ton on Unit 1 ($96,500 per ton) and Unit 2 ($7,500 per ton). From an economic analysis viewpoint, optimized SNCR systems are not economically effective NO_x controls for either unit.

This evaluation concludes that the existing SNCR/ASOFA systems on both units are the top ranked control technologies.

For SO_2 emissions, the top ranked technology for Unit 2 was to replace the existing wet scrubber with a new wet scrubber. This technology was evaluated and rejected primarily because it was determined to be excessively costly on a dollars per ton removed basis ($12,400 per ton). Furthermore, this top ranked control technology provided only limited additional removal for an order of magnitude additional costs compared to the second ranked control technology and will take years longer to implement than the second ranked technology.

The next highest ranked control technology (and also top ranked for Unit 1) is to retrofit the existing wet FGDs to increase removal. The OEM of the Unit 1 scrubber was engaged to evaluate how to increase the Unit 1 scrubber removal and re-evaluate a previous study they performed to increase removal in the Unit 2 scrubber. The mechanical upgrades the OEM included are replacing pump motors and changing nozzle designs. The various changes to operating conditions were evaluated based on the plant's previous operating history and experience to consider which conditions will improve removal, while working with the existing system and not impacting removal or reliability. There are no sufficient economic or energy reasons to reject modifying the existing scrubbers. There are non-environmental impacts to consider associated with scrubber operational changes due to potential scaling in the absorber and the long-term impact to the scrubber ponds. However, these impacts are considered manageable based on the operational changes to stoichiometric ratio and total suspended solids included in this evaluation. Based upon this analysis, modifying the existing wet FGDs in both Units is the top ranked RHCT option for SO_2 emissions.

Table 4-1 and Table 4-2 summarize the control technologies and associated emission rates recommended for Step 5 evaluation for each pollutant and for each unit. The RHCT emission rates are presented as annual averages based on the economic evaluation.

Table 4-1: RHCT Step 5 Annual Average Emission Rate, MRYS Unit 1

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_x	Existing Selective Non-Catalytic Reduction and Advanced Separated Over Fire Air	0.332
SO_2	Modify the existing Wet Flue Gas Desulfurization system	0.061

Table 4-2: RHCT Step 5 Annual Average Emission Rate, MRYS Unit 2

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_x	Existing Selective Non-Catalytic Reduction and Advanced Separated Over Fire Air	0.334
SO_2	Modify the existing Wet Flue Gas Desulfurization system	0.057

The four factor analysis was completed based on a request by the NDDEQ while utilizing the EPA 2016 RHR Guidance document. The NDDEQ has requested this information for the purpose of WRAP modeling. The emission rates in this report are for WRAP modeling and are not proposed permit emission limits. As EPA has indicated, the Regional Haze Roadmap may be updated, and the results of the WRAP modeling will provide new information to be considered. Minnkota reserves the right to modify the four factor analysis once the Regional Haze Roadmap, any additional guidance and the results of the WRAP modeling are available. In addition, Minnkota reserves the right to conduct a 5th factor analysis based on visibility modeling once the results of the WRAP modeling are available.

This analysis is provided to assist the NDDEQ in the WRAP modeling and is not intended to serve as an agreement by Minnkota to any changes in permitted emission limits or permit conditions.

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Appendix A

RRI + SNCR Capital Cost Summary Tables

CAPITAL COST ESTIMATE
Minnkota Power Coop.
Milton R Young
RRI + SNCR Unit 1
Center, ND
BMcD #107926

Acct	Area / Discipline	Direct MHRS	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	Total Cost
01	Engineered Equipment	580	$82,936		$4,200,500		$4,283,436
02	Civil						
03	Deep Foundations						
04	Concrete				$5,000		$5,000
05	Structural Steel	1,978	$275,424	$278,551			$553,975
06	Architectural						
07	Piping	11,122	$1,455,540	$155,044			$1,610,584
08	Electrical	300	$37,367	$46,000			$83,367
09	Instrument & Control				$48,000		$48,000
10	Insulation						
11	Coatings						
12	Specialty						
13	Demolition						
14	Misc Directs						
	Total Direct Cost	**13,981**	**$1,851,266**	**$479,595**	**$4,253,500**		**$6,584,361**

Rev.	Revision Date
0	01/29/19
1	05/10/19

	Cost	Revenue	
Construction Mgmt & Indirects			
Engineering			$647,243
Start-Up			
Commercial			
Escalation			
Total Indirect Cost			**$647,243**
Total Direct and Indirect Costs			**$7,231,604**
Project Contingency	10%	8%	$723,160
EPC Fee	7%	6.5%	$556,834
Total Project Cost	**17%**	**15%**	**$8,511,598**
Owner Cost - General, Taxes & Fees			
Owner Cost - Owner Contingency			
Total Project Cost Incl. Owner Cost			**$8,511,598**

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PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - RRI + SNCR Unit 1**
PROJECT # : **107926**

SUMMARY
ENGINEERED EQUIPMENT

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	EQUIPMENT COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 Treatment Equipment	220	31,458		1,128,500		**1,159,958**
P 3 Ammonia Slip Analyzers	120	17,159		82,000		**99,159**
P 4 RO / UF Train				1,500,000		**1,500,000**
P 5 Compressed Air Equipment	120	17,159		300,000		**317,159**
P 6 Cooling Water Pumps	120	17,159		90,000		**107,159**
P 7 Boiler Penetrations				1,100,000		**1,100,000**
ESTIMATE TOTALS	**580**	**$82,936**		**$4,200,500**		**$4,283,436**

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - RRI + SNCR Unit 1**
PROJECT # : **107926**

SUMMARY
CONCRETE

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 Cooling Water Pump Foundation				5,000		**5,000**
ESTIMATE TOTALS				**$5,000**		**$5,000**

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - RRI + SNCR Unit 1**
PROJECT # : **107926**

SUMMARY
STRUCTURAL STEEL

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION		LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	TOTAL COST
		MH	COST				
P 2 Fuel Tech Equipment Access Steel	33.8 tn	1,328	185,096	209,551			**394,647**
P 3 Ammonia Slip Access Steel	78.6	650	90,328	69,000			**159,328**
ESTIMATE TOTALS		**1,978**	**$275,424**	**$278,551**			**$553,975**
		58.5		8,241			16,390

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - RRI + SNCR Unit 1**
PROJECT # : **107926**

SUMMARY
PIPING

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 Urea Piping	4,215	551,546	48,156			**599,702**
P 3 Cooling Water Piping	4,841	633,495	56,289			**689,784**
P 4 Air Piping	2,067	270,499	50,599			**321,098**
ESTIMATE TOTALS	**11,122**	**$1,455,540**	**$155,044**			**$1,610,584**

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - RRI + SNCR Unit 1**
PROJECT # : **107926**

SUMMARY
ELECTRICAL

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 ELECTRICAL	300	37,367	46,000			**83,367**
ESTIMATE TOTALS	**300**	**$37,367**	**$46,000**			**$83,367**

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - RRI + SNCR Unit 1**
PROJECT # : **107926**

SUMMARY
INSTRUMENT & CONTROL

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 INSTRUMENT & CONTROL				48,000		**48,000**
ESTIMATE TOTALS				**$48,000**		**$48,000**

CAPITAL COST ESTIMATE
Minnkota Power Coop.
Milton R Young
RRI + SNCR Unit 2
Center, ND
BMcD #107926

Acct	Area / Discipline	Direct MHRS	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	Total Cost
01	Engineered Equipment	696	$99,523		$5,407,000		$5,506,523
02	Civil						
03	Deep Foundations						
04	Concrete				$5,000		$5,000
05	Structural Steel	3,027	$422,055	$472,493			$894,548
06	Architectural						
07	Piping	32,868	$4,301,241	$408,095			$4,709,336
08	Electrical	450	$56,051	$46,000			$102,051
09	Instrument & Control				$76,800		$76,800
10	Insulation						
11	Coatings						
12	Specialty						
13	Demolition						
14	Misc Directs						
	Total Direct Cost	**37,041**	**$4,878,869**	**$926,588**	**$5,488,800**		**$11,294,257**

Rev.	Revision Date
0	01/29/19
1	05/10/19

	Cost	Revenue	
Construction Mgmt & Indirects			
Engineering			$1,129,426
Start-Up			
Commercial			
Escalation			
Total Indirect Cost			**$1,129,426**
Total Direct and Indirect Costs			**$12,423,683**
	Cost	Revenue	
Project Contingency	10%	8%	$1,242,368
EPC Fee	7%	6.5%	$956,624
Total Project Cost	**17%**	**15%**	**$14,622,675**
Owner Cost - General, Taxes & Fees			
Owner Cost - Owner Contingency			
Total Project Cost Incl. Owner Cost			**$14,622,675**

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PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - RRI + SNCR Unit 2**
PROJECT # : **107926**

SUMMARY
ENGINEERED EQUIPMENT

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION		LABOR		MATERIAL COST	EQUIPMENT COST	EQUIPMENT RENT / STS	**TOTAL COST**
		MH	COST				
P 2	Treatment Equipment	336	48,045		1,435,000		**1,483,045**
P 3	Ammonia Slip Analyzers	120	17,159		82,000		**99,159**
P 4	RO / UF Train				1,500,000		**1,500,000**
P 5	Compressed Air Equipment	120	17,159		300,000		**317,159**
P 6	Cooling Water Pumps	120	17,159		90,000		**107,159**
P 7	Boiler Penetrations				2,000,000		**2,000,000**
	ESTIMATE TOTALS	**696**	**$99,523**		**$5,407,000**		**$5,506,523**

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - RRI + SNCR Unit 2**
PROJECT # : **107926**

SUMMARY
CONCRETE

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 Cooling Water Pump Foundation				5,000		**5,000**
ESTIMATE TOTALS				**$5,000**		**$5,000**

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - RRI + SNCR Unit 2**
PROJECT # : **107926**

SUMMARY
STRUCTURAL STEEL

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION			LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
			MH	COST				
P 2	Fuel Tech Equipment Access Steel	60.4 tn	2,377	331,727	403,493			**735,220**
P 3	Ammonia Slip Access Steel	78.71629139	650	90,328	69,000			**159,328**
		ESTIMATE TOTALS	**3,027**	**$422,055**	**$472,493**			**$894,548**
			50.1		7,823			14,810

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - RRI + SNCR Unit 2**
PROJECT # : **107926**

SUMMARY
PIPING

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 Urea Piping	11,947	1,563,501	116,188			**1,679,689**
P 3 Cooling Water Piping	14,650	1,917,226	154,719			**2,071,945**
P 4 Air Piping	6,270	820,514	137,188			**957,702**
ESTIMATE TOTALS	**32,868**	**$4,301,241**	**$408,095**			**$4,709,336**

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - RRI + SNCR Unit 2**
PROJECT # : **107926**

SUMMARY
ELECTRICAL

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 ELECTRICAL	450	56,051	46,000			**102,051**
ESTIMATE TOTALS	**450**	**$56,051**	**$46,000**			**$102,051**

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - RRI + SNCR Unit 2**
PROJECT # : **107926**

SUMMARY
INSTRUMENT & CONTROL

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 INSTRUMENT & CONTROL				76,800		**76,800**
ESTIMATE TOTALS				**$76,800**		**$76,800**

Appendix B

Optimized SNCR Capital Cost Summary Tables

CAPITAL COST ESTIMATE
Minnkota Power Coop.
Milton R Young
Optimized SNCR Unit 1
Center, ND
BMcD #107926

Acct	Area / Discipline	Direct MHRS	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	Total Cost
01	Engineered Equipment	400	$57,197		$1,181,175		$1,238,372
02	Civil						
03	Deep Foundations						
04	Concrete						
05	Structural Steel	650	$90,328	$69,000	$100,000		$259,328
06	Architectural						
07	Piping	2,067	$270,499	$50,599			$321,098
08	Electrical				$38,000		$38,000
09	Instrument & Control						
10	Insulation						
11	Coatings						
12	Specialty						
13	Demolition						
14	Misc Directs						
	Total Direct Cost	**3,117**	**$418,024**	**$119,599**	**$1,319,175**		**$1,856,797**

Rev.	Revision Date
0	01/29/19
1	05/17/19

	Cost	Revenue	Total Cost
Construction Mgmt & Indirects			
Engineering			$182,523
Start-Up			
Commercial			
Escalation			
Total Indirect Cost			**$182,523**
Total Direct and Indirect Costs			**$2,039,320**
	Cost	Revenue	
Project Contingency	10%	8%	$203,932
EPC Fee	7%	6.5%	$157,028
Total Project Cost	**17%**	**15%**	**$2,400,280**
Owner Cost - General, Taxes & Fees			
Owner Cost - Owner Contingency			
Total Project Cost Incl. Owner Cost			**$2,400,280**

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PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - Optimized SNCR Unit 1**
PROJECT # : **107926**

SUMMARY
ENGINEERED EQUIPMENT

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION		LABOR		MATERIAL COST	EQUIPMENT COST	EQUIPMENT RENT / STS	**TOTAL COST**
		MH	COST				
P 2	Treatment Equipment	220	31,458		762,700		**794,158**
P 3	Ammonia Slip Analyzers	120	17,159		82,000		**99,159**
P 4	Compressed Air Equipment	60	8,580		216,475		**225,055**
P 5	Boiler Penetrations				120,000		**120,000**
	ESTIMATE TOTALS	**400**	**$57,197**		**$1,181,175**		**$1,238,372**

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - Optimized SNCR Unit 1**
PROJECT # : **107926**

SUMMARY
STRUCTURAL STEEL

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION		LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
		MH	COST				
P 2	Fuel Tech Equipment Access Steel				100,000		**100,000**
P 3	Ammonia Slip Access Steel	650	90,328	69,000			**159,328**
	ESTIMATE TOTALS	**650**	**$90,328**	**$69,000**	**$100,000**		**$259,328**

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - Optimized SNCR Unit 1**
PROJECT # : **107926**

SUMMARY
PIPING

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 Air Piping	2,067	270,499	50,599			**321,098**
ESTIMATE TOTALS	**2,067**	**$270,499**	**$50,599**			**$321,098**

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - Optimized SNCR Unit 1**
PROJECT # : **107926**

SUMMARY
ELECTRICAL

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 ELECTRICAL				38,000		**38,000**
ESTIMATE TOTALS				**$38,000**		**$38,000**

CAPITAL COST ESTIMATE
Minnkota Power Coop.
Milton R Young
Optimized SNCR Unit 2
Center, ND
BMcD #107926

Acct	Area / Discipline	Direct MHRS	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	Total Cost
01	Engineered Equipment	516	$73,784		$1,191,275		$1,265,059
02	Civil						
03	Deep Foundations						
04	Concrete						
05	Structural Steel	650	$90,328	$69,000	$250,000		$409,328
06	Architectural						
07	Piping	6,270	$820,514	$137,188			$957,702
08	Electrical				$48,000		$48,000
09	Instrument & Control						
10	Insulation						
11	Coatings						
12	Specialty						
13	Demolition						
14	Misc Directs						
	Total Direct Cost	**7,436**	**$984,625**	**$206,188**	**$1,489,275**		**$2,680,088**

Rev.	Revision Date
0	01/29/19
1	05/17/19

	Cost	Revenue	
Construction Mgmt & Indirects			
Engineering			$268,009
Start-Up			
Commercial			
Escalation			
Total Indirect Cost			**$268,009**
Total Direct and Indirect Costs			**$2,948,097**
	Cost	Revenue	
Project Contingency	10%	8%	$294,810
EPC Fee	7%	6.5%	$227,003
Total Project Cost	**17%**	**15%**	**$3,469,910**
Owner Cost - General, Taxes & Fees			
Owner Cost - Owner Contingency			
Total Project Cost Incl. Owner Cost			**$3,469,910**

V 3.5

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - Optimized SNCR Unit 2**
PROJECT # : **107926**

SUMMARY
ENGINEERED EQUIPMENT

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	EQUIPMENT COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 Treatment Equipment	336	48,045		652,800		**700,845**
P 3 Ammonia Slip Analyzers	120	17,159		82,000		**99,159**
P 4 Compressed Air Equipment	60	8,580		216,475		**225,055**
P 5 Boiler Penetrations				240,000		**240,000**
ESTIMATE TOTALS	**516**	**$73,784**		**$1,191,275**		**$1,265,059**

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - Optimized SNCR Unit 2**
PROJECT # : **107926**

SUMMARY
STRUCTURAL STEEL

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 Fuel Tech Equipment Access Steel				250,000		**250,000**
P 3 Ammonia Slip Access Steel	650	90,328	69,000			**159,328**
ESTIMATE TOTALS	**650**	**$90,328**	**$69,000**	**$250,000**		**$409,328**

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - Optimized SNCR Unit 2**
PROJECT # : **107926**

SUMMARY
PIPING

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 Air Piping	6,270	820,514	137,188			**957,702**
ESTIMATE TOTALS	**6,270**	**$820,514**	**$137,188**			**$957,702**

PROJECT CLIENT: **Minnkota Power Coop.**
PROJECT DESC: **Milton R Young - Optimized SNCR Unit 2**
PROJECT # : **107926**

SUMMARY
ELECTRICAL

EST LEVEL:
ESTIMATE DUE DATE:
ESTIMATOR:

DESCRIPTION	LABOR		MATERIAL COST	SUBCON COST	EQUIPMENT RENT / STS	**TOTAL COST**
	MH	COST				
P 2 ELECTRICAL				48,000		**48,000**
ESTIMATE TOTALS				**$48,000**		**$48,000**

B.5.c – Communications

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

March 18, 2019

FILE

Mr. Kevin Thomas
Minnkota Power Cooperative, Inc.
3401 - 24th Street SW
Center, ND 58530-9507

Re: Fours Factors Analysis
M.R. Young Station

Dear Mr. Thomas:

The Department has conducted an initial review of the Four Factors Analysis that was submitted for the M.R. Young Station. Based on that review, we have the following comments:

1. All estimates of costs should be based on current (2019) dollars not 2021 dollars. EPA's Control Cost Manual, Section 1, Chapter 2, states "The method for estimating TCI in this Manual is an "overnight" estimation method. This method estimates capital cost as if no interest was incurred during construction and therefore estimates capital cost as if the project is completed "overnight." An alternate way of describing this method is the present value cost that would have to be paid as a lump sum up front to completely pay for a construction project." All estimates of capital cost must be consistent with the Control Cost Manual.

2. Section 1.1.5 and the various tables indicate the baseline emission rates were based on the maximum 30-day rolling average from 2014-2018. Baseline emissions should represent expected future **annual emissions**. Use of the maximum 30-day rolling average will generally overpredict baseline emissions. Annual average emission rates would be a better representation if operating conditions are expected to remain the same. Based on past annual emissions at M.R. Young Station, we do not disagree with the stated baseline emissions at this time (see comment 6); however, we disagree with the methodology.

3. The cost of Rich Reagent Injection (RRI) appears to be excessive. EPA's revised Control Cost Manual estimates the capital cost of RRI at $8-12/kw for a 500 MW plant. The Unit 2 capital cost estimate for RRI+SNCR/ASOFA was $15,828,000 with $2,774,000 for optimized SNCR/ASOFA. It appears that the cost of RRI equates to $27.47/kw (($15,828,000 - $2,744,00) / 477,000 kw), more than double EPA's estimate (Unit 1 calculated at $30.16/kw). The capital cost estimated for M.R. Young Unit 2 is also more than double the estimated capital cost for RRI at Leland Olds Unit 2 ($12.44/kw) and the

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Division of Municipal Facilities 701.328.5211
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Division of Water Quality 701.328.5210

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Coyote Station ($13.43/kw) which are similar size units. Please revise the estimates for both units or provide a detailed explanation for the high cost.

4. Many cost estimates throughout the analysis are based on vendor budgetary quotes or engineering estimates. When cost estimates are not based on the EPA's Control Cost Manual, evidence for the estimate must be provided. In other words, if vendor quotes or engineering estimates are used for calculations, evidence of those quotes or estimates must be provided in the analysis.

5. Sections 2.5.1.5 and 4.4.1.5 discuss "levelizing" of capital and O&M costs. As discussed in the Round 1 SIP Approval/FIP, "levelizing" of costs using the normal electric utility industry method is not acceptable (see 77 FR 201916 – 201917). Levelizing the "Installed Capital Cost" is not allowed. The cost estimates must be revised to be consistent with the Control Cost Manual.

6. In Tables 3-8 and 3-9, footnote 5 indicates the projected emissions (tpy) for a "Modified Wet FGD" were based on future higher sulfur coal. It appears the baseline emission rates were also based on future higher sulfur coal. If so, footnote 5 should also be placed on the "Baseline" in column 1 and coal sampling data provided to justify the rate. If not, the high baseline emission rates should be explained.

We ask that you revise the analysis and resubmit it as soon as possible. If you have any questions, please contact Tom Bachman of my staff at (701) 328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:saj

B.6 – MDU Heskett

B.6.a – Department Request

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

FILE

May 2, 2018

Ms. Abbie Krebsbach
Montana Dakota Utilities
400 N Fourth Street
Bismarck, ND 58501

Re: Regional Haze
Second Planning Period

Dear Ms. Krebsbach:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:
1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
Division of Municipal Facilities 701.328.5211
Division of Waste Management 701.328.5166
Division of Water Quality 701.328.5210

Coal-fired electrical generating units have been identified as one of the largest source of sulfur dioxide and nitrogen oxides in North Dakota. Therefore, the Department requests that you prepare a "four factors" analysis for your coal-fired electrical generating units. The analysis should be prepared using the draft EPA guidance noted above. The Department will identify other sources in North Dakota that will be required to submit a four factors analysis.

The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair
Director
Division of Air Quality

TLO/TB:saj
xc: Mark Dihle, Montana Dakota Utilities

B.6.b – Facility Response

MONTANA-DAKOTA
UTILITIES CO.
A Subsidiary of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
701-222-7900

January 31, 2019

Terry L. O'Clair, Director
North Dakota Department of Health
Division of Air Quality – 2nd Floor
918 East Divide Avenue
Bismarck, ND 58501-1947

Re: Regional Haze Round 2 "Four-Factor" Analysis Report for SO^2 and NOx Emissions Control at R.M. Heskett Station Unit 1 and Unit 2

Dear Mr. Stroh:

Enclosed is Montana-Dakota Utilities Co. (Montana-Dakota) Regional Haze Round 2 "Four-Factor" Analysis Report for SO2 and NOx Emissions Control at R.M. Heskett Station Unit 1 and Unit 2. This report contains the analysis the North Dakota Department of Health (NDDH) requested (for sulfur dioxide and nitrogen oxides) as applied to the review of emissions controls under the Regional Haze program for our coal-fired electrical generating units.

The NDDH May 2, 2018 letter requested that we prepare this report according to Draft Guidance provided by the U.S. Environmental Protection Agency (EPA). EPA has made known in the agency's September 11, 2018 Regional Haze Reform Roadmap that updated guidance, replacing the current Draft Guidance, as well as implementation tools, for this planning period will be available in future. However, the updated guidance has not yet been published. Montana-Dakota also understands other states in Region 8 have not yet requested a similar review process be completed by industry. Considering the information gained in the regional modeling process, future updated guidance from EPA, the short timeframe to complete and submit the attached report, and the potential need to consider site-specific conditions and costs, Montana-Dakota reserves the right to review and modify this analysis.

If you have any questions or would like to discuss the report conclusions, please contact me at (701) 222-7865.

Sincerely,

Mark Dihle
Sr. Environmental Scientist

Enclosure

cc: Jay Skabo, Vice President of Electric Supply
Alan Welte, Director Power Production Generation
Cory Zentner, Manager Heskett Station
Abbie Krebsbach, Environmental Director
David Stroh, NDDH

R.M. Heskett Station

"Four-Factor Analysis" for SO_2 and NOx Emissions Control at Unit 1 and Unit 2

Prepared for
Montana-Dakota Utilities Co.

January 2019

R.M. Heskett Station

"Four-Factor Analysis" for SO_2 and NOx Emissions Control at Unit 1 and Unit 2

Prepared for
Montana-Dakota Utilities Co.

January 2019

Joel Trinkle, QEP
Sr. Air Quality Consultant, Vice President

4300 MarketPointe Drive, Suite 200
Minneapolis, MN 55435
952.832.2600
www.barr.com

R.M. Heskett Station “Four-Factor Analysis” for SO_2 and NOx Emissions Control at Unit 1 and Unit 2

January 2019

Contents

List of Tables

List of Figures

Abbreviations

AEIR	Annual Emissions Inventory Report
AFBC	Atmospheric Fluidized Bed Combustion
BACT	Best Available Retrofit Technology
BART	Best Available Retrofit Technology
BOFA	Boosted Overfire Air
CAA	Clean Air Act
$CaCO_3$	Limestone
CaO	Lime
CCR	Coal Combustion Residuals
CEMS	Continuous Emissions Monitoring System
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CO	Carbon Monoxide
Control Cost Manual	EPA Air Pollution Control Cost Manual
D	Distance
DSI	Dry Sorbent Injection
Draft Guidance	September 11, 2018 Regional Haze Reform Roadmap
EGU	Electric Generating Unit
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
FBC	Fluidized Bed Combustion
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
Heskett Station	R.M. Heskett Station Station
Hg++	Oxidized Mercury
Hg0	Elemental Mercury
Hgp	Particulate Mercury
IRP	Integrated Resource Planning
LNB	Low NOx Burner
LOI	Loss on Ignition
LWA	Lostwood Wilderness Area
MONTANA-DAKOTA	Montana-Dakota Utilities
N_2	Molecular Nitrogen
NDDH	North Dakota Department of Health
NH_3	Ammonia
NOx	Nitrogen Oxides
O&M	Operation and Maintenance
OFA	Overfire Air
PM	Particulate Matter
PRB	Powder River Basin

Q	Emission Rate
RH	Regional Haze
Roadmap	Regional Haze Reform Roadmap
ROFA	Rotating Overfire Air
RUS	Rural Utility Service
SCR	Selective Catalytic Reduction
SDA	Spray Dry Absorption
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
TDF	Tire-Derived Fuel
TRNP	Theodore Roosevelt National Park
WRAP	Western Regional Air Partnership

1 Introduction

The Regional Haze (RH) Rule published on July 15, 2005 by the U.S. Environmental Protection Agency (EPA) defines regional haze as "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources." The RH rule requires states to submit a series of state implementation plans (SIPs) to protect visibility in certain national parks and wilderness areas, known as mandatory Federal Class I areas. The original State SIPs were due on December 17, 2007 and included milestones for establishing reasonable progress towards the visibility improvement goals, with the ultimate goal to achieve natural background visibility by 2064. The original SIP was informed by best available retrofit technology (BART) analyses that were completed on all subject-to-BART sources. The second planning period (Round 2) requires development and submittal of updated state SIPs by July 31, 2021.

The North Dakota Department of Health (NDDH) has requested Montana-Dakota Utilities Co. (MONTANA-DAKOTA) R.M. Heskett Station (Heskett Station) complete a four-factor analysis, as outlined in Section 169A(g)(1) of the Clean Air Act (CAA) as part of RH Round 2. Per the May 2, 2018 letter from the NDDH and separate confirmation from NDDH, the four-factor analysis is only required for direct emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx). The reasonable progress analysis is made using the following four factors:

1. The cost of compliance;
2. The time necessary to achieve compliance;
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements.

This report describes the background and methods for conducting a four-factor analysis for sulfur dioxide (SO_2) and nitrogen oxides (NOx) as applied to the review of emissions controls under the RH program at Heskett Station located two miles north of Mandan, ND. Heskett Station operates two coal fired electric generating units. Commercial operation commenced on Heskett Station Unit 1 (25 megawatt) in 1954 and Heskett Station Unit 2 (75 megawatt) in 1963. In 1987, Unit 2 was converted from a Riley Stoker Spreader boiler to an atmospheric fluidized-bed combustor (discussed below in Section 1.1.1.2).

The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx). Guidance provided by the U.S. Environmental Protection Agency (EPA) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas.

MONTANA-DAKOTA understands that NDDH is requesting the four-factor analysis and subsequent emissions performance numbers for submittal to the Western Regional Air Partnership (WRAP) for modeling of visibility impacts at Class I areas (i.e., TRNP and LWA).

MONTANA-DAKOTA also understands, to-date, no other states have yet requested a similar review process be completed by industry. Considering that no other WRAP industry partners are providing information, the short timeframe to complete this work, and the September 11, 2018 Regional Haze Reform Roadmap (roadmap) from EPA indicating impending implementation tools and updated guidance for the second planning period is not yet available, MONTANA-DAKOTA reserves the right to review and modify the assumptions used in this analysis, primarily concerning site-specific conditions for cost (including capital costs and actual emissions reductions potential/performance) and remaining useful life of the affected sources.

1.1 Background, Historical and Current Emissions Summary and Future Operational Considerations

MONTANA-DAKOTA Heskett Station was not subject to a formal BART review as part of Round 1 of RH. Unit 1 was not considered a BART-eligible source due to an operation commencement date before 1962 and NDDH determined it was further exempted from detailed analysis based on a calculated Q/D (emission rate (Q) divided by the distance (D) to the nearest Class I area) of less than 10. Unit 1 does not operate with any add-on SO_2 or NOx controls currently. While Unit 2 was originally considered a BART-eligible source, it was ultimately exempted from formal BART requirements due to modeling that demonstrates a contribution of less than 0.5 deciviews of visibility degradation in any Class I area. However, MONTANA-DAKOTA initiated a draft BART evaluation on Unit 2 in early 2006 with excerpts of that draft submitted to NDDH, as documented in Supplement No. 1 to the North Dakota State Implementation Plan (SIP) for RH. R.M. Heskett Station was reviewed for controls under the reasonable progress goals of North Dakota's RH SIP. Under that portion of the SIP, the NDDH included a federally enforceable permit requiring Heskett Station to comply with an SO_2 emissions rate of 0.60 lb/mmbtu, which is equal to a 70% reduction of SO_2 emissions (coal-to-stack)[1]. Heskett Station accomplished this in 2017 by implementing a project that replacing a portion of the sand utilized in the Unit 2 boiler fluidized bed with limestone. In 2017, the limestone addition project was completed. Unit 2 does not operate with add-on NOx controls currently, although the lower temperatures of the AFBC provides some NOx combustion control benefit. Both Units currently cycle load as called upon for generation needs (Unit 1 typically down to 9 MW; Unit 2 typically down to 56 MW), and these decreased operating levels result in less overall air pollution.

EPA's draft guidance allows states to use a screening step to select sources or groups of sources for which a four-factor analysis shall be completed. While the current draft guidance does not provide clear definition on conducting that screening step, the September 2018 roadmap explicitly states that the areas

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[1] R.M. Heskett Station Air Pollution Control Title V Permit to Operate, T5-F76001.

of focus in the updated guidance will include "providing states with additional information and context regarding screening sources before in-depth analysis".

As a reference point, MONTANA-DAKOTA has calculated a preliminary Q/D Analysis for both Unit 1 and Unit 2. For Unit 1, the preliminary Q/D is determined using the average of the annual tons of NOx and SO_2 (combined) emitted from 2012 to 2017, as reported to NDDH through the Annual Emissions Inventory Report (AEIR), and the distance to the nearest class 1 area consistent with the ND RH SIP (182 kilometers). For Unit 2, the preliminary Q/D is determined using the annual tons of NOx and SO_2 (combined) emitted in 2017, as reported to NDDH, and the distance to the nearest Class I area consistent with the ND RH SIP. 2017 was assumed representative of current of and future emissions due to implementation of limestone injection at Unit 2 in 2017. Preliminary Q/D values are shown below:

Table 1-1 Preliminary Q/D for Heskett Station

Unit	SO_2 + NOx (tons)	Distance (km)	Q/D (tons/km)
Unit 1	1,194	182	6.6
Unit 2	2,899	182	13.5
Combined Source	4,094	182	18.0

MONTANA-DAKOTA notes that the combined source emissions are less than the individual Unit 2 source Q/D from the ND RH SIP for Round 1. Considering the lower emissions trend for both units, it is expected that visibility modeling for Heskett Station would demonstrate commensurately lower visibility impairment. MONTANA-DAKOTA reserves the right to review and modify the assumptions used in this analysis.

1.1.1 Emissions Summary

1.1.1.1 Heskett Station Unit 1

Heskett Station Unit 1 is a 25 MW, lignite fired, spreader stoker boiler rated at 387.63 MMBtu/hour. The boiler is capable of burning up to approximately 30 tons of coal per hour. Unit 1 also has the capability to blend (with lignite) and combust tire derived fuel (TDF), and does so as a method to comply with the Mercury and Air Toxics Standard (MATS) mercury (Hg) emissions limit for units designed to burn low-rank virgin coal. As permitted, TDF can account for up to 4 tons/hr of the fuel combusted on a calendar quarter average, but the actual amount combusted is much less. Unit 1 was constructed in 1954 and an Electrostatic Precipitator (ESP) was later installed to control particulate emissions. Unit 1 currently utilizes over-fire air techniques to assist with NOx emissions mitigation. As is common with older units, there is limited ductwork and space between the boiler and the stack for any emissions control additions.

Unit 1 NOx Emissions Summary

Heskett Station Unit 1 is estimated to have the potential to emit 762 tons of NOx annually, if operated 100% of the year. Potential NOx emissions are calculated using AP-42, Vol. I, Chapter 1.7 for lignite combustion emissions factor of 5.8 lb NOx/ton of coal combusted and assuming firing at the combustion capability of the unit (30 tons per hour) for a full year. There is no continuous emissions monitoring system (CEMS) for NOx at station 1. However, based on the actual amount of coal combustion, since 2012, annual NOx emissions reported at Heskett Station Unit 1 total less than half of what the unit can potentially emit. The lower annual emissions are due to operating at a rate lower than maximum capacity. Actual emissions reported since 2012 are shown in Figure 1 below. Section 1.1.2 of this report discusses the operating capacity at Heskett Station.

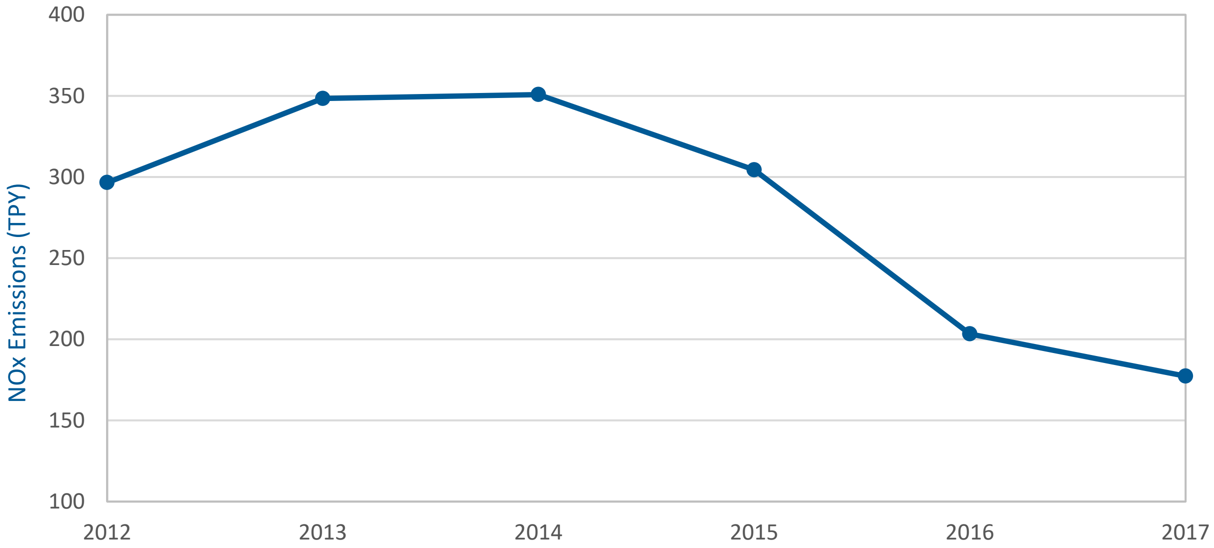

Figure 1 **Heskett Station Unit 1 Total Annual NOx Emissions**

Unit 1 SO_2 Emissions Summary

Heskett Station Unit 1 actual SO_2 emissions from 2012 through 2017 are shown below in Figure 2. The figure demonstrates that, since 2012, Unit 1 actual SO_2 performance on a lb/MMBtu basis has been much less than the permitted limit of 3.0 lb/MMBtu (3-hour rolling average). The data points shown on the graph are presented as monthly averages and are not to be construed as a compliance demonstration against the 3-hour rolling average permitted limit. Unit 1 actual mass emissions are determined as measured from the unit's CEMS. Emissions data are shown as a lb/MMBtu on a monthly average basis and includes all periods of operation.

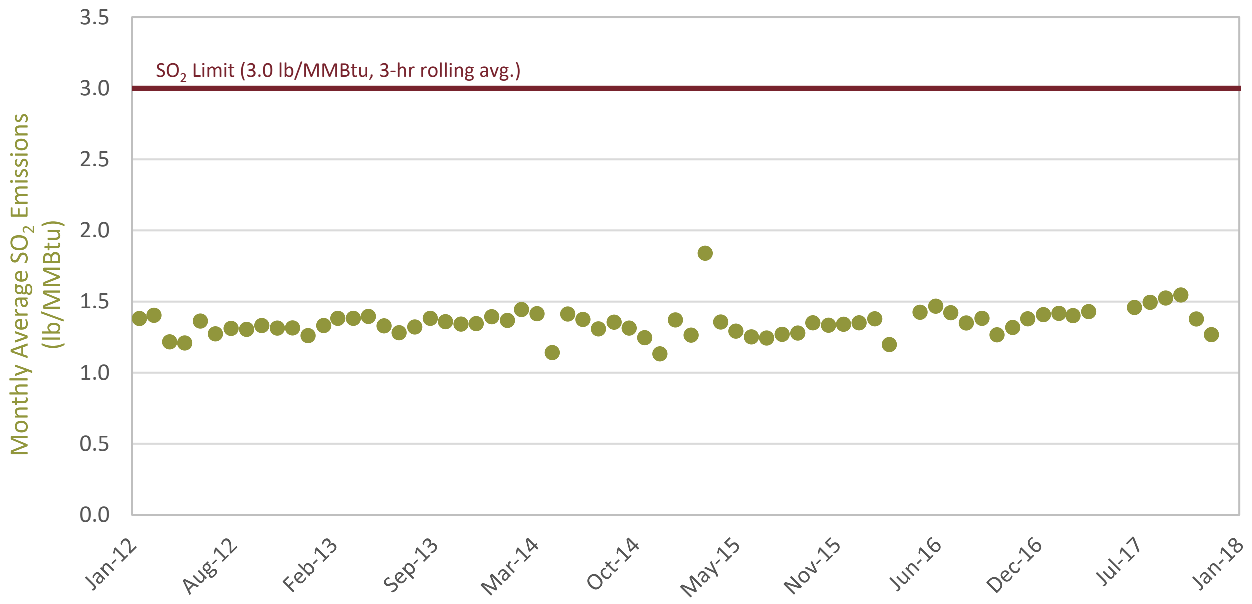

Figure 2 Heskett Station Unit 1 Average Monthly SO_2 Emissions

1.1.1.2 Heskett Station Unit 2

Heskett Station Unit 2 is a 75 MW, lignite-fired, atmospheric fluidized-bed combustor (AFBC) rated at 916.5 MMBtu/hour. The boiler is capable of firing up to approximately 75 tons of coal per hour. In atmospheric fluidized bed combustion, coal is burned in a hot sand (and limestone) bed that is aerated from bubble caps underneath. Unit 2 also has the capability to combust TDF. Unit 2 was constructed in 1963 as a Riley Stoker Spreader boiler, was converted to an AFBC in 1987 and later installed an ESP to control particulate matter emissions. Unit 2 also has limited ductwork and space between the boiler and the stack.

The conversion of the original boiler was to an AFBC, which is different from a circulating fluidized bed boiler design. The Unit 2 AFBC media is maintained in the bottom of the boiler at approximately 4 feet or less in height and has boiler tubes immersed within the bed. Transfer of heat to the tubes in the bed is optimal with certain blends of sand, limestone, and ash. Feed rate of new material to the bed and drainage of spent material can be adjusted for system management. An AFBC is also different from circulating fluidized bed boilers where the bed media circulates higher in the boiler with the flue gas; any carryover media is captured, separated from the flue gas, and returned to the boiler. An AFBC has minimal sand media carryover since the bed height is relatively low.

Unit 2 NOx Emissions Summary

Heskett Station Unit 2 actual NOx emissions from 2012 through 2017 are shown below in Figure 3. The figure demonstrates that, since 2012, Unit 2 actual NOx performance on a lb/MMBtu monthly average basis has been less than the permitted limit of 0.46 lb/MMBtu (12-month rolling average). The permitted limit is incorporated into the below figure as a reference point for comparison to current actual emissions. The data points shown on the graph are presented as monthly averages and are not to be construed as a compliance demonstration against the 12-month rolling average permitted limit. Unit 2 actual mass emissions are determined as measured from the unit's CEMS. Emissions performance data is shown as a lb/MMBtu on a monthly average basis and includes all periods of operation.

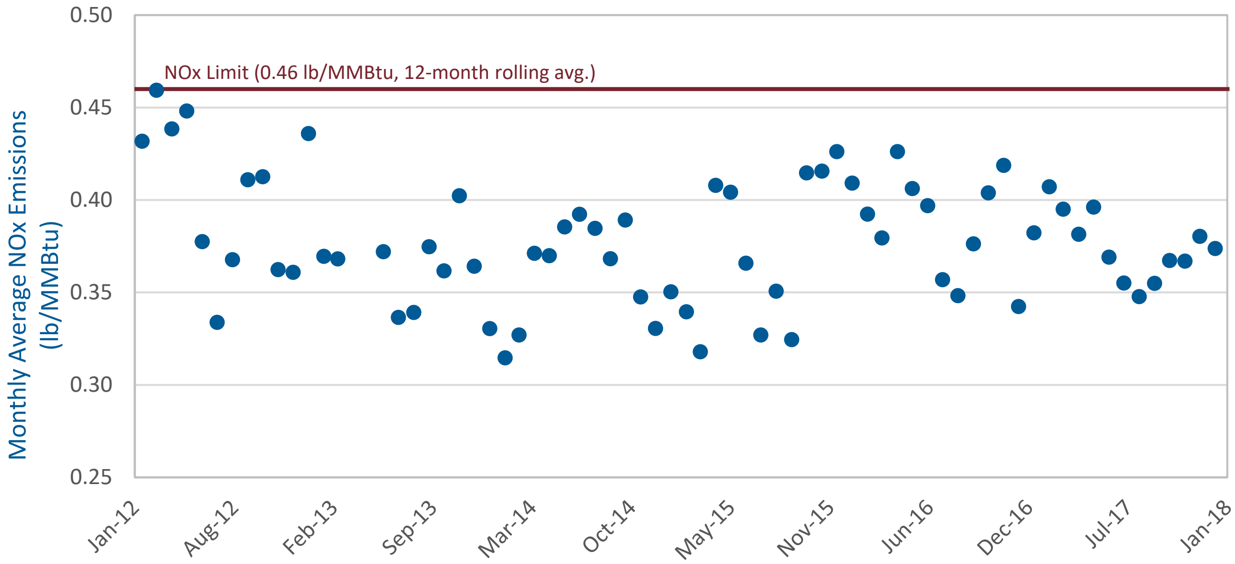

Figure 3 **Heskett Station Unit 2 Average Monthly NOx Emissions**

Unit 2 SO_2 Emissions Summary

Heskett Station Unit 2 actual SO_2 emissions from 2012 through 2017 are shown below in Figure 4. Heskett Station implemented a limestone addition to the sand bed for Unit 2 for RH emission reductions in 2017. An SO_2 limit of 0.60 lb/MMBtu was applied to Unit 2 and Heskett Station has demonstrated compliance with this 12-month rolling average limit. The permitted limits are incorporated into the below figure as a reference point for comparison to current actual emissions. The data points shown on the graph are presented as monthly averages and are not to be construed as a compliance demonstration against the rolling average permitted limits. Emissions performance data is shown as a lb/MMBtu on a monthly average basis and includes all periods of operation. Since implementation of the limestone injection project, actual SO_2 emissions have decreased from approximately 165 lb/hr to 110 lb/hr on a monthly average basis.

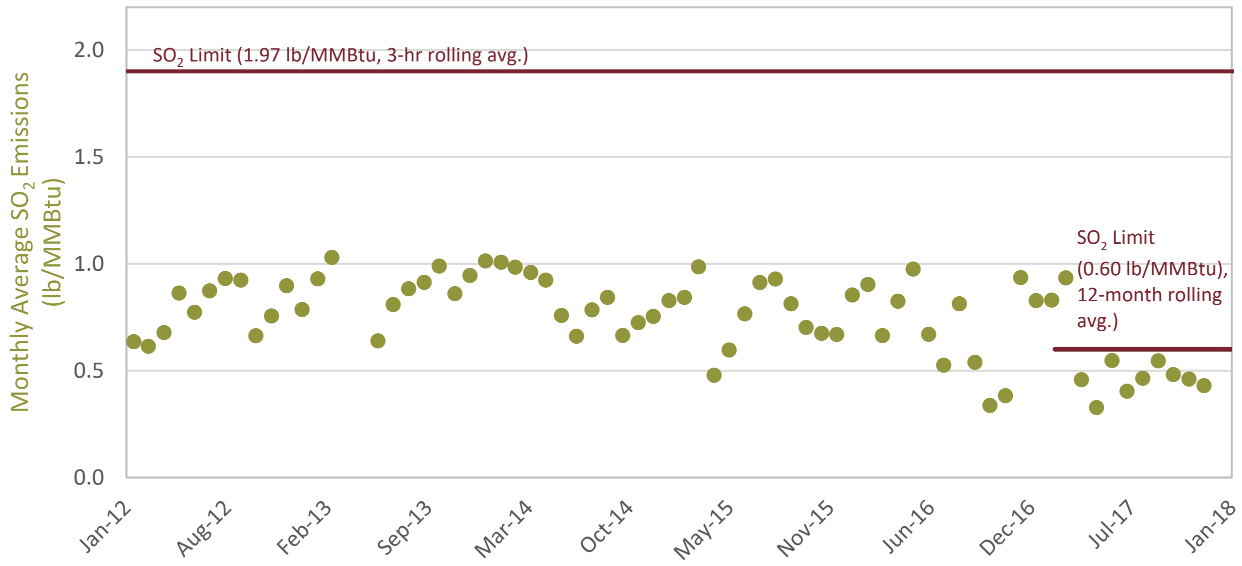

Figure 4 **Heskett Station Unit 2 Average Monthly SO$_2$ Emissions**

1.1.2 Operating Capacity

Since the early 2000's, baseload operations at coal-fired power plants located across the Western United States has decreased significantly in annual utilization. Since 2011, the majority of coal fired electric generating units (EGU) have spent less than 30% of their operating days in baseload operating mode.[2] Heskett Station is no exception to that trend. Since 2012, the annual capacity factors (on a lb/MMBtu basis) are as follows:

Table 1-2 **Annual Capacity Factor at MONTANA-DAKOTA Heskett Station Unit 1 and Unit 2**

Year	Annual Capacity Factor (lb/MMBtu basis)	
	Unit 1	Unit 2
2012	43%	60%
2013	50%	52%
2014	46%	69%
2015	44%	66%
2016	31%	65%
2017	27%	65%
2018 (through October 2018)	37%	65%
Average	**40%**	**63%**

The average capacity factors (on a lb/MMBtu basis) since 2012 are 40% for Unit 1 and 63% for Unit 2. MONTANA-DAKOTA does not anticipate a change in the trend of decreasing firing moving into the future

---

[2] Western Interstate Energy Board (2018). "*The Role of Coal in the West*" [PowerPoint slides]. Retrieved from http://www.wrapair2.org/pdf/The%20Role%20of%20Coal%20in%20the%20West-Presentation.pdf

and, therefore, is appropriately utilizing a baseline emissions estimate for both NOx and SO_2 according to the average operating capacity factor (utilization rate) and the existing emissions limits for Unit 1 and Unit 2. The current EPA draft guidance states that baseline emissions can be determined according to past practice.[3] MONTANA-DAKOTA reserves the right to change (or update) the operating capacity factors in future rounds of RH review, as warranted. Figure 5 and Figure 6 show the annual tons of NOx and SO_2 emitted from Unit 1 and Unit 2, respectively since 2012.

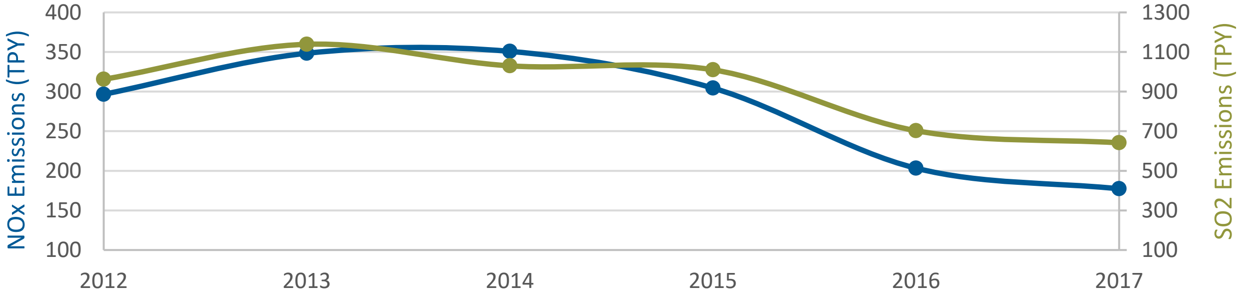

Figure 5 **Heskett Station Unit 1 Total Annual NOx and SO_2 Emissions**

The declining annual actual emissions for Unit 1 are not specifically a result of additional pollution control equipment additions, but more a result of declining unit utilization year-over-year from 2013 through 2017, as listed in Table 1-2.

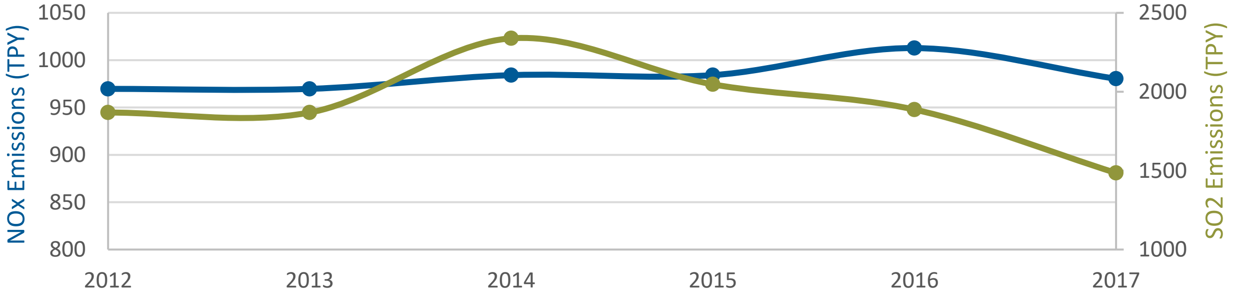

Figure 6 **Heskett Station Unit 2 Total Annual NOx and SO_2 Emissions**

Unit 2 has operated at a fairly consistent, but reduced, capacity since 2012, which is confirmed by the total annual NOx emissions from 2012 through 2017. The reduction in annual SO_2 emissions starting in 2016 at Unit 2 is a result of the initial operation and testing of the limestone injection project that was fully implemented in early 2017.

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[3] EPA July 2016 Draft Guidance, Section 6.2 (pg. 59): "In projecting future baseline emissions, typical past actual emission rates may be assumed even if lower than permitted emission rates, assuming there is no evident basis for assuming a change in emission rates"

1.2 Four-Factor Analysis Approach

The four-factor analysis is completed following the approach summarized below, as outlined in EPA's July 2016 draft guidance.

1.2.1 Identify all Emissions Control Options

Prior to completing the required four-factor analysis, all potentially available and technically feasible emissions control options for review are identified. Potentially available emissions control options include both add-on control equipment and process improvement applications. To be considered available and technically feasible, a control must have been previously installed and operated successfully on a similar source under similar physical and operating conditions. Novel controls that have not been demonstrated on full-scale, coal-fired utilities are not considered as part of this analysis. Instead, this evaluation focuses on commercially demonstrated control options.

All control options identified as available and technically feasible are then evaluated against the "four factors". Under this analysis, NOx and SO_2 emissions control options are evaluated for each unit individually.

1.2.2 Factor #1 – The Cost of Compliance

As part of Factor #1, the capital and annual operating and maintenance (O&M) costs of a control measure are estimated. As directed by the draft guidance, for purposes of Round 2, costs of emissions controls follow the accounting principles and generic factors from the EPA Air Pollution Control Cost Manual (Control Cost Manual) unless site specific factors are available and required to develop an accurate and representative control costs estimate. Under this step, the costs of compliance (dollar per ton basis) will be compared to the costs that other similar sources have had to bear in other regulatory actions to determine whether a control measure is reasonable.

The cost of compliance is calculated on a $/ton basis following the Control Cost Manual site-specific information is referenced and utilized when appropriate. However, if key information is unavailable, and should further cost refinement be necessary, a study would be required. This would mandate additional time and cost to determine the impact due to constraints of the current system, such as an extended need for shutdown, rerouting of piping to allow necessary residence time, potential redesign of backend heat recovery and associated costs that have not been evaluated. MONTANA-DAKOTA reserves the right to amend all items related to cost in the future.

The cost of compliance are categorized into capital and annual costs. Capital costs generally refer to the money required to design and build the system, and this includes direct costs, such as equipment purchases, and installation costs, such as foundations and installation of mechanical equipment. Indirect costs, such as engineering and construction field expenses, are also considered. Also taken into account when completing the economic feasibility (cost effectiveness) analysis are the baseline emissions (calculated as described above) and expected performance of the control device.

At the direction of the NDDH, this analysis uses an interest rate of 5.25% for the Round 2 four-factor economic analysis when determining annualized costs, MONTANA-DAKOTA reserves the right to use the default 7% (or another appropriate percentage) interest rate in future iterations of the economic analysis for RH Round 2 purposes. The Control Cost Manual states that "EPA policy specifies 7% interest for BACT review cost calculations". NDDH is following the EPA guidance from December 18, 2018[4] email in which EPA suggests using the bank prime rate in method outline in Section 2.5.2 of the Control Cost Manual. However, the December 18, 20218 email also notes that the recommended rate can vary. This variability has recently been demonstrated by an increase to raise the rate quoted in the email from 5.25% to 5.5%. MONTANA-DAKOTA is an investor-owned utility and finances projects differently than other utilities that are able to participate in Rural Utility Service (RUS) Electric Loan Program financing.

The emissions reduction or degree of control for each evaluated technology that is used to determine the cost of compliance is expressed as a 12-month average basis and represents the annual tons of pollutant removed to account for expected variability in emissions and provide a comparable basis for each of the control options. Baseline emissions are determined relying on permitted emissions limits and actual/expected unit operation.

1.2.3 Factor #2 – Time Necessary for Compliance

Under Factor #2, the time necessary for a source to implement a control measure to achieve compliance with a proposed emissions limitation is given consideration by setting reasonable deadlines for selected control. This includes the planning and installation of new emissions controls.

1.2.4 Factor #3 – Energy and Non-Air Environmental Impacts

The energy and non-air environmental impacts of each control technology are evaluated under Factor #3.

The environmental impact analysis assesses collateral environmental impacts associated with control of the pollutant in question. Impacts considered may include solid or hazardous waste generation, wastewater discharges from a control device, increased water consumption, and land use. The environmental impact analysis is conducted based on consideration of site-specific circumstances.

The energy impact analysis considers whether use of an emissions control technology results in any significant or unusual energy penalties or benefits. Energy use may be evaluated on an energy used per unit of production basis; energy used per ton of pollutant controlled or total annual energy use. Energy impacts may consider whether use of an emissions control technology will have an adverse impact on local energy supplies due to increased fuel consumption or the loss of fuel production or power generation.

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[4] Wortstell, Aaron (EPA). "RE: Regional Haze Economic Analysis." Message to Tom Bachman. December 18, 2018. Email.

1.2.5 Factor #4 – Remaining Useful Life of the Source

The remaining useful life of a source is considered the difference between the date that controls will be put in place and the date the facility permanently ceases operation. The remaining useful life of the source is typically longer than the useful life of the emissions control measure unless there is an enforceable cease-operation requirement. However, under Factor #4, if the useful life of the source is less than the remaining useful life of the control measure through a federally or state enforceable requirement, then that can be taken into consideration when evaluating emissions reductions, amortized costs, and cost per ton.

The remaining useful life of the two coal-fired units (Heskett Station Unit 1 and Unit 2) continues to be reviewed through MONTANA-DAKOTA'S Integrated Resource Planning (IRP) process, as required by state utility regulatory commissions. This IRP analysis considers many factors including facility age, major maintenance needs, future environmental compliance costs, and economic competitiveness to other alternatives, to determine appropriate planning for retirement of units. Until the IRP is concluded, MONTANA-DAKOTA will assume a 20-year remaining useful life for purposes of this four-factor analysis. It is possible that retirement could occur earlier than the assumed 20 years considering the culmination of additional environmental regulatory requirements and economic competitiveness of these units.

2 Unit 1 Nitrogen Oxides (NOx) Four-Factor Analysis

There are three mechanisms by which NOx production occurs: thermal, fuel, and prompt NOx. Fuel bound NOx is a primary concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process. The secondary mechanism of NOx production is through thermal NOx formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air. The thermal oxidation reaction is as follows:

$$N_2 + O_2 \rightarrow 2NO \qquad (1)$$

Downstream of the flame, significant amounts of NO_2 can be formed when NO is mixed with air. The reaction is as follows:

$$2NO + O_2 \rightarrow 2NO_2 \qquad (2)$$

Thermal oxidation is a function of the residence time, concentration of combustion gases (primarily nitrogen and oxygen) in the inlet air, and peak reaction temperature. Prompt NOx is a form of thermal NOx which is generated at the flame boundary. It is the result of reactions between nitrogen and carbon radicals generated during combustion. Only minor amounts of NOx are emitted as prompt NOx.

2.1 NOx Emissions Control Measures

There are several potentially available methods to control NOx emissions (see Table 2-1); however, not all are applicable for implementation at Unit 1. Accordingly, as part of this four-factor analysis, MONTANA-DAKOTA has narrowed the list of NOx control technology options for review to those that are functionally applicable for a retrofit installation at the Heskett Station Unit 1. The NOx retrofit control options are identified based on a review of available technical information.

Retrofit NOx control technologies can be divided into two general categories: (1) combustion controls, and (2) post-combustion controls. Combustion controls reduce the amount of NOx that is generated in the boiler, while post-combustion controls remove NOx from the boiler exhaust gas.

Table 2-1 List of Potentially Available Retrofit NOx Control Options

Control Technology
Combustion Controls
• Low NOx Burners • Overfire Air (OFA) • Flue Gas Recirculation (FGR) • Burner Tempering (Water Injection)
Post-Combustion Controls
• Selective Non-Catalytic Reduction (SNCR) • Selective Catalytic Reduction (SCR) o High-Dust SCR o Low-Dust SCR
Innovative Control Technologies
• Rotating Overfire Air (ROFA) • Boosted Overfire Air (BOFA) • ROFA + SNCR (Rotamix™) • NOxStar™ • Exxon Thermal DeNOx™ • Pahlman Process • Wet NOx Scrubbing LOTOx™

2.1.1 Combustion Controls

The rate of NOx formation in the combustion zone is a function of free oxygen, peak flame temperature and residence time. Combustion techniques designed to minimize the formation of NOx will minimize one or more of these variables. Combustion control options considered for Heskett Station Unit 1 are summarized below.

2.1.1.1 Low NOx Burners (LNB)

LNB technology utilizes advanced burner design to reduce NOx formation through the restriction of oxygen, flame temperature, and/or residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NOx formation is limited by either one of two methods. Under staged air rich (high fuel) condition, low oxygen levels limit flame temperatures resulting in less NOx formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel lean (low fuel) conditions, excess air will reduce flame temperature to reduce NOx formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NOx formation.

LNB technology is not a technically feasible control option at a stoker fired traveling grate furnace, and therefore, will not be considered further for implementation at Unit 1.

2.1.1.2 Overfire Air (OFA)

Overfire air (OFA) diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. OFA is the typical NOx control technology used in lignite-fired boilers and is primarily geared to thermal NOx reductions. Staging of the combustion air creates an initial fuel-rich combustion zone for a cooler fuel-rich combustion zone. This reduces the production of thermal NOx by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NOx is most likely to be formed.

OFA technology is currently used to control NOx emissions at Unit 1.

2.1.1.3 External Flue Gas Recirculation (FGR)

Flue gas recirculation is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizer or air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through adsorption of the combustion heat by the relatively inert flue gas, and to reduce the oxygen concentration in the combustion zone. FGR reduces thermal NOx generation in high-temperature emissions sources.

Additional ductwork and a blower would be required to recirculate flue gas. These elements must fit in the limited space around the burner. To integrate a blower and inject flue gas into the combustion zone of the existing unit would require a full design review and likely costly modifications to the existing combustion control scheme. Unit 1 currently utilizes OFA as a way to reduce thermal NOx emissions; it is unlikely that FGR would result in any additional significant NOx reductions. Further, FGR could result in reduced boiler capacity at an already small unit operating at reduced capacity.

For these reasons, FGR is not a technically feasible control option for implementation at Unit 1 and will not be considered further.

2.1.1.4 Burner Tempering (Water Injection)

The principle behind combustion tempering is to inject an atomized water spray into the high NOx production zones of the furnace flame. The water spray reduces the temperature within the zone, resulting in lower NOx production within the zone.

To integrate water injection into the combustion zone of the existing unit would require a full design review and likely costly modifications to the existing combustion control scheme. Burner tempering has been used on wall- and tangential-fired pulverized coal-fired units but not at a stoker fired traveling grate furnace and is therefore a not a technically feasible control option for implementation at Unit 1. This technology is not considered further.

2.1.2 Post-Combustion Controls

NOx can be reduced to molecular nitrogen (N_2) in add-on systems located downstream of the furnace area of the combustion process. The two main techniques in commercial service include the selective non-catalytic reduction (SNCR) process and the selective catalytic reduction (SCR) process. There are a number of different process systems in each of these categories of control techniques.

In addition to these treatment systems, there are a large number of other processes being developed and tested on the market. These approaches involve innovative techniques of chemically reducing, absorbing, or adsorbing NOx downstream of the combustion chamber. One example of these alternatives is nonselective catalytic reduction (NSCR).

2.1.2.1 Selective Non-Catalytic Reduction (SNCR)

In the SNCR process, urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to N_2 and water. SNCR control efficiency is typically 25% to 50%. Without the participation of a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:

$$NO + NH_3 + \frac{1}{4}O_2 \rightarrow N_2 + 3/2 H_2O \qquad (1)$$

$$NH_3 + \frac{1}{4}O_2 \rightarrow NO + 3/2 H_2O \qquad (2)$$

At temperature ranges of 1470°F to 1830°F, reaction (1) dominates. At temperatures above 2000°F, reaction (2) will dominate. Flue gas temperature at the point of reagent injection can greatly affect removal efficiencies and the quantity of ammonia (NH_3) that will pass through unreacted (ammonia slip). At temperatures below the desired operating range, the NOx reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NOx resulting in low NOx reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is also an important factor to SNCR performance. The SNCR system must be designed to deliver the reagent in the proper temperature window, and allow sufficient residence time of the reagent and flue gas in that temperature window. In addition to temperature, mixing, and residence time, several other factors influence the performance of an SNCR system including reagent-to-NOx ratio and NOx concentration in the flue gas.

SNCR systems are capable of achieving a NOx emissions reduction as high as 50 to 60 percent in optimum conditions (adequate reaction time, temperature, and reagent/flue gas mixing, high baseline NOx conditions, multiple levels of injectors) with ammonia slips of 10 to 50 ppmvd. Typically, optimum conditions are difficult to achieve, resulting in emissions reduction levels of 20 to 40 percent. Potential performance is very site-specific and varies with fuel type, steam generator size, allowable ammonia slip, furnace carbon monoxide (CO) concentrations, and steam generator heat transfer characteristics.

The application of SNCR to Heskett Station Unit 1 has the potential to be technically feasible because furnace temperatures are assumed (note that there is not instrumentation currently in place to measure temperature) to be within the temperature window needed for NOx reduction, and flue gas mixing and residence time within the boiler should promote the reaction kinetics. However, the effectiveness of an SNCR system at Heskett Station Unit 1 will be limited because of the design and boiler operating temperatures. The optimal condition locations are small due to the boiler size and type, and a boiler study would be required to more correctly predict feasibly and effectiveness at Unit 1. Even so, for purposes of this review, MONTANA-DAKOTA has assumed that SNCR could potentially be implemented at Unit 1 and has therefore included this in the four-factor analysis. Based on the calculated default control efficiency from EPA, an SNCR could potentially provide a NOx reduction of approximately 27% at Unit 1. With the uncertainty due to small boiler size and other issues, we reserve the right to refine this analysis in the future if necessary. MONTANA-DAKOTA is unaware of an SNCR system that is in operation today at a similar source utilizing an ESP for particulate matter control. A full review of the ESP's ability to accept and properly clean the flue gas would be needed to determine feasibility and possible costs.

2.1.2.2 Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is a post combustion NOx control technology in which NH_3 is injected into the flue gas stream in the presence of a catalyst. SCR control efficiency is typically 70% to 90%. NOx is removed through the following chemical reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \qquad (1)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O \qquad (2)$$

The catalyst bed lowers the activation energy required for NOx decomposition. The catalyst contains an active phase, such as vanadium pentoxide, on a carrier, such as titanium dioxide, and these are used for their ability to lower the activation energy required for NOx decomposition. SCR requires an optimum temperature range of 650 to 800°F.

A "high-dust" SCR arrangement in which the reactor is located between the outlet of the economizer and the inlet of the air heater and upstream of particulate control is typically the preferred arrangement where technically feasible. These arrangements typically require soot blowers for catalyst cleaning. In a "low-dust" arrangement, the SCR reactor is located after the particulate control device. This arrangement is preferred when the fly ash contains a high level of contaminants that would block catalyst actions, and removing most of the fly ash from the flue gas will help prolong the catalyst life. Firing ND lignite coal that contains high amounts of organically bound inorganics (and has a higher total sodium content), results in a stream heavily laden with particulate matter and sodium that combine to plug (block) catalyst passages. Due to the likelihood of catalyst plugging and the ability of phosphorus, sodium, other alkali and alkaline earth cations organically bound in ND lignite to mask or blind a catalyst reactions if not already plugged, a high-dust SCR system is considered technically infeasible on both Units 1 and 2. A low-dust SCR (downstream of particulate control) would require reheat to bring the stream temperature back to the effective control range after it is cooled for particulate removal. There would still be important concerns with this arrangement due to the contaminants' unique properties to inhibit the catalyst from operating, but in theory the issues would be less than with a high-dust system.

Although it would appear to be a potentially a technically feasible control option, MONTANA-DAKOTA notes that installing SCR (even a low-dust system) at similar types of sources remains limited or is altogether not feasible. MONTANA-DAKOTA is unaware of an SCR system that has been installed at a source firing North Dakota lignite. Issues associated with SCR on lignite boilers are discussed in additional detail in a 2009 study completed by the NDDH, which supports the limited feasibility of SCR.[5] Additionally, physical space constraints at Heskett Station greatly limit the opportunity for SCR system equipment and tie-ins. Even so, for purposes of this review, MONTANA-DAKOTA has assumed that a low-dust SCR system could potentially be implemented at Unit 1 and has therefore included this in the four-factor analysis (even though it is considered by MONTANA-DAKOTA as technically infeasible). Based on current NOx emissions, an SCR could potentially provide an additional NOx reduction in the range of 70%-80%. Again, due to the issues stated above, we reserve the right to refine this analysis in the future if necessary.

2.1.3 Innovative Controls

NOx controls grouped under the "Innovative Control Technologies" are not being considered in this analysis. These technologies are not considered commercially available and are not applicable at MONTANA-DAKOTA Heskett Station.

2.2 Factor 1 – The Cost of Compliance

The pollution control costs are presented on a dollar per ton of pollutant removed, calculated according to Equation 2.73 of the Cost Manual and 40 CFR 51, Appendix Y, Section IV, Subsection D. The cost effectiveness analysis compares the annualized cost of the technology per ton of pollutant removed and is evaluated on dollar per ton ($/ton) basis using the annual operating cost ($/yr) divided by the annual emissions reduction achieved by the control device (ton/yr). Additional details regarding the control equipment cost data and evaluation are noted in the control cost worksheets in Attachment A.

Table 2-2 NOx Control Cost Evaluation for Heskett Station Unit 1

Control Technology	Estimated Control Efficiency (%)	Installed Capital Cost ($)	Annualized Capital Cost ($/yr)	Pollution Control Cost ($/ton)[1]
SNCR	27%	$4,180,000	$744,000	$9,100
Low-Dust SCR	80%	$21,700,000	$2,540,000	$10,400

[1] The NDDH original BART ceiling costs were based on the June 1999 WRAP Annex to Grand Canyon Visibility Transport Report. Scaled to today's dollars, the average cost effectiveness threshold is approximately $4,460 per ton.

SNCR and SCR are both considered economically infeasible for implementation at Unit 1 as the average cost effectiveness is not justified on a dollar per ton basis.

2.3 Factor 2 – Time Necessary for Compliance

Under Factor #2, the amount of time needed for full implementation of different control strategies is reviewed. Typically, the time necessary for compliance will include the time needed to develop and implement the regulation and/or the time needed to install the necessary emissions control equipment.

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[5] *Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite.* North Dakota Department of Health, Division of Air Quality. 7/1/2009

This analysis does not support the installation of any new retrofit NOx emissions control methods at Heskett StationUnit 1 and therefore a review of the time necessary for compliance is not applicable.

2.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts

Energy impacts are primarily related to the auxiliary power consumption of the SCR and SNCR systems and are included in the cost estimates under the variable annual costs. Other indirect energy impacts, such as the energy to produce reagents, are not considered in this study.

The operation of an SCR or SNCR system could have other non-air environmental impacts. For example, the storage of ammonia on-site creates the potential for accidents due to an ammonia release. Depending on the type, concentration, and quantity of ammonia used, the material will be subject to regulation as a hazardous substance under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), Section 313 of the Emergency Planning and Community Right-to-Know Act, Section 112(r) of the CAA, and Section 311(b)(4) of the Clean Water Act.

2.5 Factor 4 – Remaining Useful Life of the Source

At this time, MONTANA-DAKOTA has assumed that the remaining useful life of the Unit 1 will be longer than the useful life of the emissions control measures evaluated in this analysis. Accordingly, as directed by the July 2006 EPA draft guidance, the useful life of the individual control measures is used to calculate emissions reductions, amortized costs, and cost effectiveness on a dollar per ton basis.

2.6 Proposed Controls and Emissions Rates

This analysis does not support the installation of any new retrofit NOx emissions controls at Heskett Station Unit 1. The available and potential technically feasible control strategies (SCNR and SCR) are economically infeasible and have significant technical and other implementation concerns for commercial scale operation at a North Dakota lignite fired boiler. Therefore, MONTANA-DAKOTA is proposing to maintain current operational practices consistent with the parameters and limits included as part of the facility's existing Air Pollution Control Title V Permit to Operate (T5-F76001). Due to the uncertainty of the actual feasibility of NOx emissions controls that was assumed as part of this four-factor analysis and the additional detailed analysis for cost refinement, MONTANA-DAKOTA reserve the right to refine this analysis in the future if necessary.

3 Unit 1 Sulfur Dioxide (SO_2) Four-Factor Analysis

Sulfur emissions from coal combustion consist primarily of SO_2, with a much lower quantity of sulfur trioxide (SO_3) and gaseous sulfates. These compounds form as the organic and pyritic sulfur in the coal is oxidized during the combustion process. The generation of SO_2 is directly related to the sulfur content and heating value of the fuel burned. The sulfur content and heating value of coal can vary dramatically depending on the source of the coal. Heskett Station uses North Dakota lignite and, for a short period in the past, used a blend of lignite and small amounts of Powder River Basin (PRB) coal as its fuel source.

3.1 SO_2 Emissions Control Measures

Several techniques can be used to reduce SO_2 emissions from coal combustion sources. SO_2 control techniques can be divided into pre- and post-combustion strategies.

Table 3-1 SO_2 Control Options with Potential Applications to Heskett Station Unit 1

Control Technology
Pre-Combustion Controls
• Fuel Switching • Fuel Washing
Post-Combustion SO_2 Control Technologies
• Wet Flue Gas Desulfurization • Dry Flue Gas Desulfurization o Spray Dryer Absorber o Dry Sorbent Injection

3.1.1 Pre-Combustion Controls

A potential control strategy for reducing SO_2 emissions from a coal-fired boiler is to reduce the amount of sulfur contained in the coal. This can be accomplished through reducing inherent impurities via coal washing or potentially, more drastically, through switching to a lower sulfur fuel source.

In general, coal washing is accomplished by separating and removing inorganic impurities from organic coal particles. Inorganic impurities, including inorganic ash constituents and inorganic iron disulfide (FeS_2 or pyrite), are typically denser than the coal particles. This property is generally used in a wet cleaning process to separate coal particles from the inorganic impurities.

While washing may be effective in removing rock inclusions from coal, including sulfur-bearing pyrites, a significant amount of coal may also be lost in the washing process requiring the mine to process significantly more coal to make up for coal lost in the washing process. Further, an inherent consequence of coal washing is the generation of wastewater and solid waste streams.

No information was identified regarding the washability, or effectiveness of washing, lignite or subbituminous PRB coals, and it is unlikely that coal washing will result in a significant decrease in controlled SO_2 emissions. Therefore, coal washing is not considered a technically feasible or commercially available retrofit control option at Heskett Station.

North Dakota lignite has a relatively high moisture content, low heating value, and low sulfur content. PRB coal typically also has relatively lower heating values compared to other fuel sources but lower sulfur content than lignite. In theory, if a boiler could utilize it for fuel and a fuel feed system could receive it; burning 100% PRB would result in lower uncontrolled SO_2 emissions rates. However, lower uncontrolled emissions rates do not necessarily translate into lower controlled emissions rates. The efficiency of pollution control equipment is a function of several operating variables, including the uncontrolled pollutant concentration. At a lower uncontrolled pollution concentration, it becomes more difficult to maintain a high emissions control efficiency.

Unit 1 is designed for lignite combustion and cannot burn 100% PRB without significant boiler modifications, including changes to the internal boiler materials of construction and modifications to provide flue gas recirculation. The amount of tube surface area required for lignite combustion is much larger than needed for PRB combustion. Burning even high blends of PRB would result in increased furnace temperatures that are too high and require changes to the superheater (and other boiler tubes) and changes to keep fly ash from becoming molten and fouling the boiler. Further, the viability of the Heskett Station is dependent upon an economic supply of fuel. As a result, switching to burning a lower sulfur subbituminous coal in amounts is not supported by the existing equipment and is not considered a technically feasible option for Heskett Station Unit 1.

3.1.2 Post-Combustion Controls

Post-combustion controls or flue gas desulfurization (FGD) systems commonly used to control SO_2 emissions can be classified as either wet or dry systems. Both systems rely on creating turbulence in the gas stream to increase contact with the absorbing medium. Wet systems are commonly capable of achieving higher removal efficiencies than dry systems because it is easier to mix a gas with a liquid than a solid. FGD requires the use of an alkali powder slurry, and lime (or limestone) as the most widely used compound for acid gas absorption. Sodium based reagents are also available, and while they provide better SO_2 solubility, they are significantly more expensive.

Wet FGD systems may discard all the waste by-product streams or regenerate and reuse them. Wet systems generally require more extensive networks of pumps and piping than dry systems to recirculate, collect and treat the scrubbing liquid. As implied by the name, dry scrubbers require less water than wet systems but also require higher temperatures to ensure that all moisture has been evaporated before leaving the scrubber. There are many available FGD systems including wet scrubbing, spray dryer absorption, and dry sorbent injection.

3.1.2.1 Wet Lime/Limestone Scrubbing

Wet lime/limestone scrubbing involves scrubbing the exhaust gas stream with a slurry comprised of lime (CaO) or limestone ($CaCO_3$) in suspension. The process takes place in a wet scrubbing tower located downstream of a particular matter (PM) control device to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. The SO_2 in the gas stream reacts with the lime or limestone slurry to form calcium sulfite ($CaSO_3$•$2H_2O$) and calcium sulfate ($CaSO_4$).

Physical space constraints at Heskett Station greatly limit the opportunity for construction and operation of an add-on control equipment such as wet gas scrubber system. However, for purposes of this analysis, a wet scrubber is considered a technically feasible retrofit control option. It is assumed, based on available information, that the wet FGD system would be able achieve an SO_2 emissions reduction of approximately 99%.[6]

Control efficiencies assumed achievable for purposes of this analysis are considered conservative due to being based on operation at high load conditions. The high rate of assumed capture may not be achieved at low load operation. Installation of a wet scrubbing system would require removal of the existing dry electrostatic precipitator (ESP) control system. Environmental and cost implications associated with said required retrofit have not been included as part of the analysis at this time. MONTANA-DAKOTA reserves the right to refine the assumptions and impacts to the cost of controls if further study is needed.

3.1.2.2 Spray Dry Absorption (SDA)

Spray dry absorption (SDA) is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO_2 is absorbed by the droplets. The absorption of the SO_2 leads to the formation of calcium sulfite ($CaSO_3$•$2H_2O$) and calcium sulfate ($CaSO_4$).

The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder that is carried out with the gas and collected with a fabric filter. The process equipment associated with a spray dryer typically includes an alkaline storage tank, mixing and feed tanks, an atomizer, spray chamber, particulate control device and a recycle system.

Designing an SDA for an existing unit presents significant design challenges. The SDA must be located upstream of the unit's particulate matter control device and the reactor vessel must be located within existing site parameters. Retrofitting Heskett Station Unit 1 with an SDA would require extensive ductwork to direct flue gas flow from the boiler to the SDA and back to the ESP. An SDA will require additional unreacted hydrated lime to the flue gas and increase particulate loading to the particulate control device. Second, to maximize utilization of the lime reactant (which is more expensive compared to limestone), the system must be designed with a solids recycling system to mix some of the controlled particulate solids product with fresh lime slurry and re-inject the mixture into the SDA. The Unit would need an in-depth study, including a full review of the existing ESP's ability to accept and properly clean the flue gas, to determine if truly feasible. Historically, SDA systems have typically been permitted as best available controls on pulverized coal-fired boilers firing low-sulfur PRB coal. Nevertheless, for purposes of this analysis, SDA is considered a technically feasible retrofit control option. It was been assumed that a

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[6] https://www3.epa.gov/ttn/catc/dir1/fsprytwr.pdf

baghouse, requiring retrofit of the existing particulate matter control system, would be required for proper operation and particulate matter control.

SDA control efficiency is typically in the 70% to 90% range. The high rate of assumed capture may not be achieved at low load operation. Due to expected low load operation and other unknowns, MONTANA-DAKOTA has assumed a control efficiency of 70%. MONTANA-DAKOTA reserves the right to refine the assumptions and impacts to the cost of controls if further study is needed.

3.1.2.3 Dry Sorbent Injection (DSI)

Dry sorbent injection (DSI) involves the injection of a lime or limestone powder into the exhaust gas stream. The stream is then passed through a baghouse to remove the sorbent and entrained SO_2. The process was developed as a lower cost FGD option because the mixing occurs directly in the exhaust gas stream instead of in a separate tower. DSI systems are simple systems, and generally require a sorbent storage tank, feeding mechanism, transfer line and blower, and an injection device. The dry sorbent is typically injected countercurrent to the gas flow. An expansion chamber is often located downstream of the injection point to increase residence time and efficiency. Particulates generated in the reaction are controlled in the systems particulate control device. Depending on the residence time and gas stream temperature, sorbent injection control efficiency is typically between 50% and 70%. Although a dry sorbent injection system may be technically feasible at Unit 1, it is not practical to assume a high level of control efficiency would be achievable due to space constraints limiting the reaction time. Further, Unit 1 exhaust gas temperature is higher (420°F) than the ideal gas stream temperature range of 300°F to 350°F and the impact on control efficiency would require further evaluation. For purposes of this analysis MONTANA-DAKOTA has assumed a control efficiency of 50% and that the existing ESP could not handle additional loading, requiring retrofit of the existing particulate matter control system for proper operation and particulate matter control.

DSI is considered a technically feasible retrofit control option for this analysis, but due to space constraints and other issues, MONTANTA-DAKOTA reserves the right to more analysis in the future to determine actual feasibility with the Unit. A full review of the ESP’s ability to accept and properly clean the flue gas with changed properties would be needed to determine feasibility and possible costs. MONTANA-DAKOTA reserves the right to refine the assumptions and impacts to the cost of controls if further study is needed.

3.2 Factor 1 – The Cost of Compliance

The pollution control costs are presented on a dollar per ton of pollutant removed calculated according to Equation 2.73 of the Cost Manual and 40 CFR 51, Appendix Y, Section IV, D. The cost effectiveness compares the annualized cost of the technology per ton of pollutant removed and is evaluated on dollar per ton ($/ton) basis using the annual operating cost ($/yr) divided by the annual emissions reduction achieved by the control device (ton/yr). Additional details regarding the control equipment cost data and evaluation are noted in the control cost worksheets in Attachment B.

Table 3-2 SO_2 Control Cost Evaluation for Heskett Station Unit 1

Control Technology	Estimated Control Efficiency (%)	Installed Capital Cost ($)	Annualized Capital Cost ($/yr)	Pollution Control Cost ($/ton)
Wet Scrubber	98%	$71,500,000	$10,300,000	$5,100
Spray Dry Absorption	70%	$55,700,000	$8,000,000	$5,600
Dry Sorbent Injection	50%	$32,300,000	$5,150,000	$5,100

[1] The NDDH original BART ceiling costs were based on the June 1999 WRAP Annex to Grand Canyon Visibility Transport Report. Scaled to today's dollars, the average cost effectiveness threshold is approximately $4,460 per ton.

The SO_2 control options evaluated as part of this analysis are considered economically infeasible for implementation at Unit 1; costs are not justified on a dollar per ton basis.

3.3 Factor 2 – Time Necessary for Compliance

Under Factor #2, the amount of time needed for full implementation of different control strategies is reviewed. Typically, time for compliance includes the time needed to develop and implement the regulation and/or the time needed to install the necessary emissions control equipment. This analysis does not support the installation of any new retrofit SO_2 emissions controls at Heskett Station Unit 1 and therefore a review of the time necessary for compliance is not applicable.

3.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts

The energy and non-air environmental impacts associated with implementation of the above-identified SO_2 control measures are discussed in the following sections.

3.4.1 Wet Lime/Limestone Scrubbing

In addition to the economic impacts of a wet FGD system, there are several collateral environmental impacts associated with its operation. Wet FGD systems generate a calcium sulfate waste by-product that must be properly managed. Historically, solid wastes generated from wet FGD systems have been dewatered and disposed of in landfills. Most new wet FGD systems utilize a forced oxidation system that results in a gypsum by-product that can sometimes be sold into the local gypsum market. If an adequate local gypsum market is not available, the gypsum by-product will require proper disposal. Currently, there is not a viable market in proximity to Heskett Station and usable quantity would be likely limited. A study of disposal at our current facility would be required and, if feasible, additional permitting needed. If not acceptable for sale, disposal costs may be significant and would have to include transport costs. In a northern climate this may be a significant issue.

A wet FGD system will also result in greater particulate matter emissions. Wet FGD systems must be located downstream of the unit's particulate control device; therefore, dissolved solids from the wet FGD system will be emitted with the wet FGD moisture plume. In addition, any SO_3 remaining in the flue gas could react with moisture in the wet FGD to generate sulfuric acid mist.

Wet FGD systems also require significantly more water than dry FGD systems or limestone injection systems. Wet FGD control systems typically require approximately 1.0 gpm of water per gross MW output.

Additional costs may result from a potential need to increase Heskett Station's existing water rights for withdrawal of water. Finally, wet FGD systems generate a wastewater stream that must be treated and discharged in compliance with Effluent Limitations Guidelines for electric steam generating units. The site faces challenges for space due to rail lines, historical disposal and archeological issues. Coal combustion residual (CCR) considerations would need to be evaluated (including location restrictions); state and federal discharge permitting requirements (from the new system) would also be applicable. These would take significant study and time.

3.4.2 Dry Flue Gas Desulfurization (FGD)

Collateral environmental impacts are less significant with dry scrubbing systems. Using a dry FGD system at Unit 1 requires the facility to handle two reactants; limestone for injection in the AFBC (Unit 2) and pebble lime for use in the dry scrubber. The receipt, storage, management and use of two reactants will result in increased material handling PM emissions.

Lime used in dry FGD systems must be hydrated prior to use, increasing the facility's overall consumption of water. However, water used to hydrate the lime reactant is evaporated in the dry scrubbing system, eliminating the need for additional wastewater treatment and discharge.

3.5 Factor 4 – Remaining Useful Life of the Source

At this time, MONTANA-DAKOTA has assumed that the remaining useful life of the Unit 1 will be longer than the useful life of the emissions control measures evaluated in this analysis. Accordingly, as directed by the July 2006 EPA draft guidance, the useful life of the individual control measures is used to calculate emissions reductions, amortized costs and cost effectiveness on a dollar per ton basis. MONTANA-DAKOTA relied on EPA's Control Cost Manual to determine the appropriate value for use in the evaluation (20 years).

3.6 Proposed Controls and Emissions Rates

This analysis does not support the installation of any new retrofit SO_2 emissions controls at Heskett Station Unit 1. The available and potential technically feasible control strategies are economically infeasible and have significant technical and other concerns for operation Heskett Station. Therefore, MONTANA-DAKOTA is proposing to maintain current operational practices consistent with the parameters and limits included as part of the facility's existing Air Pollution Control Title V Permit to Operate (T5-F76001). Due to the uncertainty of the actual performance of the potentially available control technologies evaluated, the uncertainty of technically feasible SO_2 emissions controls that we assumed as part of this four-factor analysis, the implementation concerns and the additional detailed analysis for cost refinement, MONTANA-DAKOTA reserves the right to refine this analysis in the future if necessary.

4 Unit 2 Nitrogen Oxides (NOx) Four-Factor Analysis

There are three mechanisms by which NOx production occurs: thermal, fuel and prompt NOx. Fuel bound NOx is a primary concern with solid and liquid fuel combustion sources; it is formed as nitrogen compounds in the fuel are oxidized in the combustion process. The secondary mechanism of NOx production is through thermal NOx formation. This mechanism arises from the thermal dissociation of nitrogen and oxygen molecules in combustion air. The thermal oxidation reaction is as follows:

$$N_2 + O_2 \rightarrow 2NO \qquad (1)$$

Downstream of the flame, significant amounts of NO_2 can be formed when NO is mixed with air. The reaction is as follows:

$$2NO + O_2 \rightarrow 2NO_2 \qquad (2)$$

Thermal oxidation is a function of the residence time, concentration of combustion gases (primarily nitrogen and oxygen) in the inlet air, and peak reaction temperature. Prompt NOx is a form of thermal NOx which is generated at the flame boundary. It is the result of reactions between nitrogen and carbon radicals generated during combustion. Only minor amounts of NOx are emitted as prompt NOx.

4.1 NOx Emissions Control Measures

There are several potentially available methods to control NOx emissions, as show in Table 4-1, however not all are applicable for implementation at Unit 2. Accordingly, as part of this four-factor analysis, MONTANA-DAKOTA has narrowed the list of NOx control technology options for review to those that are truly applicable for a retrofit installation at the Heskett Station Unit 2. The NOx retrofit control options are identified based on a review of available technical information.

Retrofit NOx control technologies can be divided into two general categories: (1) combustion controls, and (2) post-combustion controls. Combustion controls reduce the amount of NOx that is generated in the boiler, while post-combustion controls remove NOx from the boiler exhaust gas.

Table 4-1 List of Potentially Available Retrofit NOx Control Options

Control Technology
Combustion Controls
• Fluidized Bed Combustion • Low NOx Burners • Overfire Air (OFA) • Flue Gas Recirculation (FGR) • Burner Tempering (Water Injection)
Post-Combustion Controls
• Selective Non-Catalytic Reduction (SNCR) • Selective Catalytic Reduction (SCR) o High-Dust SCR o Low-Dust SCR
Innovative Control Technologies
• Rotating Overfire Air (ROFA) • Boosted Overfire Air (BOFA) • ROFA + SNCR (Rotamix™) • NOxStar™ • Exxon Thermal DeNOx™ • Pahlman Process • Wet NOx Scrubbing LOTOx™

4.1.1 Combustion Controls

The rate of NOx formation in the combustion zone is a function of free oxygen, peak flame temperature and residence time. Combustion techniques designed to minimize the formation of NOx will minimize one or more of these variables. Combustion control considered Heskett Station Unit 2 are summarized below.

4.1.1.1 Fluidized Bed Combustion (FBC)

Fluidized bed combustion offers the potential for lower NOx emissions due to inherently lower combustion temperatures. In an atmospheric fluidized bed combustion (AFBC) boiler, like Unit 2, fuel is burned in a bed of hot combustible particles suspended by an upward flow of combustion air. The fuel (coal) can be mixed with an inert sand or limestone (used for SO_2 control) to form the combustion bed. Bed temperatures are usually maintained around 1550°F to 1750°F because this temperature is optimal for the chemical processes needed to capture SO_2 and control NOx emissions. Efficient combustion in the AFBC is achieved because of the relatively long residence time of fuel in the bed and good gas/fuel contact. At the low combustion temperatures, the formation of thermal NOx is essentially eliminated; however, nearly all of the fuel nitrogen will be converted to nitrogen oxides. Unit 2 is an AFBC boiler and has inherently different properties than the typical FBC.

4.1.1.2 Low NOx Burners (LNB)

Low NOx burner (LNB) technology utilizes advanced burner design to reduce NOx formation through the restriction of oxygen, flame temperature, and/or residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NOx formation is limited by either one of two methods. Under staged air rich (high fuel) condition, low oxygen levels limit flame temperatures resulting in less NOx formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel lean (low fuel) conditions, excess air will reduce flame temperature to reduce NOx formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NOx formation. Low NOx burners typically achieve NOx emissions reductions of 25% to 50%.

AFBC boilers do not use burners during normal operation, as combustion takes place within the fluidized bed. Therefore, LNB combustion control technologies are not technically feasible, and not applicable to Heskett Station Unit 2.

4.1.1.3 Overfire Air (OFA)

Overfire air (OFA) diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. OFA is the typical NOx control technology used in lignite-fired boilers and is primarily geared to thermal NOx reductions. Staging of the combustion air creates an initial fuel-rich combustion zone for a cooler fuel-rich combustion zone. This reduces the production of thermal NOx by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NOx is most likely to be formed.

Heskett StationUnit 2 is currently designed with nominal staged combustion. The boiler is designed with one row of OFA ports located on the front and back wall of the furnace. Both banks of OFA ports are located relatively low in the furnace, just above the coal feeder systems and combustion bed. The degree of staging is unit-specific, and limited by operational problems since the staged combustion could result in conditions that favor incomplete combustion. Adding additional staged combustion would require the installation of more OFA ports above the existing ports or on the furnace sidewalls. Retrofitting an existing boiler with OFA ports can be challenging, and MONTANA-DAKOTA may be required to model flow within the boiler to ensure new OFA ports are properly located to provide staged combustion air. Adding OFA ports may also require the installation of additional booster fans to support mixing of the air and flue gas.

Moreover, thermal NOx emissions are essentially eliminated as a result of the AFBC, and it is therefore unlikely that additional staged combustion/OFA would result in any further significant NOx reductions. For these reasons, MONTANA-DAKOTA considers adding additional staged combustion is not technically feasible for additional NOx control at Heskett StationUnit 2.

4.1.1.4 External Flue Gas Recirculation (FGR)

Flue gas recirculation (FGR) is a flame-quenching technique that involves recirculating a portion of the flue gas from the economizer or air heater outlet and returning it to the furnace through the burner or windbox. The primary effect of FGR is to reduce the peak flame temperature through adsorption of the combustion heat by the relatively inert flue gas, and to reduce the oxygen concentration in the combustion zone. FGR reduces thermal NOx generation in high-temperature emissions sources.

Additional ductwork and a blower would be required to recirculate flue gas. These elements must fit in the limited space around the burner. The space constraints and the lowered flame temperature created by FGR make it incompatible with the existing combustion controls on Units 2. To integrate a blower and inject flue gas into the combustion zone of the existing unit would require a full design review and likely costly modifications to the existing combustion control scheme. To date, MONTANA-DAKOTA is unaware of another lignite fired AFBC boiler utilizing FGR technology. Further, the addition of FGR could further result in reduced boiler capacity. Flue gas recirculation is therefore a technically infeasible control option and is not be considered further.

4.1.1.5 Burner Tempering (Water Injection)

The principle behind combustion tempering is to inject an atomized water spray into the high NOx production zones of the furnace flame. The water spray reduces the temperature within the zone, resulting in lower NOx production within the zone. Burner tempering has been used on wall- and tangential-fired pulverized coal-fired units. The risk of any water so close to the bed material that would form concretions and encase our boiler tubes in the bed is immediately concerning.

However, FBC boilers do not use burners during normal operation, and burner tempering would not be applicable to FBC units. Therefore, burner tempering is not a technically feasible NOx control technology for Unit 2 and is not considered further.

4.1.2 Post-combustion Controls

NOx can be reduced to N_2 in add-on systems located downstream of the furnace area of the combustion process. The two main techniques in commercial service include the selective non-catalytic reduction (SNCR) process and the selective catalytic reduction (SCR) process. There are a number of different process systems in each of these categories of control techniques.

In addition to these treatment systems, there are a large number of other processes being developed and tested on the market. These approaches involve innovative techniques of chemically reducing, absorbing, or adsorbing NOx downstream of the combustion chamber. One example of these alternatives is nonselective catalytic reduction (NSCR).

4.1.2.1 Selective Non-Catalytic Reduction (SNCR)

In the selective non-catalytic reduction (SNCR) process, urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to N_2 and water. SNCR control efficiency is typically 25% to 50%. Without the participation of a catalyst, the reaction requires a high temperature range to obtain activation energy. The relevant reactions are as follows:

$$NO + NH_3 + \tfrac{1}{4}O_2 \rightarrow N_2 + 3/2H_2O \qquad (1)$$

$$NH_3 + \tfrac{1}{4}O_2 \rightarrow NO + 3/2H_2O \qquad (2)$$

At temperature ranges of 1470°F to 1830°F, reaction (1) dominates. At temperatures above 2000°F, reaction (2) will dominate. Flue gas temperature at the point of reagent injection can greatly affect removal efficiencies and the quantity of NH_3 that will pass through unreacted (ammonia slip). At temperatures below the desired operating range, the NOx reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NOx resulting in low NOx reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is also an important factor to SNCR performance. The SNCR system must be designed to deliver the reagent in the proper temperature window, and allow sufficient residence time of the reagent and flue gas in that temperature window. In addition to temperature, mixing, and residence time, several other factors influence the performance of an SNCR system including reagent-to-NOx ratio and NOx concentration in the flue gas.

SNCR systems are capable of achieving a NOx emissions reduction as high as 50 to 60 percent in optimum conditions (adequate reaction time, temperature, and reagent/ flue gas mixing, high baseline NOx conditions, multiple levels of injectors) with ammonia slips of 10 to 50 ppmvd. Typically, optimum conditions are difficult to achieve, resulting in emissions reduction levels of 20 to 40 percent. Potential performance is very site-specific and varies with fuel type, steam generator size, allowable ammonia slip, furnace CO concentrations, and steam generator heat transfer characteristics.

The application of SNCR to Heskett Station Unit 2 has the potential to be technically feasible because furnace temperatures are assumed (note that there is not instrumentation currently in place to measure temperature) to be within the temperature window needed for NOx reduction, and flue gas mixing and residence time within the boiler should promote the reaction kinetics. However, the effectiveness of an SNCR system at Heskett Station Unit 2 would be limited because of the design and boiler operating temperatures. The optimal condition locations are small due to the boiler size and type and a boiler study would be required to more correctly predict feasibly and effectiveness at Unit 2. Even so, for purposes of this review, MONTANA-DAKOTA has assumed that SNCR could potentially be implemented at Unit 2 and has therefore included this in the four-factor analysis. Based on the calculated default control efficiency from EPA, a SNCR could potentially provide a NOx reduction of approximately 27% at Unit 2. As mentioned in the discussion of Unit 1, with the uncertainty due to limited space and other issues, we reserve the right to refine this analysis in the future if necessary. A full review of the ESP's ability to accept and properly clean the flue gas with changed properties would be needed to determine feasibility and possible costs.

4.1.2.2 Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is a post combustion NOx control technology in which NH_3 is injected into the flue gas stream in the presence of a catalyst. SCR control efficiency is typically 70% to 90%. NOx is removed through the following chemical reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \qquad (1)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O \qquad (2)$$

The catalyst bed lowers the activation energy required for NOx decomposition. The catalyst contains an active phase, such as vanadium pentoxide, on a carrier, such as titanium dioxide, and these are used for their ability to lower the activation energy required for NOx decomposition. SCR requires an optimum temperature range of 650 to 800°F.

A "high-dust" SCR arrangement in which the reactor is located between the outlet of the economizer and the inlet of the air heater and upstream of particulate control is typically the preferred arrangement where technically feasible. These arrangements typically require soot blowers for catalyst cleaning. In a "low-dust" arrangement, the SCR reactor is located after the particulate control device. This arrangement is preferred when the fly ash contains a high level of contaminants that would block catalyst actions, and removing most of the fly ash from the flue gas will help prolong the catalyst life. Firing ND lignite coal that contains high amounts of organically bound inorganics (and has a higher total sodium content), results in a stream heavily laden with particulate matter and sodium that combine to plug (block) catalyst passages. Due to the likelihood of catalyst plugging and the ability of phosphorus, sodium, other alkali and alkaline earth cations organically bound in ND lignite to mask (or blind) a catalyst and it's reactions if not fully plugged, a high-dust SCR system is considered technically infeasible on both Units 1 and 2. A low-dust SCR (downstream of particulate control), would require reheat to bring the stream temperature back to the effective control range after it is cooled for particulate removal. There would still be important concerns with this arrangement due to the contaminants' unique properties to inhibit the catalyst from operating, but in theory, the issues would be less than with a high-dust system.

Although it would appear to be a potentially a technically feasible control option, MONTANA-DAKOTA notes that installing SCR (even a low-dust system) at similar types of sources remains limited or is altogether not feasible. MONTANA-DAKOTA is unaware of an SCR system that has been installed at a source firing North Dakota lignite. Issues associated with SCR on lignite boilers are discussed in additional detail in a 2009 study completed by the NDDH that supports the limited feasibility of SCR.[7] Additionally, physical space constraints at Heskett Station greatly limit the opportunity for SCR system equipment and tie-ins. Even so, for purposes of this review, MONTANA-DAKOTA has assumed that a low-dust SCR system could potentially be implemented at Unit 2 and has therefore included this in the four-factor analysis (even though it is considered by MONTANA-DAKOTA as technically infeasible). Based on current NOx emissions, an SCR could potentially provide an additional NOx reduction in the range of 70%-80%. As mentioned before, we reserve the right to refine this analysis in the future if necessary.

4.1.3 Innovative Controls

NOx controls grouped under the "Innovative Control Technologies" are not being considered in this analysis. These technologies are not considered commercially available and are not applicable at MONTANA-DAKOTA Heskett Station.

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[7] *Best Available Retrofit Technology – Selective Catalytic Reduction Technical Feasibility Analysis for North Dakota Lignite.* North Dakota Department of Health, Division of Air Quality. 7/1/2009

4.2 Factor 1 – The Cost of Compliance

The pollution control costs are presented on a dollar per ton of pollutant removed calculated according to Equation 2.73 of the Cost Manual and 40 CFR 51, Appendix Y, Section IV, D. The cost effectiveness analysis compares the annualized cost of the technology per ton of pollutant removed and is evaluated on dollar per ton ($/ton) basis using the annual operating cost ($/yr) divided by the annual emissions reduction achieved by the control device (ton/yr). Additional details regarding the control equipment cost data and evaluation are noted in the control cost worksheets in Attachment A.

Table 4-2 NOx Control Cost Evaluation for Heskett Station Unit 2

Control Technology	Estimated Control Efficiency (%)	Installed Capital Cost ($)	Annualized Capital Cost ($/yr)	Pollution Control Cost ($/ton)
Low-Dust SCR	80%	$41,600,000	$5,630,000	$6,100
SNCR	27%	$5,000,000	$1,680,000	$5,300

[1] The NDDH original BART ceiling costs were based on the June 1999 WRAP Annex to Grand Canyon Visibility Transport Report. Scaled to today's dollars, the average cost effectiveness threshold is approximately $4,460 per ton.

SNCR and SCR are both considered economically infeasible for implementation at Unit 2 as the average cost effectiveness is not justified on a dollar per ton basis.

4.3 Factor 2 – Time Necessary for Compliance

Under Factor #2, the amount of time needed for full implementation of different control strategies is reviewed. Typically, the time necessary for compliance includes the time needed to develop and implement the regulation and/or the time needed to install the necessary emissions control equipment. This analysis does not support the installation of any new retrofit NOx emissions control methods at Heskett Station Unit 2 and therefore a review of the time necessary for compliance is not applicable.

4.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts

Energy impacts are primarily related to the auxiliary power consumption of the SCR and SNCR systems and are included in the cost estimates under the variable annual costs. Other indirect energy impacts, such as the energy to produce reagents, are not considered in this study.

The operation of an SCR or SNCR system could have other non-air environmental impacts. For example, the storage of ammonia on-site creates the potential for accidents due to an ammonia release. Depending on the type, concentration, and quantity of ammonia used, the material will be subject to regulation as a hazardous substance under CERCLA, Section 313 of the Emergency Planning and Community Right-to-Know Act, Section 112(r) of the CAA, and Section 311(b)(4) of the Clean Water Act.

4.5 Factor 4 – Remaining Useful Life of the Source

At this time, MONTANA-DAKOTA has assumed that the remaining useful life of the Unit 2 will be longer than the useful life of the emissions control measures evaluated in this analysis. Accordingly, as directed by the July 2006 EPA draft guidance, the useful life of the individual control measures is used to calculate emissions reductions, amortized costs and cost effectiveness on a dollar per ton basis.

4.6 Proposed Controls and Emissions Rates

This analysis does not support the installation of any new retrofit NOx emissions controls at Heskett Station Unit 2. The available and potential technically feasible control strategies (SNCR and SCR) are economically infeasible and have significant technical and other concerns for commercial scale operation at a lignite fired boiler. Therefore, MONTANA-DAKOTA is proposing to maintain current operational practices consistent with the parameters and limits included as part of the facility's existing Air Pollution Control Title V Permit to Operate (T5-F76001). As mentioned in the discussion under Unit 1, with the uncertainty of the actual feasibility for implementation of the NOx controls evaluated as part of this four-factor analysis and the required additional cost refinement evaluation, MONTANA-DAKOTA reserves the right to refine this analysis in the future if necessary.

5 Unit 2 Sulfur Dioxide (SO_2) Four-Factor Analysis

Sulfur emissions from coal combustion consist primarily of SO_2, with a much lower quantity of SO_3 and gaseous sulfates. These compounds form as the organic and pyritic sulfur in the coal is oxidized during the combustion process. The generation of SO_2 is directly related to the sulfur content and heating value of the fuel burned. The sulfur content and heating value of coal can vary dramatically depending on the source of the coal. Heskett Station uses North Dakota lignite and, in the past, had occasionally used a blend of lignite and PRB coal as its fuel source.

5.1 SO_2 Emissions Control Measures

Several techniques can be used to reduce SO_2 emissions from coal combustion sources. SO_2 control techniques can be divided into pre- and post- combustion strategies.

Table 5-1 SO_2 Control Options with Potential Applications to Heskett Station Unit 2

Control Technology
Pre-Combustion Controls
• Fuel Switching • Fuel Washing
Combustion Control: Limestone injection at existing AFCB
Post-Combustion SO_2 Control Technologies
• Wet Flue Gas Desulfurization • Dry Flue Gas Desulfurization o Spray Dryer Absorber o Dry Sorbent Injection

5.1.1 Pre-Combustion Controls

A potential control strategy for reducing SO_2 emissions from a coal-fired boiler is to reduce the amount of sulfur contained in the coal. This can be accomplished through reducing inherent impurities via coal washing or potentially, more drastically, through switching to a lower sulfur fuel source. Coal washing is discussed above in Section 3.1.

As also noted above, North Dakota lignite has a relatively high moisture content, low heating value, and low sulfur content. PRB coal typically also has relatively lower heating values compared to other fuel sources but lower sulfur content than lignite. In theory, if a boiler could utilize it for fuel and a fuel feed system could receive it; burning 100% PRB would result in lower uncontrolled SO_2 emissions rates. However, lower uncontrolled emissions rates do not necessarily translate into lower controlled emissions rates. The efficiency of pollution control equipment is a function of several operating variables, including the uncontrolled pollutant concentration. At a lower uncontrolled pollution concentration, it becomes more difficult to maintain a high emissions control efficiency.

MONTANA-DAKOTA has studied the feasibility of firing lower sulfur PRB coal at Unit 2. Test burns conducted at Heskett Station Unit 2 indicated that significant boiler modifications, including changes to the internal boiler materials of construction and modifications to provide flue gas recirculation, would be needed to fire 100% PRB. Based on these test burns, the Unit 2 boiler is limited to firing a limited amount of PRB. Unit 2 is designed to fire lignite and any coal viability implemented for short periods of time is dependent upon an economic supply of fuel. Switching to PRB would require significant boiler modifications, essentially replacing and rebuilding the boiler internals and combustion control systems. Therefore, switching to burning a lower sulfur subbituminous coal in amounts not supported by the existing equipment is not considered a technically feasible option for Unit 2.

Additionally, PRB is not currently offered in a size that Heskett Station is able to receive and process, meaning the facility cannot accept fuel or get it to the boiler without significant modifications and equipment changes.

5.1.2 Combustion Controls: Limestone Injection at AFBC

Heskett Station has implemented a limestone addition to the sand bed for Unit 2 for RH emissions reductions in 2017. An SO_2 limit of 0.60 lb/MMBtu was applied to Unit 2 and Heskett Station has demonstrated compliance with this 12-month rolling average limit. Unit 2 has been operating at a mid to low load range over the past two to three years (a recent load range report indicates 52-66 MW for 95% of the time, only 5% operation at higher load of about 72 MW). During the same timeframe, our compliance with the 12-month rolling average was 0.46 lb/MMBtu. The relatively low 12-month rolling average compliance values represent operation at a lower load range and does not indicate improved capture efficiency that would occur within the mid to high load range as confirmed in our optimization study. All SO_2 emissions limits currently imposed from utilization of limestone for SO_2 control should remain unchanged.

5.1.3 Post-Combustion Controls

Post-combustion controls or FGD systems commonly used to control SO_2 emissions can be classified as either wet or dry systems. Both systems rely on creating turbulence in the gas stream to increase contact with the absorbing medium. Wet systems are commonly capable of achieving higher removal efficiencies than dry systems because it is easier to mix a gas with a liquid than a solid. FGD requires the use of an alkali powder slurry, with lime (or limestone) as the most widely used compound for acid gas absorption. Sodium based reagents are also available, and while they provide better SO_2 solubility, they are significantly more expensive.

Wet FGD systems may discard all of the waste by-product streams or regenerate and reuse them. Wet systems generally require more extensive networks of pumps and piping than dry systems to recirculate, collect, and treat the scrubbing liquid. As implied by the name, dry scrubbers require less water than wet systems but also require higher temperatures to ensure that all moisture has been evaporated before leaving the scrubber. There are many available FGD systems including wet scrubbing, spray dryer absorption, and dry sorbent injection.

5.1.3.1 Wet Lime/Limestone Scrubbing

Wet lime/limestone scrubbing involves scrubbing the exhaust gas stream with a slurry comprised of CaO or $CaCO_3$ in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. The SO_2 in the gas stream reacts with the lime or limestone slurry to form calcium sulfite ($CaSO_3 \bullet 2H_2O$) and calcium sulfate ($CaSO_4$).

Physical space constraints at Heskett Station greatly limit the opportunity for construction and operation of an add-on control equipment such as wet gas scrubber system. However, for purposes of this analysis, a wet scrubber is considered a technically feasible retrofit control option. It will be assumed, based on available information, that the wet FGD system would be able achieve an SO_2 emissions reduction of approximately 99%.[8]

Control efficiencies assumed achievable for purposes of this analysis are conservative due to being based on operation at high load conditions. The high rate of assumed capture may not be achieved at low load operation. MONTANA-DAKOTA reserves the right to refine the assumptions and impacts to the cost of controls if further study is needed. A full review of the ESP's ability to accept and properly clean the flue gas with changed properties would be needed to determine feasibility and possible costs. MONTANA-DAKOTA reserves the right to refine the assumptions and impacts to the cost of controls if further study is needed.

5.1.3.2 Spray Dry Absorption (SDA)

Spray dry absorption (SDA) is a dry scrubbing system that sprays a fine mist of lime slurry into an absorption tower where the SO_2 is absorbed by the droplets. The absorption of the SO_2 leads to the formation of calcium sulfite ($CaSO_3 \bullet 2H_2O$) and calcium sulfate ($CaSO_4$).

The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower. This leads to the formation of a dry powder that is carried out with the gas and collected with a fabric filter. The process equipment associated with a spray dryer typically includes an alkaline storage tank, mixing and feed tanks, an atomizer, spray chamber, particulate control device and a recycle system.

Designing an SDA for an existing unit presents significant design challenges. The SDA must be located upstream of the unit's particulate matter control device, at a point where the flue gas is already laden with combustion ash, calcium sulfite solids, and unreacted lime from the combustion bed (assuming lime or limestone is used as the bed material). The reactor vessel must also be located within existing site parameters requiring extensive ductwork to direct flue gas flow from the boiler to the SDA and back to the ESP. An SDA will add additional unreacted hydrated lime to the flue gas, and increase particulate loading to the particulate control device. Second, to maximize utilization of the lime reactant (which is expensive compared to limestone), the system must be designed with a solids recycling system to mix

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[8] https://www3.epa.gov/ttn/catc/dir1/fsprytwr.pdf

some of the controlled particulate solids product with fresh lime slurry and re-inject the mixture into the SDA. Finally, the SO_2 concentration at the inlet to the SDA will already have been reduced in the AFBC to a level generally associated with the SDA outlet SO_2 concentration, which will limit the efficiency of the system. Nevertheless, for purposes of this analysis, SDA is considered a technically feasible retrofit control option. It was been assumed that a baghouse, requiring retrofit of the existing particulate matter control system, would be required for proper operation and particulate matter control. SDA control efficiency is typically in the 70% to 90% range.

Control efficiencies assumed achievable for purposes of this analysis are conservative due to being based on operation at high load conditions. The high rate of assumed capture may not be achieved at low load operation. MONTANA-DAKOTA reserves the right to refine the assumptions and impacts to the cost of controls if further study is needed. A full review of the ESP's ability to accept and properly clean the flue gas with changed properties would be needed to determine feasibility and possible costs.

5.1.3.3 Dry Sorbent Injection (DSI)

Dry sorbent injection (DSI) involves the injection of a lime or limestone powder into the exhaust gas stream. The stream is then passed through a baghouse to remove the sorbent and entrained SO_2. The process was developed as a lower cost FGD option because the mixing occurs directly in the exhaust gas stream instead of in a separate tower. Depending on the residence time and gas stream temperature, sorbent injection control efficiency is typically between 50% and 70%. Although a dry sorbent injection system may be technically feasible, it is not practical for use with an AFBC with limestone bed material. The AFBC flue gas already contains excess unreacted lime and fly ash will be reinjected back into the AFBC combustion bed. A dry sorbent injection system would simply add additional unreacted lime to the flue gas. Because the dry sorbent injection system is not practical with an AFBC the system will not be evaluated further.

5.2 Factor 1 – The Cost of Compliance

The pollution control costs are presented on a dollar per ton of pollutant removed calculated according to Equation 2.73 of the Cost Manual and 40 CFR 51, Appendix Y, Section IV, D. The cost effectiveness compares the annualized cost of the technology per ton of pollutant removed and is evaluated on dollar per ton ($/ton) basis using the annual operating cost ($/yr) divided by the annual emissions reduction achieved by the control device (ton/yr). Additional details regarding the control equipment cost data and evaluation are noted in the control cost worksheets in Attachment B.

Table 5-2 SO_2 Control Cost Evaluation for Heskett Station Unit 2

Control Technology	Estimated Control Efficiency (%)	Installed Capital Cost ($)	Annualized Capital Cost ($/yr)	Pollution Control Cost ($/ton)
Wet Scrubber	98%	$80,300,000	$11,400,000	$7,700
Spray Dry Absorption	90%	$70,200,000	$9,990,000	$7,300

[1] The NDDH original BART ceiling costs were based on the June 1999 WRAP Annex to Grand Canyon Visibility Transport Report. Scaled to today's dollars, the average cost effectiveness threshold is approximately $4,460 per ton.

The SO_2 control options evaluated as part of this analysis are considered economically infeasible for implementation at Unit 2 as the average cost effectiveness is not justified on a dollar per ton basis.

5.3 Factor 2 – Time Necessary for Compliance

Under Factor #2, the amount of time needed for full implementation of different control strategies is reviewed. Typically, time for compliance includes the time needed to develop and implement the regulation and/or the time needed to install the necessary emissions control equipment. This analysis does not support the installation of any new retrofit SO_2 emissions controls at Heskett Station Unit 2 and therefore a review of the time necessary for compliance is not applicable.

5.4 Factor 3 – Energy and Non-Air Quality Environmental Impacts

The energy and non-air environmental impacts associated with implementation of the above-identified SO_2 control measures are discussed in the following sections.

5.4.1 Limestone Injection at AFBC

Limestone addition is currently in place at Unit 2 and MONTANA-DAKOTA is implementing best practices to mitigate energy and non-air environmental impacts. The system has been fully operating less than two years and feed rates are still under evaluation for control performance. As discussed with NDDH, when the system was first implemented in 2017, MONTANA-DAKOTA expects increases in the feed of limestone to result in additional handling and disposal issues, diminishing returns for SO_2 control (variable with load levels), and can change bed properties including transfer of energy and fouling.

5.4.2 Wet Lime/Limestone Scrubbing

In addition to the economic impacts of a wet FGD system, there are several collateral environmental impacts associated with its operation. Wet FGD systems generate a calcium sulfate waste by-product that must be properly managed. Historically, solid wastes generated from wet FGD systems have been dewatered and disposed of in landfills. Most new wet FGD systems utilize a forced oxidation system that results in a gypsum by-product that can sometimes be sold into the local gypsum market. If an adequate local gypsum market is not available, the gypsum by-product will require proper disposal. Currently, there is not a viable market in proximity to Heskett Station and usable quantity would be likely limited. A study of disposal at our current facility would be required and, if feasible, additional permitting needed. If not acceptable for sale, disposal costs may be significant and would have to include transport costs. In a northern climate this may be a significant issue.

A wet FGD system will also result in greater particulate matter emissions. Wet FGD systems must be located downstream of the unit's particulate control device therefore, dissolved solids from the wet FGD system will be emitted with the wet FGD moisture plume. In addition, any SO_3 remaining in the flue gas could react with moisture in the wet FGD to generate sulfuric acid mist.

Wet FGD systems also require significantly more water than dry FGD systems or limestone injection systems. Wet FGD control systems typically require approximately 1.0 gpm of water per gross MW output. Additional costs may result from a potential need to increase Heskett Station's existing water rights for withdrawal of water from the Missouri River for Wet FGD operation. The site faces challenges for space due to rail lines, historical disposal and archeological issues. CCR considerations would need to be evaluated (including location restrictions); state and federal discharge permitting requirements (from the new system) would also be applicable. These would take significant study and time.

5.4.3 Dry Flue Gas Desulfurization (FGD)

Collateral environmental impacts are less significant with dry scrubbing systems. Using a dry FGD system conjunction with a FBC with limestone injection would require the facility to handle two reactants; limestone for injection in the FBC and pebble lime for use in the dry scrubber. The receipt, storage, management and use of two reactants will result in increased material handling PM emissions.

Lime used in dry FGD systems must be hydrated prior to use, increasing the facility’s overall consumption of water. However, water used to hydrate the lime reactant is evaporated in the dry scrubbing system, eliminating the need for additional wastewater treatment and discharge.

5.5 Factor 4 – Remaining Useful Life of the Source

At this time, MONTANA-DAKOTA has assumed that the remaining useful life of the Unit 2 will be longer than the useful life of the emissions control measures evaluated in this analysis. Accordingly, as directed by the July 2006 EPA draft guidance, the useful life of the individual control measures is used to calculate emissions reductions, amortized costs and cost effectiveness on a dollar per ton basis.

5.6 Proposed Controls and Emissions Rates

This analysis does not support the installation of any new retrofit SO_2 emissions controls at Heskett Station Unit 2. The available and potential technically feasible control strategies are economically infeasible and have significant technical and other concerns for operation Heskett Station. Therefore, MONTANA-DAKOTA is proposing to maintain current operational practices consistent with the parameters and limits included as part of the facility’s existing Air Pollution Control Title V Permit to Operate (T5-F76001). As discussed throughout this document, the uncertainty around assumed SO_2 emissions control performance, the potential feasibility concerns tied to the operation of the control technologies evaluated and also the required additional cost refinement analysis that would be required prior to implementation, MONTANA-DAKOTA reserves the right to refine this analysis in the future if necessary.

6 Summary and Conclusion

In conclusion, as requested by the NDDH, MONTANA-DAKOTA completed a four-factor analysis evaluating direct emissions of SO_2 and NOx at Heskett Station Unit 1 and Heskett Station Unit 2. Based on the four- factor evaluation completed in this report, MONTANA-DAKOTA is proposing to maintain current operational practices consistent with the parameters and limits in the R. M. Heskett Station Air Pollution Control Title V Permit to Operate.

All available and potential technically feasible control strategies evaluated are economically infeasible for implementation at Heskett Station. Retrofit control options present significant technical and other operational concerns that would require detailed and extensive study to determine actual feasibility and emissions reduction potential at Unit 1 and Unit 2. Such studies would be costly and only serve to add to the probable highly elevated site-specific costs associated with implementation of retrofit control technologies at Heskett Station and would greatly increase the presented price of emissions reductions on a $/ton basis.

Further, MONTANA-DAKOTA reserves the right to review and modify the assumptions used in this analysis, primarily concerning site-specific conditions for cost (including capital costs and actual emissions reductions potential/performance) and remaining useful life of the affected sources.

Attachment A

NOx Control Costs

Montana-Dakota Utilities Co. R.M. Heskett Station
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis
Attachment A
Table A1: NOx Cost Evaluation Summary

Unit Summary

Unit	Unit 1		Unit 2	
Fuel Type	Lignite		Lignite	
Boiler Type	Normal		Fluidized Bed	
Maximum Hourly Production	25	MWh	75	lb/MMBtu
Maximum Hourly Heat Input Rate	387.63	MMBtu/hr	916.5	MMBtu/hr
Standardized Exhaust Flow Rate	95,133	scfm @ 68º F	235,167	scfm @ 68º F
Exhaust Temperature	420	º F	320	º F
Exhaust Moisture Content	15	%	15	%
Capacity Factor (CF) / Utilization	40	%	63	%
Fuel Sulfur Content	0.91	%		
Expected Annual Hours of Operation	8760	hours	8760	hours
Baseline Emission Rate	5.80	lb/ton lignite	0.46	lb/MMBtu
Hourly Emissions	174	lb/hr	421.59	lb/hr
Annual Emissions	304.8	tons/yr	1,163.3	tons/yr

Control Equipment Costs

Control Technology Name		Low-dust SCR	SNCR	Low-dust SCR	SNCR
Expected Equipment Life (years)		20	20	20	20
NOx Control Efficiency		80%	27%	80%	27%
Ammonia Slip		5	-	5	-
Controlled Emissions (tons/yr)		61.0	223.0	232.7	848.1
Reduction (tons/yr)		243.9	81.8	930.7	315.3
Capital Costs					
Total Capital Investment (TCI = DC + IC)	[1]	$21,729,380	$4,178,922	$41,629,238	$4,997,248
Operating Costs					
Direct Operating Costs ($/year)	[2]	$673,534	$399,546	$2,124,053	$1,270,494
Indirect Operating Costs ($/year)	[3]	$1,864,942	$344,472	$3,509,034	$411,536
Total Annual Cost ($/year)	[4]	$2,538,476	$744,018	$5,633,087	$1,682,030
Control Cost Effectiveness ($/ton)		***$10,400***	***$9,100***	***$6,100***	***$5,300***

Footnotes

[1] Capital Cost Estimates from EPA Air Pollution Control Cost Manual - Section 4 - NOx Controls (updated 12/07/17) and adjusted for inflation based on Chemical Engineering Plant Cost Index

[2] Labor, supervision, materials, replacement parts, utilities, etc.

[3] Sum indirect oper costs + capital recovery cost

[4] Total Annual Cost = Direct Operating Costs + Indirect Operating Costs

[5] Controlled Emissions = (1 - Control Efficiency) * Baseline Emissions

[6] Control Cost Effectiveness = Total Annual Cost / Tons Removed from Exhaust

Montana-Dakota Utilities Co. R.M. Heskett Station
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis
Attachment A
Table A2: Control Costs Summary for Low-dust SCR for NOx Control

	Unit 1		Unit 2		Notes
	SCR	Reheat	SCR	Reheat	
Total Annual Cost	**$2,538,476**		**$5,633,087**		annualized Capital Cost + Operating Cost
Total Capital Investment	**$21,729,380**		**$41,629,238**		sum of SCR + Reheat System Equipment Costs
SCR Reactor System in 2018 $'s	$20,472,432	-	$40,070,344	-	Revised Control Cost Manual for SCR incorporates all istallation and indirect capital costs into the calculated Total Capital Investment (TCI). Retrofit (1.25 for difficult retrofit) and elevation cost (calculated as 1.06; plant elevation at 1657.5) factors per EPA Air Pollution Control Cost Manual Section 1, Chapter 2 Section 2.5.4.2
SCR Reactor System in 2012 $'s	$10,055,473	-	$22,556,085	-	SCR Cost Estimate from EPA Air Pollution Control Cost Manual - Section 4 - Nox Controls (updated 12/07/17) and adjusted for inflation based on Chemical Engineering Plant Cost Index
Reagent Preparation System Costs in 2012 $'s	$2,051,740	-	$2,571,115	-	
Air Pre-Heater Costs in 2012 $'s	-	-	-	-	
Balance of Plant Costs in 2012 $'s	$2,796,941	-	$4,044,446	-	
Reheat Purchased Equipment Total	-	$1,256,948	-	$1,558,893	
Flue Gas Re-Heat Equipment Cost Estimate	-	$678,881	-	$841,962	EPA control cost guideline for catalytic oxidizers used for operating cost analysis. EPA Air Pollution Control Cost Manual 6th Ed 2002. Basis Thermal Oxidizer with 70% Heat Recovery
Instrumentation	-	$67,888	-	$84,196	10% of control device cost; EPA control cost guideline
Sales Tax	-	-	-	-	N/A of control device cost; EPA control cost guideline
Freight	-	$33,944	-	$42,098	5% of control device cost; EPA control cost guideline
Installation Costs					
Foundations and Supports	-	$62,457	-	$77,461	8% of purchased equip cost; EPA control cost guideline
Handling & Erection	-	$109,300	-	$135,556	14% of purchased equip cost; EPA control cost guideline
Electrical	-	$31,229	-	$38,730	4% of purchased equip cost; EPA control cost guideline
Piping	-	$15,614	-	$19,365	2% of purchased equip cost; EPA control cost guideline
Insulation	-	$7,807	-	$9,683	1% of purchased equip cost; EPA control cost guideline
Painting	-	$7,807	-	$9,683	1% of purchased equip cost; EPA control cost guideline
Indirect Capital Costs					
Engineering, supervision	-	$78,071	-	$96,826	10% of purchased equip cost; EPA control cost guideline
Construction & field expenses	-	$39,036	-	$48,413	5% of purchased equip cost; EPA control cost guideline
Contractor fees	-	$78,071	-	$96,826	10% of purchased equip cost; EPA control cost guideline
Start-up	-	$15,614	-	$19,365	2% of purchased equip cost; EPA control cost guideline
Performance test	-	$7,807	-	$9,683	1% of purchased equip cost; EPA control cost guideline
Model Studies	-	-	-	-	N/A of purchased equip cost; EPA control cost guideline
Contingencies	-	$23,421	-	$29,048	3% of purchased equip cost; EPA control cost guideline
Direct Annual Operating	**$673,534**		**$2,124,053**		
Labor & Maintenance					
Operator Labor	$62,780	$23,543	$62,780	$23,543	43.00 $/Hr, 4.5 hr/day
Supervisor Labor	-	$3,531	-	$3,531	0% of Operator Costs for SCR System; 15% of Operator Costs for Reheat System
Maintenance Labor	$102,362	$23,986	$200,352	$23,986	0.5% of Total Capital Investment for SCR system; 43.80 $/Hr, 0.5 hr/day for Reheat System
Maintenance Materials	-	$240	-	$240	0% of Maintenance Labor for SCR System; 100% of Maintenance Labor for Reheat System
Utilities, Supplies, Replacements & Waste Management					
Electricity	$32,973	$125,108	$141,706	$412,946	auxiliary power requirement for operation of SCR and reheat systems
Natural Gas	-	$209,096	-	$963,598	based on heat input required to reheat flue gas to temperature for proper operation of SCR system
Ammonia - Anhydrous	$54,054	-	$206,278	-	based on ammonia use, capacity factor calculated assuming NOx removal rate, and cost of reagent
SCR Catalyst	$35,861	-	$85,092	-	$/yr by Method 1 in EPA Air Pollution Control Cost Manual - Section 4
Indirect Annual Operating	**$1,864,942**		**$3,509,034**		
Overhead	-	$30,780	-	$30,780	60% of total labor and material costs for reheat system only
Administration	$3,112	$25,139	$4,288	$31,178	3% * (Labor +40% of maintenance costs) for SCR system; 2% of total capital co
Property tax	-	$12,569		$15,589	1% of total capital costs for reheat system only
Insurance	-	$12,569		$15,589	1% of total capital costs for reheat system only
Capital Recovery	$1,677,763	$103,010	$3,283,856	$127,755	0.0820 for a 20-year equipment life and a 5.25% interest rate

Montana-Dakota Utilities Co. R.M. Heskett Station
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis
Attachment A
Table A3: Control Costs Summary for SNCR for NOx Control

	Unit 1	Unit 2	Notes
Total Annual Cost	**$744,018**	**$1,682,030**	annualized Capital Cost + Operating Cost
Total Capital Investment	**$4,178,922**	**$4,997,248**	sum of SCR + Reheat System Equipment Costs
SNCR Reactor System in 2018 $'s	$4,178,922	$4,997,248	Revised Control Cost Manual Incorporates all of these factors into the calculated Total Capital Investment. Retrofit (1.25) and Elevation Cost (1.06) Factors per EPA Air Pollution Control Cost Manual Section 1, Chapter 2 Section 2.5.4.2
SNCR Reactor System in 2012 $'s	$1,206,956	$1,435,964	SCR Cost Estimate from EPA Air Pollution Control Cost Manual - Section 4 - NOx Controls (updated 12/07/17) and adjusted for inflation based on Chemical Engineering Plant Cost Index
Reagent Preparation System Costs in 2012 $'s	-	-	
Air Pre-Heater Costs in 2012 $'s	-	-	
Balance of Plant Costs in 2012 $'s	$1,835,345	$2,202,086	
Direct Annual Operating Costs	**$399,546**	**$1,270,494**	
Labor & Maintenance			
Operator Labor	$31,390	$31,390	43.00 $/Hr, 2 hr/day
Supervisor Labor	-	-	0% of Operator Costs
Maintenance Labor	$62,684	$74,959	1.5% of Total Capital Investment
Maintenance Materials	-	-	0% of Maintenance Labor
Utilities, Supplies, Replacements & Waste Management			
Electricity	$1,546	$5,891	auxiliary power requirement for operation of SNCR system
Coal	$8,460	$32,240	additional fuel use requirements for SNCR operation
Water	$117	$446	based on urea feed rate
Urea 50% Solution	$295,349	$1,125,567	based on urea use rate calculated assuming NOx removal rate (per EPA method)
Indirect Annual Operating Costs	**$344,472**	**$411,536**	
Overhead	-	-	
Administration	$2,000	$2,000	3% of maintenance costs
Property tax	-	-	
Insurance	-	-	
Capital Recovery	$342,472	$409,536	0.0820 for a 20-year equipment life and a 5.25% interest rate

Montana-Dakota Utilities Co. R.M. Heskett Station
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis
Attachment A
Table A4: Summary of Utility, Chemical and Supply Costs for NOx

Item	Unit Cost		Reference Cost	Year	Data Source	Notes
			Study Year:	*2018*		*Costs are adjusted for 3% inflation*
Labor						
Operating Labor	43.00	$/hr	43.00	2018	MDU	Level 2 Operator
Maintenance Labor	43.81	$/hr	43.81	2018	MDU	Mechanic
Utilities						
Electricity	0.06	$/kW-h	56.45	2018	$/MWh from MDU	
Natural Gas	3.77	$/kscf	3.77	2018	DOE Average (5 Month) Retail Price of Natural Gas for Electric Power	https://www.eia.gov/totalenergy/data/monthly/pdf/sec9_15.pdf
Coal	2.75	$/MMBtu	2.30	2012	EPA Air Pollution Control Cost Manual May 2016, Section 4 Chapter 1 SNCR.	Paragraph 1.5 - Example Problem. Example problem cost data; 2012 dollars. Price adjusted for inflation.
Water	0.32	$/kgal	0.20	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2.6.1.2.	Example Problems uses $0.20/1000 gal. Cost adjusted for 3% inflation Sec 5.2 Ch 1 also lists $0.20/1,000 gal.
Chemicals & Supplies						
Urea 50% Solution	3.69	$/ton	2.59	2006	MDU, 2006 BART Evaluation	$550/ton for urea solution; converted to $/gal for costing purposes.
Ammonia - Anhydrous	0.29	$/lb	0.20	2006	MDU, 2006 BART Evaluation	
Catalyst & Replacement Parts						
SCR Catalyst	160.00	$/ft3				
Other						
Sales Tax	0.00%					
Interest Rate	5.25%				EPA/NDDH guidance	

Attachment B

SO_2 Control Costs

Montana-Dakota Utilities Co. R.M. Heskett Station
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis
Attachment B
Table B1: SO_2 Cost Evaluation Summary

Unit Summary

Unit	Unit 1		Unit 2	
Fuel Type	Lignite		Lignite	
Boiler Type	Normal		Fluidized Bed	
Maximum Hourly Production	25	MWh	75	lb/MMBtu
Maximum Hourly Heat Input Rate	387.63	MMBtu/hr	916.5	MMBtu/hr
Standardized Exhaust Flow Rate	95,133	scfm @ 68º F	235,167	scfm @ 68º F
Exhaust Temperature	420	º F	320	º F
Exhaust Moisture Content	15	%	15	%
Capacity Factor (CF) / Utilization	40	%	63	%
Expected Annual Hours of Operation	8760	hours	8760	hours
Baseline Emission Rate	3.00	lb/MMBtu	0.60	lb/MMBtu
Hourly Emissions	1,162.9	lb/hr	549.9	lb/hr
Annual Emissions	2,037.4	tons/yr	1,517.4	tons/yr

Control Equipment Costs

Control Technology Name		Wet Scrubber	Spray Dry Absorption	Dry Sorbent Injection	Wet Scrubber	Spray Dry Absorption
Expected Equipment Life (years)		20	20	20	20	20
SO_2 Control Efficiency		98%	70%	50%	98%	90%
Controlled Emissions (tons/yr)		40.7	611.2	1018.7	30.3	151.7
Reduction (tons/yr)		1996.6	1426.2	1018.7	1487.0	1365.7
Capital Costs						
Total Capital Investment (TCI = DC + IC)	[1]	$71,535,252	$55,671,830	$32,267,572	$80,335,051	$70,273,560
Operating Costs						
Direct Operating Costs ($/year)	[2]	$1,111,404	$882,135	$875,539	$1,214,929	$1,081,768
Indirect Operating Costs ($/year)	[3]	$9,156,496	$7,124,449	$4,270,246	$10,229,651	$8,905,163
Total Annual Cost ($/year)	[4]	$10,267,899	$8,006,584	$5,145,785	$11,444,580	$9,986,931
Control Cost Effectiveness ($/ton)		***$5,100***	***$5,600***	***$5,100***	***$7,700***	***$7,300***

Footnotes

[1] See individual control cost summary tables

[2] Labor, supervision, materials, replacement parts, utilities, etc.

[3] Sum indirect oper costs + capital recovery cost

[4] Total Annual Cost = Direct Operating Costs + Indirect Operating Costs

[5] Controlled Emissions = (1 - Control Efficiency) * Baseline Emissions

[6] Control Cost Effectiveness = Total Annual Cost / Tons Removed from Exhaust

Montana-Dakota Utilities Co. R.M. Heskett Station
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis
Attachment B
Table B2: Control Costs Summary for Wet Scrubber for SO_2 Control

	Unit 1	Unit 2	Notes
Total Annual Cost	**$10,267,899**	**$11,444,580**	annualized Capital Cost + Operating Cost
Total Capital Investment	**$71,535,251.82**	**$80,335,050.77**	
Purchased Equipment Cost (2018 $'s)	$28,274,803	$51,745,604	Total Direct Capital Cost adjusted for inflation based on Chemical Engineering Plant Cost Index
Purchased Equipment Cost	$17,691,778	$41,852,200	Unit 1 cost estimate scaled from DC from IAPCS program estimate; Unit 2 cost esitmate per 2006 BART review.
Instrumentation	$2,827,480.31	$5,174,560.44	10% of control device cost; EPA control cost guideline
Sales Tax	-	-	N/A of control device cost; EPA control cost guideline
Freight	$1,413,740	$2,587,280	5% of control device cost; EPA control cost guideline
Installation Costs			
Foundations and Supports	$3,901,923	-	12% of purchased equip cost for U1; included in U2 cost estimate
Handling & Erection	$13,006,409	-	40% of purchased equip cost for U1; included in U2 cost estimate
Electrical	$325,160	-	1% of purchased equip cost for U1; included in U2 cost estimate
Piping	$9,754,807	-	30% of purchased equip cost for U1; included in U2 cost estimate
Insulation	$325,160	-	1% of purchased equip cost for U1; included in U2 cost estimate
Painting	$325,160	-	1% of purchased equip cost for U1; included in U2 cost estimate
Indirect Capital Costs			
Engineering, supervision	$3,251,602	$5,950,745	10% of purchased equip cost; EPA control cost guideline
Construction & field expenses	$3,251,602	$5,950,745	10% of purchased equip cost; EPA control cost guideline
Contractor fees	$3,251,602	$5,950,745	10% of purchased equip cost; EPA control cost guideline
Start-up	$325,160	$595,074	1% of purchased equip cost; EPA control cost guideline
Performance test	$325,160	$595,074	1% of purchased equip cost; EPA control cost guideline
Model Studies	-	-	N/A of purchased equip cost; EPA control cost guideline
Contingencies	$975,481	$1,785,223	3% of purchased equip cost; EPA control cost guideline
Direct Annual Operating Costs	**$1,111,404**	**$1,214,929**	
Labor & Maintenance			
Operator Labor	$376,680	$376,680	43.00 $/Hr, 8 hr/8 hr shift
Supervisor Labor	$56,502	$56,502	15% of Operator Costs for SCR System; 15% of Operator Costs for Reheat System
Maintenance Labor	$143,916	$143,916	43.00 $/Hr, 3 hr/8 hr shift
Maintenance Materials	$143,916	$143,916	100% of maintentance labor
Utilities, Supplies, Replacements & Waste Management			
Electricity	$48,504	$166,882	auxiliary power requirement for operation
Water	$14,103	$6,863	Liquid/Gas ratio = 10 L/G = Gal/1,000 acf
Wastewater Disposal Neutralization	$105,769	$51,475	water makeup rate/wastewater discharge = 20% of circulating water rate
Solid Waste Disposal	$35,031	$42,397	includes lime disposal costs but does not include fly ash
Lime	$186,983	$226,298	based on SO2 removal rate and 0.96lb lime/lb SO2
Indirect Annual Operating Costs	**$9,156,496**	**$10,229,651**	
Overhead	$432,608.22	$432,608.22	60% of total labor and material costs
Administration	$1,430,705	$1,606,701	2% of total capital costs
Property tax	$715,353	$803,351	1% of total capital costs
Insurance	$715,353	$803,351	1% of total capital costs
Capital Recovery	$5,862,477	$6,583,641	0.0820 for a 20-year equipment life and a 5.25% interest rate

Montana-Dakota Utilities Co. R.M. Heskett Station
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis
Attachment B
Table B3: Control Costs Summary for SDA Baghouse for SO_2 Control

	Unit 1	Unit 2	Notes
Total Annual Cost	**$8,006,584**	**$9,986,931**	annualized Capital Cost + Operating Cost
Total Capital Investment	**$55,671,830.05**	**$70,273,560.37**	
Purchased Equipment Cost (2018 $'s)	$22,105,154	$42,143,065	Total Direct Capital Cost adjusted for inflation based on Chemical Engineering Plant Cost Index
Purchased Equipment Cost	$13,831,378	$34,085,600	Unit 1 cost estimate scaled from DC from IAPCS program estimate; Unit 2 cost esitmate per 2006 BART review. Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
Instrumentation	$2,210,515.39	$4,214,306.47	10% of control device cost; EPA control cost guideline
Sales Tax	-	-	N/A of control device cost; EPA control cost guideline
Freight	$1,105,258	$2,107,153	5% of control device cost; EPA control cost guideline
Installation Costs			
Foundations and Supports	$1,016,837	-	4% of purchased equip cost for U1; included in U2 cost estimate
Handling & Erection	$12,710,463	-	50% of purchased equip cost for U1; included in U2 cost estimate
Electrical	$2,033,674	-	8% of purchased equip cost for U1; included in U2 cost estimate
Piping	$254,209	-	1% of purchased equip cost for U1; included in U2 cost estimate
Insulation	$1,779,465	-	7% of purchased equip cost for U1; included in U2 cost estimate
Painting	$1,016,837	-	4% of purchased equip cost for U1; included in U2 cost estimate
Indirect Capital Costs			
Engineering, supervision	$2,542,093	$4,846,452	10% of purchased equip cost; EPA control cost guideline
Construction & field expenses	$5,084,185	$9,692,905	20% of purchased equip cost; EPA control cost guideline
Contractor fees	$2,542,093	$4,846,452	10% of purchased equip cost; EPA control cost guideline
Start-up	$254,209	$484,645	1% of purchased equip cost; EPA control cost guideline
Performance test	$254,209	$484,645	1% of purchased equip cost; EPA control cost guideline
Model Studies	-	-	N/A of purchased equip cost; EPA control cost guideline
Contingencies	$762,628	$1,453,936	3% of purchased equip cost; EPA control cost guideline
Direct Annual Operating Costs	**$882,135**	**$1,081,768**	
Labor & Maintenance			
Operator Labor	$235,425	$235,425	43.00 $/Hr, 5 hr/8 hr shift
Supervisor Labor	$35,314	$35,314	15% of Operator Costs for SCR System; 15% of Operator Costs for Reheat System
Maintenance Labor	$143,916	$143,916	43.00 $/Hr, 3 hr/8 hr shift
Maintenance Materials	$143,916	$143,916	100% of maintentance labor
Utilities, Supplies, Replacements & Waste Management			
Electricity	$60,246	$207,904	auxiliary power requirement for operation
Water	$675	$3,188	based on 0.75 gpm per MW-gross
Compressed Air	$31,949	$110,252	compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
Wastewater Disposal Neutralization	$5,061	$23,911	based on 0.75 gpm per MW-gross
Solid Waste Disposal	$35,123	$26,159	includes lime disposal costs but does not include fly ash
Lime	$187,470	$139,623	based on SO2 removal rate and 0.96lb lime/lb SO2
Filter Bags	$3,042	$12,159	bBag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag
Indirect Annual Operating Costs	**$7,124,449**	**$8,905,163**	
Overhead	$335,142.27	$335,142.27	60% of total labor and material costs
Administration	$1,113,437	$1,405,471	2% of total capital costs
Property tax	$556,718	$702,736	1% of total capital costs
Insurance	$556,718	$702,736	1% of total capital costs
Capital Recovery	$4,562,434	$5,759,079	0.0820 for a 20-year equipment life and a 5.25% interest rate

Montana-Dakota Utilities Co. R.M. Heskett Station
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis
Attachment B
Table B4: Control Costs Summary for DSI Baghouse for SO_2 Control

	Unit 1	Notes
Total Annual Cost	**$5,145,785**	annualized Capital Cost + Operating Cost
Total Capital Investment	**$32,267,572.30**	
Purchased Equipment Cost (2018 $'s)	$12,812,219	Total Direct Capital Cost adjusted for inflation based on Chemical Engineering Plant Cost Index
Purchased Equipment Cost	$8,016,711	Unit 1 cost estimate scaled from DC from IAPCS program estimate. Dry scrubbing SO2 costs include addition of a baghouse. Assumed that the existing ESP could not handle additional loading.
Instrumentation	$1,281,221.85	10% of control device cost; EPA control cost guideline
Sales Tax	-	N/A of control device cost; EPA control cost guideline
Freight	$640,611	5% of control device cost; EPA control cost guideline
Installation Costs		
Foundations and Supports	$589,362	4% of purchased equip cost
Handling & Erection	$7,367,026	50% of purchased equip cost
Electrical	$1,178,724	8% of purchased equip cost
Piping	$147,341	1% of purchased equip cost
Insulation	$1,031,384	7% of purchased equip cost
Painting	$589,362	4% of purchased equip cost
Indirect Capital Costs		
Engineering, supervision	$1,473,405	10% of purchased equip cost; EPA control cost guideline
Construction & field expenses	$2,946,810	20% of purchased equip cost; EPA control cost guideline
Contractor fees	$1,473,405	10% of purchased equip cost; EPA control cost guideline
Start-up	$147,341	1% of purchased equip cost; EPA control cost guideline
Performance test	$147,341	1% of purchased equip cost; EPA control cost guideline
Model Studies	-	N/A of purchased equip cost; EPA control cost guideline
Contingencies	$442,022	3% of purchased equip cost; EPA control cost guideline
Direct Annual Operating Costs	**$875,539**	
Labor & Maintenance		
Operator Labor	$235,425	43.00 $/Hr, 5 hr/8 hr shift
Supervisor Labor	$35,314	15% of Operator Costs for SCR System; 15% of Operator Costs for Reheat System
Maintenance Labor	$143,916	43.00 $/Hr, 3 hr/8 hr shift
Maintenance Materials	$143,916	100% of maintentance labor
Utilities, Supplies, Replacements & Waste Management		
Electricity	$60,246	auxiliary power requirement for operation
Compressed Air	$31,949	compressed air for baghouse assumed to be 2 scfm / 1000 acfm EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.5.1.8
Solid Waste Disposal	$35,123	includes lime disposal costs but does not include fly ash
Lime	$187,470	based on SO2 removal rate and 0.96lb lime/lb SO2
Filter Bags	$2,181	bBag replacement at 10 min/bag EPA Cost Cont Manual 6th ed Section 6 Chapter 1.5.1.4 lists replacement times from 5 - 20 min per bag
Indirect Annual Operating Costs	**$4,270,246**	
Overhead	$335,142.27	60% of total labor and material costs
Administration	$645,351	2% of total capital costs
Property tax	$322,676	1% of total capital costs
Insurance	$322,676	1% of total capital costs
Capital Recovery	$2,644,401	0.0820 for a 20-year equipment life and a 5.25% interest rate

Montana-Dakota Utilities Co. R.M. Heskett Station
Regional Haze Rule Reasonable Progress Goals Four-Factor Analysis
Attachment B
Table B5: Summary of Utility, Chemical and Supply Costs for SO_2

Item	Unit Cost		Reference Cost	Year	Data Source	Notes
			Study Year:	*2018*		*Costs are adjusted for 3% inflation*
Labor						
Operating Labor	43.00	$/hr	43.00	2018	MDU	Level 2 Operator
Maintenance Labor	43.81	$/hr	43.81	2018	MDU	Mechanic
Utilities						
Electricity	0.06	$/kW-h	56.45	2018	$/MWh from MDU	
Natural Gas	3.77	$/kscf	3.77	2018	DOE Average (5 Month) Retail Price of Natural Gas for Electric Power	https://www.eia.gov/totalenergy/data/monthly/pdf/sec9_15.pdf
Water	0.32	$/kgal	0.20	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 2.6.1.2.	Example Problems uses $0.20/1000 gal. Cost adjusted for 3% inflation Sec 5.2 Ch 1 also lists $0.20/1,000 gal.
Compressed Air	0.45	$/kscf	0.25	1998	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6 Chapter 1.	Example problem; Dried & Filtered, Ch 1.6 1998 cost adjusted for 3% inflation.
Wastewater Disposal Neutralization	2.41	$/kgal	1.50	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 5 Chapter 1.	Section 2 lists $1- $2/1000 gal. Cost adjusted for 3% inflation. Sec 6 Ch 3 lists $1.30 - $2.15/1,000 gal.
Solid Waste Disposal	17.91	$/ton	15.00	2012	EPA Air Pollution Control Cost Manual May 2016, Section 4 Chapter 1 SNCR.	Paragraph 1.5 Example calculations - price for ash disposal. Cost adjusted for 3% inflation.
Chemicals & Supplies						
Lime	95.60	$/ton	95.60	2018	MDU	
Catalyst & Replacement Parts						
Filter Bags	54.09	$/bag	33.71	2002	EPA Air Pollution Control Cost Manual 6th Ed 2002, Section 6, Chapter 1	Example problem cost for 10 ft bags. Cost adjusted for 3% inflation
Other						
Sales Tax	0.00%					
Interest Rate	5.25%				EPA/NDDH guidance	

B.6.c – Communications

Stroh, David E.

From: Dihle, Mark <Mark.Dihle@mdu.com>
Sent: Tuesday, February 19, 2019 4:01 PM
To: Glatt, Dave D.; O'Clair, Terry L.; Bachman, Tom A.; Stroh, David E.; Rockeman, Karl H.; Haroldson, Marty R.; Hyatt, Chuck R.
Cc: Fong, Cory; Skabo, Jay; Dever, Justin; Welte, Alan; Davies, Samantha; Dihle, Mark; Godel, Kalle; McDonald, Andy; Peterson, Todd; Krebsbach, Abbie
Subject: Montana-Dakota Utilities Co. Generation Announcement (NDDEQ officials)
Attachments: News Release MDU Resources Subsidiary Plans Retirement of Aging Generation Units; New Generation Build 02192019.pdf

Sending on behalf of Abbie Krebsbach and Jay Skabo

Good afternoon,

I am writing to you because I want you to know about the announcement that Montana-Dakota Utilities made regarding its generation fleet. In case you haven't seen it, the news release is attached. Feel free to share with others in your organization, particularly with air quality, water quality, and waste management permitting areas, where we work closely with you and your staff on permits for our generation facilities discussed below. We will plan to reach out directly to our permitting contacts in the future to discuss our current permitting activities and any permit modifications needed as our plan moves forward.

Montana-Dakota Utilities' plan is to retire three aging coal fired units at two electric generation stations and construct a new simple cycle combustion turbine within the next two to three years.

Montana-Dakota Utilities' mission is to provide safe, reliable and cost-effective service to its customers. Our coal facilities at R.M. Heskett Station and Lewis & Clark Station have done just that for nearly six decades, but we are finding they are no longer cost-competitive.

The decision was made as part of Montana-Dakota's integrated resource plan and will cost-effectively meet the needs of its customers. The company intends to retire the coal unit at Lewis & Clark Station in Sidney, Montana around the end of 2020 and Units 1 & 2 at R.M. Heskett Station near Mandan, North Dakota around the end of 2021. The new natural gas unit will go online in early 2023 at the R.M. Heskett Station. Both stations have existing natural gas fired units that will continue to operate.

If you have questions, please feel free to get back to Abbie Krebsbach at 701-222-7844/701-663-9178 or abbie.krebsbach@mdu.com, me at the contact info further below, or reach out to others on our communications team:

Cory Fong, Director of Communications Cory.Fong@mduresources.com 701.226.7743
Justin Dever, Senior Public Affairs Specialist, MDU Resources Group Justin.Dever@mduresources.com 701.220.0185

Sincerely,

Mark Dihle
Sr. Environmental Scientist
Montana Dakota Utilities
400 North Fourth Street
Bismarck, ND 58501-4092
Bus: 701.222.7865
Fax: 701.222.7845

Press Release

MDU Resources Subsidiary Plans Retirement of Aging Generation Units; New Generation Build

Company Release - 2/19/2019 4:30 PM ET

BISMARCK, N.D., Feb. 19, 2019 /PRNewswire/ -- MDU Resources Group, Inc., (NYSE: MDU) subsidiary Montana-Dakota Utilities announced today that it intends to retire three aging coal-fired electric generation units at two locations within the next two to three years and construct a new simple-cycle natural gas combustion turbine to cost-effectively m the needs of its customers.

The analysis done while preparing the integrated resource plan (IRP), which the company puts together every two years and files with regulatory commissions, points to the retirement of two aging coal-fired plants and the construction of the natural gas combustion turbine. Low-cost power available on the market, due to low-cost natural gas and increasing wind resources, as well as rising costs to operate these facilities, led to the decision to retire the coal plants. The retirements are expected around the end of 2020 for Lewis & Clark Station in Sidney, Montana, and around the end of 2021 for units 1 and 2 at Heskett Station in Mandan, North Dakota. These dates may be impacted by the company's coal supplier's pending bankruptcy proceeding.

The company has begun the development process to construct an 88-megawatt simple-cycle peaking unit at the Heskett Station site, and anticipates submitting an advance determination of prudence request with the North Dakota Public Service Commission this fall.

The new generation resource was selected as part of Montana-Dakota's IRP. The company believes a second combustion turbine at Heskett will be cost-effective because the s has existing infrastructure and natural gas supply that serves an existing combustion unit that went online in 2014.

"Our main objective is to provide our customers with safe, reliable and low-cost service," said Nicole Kivisto, president and CEO of Montana-Dakota. "The IRP process helps gui us in making decisions to meet those objectives. Heskett and Lewis & Clark have met that objective for many years, but our analysis is showing those units are no longer cost competitive for our customers."

The total cost of building and operating a new simple-cycle combustion turbine, coupled with market purchases, is expected to be about half the total cost of continuing to run the Heskett and Lewis & Clark coal-fired units.

The first coal-fired unit at Heskett went online in 1954 and the second unit in 1963. They combine for 100 MW of power. Lewis & Clark went online in 1958 and provides 44 MW power. If the company meets the proposed retirement timeline, the plants will range in age from 58-67 years old.

"The plants have served our customers well, providing low-cost energy for many years, operating roughly twice as long as expected when they were constructed in the mid-195 and early 1960s," Kivisto said. "The age of the plants, low-cost competition on the market, and the ongoing cost to operate the plants all have contributed to the plants being too expensive to operate much longer."

Montana-Dakota has conducted an IRP for many years. The IRP is a way to consider all resource options reasonably available to meet the end-use customer's demand for relia and cost-effective energy, and provide a road map for Montana-Dakota's future resources. The IRP process includes four areas: Load forecasting, demand-side analysis, supply side analysis, and integration and risk analysis.

Montana-Dakota's customers also have benefited from low-cost energy available on the MISO market and the long-range forecast calls for similar savings in future years. MISO the Midcontinent Independent System Operator, is a not-for-profit member-based organization that ensures reliable, least-cost delivery of electricity across all or parts of 15 U.S. states and one Canadian province. In cooperation with stakeholders, MISO manages approximately 65,000 miles of high-voltage transmission and 200,000 MW of power-generating resources across its footprint.

Montana-Dakota currently employs 77 people between the two coal stations. Once the units are no longer in operation, Montana-Dakota estimates approximately 10 employees will be needed to operate the two natural gas-fired combustion turbine units at Heskett and the two natural gas-fired reciprocating internal combustion engines at Lewis & Clark. plan is in place intended to maintain staff until the plant retirements, and the company will offer training for employees who wish to fill open positions in other areas of the compa

About MDU Resources

MDU Resources Group, Inc., a member of the S&P MidCap 400 index and the S&P High-Yield Dividend Aristocrats index, is Building a Strong America® by providing essential products and services through its regulated energy delivery and construction materials and services businesses. For more information about MDU Resources, see the company website at www.mdu.com or contact the Investor Relations Department at investor@mduresources.com.

About Montana-Dakota Utilities

Montana-Dakota Utilities Co., a subsidiary of MDU Resources, distributes natural gas and generates, transmits and distributes electricity and provides related services in the northern Great Plains. The company serves approximately 143,000 electric customers and 275,000 natural gas customers in 262 communities in North Dakota, South Dakota, Montana and Wyoming.

Forward-Looking Statement

The information in this release includes certain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. The forward looking statements contained in this release, including statements made by the president and CEO of Montana-Dakota and statements relating to plans and expectations regard the construction of a simple cycle combustion turbine, retirement of existing generating stations, related costs and other benefits, and Montana-Dakota's integrated resource pla are expressed in good faith and are believed by the company to have a reasonable basis. Nonetheless, actual results may differ materially from the projected results expressed the forward-looking statements. For a discussion of important factors that could cause actual results to differ materially from those expressed in the forward-looking statements, refer to Item 1A-Risk Factors in MDU Resources' most recent Form 10-Q and 10-K.

Media Contact: Mark Hanson, senior public relations representative, 701-530-1093

B.7 – Little Knife Gas Plant

B.7.a – Department Request

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

FILE

May 18, 2018

Mr. Derek Enderud
Petro-Hunt, LLC
390 - 119th Avenue SW
Killdeer, ND 58640

Re: Regional Haze
Second Planning Period

Dear Mr. Enderud:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

The Little Knife Gas Plant emits a significant amount of SO_2 and is located close to a Class I area. Therefore, the Department requests that you prepare a "four factors" analysis for the plant. The analysis should be prepared using the draft EPA guidance noted above. The analysis should address emissions from the amine sweeting unit (Emission Unit A-1) and the flare (Emission Unit F-1).

Preparation of the Round 2 Regional Haze SIP will require extensive planning and review of emission sources in North Dakota. The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the SIP. WRAP will be conducting air quality modeling of potential regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely.

Terry O'Clair

Terry L. O'Clair
Director
Division of Air Quality

TLO/TB:saj

B.7.b – Facility Response

Stroh, David E.

From: Gary Kohler <gkohler@petrohunt.com>
Sent: Friday, January 25, 2019 3:40 PM
To: Stroh, David E.; O'Clair, Terry L.
Cc: Royce Kennedy; Derek Enderud; Elvis Entzel; Donaven Palahniuk; Ryan Solberg; Ruth R. Ehrmantraut
Subject: Petro Hunt - Regional Haze - Round Two
Attachments: Regional Haze Round Two 01-25-19.pdf

Categories: RH Facility

David,
Attached is a summary of the four factor analysis requirements relating to the second planning period of the State Implementation Plan (SIP) for Regional Haze.

The summary includes the projected reduction of sulfur dioxide with potential additional controls. The attachments include the estimated cost of the controls along with the estimated energy and non-air environmental impacts.

Thank you for proving me with the additional information you sent, as well as explaining the history of these studies. It was a great help. If you have additional questions please give me a call.

Gary A. Kohler
Plant Manager
Petro-Hunt, LLC
Little Knife Gas Plant
W: 701.863.6500
D: 701.863.6445
C: 701.290.7397
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www.petrohunt.com

Petro Hunt Little Knife Gas Plant

State Implementation Plan (SIP) for Regional Haze Round 2

Four Factor Analysis

Table 1: Outlines the emission control measures that have already been applied to these sources, the baseline levels of emissions with these current controls, and potential additional control measures that could be adopted to further reduce emissions. The table also gives the estimated control efficiency and annual emission reduction for each potential future control measure.

(1) Existing Control Measures and Potential Additional Control Options for Natural Gas Processing Operations

Source	Pollutant	Existing Controls	Baseline Emissions (tons/yr.)	Potential additional control measurers	Estimated Control efficiency (%)	Potential emission reduction (tons/yr.)	References
Sulfur recovery unit, 2-stage, 2-bed, 120 long tons/day sulfur	Sulfur Dioxide	2- stage unit with cold bed adsorption, > 88 % efficiency	432	Replacement of catalyst in Reactors 1 & 2	90%	39.42	Catalyst Replacement in Reactors 1 & 2 Attachment
Sulfur recovery unit, 2-stage, 2-bed, 120 long tons/day sulfur	Sulfur Dioxide	2- stage unit with cold bed adsorption, > 88 % efficiency	432	Acid Gas Injection Well	100%	320	Acid Gas Injection Well and Catalyst Replacement Reactor 1 & 2 Attachments

Table 2 Factor 1: Provides cost estimates for the emission control options which have been identified for the North Dakota gas processing facilities. For each option, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The table also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

Factor 2: Once the regional haze control strategy is formulated for North Dakota, up to 2 years will be needed for the state to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The ICAC has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NOX control. However, state regulators' experience indicates that closer to 18 months is required to install this technology. In the Clean Air Interstate Rule (CAIR) analysis, EPA estimated that approximately 30 months is required to design, build, and install SO2 scrubbing technology for a single emission source. The analysis also estimated that up to an additional 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility. Based on these figures, the total time required achieve emission reductions for the Petro Hunt facility would be up to 6½ years. This includes 2 years for regulatory development, 1 year for capital acquisition, and 2½ years for designing, building and installing. This estimate includes the same components as the estimate for Petro Hunt, with an additional year for staging the installation of controls for multiple emission sources.

(2) Estimated Costs of Control for Natural Gas Processing Operations - Factor 1

Source	Control Option	Pollutant	Estimated control efficiency (%)	Potential emission reduction (tons/yr.)	Estimated capitol cost ($1000)	Estimated annual cost ($1000/yr.)	Cost effectiveness ($/ton)	References
Sulfur recovery unit, 2-stage, 2-bed, 120 long tons/day sulfur	Replacement of catalyst in Reactors 1 & 2	Sulfur Dioxide	90%	39.42	103.95	10.39	2,636.99	Catalyst Replacement in Reactors 1 & 2 (attachment)
Amine Treating Unit	Acid Gas Injection Well	Hydrogen Sulfide and Carbon Dioxide	100%	320	4,229.58	624.71	13,665.53	Acid Gas Injection Well, Estimated Cost of Control, & Catalyst Replacement in Reactors 1 & 2 Attachments

Table 3 Factor 3: Shows the estimated energy and non-air pollution impacts of control measures for sources at the Petro Hunt facility. The table shows the additional fuel, electricity, and steam requirements resulting required to operate the control equipment; and the additional solid waste would be produced. CO2 emissions associated with the generation of the additional electricity and steam are also estimated in the table.

(3) Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Natural Gas Processing

Energy and non-air pollution impacts (per ton of emission reduced

Source Type	Control Technology	Pollutant Controlled	Potential emission reduction (ton/yr.)	Additional Fuel Req. (%)	Electricity Req. (kw-hr)	Steam Req. (tons steam)	Solid waste Produced (tons)	Additional CO2 emitted (tons)
Sulfur recovery unit, 2-stage, 2-bed, 120 long tons/day sulfur	Activated Alumina Promoted Claus Catalyst	Sulfur Dioxide	39.42	0	0	0	0	0
Amine Treating Unit	Downhole Formation Injection	Hydrogen Sulfide and Carbon Dioxide	320	0	3,504,000	0	0	0

Factor 4: **It is not possible to compute the remaining service lifetimes of these sources since emission sources at industrial facilities are often refurbished. The remaining lifetimes of the SRUs and compressors are expected to be longer than 15 year figure which has been used to amortize the capital costs of add-on emission controls or equipment modifications to reduce emissions. If the remaining life of an emission source is less than the projected lifetime of a pollution control device, then the capital cost of the control device would have to be amortized over a shorter period of time, corresponding to the remaining lifetime of the emission source. This would cause an increase in the amortized capital cost of the pollution control option, and a corresponding increase in the total annual cost of control.**

Attachments:

Little Knife Plant SO2 Reduction Options

Option #1

Catalyst Replacement in Reactors

Replacement of catalyst in CBA reactor bed #1 and #2

This change would take efficiency levels from 88% to 90% and reduce hourly SO2 emissions by approximately 9 pounds per hour.

COST

$	29,481.40	Catalyst reactor #1
$	17,339.50	Catalyst reactor #2
$	25,000.00	Labor
$	20,000.00	Catalyst removal
$	1,000.00	Catalyst disposal 30 tons
$	750.00	Disposal transportation
$	3,360.00	Sulfur production lost
		Residue flared for complete conversion of H2S to SO2 in process flare =2.35 times acid gas to flare
$	2,021.00	430 x 2.35= 1010.5 MCF/D 1010.5 x $2.00= $2,021.00
$	12,600.00	Crane
$	111,551.90	Total

Time to complete

14 days	Shutdown unit, cool, disassemble, enter reactor, remove catalyst, replace catalyst, warmup unit, restart

ENVIRONMENTAL IMPACT

788	pounds of H2S to flare per hour
1100	MCF residue gas flared per day
1000	MCF residue gas burned to reheat unit for restart
9	pounds of SO2 less per hour 73 lb/hr @ 88.63% efficiency versus 64 lb/hr @ 90% efficiency
	9 x 8760 hrs. / 2000 lbs = 39.42 tons.

USEFUL LIFE OF EQUIPMENT

7-10 years	After this time efficiency will be back to 88% levels

2017 Average	Acid gas to CBA	Sulfur LT	So2 lb/hr
January	338	5.73	
February	354	6.32	
March	364	6.47	
April	352	6.56	
May	399	6.21	
June	449	7.31	
July	428	6.74	
August	408	6.45	
September	364	6.11	
October	338	5.53	
November	315	4.88	
December	329	4.94	
Average	370	6.1	73

73 x 8760 hrs. / 2000 lbs. = 319.74 tons

2018 Average	Acid gas to CBA	Sulfur LT	So2 lb/hr
January	328	4.95	
February	311	4.11	
March	305	4.08	
April	335	5.02	
May	332	5.39	
June	357	5.52	
July	341	5.66	
August	407	6.62	
September	417	6.54	
October	421	6.68	
November	395	6.14	
December	418	6.48	
Average	364	5.6	85

Option #2

Acid Gas Injection Well

AFE DATA - WORKSHEET

RIG TYPE - LAND
OBM TO CSG PT, SBM IN LAT

DRILLING

Lease............ Acid Gas Well
AFE NO
DATE

Location.......... SURFACE.......
BOTTOM HOLE.......

Section........
Township..........
Range.......
COUNTY
Field.............
Prospect Name...........
STATE ND
Type of Well.. OIL/GAS
Estimated Depth...
Horizontal Length
District Manager.................................. Tommy Moffett
Address 2101 Cedar Spring Rd. STE 600
DALLAS, TX 75201
Target......................
Cost Estimated By .... Scott Peacock

SUB	EXPENDITURES								
ACCT	DRY HOLE	COMPLETED	TOTAL						
259				CSG/TBG FEET		CASING:	COST / FT:		
	$4,000		$4,000	80		DRIVE PIPE:	$50.00	16" CONDUCTOR	Drilled in conductor
	$					CONDUCTOR:	$0.00		
	$50,400		50,400	2,000		SURFACE:	$25.20	9 5/8" 36# K-55	
	$					INTER. CSG:	$0.00		
	$					INTER. CSG:	$0.00		
		$240,000	240,000		8,000	PROD. LNR/CSG:	$30.00	7" L80	
		$				TIEBACK CSG:	$0.00		
259						TUBING:			
		$175,000	175,000		7,000	TUBING:	$25.00	2 7/8" chrome	
		$					$1.80	Sucker Rods	
259						OTHER EQUIPMENT:			
						LINER HANGER			
	10,000	20,000	30,000			WELLHEAD, CSG HANGER, TBG HANGER			
		10,000	10,000			PACKER, ANCHOR CATCHER, ROD PUMP			
						NON-CONTROLLABLE:			
260									
214						FACILITIES			
221						PIPELINE			
241									
240									
	$64,400	$445,000	$509,400	TOTAL EQUIPMENT					

Acid Gas Well

AFE DATA - WORKSHEET

01/00/00

TAX RATE:		**0**	**PERCENT (example: 7.5 % = 7.5; 8 % = 8)**
RIG RATES:		**1**	**TOP DRIVE = 1 ; NO TOP DRIVE = 0**
DRL	**$18,000**	**6**	**DAYS TO DRILL**
CMPL	**$18,000**	**3**	**DAYS TO COMPLETE**
CMPL	**$10,000**	**0**	**DAYS TO COMPLETE**

SUB	**EXPENDITURES**			**DATA FOR AFE PREPARATION - INTANGIBLES**	
ACCT	**DRY HOLE**	**COMPLETED**	**TOTAL**	**DRY HOLE COSTS**	**COMPLETION COSTS**
001			0		
002			0		
002	$108,000	$54,000	$162,000	Rig dayrate - Estimate,	Rig dayrate -
003		$0	0		Completion / P&A Contract-Day Work
004			0	Drill Pipe and Tubing Rental - $1600/DAY FOR 20 DAYS + $10K DAMAGES	Drill Pipe and Tubing Rental - $1600/DAY FOR 3 DAYS
009	18,000		18,000	Drive Conductor - EST. RATHOLE DRLR COST	
010	7,200	11,600	18,800	Labor - engineer estimated cost + $1000/day	Labor - $1000/Day - engineer estimated cost + $00/day gate guard
014	10,000	7,000	17,000	Transportation – includes trucking @ $500/day + $3500/string of casing.	Transportation – includes trucking @ $500/day + $3500 for csg/tbg.
019	572,000	150,000	722,000	Drilling Contract – Rig MI, RU, & RD	Drilling Contract – Rig MI, RU, & RD
020	33,000	8,300	41,300	**$2.75** = cost / gallon **2000** gal / day	**1000** gal / day Fuel - contractor furnished.
022	66,200	10,600	76,800	Water – $30000 + $200/day	Water – $10000+$200/day + plugging cost.
031	15,000		15,000	Bits, Mills & Reamers – estimated cost	Bits, Mills & Reamers – estimated cost
032	105,000	25,000	130,000	Drilling and Completion Fluids + Disposal –	Drilling and Completion Fluids + Disposal – cmpl fluid -engineer estimated costs.
034	8,000		8,000	Welding and Repairs – recent wellhead installations & bids.	
037	20,000	10,000	30,000	Tubular and Wellhead Inspection and Testing- Clean and Drift Casing, BHA Inspection	Tubular and Wellhead Inspection and Testing -Clean and Drift Casing
039	99,000	51,500	150,500	Rental Equipment – pumps $300/day, forklift $200/day, trailers & misc. $1500/day, gas buster $100/day	Rental Equipment – pumps $200/day, forklift $200/day, trailers & misc. $800/day, gas buster $00/day
				choke $150, PVT - $350, shock sub $30K, H2S monitor $150/day, frac tanks $00/day, premix tank $200/day	choke $150, PVT - $250, shock sub $10K, H2S monitor $150/day, frac tanks $250/day, premix tank $200/day
				lights $200, speed spool $250/day, rotating head & rubbers $350/day	centrifuge $00, lights $200, speed spool $0/day, rotating head & rubbers $350/day
				mud saver valve $100/day, run csg $30K, directional, Solids Control	mud saver valve $00/day, run csg $10K, test csg $5K
040	7,400		7,400	Mud Logging	Mud Logging
047	28,100		28,100	Insurance - $ 2.34/ft.	Insurance
049	200,000	50,000	250,000	Road Location Costs,Permitting, – estimated costs. Split	Road Location Costs, Permitting – $50k permatizing Split
058	2,000	1,500	3,500	Communication – R/U $900; $180/day.	Communication - $900 R/D, $180/day.
060	19,800	5,000	24,800	**2** # foremen Geological, Engineering, & Drilling Foreman (Well Site) -	**1** # foremen Geological, Eng.and Drilling Foreman (Well Site) -
063			0		
065	4,800	2,400	7,200	Supervision, District, Camp and Warehouse.	
070		20,000	20,000	Electric Logging, Sidewall Coring,Core Analysis –	Electric Logging, Sidewall Coring,Core Analysis – CBL
071			0	Coring & Core Analysis –	
072		15,000	15,000		Production Test -
074	20,000	55,000	75,000	Cement and Cementing Services – cement + flt equip. - cmt; for sqz & plugback; flt eq. & centralizers	Cement and Cementing Services – cement + flt equip. centralizers - engr est.
077			0		Stimulation and Sand Control - , Heat, Water, Tanks & misc.. estimated cost
078		25,000	25,000		Perforating – Plugs and Perfs
	134,400	50,200	184,600	**10** % Contingency	**10** % Contingency
	$1,477,900	**$552,100**	**$2,030,000**	**TOTAL INTANGIBLES**	
	$1,542,300	**$997,100**	**$2,539,400**	**TOTAL WELL COSTS**	
	$	**$**	**$**	**(LESS CONTRIBUTIONS)**	
	$1,542,300	**$997,100**	**$2,539,400**	**NET WELL COSTS**	

preliminary

PETRO-HUNT, L. L. C.

RIG TYPE - LAND

AUTHORIZATION FOR EXPENDITURE

OBM TO CSG PT, SBM IN LAT

DRILLING

Lease............ Acid Gas Well **AFE NO** **Date ....** 01/00/00

Location.......... SURFACE....... 0

BOTTOM HOLE....... 0

Section........ 0 **Township.............** 0 **Range.....** 0 **County................................** 0

Field.............. 0 **Prospect Name..................** 0 **State....................................** ND

Type of Well.. OIL/GAS **Estimated Depth................** 0 **Horizontal Length.................** 0

District Manager........................ Elvis Entzel **Address** 2101 Cedar Spring Rd. STE 600 **Target.....** 0

Cost Estimated By .... Scott Peacock DALLAS, TX 75201

TANGIBLE EQUIPMENT

EQUIPMENT/ QUANTITY		DESCRIPTION		SUB	EXPENDITURES		
DRY HOLE	PRODUCER			ACCT	DRY HOLE	COMPLETED	TOTAL
		Casing	**Cost/Ft**	**259**			
80		16" CONDUCTOR			4,000		4,000
					0		0
2,000		9 5/8" 36# K-55			50,400		50,400
					0		0
					0		0
	8,000	7" L80				240,000	240,000
						0	0
		Tubing		**259**			
	7,000	2 7/8" chrome				175,000	175,000
		Sucker Rods				0	0
		Other Equipment		**259**			
		LINER HANGER			0	0	0
		0			0	0	0
		WELLHEAD, CSG HANGER, TBG HANGER		**259**	10,000	20,000	30,000
		PACKER, ANCHOR CATCHER, ROD PUMP				10,000	10,000
		FACILITIES				0	0
		PIPELINE				0	0
		TOTAL EQUIPMENT			**$64,400**	**$445,000**	**$509,400**

INTANGIBLES									
Drilling Contract, Footage						**001**			
Drilling Contract, Day Work w/Topdrive			Days @		+ taxes	**002**			
Drilling Contract, Day Work	**6**	**3**	Days @	**$18,000**	+ taxes	**002**	108,000	54,000	162,000
Completion / P&A Contract-Day Work			Days @	**$10,000**	+ taxes	**003**	0	0	0
Drill Pipe and Tubing Rental						**004**	0	0	0
Drive Conductor						**009**	18,000	0	18,000
Labor						**010**	7,200	11,600	18,800
Transportation						**014**	10,000	7,000	17,000
Drilling Contract - Rig MI, RU, & RD						**019**	572,000	150,000	722,000
Fuel				**$2.75**	P/GAL	**020**	33,000	8,300	41,300
Water						**022**	66,200	10,600	76,800
Bits and Mills						**031**	15,000	0	15,000
Drilling and Completion Fluids + Disposal						**032**	105,000	25,000	130,000
Welding and Repairs						**034**	8,000	0	8,000
Tubular and Wellhead Inspection and Testing						**037**	20,000	10,000	30,000
Rental Equipment						**039**	99,000	51,500	150,500
Mud Logging						**040**	7,400	0	7,400
Insurance						**047**	28,100	0	28,100
Road and Location Costs, Permittin						**049**	200,000	50,000	250,000
Communication						**058**	2,000	1,500	3,500
Geological, Engineering, and Drilling Foreman (Well Site)						**060**	19,800	5,000	24,800
Miscellaneous						**063**	0	0	0
Supervision, District, Camp and Warehouse						**065**	4,800	2,400	7,200
Electrical Logging, Sidewall Coring, and Directional Surveys & VSP						**070**	0	20,000	20,000
Coreheads, Conventional Coring, and Core Analysis						**071**	0	0	0
Production Test						**072**	0	15,000	15,000
Cement and Cementing Services						**074**	20,000	55,000	75,000
Stimulation and Sand Control						**077**	0	0	0
Perforating						**078**	0	25,000	25,000
Contingency				**10**	**%**	**089**	134,400	50,200	184,600
			TOTAL INTANGIBLES				**$1,477,900**	**$552,100**	**$2,030,000**
APPROVED BY: ____________________			**TOTAL WELL COSTS ....**				**$1,542,300**	**$997,100**	**$2,539,400**
DATE: ____________________________			**(LESS CONTRIBUTIONS)**				**$0**	**$0**	**$0**
			NET WELL COSTS				**$1,542,300**	**$997,100**	**$2,539,400**

NON-OPERATOR

Approval of this AFE constitutes NON-OPERATOR'S approval of and commitment to pay all costs incurred in connection with the performance of the operations proposed herein and agreement to bear all risks and liabilities associated with such operations as to NON-OPERATOR'S interest as specified herein and as required by any applicable operating agreement. It is specifically recognized that the costs indicated in this AFE are estimates only and the actual costs may vary from the estimate.

APPROVED BY: DATE:

This AFE includes Operator's Extra Expense (Blowout) insurance which provides coverage during drilling and completion operations. If you do not desire to have Operator provide the coverage for you, please indicate so in the space below and enclose a copy of your Insurance Certificate outlining your coverage. NO RESPONSE shall result in a conclusive presumption of acceptance.

NOT APPROVED: DATE:

GEN. FORM 360 - REVISED 1/91

Afe Category Description	Code	Budget(USD)	Budget Supplement(USD)	
IDC - DRLG CONTRACT FOOT TURNK	118.807.001	$0		
IDC - DRLG CONTRACT DAY WORK	118.807.002	$108,000		
IDC - COMPLETION / P&A DAY WRK	118.807.003	$0		
IDC - DRILL PIPE & TUBING RENT	118.807.004	$0		
IDC - CAPITALIZED INTEREST	118.807.005	$0		
IDC - DRIVE CONDUCTOR	118.807.009	$18,000		
IDC - LABOR	118.807.010	$7,200		
IDC - TRANSPORTATION	118.807.014	$10,000		
IDC - OUTSIDE PROFESSIONAL SVC	118.807.016	$0		
IDC - RIG UP / DN MOVE IN /OUT	118.807.019	$572,000		
IDC - FUEL	118.807.020	$33,000		
IDC - WATER	118.807.022	$66,200		
IDC - INSURANCE	118.807.024	$0		
IDC - INITIAL LOCATION COSTS	118.807.025	$0		
IDC - BITS & MILLS	118.807.031	$15,000		
IDC - DRILLING & COMPL FLUID	118.807.032	$105,000		
IDC - WELDING & REPAIRS	118.807.034	$8,000		
IDC - TUBULAR / WELLHEAD TEST	118.807.037	$20,000		
IDC - RENTAL EQUIPMENT	118.807.039	$99,000		
IDC - MUD LOGGING	118.807.040	$7,400		
IDC - GEN LIABILITY / OEE INS	118.807.047	$28,100		
IDC - ROAD & LOCATION COSTS	118.807.049	$200,000		
IDC - COMMUNICATIONS	118.807.058	$2,000		
IDC - GEOL ENG DRLG FOREMAN	118.807.060	$19,800		
IDC - MISCELLANEOUS	118.807.063	$0		
IDC - SUPERVISION DST CAMP WHS	118.807.065	$4,800		
IDC - ADMINISTRATIVE OVERHEAD	118.807.066	$0		
IDC - ELECTRICAL LOGGING	118.807.070	$0		
IDC - CORING & CORE ANALYSIS	118.807.071	$0		
IDC - FORMATION TESTS	118.807.072	$0		
IDC - CEMENT & CEMENTING SERVI	118.807.074	$20,000		
IDC - STIMULATION & SAND CONTR	118.807.077	$0		
IDC - PERFORATING CASED HOLE	118.807.078	$0		
IDC - MEALS & ENTERTAIN 50%DED	118.807.087	$0		
IDC - CONTINGENCY	118.807.089	$134,400		
IDC - DRY HOLE CONTRIBUTIONS	118.807.092	$0		
IDC - ADMIN OVERHEAD COM FIX R	118.807.095	$0		
IDC - AUDIT ADJUSTMENTS	118.807.099	$0		
ICC - DRLG CONTRACT FOOT/TURNK	118.808.001	$0		
ICC - DRLG CONTRACT - DAY WORK	118.808.002	$54,000		
ICC - COMPLETION / P&A DAY WRK	118.808.003	$0		
ICC - DRILL PIPE & TUBING RENT	118.808.004	$0		
ICC - CAPITALIZED INTEREST	118.808.005	$0		
ICC - DRIVE CONDUCTOR	118.808.009	$0		
ICC - LABOR	118.808.010	$11,600		
ICC - TRANSPORTATION	118.808.014	$7,000		

ICC - OUTSIDE PROFESSIONAL SVC	118.808.016	$0		
ICC - RIG UP / DN MOVE IN /OUT	118.808.019	$150,000		
ICC - FUEL	118.808.020	$8,300		
ICC - WATER	118.808.022	$10,600		
ICC - INSURANCE	118.808.024	$0		
ICC - BITS AND MILLS	118.808.031	$0		
ICC - DRILLING & COMPL FLUID	118.808.032	$25,000		
ICC - WELDING & REPAIRS	118.808.034	$0		
ICC - TUBULAR / WELLHEAD TEST	118.808.037	$10,000		
ICC - RENTAL EQUIPMENT	118.808.039	$51,500		
ICC - MUD LOGGING	118.808.040	$0		
ICC - GEN LIABILITY / OEE INS	118.808.047	$0		
ICC - ROAD AND LOCATION	118.808.049	$50,000		
ICC - COMMUNICATIONS	118.808.058	$1,500		
ICC - GEOLOG ENGR DRLG FOREMAN	118.808.060	$5,000		
ICC - MISCELLANEOUS	118.808.063	$0		
ICC - SUPER DISTR CAMP & WHSE	118.808.065	$2,400		
ICC - ADMINISTRATIVE OVERHEAD	118.808.066	$0		
ICC - ELECTRICAL LOGGING	118.808.070	$20,000		
ICC - CORING & CORE ANALYSIS	118.808.071	$0		
ICC - FORMATION TESTS	118.808.072	$15,000		
ICC - CEMENT & CEMENTING SERVI	118.808.074	$55,000		
ICC - STIMULATION & SAND CONTR	118.808.077	$0		
ICC - PERFORATING CASED HOLE	118.808.078	$25,000		
ICC - MEALS & ENTERTAIN 50%DED	118.808.087	$0		
ICC - CONTINGENCY	118.808.089	$50,200		
ICC - DRY HOLE CONTRIBUTIONS	118.808.092	$0		
ICC - ADMIN OVERHEAD COM FIX R	118.808.095	$0		
ICC - AUDIT ADJUSTMENTS	118.808.099	$0		
TDC - EQUIP FROM CONVERSION	118.809.200	$0		
TDC - CONTROLLABLE EQUIPMENT	118.809.259	$64,400		
TDC - NON - CONTROLLABLE EQUIP	118.809.260	$0		
TDC - COST OF EQUIP SALVAGED	118.809.285	$0		
TDC - VALUATION ADJUSTMENT	118.809.289	$0		
TDC - CONTINGENCY	118.809.290	$0		
TDC - AUDIT ADJUSTMENTS	118.809.299	$0		
TDC - EXCISE TAX DIESEL FUEL	118.809.785	$0		
TCC - CONTROLLABLE EQUIPMENT	118.810.259	$445,000		
TCC - NON - CONTROLLABLE EQUIP	118.810.260	$0		
TCC - COST OF EQUIP SALVAGED	118.810.285	$0		
TCC - VALUATION ADJUSTMENT	118.810.289	$0		
TCC - CONTINGENCY	118.810.290	$0		
TCC - AUDIT ADJUSTMENTS	118.810.299	$0		
TCC - EXCISE TAX DIESEL FUEL	118.810.785	$0		
			$0	$2,539,400
	Data Check	All Good		
Sum total from above		$2,539,400		
Total from 'AFE' tab		$2,539,400		

Estimated Cost

Of

Control

Table 2

Estimated Capitol Cost:

Injection Well: $2,539,400.00

Acid Gas Compressor: $1,670,000.00

Compressor piping and associated equipment, installation and labor: $20,183.71

Total: $4,229,583.71

Estimated Annual Cost:

Maintaining the compressor with pistons, rods, rings, rider bands, packings, valves, oil etc. would be approximately $15,000.00 / year.

Electrical Cost: $128,385.00

Injection Well, Acid Gas Compressor, & Piping amortization cost over seven years: $4,229,583.71

Total Cost: $4,372,968.71 / 7 = $624,709.82

Cost Effectiveness $/ton:

$4,372,968.71 / 320 tons = $13,665.53

Table 3

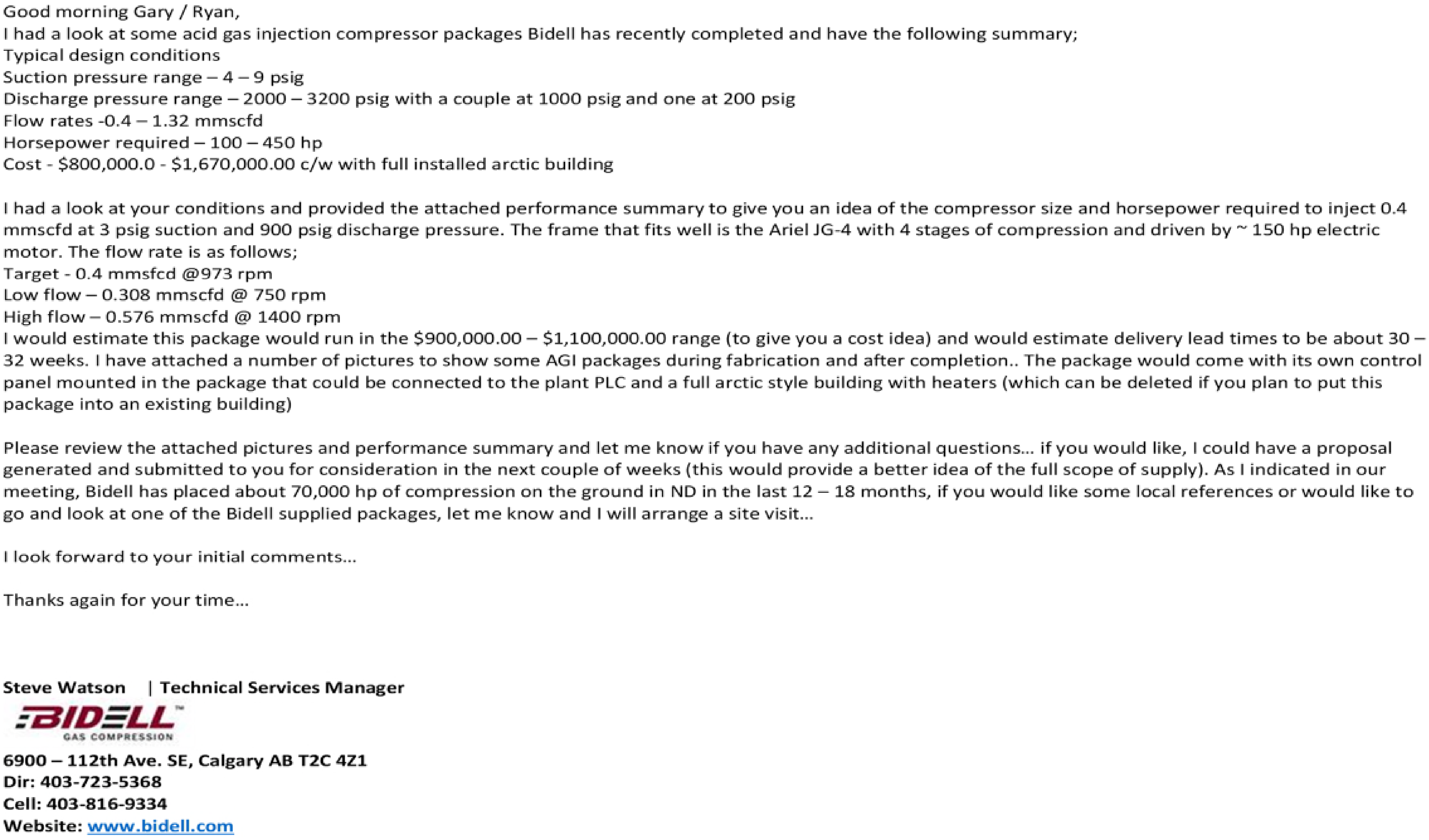
Electricity Required (kw-hr)

Operating a 2400-volt, 500 HP motor, drawing 107 amps, using 400 KWH cost $351.74 / day.

351.74 x 365 = $128,385.00 / year.

400 kwh x 8760 = 3,504,000

Acid Gas Compressor Cost



Good morning Gary / Ryan,
I had a look at some acid gas injection compressor packages Bidell has recently completed and have the following summary;
Typical design conditions
Suction pressure range – 4 – 9 psig
Discharge pressure range – 2000 – 3200 psig with a couple at 1000 psig and one at 200 psig
Flow rates -0.4 – 1.32 mmscfd
Horsepower required – 100 – 450 hp
Cost - $800,000.0 - $1,670,000.00 c/w with full installed arctic building

I had a look at your conditions and provided the attached performance summary to give you an idea of the compressor size and horsepower required to inject 0.4 mmscfd at 3 psig suction and 900 psig discharge pressure. The frame that fits well is the Ariel JG-4 with 4 stages of compression and driven by ~ 150 hp electric motor. The flow rate is as follows;
Target - 0.4 mmsfcd @973 rpm
Low flow – 0.308 mmscfd @ 750 rpm
High flow – 0.576 mmscfd @ 1400 rpm
I would estimate this package would run in the $900,000.00 – $1,100,000.00 range (to give you a cost idea) and would estimate delivery lead times to be about 30 – 32 weeks. I have attached a number of pictures to show some AGI packages during fabrication and after completion.. The package would come with its own control panel mounted in the package that could be connected to the plant PLC and a full arctic style building with heaters (which can be deleted if you plan to put this package into an existing building)

Please review the attached pictures and performance summary and let me know if you have any additional questions… if you would like, I could have a proposal generated and submitted to you for consideration in the next couple of weeks (this would provide a better idea of the full scope of supply). As I indicated in our meeting, Bidell has placed about 70,000 hp of compression on the ground in ND in the last 12 – 18 months, if you would like some local references or would like to go and look at one of the Bidell supplied packages, let me know and I will arrange a site visit…

I look forward to your initial comments…

Thanks again for your time…

Steve Watson | **Technical Services Manager**
BIDELL
GAS COMPRESSION
6900 – 112th Ave. SE, Calgary AB T2C 4Z1
Dir: 403-723-5368
Cell: 403-816-9334
Website: www.bidell.com

Ariel Performance

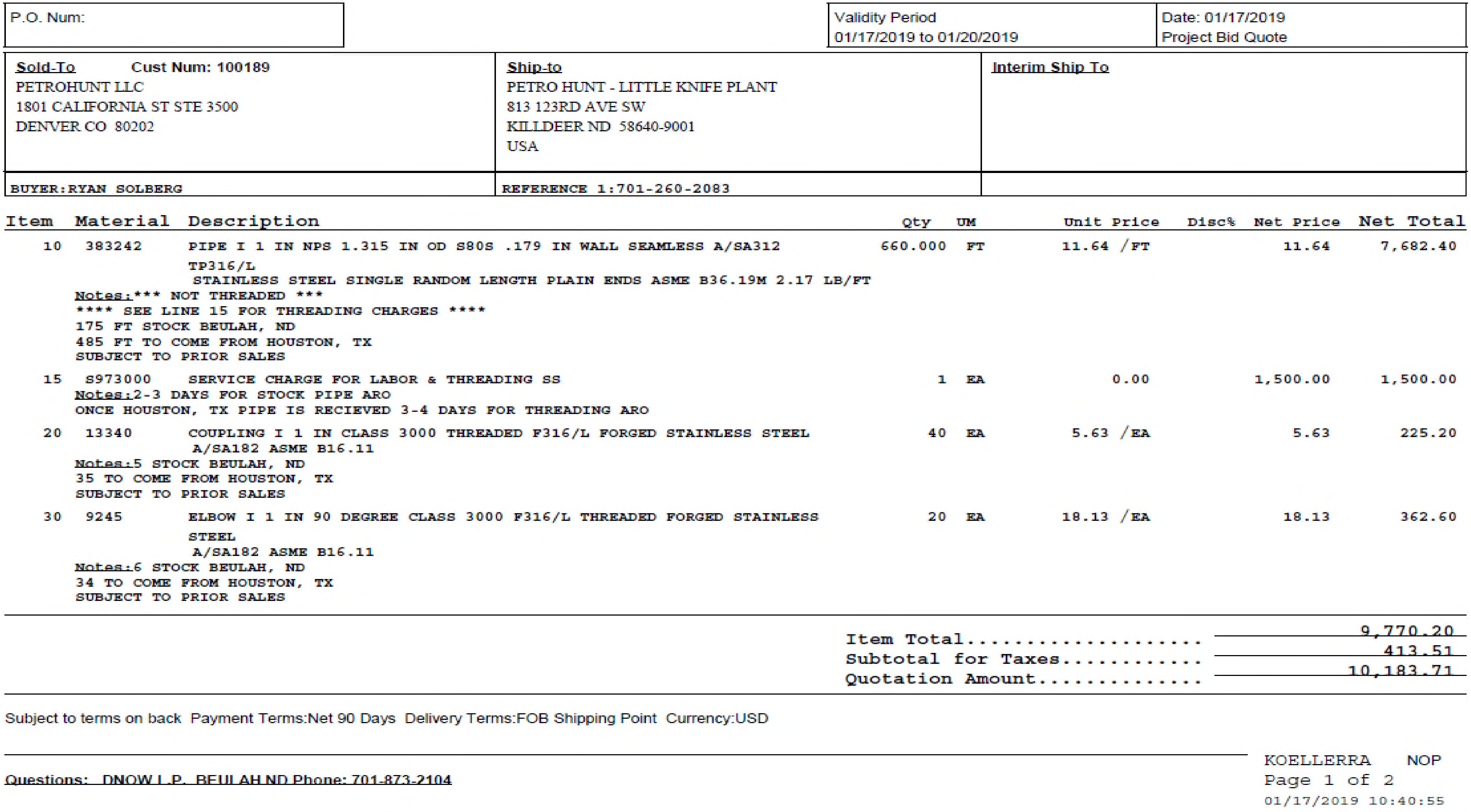
	Company:	Bidell Gas Compression	Customer:	Petro Hunt
	Quote:		Inquiry:	
7.7.6.0	Case 3:		Project:	Acid Gas Injection

Compressor Data:						**Driver Data:**	
Elevation,ft:	2600.00	Barmtr,psia:	13.350	Ambient,F:	100.00	Type:	Unselected
Frame:	JG/4	Stroke, in:	3.50	Rod Dia, in:	1.125	Mfg:	
Max RL Tot, lbf:	18000	Max RL Tens, lbf:	9000	Max RL Comp, lbf:	10000	Model:	
Rated RPM:	1500	Rated BHP:	504.0	Rated PS FPM:	875.0	BHP:	0
Calc RPM:	1400.0	BHP:	154	Calc PS FPM:	816.7	Avail:	0

SOUR GAS-2

Services	**Service 1**			
Gas Model	VMG-APRNGL2			
Stage Data:	**1**	**2**	**3**	**4**
Target Flow, MMSCFD	0.450	0.450	0.450	0.450
Flow Calc, MMSCFD	0.574	0.574	0.568	0.565
BHP per Stage	46.9	39.3	26.5	35.9
Specific Gravity	1.2696	1.2696	1.2763	1.2797
Ratio of Sp Ht (N)	1.3009	1.3001	1.3156	1.3315
Comp Suct (Zs)	0.9924	0.9800	0.9426	0.8832
Comp Disch (Zd)	0.9884	0.9718	0.9292	0.8521
Pres Suct Line, psig	3.00	N/A	N/A	N/A
Pres Suct Flg, psig	2.84	40.71	140.12	289.23
Pres Disch Flg, psig	42.05	143.77	295.89	910.00
Pres Disch Line, psig	N/A	N/A	N/A	900.00
Pres Ratio F/F	3.422	2.906	2.015	3.052
Temp Suct, F	70.00	120.00	120.00	120.00
Temp Clr Disch, F	120.00	120.00	120.00	120.00
Cylinder Data:	**Throw 1**	**Throw 2**	**Throw 4**	**Throw 3**
Cyl Model	11JG	6-1/2JG	3-5/8JG	3JG
Cyl Bore, in	11.000	6.125	3.375	2.750
Cyl RDP (API), psig	125.0	577.3	1154.5	2318.2
Cyl MAWP, psig	150.0	635.0	1270.0	2550.0
Cyl Action	DBL	DBL	DBL	DBL
Cyl Disp, CFM	536.1	164.3	47.9	30.9
Pres Suct Intl, psig	0.93	37.79	127.95	276.29
Temp Suct Intl, F	79	126	124	125
Pres Disch Intl, psig	47.78	151.15	319.81	944.79
Temp Disch Intl, F	295	307	257	329
HE Suct Gas Vel, FPM	7943	5648	6934	5069
HE Disch Gas Vel, FPM	7331	4997	6283	4522
HE Spcrs Used/Max	0/4	0/4	0/1	0/1
HE Vol Pkt Avail	1.50+51.93	1.40+56.40	1.15+48.99	0.62+33.05
Vol Pkt Used	0.00 (V) %	0.00 (V) %	0.00 (V) %	0.00 (V) %
HE Min Clr, %	14.61	15.63	14.95	20.24
HE Total Clr, %	16.11	17.03	16.09	20.86
CE Suct Gas Vel, FPM	7860	5457	6164	4220
CE Disch Gas Vel, FPM	7255	4829	5585	3765
CE Spcrs Used/Max	0/4	0/4	0/1	0/1
CE Min Clr, %	14.87	16.65	18.95	26.61
CE Total Clr, %	14.87	16.65	18.95	26.61
Suct Vol Eff HE/CE, %	67.3/69.2	71.8/72.3	83.8/81.8	64.4/56.5
Disch Event HE/CE, ms	6.8/8.1	7.5/8.9	9.9/11.2	7.0/7.7
Suct Pseudo-Q HE/CE	13.2/12.9	4.8/4.5	9.1/7.2	4.9/3.4
Gas Rod Ld Comp, %	44.6 C	33.8 C	18.6 C	42.7 C
Gas Rod Ld Tens, %	48.9 T	35.4 T	15.4 T	33.5 T
Gas Rod Ld Total, %	49.2	36.5	18.0	40.5
Xhd Pin Deg/%Rvrsl lbf	164/100.0	173/96.8	164/84.3	179/54.0
Flow Calc, MMSCFD	0.574	0.574	0.568	0.565
Cyl BHP	46.9	39.3	26.5	35.9

Acid Gas Discharge Piping and Components



P.O. Num:

Validity Period
01/17/2019 to 01/20/2019

Date: 01/17/2019
Project Bid Quote

Sold-To **Cust Num: 100189**
PETROHUNT LLC
1801 CALIFORNIA ST STE 3500
DENVER CO 80202

Ship-to
PETRO HUNT - LITTLE KNIFE PLANT
813 123RD AVE SW
KILLDEER ND 58640-9001
USA

Interim Ship To

BUYER:RYAN SOLBERG

REFERENCE 1:701-260-2083

Item	Material	Description	Qty	UM	Unit Price	Disc%	Net Price	Net Total
10	383242	PIPE I 1 IN NPS 1.315 IN OD S80S .179 IN WALL SEAMLESS A/SA312 TP316/L STAINLESS STEEL SINGLE RANDOM LENGTH PLAIN ENDS ASME B36.19M 2.17 LB/FT Notes:*** NOT THREADED *** **** SEE LINE 15 FOR THREADING CHARGES **** 175 FT STOCK BEULAH, ND 485 FT TO COME FROM HOUSTON, TX SUBJECT TO PRIOR SALES	660.000	FT	11.64 /FT		11.64	7,682.40
15	S973000	SERVICE CHARGE FOR LABOR & THREADING SS Notes:2-3 DAYS FOR STOCK PIPE ARO ONCE HOUSTON, TX PIPE IS RECIEVED 3-4 DAYS FOR THREADING ARO	1	EA	0.00		1,500.00	1,500.00
20	13340	COUPLING I 1 IN CLASS 3000 THREADED F316/L FORGED STAINLESS STEEL A/SA182 ASME B16.11 Notes:5 STOCK BEULAH, ND 35 TO COME FROM HOUSTON, TX SUBJECT TO PRIOR SALES	40	EA	5.63 /EA		5.63	225.20
30	9245	ELBOW I 1 IN 90 DEGREE CLASS 3000 F316/L THREADED FORGED STAINLESS STEEL A/SA182 ASME B16.11 Notes:6 STOCK BEULAH, ND 34 TO COME FROM HOUSTON, TX SUBJECT TO PRIOR SALES	20	EA	18.13 /EA		18.13	362.60

Item Total....................	9,770.20
Subtotal for Taxes............	413.51
Quotation Amount..............	10,183.71

Subject to terms on back Payment Terms:Net 90 Days Delivery Terms:FOB Shipping Point Currency:USD

Questions: DNOW L.P. BEULAH ND Phone: 701-873-2104

KOELLERRA NOP
Page 1 of 2
01/17/2019 10:40:55

B.7.c – Communications

PETRO-HUNT, LLC
LITTLE KNIFE PLANT
813 123RD AVE.SW
KILLDEER, ND 58640

November 29, 2018

Mr. Terry O'Clair, Director
North Dakota Department of Health
Environmental Health Section
Gold Seal Center, 918 E. Divide Ave.
Bismarck, North Dakota 58501-1947

RE: Reginal Haze
Second Planning Period

Dear Mr. O'Clair

Attached is the response to the letter referencing the Reginal Haze.

If you have any questions, or need additional information, please contact me at 701-863-6500.

Sincerely,

PETRO-HUNT, LLC

Gary Kohler
Plant Manager
Little Knife Gas Plant

Cc: Royce Kennedy / with attachments
Derek Enderud / with attachments

PETRO-HUNT, LLC
LITTLE KNIFE PLANT
813 123RD AVE.SW
KILLDEER, ND 58640

Mr. Terry O'Clair

RE: Regional Haze
Second Planning Period

This letter is regarding the second period State Implementation Plan (SIP) for regional haze. In the past forty years the Little Knife Gas Plant has always strived to achieve the very best it can to minimize emission sources and increase the national visibility utilizing the Best Available Retrofit Technology (BART) as well as making reasonable progress through ongoing process analysis.

The reports sent to the State of North Dakota Health Department are not only a requirement but an indication of our efforts to reduce emissions and improve air quality. Reports are sent on an Annual, Semi-annual and Quarterly basis documenting our emission sources, the quantity of pollutants and reliability of our emission monitoring equipment.

Though the Little Knife Plant emits a significant amount of SO_2 our records show the sulfur plant operates at 32.3% below the established hourly threshold set by the State with a recovery rate between 92 -94%. In addition to monitoring sulfur dioxide, we also monitor for GHG and VOC detection.

With the discovery of the Bakken formation, our inlet gas to the amine sweetening unit containing Hydrogen Sulfide has reduced significantly, therefore a significant reduction in sulfur dioxide. There has never been an exceedance in our process flare and only five one-hour exceedances from the incinerator on the Sulfur Plant in the past ten years.

Petro Hunt will continue to communicate with the appropriate agencies, as well as continue making reasonable progress to improve air quality. If the volume of Hydrogen Sulfide continues to decline, Petro Hunt will research the possibility of Acid Gas injection.

We are aware of the Plant's location to the Theodore Roosevelt National Park. It has always been our goal to continually improve operations to minimize the amount of sulfur dioxide, nitrous oxides, particulates, and organic compounds along with any other source of emissions to protect the environment and improve visibility impairment.

Sincerely,
Gary Kohler

NORTH DAKOTA
DEPARTMENT of HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

FILE

December 5, 2018

Mr. Gary Kohler
Plant Manager
Petro-Hunt, LLC
813 - 123rd Avenue SW
Killdeer, ND 58640

Re: Regional Haze
Second Planning Period

Dear Mr. Kohler:

We have reviewed your November 29, 2018 email response to the Department's request for a four factors analysis for the Little Knife Gas Plant. Your response did not provide the requested analysis and does not adequately address the requirements of the Regional Haze Program. An appropriate analysis must address options for reducing sulfur dioxide at the plant including acid gas injection. The analysis must provide a cost analysis of the various options, the time necessary to achieve the reductions, the energy and non-air quality environmental impacts of the options and you may consider the remaining useful life of the equipment. The required analysis is very technical and may require Petro-Hunt, LLC to retain the services of an engineering consultant. Based on your analysis and our own, the Department will require appropriate actions to aid in achieving reasonable progress toward the national visibility goal.

Under NDCC 23-25, the Department has the authority to require this analysis. We suggest a meeting be arranged between Petro-Hunt and the Department to discuss the analysis. If you have a consultant, they are free to attend the meeting. We will be in contact you to set up this meeting.

If you have any questions, please feel free to contact David Stroh of my staff at (701) 328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair
Director
Division of Air Quality

TLO/TB:saj
xc: Maggie Olson, Asst. Attorney General

B.8 – Hess Tioga Gas Plant

B.8.a – Department Request

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

FILE

May 18, 2018

Mr. Tony St. Clair
Hess Corporation
1501 McKinney Street
Office 11.012B
Houston, TX 77010

Re: Regional Haze
Second Planning Period

Dear Mr. St. Clair:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

The Tioga Gas Plant has been identified as a significant source of both SO_2 and NO_X. Therefore, the Department requests that you prepare a "four factors" analysis for the Tioga Gas Plant. The analysis should be prepared using the draft EPA guidance noted above. The following units should be addressed in the analysis:

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
Division of Municipal Facilities 701.328.5211
Division of Waste Management 701.328.5166
Division of Water Quality 701.328.5210

1. Amine Gas Sweeting Unit (Emission Unit S302)
2. Clark Compressor Engines (Emission Units C1A – C1G)
3. Flares (Emission Units S101 and S102)

Preparation of the Round 2 Regional Haze SIP will require extensive planning and review of emission sources in North Dakota. The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the SIP. WRAP will be conducting air quality modeling of potential regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely.

Terry O'Clair

Terry L. O'Clair
Director
Division of Air Quality

TLO/TB:saj

B.8.b – Facility Response

HESS CORPORATION
1501 McKinney Street
Houston, TX 77010

December 20, 2018

Mr. Terry L. O'Clair, P.E.
Director, Division of Air Quality
North Dakota Department of Health
918 East Divide Avenue, 2nd Floor
Bismarck, North Dakota 58501-1947

Re: REGIONAL HAZE
SECOND PLANNING PERIOD
TIOGA GAS PLANT

Dear Mr. O'Clair:

As requested in your letter to me dated May 18, 2018 concerning the referenced subject matter, please find enclosed the "Four Factors Analysis" report as it pertains to emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx) at the Hess Tioga Gas Plant, located in Tioga, North Dakota.

The report was developed with consideration of the four factors in Section 169A(g)(1) of the Clean Air Act, using specific guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period).

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

As requested, the following units at the Tioga Gas Plant were addressed due to their significant potential emissions of SO2 and NOx (precursors to sulfates that may lead to visibility impairment):

1. Amine Gas Sweeting Unit (Emission Unit S-302)
2. Clark Compressor Engines (Emission Units C1A – C1G)
3. Flares (Emission Units S-101 and S-102)

If you should have any questions regarding this information, please contact me at (713) 496-5031.

Sincerely,

Tony StClair

Tony R. St. Clair
EHS Advisor

Enclosures

cc: D. Schmidt
D. Morton
V. Sund
A. Lindsey
(route) Tioga Plant Files
Houston Environmental Files, Tioga Plant, Air

Regional Haze
4-Factor Analysis

Tioga Gas Plant Facility
Hess Corporation

Prepared for:

North Dakota Department of Health
Environmental Health Section
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947

Prepared by:
Bison Engineering Inc.
1400 11th Ave.
Helena, MT 59601

Prepared on behalf of:

Hess Corporation
1501 McKinney Street
Office 21.104
Houston, Texas 77010

December 20, 2018

EXECUTIVE SUMMARY

Bison Engineering, Inc. was retained by Hess Corporation to prepare a 4-Factor analysis for specific units located at their Tioga Gas Plant located at Tioga, ND. The 4-Factor analysis was requested by North Dakota's Environmental Health Section, Division of Air Quality in a letter dated May 18, 2018.

The analysis itself relates to "Round 2" of development of a State Implementation Plan (SIP) to address Regional Haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308. The purpose of the 4-Factor analysis is, to determine if there are control options at Hess to reduce emissions, that could be used to attain "reasonable progress" toward the state's visibility goals.

The 4-Factor analysis was conducted on three source groups at the Hess facility: amine sweetening unit, compressor engines and flares. The results of the analysis have indicated that additional controls on these units are not necessary to make reasonable progress due to costs and other considerations. It is concluded that these sources do not qualify for additional emission controls or limitations based on the 4-Factor analysis.

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1.0 INTRODUCTION

With the 1977 amendments to the Federal Clean Air Act (42 USC 7401 *et. seq.*) Congress declared as a national goal "… *the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution."* [42 USC 7491(a)(1)]. That goal, plans and requirements were eventually codified in the Code of Federal Regulations primarily in 40 CFR 51.308. (The entire visibility program is found in 40 CFR 51.300 → 309). Individual states are required to establish "reasonable progress goals" [40 CFR 51.308(d)(1)] in order to "attain natural visibility conditions" by the year 2064 [§308(d)(1)(i)(B)].

The state of North Dakota has met the first round of those obligations with the establishment of Best Available Retrofit Technologies (BART) for various sources. A second round of obligations is now under development. The Regional Haze Rule (RHR) requires an additional step toward 'reasonable progress' in meeting the national goal.[1] The RHR identifies four factors which should be considered in evaluating potential emission control measures to make reasonable progress toward the visibility goal. These are as follows:

Factor 1. Cost of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance
Factor 4. Remaining useful life of any existing source subject to such requirements

These four factors are collectively known as the 4-Factor analysis.

To implement the requirement, the North Dakota Department of Health (NDDH) submitted a letter to Hess dated May 18, 2018. The letter noted that NDDH needed to address 80% of the visibility impairment caused by ND sources.[2] According to NDDH, visibility data from the IMPROVE ambient monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Areas indicate that sulfates and nitrates (via SO_2 and NOx; respectively) are the largest contributors to visibility impairment.[3]

In order to determine which 'nearby' sources should be subject to a 4-Factor analysis, NDDH conducted a Q/d (emissions/distance) analysis of SO_2 and NOx for industrial

---

[1] The national goal is to attain natural visibility conditions in mandatory Class I areas by the year 2064 [40 CFR 51.308(d)(1)(i)(B)].

[2] According to NDDH this value is derived from information contained in EPA's Draft Guidance on Progress Tracking Metrics, Long Term Strategies found at: *https://www.epa.gov/sites/production/files/2016-07/documents/draft regional haze guidance July 2016.pdf.*

[3] Hess does not necessarily agree or disagree with this assessment at this time. Hess is providing the information in this document as requested by NDDH.

sources within the state. That analysis has indicated that there are three Hess sources (or source groups) that warrant the analysis according to NDDH. These sources are:

1. Amine Gas Sweeting Unit (Emission Unit S302)
2. Clark Compressor Engines (Emission Units ClA- ClG)
3. Flares (Emission Units S101 and S102)

Therefore, NDDH has requested HESS conduct at 4-Factor analysis for these units to assess potential reductions in SO_2 and NOx emissions. The May 18 letter requested the analysis be completed no later than January 31, 2019.

Although NDDH requested an analysis of both SO_2 and NOx for all three source groups, subsequent analysis prompted a small change to the request. Based on correspondence between Hess and NDDH[4], it was agreed no robust analysis was necessary for SO_2 for the Clark Compressor Engines. Since these engines are fired with pipeline quality natural gas, there are no substantive SO_2 emissions from this source category. A similar conclusion was reached with respect to NOx emissions from the Amine Gas Sweetening unit. At the time of the email correspondence it was believed that NOx emissions from these units are low, so there would be no real visibility benefit by attempting to add additional NOx controls. However, subsequent review found a published emission factor for these units. The published factor indicated a low emission rate, as suspected. However, since an emission rate was available, it was decided to proceed with an analysis even though the reduction in NOx, should additional controls be added, would not yield any measurable improvement in visibility.

Based on the discussion above and agreement with NDDH[5], no formal SO_2 analysis was conducted for the compressor engines. For completeness, an NOx review was conducted for the Amine Sweetening Unit albeit with low actual emission rates.

The remainder of this document outlines the approach used to conduct the 4-Factor analyses along with a detailed analysis for each group.

---

[4] Email to David Stroh from Tony St Clair (9/14/18) and associated reply (9/17/18)

[5] Ibid.

2.0 APPPROACH AND METHODOLOGY

The Tioga Gas Plant, the subject of this 4-Factor analysis, is located at 10340 68th Street NW in Tioga, North Dakota. The location is W½, NE¼ S26, T157N, R95W in Williams County. The plant is used to process natural gas from well sites for sale to customers.

The May 18, 2018 letter from NDDH provided some recommendations for conducting the 4-Factor analysis. That information was supplemented based on an email from David Stroh (NDDH) to Tony St. Clair (Hess) which provided further discussion and recommendations (June 2018). The matter was again discussed in a phone conference call between the staff of NDDH, Hess, and Bison Engineering on June 20.

The most complicated or in-depth analysis of the four is Factor #1: Cost of Compliance. The NDDH email and phone conversation suggested this analysis should follow, in general terms, the methods conducted for a Best Available Control Technology (BACT) review. The agency made clear that this is not, in and of itself, a pure BACT analysis; only that the typical steps might be followed.

In addition to the direct contact with NDDH described above, EPA has provided draft guidance (EPA Draft Guidance) of its own for the entire Round 2 procedures including suggested methods for assessing the Cost of Compliance as well as the other 3 factors.[6] That guidance was published in July 2016 as a draft. We are not aware that the Draft Guidance has been finalized. Nonetheless, since this was the most up-to-date EPA guidelines available, that document was consulted for conducting this 4-Factor analysis.

In general, the cost analysis uses the general approach for BACT, but is modified by the EPA Draft Guidance[7] and EPA's Control Cost manual[8]. The approach used in this analysis follows these recommendations and guidelines as much as practicable. The other 3 factors employed suggestions from the EPA Draft Guidance as much as reasonable or available data might have allowed.

---

[6] "*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,*" EPA, EPA-457/P-16-001, July 2016. https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf

[7] Ibid.

[8] EPA Cost Control Manual (sixth edition): https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

3.0 4-FACTOR ANALYSIS

A 4-Factor analysis was completed for the three Hess sources/source groups selected by the NDDH Q/d analysis. The following outlines the analysis for each source using primarily the direction of the EPA Draft Guidance[9] and the WRAP 2009 4-Factor analysis[10].

The initial step in the 4-Factor analyses was to identify possible additional control options for each source or source group. The options chosen include control techniques addressed in guidelines published by the EPA, emission control cost models such as AirControlNET, Best Available Retrofit Technology (BART) analyses, White Papers prepared by the Midwest Regional Planning Organization (MRPO), and National Association of Clean Air Agencies (NACAA).

The options for each source/source category are summarized in the Table 1.

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[9] "*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,*" EPA, EPA-457/P-16-001, July 2016. https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf

[10] "*Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota",* Brad Nelson, William Battye, Janet Hou, EC/R Incorporated, Western Regional Air Partnership (WRAP) and Western Governors' Association (WGA), May 18, 2009

Table 1: Additional Control Options by Source Group

Source	Emission Unit ID	Pollutant	Existing Controls	Control Efficiency (Existing)	Potential Additional Control Measures
Amine Gas Sweeting Unit (Sulfur Recovery Unit)	S302	SO_2	2-Stage Claus + CBA (cold bed adsorption) + tail gas incinerator	$>98^{+}\%$	Tail-Gas Scrubbing Treatment Unit (Oxidation or Reduction Options)
					Traditional Flue Gas Desulfurization (FGD)
		NO_2		---	SCR
Clark Compressor Engines (Natural gas pipeline compressor engines)	C1A through C1G	NO_2	Lean Burn Engines	---	Low Emission Combustion (LEC) - Turbocharge - Air-to-fuel - Ignition timing - Etc.
					SCR
					Electric Motor Replacement
Acid/Wet Gas Flare And High Pressure Flare	S101 and S102	SO_2 NO_2	None	---	None

Amine Gas Sweeting Unit (SO_2)

The amine gas sweeting unit at the Hess Tioga Gas Plant facility controls sulfur dioxide (SO_2) emissions via two steps. The first is a 2-stage Claus process. This process converts hydrogen sulfide (H_2S) and SO_2 into elemental sulfur (S) via the 'Claus' reaction. The general reaction is: $H_2S + SO_2 \leftrightarrow S + H_2O$ (unbalanced). To drive the reaction toward completion, the facility further utilizes Cold Bed Adsorption (CBA) which allows this reversible reaction to proceed further. The CBA was installed in 1991. All-in-all the unit collectively reduces SO_2 emissions by 98^+%.

Tail-Gas Scrubbing Treatment

The most common control measures that may be applied to a typical refinery-based Claus facility (with or without CBA) are generally categorized as Tail-Gas Scrubbing Treatment unit (TGST). These units use either an oxidation or a reduction measure to continue to convert the underlying sulfur gas to elemental sulfur. The other common measure of removing sulfur dioxide from a gas stream is a traditional Flue Gas Desulfurization (FGD) unit that is more typically used at coal or oil-fired electrical generating units.

The TGST control would add an additional scrubbing process to the Claus exhaust stream prior to the tail-gas incinerator. The processes typically convert the Claus exhaust to either H_2S (reducing process) or SO_2 (oxidizing process). In either case, the 'newly created' H_2S or SO_2 is then returned in some fashion to the Claus or CBA portion of the facility to extend the elemental sulfur recovery.

There are a number of processes that achieve this aim. Regarding the oxidation method, the exhaust stream from the CBA would oxidize the various sulfur compounds (S, H_2S, COS …) to sulfur dioxide. The sulfur dioxide is then concentrated and used in the Claus/CBA process itself. There are several varieties of processes within the oxidation method. They include the Stauffer, Wellman-Lord and Aquaclaus. Only the Wellman-Lord process has been applied successfully in any US refinery.[11]

The reduction process, however, is the more typical refinery-based method of additional sulfur dioxide control. This process converts the sulfur gases from the Claus (or CBA) to H_2S. The H_2S is then sent to a scrubber for removal prior to a tail-gas incinerator. The H_2S scrubber typically uses an amine process (similar to the amine unit itself) to capture the H_2S and then recycles this captured H_2S (now in a concentrated stream) back to the Claus plant.

Four common systems utilizing the reduction control method are the Beavon, Beavon MDEA, Shell Claus Off-gas Treatment (SCOT), and ARCO. The most common among these is the SCOT unit.

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[11] AP-42, Section 8.13, 1995, p 8.13-4.

There are other units designed for refinery-like facilities to remove additional sulfur from the CBA stream. These include the Superclaus[12], Euroclaus[13] and others. For purposes of this analysis, however, it was decided not to attempt a specific cost analysis for each process. It was reasonable to pick one of the methods described above and conduct an analysis on that process.[14] It seems more than reasonable to presume that the cost of one of these processes is within range of what might be expected for any single process. Additionally, cost estimates for these processes is not readily available. For example, there is no published data for the Superclaus or Euroclaus. Additionally, cost data is very sketchy for many of the other units as well.

It was decided to use the SCOT process as a surrogate for any and all of the TGST discussed above. While there is not a plethora of cost data for this unit, it has the most, albeit limited, available data. In addition, the removal efficiency among all the units, including the SCOT, are similar. They all range in overall sulfur removal from about 98% to $99\%^{+}$. Should the results of the SCOT (as a representative of TGST) prove favorable, then a more detailed review of some of the options would have been useful.

The SCOT system consists of a reduction process and an alkanol amine absorption process. The process starts by converting (reducing) sulfur compounds to H_2S via a catalyst, heat, and reducing agent (H_2, CO, …). The captured H_2S is sent back to the Claus feed. The remaining gas is sent to the tail-gas incinerator.

Flue Gas Desulfurization (FGD)

The second class of sulfur dioxide scrubbing for consideration is the traditional Flue Gas Desulfurization (FGD) unit. As noted earlier, this is the typical sulfur dioxide control system found in most coal and oil-fired electrical generation systems across the U.S. The FGD unit may be configured as a wet, semi-dry, or dry scrubber system. In all cases an alkaline compound (typically $CaCO_3$ or CaO) is used to react with SO_2 (an acidic gas) to form a compound such as $CaSO_3$. The $CaSO_3$ (and its related compounds) are then removed via a particulate control device such as a baghouse. EPA estimates FGD units' reduction emissions in the range of 50% to 98% where typically wet scrubbers achieve the highest control potential.[15]

While this may seem attractive, the FGD scrubbers have significant *a priori* disadvantages for this application. Among them include:

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[12] Information regarding the Superclaus may be found here: http://www.digitalrefining.com/literature/1000817,Sulphur_Recovery_SUPERCLAUS___Process.html#.W-TGFPZFzDI

[13] Information regarding the Euroclaus may be found here. http://www.digitalrefining.com/literature/1000580,Sulfur_recovery___EUROCLAUS___process.html#.W-TFnfZFzDI

[14] This approach is discussed in the EPA Guidance. (See footnote 9).

[15] EPA Air Pollution Control Technology Fact Sheet – Flue Gas Desulfurization: https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf *

(a) In order to operate an FGD system, it is necessary to have a significant amount of (solid) material handling equipment on site. This would also include a large surface area to store, move and otherwise handle the reagent and spent-reagent material. This equipment and space might typically be available and designed in an FGD installation such as a coal-fired electrical generation station which handles materials (coal, e.g.) on routine basis. For this gas processing facility, however, none of the required space nor handling equipment is readily available. This would require a significant redesign of the facility in both layout and surface disturbance.

(b) FGD systems require a particulate control device to remove the alkaline scrubbing agent ($CaCO_3$, $Ca(OH)_2$, CaO, …). In a typical power plant facility, a control device to remove particulate would be required regardless of the SO_2 scrubber. For this application, however, no such device is installed nor necessary as particulate emissions from amine sweetening units (with Claus sulfur recovery) is nearly non-existent.

Thus, in order to install and operate an FGD for this facility, not only is an FGD itself necessary, but a complete particulate removal system will be required as well (typically a fabric filter). Thus, the FGD will add a new particulate emissions source at this facility; offsetting some of the reduction achieved by the sulfur-removing FGD system.

(c) An FGD system, regardless of the type, will require disposal of the spent reagent. Since space is limited at this site, the disposal will most likely take place at a “new” landfill. Thus, in addition to the cost necessary for the FGD, a suitable landfill site would need to be identified and a permit would need to be obtained. This would be a significant undertaking and not especially productive given other non-FGD processes are available.

(d) The non-FGD processes described earlier are more efficient at reducing sulfur compounds from entering the atmosphere than FGD. The control efficiencies for FGD would likely peak at about 80 to 90% (due to low concentration streams). Non-FGD units are expected to be significantly better.

(e) For wet scrubber FGD, a complete water system, including disposal, would be required. This is clearly unnecessary given other alternatives and the potential environmental consequences.

(f) To our knowledge, no FGD system has been installed at any gas processing facility such as the Tioga plant. This fact makes it clear that an FGD system is not a viable option for consideration.

(g) Finally, it is noted that the WRAP 2009 4-Factor analysis did not itself address nor consider FGD as an available technology. There was no discussion or cost estimates for this control technology.

For all of the reasons above, it was decided to not pursue the FGD option further and it was dropped from analyses that follow.

Amine Gas Sweeting Unit (NOx)

The amine gas sweeting unit at the Hess Tioga Gas Plant facility contains no NOx post-control technologies. NOx emissions from these units are typically very small, negating the need for post controls. Hess had suggested to NDDH that it was not necessary to conduct a 4-Factor analysis for this pollutant/unit. It was later discovered that a published emission factor was available for this unit.[16] Despite a low emission rate for this unit (≈ 50 tons/year) an NOx analysis proceeded.

A review of the literature indicates that the only practical technology that might be applied to this unit would be Selective Catalytic Reduction (SCR). SCR technology and its requirements and limitations are explained in detail below in the Compressor Engines section. For the sake of brevity, it will not be repeated here. For purposes of our analysis, however, it has been assumed that such a technology might achieve 90% reduction in actual emissions.

Although a cost analysis has been conducted for this technology, it is not a foregone conclusion that such an application of SCR would be useful for Round 2. The emission reduction is small from a mass point of view. In addition, we are not aware that SCR has ever been applied at an amine unit anywhere in the US or elsewhere.

Compressor Engines (NOx)

The compressor engines at the Tioga facility drive compressors that boost the inlet field gas pressure for processing. The engines are fueled by a portion of the gas stream (pipeline quality fuel gas) produced by the plant. The exhaust gases from each compressor engine are released to the atmosphere through individual stacks.

The seven Clark Engines that have been identified by NDDH are large integral engines; i.e. the engines themselves and the compression structure are constructed as a single unit. Thus, replacement of these engines would be extraordinarily expensive and difficult as both the compression and engine would need to be replaced. Regardless, there are five 1,950 horsepower (hp) engines and two 2,250 hp engines. The two 2,250 hp engines were modified in 2004 by adding turbocharging systems and other means to lower emissions. The emissions from these two engines are about 75% less that the other engines and as such were not subject to additional analyses. The remaining five engines have not been substantively updated since they were installed in the 1950's although they have been maintained in good working order since.

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[16] Emission Factor = 0.1 lb/10^6 BTU (AP-42, Table 8.13-2, April, 2015)

Three control options were assessed for the five 1,950 hp Clark Engines: Low Emission Controls (LEC); Select Catalytic Reduction (SCR), and converting engines from gas to electric power.

i) ***Low Emission Controls (LEC)***

LEC application includes various upgrades, modifications, and engine tuning improvements. These typically include a combination of turbocharging [increases air-to-fuel (AFR) ratio], intercooling, enhanced mixing (high pressure fuel injection) and an increase in ignition energy.[17] LEC is the preferred approach to reduce lean burn engine NOx emissions when compared to alternative options such as SCR.[18]

LEC modifications provide additional air to a controlled engine which, as a result, reduces maximum combustion temperature and minimizes NOx formation. Excess air may hinder combustion of the air-to-fuel ratio in the cylinder, so a high energy ignition source is generally required for engines equipped with LEC. Pre-chamber combustions systems are generally used to aid in combustion, however the power operating range may decrease on two-stroke cycle engines as a result of an LEC conversion. The term “LEC” is often used broadly to describe a number of technology approaches that can be used depending on the engine and NOx emission limit. Normally, multiple LEC related technologies may be required. Therefore, LEC system modifications assessed for the 5 Hess compressor engines were assumed to be on the high end of any given range of costs.

The reduction in NOx emission rates expected from the application of LEC is roughly 70% to 90% (The same reduction may be expected for SCR). For purposes of this 4-Factor analysis and as a matter of consistency among the engines and control technologies (LEC vs SCR), it was presumed that each technology can achieve a controlled emission rate of 1 g/bhp-hr. This emission rate is about the same as a 90% reduction depending on the specific engine and technology. In addition, 1 g/bhp-hr is the emission rate applicable to most new internal combustion engines.[19] Since LEC would be applied to a set of older existing engines, the applied emission rate is conservatively low.

ii) ***Select Catalytic Reduction (SCR)***

SCR is an exhaust control that could be applied to lean combustion engines which reduces NOx emissions by reacting NOx with ammonia or urea over a catalyst. Ammonia or urea is injected into the stream and requires a precise feed-rate based on the NOx

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[17] “*Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOX Control for Natural Gas Transmission and Storage Compressor Drivers*,” Interstate Natural Gas Association of America (INGAA), Report No. 2016-6, December 2017. *https://www.ingaa.org/File.aspx?id=33789*

[18] “*Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry.” INGAA Foundation. July 2014. https://www.ingaa.org/Foundation/FDNreports/NOx.aspx*

[19] 40 CFR 60, Subpart JJJJ, Table 1.

concentration and the NO/NO_2 ratio of the NOx. This feed rate, coupled with a narrow temperature range, is critical. If the ammonia feed rate is too low, then the targeted reduction in NOx is not achieved; thus, failing in the agency's intent to improve regional visibility. If the ammonia rate is too high, then free ammonia is released. The ammonia will itself react in the atmosphere to form compounds such as ammonium sulfate(s) and ammonium nitrate(s). Both compounds are the primary 'culprit' that has led to the already observed regional haze concern. Thus, an improper feed rate will lead to a worsening of regional haze rather than making an improvement.

The process works by ammonia (the reagent) reacting with NOx on a catalyst bed to form water and N_2. The reaction is characterized as follows:

$$NO + NH_3 + O_2 \rightarrow N_2 + H_2O \quad \text{(unbalanced)}$$
$$NO_2 + NH_3 + O_2 \rightarrow N_2 + H_2O \quad \text{(unbalanced)}$$

While SCR has enjoyed a fairly wide applicability in power generation sources, its application to U.S. gas transmission sources has been very limited per INGAA 2014. That analysis details a number of the difficulties of applying SCR to gas transmission engines. These include:

a) There are numerous technical concerns about SCR's application to compressor engines. Among them are exhaust temperature requirements, reagent control, and the treatment of potential variations in the reciprocating engine exhaust NO/NO_2 ratio.
b) SCR has been more commonly applied to larger utility scale turbines and boilers and rarely used in compressor engines such as the Tioga facility.
c) The use of SCR is most effective when operating in the exhaust temperature range of 480 to 800°F. The typical exhaust temperature range for some lean burn engines may present challenges because the minimum operating temperature of the catalyst is dependent on the composition of the exhaust gases and the type of catalyst materials used.
d) Engines that have variable power loads, such as the case here, require more sophisticated controls to inject the proper amount of reagent, and it is not evident that robust control schemes have been developed for transmission applications.
e) The installation of a continuous emissions monitor could be required to effectively control the amount of reagent necessary to achieve the desired NOx emission rate.
f) SCR catalytic elements can be contaminated by byproducts of combustion (such as oil ash) and more importantly here; engine oil carryover. Cleaning and replacement is required on a periodic basis, and extra management is required to ensure adequate inventories of reagent are maintained.

While EPA claims that SCR is a technology applicable to compressor engines[20] SCR has, in fact, rarely been used in the natural gas transmission and related industry.[21] This does provide strong support for its use in this case.

LEC is nearly universally preferred over SCR for existing lean burn engines due to the issues described above. LEC works to prevent NOx formation while SCR acts to control already formed NOx in the exhaust stream.

iii) ***Electric Compressors***

The third option under (initial) consideration is replacing these natural gas-fired integral (engine + compressor as a single unit) units with an electric powered unit. This possibility has been rejected, however, because such an option does not fall within the suggested EPA Guidance for the identification of alternative controls.[22]

More specifically, the EPA Draft Guidance document discusses (relying on BART policies) the options that may or should be considered in identifying 4-Factor (via BART) control options. The Draft Guidance contains the following discussion (in identifying technologies outlined by BART and acceptable to the 4-Factor analysis):

> "*Potentially applicable retrofit control alternatives can be categorized in three ways. Pollution prevention: use of inherently lower-emitting processes/practices, including the use of control techniques (e.g., low NOx burners) and work practices that prevent emissions and result in lower "production-specific" emissions (note that it is* ***not our intent to direct States to switch fuel forms, e.g., from coal to gas****), …"* (emphasis added). EPA Draft Guidance, p 180.[23]

This comment alone suggests that a fuel switch is not necessarily within the realm of a 4-Factor analysis. Clearly a switch from natural gas to electricity is, in effect, a fuel switch and not the intent of the analysis. The document goes on to provide a more specific discussion:

> "*We do* ***not consider*** *BART as a requirement to* ***redesign the source*** *when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired*

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[20] "Air Pollution Control Technology Fact Sheet," SCR, EPA-452/F-03-032.

[21] INGAA Foundation, *op. cit.*

[22] *Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,*" EPA, EPA-457/P-16-001, July 2016. https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf

[23] Ibid.

> *electric turbine* ***although*** *the turbine may be* ***inherently less polluting*** *on a per unit basis.*" (emphasis added). EPA Draft Guidance p. 198.[24]

Again, the Draft Guidance suggests that one does not need, nor should, consider what amounts to be a redefinition or fundamental change in the underlying facility/unit. If EPA rejects changing an electrical generation plant from coal-fired to a gas-fired turbine as inappropriate, the same logic applies here (gas-fired to electric).

For the reasons above, replacing these gas-fired engines with electric engines has been removed from further consideration.

Flares (SO_2 & NOx)

The acid/wet gas flare (S-101) and high-pressure flare (S-102) operate intermittently at the Hess facility to combust off-spec gas and to address emergency/malfunction events. Both sources are to be assessed for additional NO_2 and SO_2 control. Additional control equipment systems for flare sources are not known or available for a facility whose emission rate is highly variable in both time and quantity. As a result, we are not able to identify any available control technologies for these two specific flares.

Even if a control technology were to present itself, the annual emissions from these two flares would almost certainly yield cost/ton of removal values that are not cost-effective. As evidence, the most recent 2-year average annual emissions for these two flares were:

SO_2

S-101 = 21 t/yr @ 79 hours of operation per year
S-102 = 40 t/yr @ 103 hours of operation per year

NOx

S-101 = 0.0 t/yr @ 79 hours of operation per year
S-102 = 4.6 t/yr @ 103 hours of operation per year

The low total emissions produced by the flare sources would result in a high cost effectiveness in $ per ton of emissions reduced since the total cost of implementation would only have the potential to control a minimal quantity of emissions. As a result, no further analyses were conducted for this source.

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[24] Ibid.

3.1 Factor 1: Cost of Compliance

The cost of compliance estimates the capital cost of purchasing and installing new control equipment along with the annual operation and maintenance (O&M) cost as generally outlined in EPA Draft Guidance. The 2009 WRAP analysis also delineated these cost parameters into the following categories: direct capital cost, indirect capital cost, labor cost, contingency cost, and annual cost. Methodologies given in the EPA Air Pollution Control Cost Manual (Control Cost Manual) are the indicated reference for determining the cost of compliance as directed by the EPA Draft Guidance.[25] Costs were expressed in terms of cost-effectiveness in a standardized unit of dollars per ton of emissions reduced by the proposed control option. The cost of compliance is analyzed by source/source group within Table 2 and the following sections.

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[25] EPA Cost Control Manual (sixth edition): https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

Table 2: Estimated Costs of Control Options for Hess Tioga Gas Plant Sources

Source	Potential Control Option	Pollutant	Estimated Control Efficiency (%)	Potential Emission Reduction (tons/year)	Estimated Capital Cost ($1000)	Estimated Annual Cost ($1000/year)	Cost Effectiveness ($/ton)
Amine Gas Sweeting Unit (SRU)	SCOT (or equivalent)	SO_2	90%	539	16,750	6,369	$11,815
	SCR	NO_2	90%	53	1,204	1,127	$23,623
Compressor Engines (Mean among 5 engines)	LEC	NO_2	1 g/bhp-hr[a]	134	4,000	996	$7,951[b]
	SCR	NO_2	1 g/bhp-hr[a]	134	877	502	$4,710[c]
Flares (2)	N/A	SO_2	--	--	--	--	--
	N/A	NO_2	--	--	--	--	--

[a] Emission reduction is assumed to achieve approximately 1 gram/bhp-hour.

[b] Cost effectiveness per engine ranged from $13,123 to $5,401. Individual values are found in Appendix A.

[c] Cost effectiveness per engine ranged from $8,917 to $3,879. Individual values are found in Appendix A.

3.1.1. Amine Gas Sweeting Unit

SO_2

The cost estimate of a SCOT unit includes the capital cost of constructing the system which comprises the reactor, cooling tower and scrubber systems. Again, the SCOT system has been assessed specifically, however it is presumed to be a representative selection for all potential add-on TGST controls. The cost estimate also includes direct and indirect costs associated with modifying the current 2-Stage Claus / CBA unit to accommodate the SCOT (or equivalent) system. Indirect costs include engineering design, permitting, construction and field expenses, contractor fees, start-up, performance testing, and contingencies. Estimated costs are delineated in Appendix A. The calculated costs included in Table 2 have been adjusted to reflect value in 2017 per the Consumer Price Index. Design, construction, and operation of a SCOT system with the Hess amine sweeting unit is projected to cost approximately $11,815 per ton of SO_2 removed.

NOx

To complete the analysis, a cost-effectiveness investigation was conducted for NOx. As noted earlier, the emission rate at this source is small and has, no doubt, an insignificant impact on regional haze. Regardless, a cost analysis was completed for SCR. Using the capital cost estimates found in EPA's Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032, Table 1a, the cost effectiveness for controlling NOx was estimated at $23,623/ton removed.[26] This value is well outside normal BACT and BART ranges and thus is removed from further consideration.

3.1.2. Compressor Engines

The Clark Engines analysis included estimated costs for updating each of the five 1,950 hp with either LEC or SCR.

LEC.

The LEC analysis is based on various upgrades and changes to the 5 engines. As a general rule, an upgrade to LEC consists of:

- Hardware and engineering costs for replacing the existing cooling systems with water pump systems to eliminate boil-off cooling.
- Field service, repairs, and parts replacement for zero-hour overhauls.
- Hardware, installation, and commissioning of a HPfi fuel injection upgrade that needs to include:
    - A single "Balance of Plant" engineering and hardware support for multiple engine revamps.
    - Hardware, installation, and start-up of the HPFi equipment.

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[26] Details of the calculation are found in Appendix A.

The cost of such upgrades is dependent on numerous factors. A literature search did not yield definitive results. There are several earlier reports, NESCAUM – 2000,[27] for example, that provided a wide range of expenses. There is, however, a recent report (December 2017) from the INGAA Foundation that provides a cost range for LEC upgrades.[28] That report addressed the cost of LEC for natural gas-fired compressor engines, among others. In particular, it provided a range for Clark engines of similar size to the 5 engines at Hess.

The report suggests a range of: $1,250 to $2,500 per hp from a base model of 1,600 hp. The engines at issue are 1,920 hp. It was decided that an upper range value would be appropriate in this analysis due the larger size of engine and the age of these 1950-era units.

In addition, the typical calculation for determining the cost effectiveness ($/ton reduction) begins with the capital expenses. Then adjustments are made to include instrumentation, freight, foundations, electrical, etc. In this case, however, the INGAA report implies that these figures ($/hp) are the "total cost." It is not clear from the report if that cost ($1,250 - $2,500) includes foundations, electrical, piping, etc. To be conservative, it was decided to assume that the report costs included this direct installation costs. To that end, the presented data in the report and appendix remove the EPA-suggested cost adjustments for foundations and the like by assuming that those costs are already included in the base cost ($1,250 - $2,500). Should this not be the case, then the cost effectiveness will be increased appropriately.

Using this information, an annual cost of roughly $1,000,000 is estimated for each engine. Details of the calculations are found in Appendix A. This cost coupled with the various emission rates for each of the five engines yielded a cost effectiveness ranging from $5,401 to $13,123 per ton of NOx removed. The average cost effectiveness among the 5 engines was $7,951.

SCR.

The capital costs for SCR, if one were to assume this was an 'achievable technology' for this application, are varied. There are a number of published cost estimates for typical coal- oil- and gas-fired medium to large sized boilers. The same cannot be said for a retrofit of a natural gas-fired compressor engine/compressor.

In addition, the cost of retrofit SCR is much higher than an original installation which would apply to this analysis. SCR systems used to retrofit an existing unit increase costs around 30%[29] more due to ductwork modification, the cost of structural steel, reactor construction

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[27] "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines Technologies & Cost Effectiveness, Northeast States for Coordinated Air Use Management (NESCAUM), December 2000.

[28] "Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOX Control for Natural Gas Transmission and Storage Compressor Drivers," Interstate Natural Gas Association of America (INGAA), Report No. 2016-6, December 2017. *https://www.ingaa.org/File.aspx?id=33789*

[29] EPA Air Pollution Control Technology Fact Sheet – SCR: https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

and so forth. O&M costs may also be substantially dependent on reagent usage, catalyst replacement, and increased electrical usage. These costs are also impacted by the overall capacity – which determines reagent and catalyst volume – and annual versus season operations schedule. The average (all 5 engines) cost effectiveness of SCR was $4,710 per ton removed. Individual engines ranged from $3,879 to $8,917. This cost effectiveness range coupled with multiple technical difficulties and its non-use in this general application does not make it an attractive Round 2 candidate.

The derivation of the capital cost figures, emission rates and other general information may be found in the appropriate tables in Appendix A.

3.2 Factor 2: Time Necessary for Compliance

Per the EPA Draft Guidance, the provisions for this factor within the BART guidelines should be utilized to estimate time necessary for compliance. Additionally, the best guide to determine time necessary for compliance is prior experience with the planning and installation of new emission controls. Source-specific factors should be considered as well.

EPA has estimated that it takes approximately 30 months to design, permit, build, and install a typical SO_2 scrubbing control unit for a single source. No specific data was located as it regards the SCOT unit (or its equivalent). Using the EPA estimate as a guide, their analysis also determined that 12-months is additionally required for a project including the installation of control equipment on multiple sources. Another 12 months may be required for staging the installation process across the multiple sources. Finally, it is generally recognized that facilities may require a 1 year (or more) for the procurement of project funding.

As a result, the time necessary for compliance for the SCOT unit is estimated at approximately five years. This time period accounts for about one year of capital acquisition; two to three years for designing, permitting, constructing, and installing the control equipment; and one year for installing controls for multiple components in stages.

A longer timeline would also be expected for the LEC conversion for the five engines discussed in this report. The installation, tuning and integration would need to be executed in a sequential fashion in order to keep the facility in operation during this time. This will stretch the 'time necessary for compliance.' No specific time-line is offered at the time of this report. However, it would be reasonable to suggest that the time needed would be at least five years and possibly more.

Although no specific data was found, it would be reasonable to assume that a five-year period would also be appropriate for the installation of SCR in lieu of LEC should that be required. Finally, it was further reasoned that this five-year period serves as an estimate for the time necessary for installation of an SCR unit on the Amine Sweetening Unit, although its installation is not justified for cost effectiveness reasons.

3.3 Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

The provisions of the BART Guidelines are recommended for assessing both energy and non-environmental impacts. The EPA Draft Guidance states that an energy impacts assessment should be considered in terms of kilowatt-hours or mass of fuels used accounting for direct energy consumption cause by control implementation. Indirect energy inputs to produce the raw materials for construction of equipment should be excluded from the analysis. The Control Cost Manual is the preferred reference and provides advice on estimating energy requirements. Non-air environmental may include the cost associated with solid waste disposal, wastewater discharge, acid or nitrogen deposition, and climate impacts.

3.3.1. Amine Gas Sweeting Unit

Two secondary waste streams are generated when using the SCOT unit TGST according to the EPA Pollution Control Technical Manuals (PCTMs). A sour water stream is generated from the quench tower due to condensation of water vapor present in the reduction effluent stream. A sour water stripper treats the sour water stream and any remaining H_2S or NH_3 is recycled into the Claus feed stream. Additionally, a second waste stream consists of spent catalyst from the reduction reactor. A SCOT system initially requires approximately 28% wt of the initial Claus catalyst requirement. According to the EPA PCTMs, this equates to 850 kg catalyst per kmol/hr H_2S converted from SO_2, COS, and CS_2. Catalyst has a typical service life of about 24,000 hours. Thus, the spent catalyst will require disposal about every four years. The implications of disposal of this waste stream has not been analyzed at this time since the cost effectiveness does not make its use a practical alternative.

There is also an energy cost associated with this added level of emission controls. It has been estimated that this level of technology would require about 700 kW-hr of use.[30]

3.3.2. Compressor Engines

SCR.

SCR control systems require the use of aqueous ammonia, anhydrous ammonia, or urea-to-ammonia reagents for the reduction reaction. Systems that use urea produce aqueous ammonia onsite. Anhydrous ammonia is nearly pure ammonia gas and must be transported and stored under pressure. Anhydrous ammonia is classified as a hazardous material which often requires special permits as well as additional procedures for transportation, handling and storage. Systems using

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[30] "*Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota",* Brad Nelson, William Battye, Janet Hou, EC/R Incorporated, Western Regional Air Partnership (WRAP) and Western Governors' Association (WGA), May 18, 2009, Table 4-3.

aqueous ammonia transport and store the reagent concentration in water, generally 19% - 29^{+}% ammonia to water.[31] While aqueous ammonia can be safer to transport and store, the diluted ammonia concentration requires more storage capacity than anhydrous ammonia and requires shipping costs for the water solvent in the solution. Hess would be required to account for additional chemical storage, protection, ad permitting with the additional reagent solution stored on site.

Additionally, SCR systems utilize catalysts to aid in NOx control. The catalysts are generally composed of active metals or ceramics with a highly porous structure. Activated sites are located within the pores of the catalyst and these sites have an acid group on the end of the compound structure where the catalytic reduction reaction occurs. The catalyst material reactivates via rehydration or oxidation after the reduction reaction occurs. This is a limited process, however, and over time the catalyst activity decreases, requiring replacement, washing/cleaning, rejuvenation, or regeneration of the catalyst. Catalyst storage, transport, and disposal must then be accounted for in the SCR control viability analysis.

An estimate was made of the aqueous ammonia feed rate necessary for the facility. It is estimated that with all 5 engines in operation, a feed rate of about 70 gallons per hour would be necessary.[32] To handle this much material would require a large storage tank (≈ 5,000 gallons) that would need recharged about every 3 days. To provide a more reasonable recharge rate (10^{+} days) would require a much larger tank(s). In either case, the storage or use of this quantity triggers the requirements of the accidental release program found in 40 CFR 68.[33] Depending upon specifics, a detailed amendment to the risk management plan (RMP) must be developed and implemented under this program. This only adds another layer of regulatory reporting along with an unnecessary risk by itself. The fact that such a plan would be required dampens its attractiveness for consideration.

LEC.

The LEC technology does not require the handling or storage of hazardous materials as is the case for SCR. The LEC technology does not require, on its face, changes in pressure drop across any system that could create an energy demand penalty.

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[31] EPA Cost Control Manual (sixth edition): https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

[32] See general calculations and data found in Appendix A (from EPA Cost Control Manual).

[33] The program is triggered for aqueous ammonia use or storage greater than 20,000 pounds. The quantities described exceed this value.

3.4 Factor 4: Remaining Useful Life

The Hess Tioga Gas Plant remaining useful/service life is not specific at this time. As discussed in the 2009 WRAP Analysis, the service life of these emission sources at industrial facilities are difficult to estimate.

The startup dates for these units were:

Amine Sweetening Unit:	1991
Compressor Engines (5):	1954
Flares:	n/a

Regardless of the ability to select a particular time, the service life of the analyzed control technologies was approximately 15 years. The 15-year figure was used to amortize the capital costs of the add-on and modified (LEC for the compressor engines) emission controls. Given the historical perspective, it is reasonable to conclude that the remaining life of the facility (Sweetening Unit and Engines) itself is expected to exceed the 15-year life of the control equipment.

The capital cost of the control equipment would need to be amortized over a shorter period if the remaining life of an emission source is less than the projected life of the new control equipment. Since this was not the case, the remaining equipment life of the facility is expected to equal or exceed the life of the analyzed technology options.

4.0 CONCLUSIONS AND RECOMMENDED SELECTION

A 4-Factor analysis has been conducted for the Hess Tioga facility. The analysis was conducted to meet the requirements of "Round 2" to develop of a State Implementation Plan (SIP) to address Regional Haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308(d)(1). To implement the requirement, the North Dakota Department of Health (NDDH) submitted a letter to Hess dated May 18, 2018, seeking such an analysis.

The 4 factors to be analyzed based on the NDDH letter and the regional haze rule were:

Factor 1. Cost of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance
Factor 4. Remaining useful life of any existing source subject to such requirements

NDDH then requested a 4-Factor analysis for SO_2 and NOx for the following source groups:

1. Amine Gas Sweetening Unit (S-302)
2. Clark Compressor Engines (C1A – C1G)
3. Flares (S-101 and S-102)

The emitting units were analyzed for these factors in general accordance with EPA's Draft Guidance.[34] The details of those results were presented in prior sections of this report.

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[34] *Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,*" EPA, EPA-457/P-16-001, July 2016.
https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf

Amine Gas Sweetening Units.

SO_2

Two control technologies were originally considered for this unit-pollutant combination: Tail-gas scrubbing treatment (SCOT) and Flue-gas de-sulfurization (FGD). The SCOT technology (or its equivalent) essentially extends the basic Claus reaction by collecting sulfur gasses (primarily SO_2 and H_2S), concentrating them, and then recycling the gasses back to the Claus plant. The FGD system, typically found in a coal-fired power plant, treats exhaust gas with an alkaline reagent (usually CaO or $CaCO_3$) to remove SO_2. The spent reagent ($CaSO_3$ or $CaSO_4$) is then collected in a fabric filter unit in which the collected dust must be treated in a licensed landfill.

It is concluded that the FGD system is not practical nor appropriate for this application. Those reasons include (but not limited to):

- A new emitting source (particulate) would be added to the plant offsetting some of the benefits of a reduction in SO_2;
- A new disposal system would be required to treat the spent reagent,
- FGD has never, to our knowledge, been used in treating SO_2 emissions from any gas processing facility; and
- The prior (2009) 4-Factor analysis for this facility did not identify nor consider FGD as a viable technology.

The SCOT technology (or its equivalent) was analyzed. While the technology may be applied to a facility like the Tioga plant, it was rejected due to its high cost effectiveness (≈ $12,000/ton).

NOx

Although the emission rate of NOx from the unit is very low, an analysis for this unit was conducted for thoroughness. The technology identified most probable for this unit is Selective Catalytic Reduction (SCR). SCR was rejected as inappropriate for numerous reasons, including its high cost effectiveness (≈ $23,000/ton). Therefore, SCR is not a candidate for Round 2 emission reductions.

Compressor Engines.

NOx

There were two control technologies identified for reducing NOx from these units: SCR and Low Emission Control (LEC).

LEC is a system of upgrades, modifications and tuning of the engines to achieve a lower emission rate. LEC could, theoretically, be applied to each of the 5 compressor engines subject to this analysis.

The cost effectiveness of this technology was excessive. The average cost effectiveness was $7,951/ton for all 5 engines. The engine-by-engine cost effectiveness ranged from roughly $5,400 to as high as $13,100 depending on the engine. Since these values are considered excessive, LEC has been removed from consideration for Round 2.

SCR was also analyzed as a potential control technology. However, SCR is rarely, if ever, used for this type of application. Evidence of that stems from several reports. One recent study (2014) makes the following comment: "*To date, SCR application to U.S. gas transmission sources has been very limited, and SCR has not been applied to an existing integral engine*."[35] The 5 engines at the Tioga facility are existing integral engines as described in the report. In addition, an even more recent report failed to consider SCR a noteworthy technology for reducing NOx emissions from transmission and storage compressors as a means of achieving the ambient NOx standards.[36]

Additionally, SCR carries the burden of handing and storing either anhydrous ammonia (NH_3) or aqueous ammonia (NH_4OH). This would require new equipment in which to transport and handle this material. In both cases, the storage quantities necessary will trigger the need for a Risk Management Plan (RMP) required by the Accidental Release program (40 CFR 68) in order to address the potential of a spill or release that could have public health implications. The addition of this equipment constitutes an unnecessary risk for the purpose of regional haze.

In addition to the burdens described, the efficacy of the control technology is at issue. For SCR to work effectively, a precise ammonia feed rate

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[35] "*Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry." INGAA Foundation. July 2014, Page 9.* *https://www.ingaa.org/Foundation/FDNreports/NOx.aspx*

[36] "*Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOX Control for Natural Gas Transmission and Storage Compressor Drivers*," Interstate Natural Gas Association of America (INGAA), Report No. 2016-6, December 2017. *https://www.ingaa.org/File.aspx?id=33789*

coupled with a narrow temperature range are necessary. Both conditions would be difficult to maintain due to varying loads on the compressor engines themselves.

Finally, the cost effectiveness of SCR is, overall, excessive. The average cost effectiveness was $4,951 for all 5 engines. The engine-by-engine effectiveness ranged from roughly $3,900 up to $8,900. Due to these costs, the technical concerns, the need to handle hazardous materials and the nearly universal lack of use of SCR for legacy compressor engines, SCR is rejected for Round 2 purposes.

Flares.

NOx and SO_2

A review of the literature does not yield any ‘available’ control technology to control either NOx or SO_2 emissions from these highly intermittent sources such as the Tioga flares. The flares primarily serve emergency and other upset conditions. For example, each flare operated 0.1% of the time in the past 2 years. Clearly, any control technology, even if it were available, would not have a measurable impact on the regional haze long-term goals. Because no reasonable technology is available, and no measurable regional haze benefit would be realized, it is concluded that there are no technology options available for these sources.

Following a careful review of the information it is concluded that additional emission controls and limitations for these sources are not necessary to make reasonable progress based on the 4-Factor analysis.

APPENDIX A: COST CALCULATIONS

Amine Sweetening Unit (S-302)

Sulfur Dioxide

SCOT (or equivalent) Control Technology

Total Capital Costs - SCOT

Total Capital Costs for SCOT

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
SCOT Capital	A	$16,750,000
Instrumentation	0.10 A	$1,675,000
Sales taxes	0.05 A	$837,500
Freight	0.05 A	$837,500
Purchased equipment cost, PEC	B = 1.15 A	**$19,262,500**
Direct installation costs		
Foundations & supports	0.08 B	$1,541,000
Handling & erection	0.14 B	$2,696,750
Electrical	0.04 B	$770,500
Piping	0.02 B	$385,250
Insulation for ductwork	0.01 B	$192,625
Painting	0.01 B	$192,625
Direct installation cost	0.30 B	**$5,778,750**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$25,041,250**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$1,926,250
Construction and field expenses	0.05 B	$963,125
Contractor fees	0.10 B	$1,926,250
Start-up	0.02 B	$385,250
Performance test	0.01 B	$192,625
Contingencies	0.03 B	$577,875
Total Indirect Cost, IC	0.31 B	**$5,971,375**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$31,012,625**

Annual Costs - SCOT

Total Annual Costs for SCOT

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
Operator	0.5	hrs/shift	30.00	$/hr	$16,200
Supervisor	15%	of operator			$2,430
Operating Materials					-
Maintenance					
Labor	0.5	hrs/shift	30.00	$/hr	$16,200
Material	100%	of maint. labor			$16,200
Utilities					
Natural Gas	0	(kft3/yr)	$ 5.18	$/kft3	$0
Electricity	0	(kWh/yr)	$0.059	$/kWh	$0
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$30,618
Administrative Charges	2%	of TCI			$620,253
Property Taxes	1%	of TCI			$310,126
Insurance	1%	of TCI			$310,126
Capital Recovery Factor (Annualized Capital Cost, 10 yrs at 10%)					$5,047,161.90
TOTAL ANNUAL COST					**$6,369,315**

(2-yr Average)	Uncontrolled Emissions (tons/yr):	599
	Control Efficiency (add'l):	90%
	Controlled Emissions (tons/yr):	59.9
	Tons Removed (tons/yr):	539.1
	Cost-Effectiveness ($/ton):	**$11,815**

Capital Recovery Factor

https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll

Capital Cost Derivation:

"Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota
Western Regional Air Partnership (WRAP), May 18, 2009
Prepared by EC/R Incorporated, Chapel Hill, NC

$15,000,000 (Table 4-2) - assumed 2009 Dollars

214.5 CPI 2009 https://www.bls.gov/cpi/tables/historical-cpi-u-201709.pdf
240 CPI 2018
1.12 Inflation value

$16,783,217 Adjusted Capital for 2017

Amine Sweetening Unit (S-302)

Nitrogen Oxides

SCR Control Technology

Amine Sweetening Unit (S-302)

	Year			
Parameter	**2016**	**2017**	**Units**	**Reference**
Fuel burned	1,100	1,131	10^6 ft^3	Annual emissions inventory
Heating Value	950	950	btu/ft^3	Assumed
Heat input	1,045,000	1,074,450	mmbtu/year	Calculated
Heat input	119	123	mmbtu/hour	Calculated
Emission Factor	0.1	0.1	#/10^6 BTU	AP-42, Table 8.13-2, April 2015
Emissions	52	54	tons/year	Calculated

Emission Factor Reference:
AP-42, Section 8.13, Table 8.13-2, April 2015

Heat input	121	(average)	mmbtu/hour
Emissions	53		tons/year

SCR - Input Calculations and Reference Information

Reference: EPA/452/B-02-001 Section 4.2 in Chapter 2

Parameter / Variable		Value	Units	Reference
Selective Catalytic Reduction (% Control);		85.0	percent	Approx ≈ 1g/bhp-hr
Actual Emissions		53	Tons/yr (actual) per Engine	2016/2017 Inventory
Q_B =Max. Heat Input at HHV, MMBtu/h		121	MM Btu/hr	Calculated from annual EI report
ASR		1.050	Actual Stoichiometric Ratio	EPA/452/B-02-001
$q_{flue\ gas}$		27,309	Inlet to SCR acfm	2017 RATA + 20%
qscfm		11,844	dscfm	2017 RATA + 20%
CF_{plant}		0.95	system capacity factor, CF_{plant}	EPA/452/B-02-001
η_{NOx}		0.85	NOx removal efficiency	Approx.
NH3 slip (ppmv)	$(ASR\text{–}\eta_{NOx})*60*MW_{Nh3}*dscfm/359.05/10\wedge6$	0.007	lb/hr	
Catalyst volume	$2.81*Q_B*\eta_{adj}*slip_{adj}*Nox_{adj}*S_{adj}*T_{adj}/N_{SCR}$	1,442	ft^3	EPA/452/B-02-001
$N_{SCR\ (\#\ of\ SCR\ reactor\ chambers)}$		1		
η_{adj}	$(0.2869+(1.058*+\eta_{NOx}))$	1.19		EPA/452/B-02-001
Slip	$(ASR\text{-}\eta_{NOx})$	0.10		EPA/452/B-02-001
$Slip_{adj}$	1.2835-(0.0567*Slip)	1.28		EPA/452/B-02-001
NOx_{in}		3.8	lb/MM Btu	2018 stack test (typical)
NOx_{adj}	$0.8524+(0.3208*NOx_{in})$	2.071		EPA/452/B-02-001
S, sulfur in fuel		7.00E-06	(weight fraction)	
S_{adj}	0.9636+(0.0455*S)	0.964		EPA/452/B-02-001
SCR inlet temp		600	F°	Presumed (req'd for SCR)
SCR inlet temp		589	K°	
T_{adj} for inlet T not = 700 F	$15.16-(0.03937*T)+(2.74*10^{-5}*T^2)$	1.40		EPA/452/B-02-001
$A_{catalyst}$	$q_{flue\ gas}/(16*60)$	28.4	ft^2	EPA/452/B-02-001
n_{layer}	$V_{catalyst}/(h_{layer}*A_{catalyst})$	16.4	assume h = 3.1	EPA/452/B-02-001
$n_{layer\ -\ final}$		3	round n_{layer} to integer	EPA/452/B-02-001
h_{layer}	$V_{catalyst}/(n_{layer}*A_{catalyst})+1$	17.9		EPA/452/B-02-001
$n_{layer\ -\ total}$	$n_{layer\ -\ final}+1$	4		EPA/452/B-02-001
h_{SCR}	$n_{layer\ -\ total}*(c_{1+}h_{layer})+c_2$	108.6	ft	EPA/452/B-02-001
SCR height adjustment	$\$6.12*h_{SCR}\text{-}187.9$	476.7	$f(h_{SCR})$	EPA/452/B-02-001
$m_{reagent}$	$(NOx_{in}*Q_B*NSR*\eta_{NOX}*MW_{reagent)}/(MW_{NOx}*SR_T)$	151.9	lb/hr	EPA/452/B-02-001
$MW_{reagent}$		17.0	MW of ammonia	
MW_{NOx}		46.0	MW of NO_2	
NSR	ASR/SR_T	1.1	normalized stoichiometric rate	EPA/452/B-02-001
SR_T		1.0	for ammonia	EPA/452/B-02-001
m_{sol}	$m_{reagent}/C_{sol}$	523.8	lb/hr	EPA/452/B-02-001
C_{sol}		0.29	concentration of aqueous soln	Typical aqueous soln
ρ_{sol}		56	lb/ft^3	EPA/452/B-02-001
v_{sol}		7.5	gal/ft^3	EPA/452/B-02-001
q_{sol}	$m_{sol}/\rho_{sol}*v_{sol}$	70.0	gal/hr	EPA/452/B-02-001
t_{store}		14.0	reagent storage for t days	assumed, EPA/452/B-02-001
Tank volume	$q_{sol}*t$	23,510	gallons	EPA/452/B-02-001
Cost of reagent	RC	0.15	$/lb	EPA/452/B-02-001, page 2-50 (Adj from 1998)
Cost of reagent (per hour)		$79.57	$/hour of ammonia	
Cost of reagent (per year)		$696,998	$/year (8,760) of ammonia	
Catalyst Cost	$CC_{replace}$	$436.12	$/$ft^3$	EPA/452/B-02-001, page 2-50 (Adj from 1998)
Catalyst Cost Replacement	$n_{SCR}*Vol_{catalyst}*(CC_{replace}/R_{layer})$	$157,248	$/replacement layer/year	EPA/452/B-02-001, Eqn 2.50 (1 layer/yr : 4 layers)
Pressure drop of SCR & ductwork	ΔP_{duct}	2.5	inches H_2O	assumed, EPA/452/B-02-001 (2 ↔ 3")
Pressure drop for catalyst	$Dp_{catalyst} = 0.875* n_{layer\text{-}final}$	2.6	inches H_2O	assumed, EPA/452/B-02-001

Hess Corporation
4-Factor Cost Analysis
Tioga Facility
Nat'l Gas Compressor Engines
NOx
SCR Control

Capital Cost Derivation

Primary Reference:
Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032

Value	Units	Reference
$2,500	$/mmBtu	Table 1a : small/large turbines : 1,500 ↔ 3,500 $/mmbtu : 1999 Dollars (assumed a mid-range value)
121.0	mmBtu/hr	Annual emissions report to NDDH (= mean of 2016 and 2017)
133.1	mmBtu/hr	10% added to simulate near full load
167	CPI 1999	*https://www.bls.gov/cpi/tables/historical-cpi-u-201709.pdf*
240	CPI 2018	
1.44	CPI2018/CPI1999	Inflation rate raio
$479,352	$	Adjusted Capital for 2017 - $/mmBtu
$623,157	30%	Premium added as a retrofit: Source: EPA Air Pollution Control Technology Fact Sheet

Annual Costs - SCR - Amine Sweetening Unit

Total Capital Costs for SCR

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Capital	A	$623,157
Instrumentation	0.10 A	$62,316
Sales taxes	0.05 A	$31,158
Freight	0.05 A	$31,158
Purchased equipment cost, PEC	B	**$747,789**
Direct installation costs		
Foundations & supports	0.08 B	$59,823
Handling & erection	0.14 B	$104,690
Electrical	0.04 B	$29,912
Piping	0.02 B	$14,956
Insulation for ductwork	0.01 B	$7,478
Painting	0.01 B	$7,478
Direct installation cost	0.30 B	**$224,337**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$972,125**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$74,779
Construction and field expenses	0.05 B	$37,389
Contractor fees	0.10 B	$74,779
Start-up	0.02 B	$14,956
Performance test	0.01 B	$7,478
Contingencies	0.03 B	$22,434
Total Indirect Cost, IC	0.31 B	**$231,815**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$1,203,940**

Annual Costs - SCR - Amine Sweetening Unit

Total Annual Costs for SCR

Cost Item				Cost
DIRECT ANNUAL COSTS				
Operating Labor				
	Operator	0.5 hrs/shift (5 units)	30.00 $/hr	$16,200
	Supervisor	15% of operator		$2,430
Operating Materials	Ammonia consumption			$696,998
	Catalyst replacement			$157,248
Maintenance				
	Labor	0.5 hrs/shift (5 units)	30.00 $/hr	$16,200
	Material	100% of maint. labor		$16,200
Utilities				
	Natural Gas	0 (kft3/yr)	$ 5.18 $/kft3	$0
	Electricity	0 (kWh/yr)	$0.059 $/kWh	$0
INDIRECT ANNUAL COSTS, IC				
	Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		$30,618
	Administrative Charges	2% of TCI		$24,079
	Property Taxes	1% of TCI		$12,039
	Insurance	1% of TCI		$12,039
	Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)			0.1186
	Annual Capital Recovery (Recovery rate * TCI)			$142,787
TOTAL ANNUAL COST				**$1,126,839**

Uncontrolled Emissions (tons/yr):	53
Emission reduction (%)	90%
Controlled Emissions (tons/yr):	5
Tons Removed (tons/yr):	48
Cost-Effectiveness ($/ton):	**$23,623**

Capital Recovery Factor
https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll

Compressor Engines
(C-1A, C-1B, C-1C, C-1E, C1-G)

Nitrogen Oxides

LEC Control Technology

Input Variables and Derivation

Nitrogen Oxides – LEC

Capital Cost Derivation - NOx - LEC

Primary Reference:

INGAA Foundation, Report No. 2016-6, December 2017
"Potential Impacts of the Ozone and Particulate Matter NAAAQS on Retrofit
NOx Control for Natural Gas Transmillion and Storage Compressor Drivers"

Value	Units	Reference
$2,083	$/hp	Table 6, p. 18: $1,250 ↔ $2,500 $/hp : 2017 Dollars (assumed) (data is for Clark LEC retrofit 2-stroke) (assumed upper ⅓ to account for older engines)
1,920	hp	Clark Engine: C-1A, C-1B, C-1C, C-1E, C11G
$4,000,000	**$/Engine**	

Emissions Inventory: Actual

Engine	tons/year (2016/2017)
C-1A	94
C-1B	157
C-1C	191
C-1E	169
C-1G	153

Total Capital Cost - C-1A - LEC

Total Capital Costs for LEC

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
LEC Capital	A	$4,000,000
Instrumentation	0.10 A	(included)
Taxes	0.05 A	$200,000
Freight	0.05 A	$200,000
Purchased equipment cost, PEC	B	**$4,400,000**
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
Direct installation cost	0.30 B	**$0**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$4,400,000**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$440,000
Construction and field expenses	0.05 B	$220,000
Contractor fees	0.10 B	$440,000
Start-up	0.02 B	$88,000
Performance test	0.01 B	$44,000
Contingencies	0.03 B	$132,000
Total Indirect Cost, IC	0.31 B	**$1,364,000**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$5,764,000**

Annual Costs - C-1A - LEC

Total Annual Costs for LEC

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
	Operator	0.5	hrs/shift (5 units)	30.00 $/hr	$16,200
	Supervisor	15%	of operator		$2,430
Operating Materials					-
Maintenance					
	Labor	0.5	hrs/shift (5 units)	30.00 $/hr	$16,200
	Material	100%	of maint. labor		$16,200
Utilities					
	Natural Gas	0	(kft3/yr)	$ 5.18 $/kft3	$0
	Electricity	0	(kWh/yr)	$0.059 $/kWh	$0
INDIRECT ANNUAL COSTS, IC					
	Overhead	60% of sum of operating labor and materials and maintenance labor and materials.			$30,618
	Administrative Charges	2%	of TCI		$115,280
	Property Taxes	1%	of TCI		$57,640
	Insurance	1%	of TCI		$57,640
	Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)				0.1186
	Annual Capital Recovery (Recovery rate * TCI)				$683,610
TOTAL ANNUAL COST					**$995,819**

Uncontrolled Emissions (tons/yr):	94
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	76
Cost-Effectiveness ($/ton):	**$13,123**

Capital Recovery Factor

https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll

Total Capital Cost - C-1B - LEC

Total Capital Costs for LEC

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
LEC Capital	A	$4,000,000
Instrumentation	0.10 A	(included)
Taxes	0.05 A	$200,000
Freight	0.05 A	$200,000
Purchased equipment cost, PEC	B	**$4,400,000**
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
Direct installation cost	0.30 B	**$0**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$4,400,000**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$440,000
Construction and field expenses	0.05 B	$220,000
Contractor fees	0.10 B	$440,000
Start-up	0.02 B	$88,000
Performance test	0.01 B	$44,000
Contingencies	0.03 B	$132,000
Total Indirect Cost, IC	0.31 B	**$1,364,000**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$5,764,000**

Annual Costs - C-1B - LEC

Total Annual Costs for LEC

Cost Item				Cost
DIRECT ANNUAL COSTS				
Operating Labor				
	Operator	0.5 hrs/shift (5 units)	30.00 $/hr	$16,200
	Supervisor	15% of operator		$2,430
Operating Materials				-
Maintenance				
	Labor	0.5 hrs/shift (5 units)	30.00 $/hr	$16,200
	Material	100% of maint. labor		$16,200
Utilities				
	Natural Gas	0 (kft3/yr)	$ 5.18 $/kft3	$0
	Electricity	0 (kWh/yr)	$0.059 $/kWh	$0
INDIRECT ANNUAL COSTS, IC				
	Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		$30,618
	Administrative Charges	2% of TCI		$115,280
	Property Taxes	1% of TCI		$57,640
	Insurance	1% of TCI		$57,640
	Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)			0.1186
	Annual Capital Recovery (Recovery rate * TCI)			$683,610
TOTAL ANNUAL COST				**$995,819**

Uncontrolled Emissions (tons/yr):	157
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	138
Cost-Effectiveness ($/ton):	**$7,197**

Capital Recovery Factor

https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll

Total Capital Cost - C-1C - LEC

Total Capital Costs for LEC

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
LEC Capital	A	$4,000,000
Instrumentation	0.10 A	(included)
Taxes	0.05 A	$200,000
Freight	0.05 A	$200,000
Purchased equipment cost, PEC	B	**$4,400,000**
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
Direct installation cost	0.30 B	**$0**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$4,000,000**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$440,000
Construction and field expenses	0.05 B	$220,000
Contractor fees	0.10 B	$440,000
Start-up	0.02 B	$88,000
Performance test	0.01 B	$44,000
Contingencies	0.03 B	$132,000
Total Indirect Cost, IC	0.31 B	**$1,364,000**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$5,364,000**

Annual Costs - C-1 - LEC

Total Annual Costs for LEC

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
Operator	0.5	hrs/shift (5 units)	30.00	$/hr	$16,200
Supervisor	15%	of operator			$2,430
Operating Materials					-
Maintenance					
Labor	0.5	hrs/shift (5 units)	30.00	$/hr	$16,200
Material	100%	of maint. labor			$16,200
Utilities					
Natural Gas	0	(kft3/yr)	$ 5.18	$/kft3	$0
Electricity	0	(kWh/yr)	$0.059	$/kWh	$0
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$30,618
Administrative Charges	2%	of TCI			$107,280
Property Taxes	1%	of TCI			$53,640
Insurance	1%	of TCI			$53,640
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)					0.1186
Annual Capital Recovery (Recovery rate * TCI)					$636,170
TOTAL ANNUAL COST					**$932,379**

Uncontrolled Emissions (tons/yr):	191
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	173
Cost-Effectiveness ($/ton):	**$5,401**

Capital Recovery Factor

https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll

Total Capital Cost - C-1E - LEC

Total Capital Costs for LEC

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
LEC Capital	A	$4,000,000
Instrumentation	0.10 A	(included)
Taxes	0.05 A	$200,000
Freight	0.05 A	$200,000
Purchased equipment cost, PEC	B	**$4,400,000**
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
Direct installation cost	0.30 B	**$0**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$4,400,000**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$440,000
Construction and field expenses	0.05 B	$220,000
Contractor fees	0.10 B	$440,000
Start-up	0.02 B	$88,000
Performance test	0.01 B	$44,000
Contingencies	0.03 B	$132,000
Total Indirect Cost, IC	0.31 B	**$1,364,000**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$5,764,000**

Annual Costs - C-1E - LEC

Total Annual Costs for LEC

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
Operator	0.5	hrs/shift (5 units)	30.00	$/hr	$16,200
Supervisor	15%	of operator			$2,430
Operating Materials					-
Maintenance					
Labor	0.5	hrs/shift (5 units)	30.00	$/hr	$16,200
Material	100%	of maint. labor			$16,200
Utilities					
Natural Gas	0	(kft3/yr)	$ 5.18	$/kft3	$0
Electricity	0	(kWh/yr)	$0.059	$/kWh	$0
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$30,618
Administrative Charges	2%	of TCI			$115,280
Property Taxes	1%	of TCI			$57,640
Insurance	1%	of TCI			$57,640
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)					0.1186
Annual Capital Recovery (Recovery rate * TCI)					$683,610
TOTAL ANNUAL COST					**$995,819**

Uncontrolled Emissions (tons/yr):	169
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	151
Cost-Effectiveness ($/ton):	**$6,609**

Capital Recovery Factor

https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll

Total Capital Cost - C-1G - LEC

Total Capital Costs for LEC

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
LEC Capital	A	$4,000,000
Instrumentation	0.10 A	(included)
Taxes	0.05 A	$200,000
Freight	0.05 A	$200,000
Purchased equipment cost, PEC	B	**$4,400,000**
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
Direct installation cost	0.30 B	**$0**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$4,400,000**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$440,000
Construction and field expenses	0.05 B	$220,000
Contractor fees	0.10 B	$440,000
Start-up	0.02 B	$88,000
Performance test	0.01 B	$44,000
Contingencies	0.03 B	$132,000
Total Indirect Cost, IC	0.31 B	**$1,364,000**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$5,764,000**

Annual Costs - C-1G - LEC

Total Annual Costs for LEC

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
	Operator	0.5	hrs/shift (5 units)	30.00 $/hr	$16,200
	Supervisor	15%	of operator		$2,430
Operating Materials					-
Maintenance					
	Labor	0.5	hrs/shift (5 units)	30.00 $/hr	$16,200
	Material	100%	of maint. labor		$16,200
Utilities					
	Natural Gas	0	(kft3/yr)	$ 5.18 $/kft3	$0
	Electricity	0	(kWh/yr)	$0.059 $/kWh	$0
INDIRECT ANNUAL COSTS, IC					
	Overhead	60% of sum of operating labor and materials and maintenance labor and materials.			$30,618
	Administrative Charges	2%	of TCI		$115,280
	Property Taxes	1%	of TCI		$57,640
	Insurance	1%	of TCI		$57,640
	Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)				0.1186
	Annual Capital Recovery (Recovery rate * TCI)				$683,610
TOTAL ANNUAL COST					**$995,819**

Uncontrolled Emissions (tons/yr)	153
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	134
Cost-Effectiveness ($/ton):	**$7,425**

Capital Recovery Factor

https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll

Compressor Engines
(C-1A, C-1B, C-1C, C-1E, C1-G)

Nitrogen Oxides

SCR Control Technology

Capital Cost Derivation

Primary Reference:

Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032

Value	Units	Reference
\$35,000	\$/mmBtu	Table 1a : small turbines : 17,000 ↔ 35,000 \$/mmbtu : 1999 Dollars
		(assumed higher number since RICE, old engines and intermittent operation)
1,920	hp	Clark Engine
14.5	mmBtu/hr	Typical heat input to engine (from 2018 stack test)
17.4	mmBtu/hr	20% added since not at 100% load
167	CPI 1999	*https://www.bls.gov/cpi/tables/historical-cpi-u-201709.pdf*
240	CPI 2018	
1.44	CPI2018/CPI1999	Inflation rate raio
\$50,420	\$/Engine/mmBtu/hr	Adjusted Capital for 2017 - \$/mmBtu
\$65,546	\$/Engine/mmBtu/hr	Premium added as a retrofit: Source: EPA Air Pollution Control Technology Fact Sheet
\$1,140,504.20	\$/Engine	

\$1,140,504 Capital Cost per engine (2017 dollars @ 17.4 mmBtu/hr)

SCR - Input Calculations and Reference Information

Data is on a per engine basis.

Reference: EPA/452/B-02-001 Section 4.2 in Chapter 2

Parameter / Variable		Value	Units	Reference
Selective Catalytic Reduction (% Control);		85.0	percent	Approx ≈ 1g/bhp-hr
Uncontrolled emissions each RICE		153	Tons/yr (actual) per Engine	2016/2017 Inventory
Q_B =Max. Heat Input at HHV, MMBtu/h		17.200	MM Btu/hr per RICE	Test C1-C 2018 + 20%
ASR		1.5	Actual Stoichiometric Ratio	Chpt 2, SCR, Cost Control Manual, 2016, Eqn 2.1a-b for NO and NO_2[1]
$q_{flue\ gas}$		20,800	Inlet to SCR acfm	2018 stack test + 20%
qscfm		8,000	dscfm	2018 stack test + 20%
CF_{plant}		0.95	system capacity factor, CF_{plant}	EPA/452/B-02-001
η_{NOx}		0.85	NOx removal efficiency	Approx.
NH3 slip (ppmv)	$(ASR–\eta_{NOx})*60*MW_{Nh3}*dscfm/359.05/10\hat{}6$	0.015	lb/hr	
Catalyst volume	$2.81*Q_B*\eta_{adj}*slip_{adj}*Nox_{adj}*S_{adj}*T_{adj}/N_{SCR}$	205	ft^3	EPA/452/B-02-001
$N_{SCR\ (\#\ of\ SCR\ reactor\ chambers)}$		1		
η_{adj}	$(0.2869+(1.058*+\eta_{NOx}))$	1.19		EPA/452/B-02-001
Slip	$(ASR-\eta_{NOx})$	0.10		EPA/452/B-02-001
$Slip_{adj}$	1.2835-(0.0567*Slip)	1.28		EPA/452/B-02-001
NOx_{in}		3.8	lb/MM Btu	2018 stack test (typical)
NOx_{adj}	$0.8524+(0.3208*NOx_{in})$	2.071		EPA/452/B-02-001
S, sulfur in fuel		7.00E-06	(weight fraction)	Caterpillar
S_{adj}	0.9636+(0.0455*S)	0.964		EPA/452/B-02-001
SCR inlet temp		600	F^o	EPA/452/B-02-001
SCR inlet temp		589	K^o	
T_{adj} for inlet T not = 700 F	$15.16-(0.03937*T)+(2.74*10^{-5}*T^2)$	1.40		EPA/452/B-02-001
$A_{catalyst}$	$q_{flue\ gas}/(16*60)$	21.7	ft^2	EPA/452/B-02-001
n_{layer}	$V_{catalyst}/(h_{layer}*A_{catalyst})$	3.1	assume h = 3.1	EPA/452/B-02-001
$n_{layer\ -\ final}$		3	round n_{layer} to integer	EPA/452/B-02-001
h_{layer}	$V_{catalyst}/(n_{layer}*A_{catalyst})+1$	4.2		EPA/452/B-02-001
$n_{layer\ -\ total}$	$n_{layer\ -\ final}+1$	4		EPA/452/B-02-001
h_{SCR}	$n_{layer\ -\ total}*(c_{1+}h_{layer})+c_2$	53.6	ft	EPA/452/B-02-001
SCR height adjustment	$\$6.12*h_{SCR}-187.9$	140.2	$f(h_{SCR})$	EPA/452/B-02-001
$m_{reagent}$	$(NOx_{in}*Q_B*NSR*\eta_{NOX}*MW_{reagent)}/(MW_{NOx}*SR_T)$	30.8	lb/hr	EPA/452/B-02-001
$MW_{reagent}$		17.0	MW of ammonia	
MW_{NOx}		46.0	MW of NO_2	
NSR	ASR/SR_T	1.5	normalized stoichiometric rate	EPA/452/B-02-001 w/ NO_2:NO adjustment
SR_T		1.0	for ammonia	EPA/452/B-02-001
m_{sol}	$m_{reagent}/C_{sol}$	106.4	lb/hr	EPA/452/B-02-001
C_{sol}		0.29	concentration of aqueous soln	Typical solution concentration
ρ_{sol}		56	lb/ft^3	EPA/452/B-02-001
v_{sol}		7.5	gal/ft^3	EPA/452/B-02-001
q_{sol}	$m_{sol}/\rho_{sol}*v_{sol}$	14.2	gal/hr	EPA/452/B-02-001
t_{store}		14.0	reagent storage for t days	assumed, EPA/452/B-02-001
Tank volume	$q_{sol}*t$	4,774	gallons	EPA/452/B-02-001
Cost of reagent	RC	0.15	\$/lb	EPA/452/B-02-001, page 2-50 (Adj from 1998)
Cost of reagent (per hour)		\$16.16	\$/hour of ammonia	
Cost of reagent (per year)		\$141,539	\$/year (8,760) of ammonia	
Catalyst Cost	$CC_{replace}$	\$436.12	$\$/ft^3$	EPA/452/B-02-001, page 2-50 (1998 adjusted)
Catalyst Cost Replacement	$n_{SCR}*Vol_{catalyst}*(CC_{replace}/R_{layer})$	\$22,353	\$/replacement layer/year	EPA/452/B-02-001, Eqn 2.50 (1 layer/yr : 4 layers)
Pressure drop of SCR & ductwork	ΔP_{duct}	2.5	inches H_2O	assumed, EPA/452/B-02-001 (2 ↔ 3")
Pressure drop for catalyst	$Dp_{catalyst} = 0.875*n_{layer-final}$	2.6	inches H_2O	assumed, EPA/452/B-02-001

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[1] Stoichiometry adjusted for NO_2:NOx ratio from EPA database for the 60 reporting 2SLB engines = 46% : https://www3.epa.gov/scram001/no2_isr_database.htm
(2 molecules of ammonia required for 1 molecule of NO_2 reduction)
$2NO_2 + 4HN_3 \rightarrow 3N_2 + 6H_20$

Annual Costs - C-1A -SCR

Total Capital Costs for SCR

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Capital (5 engines)	A	$1,140,504
Instrumentation	0.10 A	$114,050
Sales taxes	0.05 A	$57,025
Freight	0.05 A	$57,025
Purchased equipment cost, PEC	B	**$1,368,605**
Direct installation costs		
Foundations & supports	0.08 B	$109,488
Handling & erection	0.14 B	$191,605
Electrical	0.04 B	$54,744
Piping	0.02 B	$27,372
Insulation for ductwork	0.01 B	$13,686
Painting	0.01 B	$13,686
Direct installation cost	0.30 B	**$410,582**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$1,779,187**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$136,861
Construction and field expenses	0.05 B	$68,430
Contractor fees	0.10 B	$136,861
Start-up	0.02 B	$27,372
Performance test	0.01 B	$13,686
Contingencies	0.03 B	$41,058
Total Indirect Cost, IC	0.31 B	**$424,268**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$2,203,454**

Annual Costs - C-1A -SCR

Total Annual Costs for SCR

Cost Item						Cost
DIRECT ANNUAL COSTS						
Operating Labor						
Operator		1	hrs/shift (5 units)	30.00	$/hr	$32,400
Supervisor		15%	of operator			$4,860
Operating Materials	Ammonia		yearly			$141,539
	Catalyst		yearly			$22,353
Maintenance						
Labor		1	hrs/shift (5 units)	30.00	$/hr	$32,400
Material		100%	of maint. labor			$32,400
Utilities						
Natural Gas		0	(kft3/yr)	$ 5.18	$/kft3	$0
Electricity		0	(kWh/yr)	$0.059	$/kWh	$0
INDIRECT ANNUAL COSTS, IC						
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.					$61,236
Administrative Charges				2%	of TCI	$44,069
Property Taxes				1%	of TCI	$22,035
Insurance				1%	of TCI	$22,035
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)						0.1186
Annual Capital Recovery (Recovery rate * TCI)						$261,330
TOTAL ANNUAL COST						**$676,656**

Uncontrolled Emissions (tons/yr): (5 units)	94
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	76
Cost-Effectiveness ($/ton):	**$8,917**

Capital Recovery Factor

https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll

Annual Total Capital Costs - C-1B - SCR

Total Capital Costs for SCR

Cost Item	**Factor**	**Cost**
DIRECT COSTS		
Purchased equipment costs		
Capital (5 engines)	A	$1,140,504
Instrumentation	0.10 A	$114,050
Sales taxes	0.05 A	$57,025
Freight	0.05 A	$57,025
Purchased equipment cost, PEC	B	**$1,368,605**
Direct installation costs		
Foundations & supports	0.08 B	$109,488
Handling & erection	0.14 B	$191,605
Electrical	0.04 B	$54,744
Piping	0.02 B	$27,372
Insulation for ductwork	0.01 B	$13,686
Painting	0.01 B	$13,686
Direct installation cost	0.30 B	**$410,582**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$1,779,187**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$136,861
Construction and field expenses	0.05 B	$68,430
Contractor fees	0.10 B	$136,861
Start-up	0.02 B	$27,372
Performance test	0.01 B	$13,686
Contingencies	0.03 B	$41,058
Total Indirect Cost, IC	0.31 B	**$424,268**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$2,203,454**

Annual Costs - C-1B -SCR

Total Annual Costs for SCR

Cost Item					**Cost**
DIRECT ANNUAL COSTS					
Operating Labor					
Operator	1	hrs/shift (5 units)	30.00	$/hr	$32,400
Supervisor	15%	of operator			$4,860
Operating Materials	Ammonia	yearly			$141,539
	Catalyst				$22,353
Maintenance					
Labor	1	hrs/shift (5 units)	30.00	$/hr	$32,400
Material	100%	of maint. labor			$32,400
Utilities					
Natural Gas	0	(kft3/yr)	$ 5.18	$/kft3	$0
Electricity	0	(kWh/yr)	$0.059	$/kWh	$0
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$61,236
Administrative Charges	2%	of TCI			$44,069
Property Taxes	1%	of TCI			$22,035
Insurance	1%	of TCI			$22,035
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)					0.1186
Annual Capital Recovery (Recovery rate * TCI)					$261,330
TOTAL ANNUAL COST					**$676,656**

Uncontrolled Emissions (tons/yr): (5 units)	157
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	138
Cost-Effectiveness ($/ton):	**$4,890**

Capital Recovery Factor

https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll

Annual Total Capital Costs - C-1C - SCR

Total Annual Costs for SCR

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Capital (5 engines)	A	$1,140,504
Instrumentation	0.10 A	$114,050
Sales taxes	0.05 A	$57,025
Freight	0.05 A	$57,025
Purchased equipment cost, PEC	B	**$1,368,605**
Direct installation costs		
Foundations & supports	0.08 B	$109,488
Handling & erection	0.14 B	$191,605
Electrical	0.04 B	$54,744
Piping	0.02 B	$27,372
Insulation for ductwork	0.01 B	$13,686
Painting	0.01 B	$13,686
Direct installation cost	0.30 B	**$410,582**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$1,779,187**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$136,861
Construction and field expenses	0.05 B	$68,430
Contractor fees	0.10 B	$136,861
Start-up	0.02 B	$27,372
Performance test	0.01 B	$13,686
Contingencies	0.03 B	$41,058
Total Indirect Cost, IC	0.31 B	**$424,268**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$2,203,454**

Annual Costs - C-1C -SCR

Total Annual Costs for SCR

Cost Item				Cost
DIRECT ANNUAL COSTS				
Operating Labor				
Operator		1 hrs/shift (5 units)	30.00 $/hr	$32,400
Supervisor		15% of operator		$4,860
Operating Materials	Ammonia	yearly		$141,539
	Catalyst			$22,353
Maintenance				
Labor		1 hrs/shift (5 units)	30.00 $/hr	$32,400
Material		100% of maint. labor		$32,400
Utilities				
Natural Gas		0 (kft3/yr)	$ 5.18 $/kft3	$0
Electricity		0 (kWh/yr)	$0.059 $/kWh	$0
INDIRECT ANNUAL COSTS, IC				
Overhead		60% of sum of operating labor and materials and maintenance labor and materials.		$61,236
Administrative Charges		2% of TCI		$44,069
Property Taxes		1% of TCI		$22,035
Insurance		1% of TCI		$22,035
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)				0.1186
Annual Capital Recovery (Recovery rate * TCI)				$261,330
TOTAL ANNUAL COST				**$676,656**

Uncontrolled Emissions (tons/yr): (5 units)	191
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	173
Cost-Effectiveness ($/ton):	**$3,920**

Capital Recovery Factor

https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll

Annual Total Capital Costs - C-1E - SCR

Total Capital Costs for LEC

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Capital (5 engines)	A	$1,140,504
Instrumentation	0.10 A	$114,050
Sales taxes	0.05 A	$57,025
Freight	0.05 A	$57,025
Purchased equipment cost, PEC	B	**$1,368,605**
Direct installation costs		
Foundations & supports	0.08 B	$109,488
Handling & erection	0.14 B	$191,605
Electrical	0.04 B	$54,744
Piping	0.02 B	$27,372
Insulation for ductwork	0.01 B	$13,686
Painting	0.01 B	$13,686
Direct installation cost	0.30 B	**$410,582**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$1,779,187**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$136,861
Construction and field expenses	0.05 B	$68,430
Contractor fees	0.10 B	$136,861
Start-up	0.02 B	$27,372
Performance test	0.01 B	$13,686
Contingencies	0.03 B	$41,058
Total Indirect Cost, IC	0.31 B	**$424,268**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$2,203,454**

Annual Costs - C-1E -SCR

Total Annual Costs for SCR

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
Operator		1	hrs/shift (5 units)	30.00 $/hr	$32,400
Supervisor		15%	of operator		$4,860
Operating Materials	Ammonia Catalyst		yearly		$71,753
Maintenance					
Labor		1	hrs/shift (5 units)	30.00 $/hr	$32,400
Material		100%	of maint. labor		$32,400
Utilities					
Natural Gas		0	(kft3/yr)	$ 5.18 $/kft3	$0
Electricity		0	(kWh/yr)	$0.059 $/kWh	$0
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$61,236
Administrative Charges			2% of TCI		$44,069
Property Taxes			1% of TCI		$22,035
Insurance			1% of TCI		$22,035
Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)					0.1186
Annual Capital Recovery (Recovery rate * TCI)					$261,330
TOTAL ANNUAL COST					**$584,517**

Uncontrolled Emissions (tons/yr): (5 units)	169
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	151
Cost-Effectiveness ($/ton):	**$3,879**

Capital Recovery Factor

https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll

Annual Total Capital Costs - C-1E - SCR

Total Annual Costs for SCR

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Capital (5 engines)	A	$1,140,504
Instrumentation	0.10 A	$114,050
Sales taxes	0.05 A	$57,025
Freight	0.05 A	$57,025
Purchased equipment cost, PEC	B	**$1,368,605**
Direct installation costs		
Foundations & supports	0.08 B	$109,488
Handling & erection	0.14 B	$191,605
Electrical	0.04 B	$54,744
Piping	0.02 B	$27,372
Insulation for ductwork	0.01 B	$13,686
Painting	0.01 B	$13,686
Direct installation cost	0.30 B	**$410,582**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$1,779,187**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$136,861
Construction and field expenses	0.05 B	$68,430
Contractor fees	0.10 B	$136,861
Start-up	0.02 B	$27,372
Performance test	0.01 B	$13,686
Contingencies	0.03 B	$41,058
Total Indirect Cost, IC	0.31 B	**$424,268**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$2,203,454**

Annual Costs - C-1E -SCR

Total Annual Costs for SCR

Cost Item						Cost
DIRECT ANNUAL COSTS						
Operating Labor						
	Operator	1	hrs/shift (5 units)	30.00	$/hr	$32,400
	Supervisor	15%	of operator			$4,860
Operating Materials	Ammonia		yearly			$141,539
	Catalyst					$22,353
Maintenance						
	Labor	1	hrs/shift (5 units)	30.00	$/hr	$32,400
	Material	100%	of maint. labor			$32,400
Utilities						
	Natural Gas	0	(kft3/yr)	$ 5.18	$/kft3	$0
	Electricity	0	(kWh/yr)	$0.059	$/kWh	$0
INDIRECT ANNUAL COSTS, IC						
	Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$61,236
	Administrative Charges	2%	of TCI			$44,069
	Property Taxes	1%	of TCI			$22,035
	Insurance	1%	of TCI			$22,035
	Capital Recovery Factor (15 yrs & prime rate + 3% = 8.25%)					0.1186
	Annual Capital Recovery (Recovery rate * TCI)					$261,330
TOTAL ANNUAL COST						**$676,656**

Uncontrolled Emissions (tons/yr): (5 units)	169
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	151
Cost-Effectiveness ($/ton):	**$4,491**

Capital Recovery Factor

https://www.ajdesigner.com/phpdiscountfactors/capital_recovery_equation.php#ajscroll

Stroh, David E.

From: St Clair, Tony <tstclair@hess.com>
Sent: Wednesday, March 13, 2019 3:21 PM
To: Stroh, David E.; O'Clair, Terry L.
Cc: Hal Robbins; Brian Murphy; Epperson, Brian; Sund, Vicky; Schmidt, David D.; Bugbee, Curtis; Lohnes, Brent
Subject: Hess Response to Regional Haze Second Planning Period Request
Attachments: 4-Factor Hess Tioga March 2019 Report.pdf

Follow Up Flag: Follow up
Due By: Monday, May 20, 2019 8:00 AM
Flag Status: Flagged

Categories: RH Facility

David,

In response to the Department's request for a four-factor analysis concerning emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx) at Hess's Tioga Gas Plant (letter request dated May 18, 2018), please find attached our report, which has been prepared in consultation with Bison Engineering Inc and guidance from the Department.

Should you have any questions after your review of our submittal, please do not hesitate to contact me for additional clarification or information.

Regards,

Tony St. Clair, P.E., BCEE, QEP, REM
Advisor, EHS - Environmental & Regulatory

HESS CORPORATION
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Houston, Texas 77010
Office: (713) 496-5031
Cell: (832) 570-6741
Email: tstclair@hess.com

Regional Haze
4-Factor Analysis

Tioga Gas Plant Facility
Hess Corporation

Prepared for:

North Dakota Department of Health
Environmental Health Section
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947

Prepared by:
Bison Engineering Inc.
1400 11th Ave.
Helena, MT 59601

Prepared on behalf of:

Hess Corporation
1501 McKinney Street
Office 21.104
Houston, Texas 77010

March 15, 2019

EXECUTIVE SUMMARY

Bison Engineering, Inc. was retained by Hess Corporation to prepare a 4-Factor analysis for specific units located at their Tioga Gas Plant located at Tioga, ND. The 4-Factor analysis was requested by North Dakota's Environmental Health Section, Division of Air Quality in a letter dated May 18, 2018.

The analysis itself relates to "Round 2" of development of a State Implementation Plan (SIP) to address Regional Haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308. The purpose of the 4-Factor analysis is, to determine if there are control options at Hess to reduce emissions that could be used to attain "reasonable progress" toward the state's visibility goals.

The 4-Factor analysis was conducted on three source groups at the Hess facility: amine sweetening unit, compressor engines and flares. The results of the analysis have indicated that additional controls on these units are not necessary to make reasonable progress due to costs and other considerations. It is concluded that these sources do not qualify for additional emission controls or limitations based on the 4-Factor analysis.

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1.0 INTRODUCTION

With the 1977 amendments to the Federal Clean Air Act (42 USC 7401 *et. seq.*) Congress declared as a national goal "… *the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution."* [42 USC 7491(a)(1)]. With that goal, plans and requirements were eventually codified in the Code of Federal Regulations primarily in 40 CFR 51.308. (The entire visibility program is found in 40 CFR 51.300 → 309). Individual states are required to establish "reasonable progress goals" [40 CFR 51.308(d)(1)] in order to "attain natural visibility conditions" by the year 2064 [§308(d)(1)(i)(B)].

The state of North Dakota has met the first round of those obligations with the establishment of Best Available Retrofit Technologies (BART) for various sources. A second round of obligations is now under development. The Regional Haze Rule (RHR) requires an additional step toward 'reasonable progress' in meeting the national goal.[1] The RHR identifies four factors which should be considered in evaluating potential emission control measures to make reasonable progress toward the visibility goal. These are as follows:

Factor 1. Cost of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance
Factor 4. Remaining useful life of any existing source subject to such requirements

These four factors are collectively known as the 4-Factor analysis.

To implement the requirement, the North Dakota Department of Health (NDDH) submitted a letter to Hess dated May 18, 2018. The letter noted that NDDH needed to address 80% of the visibility impairment caused by ND sources.[2] According to NDDH, visibility data from the IMPROVE ambient monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Areas indicate that sulfates and nitrates (via SO_2 and NOx; respectively) are the largest contributors to visibility impairment.[3]

In order to determine which 'nearby' sources should be subject to a 4-Factor analysis, NDDH conducted a Q/d (emissions/distance) analysis of SO_2 and NOx for industrial

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[1] The national goal is to attain natural visibility conditions in mandatory Class I areas by the year 2064 [40 CFR 51.308(d)(1)(i)(B)].

[2] According to NDDH this value is derived from information contained in EPA's Draft Guidance on Progress Tracking Metrics, Long Term Strategies found at: *https://www.epa.gov/sites/production/files/2016-07/documents/draft regional haze guidance July 2016.pdf.*

[3] Hess does not necessarily agree or disagree with this assessment at this time. Hess is providing the information in this document as requested by NDDH.

sources within the state. That analysis has indicated that there are three Hess sources (or source groups) that warrant the analysis according to NDDH. These sources are:

1. Amine Gas Sweeting Unit (Emission Unit S302)
2. Clark Compressor Engines (Emission Units CIA- CIG)
3. Flares (Emission Units S101 and S102)

Therefore, NDDH has requested HESS conduct at 4-Factor analysis for these units to assess potential reductions in SO_2 and NOx emissions. The May 18 letter and followup communication requested the analysis be completed no later than March 15, 2019.

Although NDDH requested an analysis of both SO_2 and NOx for all three source groups, subsequent analysis prompted a small change to the request. Based on correspondence between Hess and NDDH[4], it was agreed no robust analysis was necessary for SO_2 for the Clark Compressor Engines. Since these engines are fired with pipeline quality natural gas, there are no substantive SO_2 emissions from this source category. A similar conclusion was reached with respect to NOx emissions from the Amine Gas Sweetening unit. At the time of the email correspondence it was believed that NOx emissions from these units are low, so there would be no real visibility benefit by attempting to add additional NOx controls. However, subsequent review found a published emission factor for these units. The published factor indicated a low emission rate, as suspected. However, since an emission rate was available, it was decided to proceed with an analysis even though the reduction in NOx, should additional controls be added, would not yield any measurable improvement in visibility.

Based on the discussion above and agreement with NDDH[5], no formal SO_2 analysis was conducted for the compressor engines. For completeness, an NOx review was conducted for the Amine Sweetening Unit albeit with low actual emission rates.

The remainder of this document outlines the approach used to conduct the 4-Factor analyses along with a detailed analysis for each group.

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[4] Email to David Stroh from Tony St Clair (9/14/18) and associated reply (9/17/18)

[5] Ibid.

2.0 APPPROACH AND METHODOLOGY

The Tioga Gas Plant, the subject of this 4-Factor analysis, is located at 10340 68th Street NW in Tioga, North Dakota. The location is W½, NE¼ S26, T157N, R95W in Williams County. The plant is used to process natural gas from well sites for sale to customers.

Letters dated May 18, 2018 and January 16, 2019 from NDDH provided some recommendations for conducting the 4-Factor analysis. That information was supplemented based on an email from David Stroh (NDDH) to Tony St. Clair (Hess) which provided further discussion and recommendations (June 2018). The matter was again discussed in two conference phone calls between the staff of NDDH, Hess, and Bison Engineering on June 20, 2018 and January 30, 2019.

The most complicated or in-depth analysis of the four factors is Factor #1: Cost of Compliance. The NDDH email and phone conversation suggested this analysis should follow, in general terms, the methods conducted for a Best Available Control Technology (BACT) review. The agency made clear that this is not, in and of itself, a pure BACT analysis; only that the typical steps might be followed.

In addition to the direct contact with NDDH described above, EPA has provided draft guidance (EPA Draft Guidance) of its own for the entire Round 2 procedures including suggested methods for assessing the Cost of Compliance as well as the other 3 factors.[6] That guidance was published in July 2016 as a draft. We are not aware that the Draft Guidance has been finalized. Nonetheless, since this was the most recent EPA guideline available, that document was consulted for conducting this 4-Factor analysis.

In general, the cost analysis uses the overall approach for BACT, but is modified by the EPA Draft Guidance[7] and EPA's Control Cost manual[8]. The approach used in this analysis follows these recommendations and guidelines as much as practicable. The other 3 factors employed suggestions from the EPA Draft Guidance as much as reasonable or available data might have allowed.

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[6] "*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,*" EPA, EPA-457/P-16-001, July 2016. https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf

[7] Ibid.

[8] EPA Cost Control Manual (sixth edition): https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

3.0 4-FACTOR ANALYSIS

A 4-Factor analysis was completed for the three Hess sources/source groups selected by the NDDH Q/d analysis. The following outlines the analysis for each source using primarily the direction of the EPA Draft Guidance[9] and the WRAP 2009 4-Factor analysis[10].

The initial step in the 4-Factor analyses was to identify possible additional control options for each source or source group. The options chosen include control techniques addressed in guidelines published by the EPA, emission control cost models such as AirControlNET, Best Available Retrofit Technology (BART) analyses, White Papers prepared by the Midwest Regional Planning Organization (MRPO), and National Association of Clean Air Agencies (NACAA).

The options for each source/source category are summarized in the Table 1.

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[9] "*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,*" EPA, EPA-457/P-16-001, July 2016. https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf

[10] "*Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in North Dakota",* Brad Nelson, William Battye, Janet Hou, EC/R Incorporated, Western Regional Air Partnership (WRAP) and Western Governors' Association (WGA), May 18, 2009

Table 1: Additional Control Options by Source Group

Source	Emission Unit ID	Pollutant	Existing Controls	Control Efficiency (Existing)	Potential Additional Control Measures
Amine Gas Sweeting Unit (Sulfur Recovery Unit)	S302	SO_2	2-Stage Claus + Cold Bed Adsorption (CBA) + tail gas incinerator	$>98^{+}\%$	Oxidation or Reduction Options (Tail-Gas Scrubbing Treatment Unit, LO-CAT, Paques biological processes)
					Traditional Flue Gas Desulfurization (FGD)
		NO_2		---	SCR
		SO_2		$>98^{+}\%$	Acid Gas Disposal via Injection Well
Clark Compressor Engines (Natural gas pipeline compressor engines)	C1A through C1G	NO_2	Lean Burn Engines	---	Low Emission Combustion (LEC) - Turbocharge - Air-to-fuel - Ignition timing - Etc.
					SCR
					Electric Motor Replacement
Acid/Wet Gas Flare And High Pressure Flare	S101 and S102	SO_2 NO_2	None	---	Flare Management Plan

Amine Gas Sweeting Unit (SO_2)

The amine gas sweeting unit at the Hess Tioga Gas Plant facility controls sulfur dioxide (SO_2) emissions via two steps. The first is a 2-stage Claus process. This process converts hydrogen sulfide (H_2S) and SO_2 into elemental sulfur (S) via the 'Claus' reaction. The general reaction is: $H_2S + SO_2 \leftrightarrow S + H_2O$ (unbalanced). To drive the reaction toward completion, the facility further utilizes Cold Bed Adsorption (CBA) which allows this reversible reaction to proceed further. The CBA was installed in 1991. All-in-all the unit collectively reduces SO_2 emissions by 98^+%.

Treatment Options

The most common control measures that may be applied to a typical refinery-based Claus facility (with or without CBA) are generally categorized as Tail-Gas Scrubbing Treatment units (TGST). These units use either an oxidation or a reduction measure to continue to convert the underlying sulfur gas to elemental sulfur. Another common measure of removing sulfur dioxide from a gas stream is a traditional Flue Gas Desulfurization (FGD) unit that is more typically used at coal or oil-fired electrical generating units. The final option which could be applied is injecting the gas into a deep well for disposal.

The TGST control typically adds an additional scrubbing process to the Claus exhaust stream prior to the tail-gas incinerator. The processes classically convert the Claus exhaust to either H_2S (reducing process) or SO_2 (oxidizing process). In either case, the 'newly created' H_2S or SO_2 is then, in most cases, returns these gases to the Claus or CBA portion of the facility to extend the elemental sulfur recovery.

There are a number of processes that achieve this aim. Regarding the oxidation method, the exhaust stream from the CBA would oxidize the various sulfur compounds (S, H_2S, COS …) to sulfur dioxide. The sulfur dioxide is then concentrated and used in the Claus/CBA process itself. There are several varieties of processes within the oxidation method. They include the Stauffer, Wellman-Lord, and Aquaclaus. Only the Wellman-Lord process has been applied successfully in any US refinery.[11]

The reduction process, however, is the more typical refinery-based method of additional sulfur dioxide control. This process converts the sulfur gases from the Claus (or CBA) to H_2S. The H_2S is then sent to a scrubber for removal prior to a tail-gas incinerator. The H_2S scrubber typically uses an amine process (similar to the amine unit itself) to capture the H_2S and then recycles this captured H_2S (now in a concentrated stream) back to the Claus plant.

Five common systems utilizing the reduction control method are the LO-CAT®, Beavon, Beavon MDEA, Shell Claus Off Treatment (SCOT), and ARCO. The most common among these are the LO-CAT® and SCOT units. Additional oxidation-reduction processes

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[11] AP-42, Section 8.13, 1995, p 8.13-4.

for converting H_2S into sulfur include Sulferox, Stretford, and Paques biological process. For the oxidation-reduction processes, LO-CAT® has been among the predominant industry choice.[12] LO-CAT® is a proprietary liquid redox process that converts H_2S in the acid gas to solid elemental sulfur using an aqueous solution of iron as catalyst. LO-CAT® units are in service treating refinery fuel gas, off gas, sour-water-stripper gas, amine acid gas, and Claus tail gas. The acid gas stream is compressed and fed to a LO-CAT® Absorber unit where it contacts a dilute, iron chelate catalyst solution and the H_2S is absorbed and oxidized to solid sulfur. Sweet gas leaves the absorber for disposal via a tail gas disposal system. The reduced catalyst solution returns to the oxidizer, where sparged air reoxidizes the catalyst solution. The catalyst solution is then returned to the absorber. Sulfur is concentrated in the bottom of the oxidizer and sent to a sulfur filter, which produces the solid sulfur filter cake.

The other oxidation-reduction processes are not included for further consideration for the following reasons:

- Shell's Sulferox is effectively a more concentrated form of the LO-CAT® solution, but with resulting operational issues that makes it less widely used.
- Stretford has significantly declined in popularity due to environmental concerns due to the heavy metal vanadium used in the process.
- The Paques Biological Process has capital intensity similar to LO-CAT®, but with much less operational history, using sodium hydroxide and a bioreactor in the process to generate sulfur cake instead of the LO-CAT® approach using aqueous iron catalyst and air.

There are other units designed for refinery-like facilities to remove additional sulfur from the CBA stream. These include the Superclaus[13], Euroclaus[14] and others. For purposes of this analysis, however, it was decided not to attempt a specific cost analysis for each process mentioned above. It is more reasonable to pick one of the methods described above and conduct an analysis on that process.[15] It seems more than reasonable to presume that the cost of one of these processes is within the range of what might be expected for any single process. Additionally, cost estimates for these other processes is not readily available. For example, there is no recent published data for the SCOT, Superclaus or Euroclaus. Additionally, cost data is very vague or not available for many of the other units as well.

It was decided to use the LO-CAT® process as a surrogate for any and all of the oxidation or reduction options discussed above. Hess has received cost estimates from a proprietary vendor, Merichem, that provided some of the capital, indirect, and operation

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[12] MeriChem reports 200⁺ installations. http://www.merichem.com/gas/upstream/natural-gas/lo-cat

[13] Information regarding the Superclaus may be found here: http://www.digitalrefining.com/literature/1000817,Sulphur_Recovery_SUPERCLAUS___Process.html#.W-TGFPZFzDI

[14] Information regarding the Euroclaus may be found here. http://www.digitalrefining.com/literature/1000580,Sulfur_recovery___EUROCLAUS___process.html#.W-TFnfZFzDI

[15] This approach is discussed in the EPA Guidance. (See footnote 9).

costs associated with the installation and operation of the system specifically at the Tioga facility. The removal efficiency among all the units, including the LO-CAT®, are similar. They all range in sulfur removal from about 80 to 90% above the current operating system (98^+%). Should the results of the LO-CAT® (as a representative of oxidation or reduction option) prove favorable, then a more detailed review of some of the options would have been useful.

Flue Gas Desulfurization (FGD)

The second class of sulfur dioxide scrubbing for consideration is the traditional Flue Gas Desulfurization (FGD) unit. As noted earlier, this is the typical sulfur dioxide control system found in most coal and oil-fired electrical generation systems across the U.S. The FGD unit may be configured as a wet, semi-dry, or dry scrubber system. In all cases an alkaline compound (typically $CaCO_3$ or CaO) is used to react with SO_2 (an acidic gas) to form a compound such as $CaSO_3$. The $CaSO_3$ (and its related compounds) are then removed via a particulate control device such as a baghouse. EPA estimates FGD units' reduction emissions in the range of 50% to 98% where typically wet scrubbers achieve the highest control potential.[16]

While this may seem attractive, the FGD scrubbers have significant *a priori* disadvantages for this application. Among them include:

(a) In order to operate an FGD system, it is necessary to have a significant amount of (solid) material handling equipment on site. This would also include a large surface area to store, move and otherwise handle the reagent and spent-reagent material. This equipment and space might typically be available and designed in an FGD installation such as a coal-fired electrical generation station which handles materials (coal, e.g.) on routine basis. For this gas processing facility, however, none of the required space nor handling equipment is readily available. This would require a significant redesign of the facility in both layout and surface disturbance.

(b) FGD systems require a particulate control device to remove the alkaline scrubbing agent ($CaCO_3$, $Ca(OH)_2$, CaO, …). In a typical power plant facility, a control device to remove particulate would be required regardless of the SO_2 scrubber. For this application, however, no such device is installed nor necessary as particulate emissions from amine sweetening units (with Claus sulfur recovery) is nearly non-existent.

Thus, in order to install and operate an FGD for this facility, not only is an FGD itself necessary, but a complete particulate removal system will be required as well (typically a fabric filter). Thus, the FGD will add a new

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[16] EPA Air Pollution Control Technology Fact Sheet – Flue Gas Desulfurization: https://www3.epa.gov/ttncatc1/dir1/ffdg.pdf *

particulate emissions source at this facility; offsetting some of the reduction achieved by the sulfur-removing FGD system.

(c) An FGD system, regardless of the type, will require disposal of the spent reagent. Since space is limited at this site, the disposal will most likely take place at a “new” landfill. Thus, in addition to the cost necessary for the FGD, a suitable landfill site would need to be identified and a permit would need to be obtained. This would be a significant undertaking and not especially productive given other non-FGD processes are available.

(d) The non-FGD processes described earlier are more efficient at reducing sulfur compounds from entering the atmosphere than FGD. The control efficiencies for FGD would likely peak at about 80 to 90% (due to low concentration streams). Non-FGD units are expected to be significantly better.

(e) For wet scrubber FGD, a complete water system, including disposal, would be required. This is clearly unnecessary given other alternatives and the potential environmental consequences.

(f) To our knowledge, no FGD system has been installed at any gas processing facility such as the Tioga plant. This fact makes it clear that an FGD system is not a viable option for consideration.

(g) Finally, it is noted that the WRAP 2009 4-Factor analysis did not itself address nor consider FGD as an available technology. There was no discussion or cost estimates for this control technology.

For all of the reasons above, it was decided to not pursue the FGD option further and it was dropped from analyses that follow.

Acid Gas Disposal (AGD) Injection Well

Another theoretical control option is acid gas disposal (AGD) for the removal of sulfur dioxide and additional waste stream pollutants. This alternative was suggested by the agency as an item for consideration. AGD disposes of the SRU waste gas stream by compressing and injecting the acid gas into a suitable reservoir through an injection well. The control could dispose of the waste stream directly from the SRU.

The gas would be compressed through five stages (engines) of compression to achieve the appropriate pressure for injection into a reservoir. A gas dehydration unit would be required between compression stages four and five to remove water from the acid gas prior to injection. This step reduces hydrate and corrosion risks since water in the presence of high-pressure acid gas would prevent the use of normal metallic equipment and would result in significantly increased costs for the disposal of pipeline and well material. Compression would be achieved by electric drivers.

It has not been established at this early stage whether this option is technically feasible within the meaning of the 4-Factor (via BART) analysis. It is true that this technology has been used in some limited cases and thus it is ‘possible’ to apply. However, this technology is applied much differently than a typical pollution control technology. Typically, a particular control device is engineered, purchased and then installed on site. AGD is not that case. A key feature is to remove the gas many miles away and dispose of the gas in an unknown location. All of this assumes that it would be ‘feasible’ to purchase or lease land that Hess does not own and install or purchase a well for which no permit has been obtained and no location identified. Thus it is a folly to suggest this option is technically feasible at this time. It is not known if any disposal well might be appropriate or available in which multiple miles of right-of-way are required through property not yet identified or if the land owner would, in fact, provide permission and at a cost not yet determined. Nonetheless and at the request of the agency, a modest analysis as attempted. Hess does not acquiesce that this option is feasible.

AGD would require the construction of a pipeline and installation of an injection well into an effective formation. Pipeline and injection well tubing size were estimated by Hess along with associated costs for this analysis. Capital cost of compression and dehydration equipment are provided by proprietary vendor data. The project assumes that the compression system would be installed at the Tioga Gas Plant and the high-pressure acid gas would be exported via a 5-mile (initial estimate) pipeline to a new injection well. The assumed formation for injection was the Dakota formation, an aquifer currently used for water disposal from Tioga Gas Plant.

Acid gas injection has, from time to time, been used in North Dakota and has been used before to replace SRU units. However; confirmation of an acceptable injection zone and well location would require significant evaluation, no yet achieved, to understand the risks associated with the process (i.e., sufficient pressure/capacity/seal of a formation, integrity of the casing of nearby wells, and proximity of the Tioga community). In addition, the time to complete the required subsurface work and obtain the required permits for the AGD operation would make this a multi-year endeavor even if the option were feasible.[17]

Amine Gas Sweeting Unit (NOx)

The amine gas sweeting unit at the Hess Tioga Gas Plant facility contains no NOx post-control technologies; nor are any needed. NOx emissions from these units are typically very small, negating the need for post controls. Hess had suggested to NDDH that it was not necessary to conduct a 4-Factor analysis for this pollutant/unit. It was later discovered that a published emission factor was available for this unit.[18] Despite a low baseline emission rate for this unit (< 50 tons/year) an NOx analysis proceeded.

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[17] The vendor estimates a 3-year delivery time for the basic package.

[18] Emission Factor = 0.1 lb/10^6 BTU (AP-42, Table 8.13-2, April 2015)

A review of the literature indicates that the only practical technology that might be applied to this unit would be Selective Catalytic Reduction (SCR). SCR technology and its requirements and limitations are explained in detail below in the Compressor Engines section. For the sake of brevity, it will not be repeated here. For purposes of our analysis, however, it has been assumed that such a technology might achieve between 70% and 90% reduction in actual emissions.[19] (The actual NOx concentration in the steam is low, thus the anticipated percentage reduction would be modest at best).

Although a cost analysis has been conducted for this technology, it is not a foregone conclusion that such an application of SCR would be useful for Round 2. The emission reduction is small from a mass point of view. In addition, we are not aware that SCR has ever been applied at an amine unit anywhere in the US or elsewhere.

Compressor Engines (NOx)

The gas-fired engines at the Tioga facility drive integral compressors that boost the inlet field gas pressure for processing. The engines are fueled by a portion of the gas stream (pipeline quality fuel gas) produced by the plant. The exhaust gases from each compressor engine are released to the atmosphere through individual stacks.

The seven Clark Engines that have been identified by NDDH are large integral engines; i.e. the engines themselves and the compression structure are constructed as a single unit. Thus, replacement of these engines would be extraordinarily expensive and difficult as both the compression and engine would need to be replaced. Regardless, there are five 1,950 horsepower (hp) engines and two 2,250 hp engines. The two 2,250 hp engines were modified in 2004 by adding turbocharging systems and other means to lower emissions. The emissions from these two engines are about 75% less that the other engines and as such were not subject to additional analyses. The remaining five engines have not been substantively updated since they were installed in the 1950's although they have been maintained in good working order.

Three control options were assessed for the five 1,950 hp Clark Engines: Low Emission Controls (LEC); Select Catalytic Reduction (SCR) and converting engines from gas to electric power.

i) Low Emission Controls (LEC)

LEC application includes various upgrades, modifications, and engine tuning improvements. These typically include a combination of turbocharging [increases air-to-fuel (AFR) ratio], intercooling, enhanced mixing (high pressure fuel injection) and an

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[19] This is the range provided by the EPA Air Pollution Control Technology Fact Sheet for SCR: https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

increase in ignition energy.[20] LEC is the preferred approach to reduce lean burn engine NOx emissions when compared to alternative options such as SCR.[21]

LEC modifications provide additional air to a controlled engine which, as a result, reduces maximum combustion temperature and minimizes NOx formation. Excess air may hinder combustion of the air-to-fuel ratio in the cylinder, so a high energy ignition source is generally required for engines equipped with LEC. Pre-chamber combustions systems are generally used to aid in combustion, however the power operating range may decrease on two-stroke cycle engines as a result of an LEC conversion. The term “LEC” is often used broadly to describe a number of technology approaches that can be used depending on the engine and NOx emission limit. Normally, multiple LEC related technologies may be required. Therefore, LEC system modifications assessed for the 5 Hess compressor engines were assumed to be on the high end of any given range of costs.

The reduction in NOx emission rates expected from the application of LEC is roughly 70% to 90% (The same reduction may be expected for SCR). For purposes of this 4-Factor analysis and as a matter of consistency among the engines and control technologies (LEC vs SCR), it was presumed that each technology can achieve a controlled emission rate of 1 g/bhp-hr. This emission rate is about the same as a 90% reduction depending on the specific engine and technology. In addition, 1 g/bhp-hr is the emission rate applicable to most new internal combustion engines.[22] Since LEC would be applied to a set of older existing engines, the applied emission rate is conservatively low. The cost of compliance is assessed for LEC application to each of the five 1,950 hp Clark engines.

ii) ***Select Catalytic Reduction (SCR)***

SCR is an exhaust control that could be applied to lean combustion engines which reduces NOx emissions by reacting NOx with ammonia or urea over a catalyst. Ammonia or urea is injected into the stream and requires a precise feed-rate based on the NOx concentration and the NO/NO_2 ratio of the NOx. This feed rate, coupled with a narrow temperature range, is critical. If the ammonia feed rate is too low, then the targeted reduction in NOx is not achieved; thus, failing in the agency’s intent to improve regional visibility. If the ammonia rate is too high, then free ammonia is released. The ammonia will itself react in the atmosphere to form compounds such as ammonium sulfate(s) and ammonium nitrate(s). Both compounds are the primary ‘culprit’ that has led to the already observed regional haze concern. Thus, an improper feed rate will lead to a worsening of regional haze rather than making an improvement.

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[20] “*Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOX Control for Natural Gas Transmission and Storage Compressor Drivers*,” Interstate Natural Gas Association of America (INGAA), Report No. 2016-6, December 2017. *https://www.ingaa.org/File.aspx?id=33789*

[21] “*Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry.” INGAA Foundation. July 2014. https://www.ingaa.org/Foundation/FDNreports/NOx.aspx*

[22] 40 CFR 60, Subpart JJJJ, Table 1.

The process works by ammonia (the reagent) reacting with NOx on a catalyst bed to form water and N_2. The reaction is characterized as follows:

$$NO + NH_3 + O_2 \rightarrow N_2 + H_2O \text{ (unbalanced)}$$
$$NO_2 + NH_3 + O_2 \rightarrow N_2 + H_2O \text{ (unbalanced)}$$

While SCR has enjoyed a fairly wide applicability in power generation sources, its application to U.S. gas transmission sources has been very limited per INGAA 2014. That analysis details a number of the difficulties of applying SCR to gas transmission engines. These include:

a) There are numerous technical concerns about SCR's application to compressor engines. Among them are exhaust temperature requirements, reagent control, and the treatment of potential variations in the reciprocating engine exhaust NO/NO_2 ratio.
b) SCR has been more commonly applied to larger utility scale turbines and boilers and rarely used in compressor engines such as the Tioga facility.
c) The use of SCR is most effective when operating in the exhaust temperature range of 480 to 800°F. The typical exhaust temperature range for some lean burn engines may present challenges because the minimum operating temperature of the catalyst is dependent on the composition of the exhaust gases and the type of catalyst materials used.
d) Engines that have variable power loads, such as the case here, require more sophisticated controls to inject the proper amount of reagent, and it is not evident that robust control schemes have been developed for transmission applications.
e) The installation of a continuous emissions monitor could be required to effectively control the amount of reagent necessary to achieve the desired NOx emission rate.
f) SCR catalytic elements can be contaminated by byproducts of combustion (such as oil ash) and more importantly here; engine oil carryover. Cleaning and replacement is required on a periodic basis, and extra management is required to ensure adequate inventories of reagent are maintained.

While EPA claims that SCR is a technology applicable to compressor engines[23] SCR has, in fact, rarely been used in the natural gas transmission and related industry.[24] This does provide strong support for its use in this case.

LEC is nearly universally preferred over SCR for existing lean burn engines due to the issues described above. LEC works to prevent NOx formation while SCR acts to control already formed NOx in the exhaust stream.

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[23] "Air Pollution Control Technology Fact Sheet," SCR, EPA-452/F-03-032.
[24] INGAA Foundation, *op. cit.*

iii) ***Electric Compressors***

The third option under (initial) consideration is replacing these natural gas-fired integral (engine + compressor as a single unit) units with an electric powered unit. This possibility has been rejected, however, because such an option does not fall within the suggested EPA Guidance for the identification of alternative controls.[25]

More specifically, the EPA Draft Guidance document discusses (relying on BART policies) the options that may or should be considered in identifying 4-Factor (via BART) control options. The Draft Guidance contains the following discussion (in identifying technologies outlined by BART and acceptable to the 4-Factor analysis):

> "*Potentially applicable retrofit control alternatives can be categorized in three ways. Pollution prevention: use of inherently lower-emitting processes/practices, including the use of control techniques (e.g., low NOx burners) and work practices that prevent emissions and result in lower "production-specific" emissions (note that it is* ***not our intent to direct States to switch fuel forms, e.g., from coal to gas****), …"* (emphasis added). EPA Draft Guidance, p 180.[26]

This comment alone suggests that a fuel switch is not necessarily within the realm of a 4-Factor analysis. Clearly a switch from natural gas to electricity is, in effect, a fuel switch and not the intent of the analysis. The document goes on to provide a more specific discussion:

> "*We do* ***not consider*** *BART as a requirement to* ***redesign the source*** *when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired electric turbine* ***although*** *the turbine may be* ***inherently less polluting*** *on a per unit basis.*" (emphasis added). EPA Draft Guidance p. 198.[27]

Again, the Draft Guidance suggests that one does not need, nor should, consider what amounts to be a redefinition or fundamental change in the underlying facility/unit. If EPA rejects changing an electrical generation plant from coal-fired to a gas-fired turbine as inappropriate, the same logic applies here (gas-fired to electric).

For the reasons above, replacing these gas-fired engines with electric engines has been removed from further consideration.

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[25] *Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,*" EPA, EPA-457/P-16-001, July 2016. https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf

[26] Ibid.

[27] Ibid.

Flares (SO_2 & NOx)

The acid/wet gas flare (S-101) and high-pressure flare (S-102) operate intermittently at the Hess facility to combust off-spec gas and to address emergency/malfunction events. Both sources are to be assessed for additional NO_2 and SO_2 control. Additional control equipment systems for flare sources are not known or available for a facility whose emission rate is highly variable in both time and quantity. As a result, we are not able to identify any available control technologies for these two specific flares.

Even if a control technology were to present itself, the annual emissions from these two flares would almost certainly yield cost/ton of removal values that are not cost-effective. As evidence, the most recent 2-year average annual emissions for these two flares were:

SO_2

S-101 = 21 t/yr @ 79 hours of operation per year
S-102 = 40 t/yr @ 103 hours of operation per year

NOx

S-101 = 0.0 t/yr @ 79 hours of operation per year
S-102 = 4.6 t/yr @ 103 hours of operation per year

The low total emissions produced by the flare sources would result in a high cost effectiveness in $ per ton of emissions reduced since the total cost of implementation would only have the potential to control a minimal quantity of emissions. As a result, no further analyses of potential add-on controls were conducted for this source.

Nonetheless, a Flare Management Plan was also considered as a method for managing efficient operations of S-101 and S-102. The plan design could be similar to flare sources at petroleum refineries subject to 40 CFR Part 60 Subpart Ja which details the Standards of Performance for Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After May 14, 2007. A Flare Management Plan under subpart Ja requires various information such as: listing all refinery process units and systems connected to the flare; an assessment of whether discharges to the flare can be minimized; and an evaluation of the baseline flow to the flare. However, Hess, in agreement with NDDH, determined a Flare Management Plan would not be a necessary analysis due to the minimal operation of S-101 and S-102. Therefore, no additional analysis of a Flare Management Plan was conducted for these sources and is not included in Section 3.1 Cost of Compliance.

3.1 Factor 1: Cost of Compliance

The cost of compliance estimates the capital cost of purchasing and installing new control equipment along with the annual operation and maintenance (O&M) cost as generally outlined in EPA Draft Guidance. The 2009 WRAP analysis also delineated these cost parameters into the following categories: direct capital cost, indirect capital cost, labor cost, contingency cost, and annual cost. Methodologies given in the EPA Air Pollution Control Cost Manual (Control Cost Manual) are the indicated reference for determining the cost of compliance as directed by the EPA Draft Guidance.[28]

Costs were expressed in terms of cost-effectiveness in a standardized unit of dollars per ton of actual emissions reduced by the proposed control option. Baseline emissions for the Clark engines and SRU were evaluated to provide emission rates that are representative of the current operations' impact on actual observed visibility (haze) observations at Theodore Roosevelt National Park and the Lostwood Wilderness areas.[29] Appendix B contains a brief discussion and rationale for the specific baseline emissions chosen for the analyses in this document.

The capital recovery factor was applied to the control options based on a 20-year equipment life expectancy (25 years for SCR & LEC) applying the prime interest rate (5.5% as of December 19, 2018)[30]. The cost of compliance is analyzed by source/source group within Table 2 and the following sections.

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[28] EPA Cost Control Manual (sixth edition): https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

[29] These are the two closest Mandatory Class I areas that are the subject of a regional haze analysis and form the basis for the need for any potential reduction in emissions from sources in and around North Dakota.

[30] http://www.fedprimerate.com/

Table 2: Estimated Costs of Control Options for Hess Tioga Gas Plant Sources

Source	Potential Control Option	Pollutant	Estimated Control Efficiency (%)	Potential Emission Reduction (tons/year)	Estimated Capital Cost ($1000)	Estimated Annual Cost ($1000/year)	Cost Effectiveness ($/ton)
Amine Gas Sweeting Unit (SRU)	LO-CAT (or equivalent)	SO_2	90%	545	32,193	7,199	$13,217
	SCR	NO_2	80% ↔ 90%	37	435	273	$7,414
	Acid Gas Disposal via Injection Well	SO_2	99%	599	17,788	2,288	$3,821
Compressor Engines (Mean among 5 engines)	LEC	NO_2	1 g/bhp-hr[a]	139	9,095	1,205	$9,589[b]
	SCR	NO_2	1 g/bhp-hr[a]	139	745	892	$7,098[c]
Flares (2)	N/A	SO_2	--	--	--	--	--
	N/A	NO_2	--	--	--	--	--

[a] Emission reduction is assumed to achieve approximately 1 gram/bhp-hour.

[b] Cost effectiveness per engine ranged from $16,567 to $6,890. Individual values are found in Appendix A.

[c] Cost effectiveness per engine ranged from $12,275 to $5,103. Individual values are found in Appendix A.

[d] Capital cost does not include complete analyses in determining appropriate formation and injection scheme. Base-level research costs are accounted for however these costs could greatly vary in scale depending upon suitable geology, formation availability, and well and pipeline feasibility. While annual cost effectiveness appears favorable due to the 99% emissions reduction, the total capital cost is substantial and could likely exceed these early estimates.

3.1.1. Amine Gas Sweeting Unit

LO-CAT® (SO_2)

The cost estimate of a LO-CAT® unit includes the capital cost of constructing the system which comprises the absorber, oxidizer, and filtrate systems. Additionally, the system will require an enclosure because the sulfur forms a solid filter cake that is moist. This creates freezing risks in the winter that necessitates a predominately indoor operation. Capital costs were provided as proprietary information from the vendor; Merichem.[31] Direct and indirect costs are evaluated using the EPA Control Cost Manual. Indirect costs include engineering design, permitting, construction and field expenses, contractor fees, start-up, performance testing, and contingencies. Operational costs are evaluated primarily from vendor data and other standard techniques. Operating chemical consumption costs are based on system requirements using Merichem proprietary chemicals and utilities. Estimated costs are detailed in Appendix A. Design, construction, and operation of a LO-CAT® system is projected to cost approximately $13,217 per ton of SO_2 removed.

SCR (NOx)

To complete the analysis, a cost-effectiveness investigation was conducted for NOx. As noted earlier, the emission rate at this source is small and has, no doubt, an insignificant impact on regional haze. Regardless, a cost analysis was completed for SCR. Using the capital cost estimates found in EPA's Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032,[32] Table 1a, the cost effectiveness for controlling NOx was estimated at $7,414 per ton removed.[33] This value is outside the normal cost effectiveness range and thus is removed from further consideration.

Acid Gas Disposal (SO_2)

The cost estimate of an AGD system includes the capital cost of constructing a 5-stage compression and acid gas dehydration system, a pipeline to export waste gas, and an injection well into a qualifying reservoir. Indirect costs are substantive due to the overall development of an AGD system which include engineering design of the compression and dehydration system, pipeline, well, and stormwater management system; soil site characterization; geological surveying for reservoir characterization; environmental, cultural, and wetland delineation for an environmental assessment; site surveying; field inspections; industrial commission permitting; and contractor and equipment transportation fees. Capital costs for the compression and dehydration equipment are derived from proprietary vendor data that does not include EXW cost such as loading, freight, installation, etc. Direct and indirect costs for freight, engineering, construction, etc. are calculated using guidance and factors provided in the EPA Air Pollution Control Cost Manual. Installation and equipment cost of the pipeline and injection well are estimated by Hess as these activities directly involve their product/business lines. Pipeline

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[31] General information regarding Merichem and LO-CAT may be found: http://www.merichem.com/gas. The specific costs provided are considered Business Confidential by the vendor and are thus not provided in this document.

[32] https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

[33] Details of the calculation are found in Appendix A.

installation is calculated based on $125,000 per foot-diameter mile of pipeline and the installation well cost is estimated at 10,000 ft true vertical depth with 2-7/8” tubing.

The total capital investment of an AGD system is estimated at approximately $17,800,000 not including operating expenses or many other factors for which there is not enough information at this early stage. Based on this incomplete data, the cost effectiveness was estimated as $3,821 per ton removed ($SO_2$). If a more detailed analysis is warranted, the cost will, no doubt, rise substantially. This control option will require significant further evaluation to understand surface and subsurface risks (i.e., formation pressure-volume-seal, integrity of casing of nearby wells, proximity of the Tioga community, etc.) that are difficult to estimate at this early juncture. As a result, the cost of compliance is expected to be larger than this early estimate. Cost calculations for AGD are detailed in Appendix A.

3.1.2. Compressor Engines

The Clark Engines analysis included estimated costs for updating each of the five 1,950 hp with either LEC or SCR.

LEC (NOx)
The LEC analysis is based on various upgrades and changes to the 5 engines. At Hess’ request, and unrelated to this 4-Factor project, Siemens[34] provided a cost estimate for a LEC upgrade to a Clark engines. The scope of work and cost estimate is Siemens proprietary information. An upgrade to LEC consists of the following per Siemens:

- Hardware and engineering costs for replacing the existing cooling systems with water pump systems to eliminate boil-off cooling.
- Field service, repairs, and parts replacement for zero-hour overhaul.
- Hardware, installation, and commissioning of a HPfi fuel injection upgrade that needs to include:
    - A single “Balance of Plant” engineering and hardware support for multiple engine revamps.
    - Hardware, installation, and start-up of the HPfi equipment.

Using this information, LEC direct capital costs are approximately $4 million per engine. This cost coupled with the various emission rates for each of the five engines yielded a cost effectiveness ranging from $16,567 to $6,890 per ton of NOx removed. This equates to an average cost effectiveness among the 5 engines of $7,577.

It is theoretically possible to apply LEC to a subset of engines (e.g., 2 of the 5 engines). Doing so would yield a slightly lower cost effectiveness because one of the capital expenditures quoted by the vendor (balance of plant) need only be done a single time regardless of how many engines are retrofitted at the instant in time. This cost savings

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[34] https://new.siemens.com/us/en.html

assumes, of course, that all the retrofitted engines would be completed at the same time. That might prove problematic for plant operations as it is always imperative to have the necessary compression in the plant.

Regardless, it was instructive to briefly review the cost effectiveness of a retrofit for 2 (as an example) of the engines. Choosing the 2 lowest cost engines ($/ton) would result as follows:

Engine C-1C:		
	Stand Alone = $6,890/ton	With 2 Engines = $6,235
Engine C-1E:		
	Stand Alone = $7,050/ton	With 2 Engine = $6,296

While a savings would be recognized, the degree of improvement is not notable nor would likely change a final 4-Factor conclusion (assuming there is any perceptible improvement in regional haze impact from any of the control options).

SCR (NOx)

The capital costs for SCR, if one were to assume this was an ‘achievable technology’ for this application, are varied. There are a number of published cost estimates for typical coal- oil- and gas-fired medium to large sized boilers. The same cannot be said for a retrofit of a natural gas-fired compressor engine/compressor.

In addition, the cost of retrofit SCR is much higher than an original installation which would apply to this analysis. SCR systems used to retrofit an existing unit increase costs up to about 30%.[35] O&M costs may also be substantially dependent on reagent usage, catalyst replacement, and increased electrical usage. The average (all 5 engines) cost effectiveness of SCR was $7,098 per ton removed. Individual engines ranged from $12,275 to $5,103. This cost effectiveness range coupled with multiple technical difficulties and its non-use in this general application does not make it an attractive Round 2 candidate.

The derivation of the capital cost figures, emission rates and other general information may be found in the appropriate tables in Appendix A.

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[35] EPA Air Pollution Control Technology Fact Sheet – SCR: https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

3.2 Factor 2: Time Necessary for Compliance

Per the EPA Draft Guidance, the provisions for this factor within the BART guidelines should be utilized to estimate time necessary for compliance. Additionally, the best guide to determine time necessary for compliance is prior experience with the planning and installation of new emission controls. Source-specific factors should be considered as well.

EPA has estimated that it takes approximately 30 months to design, permit, build, and install a typical SO_2 scrubbing control unit for a single source. No specific data was located as it regards the LO-CAT unit (or its equivalent). Using the EPA estimate as a guide, their analysis also determined that 12-months is additionally required for a project including the installation of control equipment on multiple sources. Another 12 months may be required for staging the installation process across the multiple sources. Finally, it is generally recognized that facilities may require a 1 year (or more) for the procurement of project funding.

As a result, the time necessary for compliance for the LO-CAT unit is estimated at between four and five years. This time period accounts for about one year of capital acquisition; two to three years for designing, permitting, constructing, and installing the control equipment; and one year for shakedown and commissioning.

A longer timeline would also be expected for the LEC conversion for the five engines discussed in this report. The installation, tuning and integration would need to be executed in a sequential fashion in order to keep the facility in operation during this time. This will stretch the 'time necessary for compliance.' No specific time-line is offered at the time of this report. However, it would be reasonable to suggest that the time needed would be 5 years (one per year) as a minimum and perhaps as long as 7 depending on commissioning and plant operations.

Although no specific data was found, it would be reasonable to assume that a five-year period would also be appropriate for the installation of SCR in lieu of LEC being required. Finally, it was further reasoned that this five-year period serves as an estimate for the time necessary for installation of an SCR unit on the Amine Sweetening Unit, although its (and others) installation is not justified for cost effectiveness reasons.

It is likely that an even longer timeframe would be required for AGD installation. To begin, a likely vendor/supplier of the compressor engines and acid gas dehydration equipment estimated a 3-year delivery for that equipment alone. Additionally, AGD requires initial land surveying and additional permitting. Substantial surveying would be required to determine the appropriate location for an injection well for both surface and subsurface purposes. Land acquisition could be required for the location of the injection well which would require surface title research to determine a database of landowners whom would allow AGD injection within their property. Subsurface research would also be required to verify mineral title requirements and geotechnical evaluations that ensure the proposed formation has appropriate pressure limitations, volume, and seal. Additionally, a pipeline would need to be designed and permitted to connect the Tioga Gas Plant to a proposed injection well location posing additional challenges. These evaluations and logistics could add considerable time and unforeseen expense to an AGD project.

3.3 Factor 3: Energy and Non-Air Quality Environmental Impacts of Compliance

The provisions of the BART Guidelines are recommended for assessing both energy and non-environmental impacts. The EPA Draft Guidance states that an energy impacts assessment should be considered in terms of kilowatt-hours or mass of fuels used accounting for direct energy consumption cause by control implementation. Indirect energy inputs to produce the raw materials for construction of equipment should be excluded from the analysis. The Control Cost Manual is the preferred reference and provides advice on estimating energy requirements. Non-air environmental may include the cost associated with solid waste disposal, wastewater discharge, acid or nitrogen deposition, and climate impacts.

3.3.1. Amine Gas Sweeting Unit

LO-CAT® or Equivalent.

Per Merichem (proprietary), a LO-CAT system does not use any toxic chemicals and does not produce any hazardous waste byproducts. It requires a reasonable amount of catalyst however it is continuously regenerated in the process. Spent catalyst may require disposal though the implications of disposal of this waste stream has not been analyzed at this time since the cost effectiveness does not make its use a practical alternative.

There is also an energy cost associated with this added level of emission controls. It has been estimated that this level of technology would require about 610 kW-hr of use.[36]

AGD Injection Well.

A new waste stream from compression and dehydrator unit will be generated from this control method. AGD via an injection well is the disposal of pipeline and well tubulars in the event of water entering the system due to dehydrator breakdown/failure. Acid gas in the presence of water creates hydrate and corrosion risk which significantly increases the proper disposal of pipeline and well material. Additional environmental risks from the construction of the pipeline and injection well will need to be mitigated through various permitting and Environmental Assessment processes.

There is also a substantial electrical input required to operate the 5-stages of compression. The compression units are estimated to require approximately 950 kW-hr of energy.[37]

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[36] Proprietary information provided by Merichem.

[37] Proprietary information provided by compression and dehydration vendor.

3.3.2. Compressor Engines

SCR.

SCR control systems require the use of aqueous ammonia, anhydrous ammonia, or urea-to-ammonia reagents for the reduction reaction. Systems that use urea produce aqueous ammonia onsite. Anhydrous ammonia is nearly pure ammonia gas and must be transported and stored under pressure. Anhydrous ammonia is classified as a hazardous material which often requires special permits as well as additional procedures for transportation, handling and storage. Systems using aqueous ammonia transport and store the reagent concentration in water, generally ≈28% ammonia to water.[38] While aqueous ammonia can be safer to transport and store, the diluted ammonia concentration requires more storage capacity than anhydrous ammonia and requires shipping costs for the water solvent in the solution. Hess would be required to account for additional chemical storage, protection, ad permitting with the additional reagent solution stored on site.

Additionally, SCR systems utilize catalysts to aid in NOx control. The catalysts are generally composed of active metals or ceramics with a highly porous structure. Activated sites are located within the pores of the catalyst and these sites have an acid group on the end of the compound structure where the catalytic reduction reaction occurs. The catalyst material reactivates via rehydration or oxidation after the reduction reaction occurs. This is a limited process, however, and over time the catalyst activity decreases, requiring replacement, washing/cleaning, rejuvenation, or regeneration of the catalyst. Catalyst storage, transport, and disposal must then be accounted for in the SCR control viability analysis.

An estimate was made of the aqueous ammonia feed rate necessary for the facility. It is estimated that with all 5 engines in operation, a feed rate of about 15 gallons per hour per engine would be necessary.[39] To handle this much material would require a large storage tank (≈ 18,000 gallons for all engines) to have a 10-day supply. The storage or use of this quantity triggers the requirements of the accidental release program found in 40 CFR 68.[40] Depending upon specifics, a detailed amendment to the risk management plan (RMP) must be developed and implemented under this program. This only adds another layer of regulatory reporting along with an unnecessary risk by itself. The fact that such a plan would be required dampens its attractiveness for consideration.

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[38] EPA Cost Control Manual (sixth edition): https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

[39] See general calculations and data found in Appendix A (from EPA Cost Control Manual).

[40] The program is triggered for aqueous ammonia use or storage greater than 20,000 pounds. The quantities described exceed this value.

LEC.

The LEC technology does not require the handling or storage of hazardous materials as is the case for SCR. The LEC technology does not require, on its face, changes in pressure drop across any system that could create an energy demand penalty.

3.4 Factor 4: Remaining Useful Life

The Hess Tioga Gas Plant remaining useful/service life is not specific at this time. As discussed in the 2009 WRAP Analysis, the service life of these emission sources at industrial facilities are difficult to estimate.

The startup dates for these units were:
Amine Sweetening Unit: 1991
Compressor Engines (5): 1954
Flares: n/a

Regardless of the ability to select a particular time, the service life of the analyzed control technologies was estimated to be 20 years (25 years for LEC & SCR). The 20-year figure was used to amortize the capital costs of the add-on and modified (LEC and SCR for the compressor engines) emission controls at the recommendation of NDDH. Given the historical perspective, it is reasonable to conclude that the remaining life of the facility (Sweetening Unit and Engines) itself is expected to exceed the life of the control equipment.

The capital cost of the control equipment would need to be amortized over a shorter period if the remaining life of an emission source is less than the projected life of the new control equipment. Since this was not the case, the remaining equipment life of the facility is expected to equal or exceed the life of the analyzed technology options.

4.0 CONCLUSIONS AND RECOMMENDED SELECTION

A 4-Factor analysis has been conducted for the Hess Tioga facility. The analysis was conducted to meet the requirements of “Round 2” to develop of a State Implementation Plan (SIP) to address Regional Haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308(d)(1). To implement the requirement, the North Dakota Department of Health (NDDH) submitted a letter to Hess dated May 18, 2018, seeking such an analysis.

The 4 factors to be analyzed based on the NDDH letter and the regional haze rule were:

Factor 1. Cost of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance
Factor 4. Remaining useful life of any existing source subject to such requirements

NDDH then requested a 4-Factor analysis for SO_2 and NOx for the following source groups:

1. Amine Gas Sweetening Unit (S-302)
2. Clark Compressor Engines (C1A – C1G)
3. Flares (S-101 and S-102)

The emitting units were analyzed for these factors in general accordance with EPA’s Draft Guidance.[41] The details of those results were presented in prior sections of this report.

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[41] *Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period,”* EPA, EPA-457/P-16-001, July 2016. https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf

Amine Gas Sweetening Units.

SO_2

Three control technologies were considered for this unit-pollutant combination: Oxidation or Reduction Control (LO-CAT), Flue-gas desulfurization (FGD), and Acid gas disposal (AGD) via injection well. The LO-CAT technology (or its equivalent) essentially converts H_2S in the acid gas to solid elemental sulfur using an aqueous solution of iron as catalyst. The FGD system, typically found in a coal-fired power plant, treats exhaust gas with an alkaline reagent (usually CaO or $CaCO_3$) to remove SO_2. The spent reagent ($CaSO_3$ or $CaSO_4$) is then collected in a fabric filter unit in which the collected dust must be treated in a licensed landfill. AGD requires substantial design and preliminary surveying to determine the appropriate geological formation to install an injection well, pipeline, and compression-dehydration system.

It is concluded that the FGD system is not practical nor appropriate for this application. Those reasons include (but not limited to):

- A new emitting source (particulate) would be added to the plant offsetting some of the benefits of a reduction in SO_2;
- A new disposal system would be required to treat the spent reagent,
- FGD has never, to our knowledge, been used in treating SO_2 emissions from any gas processing facility; and
- The prior (2009) 4-Factor analysis for this facility did not identify nor consider FGD as a viable technology.

The LO-CAT® technology (or its equivalent) was analyzed. While the technology may be applied to a facility like the Tioga plant, it was rejected due to its high cost effectiveness (≈ $13,217/ton).

AGD is also not practical nor appropriate due to the unknown costs associated with determining surface and subsurface risks prior to the development of the pipeline and injection well. Additionally, the energy and environmental impacts add to the impracticality of this control option due to the additional electricity required to drive compression (nearly 1 megawatt).

NOx

Although the emission rate of NOx from the unit is very low, an analysis for this unit was conducted for thoroughness. The technology identified most probable for this unit is Selective Catalytic Reduction (SCR). SCR was rejected as inappropriate for numerous reasons including its rare use in integral engine-compressors and even more notably SCR's high cost (≈ $7,414/ton). Therefore, SCR is not a candidate for Round 2 emission reductions.

Compressor Engines.

NOx

There were two control technologies identified for reducing NOx from these units: SCR and Low Emission Control (LEC).

LEC is a system of upgrades, modifications and tuning of the engines to achieve a lower emission rate. LEC could, theoretically, be applied to each of the 5 compressor engines subject to this analysis.

The cost effectiveness of this technology was excessive. The average cost effectiveness was $9,589/ton for each of the 5 engines. The engine-by-engine cost effectiveness ranged from roughly $6,890 to as high as $16,567 depending on the engine. Since these values are considered excessive, LEC has been removed from consideration for Round 2.

SCR was also analyzed as a potential control technology. However, SCR is rarely, if ever, used for this type of application. Evidence of that stems from several reports. One recent study (2014) makes the following comment: "*To date, SCR application to U.S. gas transmission sources has been very limited, and SCR has not been applied to* ***an existing integral engine*** *(emphasis added)*."[42] The 5 engines at the Tioga facility are existing integral engines as described in the report. In addition, an even more recent report failed to consider SCR a noteworthy technology for reducing NOx emissions from transmission and storage compressors as a means of achieving the ambient NOx standards.[43]

Additionally, SCR carries the burden of handling and storing either anhydrous ammonia (NH_3) or aqueous ammonia (NH_4OH). This would require new equipment in which to transport and handle this material. In both cases, the storage quantities necessary will trigger the need for a Risk Management Plan (RMP) required by the Accidental Release program (40 CFR 68) in order to address the potential of a spill or release that could have public health implications. The addition of this equipment constitutes an unnecessary risk for the purpose of regional haze.

In addition to the burdens described, the efficacy of the control technology is at issue. For SCR to work effectively, a precise ammonia feed rate

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[42] "*Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry." INGAA Foundation. July 2014, Page 9.* *https://www.ingaa.org/Foundation/FDNreports/NOx.aspx*

[43] "*Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOX Control for Natural Gas Transmission and Storage Compressor Drivers*," Interstate Natural Gas Association of America (INGAA), Report No. 2016-6, December 2017. *https://www.ingaa.org/File.aspx?id=33789*

coupled with a narrow temperature range are necessary. Both conditions would be difficult to maintain due to varying loads on the compressor engines themselves.

Finally, the cost effectiveness of SCR is, overall, excessive. The average cost effectiveness was $7,098 for all 5 engines. The engine-by-engine effectiveness ranged from roughly $5,103 up to $12,275. Due to these costs, the technical concerns, the need to handle hazardous materials and the nearly universal lack of use of SCR for legacy compressor engines, SCR is rejected for Round 2 purposes.

Flares.

NOx and SO_2

A review of the literature does not yield any ‘available’ control technology to control either NOx or SO_2 emissions from these highly intermittent sources such as the Tioga flares. The flares primarily serve emergency and other upset conditions. For example, each flare operated 0.1% of the time in the past 2 years. Clearly, any control technology, even if it were available, would not have a measurable impact on the regional haze long-term goals. Because no reasonable technology is available, and no measurable regional haze benefit would be realized, it is concluded that there are no technology options available for these sources.

A Flare Management Plan similar to flare sources at petroleum refineries subject to 40 CFR Part 60 Subpart Ja would also not be appropriate due to the minimal flaring events at S-101 and S-102. Therefore, no additional analysis of a Flare Management Plan was conducted for this source.

Following a careful review of the information it is concluded that additional emission controls and limitations for these sources are not necessary to make reasonable progress based on the 4-Factor analysis.

APPENDIX A: COST CALCULATIONS

Amine Sweetening Unit (S-302)

Sulfur Dioxide

LO-CAT (or equivalent) Control Technology

Hess Corporation
4-Factor Cost Analysis
Tioga Facility
SRU

Total Capital Costs - Lo-Cat

Total Capital Costs for LO-CAT

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
LO-CAT Capital	A	$21,000,000
Instrumentation	0.10 A	(included)
Sales taxes	0.05 A	(included)
Freight	0.05 A	$1,050,000
Purchased equipment cost, PEC	B = 1.15 A	**$22,050,000**
Direct installation costs		
Foundations & supports	0.08 B	$1,764,000
Handling & erection	0.14 B	$3,087,000
Electrical	0.04 B	$882,000
Piping	0.02 B	$441,000
Insulation for ductwork	0.01 B	$220,500
Painting	0.01 B	$220,500
Direct installation cost	0.30 B	**$6,615,000**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$28,665,000**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	$2,205,000
Construction and field expenses	0.05 B	$1,102,500
Contractor fees	0.10 B	(included)
Start-up	0.02 B	(included)
Performance test	0.01 B	$220,500
Contingencies	0.03 B	(included)
Total Indirect Cost, IC	0.31 B	**$3,528,000**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + SP + Bldg.	**$32,193,000**

Annual Costs - Lo-Cat

Total Annual Costs for LO-CAT

Cost Item					Cost
DIRECT ANNUAL COSTS					
Hess and other estimtes					
Operator	1	hrs/shift	60.00	$/hr [1]	$65,700
Supervisor	15%	of operator			
Operating Materials				(2 train system)	
Merichem - 510	365	gal/day	$3,345	$/day/train	$2,441,850
Merichem - 520	12	gal/day	$655	$/day/train	$478,150
Merichem - 530	20	gal/day	$215	$/day/train	$156,950
KOH	460	lb/day	$58	$/day/train	$41,975
Maintenance					
Labor	0.5	hrs/shift	60.00	$/hr [1]	$32,850
Material	100%	of maint. labor			
Utilities					
Natural Gas	0	(kft3/yr)	$ 5.18	$/kft3	$0
Electricity	0	(kWh/yr)	$0.059	$/kWh	$0
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				
Administrative Charges	2%	of TCI			$643,860
Property Taxes	1%	of TCI			$321,930
Insurance	1%	of TCI			$321,930
Capital Recovery Rate Factor	(20 years at Prime (5.5%))				0.0837
Annualized Capital Recovery					$2,693,889
TOTAL ANNUAL COST					**$7,199,084**

(11-yr Average; w/o min and max)		
	Uncontrolled Emissions (tons/yr):	605
	Control Efficiency (additional):	90%
	Controlled Emissions (tons/yr):	60.5
	Tons Removed (tons/yr):	544.7
	Cost-Effectiveness ($/ton):	**$13,217**

Note:

Capital costs are from vendor (Merichem) and do not include freight, direct installation and (some) indirect installation

Operating materials are Merichem proprietary chemicals. Costs of those materials (Merichem-510, 520 & 530) were provided by Americhem

Capital Recovery Factor

$$CR = \frac{i(1+i)^n}{-1+\ (1+i)^n}$$

n = 20 years
i = 5.5% interest rate
CR = 0.0837

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[1] EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

Amine Sweetening Unit (S-302)

Nitrogen Oxides

SCR Control Technology

Amine Sweetening Unit (S-302)

SRU Claus Plant Tail Gas Incineration

	Year					
Parameter	2014	2015	2016	2017	Units	Reference
Fuel burned	773	821	1,100	1,131	10^6 ft^3	Annual emissions inventory
Heating Value	980	980	950	950	btu/ft^3	Assumed
Heat input	7.57E+05	8.04E+05	1.05E+06	1.07E+06	mmbtu/year	Calculated
Heat input	86	92	119	123	mmbtu/hour	Calculated
Emission Factor	0.1	0.1	0.1	0.1	#/10^6 BTU	AP-42, Table 8.13-2, April 2015
Emissions	38	40	52	54	tons/year	Calculated

Emission Factor Reference:
AP-42, Section 8.13, Table 8.13-2, April 2015

Heat input	105	(average)	mmbtu/hour
Emissions	46		tons/year

SCR - Input Calculations and Reference Information

Reference: EPA/452/B-02-001 Section 4.2 in Chapter 2

Parameter / Variable		Value	Units	Reference
Removal Efficiency	η_{NOx}	80	%	EPA-CICA Fact Sheet EPA-452/F-03-032 - Mean value is chosen
Actual Emissions		46	Tons/yr (actual)	Mean emissions: 2014→ 2017. AP-42, Table 8.13-2, April 2015 (0.1
Q_B =Max. Heat Input at HHV, MMBtu/h		107	Max MM Btu/hr	Max annual value from annual EI report - most recent 4 years
ASR (or SRF)		1.050	Actual Stoichiometric Ratio	EPA/452/B-02-001; p 2-55; May 2016
$q_{flue\ gas}$		27,309	Inlet to SCR ft^3/min_{dry}	2017 RATA
qscfm		11,844	$ft^3/min_{dry\text{-}std\ temperature\ \&\ pressure}$	2017 RATA
CF_{plant}		0.95	system capacity factor, CF_{plant}	EPA/452/B-02-001
η_{NOx}		0.8	NOx removal efficiency	Assumes mean reported EPA Fact Sheet value - see 1st reference ab
NH_3 slip	$(ASR-\eta_{NOx})*60*MW_{Nh3}*dscfm/359.05/10^6$	0.008	lb/hr	Conversion to lb/hour
Catalyst volume ($V_{catalyst}$)	$2.81*Q_B*\eta_{adj}*slip_{adj}*Nox_{adj}*S_{adj}*T_{adj}/N_{SCR}$	519	ft^3	EPA/452/B-02-001: eqn. 2.22
$N_{SCR\ (\#\ of\ SCR\ reactor\ chambers)}$		1		
η_{adj}	$(0.2869+(1.058*+\eta_{NOx}))$	1.13	NOx efficiency adjustment factor	EPA/452/B-02-001; eqn. 2.23
Slip	$(ASR-\eta_{NOx})$	0.15	Ammonia slip factor	EPA/452/B-02-001; eqn. 2.24
$Slip_{adj}$	1.2835-(0.0567*Slip)	1.27		EPA/452/B-02-001; eqn. 2.26
NOx_{in}		0.1	lb/MM Btu	AP-42, Section 8.13, Table 8.13-2; April, 2015
NOx_{adj}	$0.8524+(0.3208*NOx_{in})$	0.884		EPA/452/B-02-001; eqn. 2.25
S, sulfur in fuel		1.8E-05	(weight fraction)	https://www.pge.com/pipeline/operations/sulfur/sulfur_info/index.page
S_{adj}	0.9636+(0.0455*S)	0.964		EPA/452/B-02-001
SCR inlet temp		600	F°	Presumed (req'd for SCR)
SCR inlet temp		589	K°	Calculated (from F°)
T_{adj} for inlet T not = 700 F	$15.16-(0.03937*T)+(2.74*10^{-5}*T^2)$	1.40		EPA/452/B-02-001; 7th Edition; Eqn. 2.27
$A_{catalyst}$	$q_{flue\ gas}/(16*60)$	28.4	ft^2	EPA/452/B-02-001; 7th Edition; Eqn. 2.28
n_{layer}	$V_{catalyst}/(h_{layer}*A_{catalyst})$	5.9	ft^3 (use nominal h = 3.1 feet)	EPA/452/B-02-001; 7th Edition; Eqn. 2.31
$n_{layer\ -\ final}$		6	# of layers (rounded to integer)	Calculated
h_{layer}	$V_{catalyst}/(n_{layer}*A_{catalyst})+1$	4.1	ft	EPA/452/B-02-001; 7th Edition; Eqn. 2.32
$n_{layer\ -\ total}$	$n_{layer\ -\ final}+1$	7		EPA/452/B-02-001; 7th Edition; Eqn. 2.33
h_{SCR}	$n_{layer\ -\ total}*(c_{1+}h_{layer})+c_2$	85.5	ft : c_1=7, c_2=9 per eqn. 2.34	EPA/452/B-02-001; 7th Edition; Eqn. 2.34
$m_{reagent}$	$(NOx_{in}*Q_B*NSR*\eta_{NOX}*MW_{reagent)}/(MW_{NOx}*SR_T)$	3.3	lb/hr	EPA/452/B-02-001; 7th Edition; Eqn. 2.35
$MW_{reagent}$		17.0	MW of ammonia	https://pubchem.ncbi.nlm.nih.gov/compound/ammonia
MW_{NOx}		46.0	MW of NO_2	https://pubchem.ncbi.nlm.nih.gov/compound/nitrogen%20dioxide
NSR	ASR/SR_T	1.05	normalized stoichiometric rate	EPA/452/B-02-001; Section 2.5
SR_T		1.0	for ammonia	EPA/452/B-02-001
C_{sol}		0.29	concentration of aqueous soln	Typical aqueous soln
m_{sol}	$m_{reagent}/C_{sol}$	11.5	lb/hr	EPA/452/B-02-001; 7th Edition; Eqn. 2.36
ρ_{sol}		56	lb/ft^3 (solution density)	https://www.sigmaaldrich.com/catalog/product/aldrich/380539?lang=en&region=US
v_{sol}		7.5	gal/ft^3 (volume conversion)	https://en.wikipedia.org/wiki/Cubic_foot
q_{sol}	$m_{sol}/\rho_{sol}*v_{sol}$	1.5	gal/hr (reagent feed rate)	EPA/452/B-02-001; 7th Edition; Eqn. 2.37
t_{store}		14.0	reagent storage for t days	Assumed minimum required storage period
Tank volume	$q_{sol}*t$	515	gallons	Calculated
Cost of reagent	RC	0.48	$/lb	EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)
Cost of reagent (per hour)		$5.45	$/hour of ammonia	Calculated
Cost of reagent (per year)		$47,740	$/year of ammonia	Calculated
Catalyst Cost	$CC_{replace}$	$160	$/$ft^3$	EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)
Catalyst Cost Replacement	n_{SCR} * $Vol_{catalyst}$ * $(CC_{replace}/R_{layer})$	$12,038	$/one replacement layer/year	EPA/452/B-02-001, Eqn 2.50

https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

Hess Corporation
4-Factor Cost Analysis
Tioga Facility
SRU Claus Plant Tail Gas Incineration
NOx
SCR Control

Capital Cost Derivation

Primary Reference:
Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

Value	Units	Reference
$2,500	$/mmBtu	Table 1a : small/large turbines : 1,500 ↔ 3,500 $/mmbtu : 1999 Dollars (assumed a mid-range value)
105.0	mmBtu/hr	Annual emissions report to NDDH (= 4 year mean: 2014 → 2017)
167	CPI 1999	*https://www.bls.gov/cpi/tables/historical-cpi-u-201709.pdf*
240	CPI 2017	
1.44	CPI2017/CPI1999	Price Index Ratio
$378,314	$	Adjusted Capital for 2017 - $/mmBtu
$435,061	15%	EPA suggests retrofit costs is up to 30% premium addition. A mid-range of 15% was used as a reasonble estimate.

Annual Costs - SCR - Amine Sweetening Unit

Total Capital Costs for SCR

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Capital	A	$435,061
Instrumentation	0.10 A	(included)
Sales taxes	0.05 A	(included)
Freight	0.05 A	(included)
Purchased equipment cost, PEC	B	**$435,061**
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
Direct installation cost	0.30 B	**$0**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$435,061**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	(included)
Construction and field expenses	0.05 B	(included)
Contractor fees	0.10 B	(included)
Start-up	0.02 B	(included)
Performance test	0.01 B	(included)
Contingencies	0.03 B	(included)
Total Indirect Cost, IC	0.31 B	**$0**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$435,061**

Annual Costs - SCR - Amine Sweetening Unit

Total Annual Costs for SCR

Cost Item				Cost
DIRECT ANNUAL COSTS				
Operating Labor				
	Operator	0.5 hrs/shift	60.00 $/hr [2]	$32,400
	Supervisor	15% of operator		$4,860
Operating Materials	Ammonia consumption			$47,740
	Catalyst replacement (4 layers: 1 layer/year)			$12,038
Maintenance				
	Labor	0.5 hrs/shift	60.00 $/hr [2]	$32,400
	Material	100% of maint. labor		$32,400
Utilities				
	Natural Gas	0 (kft3/yr)	$ 5.18 $/kft3	$0
	Electricity	0 (kWh/yr)	$0.059 $/kWh	$0
INDIRECT ANNUAL COSTS, IC				
	Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		$61,236
	Administrative Charges	2% of TCI		$8,701
	Property Taxes	1% of TCI		$4,351
	Insurance	1% of TCI		$4,351
	Capital Recovery Factor (25 yrs & prime rate = 5.5%)			0.0745
	Annual Capital Recovery (Recovery rate * TCI)			$32,434
TOTAL ANNUAL COST				**$272,910**

Uncontrolled Emissions (tons/yr): [1]	46
Emission reduction (%) [3]	80%
Controlled Emissions (tons/yr):	9
Tons Removed (tons/yr):	37
Cost-Effectiveness ($/ton):	**$7,414**

[1] Mean emissions for last 4 reporting years

[2] EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

[3] EPA-452/F-03-32; Efficiency range = 70% ↔ 90%; a lower range is expected since the inlet concentration is very low (0.1 #/mmbtu). A mid value of 80% was chosen.

Capital Recovery Factor $CR = \frac{i(1+i)^n}{-1+(1+i)^n}$

n =	25	years
i =	5.50%	interest rate
CR =	0.0745	

Amine Sweetening Unit (S-302)

Sulfur Dioxide and NOx

Acid Gas Injection Well

Total Capital Costs - Acid Gas Injection Well

Total Capital Costs for Acid Gas Injection

Cost Item	Factor	Cost
DIRECT COSTS - *Compression and Dehydration System*		
Purchased equipment costs		
Compressor Engine Package (vendor data at EXW)	A	$3,500,000
Acid Gas Dehy package (vendor data at EXW)	A	$1,750,000
Instrumentation	0.10 A	$525,000
Sales taxes	0.05 A	$262,500
Freight	0.05 A	$262,500
Purchased equipment cost, PEC	B = 1.15 A	**$6,300,000**
Direct installation costs		
Foundations & supports	0.08 B	$504,000
Handling & erection	0.14 B	$882,000
Electrical	0.04 B	$252,000
Piping	0.02 B	$126,000
Insulation for ductwork	0.01 B	$63,000
Painting	0.01 B	$63,000
Direct installation cost	0.30 B	**$1,890,000**
Total Direct Cost, DC (Compression/Dehydration)	1.30 B	**$8,190,000**
INDIRECT COSTS - *Compression and Dehydration System*		
Engineering	0.10 B	$630,000
Construction and field expenses	0.05 B	$315,000
Contractor fees	0.10 B	$630,000
Start-up	0.02 B	$126,000
Performance test/Site inspections	0.01 B	$63,000
Contingencies	0.03 B	$189,000
Total Indirect Cost, IC (Compression/Dehydration)	0.31 B	**$1,953,000**
DIRECT & INDIRECT COSTS - *Pipeline and Injection Well*		
Pipeline Installation (Hess provided cost)		$2,500,000
(5 miles; 4", Sch. 80; $125,000/diameter mile)		
Install Disposal Well (Hess provided cost)		$5,000,000
(10,000 ft., TVD, 2-7/8" tubing)		
Land Acquisition	Stand alone value	$20,000
Permitting	Stand alone value	$125,000
Total DC & IC (Pipeline and Disposal Well		**$7,645,000**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	1.61 B + Pipe + Well	**$17,788,000**

Annual Costs - Acid Gas Injection Well

Total Annual Costs for Acid Gas Injection

Cost Item		Cost
DIRECT ANNUAL COSTS	***(Does not include Well Workovers)***	
Hess and other estimtes		
Annual Operating Expense		
Compression electricity		$800,000
Gas dehydration		
Compressor maintenance		
INDIRECT ANNUAL COSTS, IC		
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.	
Administrative Charges	2% of TCI	
Property Taxes	1% of TCI	
Insurance	1% of TCI	
Capital Recovery Factor (Annualized Capital Cost, 20 yrs at 5.5%)		0.0837
Capital Recovery Factor	$CR = \frac{i(1+i)^n}{-1+\ (1+i)^n}$	
n =	20 years	
i =	5.50% interest rate	
CR =	0.0837	
Capital Recovery Cost (Capital Recovery Factor x TCI):		$1,488,488
TOTAL ANNUAL COST (Capital Recovery Cost + Annual Operating Expense)		**$2,288,488**
Uncontrolled Emissions (tons/yr) [11 yr mean w/o min and max]:		605
Control Efficiency (additional) [assumes near zero emissions]:		99%
Controlled Emissions (tons/yr):		6.1
Tons Removed (tons/yr):		599.0
Cost-Effectiveness ($/ton):		**$3,821**

Compressor Engines
(C-1A, C-1B, C-1C, C-1E, C1-G)

Nitrogen Oxides

LEC Control Technology

Input Variables and Derivation

Nitrogen Oxides – LEC

Capital Cost Derivation - NOx - LEC

Primary Reference:

Siemen's Budgetary Proposal
Hess Tioga Facility: Estimate to Revamp/Upgrade Unit 5 (Serial 54040) : C1-E
September, 2018

Item #	Cost	Basis	Discussion
1	$345,000	Per Engine	Replace existing cooling system to eliminate boil-off and replace water pump system. This includes hardware and engineering only.
2	$2.5 million	Per Engine	Complete "zero-hour" overhaul. Includes field service, repairs and necessary parts replacement.
3	$3.7 ↔ $4.2 million	Per Engine	Provide high pressure fuel injection (HPFi) upgrade implementation. Includes hardware, installation and commissioning.
4	$2.0 ↔ $2.5 million	One-time cost	One-time "balance of plant" engineering and hardware to support multiple engine retrofits. Cost is the same regardless of 1 or all 5 engines.

Emissions Inventory: Actual (Average of past 5 years with min & max years removed from the calculation)

Engine	Tons/Year (5-yr mean with min & max removed)
C-1A	91
C-1B	160
C-1C	193
C-1E	189
C-1G	153
Mean: All 5 Engines	**158**

Single Engine Only

Total Capital Cost - C-1A - LEC

Total Capital Costs for LEC

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
High pressure fuel injection upgrade, including hardware installation and commissioning	(cost per engine)	$4,000,000
Subtotal:		**$4,000,000**
Direct installation costs		
Zero-Hour overhaul (+ field services, repairs etc.)	(mean cost per engine)	$2,500,000
Replace cooling system (hardware & engineering only)	(per engine)	$345,000
Electrical		(included)
Piping		(included)
Insulation for ductwork		(included)
Painting		(included)
Subtotal:		**$2,845,000**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$6,845,000**
INDIRECT COSTS (Installation)		
Balance of Plajnt Engineering + Hardware	(mean cost for one engine)	$2,250,000
Construction and field expenses		(included)
Contractor fees		(included)
Start-up		(included)
Performance test		(included)
Contingencies		
Total Indirect Cost, IC		**$2,250,000**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$9,095,000**

Annual Costs - C-1A - LEC

Total Annual Costs for LEC

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
Operator	0.5	hrs/shift (5 units)	60.00	$/hr [1]	$32,400
Supervisor	15%	of operator			$4,860
Operating Materials					-
Maintenance					
Labor	0.5	hrs/shift (5 units)	60.00	$/hr [1]	$32,400
Material	100%	of maint. labor			$32,400
Utilities					
Natural Gas	0	(kft3/yr)	$ 5.18	$/kft3	$0
Electricity	0	(kWh/yr)	$0.059	$/kWh	$0
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$61,236
Administrative Charges	2%	of TCI			$181,900
Property Taxes	1%	of TCI			$90,950
Insurance	1%	of TCI			$90,950
Capital Recovery Factor (20 yrs @ prime rate 5.25%)					0.0745
Annual Capital Recovery (Recovery rate * TCI)					$678,026
TOTAL ANNUAL COST					**$1,205,122**

Uncontrolled Emissions (tons/yr):	91
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	73
Cost-Effectiveness ($/ton):	**$16,567**

Capital Recovery Factor $CR = \frac{i(1+i)^n}{-1+\ (1+i)^n}$

n = 25 years
i = 5.50% interest rate
CR = 0.0745

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[1] EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

Single Engine Only

Total Capital Cost - C-1B - LEC

Total Capital Costs for LEC

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
High pressure fuel injection upgrade, including hardware installation and commissioning	(cost per engine)	$4,000,000
Subtotal:		**$4,000,000**
Direct installation costs		
Zero-Hour overhaul (+ field services, repairs etc.)	(mean cost per engine)	$2,500,000
Replace cooling system (hardware & engineering	(per engine)	$345,000
Electrical		(included)
Piping		(included)
Insulation for ductwork		(included)
Painting		(included)
Subtotal:		**$2,845,000**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$6,845,000**
INDIRECT COSTS (Installation)		
Balance of Plajnt Engineering + Hardware	(mean cost for one engine)	$2,250,000
Construction and field expenses		(included)
Contractor fees		(included)
Start-up		(included)
Performance test		(included)
Contingencies		
Total Indirect Cost, IC		**$2,250,000**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$9,095,000**

Annual Costs - C-1B - LEC

Total Annual Costs for LEC

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
Operator	0.5	hrs/shift (5 units)	60.00	$/hr [1]	$32,400
Supervisor	15%	of operator			$4,860
Operating Materials					-
Maintenance					
Labor	0.5	hrs/shift (5 units)	60.00	$/hr [1]	$32,400
Material	100%	of maint. labor			$32,400
Utilities					
Natural Gas	0	(kft3/yr)	$ 5.18	$/kft3	$0
Electricity	0	(kWh/yr)	$0.059	$/kWh	$0
INDIRECT ANNUAL COSTS, IC					
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$61,236
Administrative Charges	2%	of TCI			$181,900
Property Taxes	1%	of TCI			$90,950
Insurance	1%	of TCI			$90,950
Capital Recovery Factor (20 yrs @ prime rate 5.25%)					0.0745
Annual Capital Recovery (Recovery rate * TCI)					$678,026
TOTAL ANNUAL COST					**$1,205,122**

Uncontrolled Emissions (tons/yr):	160
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	142
Cost-Effectiveness ($/ton):	**$8,503**

Capital Recovery Factor $CR = \frac{i(1+i)^n}{-1+\ (1+i)^n}$

n = 25 years

i = 5.50% interest rate

CR = 0.0745

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[1] EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

Single Engine Only

Total Capital Cost - C-1C - LEC

Total Capital Costs for LEC

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
High pressure fuel injection upgrade, including hardware installation and commissioning	(cost per engine)	$4,000,000
Subtotal:		**$4,000,000**
Direct installation costs		
Zero-Hour overhaul (+ field services, repairs etc.)	(mean cost per engine)	$2,500,000
Replace cooling system (hardware & engineering	(per engine)	$345,000
Electrical		(included)
Piping		(included)
Insulation for ductwork		(included)
Painting		(included)
Subtotal:		**$2,845,000**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$6,845,000**
INDIRECT COSTS (Installation)		
Balance of Plajnt Engineering + Hardware	(mean cost for one engine)	$2,250,000
Construction and field expenses		(included)
Contractor fees		(included)
Start-up		(included)
Performance test		(included)
Contingencies		
Total Indirect Cost, IC		**$2,250,000**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$9,095,000**

Annual Costs - C-1 - LEC

Total Annual Costs for LEC

Cost Item			Cost
DIRECT ANNUAL COSTS			
Operating Labor			
Operator	0.5 hrs/shift (5 units)	60.00 $/hr [1]	$32,400
Supervisor	15% of operator		$4,860
Operating Materials			-
Maintenance			
Labor	0.5 hrs/shift (5 units)	60.00 $/hr [1]	$32,400
Material	100% of maint. labor		$32,400
Utilities			
Natural Gas	0 (kft3/yr)	$ 5.18 $/kft3	$0
Electricity	0 (kWh/yr)	$0.059 $/kWh	$0
INDIRECT ANNUAL COSTS, IC			
Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		$61,236
Administrative Charges	2% of TCI		$181,900
Property Taxes	1% of TCI		$90,950
Insurance	1% of TCI		$90,950
Capital Recovery Factor (20 yrs @ prime rate 5.25%)			0.0745
Annual Capital Recovery (Recovery rate * TCI)			$678,026
TOTAL ANNUAL COST			**$1,205,122**

Uncontrolled Emissions (tons/yr):	193
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	175
Cost-Effectiveness ($/ton):	**$6,890**

Capital Recovery Factor $CR = \dfrac{i(1+i)^n}{-1+\ (1+i)^n}$

n = 25 years

i = 5.50% interest rate

CR = 0.0745

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[1] EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

Single Engine Only

Total Capital Cost - C-1E - LEC

Total Capital Costs for LEC

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
High pressure fuel injection upgrade, including hardware installation and commissioning	(cost per engine)	$4,000,000
Subtotal:		**$4,000,000**
Direct installation costs		
Zero-Hour overhaul (+ field services, repairs etc.)	(mean cost per engine)	$2,500,000
Replace cooling system (hardware & engineering	(per engine)	$345,000
Electrical		(included)
Piping		(included)
Insulation for ductwork		(included)
Painting		(included)
Subtotal:		**$2,845,000**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$6,845,000**
INDIRECT COSTS (Installation)		
Balance of Plajnt Engineering + Hardware	(mean cost for one engine)	$2,250,000
Construction and field expenses		(included)
Contractor fees		(included)
Start-up		(included)
Performance test		(included)
Contingencies		
Total Indirect Cost, IC		**$2,250,000**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$9,095,000**

Annual Costs - C-1E - LEC

Total Annual Costs for LEC

Cost Item						Cost
DIRECT ANNUAL COSTS						
Operating Labor						
	Operator	0.5	hrs/shift (5 units)	60.00	$/hr [1]	$32,400
	Supervisor	15%	of operator			$4,860
Operating Materials						-
Maintenance						
	Labor	0.5	hrs/shift (5 units)	60.00	$/hr [1]	$32,400
	Material	100%	of maint. labor			$32,400
Utilities						
	Natural Gas	0	(kft3/yr)	$ 5.18	$/kft3	$0
	Electricity	0	(kWh/yr)	$0.059	$/kWh	$0
INDIRECT ANNUAL COSTS, IC						
	Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$61,236
	Administrative Charges	2%	of TCI			$181,900
	Property Taxes	1%	of TCI			$90,950
	Insurance	1%	of TCI			$90,950
	Capital Recovery Factor (20 yrs @ prime rate 5.25%)					0.0745
	Annual Capital Recovery (Recovery rate * TCI)					$678,026
TOTAL ANNUAL COST						**$1,205,122**

Uncontrolled Emissions (tons/yr):	189
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	171
Cost-Effectiveness ($/ton):	**$7,050**

Capital Recovery Factor $CR = \frac{i(1+i)^n}{-1+(1+i)^n}$

n = 25 years

i = 5.50% interest rate

CR = 0.0745

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[1] EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

Single Engine Only

Total Capital Cost - C-1G - LEC

Total Capital Costs for LEC

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
High pressure fuel injection upgrade, including hardware installation and commissioning	(cost per engine)	$4,000,000
Subtotal:		**$4,000,000**
Direct installation costs		
Zero-Hour overhaul (+ field services, repairs etc.)	(mean cost per engine)	$2,500,000
Replace cooling system (hardware & engineering	(per engine)	$345,000
Electrical		(included)
Piping		(included)
Insulation for ductwork		(included)
Painting		(included)
Subtotal:		**$2,845,000**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$6,845,000**
INDIRECT COSTS (Installation)		
Balance of Plajnt Engineering + Hardware	(mean cost for one engine)	$2,250,000
Construction and field expenses		(included)
Contractor fees		(included)
Start-up		(included)
Performance test		(included)
Contingencies		
Total Indirect Cost, IC		**$2,250,000**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$9,095,000**

Annual Costs - C-1G - LEC

Total Annual Costs for LEC

Cost Item				Cost
DIRECT ANNUAL COSTS				
Operating Labor				
	Operator	0.5 hrs/shift (5 units)	60.00 $/hr [1]	$32,400
	Supervisor	15% of operator		$4,860
Operating Materials				-
Maintenance			60.00 $/hr [1]	
	Labor	0.5 hrs/shift (5 units)	60.00 $/hr [1]	$32,400
	Material	100% of maint. labor		$32,400
Utilities				
	Natural Gas	0 (kft3/yr)	$ 5.18 $/kft3	$0
	Electricity	0 (kWh/yr)	$0.059 $/kWh	$0
INDIRECT ANNUAL COSTS, IC				
	Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		$61,236
	Administrative Charges	2% of TCI		$181,900
	Property Taxes	1% of TCI		$90,950
	Insurance	1% of TCI		$90,950
	Capital Recovery Factor (20 yrs @ prime rate 5.25%)			0.0745
	Annual Capital Recovery (Recovery rate * TCI)			$678,026
TOTAL ANNUAL COST				**$1,205,122**

Uncontrolled Emissions (tons/yr):	153
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	135
Cost-Effectiveness ($/ton):	**$8,933**

Capital Recovery Factor $CR = \frac{i(1+i)^n}{-1+\ (1+i)^n}$

n = 25 years
i = 5.50% interest rate
CR = 0.0745

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[1] EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

Compressor Engines
(C-1A, C-1B, C-1C, C-1E, C1-G)

Nitrogen Oxides

SCR Control Technology

Capital Cost Derivation - SCR for Clark Engines

Primary Reference:

Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032

Value	Units	
See formula	$/Hp	NESCAUM report; December 2000 (1994 Dollars) Page III-30 Above report is referenced in the following document: EPA/452/B-02-001; 7th Edition; Table 2.1b; Endnote 15 (p. 2-97) Total Capital Cost = $310,000 + $72.7*Hp
1,920	Hp	Clark Engine
$449,584	1994 $	Capital Cost = $310,000 + $72.70/Hp
147	CPI 1994	*https://www.bls.gov/cpi/tables/historical-cpi-u-201709.pdf*
244	CPI 2017	
1.66	CPI2017/CPI1994	Escalation adjustment
$745,466	**$/Engine**	

147	CPI for Calendar 1994
244	CPI for Calendar 2017
1.66	CPI Adjustment: 2017:2000

Report below is referenced in:

EPA/452/B-02-001; 7th Edition; Table 2.1b; Endnote 15 (p. 2-97)

NESCAUM report; December 2000 (1994 Dollars)

Page III-30

Total Capital Cost

Lean Burn	TCC =	$310,000	+	$72.70	* HP
Diesel	TCC =	$187,000	+	$98.00	* HP

Clark Engine:	TCC (1994)
1920 hp	$449,584

SCR - Input Calculations and Reference Information

Data is on a per engine basis unless othewise noted

Reference: EPA/452/B-02-001 Section 4.2 in Chapter 2

Parameter / Variable		Value	Units	Reference
Selective Catalytic Reduction (% Control);		85.0	percent	Approx ≈ 1g/bhp-hr
Uncontrolled emissions each RICE		158	Tons/yr (actual) per Engine	Baseline Emissions (mean of last 5 yrs sans min and max)
Q_B =Max. Heat Input at HHV, MMBtu/h		17.2	MM Btu/hr per RICE	Test C1-C 2018 + 20% to reach Max
ASR (or SRF)		1.5	Actual Stoichiometric Ratio	EPA/452/B-02-001; 7th Edition; May 2016; Eqn. 2.1a & 2.1b [1]
$q_{flue\ gas}$		20,800	Inlet to SCR acfm	2018 stack test
qscfm		8,000	dscfm	2018 stack test
CF_{plant}		0.9	system capacity factor, CF_{plant}	EPA/452/B-02-001
η_{NOx}		0.85	NOx removal efficiency	Approx. to reach ≈ 1 gr/hp-hr
NH3 slip (ppmv)	$(ASR-\eta_{NOx})*60*MW_{Nh3}*dscfm/359.05/10^6$	0.015	lb/hr	
Catalyst volume	$2.81*Q_B*\eta_{adj}*slip_{adj}*Nox_{adj}*S_{adj}*T_{adj}/N_{SCR}$	213	ft^3	EPA/452/B-02-001: eqn. 2.22
$N_{SCR\ (\#\ of\ SCR\ reactor\ chambers)}$		1		
η_{adj}	$(0.2869+(1.058*+\eta_{NOx}))$	1.19	NOx efficiency adjustment factor	EPA/452/B-02-001; eqn. 2.23
Slip	$(ASR-\eta_{NOx})$	0.05	Ammonia slip factor	EPA/452/B-02-001; eqn. 2.24
$Slip_{adj}$	1.2835-(0.0567*Slip)	1.28		EPA/452/B-02-001; eqn. 2.26
NOx_{in}		4.0	lb/MM Btu	Most recent 5-year mean sans min and max
NOx_{adj}	$0.8524+(0.3208*NOx_{in})$	2.143		EPA/452/B-02-001; eqn. 2.25
S, sulfur in fuel		1.8E-05	(weight fraction - total S)	https://www.pge.com/pipeline/operations/sulfur/sulfur_info/index.page
S_{adj}	0.9636+(0.0455*S)	0.964		EPA/452/B-02-001
SCR inlet temp		600	F^o	Presumed (req'd for SCR)
SCR inlet temp		589	K^o	Calculated (from F^o)
T_{adj} for inlet T not = 700 F	$15.16-(0.03937*T)+(2.74*10^{-5}*T^2)$	1.40		EPA/452/B-02-001; 7th Edition; p. 2-82
$A_{catalyst}$	$q_{flue\ gas}/(16*60)$	21.7	ft^2	EPA/452/B-02-001; eqn. 2.27
n_{layer}	$V_{catalyst}/(h_{layer}*A_{catalyst})$	3.2	ft^3 (use nominal h = 3.1 feet)	EPA/452/B-02-001; eqn. 2.31 and discussion
$n_{layer\ -\ final}$		3	round n_{layer} to integer	Calculated
h_{layer}	$V_{catalyst}/(n_{layer}*A_{catalyst})+1$	4.1		EPA/452/B-02-001; eqn. 2.32
$n_{layer\ -\ total}$	$n_{layer\ -\ final}+1$	4		EPA/452/B-02-001; eqn. 2.33
h_{SCR}	$n_{layer\ -\ total}*(c_{1+}h_{layer})+c_2$	55.5	ft	EPA/452/B-02-001; eqn. 2.34
$m_{reagent}$	$(NOx_{in}*Q_B*NSR*\eta_{NOX}*MW_{reagent)}/(MW_{NOx}*SR_T)$	32.9	lb/hr	EPA/452/B-02-001; eqn. 2.35
$MW_{reagent}$		17.0	MW of ammonia	https://pubchem.ncbi.nlm.nih.gov/compound/ammonia
MW_{NOx}		46.0	MW of NO_2	https://pubchem.ncbi.nlm.nih.gov/compound/nitrogen%20dioxide
NSR	ASR/SR_T	1.5	normalized stoichiometric rate	EPA/452/B-02-001 w/ NO_2:NO adjustment [1]
SR_T		1.0	for ammonia	EPA/452/B-02-001
C_{sol}		0.29	concentration of aqueous soln	Typical solution concentration
m_{sol}	$m_{reagent}/C_{sol}$	113.4	lb/hr	EPA/452/B-02-001; 7th Edition; Eqn. 2.36
ρ_{sol}		56	lb/ft^3 (solution density)	https://www.sigmaaldrich.com/catalog/product/aldrich/380539?lang=en&region=US
v_{sol}		7.5	gal/ft^3 (volume conversion)	https://en.wikipedia.org/wiki/Cubic_foot
q_{sol}	$m_{sol}/\rho_{sol}*v_{sol}$	15.1	gal/hr (reagent feed rate)	EPA/452/B-02-001; 7th Edition; Eqn. 2.37
t_{store}		14.0	reagent storage for t days	Assumed minimum required storage period
Tank volume	$q_{sol}*t$	5,088	gallons	Calculated
Cost of reagent	RC	0.48	$/lb	EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)
Cost of reagent (per hour)		$53.85	$/hour of ammonia	Calculated
Cost of reagent (per year)		$471,761	$/year of ammonia	Calculated
Catalyst Cost	$CC_{replace}$	$160.00	$/ft^3	EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)
Catalyst Cost Replacement	$n_{SCR} * Vol_{catalyst} * (CC_{replace}/R_{layer})$	$8,098	$/replacement layer/year	EPA/452/B-02-001, Eqn 2.50

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[1] Stoichiometry adjusted for NO_2:NOx ratio from EPA database for the 60 reporting 2SLB engines = 46% : https://www3.epa.gov/scram001/no2_isr_database.htm
(2 molecules of ammonia required for 1 molecule of NO_2 reduction)
$2NO_2 + 4HN_3 \rightarrow 3N_2 + 6H_20$

Clark Engine Cost Effectiveness

Annual Costs - C-1A -SCR

Total Capital Costs for SCR

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Capital (5 engines)	A	$745,466
Instrumentation	0.10 A	(included)
Sales taxes	0.05 A	(included)
Freight	0.05 A	(included)
Purchased equipment cost, PEC	B	**$745,466**
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
Direct installation cost	0.30 B	**$0**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$745,466**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	(included)
Construction and field expenses	0.05 B	(included)
Contractor fees	0.10 B	(included)
Start-up	0.02 B	(included)
Performance test	0.01 B	(included)
Contingencies	0.03 B	(included)
Total Indirect Cost, IC	0.31 B	**$0**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$745,466**

Annual Costs - C-1A -SCR

Total Annual Costs for SCR

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
	Operator	1	hrs/shift	60.00 $/hr [1]	$64,800
	Supervisor	15%	of operator		$9,720
Operating Materials	Ammonia		yearly		$471,761
	Catalyst		yearly		$8,098
Maintenance					
	Labor	1	hrs/shift	60.00 $/hr [1]	$64,800
	Material	100%	of maint. labor		$64,800
Utilities					
	Natural Gas	0	(kft3/yr)	$ 5.18 $/kft3	$0
	Electricity	0	(kWh/yr)	$0.059 $/kWh	$0
INDIRECT ANNUAL COSTS, IC					
	Overhead	60% of sum of operating labor and materials and maintenance labor and materials.			$122,472
	Administrative Charges	2%	of TCI		$14,909
	Property Taxes	1%	of TCI		$7,455
	Insurance	1%	of TCI		$7,455
	Capital Recovery Factor (20 yrs & prime rate = 5.5%)				0.0745
	Annual Capital Recovery (Recovery rate * TCI)				$55,574
TOTAL ANNUAL COST					**$891,844**

Uncontrolled Emissions (tons/yr): (5 units)	91
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	73
Cost-Effectiveness ($/ton):	**$12,275**

Capital Recovery Factor

Capital Recovery Factor

$$CR = \frac{i(1+i)^n}{-1+\ (1+i)^n}$$

n = 25 years
i = 5.5% interest rate
CR = 0.0745

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[1] EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

Clark Engine Cost Effectiveness

Annual Total Capital Costs - C-1B - SCR

Total Capital Costs for SCR

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Capital (5 engines)	A	$745,466
Instrumentation	0.10 A	(included)
Sales taxes	0.05 A	(included)
Freight	0.05 A	(included)
Purchased equipment cost, PEC	B	**$745,466**
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
Direct installation cost	0.30 B	**$0**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$745,466**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	(included)
Construction and field expenses	0.05 B	(included)
Contractor fees	0.10 B	(included)
Start-up	0.02 B	(included)
Performance test	0.01 B	(included)
Contingencies	0.03 B	(included)
Total Indirect Cost, IC	0.31 B	**$0**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$745,466**

Annual Costs - C-1B -SCR

Total Annual Costs for SCR

Cost Item				Cost
DIRECT ANNUAL COSTS				
Operating Labor				
	Operator	1 hrs/shift	60.00 $/hr [1]	$64,800
	Supervisor	15% of operator		$9,720
Operating Materials	Ammonia	yearly		$471,761
	Catalyst			$8,098
Maintenance				
	Labor	1 hrs/shift	60.00 $/hr [1]	$64,800
	Material	100% of maint. labor		$64,800
Utilities				
	Natural Gas	0 (kft3/yr)	$ 5.18 $/kft3	$0
	Electricity	0 (kWh/yr)	$0.059 $/kWh	$0
INDIRECT ANNUAL COSTS, IC				
	Overhead	60% of sum of operating labor and materials and maintenance labor and materials.		$122,472
	Administrative Charges	2% of TCI		$14,909
	Property Taxes	1% of TCI		$7,455
	Insurance	1% of TCI		$7,455
				0.0745
	Annual Capital Recovery (Recovery rate * TCI)			$55,574
TOTAL ANNUAL COST				**$891,844**

Uncontrolled Emissions (tons/yr): (5 units)	160
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	142
Cost-Effectiveness ($/ton):	**$6,289**

Capital Recovery Factor

$$CR = \frac{i(1+i)^{n}}{-1+\ (1+i)^{n}}$$

n = 25 years

i = 5.50% interest rate

CR = 0.0745

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[1] EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

Clark Engine Cost Effectiveness

Total Capital Costs - C-1C - SCR

Total Annual Costs for SCR		
Cost Item	**Factor**	**Cost**
OSTS		
sed equipment costs		
Capital	A	$745,466
Instrumentation	0.10 A	(included)
Sales taxes	0.05 A	(included)
Freight	0.05 A	(included)
Purchased equipment cost, PEC	B	**$745,466**
nstallation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
Direct installation cost	0.30 B	**$0**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$745,466**
COSTS (Installation)		
Engineering	0.10 B	(included)
Construction and field expenses	0.05 B	(included)
Contractor fees	0.10 B	(included)
Start-up	0.02 B	(included)
Performance test	0.01 B	(included)
Contingencies	0.03 B	(included)
Total Indirect Cost, IC	0.31 B	**$0**
APITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$745,466**

Annual Costs - C-1C -SCR

Total Annual Costs for SCR						
Cost Item						**Cost**
DIRECT ANNUAL COSTS						
Operating Labor						
	Operator	1	hrs/shift	60.00	$/hr [1]	$64,800
	Supervisor	15%	of operator			$9,720
Operating Materials	Ammonia		yearly			$471,761
	Catalyst					$8,098
Maintenance						
	Labor	1	hrs/shift	60.00	$/hr [1]	$64,800
	Material	100%	of maint. labor			$64,800
Utilities						
	Natural Gas	0	(kft3/yr)	$ 5.18	$/kft3	$0
	Electricity	0	(kWh/yr)	$0.059	$/kWh	$0
INDIRECT ANNUAL COSTS, IC						
	Overhead	60% of sum of operating labor and materials and maintenance labor and materials.				$122,472
	Administrative Charges	2%	of TCI			$14,909
	Property Taxes	1%	of TCI			$7,455
	Insurance	1%	of TCI			$7,455
	Capital Recovery Factor (20 yrs & prime rate = 5.5%)					0.0745
	Annual Capital Recovery (Recovery rate * TCI)					$55,574
TOTAL ANNUAL COST						**$891,844**

Uncontrolled Emissions (tons/yr):	193
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	175
Cost-Effectiveness ($/ton):	**$5,103**

Capital Recovery Factor $CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$

n = 25 years
i = 5.50% interest rate
CR = 0.0745

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[1] EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

Clark Engine Cost Effectiveness

Annual Total Capital Costs - C-1E - SCR

Total Annual Costs for SCR

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Capital (5 engines)	A	$745,466
Instrumentation	0.10 A	(included)
Sales taxes	0.05 A	(included)
Freight	0.05 A	(included)
Purchased equipment cost, PEC	B	**$745,466**
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
Direct installation cost	0.30 B	**$0**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$745,466**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	(included)
Construction and field expenses	0.05 B	(included)
Contractor fees	0.10 B	(included)
Start-up	0.02 B	(included)
Performance test	0.01 B	(included)
Contingencies	0.03 B	(included)
Total Indirect Cost, IC	0.31 B	**$0**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$745,466**

Annual Costs - C-1E -SCR

Total Annual Costs for SCR

Cost Item				Cost
DIRECT ANNUAL COSTS				
Operating Labor				
Operator		1 hrs/shift	60.00 $/hr [1]	$64,800
Supervisor		15% of operator		$9,720
Operating Materials	Ammonia	yearly		$471,761
	Catalyst			$8,098
Maintenance				
Labor		1 hrs/shift	60.00 $/hr [1]	$64,800
Material		100% of maint. labor		$64,800
Utilities				
Natural Gas		0 (kft3/yr)	$ 5.18 $/kft3	$0
Electricity		0 (kWh/yr)	$0.059 $/kWh	$0
INDIRECT ANNUAL COSTS, IC				
Overhead		60% of sum of operating labor and materials and maintenance labor and materials.		$122,472
Administrative Charges		2% of TCI		$14,909
Property Taxes		1% of TCI		$7,455
Insurance		1% of TCI		$7,455
Capital Recovery Factor (20 yrs & prime rate = 5.5%)				0.0745
Annual Capital Recovery (Recovery rate * TCI)				$55,574
TOTAL ANNUAL COST				**$891,844**

Uncontrolled Emissions (tons/yr): (5 units)	190
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	171
Cost-Effectiveness ($/ton):	**$5,213**

Capital Recovery Factor

Capital Recovery Factor $$CR = \frac{i(1+i)^n}{-1+\ (1+i)^n}$$

n = 25 years
i = 5.50% interest rate
CR = 0.0745

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[1] EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

Clark Engine Cost Effectiveness

Annual Total Capital Costs - C-1G - SCR

Total Capital Costs for SCR

Cost Item	Factor	Cost
DIRECT COSTS		
Purchased equipment costs		
Capital (5 engines)	A	$745,466
Instrumentation	0.10 A	(included)
Sales taxes	0.05 A	(included)
Freight	0.05 A	(included)
Purchased equipment cost, PEC	B	**$745,466**
Direct installation costs		
Foundations & supports	0.08 B	(included)
Handling & erection	0.14 B	(included)
Electrical	0.04 B	(included)
Piping	0.02 B	(included)
Insulation for ductwork	0.01 B	(included)
Painting	0.01 B	(included)
Direct installation cost	0.30 B	**$0**
Site preparation	As required, SP	-
Buildings	As required, Bldg.	-
Total Direct Cost, DC	1.30 B + SP + Bldg.	**$745,466**
INDIRECT COSTS (Installation)		
Engineering	0.10 B	(included)
Construction and field expenses	0.05 B	(included)
Contractor fees	0.10 B	(included)
Start-up	0.02 B	(included)
Performance test	0.01 B	(included)
Contingencies	0.03 B	(included)
Total Indirect Cost, IC	0.31 B	**$0**
TOTAL CAPITAL INVESTMENT (TCI) = DC + IC	DC + IC	**$745,466**

Annual Costs - C-1G -SCR

Total Annual Costs for SCR

Cost Item					Cost
DIRECT ANNUAL COSTS					
Operating Labor					
	Operator	1	hrs/shift	60.00 $/hr [1]	$64,800
	Supervisor	15%	of operator		$9,720
Operating Materials	Ammonia		yearly		$471,761
	Catalyst				$8,098
Maintenance					
	Labor	1	hrs/shift	60.00 $/hr [1]	$64,800
	Material	100%	of maint. labor		$64,800
Utilities					
	Natural Gas	0	(kft3/yr)	$ 5.18 $/kft3	$0
	Electricity	0	(kWh/yr)	$0.059 $/kWh	$0
INDIRECT ANNUAL COSTS, IC					
	Overhead	60% of sum of operating labor and materials and maintenance labor and materials.			$122,472
	Administrative Charges	2%	of TCI		$14,909
	Property Taxes	1%	of TCI		$7,455
	Insurance	1%	of TCI		$7,455
	Capital Recovery Factor (20 yrs & prime rate = 5.5%)				0.0745
	Annual Capital Recovery (Recovery rate * TCI)				$55,574
TOTAL ANNUAL COST					**$891,844**

Uncontrolled Emissions (tons/yr): (5 units)	153
Controlled Emission Rate (g/bhp-hr)	1
Controlled Emissions (tons/yr):	19
Tons Removed (tons/yr):	135
Cost-Effectiveness ($/ton):	**$6,612**

Capital Recovery Factor $CR = \frac{i(1+i)^n}{-1 + (1+i)^n}$

n = 25 years
i = 5.50% interest rate
CR = 0.0745

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[1] EPA/452/B-02-001; 7th Edition; Sec. 2.5 and 2.6; (2012 dollars)

APPENDIX B: BASELINE EMISSION RATES

This appendix contains a brief summary of the derivation of emission rates used to define the "Baseline" emissions for this analysis. The 4-Factor analysis requires that a "cost effectiveness" be determined for each (or combination) control option identified as practical or available.

Clark Engines - NOx

The 5 Clark engines, subject to this analysis, are expected to be used less in the future. Part of the reason relates to the nature of the gas field(s) processed and part of the reason is that Hess expects it will slowly switch from the current gas-fired units to electric driven compressor engines. Regardless, baseline emissions for the existing Clark engines were evaluated using the most recent 5 years of data (2014 → 2018). It did not seem necessary to go further back in time since it would be less and less likely to represent a current (or near current) emission rate.

A review of historical data shows that there is a modest degree of variability in emission rates both within and among the engines. There is roughly a 30% difference in NOx emission results (emission factor) for the same engine over several years. The same is true when comparing the 5 engines across a specific testing period. As a result, the baseline emission rate should be established not so much by a particular rate based on NOx itself but on the underlying function of the engines (to avoid setting a value based on random testing variability).

To evaluate the baseline emissions, it is necessary to understand and review the hours of operation for these devices. Recall that the purpose of these engines is to compress gas and move it from one point to the other. Given each of the 5 engines is the same size, each hour of operation represents, more or less, a known or set quantity of compression. Therefore, to determine baseline emissions, it is necessary to establish the baseline hours. From the baseline of hours, one can then determine the NOx emissions rate that is most representative of recent and expected operation (i.e. compression).

The table below provides a summary of the hours of operation for each engine.

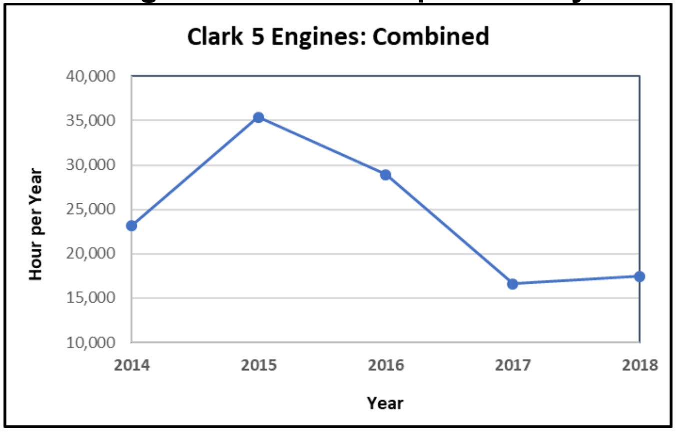
Clark Engines: Hours of Operation by Year

Year	**C-1A**	**C-1B**	**C-1C**	**C-1E**	**C-1G**	C-1D*	C-1F*	All
2014	2400	4814	5012	5594	5312	7220	4820	35172
2015	6520	7749	5818	7437	7885	10276	10487	56072
2016	3720	6417	6965	6600	5217	8623	9745	47287
2017	528	3506	4258	2070	6240	9994	8210	34806
2018	3136	4437	4647	0	5253	4489	6518	28482

* Note the hours on these units were normalized (upward) to account for the fact that these units have a higher horse power rating and thus compress more gas than the 5 engines of interest.

For interest the same information is shown in the graphic below for the 5 Clark engines.

Clark Engines: Hours of Operation by Year



The data suggests that there may be a downward trend. The R^2 value is 0.36 which roughly indicates that about 36% of the observed data fits the linear model (as a linear least-squares correlation) well. This fits our contention that the engines are used less and less.

A review of the data does not lead to an obvious baseline value. It was hypothesized that perhaps the best non-biased method to use would be to use an average of the results (per engine). On the other hand, the variability of the data is quite large. It ranges from roughly 35,000 hours per year to 16,000; a factor of 2 difference. Upon reflection, a better approach would be to remove the minimum and maximum values from the data set to remove some of the variability. This was the approach taken to determine hours of operation per engine which then leads to the baseline NOx emission rate.

The data above, thusly, indicates that years 2014, 2016 and 2017 were selected. From that information, the following baseline emissions data emerges.

NOx Emissions (tons) – Baseline Years

Year	C-1A	C-1B	C-1C	C-1E	C-1G
2014	85	167	198	230	155
2016	171	215	255	257	150
2017	18	99	127	81	155
Baseline	91	160	193	190	153

Interestingly these values, taken as a whole and as a representation of total gas compression, are quite similar to using the simple average from the 5 years. This confirms that the choice of baseline data is reasonable.

Sulfur Recovery Unit (Amine Sweetening Unit): SO_2 & NOx

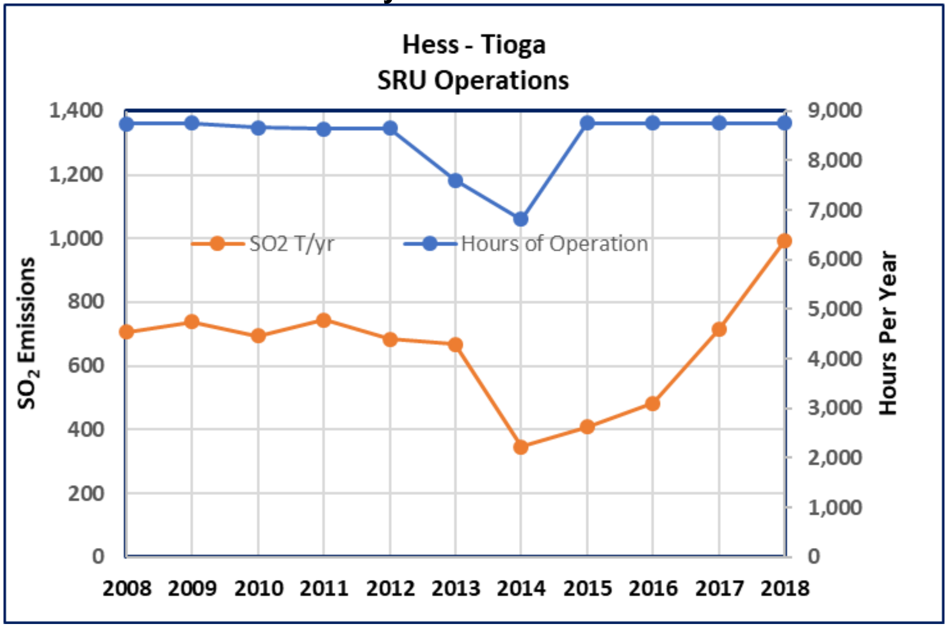
The selection of the baseline year(s) data for the SRU is a simpler task than the Clark engines. A historical review of the hours of operation of this unit reveals a relatively straight flat line as time progresses. Both the year hours and emissions from this unit are shown in the table below covering an 11-year period.

SRU Yearly Hours and Emissions

Year	Hours	Tons SO_2
2008	8,750	707
2009	8,759	739
2010	8,665	694
2011	8,638	745
2012	8,649	683
2013	7,604	668
2014	6,816	345
2015	8,760	408
2016	8,760	482
2017	8,760	715
2018	8,760	994

The same information is shown in the figure below.

SRU Yearly Hours and Emissions



The table and figure show a very consistent operation from this unit. Nearly every year annual operation approaches 100% utilization with a few minor exceptions. Those years most at odds with the typical year coincide with various operational changes occurring at the unit at that time.

One item of note is an apparent increase in SO_2 from 2014 forward. It should be noted that this increase is not particularly relevant as an indication of a future trend. The reason for the increase relates to the operation of the Claus plant; not the amount of gas processed. For example; below is the amount of produced gas at the plant from 2014:

Gas Processing
(billion ft^3)

Year	Received (wet)	Produced	SO_2 (tons)
2014	39	20	345
2015	71	36	408
2016	62	36	482
2017	64	39	715

Clearly the amount of gas processed at the plant has no distinct correlation with the SO_2 emissions. The reason for the increase in SO_2 during this time period relates to proper operation of the Claus plant itself. The changes in the concentration of H_2S in received gas along with other operational parameters has led Hess to conduct a study of the Claus operation and possible remedies to bring it back to its achievable efficiency. It was this analysis that led to obtaining vendor quote for alternatives such as the LO-CAT® and acid gas injection well.

As was the case with the Clark engines, it was deemed appropriate to remove the maximum and minimum year data from the data set. This results in a 9-year average value which seems reasonable for this 4-Factor analysis. The annual baseline emissions for the SRU are 605 tons/year.[44]

For NOx emissions, the baseline emissions were calculated using AP-42 values (AP-42, Section 8.13, Table 8.13-2, April 2015). As a matter of convenience only the past 4 years of available data were reviewed since they are based on fuel burned at the unit; not emissions testing. The NOx emissions from the SRU were calculated as follows:

SRU Yearly Hours and Emissions

Year	Hours	Tons NOx
2014	6,816	38
2015	8,760	40
2016	8,760	52
2017	8,760	54

Given the smaller sample size, it was decided to include the values from all 4 years yielding a baseline emission rate of 46 tons per year.

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[44] As a side note, the annual emission value is only slightly different with or without removing the min and max year's data.

B.8.c – Communications

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

January 16, 2019

FILE

Mr. Tony St. Clair
EHS Advisor
Hess Corporation
1501 McKinney Street
Office 11.012B
Houston, TX 77010

Re: Regional Haze 4-Factors Analysis
Hess Tioga Gas Plant

Dear Mr. St. Clair:

The North Dakota Department of Health (Department) has conducted an initial review of your four-factors analysis for the Hess Corporation (Hess) – Tioga Gas Plant (TGP) in North Dakota. With respect to the analysis we have the following comments:

1. The expected life of the control equipment selected appears too low: tail-gas scrubbing treatment (SCOT), low-emission combustion (LEC), and selective catalytic reduction (SCR) are each listed in the economic analysis with an expected life of 10 to 15 years.

    a. A more appropriate life of a SCOT is 20 years.
    b. A more appropriate life of a LEC is, at a minimum, 20 years. It has already been ~17 years since upgrades were performed on C1D and C1F at the TGP.
    c. A more appropriate life of a SCR for a natural gas-fired unit is 20-30 years (see EPA's Control Cost Manual, Section 4.2, Chapter 2, p 2-78).

    The analysis must be redone using an appropriate expected life. At a minimum, justification of why each value was chosen needs to be included.

2. The 10% interest rate for the Amine/SCOT (Appendix A-3) and the 8.25% interest rate for the Engines (Appendix A-10 through A-21) used in the economic analysis appear to be too high. EPA's Control Cost Manual (Manual) states "When performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, **the correct interest rate to use is the nominal interest rate, which is the rate firms actually face** [emphasis added]". The Manual further states "For input to analysis of rulemakings, assessments of private cost should be prepared using firm-specific nominal interest rates if possible, or the bank prime rate if firm-specific interest rates cannot be estimated or verified." The current bank prime rate is 5.25%. The Department believes an interest rate no higher than 5.25% should be used. Attached to this letter is an email we received from EPA regarding this matter.

The economic analysis must be redone using an appropriate interest rate. At a minimum, justification of why each value was chosen needs to be included.

3. The baseline emission rates for Emission Units C1A, C1B, C1C, C1E, and C1G appear to be too low. While the most recent 2-years of data (2016-2017) were used, this doesn't appear to be representative of past operations or future expected operations. Average utilization was low in 2016-2017 (mainly due to 2017 operations). See tables below for the data the Department has on file regarding recent emissions and utilization, which were derived from hours of operation.

2-year averages Emissions	C1A	C1B	C1C	C1E	C1G	C1D	C1F
2014-15	161.6	230.2	203.4	291.6	181.1	21.9	24.4
2015-16	204.9	254.0	232.4	305.3	178.6	27.2	32.4
2016-17	94.4	156.9	191.2	169.2	152.7	25.1	29.6

Utilization	C1A	C1B	C1C	C1E	C1G	C1D	C1F
2014-15	51%	72%	62%	74%	75%	81%	71%
2015-16	58%	81%	73%	80%	75%	88%	94%
2016-17	24%	57%	64%	49%	65%	87%	84%

Avg. Engine Utilization	A/B/C/E/G	D/F	All engines
2014	53%	56%	54%
2015	81%	96%	85%
2016	66%	85%	71%
2017	38%	85%	51%

Years 2015 and 2016 appear to be more representative of baseline numbers. Justification of the baseline years selected needs to be provided, especially when the baseline is not easily determined.

4. Are there any limitations to refurbishing, rebuilding, or retrofitting two to three of the engines, which have not already been modified (C1A, C1B, C1C, C1E, C1G) and operating them at an increased utilization? This is more consistent with C1D and C1F utilization.

    a. Future operations could utilize the LEC modified engines first with the non-LEC modified as backup in the event of SSM (i.e. C1A, C1B, C1C, C1D, and C1F would have priority and C1E and C1G would operate as backup). Based on past plant data, this looks like the plant would still have enough inlet capacity to handle daily operations.

5. Documentation must be provided for the cost estimates. Any references, other than EPA's Control Cost Manual, must either be submitted with the analysis or a website address must be provided where the documents can be downloaded. Documentation must also be provided for any scaling done to obtain the cost estimates.

6. The capital cost derivation for a LEC was estimated at $4 million. The referenced paper used for the cost estimate indicates a **total cost** of $ 2-4 million. It is indicated the upper

one-third was used to account for older engines. The upper one-third would be $3.33 million. Also, additional costs for equipment, installation and indirect costs were added. The Department's interpretation is that the referenced **total cost** ($ 2-4 million) is the "total capital investment" (TCI). Justification for the additional capital costs is required.

7. Acid gas injection must be considered for SO_2 reductions at the SRU.

8. The preparation and implementation of a flare management plan to control emissions from flares must be addressed and included in the analysis.

9. The cost estimate for the SCOT tail gas clean-up system references WRAP's 4-factors analysis for North Dakota from 2009. The $15 million estimated capital cost in WRAP's report includes purchased equipment, installation costs and indirect capital costs (i.e. Total Capital Investment (TCI) – see page 2-1 of the WRAP report). Hess's SCOT estimate adds additional capital costs, installation and indirect capital costs which are already included in the $15 million capital cost. The additional capital costs must be eliminated.

10. Note: Historic emissions from S302 appear to be incorrect and overreported from 2008-2015. The Department did not look back farther than 2008 during this review. Emissions data for 2016 and 2017 appear to be correct.

Year	SO_2 Emissions tpy (reported)	Tail Gas Incinerated MMcf/y	Average H_2S mole%	Operating Time hours	SO_2 Emissions tpy (calculated from inputs)	Reported minus Calculated (per equation in AEIR form)	
2008	1049	2095.48	0.40	8750	707	343	These are significantly different
2009	1102	1825.8	0.48	8759	739	363	
2010	1045	1469.73	0.56	8665	694	351	
2011	1126	1522.95	0.58	8638	745	382	
2012	1022	1350.31	0.60	8649	683	339	
2013	1022	1056.08	0.75	7604	668	354	
2014	515	772.64	0.53	6816	345	170	
2015	614	820.56	0.59	8760	408	206	
2016	481	1100.14	0.52	8760	482	-1	
2017	719	1130.73	0.75	8760	715	4	

The revised analysis should be submitted as soon as possible. If you have any questions, please contact David Stroh or Tom Bachman of my staff at (701) 328-5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/AS:saj

B.9 – Northern Boarder CS4

B.9.a – Department Request

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

FILE

May 18, 2018

Ms. Ruth Jensen
Northern Border Pipeline
13710 FNB Parkway, Ste 300
Omaha, NE 68154

Re: Regional Haze
Second Planning Period

Dear Ms. Jensen:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

Northern Border Pipeline's Compress Station No.4 is a significant source of NO_X and is located very close to a Class I area. Therefore, the Department requests that you prepare a "four factors" analysis for the turbine (Emission Unit CE1) at this station. The analysis should be prepared using the draft EPA guidance noted above.

Preparation of the Round 2 Regional Haze SIP will require extensive planning and review of emission sources in North Dakota. The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of potential regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely.

Terry O'Clair

Terry L. O'Clair
Director
Division of Air Quality

TLO/TB:saj

B.9.b – Facility Response

Northern Border Pipeline Company
Operated by TransCanada

December 10, 2018

FedEx No. 8136 7919 7968

2018
Received
Air Quality

Mr. Terry L. O'Clair, P.E.
Director, Division of Air Quality
North Dakota Department of Environmental Quality
Gold Seal Center
918 E. Divide Ave.
Bismarck, ND 58501-1947

Re: Regional Haze Second Planning Period and Request for "Four Factor" Analysis for the Northern Border Pipeline Company Compressor Station No. 4

Dear Mr. O'Clair:

This letter has been prepared in response to a request by the North Dakota Department of Environmental Quality (NDDEQ) to complete a "four factors" analysis[1] by January 31, 2019 for Northern Border Pipeline Company's (NBPL) Compressor Station No. 4 (CS4). The main intent of this letter is to provide the four factor analysis requested for the facility turbine. However, our review of related material raised several questions, and the attached four factor analysis includes supplementary information. The attachment includes:

- The four-factor analysis considering NOx control of the facility turbine;
- A request for feedback from NDDEQ to clarify the screening or selection criteria that concludes a four-factor analysis is warranted;
- Questions regarding Western Regional Air Partnership emission inventory parameters, such as exhaust temperature, that are relevant for dispersion modeling; and
- Compressor Station #4 location and turbine stack parameters.

As discussed in the attachment, NBPL believes the NOx control cost effectiveness for two available add-on control technologies exceed a reasonable cost threshold. Please contact me if there are any questions or comments at 402-492-7465. Thank you for your review and consideration of this submittal.

Sincerely,

Ruth Jensen

Ruth Jensen
Air Quality Specialist

Attachments: Attachment 1: Compressor Station No. 4 – Four Factor Analysis and Related Questions and Comments

cc. David Stroh, NDDEQ

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[1] Section 16 A(g)(l) of the Clean Air Act

13710 FNB Parkway, Suite 300 Omaha, NE 68154-5200 (402) 492-7300

Attachment 1:

Compressor Station No. 4 – Four Factor Analysis and Related Questions and Comments

This attachment includes the four factor analysis for Compressor Station No. 4, as well as a request for feedback on the NDDEQ screening and selection process that concluded the analysis is warranted, and comments regarding potential air quality modeling and source characteristics.

Four-Factor Analysis for Compressor Station No. 4

Northern Border Pipeline Company's Compressor Station No. 4 is located in McKenzie County, North Dakota and operates under NDDEQ permit number T5-O84001. NDDEQ has requested a four factors analysis associated with its regional haze second planning period (Round 2) State Implementation Plan (SIP). As discussed below, Northern Border would appreciate additional insight into the screening and selection criteria that determined this analysis is needed. The four factor analysis considers application of NOx control on the facility combustion turbine, and the analysis follows EPA's draft guidance document[2] and standard methodologies from the EPA Control Cost Manual that are recommended in section 7 of the EPA guidance document.

CS4 includes a 20,000 horsepower (hp) simple cycle natural gas-fired combustion turbine that drives a natural gas compressor. The facility also includes a small emergency generator. Control cost effectiveness is not reviewed for the emergency generator in the four factor analysis because of its very limited run time. The turbine is a Rolls Royce Avon unit with a diffusion flame combustor.

The manufacturer does not offer a burner retrofit option for "lean premixed" combustion, which would decrease NOx emissions, so other control options are considered. Despite the lack of retrofit burner technology, turbines with standard burners are still relatively low emitting combustion sources (i.e., emissions are relatively low in comparison to other combustion devices such as boilers or engines and other fuel types).

Factor #1 – NOx Emissions Controls and Control Cost

The pollutant of concern for a natural gas-fired turbine is nitrogen oxides (NOx). As noted above, the Avon turbine does not offer a low NOx combustor (lean premixed combustion) as a retrofit option. The EPA guidance document indicates that both retrofit and replacement should be considered. However, replacement costs for a 20,000 hp unit would be exorbitant and more than an order of magnitude higher than the two add-on control options discussed below. The achieved emissions level for replacement would be similar to the controlled NOx emissions discussed below, thus NOx cost effectiveness would be more than an order of magnitude higher and exceed $100,000 per ton. Replacement is not discussed further in this analysis.

Since combustion control is also not an option, the remaining add-on control technologies applicable to a combustion turbine are selective catalytic reduction (SCR) or water/steam injection. Consistent with the EPA guidance document, methodologies from the EPA Control Cost Manual are used to evaluate the NOx control cost effectiveness for these two technologies.

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[2] Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, EPA document number EPA-457/P-16-001 (July 2016).

SCR control cost analysis

SCR has had limited application as a retrofit control option for natural gas-fired compressor drivers. In addition to Control Cost Manual methods, costs for the analysis are based on several sources, including:

- A Department of Energy (DOE) Report, "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines."[3]
- Analysis conducted by the Pennsylvania Department of Environmental Protection (PADEP)[4] associated with NOx control requirements for a general permit program, which included SCR and associated reagent costs (as "Total Capital Investment") for turbines.
- Actual design and installation costs from a recent pipeline installation that were presented to PADEP during recent revisions to the general permit program.
- Capital cost comparison to EPA's Control Strategy Tool (CoST) software, which is cited in the EPA guidance document.

Table 1 presents the cost details and the source for specific itemized cost elements. Primary assumptions for the analysis include:

- A capital cost of $720,000 to achieve 80% reduction in NOx. This control efficiency would achieve 37 tons per year (TPY) of NOx reductions with 74% annual utilization (i.e., 6500 operating hours).
  - This cost is conservative, and may be very low based on available references. Costs from the PA DEP analysis are higher and the CoST software estimate would be more than double.
- Uncontrolled emissions are based on the 1997 performance test, and these actual emissions (approximately 100 ppmv) from testing at full load are nominally higher than the results from numerous portable analyzer tests conducted in the last fifteen years. The turbine frequently runs at marginally lower load and NOx emissions decrease at lower load.
- Utilization was reviewed for five years, and the analysis presented in the tables below is based on 6,500 annual operating hours (74% utilization) which is marginally higher than the 5-year average of approximately 6,000 annual operating hours.
- Installation costs based on the real-world example for SCR installed on a smaller unit were *not* scaled based on the unit size. *Direct installation* costs from the real world example are higher than the generic assumptions in the EPA Control Cost Manual, but these are conservative assumptions because some costs (e.g., site preparation, foundation and supports) would likely be higher for the larger unit at CS4. Some *indirect installation* costs are lower than the generic assumptions in the EPA Control Cost Manual, but the "real world" costs are used in this analysis. The default Cost Manual assumptions (i.e., "multipliers" that were not used in the analysis) are shown in Table 1 with ~~strikethrough~~ text.
- Reagent costs are from the PA DEP analysis and usage / cost is scaled based on the relative mass emissions of NOx.

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[3] "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines," Department of Energy, Prepared by ONSITE SYCOM Energy Corporation under Contract No. DE-FC02-97CHIO877 (November 1999).

[4] "Technical Support Document, General Permit GP-5" Pennsylvania Department of Environmental Protection (January 2013).

- EPA Control Cost Manual factors and assumptions from similar EPA analysis are used for other cost elements.

Using a conservative approach to determine cost-effectiveness the resulting NOx control cost is estimated to be $14,435 per ton. Even using this approach, this is above a reasonable cost threshold. If NDDEQ disagrees, NBPL requests an opportunity to further confirm and/or adjust the conservatively low estimates included for several assumptions, especially for the equipment capital cost.

Water injection control cost analysis

Water injection control is a technology that was applied to turbines over two decades ago, but has had very limited use in recent years, as combustion controls or SCR have been employed. A key concern with water injection is significant increases in emissions of products of incomplete combustion such as carbon monoxide (CO). The manufacturer estimates a five to eight fold increase in CO, which may necessitate installation of an oxidation catalyst, with a cost similar to the NOx technology. Thus, environmental and economic implications are broader than reflected in the NOx control cost effectiveness.

The basis for water injection costs and other assumptions include:

- A capital cost of $2.25 million to achieve 25 ppmv NOx (i.e., approximately 75% reduction from uncontrolled emissions). This control efficiency would achieve 35 tons per year of NOx reductions with 65% annual utilization.
- Assumptions for utilization and uncontrolled emissions as discussed above for SCR.
- The technology life of fifteen years is based on the DOE Report.
- EPA Control Cost Manual factors and assumptions from similar EPA analysis are used for most other cost elements.
- Costs are not considered for add-on control to mitigate increases in CO and other emissions.

Table 2 presents the cost details and the resulting NOx cost effectiveness is $20,160 per ton. This would appear to be above a reasonable cost threshold.

Factor #2 – Time Necessary for Compliance

Both NOx control technologies would require a timeline of 18 months to two years. This time is required for engineering design, permitting, site preparation, installation, commissioning, and startup. A longer schedule could be required because previous retrofit installations of SCR on natural gas transmission compressor drivers are very limited, and have resulted in extended commissioning periods to address performance issues with the reagent control system (e.g., ability of the reagent flow control to adequately respond to emissions changes as pipeline demand changes turbine load and NOx emissions). The schedule would also need to consider the timing of facility outage to ensure that natural gas demand is not affected by the lost compression capacity.

Factor #3 – Energy and Non-Air Environmental Impacts

As briefly noted above, both NOx control technologies result in a fuel penalty and require use of electricity to drive pumps, etc. The penalty is more severe for water injection, and the DOE report estimates a 3.5% performance loss. Performance loss and electrical usage would increase greenhouse gas (GHG) emissions from the facility. Both technologies introduce other air impacts – e.g., ammonia emissions (which are a particulate precursor) from SCR and relatively large increases in CO and other "products of incomplete" ("PICs", such as aldehyde emissions) from water injection.

The turbine manufacturer estimates a 5 to 8 fold increase in CO emissions, which may result in the need for an oxidation catalyst retrofit installation that incurs costs similar in magnitude to the NOx control technology cost, with ultimate emissions of post-control PICs similar to the previous uncontrolled level (i.e., 80% reduction after a five-fold increase). Water injection would consume that resource from the local water supply. SCR technology requires use of ammonia or urea as a reagent, and catalysts must be periodically cleaned and replaced (typically 10 year life is anticipated).

Factor #4 – Remaining Useful Life of the Source

As noted in the EPA guidance document, control technology life will likely be shorter than the expected life of the stationary source. That is the case for a combustion turbine. The cost analysis assumes control technology life of ten years for SCR and fifteen years for water injection. These lifetimes are typical for emission control analysis presented in the DOE report and control technology analysis in EPA regulations and regulations from other states. The turbine life is much longer and not limited if standard maintenance requirements are followed.

Summary

In summary, the four factor analysis indicates a NOx cost effectiveness of $14,435 per ton or higher. If less conservative assumptions are used (e.g., for SCR cost) the cost per ton would increase. There are deleterious impacts on energy (e.g., efficiency loss), the environment (e.g., ammonia, CO emissions), and other factors (e.g., water use, catalyst disposal, reagent use and transport). NBPL recommends no further control requirements for Compressor Station No. 4.

Table 1. Rolls Royce Avon Turbine Selective Catalytic Reduction NOx Control Cost Effectiveness.

Emission Controls Cost Effectiveness Estimate

Engine Manufacturer	Cooper-Rolls
Model No.	Avon
Engine Type	
Fuel Used	Natural Gas
Emissions Control	SCR
Combustion Control Purpose	NOx
Target Reduction	80%

Color Legend
User Data / Information Input Cell
"Cumulative" Cost Cell for Primary Categories
Cost Effectiveness ($ / ton)

1 Engine Design Conditions

				Comments
Power Output	20000	(hp)		
Engine Exhaust Temperature		(F)		*optional input*
Engine Exhaust Rate		(lb/hr)		*optional input*
Gas Volume		(dscfm)		*optional input*

2 Full Load Engine Exhaust Composition:

				Comments
Oxygen (O_2)		(vol. %)		*optional input*
Carbon Dioxide (CO_2)		(vol. %)		*optional input*
Oxides of Nitrogen (NOx)		(ppmvd)		*optional input*
NOx	14.32	lb/hr	0.325 (lb/MMBtu)	full load NOx emissions from test (0.325 lb/MMBtu)

3 Engine Parameters

				Comments
Total Operating Hours per Season	6500	(hrs)	74% utilization	

4 Final Exhaust Gas Composition

				Comments
Oxides of Nitrogen (NOx)	2.86		0.07 (lb/MMBtu)	Assume 80% reduction

5 Economic Parameters

			Comments
Source of Cost Data	see Comments		

Direct Costs		Cost Formula	Comments
Combustion Control Equipment and Auxiliary Equipment	$725,000	(A)	Based on DOE report (and lower than estimate from EPA Control Strategy Tool (CoST) and recent PA DEP analysis)
Instrumentation	$0	included	included in equiment cost
Sales Taxes	$21,750	(0.03*A)	3% Sales Tax in this example
Freight	$36,250	(0.05*A)	Calculated Cost using EPA Control Cost Manual
Purchased Equipment Cost (PEC)	**$783,000**	PEC	

6 Direct Installation Costs		Cost Formula	Comments
Foundations and Supports	$250,000	~~(0.08*PEC)~~	Approximate actual costs from recent SCR installation
Handling and Erection	$220,000	~~(0.14*PEC)~~	Approximate actual costs from recent SCR installation
Electrical	$100,000	~~(0.04*PEC)~~	Approximate actual costs from recent SCR installation
Piping	$0	~~(0.02*PEC)~~	included above
Insulation for ductwork	$0	~~(0.01*PEC)~~	included above
Painting	$0	~~(0.01*PEC)~~	included above
Site Preparation	$120,000	SP	Approximate actual costs from recent SCR installation
Buildings	$0	Bldg	As required
Total Installation Cost (TIC)	**$690,000**		
Total Direct Costs (PEC+TIC)	**$1,473,000**		

Table 1 (continued).

7 Indirect Costs		Cost Formula	Comments
Engineering	$50,000	~~(0.10*PEC)~~	Approximate actual costs from recent SCR installation
Construction and field expenses	$64,000	~~(0.05*PEC)~~	Approximate actual costs from recent SCR installation
Contractor fees	$10,000	~~(0.10*PEC)~~	Approximate actual costs from recent SCR installation
Start-up	$21,000	~~(0.02*PEC)~~	Approximate actual costs from recent SCR installation
Performance test	$7,830	(0.01*PEC)	Calculated Cost using EPA Control Cost Manual
Contingencies	$23,490	(0.03*PEC)	Calculated Cost using EPA Control Cost Manual
Total Indirect Costs (IC)	**$176,320**	(0.31*PEC)	

8 Capital Cost Summary		Comments
Total Direct Capital Costs (DC)	$1,473,000	
Total Indirect Capital Costs (IC)	$176,320	
Total Capital Investment (TCI)	**$1,649,320**	

9 Direct Annual Costs		Cost Formula	Comments
Operator Labor	$12,500	nominal cost	0.5 hr/shift; example from similar EPA analysis
Supervisor Labor	$1,875		15% of operator
Operating Materials - SCR reagent	$73,000		estimate of materials - annual reagent cost scaled from PADEP quote
Maintenance - Labor	$12,500	nominal cost	0.5 hr/shift; rate example from EPA
Maintenance - Materials	$5,000	nominal cost	Engineering Estimate
Catalyst replacemet / maintenance	$72,500		Engineering Estimate (10% of Cap Cost; similar to DOE report)
Testing and QA/QC	$20,000		Engineering estimate - Annual test; reagent controller QA/QC
Electricity	$20,000		(Approximate, scale from PADEP and DOE references)
Total Direct Annual Costs	**$217,375**		

10 Indirect Annual Costs		Cost Formula	Capital Recovery Factor	Comments
Overhead	$19,125	(0.6*(OL+SL+ML+MM))		
Administrative Charges	$32,986	(0.02*TCI)		Engine ACT Document
Property Taxes	$16,493	(0.01*TCI)		Engine ACT Document
Insurance	$16,493	(0.01*TCI)	**CRF**	
Capital Recovery	$234,863	CRF[TCI]	0.1424	Factor for costs annualized over 10 years at 7% interest.
Total Indirect Annual Costs	**$319,961**			CRF = i * (1+i)^n / [(1+i)^n - 1] (i expressed as a decimal - e.g., 10% = 0.1)

11 Summary			Comments
Total Direct Annual Operating Costs	$217,375		
Total Indirect Annual Operating Costs	$319,961		
Total Annual Costs	$537,336	$27 $ per hp	
Incremental Annual Costs Over Baseline	$537,336		

12 Annual Emissions Reduction Over Baseline		Comments
Oxides of Nitrogen (NOx)	37.22 (Tons)	

Cost Effectiveness ($/Ton)		Comments
Oxides of Nitrogen (NOx)	$14,435	

Table 2. Rolls Royce Avon Turbine Water Injection NOx Control Cost Effectiveness.

Emission Controls Cost Effectiveness Estimate

Engine Manufacturer	Cooper-Rolls
Model No.	Avon
Engine Type	
Fuel Used	Natural Gas
Emissions Control	Water injection
Combustion Control Purpose	NOx
Target Reduction	

Color Legend
User Data / Information Input Cell
"Cumulative" Cost Cell for Primary Categories
Cost Effectiveness ($ / ton)

				Comments
1 Engine Design Conditions				
Power Output	20000	(hp)		
Engine Exhaust Temperature		(F)		*optional input*
Engine Exhaust Rate		(lb/hr)		*optional input*
Gas Volume		(dscfm)		*optional input*
2 Full Load Engine Exhaust Composition:				**Comments**
Oxygen (O_2)		(vol. %)		*optional input*
Carbon Dioxide (CO_2)		(vol. %)		*optional input*
Oxides of Nitrogen (NOx)		(ppmvd)		*optional input*
NOx	14.32	lb/hr	0.325 (lb/MMBtu)	NOx emissions from test (0.325 lb/MMBtu)
3 Engine Parameters				**Comments**
Total Operating Hours per Season	6500	(hrs)	74% utilization	
4 Final Exhaust Gas Composition				**Comments**
Oxides of Nitrogen (NOx)	3.58		0.08 (lb/MMBtu)	Assume 75% reduction based on manufacturer quote
5 Economic Parameters				**Comments**
Source of Cost Data	see Comments			Based on PA DEP capital and ammonia costs; EPA Control Cost Manual
Direct Costs		**Cost Formula**		**Comments**
Combustion Control Equipment and Auxiliary Equipment	$2,250,000	(A)		Estimate from Turbine Manufacturer, includes required burner upgrades
Instrumentation	$225,000	(0.1*A - default example from EPA Manual)		EPA Control Cost Manual Example
Sales Taxes	$74,250	(0.03*A)		3% Sales Tax in this example
Freight	$112,500	(0.05*A)		Calculated Cost using EPA Control Cost Manual
Purchased Equipment Cost (PEC)	**$2,661,750**	PEC		
6 Direct Installation Costs		**Cost Formula**		**Comments**
Foundations and Supports	$212,940	(0.08*PEC)		Calculated Cost using EPA Control Cost Manual
Handling and Erection	$372,650	(0.14*PEC)		Calculated Cost using EPA Control Cost Manual
Electrical	$106,470	(0.04*PEC)		Calculated Cost using EPA Control Cost Manual
Piping	$53,240	(0.02*PEC)		Calculated Cost using EPA Control Cost Manual
Insulation for ductwork	$26,620	(0.01*PEC)		Calculated Cost using EPA Control Cost Manual
Painting	$26,620	(0.01*PEC)		Calculated Cost using EPA Control Cost Manual
Site Preparation	$0	SP		As required
Buildings	$0	Bldg		As required
Total Installation Cost (TIC)	**$798,540**			
Total Direct Costs (PEC+TIC)	**$3,460,290**			

Table 2 (continued).

7 Indirect Costs		**Cost Formula**		**Comments**
Engineering	$266,175	(0.10*PEC)		Calculated Cost using EPA Control Cost Manual
Construction and field expenses	$133,088	(0.05*PEC)		Calculated Cost using EPA Control Cost Manual
Contractor fees	$0	(0.10*PEC)	[ZERO in this analysis]	Calculated Cost using EPA Control Cost Manual
Start-up	$53,235	(0.02*PEC)		Calculated Cost using EPA Control Cost Manual
Performance test	$26,618	(0.01*PEC)		Calculated Cost using EPA Control Cost Manual
Contingencies	$79,853	(0.03*PEC)		Calculated Cost using EPA Control Cost Manual
Total Indirect Costs (IC)	**$558,968**	(0.31*PEC)		
8 Capital Cost Summary				**Comments**
Total Direct Capital Costs (DC)	$3,460,290			
Total Indirect Capital Costs (IC)	$558,968			
Total Capital Investment (TCI)	**$4,019,258**			
9 Direct Annual Costs		**Cost Formula**		**Comments**
Operator Labor	$12,500	nominal cost		0.5 hr/shift; example from similar EPA analysis
Supervisor Labor	$1,875			15% of operator
Operating Materials	$8,512			estimate of materials - annual ammonia at $600 per ton
Maintenance - Labor	$12,500	nominal cost		0.5 hr/shift; rate example from EPA
Maintenance - Materials	$5,000	nominal cost		Engineering Estimate
Maintenance / water treatment	$25,000			Approximate based on DOE Report
Testing and QA/QC	$15,000			Engineering estimate - Annual test
Electricity	$2,000			Approximate based on DOE Report
Total Direct Annual Costs	**$82,387**			
10 Indirect Annual Costs		**Cost Formula**	**Capital Recovery Factor**	**Comments**
Overhead	$19,125	(0.6*(OL+SL+ML+MM))		
Administrative Charges	$80,385	(0.02*TCI)		Engine ACT Document
Property Taxes	$40,193	(0.01*TCI)		Engine ACT Document
Insurance	$40,193	(0.01*TCI)	**CRF**	
Capital Recovery	$441,314	CRF[TCI]	0.1098	Costs annualized over 15 years (per DOE report) at 7% interest.
Total Indirect Annual Costs	**$621,210**			CRF = i * (1+i)^n / [(1+i)^n - 1] (i expressed as a decimal - e.g., 10% = 0.1)
11 Summary				**Comments**
Total Direct Annual Operating Costs	$82,387			
Total Indirect Annual Operating Costs	$621,210			
Total Annual Costs	$703,597		$35 $ per hp	
Incremental Annual Costs Over Baseline	$703,597			
12 Annual Emissions Reduction Over Baseline				**Comments**
Oxides of Nitrogen (NOx)	34.90 (Tons)			
Cost Effectiveness ($/Ton)				**Comments**
Oxides of Nitrogen (NOx)	$20,161			

Source Selection Criteria for Inclusion in Four-Factor Analysis

Section 6.3 of the EPA draft regional haze guidance[5] addresses how a state may select sources for four-factor analysis based on visibility impacts. While Northern Border Pipeline Company acknowledges that the 2016 guidance requires states to address 80% of the visibility impairment caused by in-state sources, the screening analysis and/or selection criteria have not been provided.

It is unclear how the Northern Border Pipeline Company Compressor Station No. 4 (CS4) has been selected for inclusion in the second planning period (Round 2) NDDEQ regional haze reasonable progress analysis. We would appreciate additional insight into that decision. The February 24, 2010 North Dakota regional haze SIP noted a lower emitting turbine replacement in 2005 resulting in elimination of CS4 from further consideration based on actual emissions from the source and the distance of CS4 to the Theodore Roosevelt National Park (TRNP) (nearest Class I Federal area).

> "The Northern Border Pipeline Company Compressor Station No. 4 is powered by a natural gas turbine. In 2005, Northern Border replaced this turbine with a lower emitting turbine. From 2006-2008, the average nitrogen oxides plus sulfur dioxide emissions were 118 tons per year for a Q/D of 6.6. Because of the installation of the lower emitting turbine, this facility was eliminated from consideration of additional controls during this planning period."[6]

Please note that this quote includes an error, because the lower emitting unit was installed in the early 1990s and not 2005. However, the lower emission levels noted were appropriately used in the 2006-2008 analysis and supported the conclusion that added controls were not needed. We would appreciate insight into recent screening or other analysis conducted that concludes additional analysis is warranted for CS4.

Western Regional Air Partnership (WRAP) Inventory for Modeling

A review of the CS4 2014 base case emission inventory spreadsheet[7] appears to contain incorrect stack parameters for facility equipment (e.g., stack temperature of 500). Assuming that the engineering units are Fahrenheit, the significant difference from actual, higher exhaust temperature would result in increased buoyancy plume rise and dispersion from the turbine. The column headings in the WRAP inventory spreadsheet should state the units for each stack parameter. The parameters should be reviewed and cross checked with individual permits or source test data to ensure proper model inputs. For example, information recently provided to NDDEQ indicated an exhaust temperature of 805 °F, and we assume this parameter will be updated in the modeling file.

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[5] EPA Office of Air Quality Planning and Standards Air Quality Policy Division, Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, EPA-457/P-16-001, July 2016

[6] North Dakota State Implementation Plan for Regional Haze, February 24, 2010; page 199 https://deq.nd.gov/publications/aq/planning/regionalHaze/RegHazDocuments/Main_SIP_Sections_1-12.pdf

[7] https://www.wrapair2.org/pdf/WESTAR_OGWG_Emissions_Inventory_2014_Webdistribution_081018.xlsx

Further, care must be taken when including emergency generators to accurately reflect the low utilization rate for this source group. Conservatively dividing the annual actual emissions by 8,760 to develop a commensurate hourly emission rate does not accurately reflect impacts from this source group. Including these as continuous lower emitting sources for 8,760 hours does not accurately pair the emission events with the meteorological condition during the few hours of operation over the year.

In summary, it is unclear how NDDEQ established a visibility impact level and/or screened the source inventory to serve as a threshold below which no further analysis of additional control measures will be undertaken – and therefore exclude a "four factors" analysis.

Northern Border Pipeline Company Compressor Station #4 Location:
SE¼, NE¼, Sec. 32, TISON, RlOOW
2461 - 136th Avenue NW, Arnegard
McKenzie County, North Dakota

Stack Parameters

Description	Cooper-Rolls Model Coberra 2648S Avon GG/RT 48 power natural gas-fired turbine
Nominal rating	20,000 hp
latitude longitude	47°46'10.30"N 103°29'58.98"W
Stack Height:	40 feet 12.2 meters
Effective Stack Cross Sectional Area:	38.5 square feet 3.6 square meters
Exhaust Volume:	357,400 acfm
Exit Temperature:	805 F 429.4 C 702.6 K
Stack Exit Velocity:	155 ft/sec 47.2 m/sec

Northern Border
Pipeline Company
Operated by TransCanada

March 1, 2019 FedEx No.8136 7919 8302

Mr. Terry L. O'Clair, P.E.
Director, Division of Air Quality
North Dakota Department of Health
Gold Seal Center
918 E. Divide Ave.
Bismarck, ND 58501-1947

Re: Regional Haze Second Planning Period and Request for "Four Factor" Analysis for the Northern Border Pipeline Company Compressor Station No. 4 – Revision 1

Dear Mr. O'Clair:

This letter has been prepared in response to a request by the North Dakota Department of Health (NDDH) to complete a "four factors" analysis[1] for Northern Border Pipeline Company's (NBPL) Compressor Station No. 4 (CS4). The main intent of this letter is to provide the four factor analysis requested for the facility turbine and update a December letter from NBPL. This letter responds to NDDH comments and discussion in a recent conference call. The attachment includes the four-factor analysis considering NOx control of the facility turbine, and addresses NDDH comments.

As discussed in the attachment, NBPL believes the NOx control cost effectiveness for SCR exceeds a reasonable cost threshold and water injection is not technologically feasible. Please contact me if there are any questions or comments at 402-492-7465. Thank you for your review and consideration of this submittal.

Sincerely,

Ruth Jensen
Ruth Jensen
Air Quality Specialist

Attachments: Attachment 1: Compressor Station No. 4 – Four Factor Analysis (Revision 1)

cc. David Stroh, NDDH

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[1] Section 16 A(g)(l) of the Clean Air Act

Attachment 1:

Compressor Station No. 4 – Four Factor Analysis (February 2019 Revision)

This attachment includes the updated four factor analysis for Compressor Station No. 4.

Four-Factor Analysis for Compressor Station No. 4

Northern Border Pipeline Company's Compressor Station No. 4 is located in McKenzie County, North Dakota and operates under NDDH permit number T5-O84001. NDDH has requested a four factors analysis associated with its regional haze second planning period (Round 2) State Implementation Plan (SIP). Northern Border provided a letter submittal in December 2018. NDDH responded in January and NDDH comments were discussed in a conference call. This document updates the four factor analysis based on the comments and discussion. The four factor analysis considers application of NOx control on the facility combustion turbine, and the analysis follows EPA's draft guidance document[1] and standard methodologies from the EPA Control Cost Manual that are recommended in section 7 of the EPA guidance document.

CS4 includes a 20,000 horsepower (hp) simple cycle natural gas-fired combustion turbine that drives a natural gas compressor. The facility also includes a small emergency generator. Control cost effectiveness is not reviewed for the emergency generator in the four factor analysis because of its very limited run time. The turbine is a Rolls Royce Avon unit with a diffusion flame combustor.

The manufacturer does not offer a burner retrofit option for "lean premixed" combustion, which would decrease NOx emissions, so other control options are considered. Despite the lack of retrofit burner technology, turbines with standard burners are still relatively low emitting combustion sources (i.e., emissions are relatively low in comparison to other combustion devices such as boilers or engines and other fuel types).

Factor #1 – NOx Emissions Controls and Control Cost

The pollutant of concern for a natural gas-fired turbine is nitrogen oxides (NOx). As noted above, the Avon turbine does not offer a low NOx combustor (lean premixed combustion) as a retrofit option. The EPA guidance document indicates that both retrofit and replacement should be considered. However, replacement costs for a 20,000 hp unit would be exorbitant and more than an order of magnitude higher than the two add-on control options discussed below. The achieved emissions level for replacement would be similar to the controlled NOx emissions discussed below, thus NOx cost effectiveness would be more than an order of magnitude higher and exceed $100,000 per ton. Replacement is not discussed further in this analysis.

Since combustion control is also not an option, the remaining add-on control technologies applicable to a combustion turbine are selective catalytic reduction (SCR) or water/steam injection. As discussed below, the latter is not technologically feasible for a turbine driving a natural gas compressor. Consistent with the EPA guidance document, methodologies from the EPA Control Cost Manual are used to evaluate the NOx control cost effectiveness for SCR.

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[1] Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, EPA document number EPA-457/P-16-001 (July 2016).

Analysis was not conducted for water injection due to its very limited application to industrial turbines. Additional discussion on water injection technical feasibility is provided below and cost effectiveness could be evaluated if desired.

SCR control cost analysis

SCR has had limited application as a retrofit control option for natural gas-fired compressor drivers. The initial analysis presented in the December letter included several sources, such as a Department of Energy report and information on design, engineering, and installation from a compressor station application in the northeast U.S. Based on NDDH comments and the conference call discussion, the analysis was revisited to primarily rely on Control Cost Manual methods. A key input for the analysis is the capital cost, and a 2016 Control Cost Manual supplementary document that updated the SCR chapter[2] was used to estimate the capital cost.

Table 1 presents the cost details and the source for specific itemized cost elements. In addition to the SCR capital cost, an important assumption for the analysis is the estimate of *actual* NOx emissions. The current and anticipated ongoing operation of the turbine at CS4 is lower than full load. Thus, actual emissions should be based on the best estimate of ongoing operation and associated NOx emissions. Primary assumptions for the analysis include:

- A capital cost of $3,740,000 to achieve 80% reduction in NOx; based on Chapter 2 of the Control Cost Manual with the cost adjusted to 2018 using the consumer price index (CPI).
- Uncontrolled emissions are based on a best estimate of actual emissions. The average value from 26 portable analyzer tests conducted from 2004 through 2017 is 0.264 lb/MMBtu, and the average operating load for these tests was about 70% load. This is consistent with average annual load in recent years and anticipated future operation.
    - The annual fuel rate and natural gas heating value, averaged for five year (from 2014 through 2018) is used in conjunction with the emission rate to calculate the average hourly emission rate of 38.2 lb/hr shown in Table 1.
- Capital cost recovery is based on a twenty year life and interest rate of 5.25% (consistent with the current prime rate). Longer life is not appropriate for catalytic systems which typically have a warranty of no longer than five years.
- Utilization was reviewed for five years, and the analysis is based on 6,500 annual operating hours (74% utilization) which is marginally higher than the 5-year average of approximately 5,740 annual operating hours. The marginally higher utilization assumed is expected to be a conservative estimate of ongoing annual operation.
    - The resulting uncontrolled annual NOx emissions are approximately 124 tons and the annual reduction at 80% control is 99 tons.
- Most other costs (direct and indirect installation costs, etc.) are based on the Control Cost Manual.
- Reagent costs are from a current cost quote for an SCR installation with usage / cost scaled based on the relative mass emissions of NOx.

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[2] "Chapter 2, Selective Catalytic Reduction," EPA update to Control Cost Manual, Table 2.1b (May 2016).

The resulting NOx control cost is estimated to be $13,280 per ton. NBPL believes this is well above a reasonable cost threshold. If NDDH disagrees, NBPL requests an opportunity to further review several assumptions to further refine the analysis.

Water injection control analysis

Water injection control is a technology that was applied to turbines over two decades ago, but has had very limited use in recent years, as combustion controls or SCR have been employed. A key concern with water injection is significant increases in emissions of products of incomplete combustion such as carbon monoxide (CO). NOx reductions would be lower than for the SCR analysis discussed above. For example, vendors may estimate a NOx reduction of 75% at full load, but at the reduced operation that will occur at CS4, lower uncontrolled NOx emissions and less reduction would be anticipated. Manufacturers estimate a five to eight fold increase in CO. This may necessitate installation of an oxidation catalyst, with a cost similar to the NOx technology costs. In addition, a larger increase in CO emissions will occur at the reduced load operation typical for the CS4 turbine.

Performance could also be worse due to operational challenges, because this technology has not been demonstrated for natural gas transmission facilities, at least not in recent years. This technology was supplanted by low emissions combustion, which is not available for the Avon turbine at CS4. For water injection, NBPL believes that environmental and technological issues result in a conclusion that water/steam injection is not technologically feasible. A cost effectiveness analysis is not presented, but could be completed if desired. Costs would be incurred beyond base costs for NOx control, including: (1) addressing emissions of CO and other products of incomplete combustion, and (2) contingencies associated with implementing a technology with very limited historical application and no installations at compressor stations in recent years.

Factor #2 – Time Necessary for Compliance

Both NOx control technologies would require a timeline of three years or more. This time is required for engineering design, permitting, site preparation, installation, commissioning, and startup. A schedule up to five years could be required because previous retrofit installations of SCR on natural gas transmission compressor drivers are very limited, and have resulted in extended commissioning periods to address performance issues with the reagent control system (e.g., ability of the reagent flow control to adequately respond to emissions changes as pipeline demand changes turbine load and NOx emissions). The schedule would also need to consider the timing of facility outage to ensure that natural gas demand is not affected by the lost compression capacity.

Factor #3 – Energy and Non-Air Environmental Impacts

As briefly noted above, both NOx control technologies result in a fuel penalty and require use of electricity to drive pumps, etc. The penalty is more severe for water injection, and the DOE report estimates a 3.5% performance loss. Performance loss and electrical usage would increase greenhouse gas (GHG) emissions from the facility. Both technologies introduce other air impacts – e.g., ammonia emissions (which are a particulate precursor) from SCR and relatively large increases in CO and other "products of incomplete combustion" ("PICs", such as aldehyde emissions) from water injection.

The turbine manufacturer estimates a 5 to 8 fold increase in CO emissions, which may result in the need for an oxidation catalyst retrofit installation that incurs costs similar in magnitude to the NOx control technology cost, with ultimate emissions of post-control PICs similar to the previous uncontrolled level (i.e., 80% reduction after a five-fold increase). The emission levels would be further increased (with implications for catalyst design and cost) due to reduced load operation for the turbine. Water injection would consume that resource from the local water supply. SCR technology requires use of ammonia or urea as a reagent, and catalysts must be periodically cleaned and replaced.

Factor #4 – Remaining Useful Life of the Source

As noted in the EPA guidance document, control technology life will likely be shorter than the expected life of the stationary source. That is the case for a combustion turbine. The cost analysis assumes control technology life of twenty years for SCR. A twenty year lifetime exceeds typical estimates for emission control analysis presented in the DOE report and control technology analysis in EPA regulations and regulations from other states, and greatly exceeds the technology warranty. The turbine life is much longer and not limited if standard maintenance requirements are followed.

Summary

In summary, the four factor analysis indicates a NOx cost effectiveness of over $13,000 per ton for SCR. Water/steam injection is not technologically feasible. There are deleterious impacts on energy (e.g., efficiency loss), the environment (e.g., ammonia, CO emissions), and other factors (e.g., water use, catalyst disposal, reagent use and transport). NBPL recommends no further control requirements for Compressor Station No. 4.

Table 1. Rolls Royce Avon Turbine Selective Catalytic Reduction NOx Control Cost Effectiveness.

NOx Control Cost Effectiveness Estimate

Engine Manufacturer	Cooper-Rolls				
Model No.	Cobrerra 2648S Avon				
Engine Type					
Fuel Used	Natural Gas				**Color Legend**
Emissions Control	SCR				User Data / Information Input Cell
Combustion Control Purpose	NOx				"Cumulative" Cost Cell for Primary Categories
Target Reduction					Cost Effectiveness ($ / ton)
1 Engine Design Conditions					**Comments**
Power Output	20000	(hp)			
Engine Exhaust Temperature		(F)			*optional input*
Engine Exhaust Rate		(lb/hr)			*optional input*
Gas Volume		(dscfm)			*optional input*
2 Full Load Engine Exhaust Composition:					**Comments**
Oxygen (O_2)		(vol. %)			*optional input*
Carbon Dioxide (CO_2)		(vol. %)			*optional input*
Water (H_2O)		(vol. %)			*optional input*
Oxides of Nitrogen (NOx)		(ppmvd)			*optional input*
Nitrogen (N_2)		(vol. %)			*optional input*
NOx	38.2	lb/hr		0.264 (lb/MMBtu)	NOx emissions - average from portables tests
3 Engine Parameters			124.0668		**Comments**
Total Operating Hours per Season	6500	(hrs)	74%	utilization	
4 Final Exhaust Gas Composition					**Comments**
Oxides of Nitrogen (NOx)	7.6			0.053 (lb/MMBtu)	Assume 80% reduction from uncontrolled
5 Economic Parameters					**Comments**
Source of Cost Data	see Comments				Analysis primarily relying on EPA Cost Manual
Direct Costs		**Cost Formula**			**Comments**
Combustion Control Equipment and Auxiliary Equipment	$3,740,000	(A)			Based on EPA control cost manual ($167/kw; adjust to 2018$)
Instrumentation	$85,000	(0.1*A)			Default is 0.1*A; use lower value from example (improved flow control)
Sales Taxes	$114,750	(0.03*A)			3% Sales Tax in this example
Freight	$187,000	(0.05*A)			Calculated Cost using EPA Control Cost Manual
Purchased Equipment Cost (PEC)	$4,126,750	PEC			
6 Direct Installation Costs		**Cost Formula**			**Comments**
Foundations and Supports	$330,140	(0.08*PEC)			Calculated Cost using EPA Control Cost Manual
Handling and Erection	$577,750	(0.14*PEC)			Calculated Cost using EPA Control Cost Manual
Electrical	$165,070	(0.04*PEC)			Calculated Cost using EPA Control Cost Manual
Piping	$82,540	(0.02*PEC)			Calculated Cost using EPA Control Cost Manual
Insulation for ductwork	$41,270	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
Painting	$41,270	(0.01*PEC)			Calculated Cost using EPA Control Cost Manual
Site Preparation	$0	SP			As required
Buildings	$0	Bldg			As required
Total Installation Cost (TIC)	$1,238,040				
Total Direct Costs (PEC+TIC)	$5,364,790				

Table 1 (continued).

7	**Indirect Costs**		**Cost Formula**		**Comments**
	Engineering	$412,675	(0.10*PEC)		Calculated Cost using EPA Control Cost Manual
	Construction and field expenses	$206,338	(0.05*PEC)		Calculated Cost using EPA Control Cost Manual
	Contractor fees	$412,675	(0.10*PEC)		Calculated Cost using EPA Control Cost Manual
	Start-up	$82,535	(0.02*PEC)		Calculated Cost using EPA Control Cost Manual
	Performance test	$41,268	(0.01*PEC)		Calculated Cost using EPA Control Cost Manual
	Contingencies	$123,803	(0.03*PEC)		Calculated Cost using EPA Control Cost Manual
	Total Indirect Costs (IC)	$1,279,293	(0.31*PEC)		
8	**Capital Cost Summary**				**Comments**
	Total Direct Capital Costs (DC)	$5,364,790			
	Total Indirect Capital Costs (IC)	$1,279,293			
	Total Capital Investment (TCI)	$6,644,083			
9	**Direct Annual Costs**		**Cost Formula**		**Comments**
	Operator Labor	$12,500	nominal cost		0.5 hr/shift; example from similar EPA analysis
	Supervisor Labor	$1,875			15% of operator
	Operating Materials - ammonia	$57,500			estimate of materials - annual ammonia at $600 per ton
	Maintenance - Labor	$12,500	nominal cost		0.5 hr/shift; rate example from EPA
	Maintenance - Materials	$5,000	nominal cost		Engineering Estimate
	Catalyst maintenance / replacement	$374,000			Engineering Estimate (10% of Cap Cost)
	Testing and QA/QC	$20,000			Engineering estimate - Annual test; reagent controller QA from PA DEP TSD
	Electricity	$5,000			
	Total Direct Annual Costs	$488,375			
10	**Indirect Annual Costs**		**Cost Formula**	**Capital Recovery Factor**	**Comments**
	Overhead	$19,125	(0.6*(OL+SL+ML+MM))		
	Administrative Charges	$132,882	(0.02*TCI)		Engine ACT Document
	Property Taxes	$66,441	(0.01*TCI)		Engine ACT Document
	Insurance	$66,441	(0.01*TCI)	**CRF**	
	Capital Recovery	$544,815	CRF[TCI]	0.082	Factor for costs annualized over 20 years at 5.25% interest.
	Total Indirect Annual Costs	$829,703			CRF = i * (1+i)^n / [(1+i)^n - 1] (i expressed as a decimal - e.g., 10% = 0.1)
11	**Summary**				**Comments**
	Total Direct Annual Operating Costs	$488,375			
	Total Indirect Annual Operating Costs	$829,703			
	Total Annual Costs	$1,318,078		$66 $ per hp	
	Incremental Annual Costs Over Baseline	$1,318,078			
12	**Annual Emissions Reduction Over Baseline**				**Comments**
	Oxides of Nitrogen (NOx)	99.25	(Tons)		
	Cost Effectiveness ($/Ton)				**Comments**
	Oxides of Nitrogen (NOx)	$13,280			

B.9.c – Communications

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

December 28, 2018

FILE

Ms. Ruth Jensen
Air Quality Specialist
Northern Border Pipeline Company
13710 FNB Parkway, Ste 300
Omaha, NE 68154-5200

Re: Regional Haze 4-Factors Analysis
Compressor Station No. 4

Dear Ms. Jensen:

The North Dakota Department of Health (Department) has conducted an initial review of your four-factors analysis for Northern Border Pipeline Company (NBPL) – Compressor Station No. 4 (CS4) in North Dakota. With respect to the analysis we have the following comments:

1. The expected life of the selective catalytic reduction (SCR) system listed in the economic analysis is 10 years. We believe a more appropriate life of an SCR for a natural gas-fired unit is 20-30 years (see EPA's Control Cost Manual, Section 4.2, Chapter 2, p 2-78). The economic analysis must be redone using an appropriate expected life of the SCR and water injection control system.

2. The 7% interest rate used in the economic analysis appears to be too high. EPA's Control Cost Manual states "When performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, **the correct interest rate to use is the nominal interest rate, which is the rate firms actually face** [emphasis added]". The manual further states "For input to analysis of rulemakings, assessments of private cost should be prepared using firm-specific nominal interest rates if possible, or the bank prime rate if firm-specific interest rates cannot be estimated or verified." The current bank prime rate is 5.25%. We believe an interest rate no higher than 5.25% should be used. Attached to this letter is an email we received from EPA regarding this matter. The economic analysis must be redone using an appropriate interest rate.

3. The baseline emission rate for the unit appears to be too low. The baseline emission rate should represent a realistic depiction of anticipated future annual emissions for the source. In general, estimates of anticipated emissions are based upon actual emissions from the baseline period (two-year period) that are representative of expected future emissions. Although no baseline emission rate is stated in the analysis, a back-calculation indicates a

baseline emission rate of 46.5 tons of NO_x per year (i.e. 37.22 tons reduction divided by 80% reduction for SCR). The 2016 and 2017 Annual Emission Inventory Reports submitted by Northern Border Pipeline Co. indicated an average of 171 tons of NO_x per year based on 1997 emissions testing results. Based on more recent testing at this unit, we believe the emission rate is even higher. The economic analysis must be redone using an appropriate baseline emission rate. Proper documentation should be provided explaining why the baseline selected for the facility is required in cases where the baseline emissions are not easily understood. As an example of our concern for the baseline emission rate of 46.5 tons of NO_x per year and our expected thoroughness of calculations, please see the attached calculation summary.

4. Documentation must be provided for the cost estimates. Any references, other than the Control Cost Manual, must either be submitted with the analysis or a website address provided where the documents can be downloaded. Documentation must also be provided for any scaling that was done to obtain the cost estimates.

The Department's response to questions posed by NBPL in the four-factor analysis are:

5. NBPL CS4 was selected as a source to perform a four-factor analysis based on the 2012-2016 average combined NO_x and SO_2 emissions of 157 tons per year, with a distance to the North Unit of Theodore Roosevelt National Park of 18 km. This results in a Q/d (tons/km) of 9, which is in line with the other sources selected for analysis and the 2016 draft guidance. Q/d was a metric used during Regional Haze Round 1 to identify sources for evaluation. Similarly, Q/d is also being used for initial source selection for analysis in Regional Haze Round 2.

   Using the average emissions from 2012-2016 was beneficial (looking at Q/d) for NBPL CS4, since operating hours in 2014 and 2015 indicate 44% utilization, compared to a utilization average of 88% in 2012, 2013, 2016 and 2017. If only the last two years of NO_x emissions data (2016 and 2017) provided to the Department are utilized, the Q/d becomes 11.3 (*note: NO_x appears to have been underreported by NBPL CS4 based on test results submitted to the Department; see Number 3*). Using corrected data that has not been underreported, Q/d would become 14.1 (again only using NO_x); therefore, NBPL CS4 was identified as a source to conduct a four-factor analysis.

   Through the four-factor analysis, North Dakota is addressing approximately 80% of the visibility impairment (nitrates and sulfates) as determined by the IMPROVE monitoring network in North Dakota (http://vista.cira.colostate.edu/Improve/aqrv-summaries/). Sending four factor letters to the ten highest Q/d facilities in North Dakota addresses 94% of the 2012-2016 emissions from stationary sources included in the 2014 National Emissions Inventory (NEI), which is being used for the 2014 baseline modeling performed by the Western Regional Air Partnership (WRAP). Q/d for the sources selected in North Dakota ranged from 7 to 164.

   See attachment containing detailed emissions information and distance to Class 1 areas used to select the sources for a four-factor analysis.

6. The Department will ensure that the information used in the 2014 Baseline Modeling, completed by WRAP, will be consistent with the information provided by Northern Border Pipeline Co. for Compressor Station No. 4. Thank you for providing the correct stack parameters for the facility equipment.

The revised analysis should be submitted as soon as possible. If you have any questions, please contact David Stroh or Tom Bachman of my staff at (701) 328-5188.

Respectfully,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:saj

From:	Worstell, Aaron <Worstell.Aaron@epa.gov>
Sent:	Tuesday, December 18, 2018 11:55 AM
To:	Bachman, Tom A.; Dobrahner, Jaslyn
Cc:	Sorrels, Larry
Subject:	RE: Regional Haze Economic Analyses

Hi Tom-

The interest rate recommended by EPA can vary by firm or industry, but the bank prime rate is a default rate that can be used for annualization of capital costs. The most recent bank prime rate (currently ~5.25%) can be found on the Federal Reserve website here:

https://www.federalreserve.gov/releases/h15/

Also, consult the somewhat recently revised Cost Estimation chapter of EPA's Control Cost Manual. See discussion of the bank prime rate in Section 2.5.2, Interest Rates:

https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

I hope that is helpful.

Happy Holidays!

Aaron

From: Bachman, Tom A. <tbachman@nd.gov>
Sent: Tuesday, December 18, 2018 9:48 AM
To: Worstell, Aaron <Worstell.Aaron@epa.gov>; Dobrahner, Jaslyn <Dobrahner.Jaslyn@epa.gov>
Subject: Regional Haze Economic Analyses

Aaron/Jaslyn:

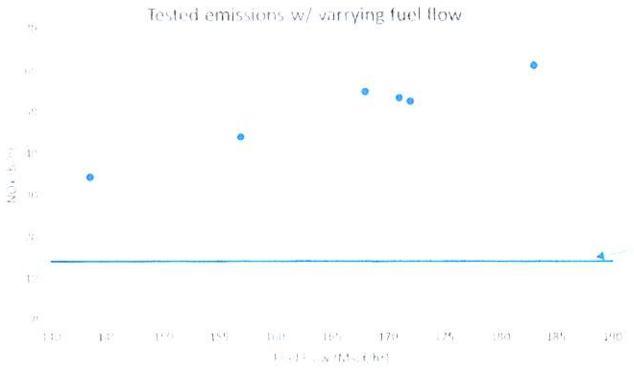
Now that our sources are working on four-factor analyses (and GRE is contemplating a revised BART analysis for Coal Creek Station), a question regarding the analysis has come up. That is – what is the appropriate interest rate to be used in the economic analysis to determine annualized costs? In the past we have generally used 7%; however some analyses used a lower value. Given current low interest rates, is 7% still valid?

Any information you can provide will be appreciated!

Tom Bachman, P.E.
ND Dept. of Health
(701) 328-5188

[illegible]	Year	Tested lb/hr	MMScf/yr	btu/scf	MMbtu/yr	hr/yr	lbs/year	tpy (calc'd)	*tpy (reported)*	lb/MMbtu (calc'd)	PTE tpy (testing)	Utilization
157	2012	44	1232.698	1024.16	1,262,479.98	8493.5	373,714.00	186.86	*205.20*	0.296	192.72	97%
172	2013	52.7	1287.322	1032	1,328,516.30	8346.4	439,855.28	219.93	*215.90*	0.331	230.826	95%
144	2014	34.4	566.703	1048.5	594,188.10	4115.75	141,581.80	70.79	*96.60*	0.238	150.672	47%
171	2015	53.5	472.156	1057.95	499,517.44	3712.5	198,618.75	99.31	*81.20*	0.398	234.33	42%
168	2016	54.9	994.458	1058.79	1,052,922.19	7161.43	393,162.51	196.58	*171.10*	0.373	240.462	82%
183	2017	61.3	987.398	1061.67	1,048,290.83	6821.5	418,157.95	209.08	*170.40*	0.399	268.494	78%

74% 2012-2017
45% 2014-2015
88% 2012-2013, 2016-2017



2012-2017 Max (averaged for entire year)
159.17 MMbtu/hr
51.73 lb/hr

0.325 lb/MMbtu '97 test (used in all AEIRs and 4F)
66.8 lb/hr limit in TV

comparable

max per '97 test and lb/hr TV limit
205.54 MMBtu/hr
1,800,517 MMbtu/yr

Information Provided in 4F analsysis

ER: 14.32 lb/hr
EF: 0.325 lb/MMbtu
calc'd duty: 44.1 MMBtu/hr

62.7216 tpy calc'd (8760)
46.54 tpy calc'd (6500 hours/yr)

2.864 lb/hr -@ 80% control
9.308 tpy (6500 hours/yr)

37.2 tpy reduction

16-'17 Q/d based on under-reported emissions
11.27
16-'17 Q/d based on corrected potential emissions
14.14
Distance to Class 1
18 km

Permittee	Plant	2012-2016 Average SO2 + NOx (tons)	Nearest Class I Area	Distance to Nearest Class I Area (km)	Nearest Q/D (tons/km) (2012-2016)	Notes	**% 2012-2016 Emissions**	**% 2012-2016 Q/D**
BASIN ELECTRIC POWER COOP.	AVS 1	10,592	TRNP/NU	117	91			
BASIN ELECTRIC POWER COOP.	AVS 2	12,188	TRNP/NU	117	104			
BASIN ELECTRIC POWER COOP.	LELAND OLDS 1	6,650	TRNP/NU	157	42			
BASIN ELECTRIC POWER COOP.	LELAND OLDS 2	9,967	TRNP/NU	157	63			
MINNKOTA POWER COOP.	M.R. YOUNG 1	3,877	TRNP/SU	161	24			
MINNKOTA POWER COOP.	M.R. YOUNG 2	6,863	TRNP/SU	161	43			
OTTERTAIL POWER CO.	COYOTE	21,096	TRNP/NU	129	164			
MONTANA DAKOTA UTILITIES	HESKETT 1	1,269	TRNP/SU	185	7			
MONTANA DAKOTA UTILITIES	HESKETT 2	2,941	TRNP/SU	185	16			
GREAT RIVER ENERGY	*STANTON 1*	*3,218*	*TRNP/NU*	*156*	*21*	*shutdown*		
GREAT RIVER ENERGY	*STANTON 10*	*701*	*TRNP/NU*	*156*	*4*	*shutdown*		
GREAT RIVER ENERGY	COAL CREEK 1	12,675	TRNP/NU	168	75			
GREAT RIVER ENERGY	COAL CREEK 2	10,631	TRNP/NU	168	63			
GREAT RIVER ENERGY	SPIRITWOOD	142	TRNP/SU	366	0	No 4F		
Subtotal (EGUs)		**102,809**			718	**EGU's only**	**86.1%**	**78.2%**
Dakota Gasification Co.	Great Plains Synfuels	6,550	TRNP/NU	107	61			
Hess Corporation	Tioga Gas Plant	1,920	Lostwood	35	55			
Petro-Hunt	Little Knife Gas Plant	475	TRNP/NU	39	12			
Northern Border Pipeline	Comp. Station No. 4	157	TRNP/NU	18	9			
Subtotal (gas sources)		**9,102**				**All**	**93.7%**	**93.1%**
Subtotal of remaining tracked sources		**7,496**				**Total**	**119,407**	**918.2**

Stroh, David E.

From: Ruth Jensen <ruth_jensen@transcanada.com>
Sent: Friday, March 1, 2019 1:06 PM
To: Stroh, David E.
Subject: FW: [EXTERNAL] CS4 NOx - table
Attachments: CS4 NOx data_2004-2017.xlsx

CAUTION: This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

Here’s the additional information you requested. I will send the letter by FedEx.

Ruth Jensen
Air Quality Specialist
TransCanada
Phone: 402-492-7465
Cell: 402-639-2785

From: Jim McCarthy [mailto:jamesmccarthy@comcast.net]
Sent: Friday, March 1, 2019 12:09 PM
To: Ruth Jensen <ruth_jensen@transcanada.com>
Cc: 'Panek Jeffrey A.' <japanek@ameritech.net>
Subject: [EXTERNAL] CS4 NOx - table

The attached file is data you provided. Average for all is 0.264 lb/MMBtu which is the NOx emission rate used in the cost analysis XLS included in the submittal.

Let me know if you have additional questions.

Thanks.

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Date	Lb NOx/MMBtu	NOx ppm @ 15% O2	Ambient Temp F	HP	% load
5/19/2004	0.2548	69.7	62.8	11503	57.5%
10/4/2004	0.2657	72.7	52.5	14483	72.4%
5/10/2005	0.2425	66.3	61.1	10402	52.0%
11/7/2005	0.2665	79.6	44.2	11198	56.0%
6/13/2006	0.2377	65.0	55.1	11591	58.0%
10/9/2006	0.1938	53.0	15.5	9196	46.0%
6/6/2007	0.2232	61.0	68.3	14598	73.0%
10/31/2007	0.2878	78.7	50.6	7967	39.8%
5/5/2008	0.2996	81.8	64.3	13132	65.7%
10/21/2008	0.2933	80.3	41.9	15433	77.2%
5/18/2009	0.2395	65.5	70.2	9470	47.4%
12/9/2009	0.2807	76.7	-0.4	19435	97.2%
4/20/2010	0.2510	68.7	62.5	10864	54.3%
10/6/2010	0.3148	86.1	67.1	14159	70.8%
5/11/2011	0.2655	72.6	49.5	13414	67.1%
10/11/2011	0.2739	75.0	64.6	12164	60.8%
5/18/2012	0.2334	63.8	64.1	11546	57.7%
6/18/2012	0.2743	75.0	57.0	15641	78.2%
11/5/2012	0.2793	76.4	60.7	15842	79.2%
5/24/2013	0.2293	62.7	61.4	13836	69.2%
9/20/2013	0.2830	77.3	51.1	17860	89.3%
6/10/2014	0.2121	58.0	68.2	NA	NA
11/17/2014	0.2250	61.5	14.4	14386	71.9%
10/28/2015	0.2966	81.1	33.3	18264	91.3%
10/21/2016	0.3063	83.7	57.5	16896	84.5%
10/26/2017	0.3284	89.8	34.7	19062	95.3%
average	**0.264**				

-

B.10 – Basin DGC

B.10.a – Department Request

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

FILE

May 18, 2018

Mr. Daniel Whitley
Dakota Gasification Company
420 County Road 26
Beulah, ND 58523

Re: Regional Haze
Second Planning Period

Dear Mr. Whitley:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

The Great Plains Synfuels Plant has been identified as a significant source of SO_2 and NO_X emissions. Therefore, the Department requests that you prepare a "four factors" analysis for your facility. The analysis should be prepared using the draft EPA guidance noted above. The analysis should include all source units that emit through the main stack as well as the flares at the facility.

Preparation of the Round 2 Regional Haze SIP will require extensive planning and review of emission sources in North Dakota. The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of potential regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely.

Terry O'Clair

Terry L. O'Clair
Director
Division of Air Quality

TLO/TB:saj

B.10.b – Facility Response

Great Plains
SYNFUELS

**DAKOTA
GASIFICATION
COMPANY**
**A BASIN ELECTRIC POWER
COOPERATIVE SUBSIDIARY**

January 31, 2019

Mr. Terry L. O'Clair, Director
Division of Air Quality
North Dakota State Department of Health
918 E. Divide Ave.
Bismarck, ND 58501-1947

RE: Great Plains Synfuels Plant Regional Haze Second Planning Period Reasonable Progress Four Factor Analysis

Dear Mr. O'Clair:

At the request of the North Dakota Department of Health (NDDH), Dakota Gasification Company (DGC) has prepared a four factor analysis for the NDDH's Regional Haze Second Planning Period Reasonable Progress analysis. As part of this analysis NOx and SO_2 emissions were evaluated at the Great Plains Synfuels Plant (GPSP). The four factor analysis is attached to this letter.

In addition to the four factor analysis, the NDDH requested DGC to provide hourly NOx and SO_2 emissions rates to be included as part of the Western Regional Air Partnership (WRAP) visibility modeling. The rates provided for the GPSP facility represent actual maximum rolling 24-hour average emission rates in lb/hr and should not be construed to represent actual long-term average baseline emissions rates or proposed permit emission limits. The following three sources were identified by the NDDH to be included in the modeling effort.

Emission Source	**NOx Emission Rate lb/hr**	**SO_2 Emission Rate lb/hr**
Main Stack(Note 1)	944	1,681
Main Flare	224	1,598
Startup Flare	171	334

Note 1. Main Stack emission rates include emissions from three (3) Riley Boilers and two (2) Superheaters.

Based on the results of the four factor analysis, there are no additional reductions expected from current baseline emission rates either due to the technical infeasibility of installing additional emissions controls, or the control options having excessive costs and, therefore, not being cost effective.

DGC looks forward to working with the NDDH in establishing the state's reasonable progress goals. Should you or your staff have any questions regarding the GPSP four factor analysis or

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inputs to the WRAP modeling, please do not hesitate to contact me at (701) 873-6619 or by email at dwhitley@bepc.com.

Sincerely,

Daniel Whitley
Environmental Engineering Supervisor

dmw/dew/tlm
ENCLOSURE
c: David Stroh, NDDH
Nicole Rivinius, NDDH
9850-DMW-19-005

DAKOTA
GASIFICATION
COMPANY
A BASIN ELECTRIC POWER
COOPERATIVE SUBSIDIARY

GREAT PLAINS SYNFUELS PLANT

NORTH DAKOTA REGIONAL HAZE SECOND PLANNING PERIOD FOUR-FACTOR ANALYSIS

SL-014820
Final

January 31, 2019
Project No. 13772-003

Sargent & Lundy

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000
www.sargentlundy.com

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A. North Dakota Department of Health Letter
B. GPSP Baseline Emissions
C. NO_X Control Cost Effectiveness Estimates

ABBREVIATIONS/ACRONYMS

Abbreviation/Acronym	Explanation
ABS	ammonium bisulfate
AUS	Applied Utility System Inc.
AVS	Antelope Valley Station
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BTU	British Thermal Unit
Ca	calcium
CAA	Clean Air Act
CATC	Clean Air Technology Center
$CaSO_4$	calcium sulfate
CERMS	continuous emission rate monitoring system
CFR	Code of Federal Regulations
CRF	capital recovery factor
CO	carbon monoxide
CO_2	carbon dioxide
DCS	distributed control system
DGC	Dakota Gasification Company
EPA	Environmental Protection Agency
FGD	flue gas desulfurization
FGR	flue gas recirculation
G&A	general and administration
gpm	gallons per minute
GPSP	Great Plains Synfuels Plant
GHG	greenhouse gas
H_2	hydrogen
H_2O	water
H_2S	hydrogen sulfide
ID	induced draft

Abbreviation/Acronym	Explanation
K	potassium
LNB	Low-NO_X burner
LTS	Long-term strategy
Mg	magnesium
MMBtu	million British thermal units
Na	sodium
N_2	nitrogen
ND	North Dakota
NDDH	North Dakota Department of Health
NH_3	ammonia
$(NH_2)_2CO$	urea
$(NH_4)_2SO_4$	ammonium sulfate
NH_4HSO_4	ammonium bisulfate
NO	nitric oxide
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
N/P	naphtha / phenol
NSPS	New Source Performance Standard
NSR	New Source Review
NSR	normalized stoichiometric ratio
OEM	original equipment manufacturer
OFA	overfire air
O&M	operations and maintenance
PM	particulate matter
ppm	parts per million
RBLC	RACT/BACT/LAER Clearinghouse
RPG	Reasonable Progress Goals
RPO	Regional Planning Organization
S&L	Sargent & Lundy, L.L.C.
SCR	selective catalytic reduction

Abbreviation/Acronym	Explanation
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SNG	synthetic natural gas
SO_2	sulfur dioxide
SO_3	sulfur trioxide
TAC	total annual cost
TCI	total capital investment
TE-SCR	tail-end SCR
tpy	tons per year
URP	uniform rate of progress
ULNB	ultra-low NOx burners
US	United States
VOC	volatile organic compound
WESP	wet electrostatic precipitator
WFGD	wet flue gas desulfurization
WRAP	Western Region Air Partnership

EXECUTIVE SUMMARY

The Great Plain Synfuels Plant (GPSP), located near Mercer County, ND, commenced operation in 1984. The facility is owned and operated by Basin Electric Power Cooperative (Basin Electric) through its for-profit subsidiary, Dakota Gasification Company (DGC), which acquired the facility in 1988. The facility uses lignite coal to produce synthetic natural gas (SNG), fertilizers, and other products utilizing coal gasification process and is the only facility of its kind in the U.S. Lignite is delivered from the nearby Freedom mine.

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published regulations implementing Section 169A of the Clean Air Act (CAA), establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).[1] The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. The Regional Haze Rule established a schedule setting forth deadlines by which the States must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter. [2] Second planning period Regional Haze SIPs must be submitted to EPA for review by July 31, 2021.

At the request of the North Dakota Department of Health (NDDH), a Four Factor Analysis was prepared for GPSP. The analysis identified sulfur dioxide (SO_2) and nitrogen oxides (NO_X) control options for the three Riley Boilers, two Superheaters, auxiliary Package Boiler, Main Flare, and Startup Flare, and evaluated each of the control measures for the following four statutory factors:

1. The estimated cost of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

---

[1] 64 FR 35713
[2] On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period SIPs (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

The technical feasibility evaluation concluded that there are no technically feasible options for further SO_2 control on the individual sources, including the Riley Boilers, Superheaters, Package Boiler, Main Flare, and Startup Flare. Furthermore, the evaluation concluded that there are no technically feasible options for further NOx control on the Package Boiler, Main Flare, and Startup Flare. NO_X control strategy options that are evaluated as part of the Four Factor Analysis for the Riley Boilers and Superheaters are included in Table ES-1 and Table ES-2. The tables also show baseline emission rates and estimated emission reductions for each control option.

Table ES-1. NOx Control Options for GPSP Riley Boilers

Control Technology	NOx Emission Rate (Note 1) lb/hr	% Reduction from Baseline Emission Rate
Selective Catalytic Reduction (tail-end) (Note 2)	103	80%
Baseline (Combustion Optimization / OFA / LNB)	517	--

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an ongoing long-term basis under normal operating conditions for GPSP Riley Boilers. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on an emission source type and control system-specific basis.
Note 2. TE-SCR has not been installed on a North Dakota lignite-fired unit or lignite-derived-fuel unit, and extended trials would be needed to better understand the design and operation of TE-SCR on the GPSP Riley Boilers. Nevertheless, during the initial planning period, NDDH evaluated the costs and cost-effectiveness of the control system on the Riley Boilers. TE-SCR will therefore be carried forward to the Four Factor Analysis to present hypothetical costs since the Department included it in the reasonable progress analysis for GPSP during the first planning period; however, technical feasibility has never actually been demonstrated for TE-SCR for lignite-based fuels.

Table ES-2. NO_X Control Options for GPSP Superheaters

Control Technology	NO_X Emission Rate (Note 1) lb/hr	% Reduction from Baseline Emission Rate
Combustion Optimization	42	5%
Baseline (Combustion Optimization / FGR / LNB)	44	--

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an ongoing long-term basis under normal operating conditions for GPSP Superheaters. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a source-specific and control system-specific basis.

Costs of Compliance (Statutory Factor One)

Capital and operating and maintenance (O&M) cost estimates were developed for each of the NO_X control options. The GPSP cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the control system upgrades.

Table ES-3 includes estimated costs for NO_X control options for the Riley Boilers combined and the two Superheaters combined. The table provides the estimated annualized capital and O&M costs, estimated emissions reductions, and average annual cost effectiveness.

Table ES-3. NOx Emissions Control System Cost Effectiveness ($2018)

Unit (Note 1)	NO_X Control Option	Total Annual Cost $/yr	Expected Emission Reduction tons NO_X/yr	Average Annual Cost Effectiveness (Note 2) $/ton NO_X removed
Riley Boilers	TE-SCR	$69,854,000	1,808	$38,639
Superheaters	Combustion Optimization	$229,000	10	$23,596

Note 1. Costs are provided for the combination of the three Riley Boilers or two Superheaters.
Note 2. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.

Time Necessary for Compliance (Statutory Factor Two)

Table ES-4 provides estimated timeframes needed to implement each of the evaluated control options. Notably, the estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve North Dakota's SIP.

Table ES-4. NOx Emissions Control System Implementation Schedule

NO_X Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
TE-SCR on Riley Boilers	10	18	24	Up to 60 months
Combustion Optimization on Superheaters	2	4	4	Up to 60 months

Energy and Non-Air Quality Environmental Impacts (Statutory Factor Three)

An evaluation of energy impacts indicates that certain control options (e.g., TE-SCR) will increase electrical power requirements due to increased pressure drop. Use of a combustion optimization system for NOx control may also result in reduced boiler efficiency, which would increase the amount of fuels fired to maintain steam generation. Collateral environmental impacts with regard to TE-SCR include an increase in solid waste generation due to sorbent injection; increases in other stack emission such as CO, VOC and ammonia slip; as well as additional power consumption. A summary of the environmental and energy impact analysis is provided in Table ES-5.

Table ES-5. Summary of Energy and Non-Air Quality Environmental Impacts

Control Option	Collateral Environmental & Energy Impacts
Baseline	GPSP Riley Boilers are currently equipped with WFGD / WESP control systems for SO_2 control. The Riley Boilers and Superheaters are equipped with a combination of LNB, FGR, and OFA for NOx control. Existing collateral environmental and energy impacts include: ➢ Solid WFGD by-product management or disposal ➢ Increased water consumption ➢ Increased electrical power requirements
NOx Control Options	
Selective Catalytic Reduction (SCR) - Tail End Configuration (Riley Boilers)	➢ Increased electrical power requirements ➢ Increased ammonia slip emissions and potential for ABS emissions ➢ Potential increase in SO_3 emissions ➢ Additional solid waste disposal ➢ Additional NOx, CO, and VOC emissions from duct firing
Combustion Optimization (Superheaters)	➢ Potential decrease in boiler efficiency to reduce NOx emissions ➢ Potential increase in CO emissions

Remaining Useful Life (Statutory Factor Four)

Regarding remaining useful life, the GPSP owners do not have an enforceable or suggested remaining useful life that is less than 20 years. However, implementation of control technologies that eliminate any profitability for the facility may have an effect on the remaining life. Nevertheless, a 20 year remaining useful life is evaluated.

1. INTRODUCTION

Sargent & Lundy, L.L.C. (S&L) was hired by Basin Electric's Dakota Gasification Company (DGC) to prepare a reasonable progress four-factor analysis for the control of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) emissions from the Great Plains Synfuels Plant (GPSP). The evaluation is in response to the North Dakota Department of Health's (NDDH) formal letter dated May 18, 2018, attached in Appendix A. The evaluation includes an assessment of potentially available emission reduction measures for the four statutory factors listed in 40 CFR 51.308(f)(2), and takes into consideration U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period* (the "Draft EPA Guidance").[3] Technically feasible NO_X and SO_2 emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliance
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

The reasonable progress four factor analysis for the Great Plains Synfuels Plant (the "Four Factor Analysis") is presented in the following sections:

Section 2: **Facility Description** contains information describing the facility, site location, and existing equipment.

Section 3: **Four-Factor Analysis Requirements** provides a brief description of the Regional Haze Program requirements set forth in 40 CFR 51.308.

Section 4: **Baseline SO_2 and NO_X Emissions** establishes representative baseline SO_2 and NO_X emissions for the period 2013 to present.

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[3] On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Dakota Gasification Company reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

Sections 5-8:	**NO_X and SO_2 Control Measures** identifies potentially available emission control technologies, and evaluates each control option for technical feasibility and effectiveness for each of the Riley Boilers and Superheaters, the Package Boiler, the Main Flare and the Startup Flare.
Section 9:	**Costs of Compliance (Statutory Factor One)** evaluates the cost and cost-effectiveness of each technically feasible control option.
Section 10:	**Time Necessary for Compliance (Statutory Factor Two)** provides typical timelines required to design, engineer, procure, and install the technically feasible control options.
Section 11:	**Energy and Non-Air Quality Environmental Impacts (Statutory Factor Three)** identifies the energy and non-air quality environmental impacts associated with each technically feasible control option**.**
Section 12:	**Remaining Useful Life (Statutory Factor Four)** includes a discussion of the planned remaining useful life of GPSP, including an evaluation of how remaining useful life affects the cost-effectiveness of each technically feasible control option.
Section 13:	**Summary**

Appendix A: North Dakota Department of Health Letter

Appendix B: GPSP Baseline Emissions

Appendix C: NO_X Control Cost Effectiveness Estimates

2. FACILITY DESCRIPTION

The GPSP, located near Mercer County, ND, commenced operation in 1984. The facility is owned and operated by Basin Electric Power Cooperative (Basin Electric) through its for-profit subsidiary, DGC, which acquired the facility in 1988. The facility uses lignite coal to produce synthetic natural gas (SNG), fertilizers, and other products utilizing coal gasification process and is the only facility of its kind in the U.S. Lignite is delivered from the nearby Freedom mine.

The plant consists of various emission sources, including, but not limited to, the following main sources: three (3) Riley Boilers, two (2) Coen heat transfer superheaters (a.k.a. “Superheaters”), a Main Flare, a Startup Flare, a Backup Flare, and a Rentech Auxiliary Boiler (a.k.a “Package Boiler”). There are additional emission sources at the GPSP; however, the NDDH has confirmed that the emissions from these other sources are not expected to significantly contribute to visibility impairment. As such, only the main sources identified above will be included in this Four Factor Analysis.

The Riley Boilers and Superheaters generate steam required for the gasification process, and for other uses at the facility. Each Riley Boiler fires up to 763 million British thermal units per hour (MMBtu/hr) of fuels and is designed to burn a combination of gasification products, including liquid and gaseous fuels consisting of waste gas, stink gas, tar oil, naphtha/phenol (N/P) blend, lock gas, medium BTU purge gas, and SNG. The Riley Boilers complete regular combustion tuning and are equipped with low NOx burners (LNB) and a pseudo-overfire air (OFA) system for NO_X control.[4] The Riley Boilers are also equipped with a single wet flue gas desulfurization (WFGD) system for SO_2 and particulate matter (PM) control, and a wet electrostatic precipitator (WESP) system for acid gas and PM control.

Each Superheater fires up to 169 MMBtu/hr of fuels and is designed to fire SNG and tar oil in combination or up to 100% of either fuel. The Superheaters complete regular combustion tuning and are equipped with LNB and partial

---

[4] The GPSP Riley Boilers were upgraded with windbox partitions that provide staging of combustion air to the upper burner compartment similar to overfire air systems, and subsequently provides NOx reduction.

flue gas recirculation (FGR) for NOx control. Hot exhaust flue gas from the Superheaters is combined with the WFGD outlet from the Riley Boilers to reheat the flue gas prior to exiting to atmosphere in a common stack.

Due to the nature of the gasification process and various backend components, the facility is equipped with five process gas flares: the Main Flare, Startup Flare, Ammonia Plant Flare, Ammonia Storage Tank Flare, and Backup Flare. Based on discussion with NDDH, only the Main Flare and Startup Flare are evaluated in this Four Factor Analysis; the other flares operate intermittently and/or are not expected to significantly contribute to visibility impairment. The Main Flare and Startup Flares are typically used in times of startup, shutdown, or malfunction to fire numerous process gases purged along different points of the gasification process. The flares are used as an emission control device to combust midstream components prior to emitting to the atmosphere. The Main Flare is where process relief discharges from safety or pressure control vents. The Main Flare has the ability to inject steam at the flare tip for smokeless operation. The Startup Flare is primarily used during the startup of the gasifiers when the raw gas is not of sufficient composition for additional processing. There are currently no NOx or SO_2 controls on the flares.

The Package Boiler was installed in 2017. It is designed to fire SNG at a rate of 318 MMBtu/hr and provides process steam primarily to the GPSP urea production facility. The Package Boiler is equipped with ultra-low NOx burners (ULNB) for NOx control. DGC fires low-to-no sulfur SNG fuel exclusively in the Package Boiler.

3. FOUR-FACTOR ANALYSIS REQUIREMENTS

3.1 REGIONAL HAZE RULE BACKGROUND

Section 169A of the 1977 Amendments to the Clean Air Act (CAA) sets forth a program for protecting visibility in Federal Class I areas which calls for the “prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Federal Class I areas which impairment results from manmade air pollution.” Federal Class I areas include national parks, memorial parks, and wilderness areas over a certain size. Figure 3-1. shows the locations of the 156 federally mandated Class I areas. Federal Class I areas located within North Dakota include the Theodore Roosevelt National Park and the Lostwood National Wildlife Refuge.

Figure 3-1. Federal Class I Areas

On July 1, 1999, the U.S. EPA published regulations implementing Section 169A of the CAA, establishing a comprehensive visibility protection program for Federal Class I areas (the Regional Haze Rule).[5] The Regional Haze Rule requires each state to develop, and submit for approval by EPA, a state implementation plan (SIP) detailing the state's plan to protect visibility in Class I areas. Regional Haze SIPs must contain such emission limits, schedules of compliance, and other measures as may be necessary to make reasonable progress toward meeting the national visibility goal of achieving visibility in Class 1 areas which reflects natural conditions by 2064.

To address the combined visibility effects of various pollution sources over a wide geographic region, EPA designated five Regional Planning Organizations (RPOs) to assist with the coordination and cooperation needed to address the visibility issue. The five RPOs are shown in Figure 3-2. . North Dakota is a member of the Western Regional Air Partnership (WRAP), which serves as the RPO for visibility protection at 118 Class I areas in the 15 western states.

Figure 3-2. Regional Planning Organization Map

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[5] 64 FR 35713

3.1.1 First Implementation Period

The Regional Haze Rule established a schedule setting forth deadlines by which the States must submit their initial regional haze SIPs and subsequent revisions to the SIPs. Regional Haze SIPs for the initial planning period were due in 2007, with subsequent SIP updates due in 2018 and every 10 years thereafter.[6]

Regional Haze SIP requirements for the first planning period required that states incorporate into their plans the core program requirements in 40 CFR 51.308(d), including: (1) establishing reasonable progress goals (RPGs) for each Class I area within the state that provide for measurable progress towards achieving natural visibility conditions; (2) developing a long-term strategy (LTS) including enforceable emissions limitations and compliance schedules to achieve the RPGs; and (3) developing plans to monitor and assess the effectiveness of the LTS to achieve the RPGs over the prior implementation period and affirmation of or revision to the RPGs.

The Regional Haze Rule requires that states determine the consistent rate of progress over time needed to attain natural visibility conditions on the 20 percent most impaired days by the year 2064. This “glidepath” is referred to as the uniform rate of progress (URP) line. States must consider the URP, and the emission reduction measures needed to achieve this level of improvement, when developing their RPGs and LTS. Regulations at 40 CFR 51.308(g) require each state to submit progress reports, in the form of SIP revisions, every 5 years following the submission of the initial SIP. These progress reports must evaluate the progress made towards the RPGs for Class I areas located within the state as well as those Class I areas located outside the state that may be affected by emissions from within the state.

3.1.1.1 Best Available Retrofit Technology

As a one-time requirement during the first implementation period, potential best available retrofit technology (BART) controls had to be evaluated for certain large stationary sources. States were required to conduct BART determinations for “BART-eligible” sources anticipated to cause or contribute to any visibility impairment in one or more Class I area. BART-eligible sources are stationary sources that were put in place between August 7, 1962 and August 7, 1977, and whose operations fall within one or more of the 26 listed source categories, including fossil-

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[6] On January 10, 2017, EPA made a one-time adjustment to the due date for the second implementation period SIPs (2018 – 2028) by extending the deadline from July 31, 2018 to July 31, 2021 (82 FR 3078).

fuel fired boilers of more than 250 MMBtu/hr heat input.[7] The Riley Boilers fall within the 26 listed source categories, but were not in operation prior to August 7, 1977. In its determination of BART, states were required to take into consideration the costs of compliance, the energy and non-air quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[8] As an alternative to requiring source-specific BART controls, states also had the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provided greater reasonable progress towards improving visibility than BART.

3.1.1.2 Reasonable Progress Control Requirements for GPSP during First Planning Period

GPSP commenced operation in 1984, and was not classified as a BART-eligible source or subject to the BART requirements. Nevertheless, during the initial planning period, the NDDH evaluated emissions from the three GPSP Riley Boilers as reasonable progress sources. The reasonable progress analysis prepared by NDDH did not include the Superheaters, flares, or auxiliary combustion sources. The NDDH concluded that no additional controls would be required on the Riley Boilers during the initial planning period and suggested that SNCR or SCR may not be technically feasible NO_X control options.

3.1.2 Second Implementation Period

Second planning period Regional Haze SIPs must be submitted to EPA for review by July 31, 2021. Among other requirements, second planning period SIPs are required to include an assessment of the state's RPGs and LTS. To support states in their efforts to develop the second planning period SIPs, in July 2016 EPA released a draft guidance document titled "*Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*" ("Draft EPA Guidance").[9] The Draft EPA Guidance document describes key steps states

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[7] The term "fossil fuel" is generally defined to include natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

[8] CAA Section 169A(g)(2).

[9] See, EPA-457/P-16-001. On September 11, 2018, EPA released a "*Regional Haze Reform Roadmap*" announcing its plan to "release a series of implementation tools and guidance documents that will help focus states' efforts and reduce and streamline the time and resources needed to meet the statutory and regulatory requirements for reducing regional haze in National Parks, wildlife refuges, and wilderness areas." EPA stated

should implement when developing their RPGs and LTS for the second implementation period. Key steps identified in the Draft EPA Guidance are listed in Table 3-1.

Table 3-1. Key Steps in Developing Regional Haze SIPs for Second Planning Period

1. *Ambient data analysis* – Quantify baseline, current and natural conditions and the uniform rate of progress that would achieve natural conditions in 2064. (40 CFR 51.308(f)(1))

2. *Screening of sources* – Identify the pollutants and emission sources for which a full reasonable progress analysis will be completed and explain why it is appropriate to limit the full analysis to only these sources. (40 CFR 51.308(f)(2))

3. *Source and emission control measure analysis* – Identify potential emission control measures for sources selected in the screening step and develop data on the four statutory factors and visibility benefits if they will be considered. (40 CFR 51.308(f)(2))

4. *Decisions on the content of the LTS* – Consider applicable factors and decide on new emission controls for incorporation into the LTS. (40 CFR 51.308(f)(2))

5. *Regional scale modeling* – Model the emissions reductions that will result from implementation of the LTS and other enforceable measures that will reduce visibility impairment to set the RPGs for 2028. (40 CFR 51.308(f)(3))

6. *Progress, degradation and glidepath checks* – Demonstrate that there will be an improvement on the 20 percent most impaired days. Demonstrate that there is no degradation on the 20 percent clearest days. Compare the 2028 RPG for the 20 percent most impaired days to the 2028 point on the URP line (the glidepath) and, if required, provide additional justification for the reasonableness of the RPG. Revise the LTS if additional measures are identified as necessary to make reasonable progress. (40 CFR 51.308(f)(3))

7. *Additional requirements for SIPs* – Provide additional information necessary to ensure that other requirements of the Regional Haze rule are met.

The Draft EPA Guidance recommends that states evaluate all technically feasible emission control options for stationary sources and source categories identified as having the greatest potential to impact visibility at one or more Class I area. The Draft EPA Guidance recommends several options for states to consider when evaluating

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that it plans to issue a new guidance document on Regional Haze SIP Development by Spring, 2019. Dakota Gasification Company reserves the right to update and modify this four-factor analysis, as needed, to be consistent with any new guidance issued by the agency.

potential emission reductions, including work practices, replacement and retrofit controls, existing control upgrades, fuel switching, year-round operation of controls, and operating restrictions.[10]

Emission control evaluations must consider the four statutory factors identified in 40 CFR 51.308(f)(2)(i) (discussed in Section 3.2). In addition, the Draft EPA Guidance notes that control technology assessment recommendations presented in the BART Guidelines continue to be relevant as recommendations for how a state should evaluate and select emission control measures for stationary sources.[11] Recommendations in the BART Guidelines that continue to be relevant to the reasonable progress Four Factor Analysis are listed in Appendix D of the Draft EPA Guidance, and include, in general, the recommended approach for evaluating the technical feasibility, effectiveness, costs, and cost-effectiveness of available emission control measures.[12]

3.2 DESCRIPTIONS OF THE FOUR STATUTORY FACTORS

Under 40 CFR 51.308(f)(2)(i), states must consider four statutory factors when evaluating and determining emissions reduction measures from stationary sources, or groups of sources that are necessary to make reasonable progress towards achieving natural visibility conditions. The four statutory factors are:

1. The estimated cost of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

A brief description of each of the four statutory factors, and EPA's recommendations for evaluating each of the four factors (from the Draft EPA Guidance), is provided below.

3.2.1 Costs of Compliance

Cost estimates should be developed for each technically feasible control option. Costs include the total capital costs to engineer, design, procure, and install the control technology, and annual operating and maintenance (O&M) costs. O&M costs include both fixed and variable O&M. Fixed O&M includes costs that are independent of

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[10] See, Draft EPA Guidance, pgs. 85-86.

[11] Draft EPA Guidance, pg. 85. The BART Guidelines are published at 40 CFR Part 51 Appendix Y.

[12] Draft EPA Guidance, Appendix D, pgs. 186-196.

control system operation and would be incurred even if the control system were shut down. Fixed O&M includes categories such as operating and maintenance labor, administrative charges, property taxes, and insurance. Variable O&M includes the cost of consumables, including reagent (e.g., lime or limestone, ammonia, urea, etc.), by-product management, water consumption, and electric power requirements associated with operating the control system. For existing facilities, O&M cost estimates should represent the control option's incremental increase over current O&M costs.

Capital costs include all costs required to engineer, design, procure, and install equipment needed for the control system. The Draft EPA Guideline recommends that states adhere to the accounting principles described in Chapter 2 of Section 1 of EPA's Air Pollution Control Cost Manual (the "Control Cost Manual") when calculating control system costs for a four factor analysis.[13]

Section 2.3 of the Control Cost Manual (Section 1, Chapter 2) describes the cost categories generally used to calculate the total capital cost of a retrofit control technology. Cost categories include total capital investment (TCI), which is defined to "include all costs required to purchase equipment needed for the control systems (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also includes costs for land, working capital, and off-site facilities." Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (i.e., cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies.[14]

The total annual cost (TAC) of a control option includes the annualized capital recovery cost plus the total annual O&M costs. The Control Cost Manual recommends using an equivalent uniform annual cash flow method to annualize the total capital investment by multiplying the total capital investment by a capital recovery factor

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[13] Draft EPA Guidance, pg.89.

[14] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, pg. 2-5.

(CRF).[15] The product of the total capital investment and CRF gives a uniform end-of-year payment necessary to repay the initial capital investment in "n" years at an interest rate of "i". The CRF is calculated using the following equation:

$$\mathrm{CRF} = \frac{i * (1+i)^{n}}{(1+i)^{n} - 1}$$

Where:
i = interest rate; and
n = economic life of the emission control system

The Draft EPA Guidance suggests that states may use generic cost estimates or estimating algorithms for estimating control system costs; however, source specific estimates prepared by knowledgeable engineering professionals provide more reliable information than generic cost estimates.[16] Source-specific cost estimates should be well documented for purposes of public comment and EPA review.[17]

The total annual cost of each control option ($/yr) is divided by the total annual emissions reduction (tpy) to determine the control option's average cost-effectiveness on a $/ton basis. Emissions reductions are calculated based on the difference between baseline annual emissions and post-control annual emissions. The Draft EPA Guidance generally recommends calculating baseline emissions based on projected 2028 emissions assuming source compliance with emission limits that have been adopted and are enforceable. As an alternative, baseline emissions may be based on representative past actual emissions, assuming there is no evident basis for using a different emissions rate.

3.2.2 Time Necessary for Compliance

For stationary sources, the provisions of the BART Guidelines regarding the time necessary for compliance are relevant to reasonable progress analyses. EPA recommends that prior experiences with the planning and installation of new emission controls is the best guide to how much time a particular source will reasonably need for compliance. However, source-specific factors should be considered when evaluating the time necessary to

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[15] Ibid., at pg. 2-21.
[16] Draft EPA Guidance, pg. 91.
[17] *Ibid*.

engineer, procure, and install an available and technically feasible control option. Source-specific factors that affect the time necessary to install new emission controls should be identified and documented in the Four Factor Analysis.

3.2.3 Energy and Non-Air Quality Environmental Impacts

For stationary sources, the provisions of the BART Guidelines regarding energy impacts are relevant to reasonable progress analyses. Energy impacts of an emission control measure are a matter of engineering design and control system operation; thus, EPA recommends that prior experience at similar sources will be informative. Energy impacts may be considered in terms of kilowatt-hours or fuels used to operate the control system. The energy impact analysis should focus on direct energy consumption at the source rather than indirect energy inputs needed to produce raw materials for the construction and operation of control equipment.

For stationary sources, the provisions of the BART Guidelines regarding non-air quality environmental impacts are relevant to reasonable progress analyses. Non-air quality impacts include solid or hazardous waste generation, increased water consumption, wastewater discharge, land use impacts, and impacts to threatened and endangered species or their natural habitat. Characterizing the non-air quality environmental impacts should be done on a source-specific basis. Other guidance intended for use in assessments under the National Environmental Policy Act may be relevant to this evaluation.

Even though states are not required to consider GHG emission impacts, the Draft EPA Guidance encourages states to consider GHG impacts when developing their LTS.[18] As an example, some measures that would reduce emissions that contribute to visibility impairment will also reduce GHG emissions, such as measures that reduce the use of energy produced from combusting fossil fuels with relatively high GHG emissions. Conversely, control measures that require significant energy to capture visibility impairing emissions could result in increased GHG emissions. Where a measure necessary to make reasonable progress towards natural visibility conditions would increase GHG emissions, Draft EPA Guidance encourages states to work to harmonize visibility and climate change objectives.[19]

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[18] Draft EPA Guidance, pg. 92.
[19] *Ibid*.

3.2.4 Remaining Useful Life

For stationary sources, the provisions of the BART Guidelines regarding remaining useful life are relevant to reasonable progress analyses. In general, the remaining useful life of the source itself will be longer than the useful life of the emission control measure under consideration unless there is an enforceable requirement for the source to cease operation sooner. Thus, the useful life of the control measure will normally be used in the Four Factor Analysis to calculate emission reductions, amortized costs, and cost-effectiveness. However, if there is an enforceable requirement for the source to cease operation by a date before the end of what would otherwise be the useful life of the control measure under consideration, then the enforceable shutdown date should be used to calculate remaining useful life and evaluate control technology cost-effectiveness.

3.2.5 Four Factor Analysis Approach

S&L used a top-down approach to identify and evaluate the technical feasibility and effectiveness of potentially available SO_2 and NOx control measures. S&L followed Steps 1 through 3 of the top-down approach described in the BART Guidelines to identify all available retrofit emission control measures, eliminate technically infeasible options, and evaluate the effectiveness of the technically feasible options. A brief description of each step is provided below.

Step 1 - Identify All Available Control Options

Available control options are those air pollution control technologies with a practical potential for application to the emission unit and the regulated pollutant under evaluation. Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant, and include not only existing controls for the source category but also take into account technology transfer of controls that have been applied to similar source categories and gas streams. Technologies which have not been applied to (or permitted for) full scale operations need not be considered as available.

In an effort to identify all potentially available emission control technologies, S&L searched a broad range of information sources including, but not necessarily limited to:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC);
- EPA’s New Source Review (NSR) and Clean Air Technology Center (CATC) Web sites;

- BART evaluations prepared during the initial Regional Haze planning period;
- Information from control technology vendors and engineering/environmental consultants;
- Federal and State NSR permits and Best Available Control Technology (BACT) determinations for similar sources; and
- Technical journals, reports, newsletters, and air pollution control seminars.

Step 2 - Eliminate Technically Infeasible Control Options

In Step 2, S&L evaluated the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. Control technologies are technically feasible if either: (1) they have been installed and operated successfully for the type of source under review under similar conditions; or (2) the technology could be applied to the source under review. In order for a control option to be technically feasible, it must be “available” and “applicable” to the source under consideration. A technology is considered “available” if the source owner may obtain it through commercial channels. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration.

Control technologies that are technically infeasible (i.e., not available or not applicable to the source under consideration) are eliminated from further evaluation. A demonstration of technical infeasibility must be based on physical, chemical, and/or engineering principals, and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/infeasibility.

Step 3 - Evaluate Technically Feasible Control Technologies for Effectiveness

Step 3 involves evaluating the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review. Control effectiveness should be expressed using a metric that ensures an “apples-to-apples” comparison of emissions performance levels among options, and is generally expressed as the rate that a pollutant is emitted after installation of the control measure. Control technology evaluations for existing sources should consider ways to improve the performance of existing control devices. Special circumstances pertinent to the specific unit under review should be identified and taken into consideration when assessing the capability of the control alternative and determining control effectiveness.

For this evaluation, S&L assessed the technically feasible SO_2 and NOx control options for effectiveness on various sources at the GPSP facility, including the Riley Boilers, Superheaters, Package Boiler, Main Flare, and Startup Flare.

4. BASELINE SO_2 AND NO_X EMISSIONS

The first step in developing the Four Factor Analysis is to establish the baseline SO_2 and NO_X emissions for the Riley Boilers, Superheaters, Package Boiler, Main Flare, and Startup Flare. Different averaging periods were used to determine representative emissions for each of the sources due to the variability in the nature of their operation.

To establish representative baseline emissions, S&L evaluated Riley Boiler and Superheater operating data for the period January 1, 2016 to September 30, 2018 to identify periods of normal operation (i.e., periods of operation when the boiler was not limited by infrequent or extraordinary operating restrictions). Based on review of fuels consumed, heat input, emissions control systems in place, as well as input from DGC, it was determined that this entire period was representative of normal operation for the Riley Boilers and Superheaters. The maximum 24-consecutive month annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons per year [tpy]) for the three Riley Boilers combined and the two Superheaters combined.

Baseline annual SO_2 and NO_X emissions for the Riley Boilers and Superheaters were determined based on data obtained from the GPSP continuous emission rate monitoring systems (CERMS) and emissions calculations that the facility uses to report to the NDDH. While the Riley Boiler and Superheater flue gases are routed to a common stack, the NDDH has referred to them as separate emission sources. As such, the three Riley Boilers will be evaluated as a single source and the two Superheaters will be evaluated as a single source. Since the Riley Boilers and Superheaters combine to a single stack, the stack SO_2 CERMS and reheat duct process monitor operating data were evaluated to determine the emissions generated from the Riley Boilers and the Superheaters. Stack NOx CERMS and flue gas test reports were used to determine the emissions generated between the Riley Boilers and the Superheaters.

S&L also evaluated the GPSP Package Boiler emissions data for the baseline period of December 20, 2017 through October 11, 2018. Less than a full year of data is available since the unit only recently came into service; therefore, the total heat input was scaled to estimate the total expected annual heat input. S&L and DGC determined that the baseline operating period was representative of normal operation for the Package Boiler and encompasses operation of the ULNB system for NOx control. Since a full year of operation has not occurred at the time of this evaluation, the maximum 30-day rolling annual average emission rate during the representative baseline period was used to establish baseline annual emissions (in tpy) for the Package Boiler.

S&L evaluated the Main Flare and Startup Flare monthly emissions data for the representative period January 1, 2015 through October 31, 2018 to determine periods of normal operation. Since the facility's flares do not have a prescribed normal operating condition, it was determined that all operation during the baseline time period was representative of typical operation. As such, to determine a realistic emission rate, the maximum annual average emission rate calculated during the representative time period was used to establish baseline annual emissions (in tpy) for the Main Flare and the Startup Flare.

Using the baseline annual average emissions and the respective baseline heat inputs described above for each source, representative emissions in terms of lb/hr were developed. Table 4-1 provides a summary of the GPSP SO_2 and NO_X representative baseline emissions for each source. Additional details are included in Appendix B.

Table 4-1. Baseline Emissions

Source	Pollutant	Baseline Controls	Emissions		Heat Input	Notes
			lb/hr	tpy	MMBtu/yr	
Three (3) Riley Boilers	SO_2	WFGD	671	2757	13,691,041	SO_2 emissions based on 24-month annual average tpy for period January 1, 2016 – December 31, 2017
	NO_X	Combustion tuning, LNB & OFA	517	2260	14,265,939	NOx emissions based on 24-month annual average tpy for period August 18, 2016 – August 17, 2018
Two (2) Superheaters	SO_2	Low-sulfur fuel	56	246	1,971,982	Emissions based on 24-month annual average tpy for period May 1, 2016 – April 30, 2018.
	NO_X	Combustion tuning, FGR & LNB	44	194	1,971,982	
Package Boiler	SO_2	Low-sulfur fuel	Non-detect	Non-detect	1,265,958	Emissions based on maximum 30-day rolling annual average for period December 20, 2017 – October 11, 2018. Annual emissions and annual heat input based on assuming similar operation for 12 months of the year to develop tpy.
	NO_X	ULNB	4	19	1,265,958	
Main Flare	SO_2	n/a	75	327	2,462,437	Emissions based on annual average emission rate tpy for 2018.
	NO_X	n/a	24	105	3,523,823	Emissions based on annual average emission rate tpy for 2015.
Startup Flare	SO_2	n/a	17	74	363,233	Emissions based on annual average emission rate tpy for 2015.
	NO_X	n/a	3	12	363,233	

5. RILEY BOILER CONTROL MEASURES

5.1 SO_2 EMISSIONS CONTROLS

In 1996, an ammonia-based WFGD system was installed on the Riley Boilers, and has been providing SO_2 reduction. Outside of startup, shutdown, maintenance, or malfunction, the single WFGD system is designed to treat 100% of the flue gas from the three Riley Boilers. During normal operation, the WFGD most often operates at 97-98% SO_2 removal efficiency across the absorber.

As part of the first planning period for Regional Haze, the NDDH concluded that Riley Boiler WFGD system is comparable to BACT or BART for industrial boilers of similar size.[20] Since its installation in 1996, limited improvements in the industry have been made to provide over 98% removal efficiency on ammonia-based scrubbers, especially on inlet rates over 10 lb SO_2/MMBtu. Furthermore, as indicated in the Draft EPA Guidance, operation of WFGD at 97-98% removal efficiency is similar to the levels expected from advanced FGD systems.[21] Since the WFGD is operating at BACT levels and is considered an advanced FGD system, SO_2 controls will not be evaluated further for the Riley Boilers.

5.2 NO_X EMISSIONS CONTROLS

The Riley Boilers are regularly tuned to optimize combustion and are equipped with low-NO_X burners (LNB), and a pseudo-overfire air (OFA) windbox. The Riley Boilers underwent upgrades to their firing systems and combustion air systems in 2000. Specifically, the boilers were upgraded with windbox partition plates, burner air supply dampers with pneumatic rotary actuators, air monitor probes, six staged fuel tips for synthetic natural gas (SNG) guns, six tar oil atomizers, and six tar oil meter valves. By diverting a majority of the combustion air to the windbox, the main combustion zone temperature is lowered, which lowers the thermal NO_X formation in the combustion zone. The purpose of this pseudo-OFA upgrade was to optimize performance of the boilers and reduce NOx emissions. The flow measuring devices allow for consistent fuel-to-air ratios at each individual burner location within the furnace. NOx formation is optimized by monitoring and controlling fuel-to-air ratios throughout

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[20] North Dakota Regional Haze SIP, pg. 183.
[21] Draft EPA Guidance, pg. 87.

combustion zones within the furnace. Finally, upgrades to the burners themselves with staged fuel tips creates a gradient of fuel-rich and fuel-lean zones within the burners, which further reduces NO_X formation.

5.2.1 Identify Available NO_X Control Options

After establishing baseline emissions for the source being evaluated, S&L reviewed the available NOx control options. Available control options are those air pollution control technologies and operational measures with a practical potential for application to the emission source and the regulated pollutant under evaluation. Based on a review of available NO_X control technologies installed on existing liquid- and gas-fired boilers, as well as operational practices and equipment upgrades implemented on existing control systems, the potentially available options to control NO_X emissions from the GPSP Riley Boilers are listed in Table 5-1.

Table 5-1. Available NO_X Control Options

NO_X Control Technologies
Combustion Optimization
Flue Gas Recirculation (FGR)
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)

5.2.2 Technical Feasibility of Available NO_X Control Options

Potentially available NOx control options identified in Table 5-1 were evaluated for technical feasibility (i.e. availability and applicability to the GPSP Riley Boilers) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options deemed to be technically infeasible, or options that have no practical application to the evaluated source, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible and established an emission performance level (i.e., controlled emission rate) for each.

5.2.2.1 Combustion Optimization

Combustion optimization methods using online analyzers have been developed to improve boiler performance through implementation of artificial intelligence concepts (e.g., neural networks). These control strategies are capable of setting target objectives, like NO_X output, and adjusting multiple input variables to meet these target objectives. Neural networks have the ability to connect inputs and objectives based on continuous monitoring of plant information. These systems will automatically adjust digital control system (DCS) parameters in real time by implementing bias and trim settings on pressures, temperatures, and flows that result in the optimal boiler performance for the parameter(s) being controlled. Combustion optimization programs are meant to act as an automated real-time boiler tuning mechanism, rather than manual tuning. Depending on the complexity of the system to which it is applied and on the quality of DCS installed at a facility, the improvement in boiler efficiency can be significant. A side-effect of improved boiler efficiency is a potential improvement in NO_X emissions.

Operation of the Riley Boilers is significantly more involved than typical single- or dual-fired boilers. The boilers are required to adapt to upsets and changes in product and fuel production rates, especially with gaseous fuel production since it cannot be stored. Boiler fuel sources are dictated by the gasification process conditions, requiring the boilers to adjust quickly to changes in fuel inputs. With seven different fuels injected at various elevations within the boiler, it is difficult to maintain steam production quality and quantity, as well as optimize combustion temperatures and oxygen concentrations. Furthermore, fuel quality alters as the gasification process conditions change.

Attempts to operate the Riley Boilers, and other combustion sources, in automatic mode has caused detrimental impacts to steam production rates to a complex steam system with 11 different grades of steams and multiple steam uses, which all require different flow rates and steam qualities. Operators are needed to manually adjust the steam production rates between the Riley Boilers, Superheaters, and Package Boiler to maintain the steam balance in real-time for the entire facility. As such, fine tuning of the fuel flow rates and locations within the Riley Boilers on an automatic basis is unlikely to provide consistent NOx reduction while being able to maintain fuel firing flexibility and steam production quality and quantity. Furthermore, the primary purpose of neural networks and combustion optimization systems are to improve boiler efficiency rather than reduce emissions. Neural network original equipment manufacturers (OEMs) often suggest a potential reduction in NOx emissions, but typically do not provide a guaranteed emissions reduction.

For these reasons, on-line combustion optimization is not considered a technically feasible NOx reduction technology for the Riley Boilers and will not be evaluated further.

5.2.2.2 Flue Gas Recirculation (FGR)

Flue Gas Recirculation (FGR) is a method of NO_X control in which the flue gas produced in the boiler is directed back into the furnace via the primary combustion zone in the windbox. The flue gas is mixed with the combustion air and enters the boiler via the burners. The reused flue gas both limits the amount of oxygen at the burners and cools the combustion temperature, which reduces NO_X formation. The two major challenges to implementing FGR on existing boilers are maintaining flame stability and retaining steam temperatures.

FGR is a proven technology which has been implemented in the industry over various applications, but most often in single-fuel-fired boilers (e.g., natural gas boilers). Because boiler furnaces are initially engineered for precise combustion conditions, major modifications like FGR pose challenges in implementation and troubleshooting. FGR systems also often require significant modifications in ductwork, supports, boiler tuning, and operations. There are concerns regarding the application of an FGR system at the GPSP Riley Boilers due to the use of both liquid and gaseous fuels and the variation in fuel flows and heat inputs. As the process dictates, fuels will change drastically in the firing rates as well as location of firing within the boiler, which will cause swings in combustion temperatures and boiler O_2. The variation in the fuel firing rate will require precise operation of FGR to ensure the FGR ratio is maintained throughout all operating regimes.

DGC has received proposals for FGR systems on the Riley Boilers for additional NOx control. In 1999, Applied Utility Systems Inc. (AUS) proposed a retrofit of FGR technology on all three Riley Boilers. However, further investigation determined that the FGR system would not provide any additional NOx reduction since the Riley Boilers fire waste gas, which is predominantly CO_2. AUS suggested that the waste gas fired at DGC, which contains a substantial amount of inert compounds, quenches the flame as it is combusted and reduces the amount of thermal NOx formation, which is typically the largest contributor to NOx emissions. The OEM suggested that as long as waste gas continues to be fired in the boilers, the potential for NOx reduction using FGR is limited and impractical. At this time, the facility already receives the benefits similar to an FGR system. Therefore, FGR is not considered a technically feasible option for additional NOx control on the Riley Boilers and will not be evaluated further.

5.2.2.3 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH_3) or urea ($(NH_2)_2CO$) at high flue gas temperatures (approximately 1,600ºF – 2,100ºF) in an oxidizing environment. The ammonia or urea reacts with NO_x in the flue gas to produce N_2 and water as shown below.

$$(NH_2)_2CO + 2NO + ½O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$
$$2NH_3 + 2NO + ½O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reagent injection can greatly affect NO_x removal efficiencies and the quantity of NH_3 or urea that will pass through the SNCR unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective in the range of 1,600ºF – 2,100ºF. At temperatures below the desired operating range, the NO_x reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NO_x resulting in low NO_x reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Furnace geometry, urea spray coverage, and droplet size must be considered when developing good mixing of reagent and flue gas, injecting reagent in the proper temperature window, and ensuring sufficient residence time of the reagent and flue gas in that temperature window. As the boiler cycles in load, the optimum injection region may change; thus, most facilities require multiple injection zones which are placed in and out of service as the unit ramps in load. This can include modifying the zones of injectors that are operating at different fuel inputs and temperatures.

In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to-NO_x ratio, and fuel sulfur content. Increasing the normalized stoichiometric ratio (NSR) can improve NOx removal.[22] This can be achieved by increasing urea solution flow through the injectors or changing the concentration of urea in the solution. However, too high of reagent injection rates will

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[22] NSR defines the amount of reagent needed to achieve the targeted NOx reduction. Based on the reaction equations in 5.2.2.2, two moles of NOx can be removed with one mole of urea or two moles of ammonia. In practice, more than the theoretical amount of reagent needs to be injected into the boiler flue gas to obtain a specific level of NOx reduction. This is due to the complexity of the actual chemical reactions involving NOx and injected reagent and mixing limitations between reagent and flue gas. Factors that influence the NSR value: (1) percent NOx reduction; (2) uncontrolled NOx concentration in the flue gas; (3) temperature and residence time available for the NOx reduction reactions; (4) extent of mixing achievable in the boiler; and (5) allowable ammonia slip.

increase the ammonia slip. Ammonia remaining in the flue gas past the reaction window will cause issues with downstream components, especially if the sulfur concentrations in the flue gas are high. For typical boilers, 10 ppm ammonia slip is the maximum recommended amount for SNCR operation, due to formation of ammonia salts, which can cause corrosion.

One significant drawback of ammonia-based NO_X control systems is the undesired side-reaction of ammonium sulfate and ammonium bisulfate (ABS). The reaction mechanism is carried out as shown below:

$$2NH_3 + SO_3 + H_2O \leftrightarrow (NH_4)_2SO_4\ Ammonium\ Sulfate$$
$$NH_3 + SO_3 + H_2O \leftrightarrow NH_4HSO_4\ Ammonium\ Bisulfate$$

These reactions take place when unreacted ammonia from the SNCR process comes in the presence of sulfur trioxide (SO_3) compounds. The reaction carries out more readily as the temperature lowers within the process. ABS deposits out of the flue gas as a sticky liquid and will foul the inside of ductwork and within open spaces in equipment along the flue gas pathway.

While SNCR can be applied to various types of boilers, NOx reduction potential is specific to the temperature windows and residence time. Oftentimes, the reagent utilization, and subsequent ammonia slip rates, is the limiting factor for NOx reduction potential.

In September and October of 1997 DGC tested the injection of aqueous ammonia into Riley Boiler B. Ammonia solution was introduced into two separate zones of the boiler to partially simulate operation of an SNCR system. After a week of testing the ammonia system, the Riley Boiler experienced economizer leakage, high furnace pressure, and loss of outlet air flow. An investigation revealed the source of the furnace pressure buildup was due to buildup of ammonium sulfate on the Ljungström air pre-heater baskets. Results of the testing were inconclusive, as the main stack CEMS was utilized for determining impact to NO_X, and four other emission sources that fire into the main stack were in operation during the testing.

During a second test run, a rental NO_X analyzer was used to isolate NO_X emissions reductions during ammonia injection in the Riley B Boiler. The results of this test showed 3-5% reduction in NO_X emissions. D.B. Riley, the boiler and SNCR OEM, provided new spray nozzles and the average NO_X reduction improved to 17%. Eventually, the boiler experienced similar issues with economizer leakage, low outlet flow, high furnace pressure, and plugging of the air pre-heater with ammonium sulfate after a few days of testing. Ammonium sulfate generation was likely due to the high sulfur content of the fuels fired in the Riley Boilers combined with ammonia slip from the SNCR process. The operators noticed significant buildup of ammonia salts on the air heater baskets, which causes corrosion and added pressure drop. Ammonium sulfate can also deposit on boiler tubes, which will cause issues with the process steam production. The facility witnessed ammonia salt formation on the boiler tube banks during testing, which reduces heat transfer efficiency. While many utilities can still operate with reduced steam quality, at the cost of a partial derate, the reduction in steam quality at GPSP may eliminate the possibility of using the steam in all locations it is needed within the facility and limit the total production rate of the facility. Because of the consistent operational failures, the ammonia system was abandoned in place, and removed years later. The conclusion of the ammonia injection project was that high levels of SO_2 in the gasification facility's produced fuels were the main contributor to the formation of the ammonium salts.

The formation of ammonium sulfate and ABS salts is a problem experienced by plants with high ammonia slip, high sulfur levels, and reduced temperature windows near the air preheaters. The unique operational configuration and fuels combusted by the Riley Boilers exacerbates sulfate salt formation by introducing unpredictable variations in sulfur content to the boiler furnace over time. This can lead to significant ABS formation, and therefore air preheater plugging and boiler malfunction, which was noticed in a short SNCR trial. For these reasons, the NDDH suggested in the first planning period that SNCR is not a technically feasible NOx control technology on the Riley Boilers. At the very least, the NDDH concluded that pilot scale testing would be needed to determine the feasibility of SNCR application on a high sulfur flue gas.[23] Because of the site's historical issues with ammonia injection, SNCR technology is not considered a technically feasible option for the Riley Boilers and will not be evaluated further.

5.2.2.4 Selective Catalytic Reduction

SCR is a process by which ammonia reacts with nitric oxide (NO) and nitrogen dioxide (NO_2), collectively NOx, in the presence of a catalyst to reduce the NO_X to nitrogen (N_2) and water. SCR technology has been applied to NO_X-bearing flue gases generated from solid-, liquid-, and gas-fired facilities burning various types of fuels. S&L is unaware of any instances where SCR has been implemented on a boiler that burns gasification products. However,

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[23] North Dakota Regional Haze SIP, February 24, 2010, pg. 184.

it can be considered similar to other liquid- and gas-fired boilers when considering flue gas conditions and NOx composition, where SCR has been considered appropriate. The principal reactions resulting in NO_X reduction are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NO_2 + 8NH_3 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

Because these reactions proceed slowly at typical boiler exit gas temperatures, a catalyst is used to increase the reaction rate between NO_X and ammonia. Depending on the specific constituents in the flue gas, a typical temperature range of 550°F to 780°F is necessary to achieve normal performance of the catalyst; however, the low end of the temperature window is dependent on the sulfur concentration of the flue gas, due to the lower formation temperature with higher sulfur presence. Therefore, many facilities with high sulfur fuels require a minimum operating temperature closer to 700°F to reduce the potential of localized ammonium salt formation.

SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation) or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition). Loss of catalyst activity through thermal degradation or poisoning is permanent, and reactivity can only be restored by replacing the catalyst.

SCR catalyst poisoning is expected to result from the presence of trace elements and strong alkaline substances in flue gas, including sodium (Na), potassium (K), magnesium (Mg), and calcium (Ca). Alkaline metals can chemically attach to active catalyst pore sites and cause deactivation. Sodium and potassium are of prime concern, especially in their water-soluble forms, which are more mobile and can penetrate into the catalyst pores. Earth metals, especially calcium, can react with SO_3 absorbed within the catalyst to form $CaSO_4$ and blind the catalyst. The North Dakota lignite fuel gasified at GPSP contains relatively high levels of organically associated alkali and alkaline-earth elements, including Na, K, Mg, and Ca. While these components are not tracked in the fuels fired in the boiler, it is expected that the alkali metals will concentrate in the liquid fuels fired in the boiler (e.g., tar oil, N/P), analogous to the relatively high concentration of mercury measured in the liquid fuels in comparison to the feedstock lignite at the facility. It is expected that other metals, such as alkali earth metals, would follow a similar path of volatilization in the gasifier and condensation in the water-gas-shift reaction, cooling train, and Rectisol unit.[24]

Traditionally, SCR application on coal-fired boilers is in a high-dust configuration, where the SCR reactor is located in the flue gas stream between the economizer outlet and the air heater inlet. This configuration locates the SCR within the inherently optimal temperature range environment for NOx reduction (i.e., 650°F to 750°F); however, the high fly ash loading at the economizer outlet can also have detrimental effects on the SCR catalyst. In a low-dust configuration, the SCR reactor vessel is located in the flue gas stream (e.g., downstream of WESP). In the case of GPSP's Riley Boilers, only gaseous and liquid fuels are fired, resulting in an inherently low-dust environment between the economizer and air preheater. The lack of fly ash particles is beneficial in reducing potential for erosion and pluggage of catalyst; however, employing this configuration is expected to expose the catalyst to potentially high levels of vapor-phase alkalis, such as sodium, which is expected to be concentrated in the tar oil produced from North Dakota lignite fuel. It is expected that the metals are concentrated in the liquid fuels (e.g., tar oil, N/P) rather than leaving the gasification system through other means (e.g., SNG, urea, etc.). The high concentration of alkalis immediately downstream of the boiler may preclude the applicability of low-dust SCR catalyst functionality. As such, both the high-dust and low-dust SCR configurations are not considered technically feasible NOx control options and will not be evaluated further.

In the tail-end configuration for the Riley Boilers, the SCR reaction vessel would be located in the flue gas stream after the FGD control system. The potential advantage of a tail-end SCR (TE-SCR) configuration at GPSP is that the flue gas from the Riley Boilers will have passed through the WFGD system prior to the SCR catalyst. As such, there is the possibility that the mass transfer mechanism that results in the capture of SO_2 will also capture some of the vapor-phase alkali particles, reducing the risk of catalyst poisoning and/or deactivation.

Operation of the tail-end configuration would require significant heating to raise the temperature of the flue gas to the activated temperature range of the SCR catalyst, to at least 550°F. Successful operation of the tail-end configuration would require a gas-to-gas heat exchanger to reheat the flue gas to support the SCR NOx reactions.

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[24] The water-gas-shift reaction utilizes water to convert CO into CO_2 and H_2. After the gas is shifted, it enters a cooling train, where process cooling water is used to chill the shifted gas and condense tar components. The gas then is subcooled prior to the Rectisol unit, where it is treated to further remove sulfurous compounds and CO_2 with a solvent. These consecutive process islands all provide mechanisms for alkalis and other metals to condense into the liquid fuels (e.g., tar oil, N/P).

Installation of the SCR downstream of the reheat duct tie-in would be advantageous due to the higher temperature flue gas; however, this option is not technically feasible due to the potential presence of alkalis, as will be discussed further in Section 6.2.2.3. Due to the presence of residual SO_3 at the WFGD and WESP outlet, the formation of ABS is of concern. As such, an additional in-duct heating element should be employed to raise the SCR inlet temperature to 600°F, using SNG-fired duct burners. After the flue gas passes through the SCR (at approximately 600°F), it would pass through the hot side of the gas-to-gas heat exchanger to recover the heat and cool the flue gas prior to combining with the reheat duct upstream of the stack.

TE-SCR has not been demonstrated on a unit similar to the Riley Boilers in which solid-derived fuels are fired. There are also concerns of the remaining SO_2 in the flue gas reacting with the ammonia slip from the SCR and forming ABS on the gas-to-gas heat exchanger tubes. Furthermore, a percentage of the SO_2 remaining in the flue gas will oxidize to SO_3 as it passes through the SCR catalyst, potentially requiring additional SO_3 controls on the source upstream of the SCR. To mitigate SO_3 increases, dry sorbent injection could be required. However, the introduction of a calcium or sodium sorbent upstream of the WFGD will result in additional calcium- or sodium-based sulfur byproducts in the ammonia sulfate solids. It is assumed that this combination will result in loss of sales of the ammonia sulfate fertilizer. As such, cost is included to reflect loss of sales and increased waste disposal costs. Currently, the landfill permit only allows a small amount of ammonium sulfate disposal; as such, if all of the WFGD byproduct is disposed in the landfill, the current solid waste disposal permit or landfill designation will require modification.

In general, catalyst in a TE-SCR will still be vulnerable to alkali poisoning, pore pluggage, and premature catalyst deactivation, and it is not known whether the comparatively high levels of soluble sodium and potassium in North Dakota lignite will be effectively removed by the upstream WFGD. In order to understand the applicability of installing an SCR on gasification product-fired boilers or the effect of North Dakota lignite-derived flue gas on the SCR catalyst, identify potential design solutions, and evaluate the technical feasibility and effectiveness of TE-SCR with any degree of certainty, pilot scale testing of the control configuration would be needed. Since there has not been a similar application of SCR on similar fuels or boiler configurations, extended trials would be needed to better understand the design and operation of a TE-SCR at GPSP. Because there are unresolved issues associated with catalyst poisoning, it is unlikely that DGC could obtain a viable commercial offering for TE-SCR at the GPSP facility. Furthermore, during the initial planning period, NDDH suggested there were concerns regarding technical feasibility of SCR as a NOx control technology at GPSP and pilot scale testing would be required to determine feasibility.[25] In the years following the initial planning period, during the BART analysis for other North Dakota boilers, TE-SCR was considered technically infeasible based on the lack of vendor guarantees and need for pilot testing.[26] However, since cost data was developed by the NDDH in the first planning period, it will be carried forward in the Four Factor Analysis to evaluate hypothetical cost effectiveness.

S&L assumed that the TE-SCR control option could achieve 80% removal efficiency on average on the Riley Boilers, for a controlled NOx emission rate of approximately 103 lb/hr.

5.2.2.5 NO_X Control Summary

Table 5-2 summarizes the results of the feasibility evaluation of available control options for the GPSP Riley Boilers.

Table 5-2. Summary of Technically Feasible NO_X Control Options – Riley Boilers

NOx Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Combustion Optimization	No	Implementation of on-line combustion optimization is not considered a technically feasible control option for the GPSP Riley Boilers due to the unique operating requirements to maintain steam conditions and flexibility in fuel firing.
Flue Gas Recirculation	No	Flue Gas Recirculation (FGR) is not considered a technically feasible control option for the GPSP Riley Boilers due to the fuel firing profile (e.g., waste gas) which results in similar combustion flame temperature and oxygen content as traditional FGR.
Selective Non-Catalytic Reduction (SNCR)	No	SNCR is not considered a technically feasible NOx control technology for the GPSP Riley Boilers. Historic tests preclude the viability of SNCR operation on the Riley Boilers at GPSP due to significant issues with air preheater pluggage and boiler tube deposits.
Tail-end Selective Catalytic Reduction (TE-SCR)	No*	TE-SCR installation on the Riley Boilers would be a first-of-a-kind installation on a boiler firing North Dakota lignite gasification products. Further, extensive testing would be required to determine the impact of alkalis on deactivation of SCR catalyst on the North Dakota lignite-derived fuels fired at GPSP. Because there are unresolved issues associated with catalyst poisoning, it's unlikely that DGC could obtain a viable commercial offering for TE-SCR on the Riley boilers. *TE-SCR will be carried forward to the Four Factor Analysis to present hypothetical costs since the Department included it in the reasonable progress analysis for GPSP during the first planning period.

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[25] North Dakota SIP, pg. 184.

26 Docket EPA-RO8-OAR-2010-0406. State of North Dakota November 21, 2011 comments to USEPA Region 8.

5.2.3 Effectiveness of NO_X Control Options

The NO_X control technologies that are evaluated as part of the Four Factor Analysis are listed in Table 5-3 in descending order of control efficiency. Table 5-3 also provides control option-specific NOx emission rates in terms of lb/hr. Emission rates shown in Table 5-3 represent average emission rates that the control options would be expected to achieve during normal operations on a long-term annual basis.

Table 5-3. Effectiveness of NO_X Control Options – Riley Boilers

Control Technology	NOx Emission Rate (Note 1) lb/hr	% Reduction from Baseline Emission Rate
Selective Catalytic Reduction (tail-end) (Note 2)	103	80%
Baseline (Combustion Optimization / OFA / LNB)	517	--

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an ongoing long-term basis under normal operating conditions for GPSP Riley Boilers. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on an emission source type and control system-specific basis.

Note 2. TE-SCR has not been installed on a North Dakota lignite-fired unit or lignite-derived-fuel unit, and extended trials would be needed to better understand the design and operation of TE-SCR on the GPSP Riley Boilers. Nevertheless, during the initial planning period, NDDH evaluated the costs and cost-effectiveness of the control system on the Riley Boilers. TE-SCR will, therefore, be carried forward to the Four Factor Analysis to present hypothetical costs since the Department included it in the reasonable progress analysis for GPSP during the first planning period; however, technical feasibility has never actually been demonstrated for TE-SCR for lignite-based fuels.

6. SUPERHEATER CONTROL MEASURES

6.1 SO_2 EMISSIONS CONTROLS

The Superheaters at the GPSP currently fire a mixture of SNG and tar oil. The exhaust from Superheaters A and B are combined into a reheat duct, which heats the Riley Boiler WFGD outlet stream above the dew point prior to being routed up the main stack.

Annual SO_2 emissions from the Superheaters are minimized by firing a blend of SNG and tar oil, with a higher percentage of SNG being fired. The Superheaters typically fire between 80-90% SNG; repeated fuel samples of the SNG show that sulfur composition is non-detectable. The majority of sulfur is introduced into the Superheaters through the firing of tar oil.

On average, the Superheaters account for 13% of the total baseline heat input to the Main Stack. In addition, the Superheaters contribute an insignificant amount of SO_2 (on average less than 10%) emissions to the Main Stack SO_2 emissions for the same time period. Furthermore, due to the efficiency of the WFGD on the Riley Boilers and minimal SO_2 generated in the Superheaters, 96% of the SO_2 generated by the Riley Boilers and Superheaters does not reach the stack, as shown in Table 6-1.

Table 6-1. Comparison of Baseline SO_2 Emissions

	Units	Riley Boilers (Baseline)	Superheaters (Baseline)	Main Stack (Baseline)
Uncontrolled SO_2 Emissions	tpy	19,905	56	19,961
Stack SO_2 Emissions	tpy	671	56	727
SO_2 Removal Rate	%	97	0	96

One potential option for further SO_2 reduction from the Superheaters would be changing the firing profile of the tar oil and SNG so that the SNG firing is at its maximum; however, the facility needs to maintain flexibility to fire up to 100% tar oil to provide process relief during unexpected tar oil production rates or system buildup. While the Superheaters are designed to fire up to 100% tar oil, GPSP typically fires a high percentage of SNG that in turn minimizes SO_2 emissions. As a result, there is no additional opportunity to reduce the amount of tar oil that is fired without removing the facility's needed flexibility. As such, there are no technically feasible options to reduce SO_2 emissions from the GPSP Superheaters.

6.2 NO_X EMISSIONS CONTROLS

Superheaters A and B are equipped with LNB and FGR for NOx control. The LNBs are John Zink burners designed for axial flow combustion. Combustion air flow is evenly distributed to the burners by baffles within the windbox. The airflow is diverged into primary air, air that flows through the swirler and angularly outward from the burner centerline, and secondary air, which passes outside the periphery of the swirler and reacts with the unburned fuel to complete the combustion process. FGR technology is also implemented for the Superheaters, in which a portion of the flue gas is reintroduced to the burners to lower combustion temperatures and oxygen concentrations.

During the plant modifications in 2000, two-stage fuel tar oil atomizers were installed to provide highly efficient liquid fuel distribution to each burner within the Superheaters, resulting in reduction in overall NO_X formation.

6.2.1 Identify Available NO_X Control Options

Based on a review of available NO_X control technologies installed on existing sources, as well as operational practices and equipment upgrades implemented on existing control systems, potentially available options to control NO_X emissions from the GPSP Superheaters are listed in Table 6-1.

Table 6-2. Available NO_X Control Options

NO_X Control Technologies
Combustion Optimization
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)

6.2.2 Technical Feasibility of Available NO_X Control Options

Potentially available NOx control options identified in Table 6-1 were evaluated for technical feasibility (i.e. availability and applicability to the GPSP Superheaters) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options deemed to be technically infeasible, or options that have no practical application to the evaluated source, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emission performance level (i.e., controlled emission rate) for each.

6.2.2.1 Combustion Optimization

Combustion optimization methods using online analyzers have been developed to improve boiler performance through implementation of artificial intelligence concepts (e.g., neural networks). These control strategies are capable of setting target objectives like NO_X output, and adjusting multiple input variables to meet these target objectives. Neural networks have the ability to connect inputs and objectives based on continuous monitoring of plant information. These systems will automatically adjust DCS parameters in real time by implementing bias and trim settings on pressures, temperatures, and flows that result in the optimal boiler performance for the parameter(s) being controlled. Combustion optimization programs are meant to act as a real-time boiler tuning mechanism, rather than an annual on-site manual tuning. Depending on the complexity of the system to which it is applied and on the quality of DCS installed at a facility, the improvement in boiler efficiency can be significant.

Based on the improvements to NOx emissions that are often realized with completion of boiler combustion tuning, NOx emissions may be achievable on a long-term annual average basis with a neural network system for constant online combustion optimization. Unlike the Riley Boilers, the Superheaters fire only two fuels. This limits the amount of burner and injector elevations as well as input parameters that need to be tuned. Furthermore, the Superheaters are only required to generate one steam source, which also reduces the amount of manual steam balancing required by operators. However, as discussed previously, combustion optimizer OEMs typically do not provide a guaranteed emissions reduction. Based on an analysis of the nominal NOx emission reductions that were achieved between Superheater combustion tuning periods, the facility may be able achieve an additional 5% NOx reduction on a long-term basis from the current annual average. However, further detailed review with the Superheater OEM as well as neural network OEMs would be required prior to determining actual emission reduction that could be achieved under various operating conditions. As such, combustion optimization is considered a technically feasible control option for the Superheaters. It is expected that the on-line combustion optimization could achieve 5% NOx reduction resulting in a long-term average NOx emission rate of 42 lb/hr.

6.2.2.2 Selective Non-Catalytic Reduction

As discussed in Section 5.2.2.3, SNCR is a viable technology for steam generators that combust liquid or gaseous fuels. The GPSP Superheaters have the potential to install reagent injectors in the furnace area; however, the temperature profile is unknown. Furnace temperature mapping and injection testing has not been modeled or studied in depth on the Superheaters. However, it is expected that the limiting process consideration may be the Superheater exhaust temperature. Plant personnel report that the temperature between the Superheater outlet and ID fan inlet is on average 620ºF, which is within the ammonia salt formation temperature range for the sulfur levels present when high levels of tar oil are fired. At these exit temperatures, excess ammonia in the presence of sulfur will result in ammonium salt formation. ABS formation is expected to cause fouling within and downstream of the reheat duct and may impact the rear tube bundles, especially at low unit heat input or when one Superheater is offline for maintenance.

The formation of ammonium salts is a problem experienced by plants with high ammonia slip, high sulfur levels, and reduced temperature windows near the air preheaters. The unique operational configuration and fuels fired at the gasification facility exacerbates these sulfate salt formation issues by introducing unpredictable variations in sulfur content to the Superheaters over time. During periods of time when the facility is required to purge additional tar oil, it is expected that significant amounts of sulfur would be present in the Superheater flue gas and cause issues with ammonia salt formation if urea or ammonia is used for NOx control. This can lead to significant ABS formation on heat transfer surface areas and lead to boiler malfunction, similar to that experienced by the Riley Boilers during SNCR testing. Furthermore, the baseline NOx concentration (equivalent to 0.17 lb/MMBtu) is close to the emission rate achievable by SNCR systems. Due to historical issues with ammonia injection and the relatively low temperatures in the reheat duct, the SNCR technology option is not considered a technically feasible control option and will not be evaluated further.

6.2.2.3 Selective Catalytic Reduction

The SCR configuration that is most applicable to the Superheaters is the in-duct installation. Similar to SCR systems at combined cycle plants, the catalyst layers and ammonia injection grid would be installed downstream of the burners within the ductwork. This configuration, however, has numerous technical issues. Plant personnel have reported that the temperature between the Superheater outlet and ID fan inlet is on average 620ºF. At these temperatures, there is the potential for ABS formation within the in-duct catalyst pores, limiting the NOx removal efficiency. ABS formation is even more concerning during time periods of high SO_2 formation from tar oil firing. Additionally, SO_2 in flue gas will oxidize to SO_3 as it passes over the SCR catalyst, likely increasing plant-wide sulfuric acid emissions. Due to the lack of downstream particulate collection devices on the gas- and liquid-fired steam generators, dry sorbent injection prior to the catalyst is not an option.

However, the critical issue with installation of an SCR downstream of the Superheaters is the presence of vapor phase alkali metals. As discussed in Section 5.2.2.3, combustion of the liquid fuels at GPSP is expected to have a detrimental effect on the SCR catalyst due to the expected presence of alkalis in the liquid fuels (e.g., tar oil). Since there is no treatment of the Superheater gas stream to remove these alkalis prior to the catalyst, SCR is determined to be technically infeasible for the Superheaters and will not be evaluated further.

6.2.2.4 NOx Control Summary

Table 6-3 summarizes the results of the feasibility evaluation of available control options for GPSP.

Table 6-3. Summary of Technically Feasible NO_X Control Options – Superheaters

NOx Control Option	Technically Feasible (Yes/No)	Technical Feasibility Summary
Combustion Optimization	Yes	Combustion optimization is considered a technically feasible control option for the GPSP Superheaters.
Selective Non-Catalytic Reduction (SNCR)	No	SNCR is not considered a technically feasible option for the Superheaters due to low reheat duct temperatures and presence of sulfur, which will lead to significant ABS formation issues within the existing ductwork and rear steam tube banks.
Selective Catalytic Reduction (SCR)	No	SCR applied to the Superheaters would introduce alkalis to the catalyst. As such, SCR is considered technically infeasible.

6.2.3 Effectiveness of NO_X Control Options

The NO_X control technologies that will be evaluated as part of the Four Factor Analysis are listed in Table 6-3 in descending order of control efficiency. Table 6-3 also provides control option-specific NOx emission rates in terms of lb/hr. Emission rates shown in Table 6-3 represent average emission rates that the control options would be expected to achieve during normal operations on a long-term annual basis.

Table 6-4. Effectiveness of NO_X Control Options – Superheaters

Control Technology	NO_X Emission Rate (Note 1) lb/hr	% Reduction from Baseline Emission Rate
Combustion Optimization	42	5%
Baseline (Combustion Optimization / FGR / LNB)	44	--

Note 1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an ongoing long-term basis under normal operating conditions for GPSP Superheaters. Emission rates are provided for comparative purposes, and should not be construed to represent proposed emission limits. Corresponding permit limits must be evaluated on a source-specific and control system-specific basis.

7. PACKAGE BOILER CONTROL MEASURES

The Package Boiler was permitted in 2014 during the Urea Project addition at GPSP. The Package Boiler subsequently commenced operation in December 2017. To minimize NOx emissions from the Package Boiler, it was determined that ULNB would be used to achieve emission rates below the new source performance standard (NSPS). While a BACT analysis was not completed for NOx control on the Package Boiler, an evaluation of the RBLC conclude that LNB is typically considered BACT for gas boilers of similar size. The Package Boiler is currently achieving a long-term average NOx rate equivalent to approximately 30 ppmvd, which is comparable to other facilities operating with LNB or ULNB. As such, no additional NOx emissions controls will be evaluated for the Package Boiler. Furthermore, the design of the Package Boiler is such that it can only fire natural gas or SNG. Based on SNG fuel analyses completed by GPSP, the sulfur content is considered non-detect. Therefore, no additional SO_2 emission controls will be evaluated for the Package Boiler at GPSP.

8. FLARE CONTROL MEASURES

The Main Flare is the primary control device for volatile process gases throughout the process areas in the facility. Process relief streams are either discharged through safety and control valves or equipment vents. One of the components of the process gases flared is hydrogen sulfide (H_2S). It is conservatively assumed that 100% of the H_2S vented to the flare from the process is combusted to SO_2. The Startup Flare is used during startup, shutdown, and malfunction of the facility gasifiers. During startup, the gases originating from the lignite coal are not yet of sufficient composition for further processing and are instead flared.

S&L approached various flare vendors to gather feasible options for mitigating NO_X and SO_2 (H_2S) emissions from the flared process gases. S&L provided background information on a range of flare stream compositions, maximum volumetric and mass flows, typical emission concentration values, steam injection mass flows and pressures, flare tip diameters, general arrangement drawings, and brief operations and control descriptions. S&L requested feasible control technologies that could be implemented to reduce emissions from the baseline values provided in Table 4-1.

Under typical operation, H_2S is being scrubbed from the raw gas produced from the lignite gasification process via the Rectisol unit. Depending on which segment needs to be flared during upset conditions, certain flared components would not have substantial H_2S to remove. Most process streams are vented to the Main Flare during times of emergency pressure release, or during times of process failure in the gasification process. However, the Main Flare does experience a relatively consistent stream of process “leakage” from various locations within the facility. This leakage contributes approximately 35 lb/hr of SO_2, which is significantly below the Riley Boiler WFGD outlet rates. The Startup flare is typically not flaring process gas (i.e., lock gas); instead, the majority of the flared fuel is SNG, which has non-detectable sulfur concentration. Overall, the baseline lb/hr SO_2 emissions from the Main and Startup Flares combined only comprise approximately 11% of the total plant baseline SO_2 emissions.

Recent technologies have emerged on the market for H_2S and volatile organic carbon (VOC) scrubbing instead of flaring to reduce emissions. However, these systems are typically applied to flare gases with very high H_2S concentrations. At GPSP, the process leakage gas going to the Main Flare has a typical H_2S concentration in the 0.05% range, which is well below the typical application of the emerging technology’s typical application, which often deals with 5-20% ranges. Furthermore, these systems are designed for continuous operation at steady flow rates, rather than fluctuating purge conditions.

If an H_2S scrubbing system was pursued, the system would be best applied to treat the relatively continuous process leakage stream. There would be design issues to the system if treatment is expected of all other process stream purges sent to the Main Flare for process pressure relief in times of plant-wide upsets. Due to the safety concerns associated with adding back pressure to a pressure relief or emergency condition, it is suggested that other process gases would need to bypass the scrubber directly.

Prior to implementing the Riley Boiler WFGD system, the GPSP facility treated the gasification products and fuels using various H_2S scrubbing solutions, including Stretford® and Sulfolin®. The gaseous fuels were treated prior to combustion in the Riley Boilers; however, the facility was never able to continuously achieve the permitted limits in place at the time. During the years when the solutions were used for scrubbing, the effectiveness of the scrubbing was minimal; furthermore, the facility reported significant fugitive odors. It was concluded that the H_2S scrubbing was ineffective due to chemistry issues stemming from the fuel composition, specifically the various other sulfurous compounds that can be present in the products or purged gases. It is expected that there would be similar issues with the effectiveness of H_2S scrubbing of the flared gases.

Due to the limited experience with the flare scrubbing technology and low H_2S inlet rates, pilot testing would have to be completed to determine the continuous effectiveness of treating the process gas without impacts to the typical emergency operation of the flare. Additionally, because of the historic issues associated with H_2S scrubbing at GPSP, H2S control is not considered a technically feasible technology at this time for SO_2 emission reduction on either the Main Flare or Startup Flare.

Additionally, no vendors were able to provide viable solutions for NO_X mitigation on the GPSP Main Flare or Startup Flare. Vendors cited numerous issues with providing solutions to this facility. One notable reason for not being able to provide additional controls was the already low baseline NO_X value (equivalent to approximately 0.06 lb/MMBtu). The vendors concluded it would be difficult to obtain significant reductions beyond what is already being achieved at the facility. For comparison purposes, SCR systems achieve 0.06 lb/MMBtu and these systems are considered BACT on coal-fired units.

For these reasons, there are no technically feasible control options available to further reduce SO_2 or NOx emission from the Main or Startup Flares.

9. COSTS OF COMPLIANCE (STATUTORY FACTOR ONE)

The economic analysis performed as part of the Four Factor Analysis examines the cost-effectiveness of each control technologies identified in Table 5-3 and Table 6-4, on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. For units with existing controls, the base case represents existing baseline actual emissions. Annual costs for each control option are calculated relative to the base case by adding annual operation and maintenance (O&M) costs to the annualized cost of capital and, if applicable, lost revenue due to extended outage required for installation of control equipment. Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.5% and equipment life of 20 years.[27,28] Cost effectiveness ($/ton) of a particular control option is simply the annual cost ($/yr) divided by the annual reduction in annual emissions (ton/yr). In addition to cost-effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next, more stringent, level of control may also be calculated to evaluate the incremental cost effectiveness of the more stringent control.

Capital and O&M cost estimates were developed for each of the evaluated control options. The GPSP cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the GPSP control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on GPSP-specific design parameters, including typical fuels firing profiles, fuel characteristics, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the GPSP retrofit technologies as “concept screening” cost estimates generally based on parametric models, judgment, or analogy.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to

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[27] The assumed 20-year equipment life is consistent with the control system equipment life used by NDDH in its evaluation of NO_X and SO_2 control technologies for BART-eligible sources. (see, e.g., ND Regional Haze Final SIP, Appendix C.1, “BART Determination Study for Leland Olds Station Units 1 & 2, Basin Electric Power Cooperative, August 2006, pgs. 64 (NOx controls) and 158 (SO2 controls). See also, ND Regional Haze Final SIP, Appendix C4, “NOx Best Available Control Technology Study for Milton R. Young Station Unit 1, Minnkota Power Cooperative, Inc., October 2006, pg. 3-22).

[28] Based on discussion with the NDDH, the state has elected to utilize the current Federal Reserve interest rate, which was 5.5% at the time of this analysis.

retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, contractor general and administration (G&A) expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

Additional costs were developed based on outage duration needed to tie-in the new control technology. Based on the location of the control technology (specifically the SCR), a special outage would be required to integrate into the flue gas path at a time when no process steam is required (i.e., when all three Riley Boilers and two Superheaters are offline). Since GPSP facility does not typically take a full facility outage on a yearly basis, a special outage is included; loss of facility profit is estimated for the outage and annualized similarly to the capital costs.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and electrical power requirements. Electrical power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing control systems.

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

The results of the SO_2 and NO_X control cost evaluations are included below in Sections 9.1 and Section 9.2.

9.1 ECONOMIC EVALUATION – SO_2 CONTROLS

In the previous sections, it was determined that WFGD was established as BACT by the NDDH for the three Riley Boilers and continues to operate at approximately 97% reduction; thus no further SO_2 control options will be evaluated on the Riley Boilers. The two Superheaters currently generate an insignificant amount of SO_2 in comparison to the total SO_2 present at the stack. Furthermore, the WFGD is providing 96% overall SO_2 reduction for the combination of Superheaters and Riley Boilers, which is still within BACT levels. As such, no additional SO_2 control options are evaluated for the Superheaters.

The Package Boiler was recently commissioned and is only permitted to fire natural gas or SNG to limit SO_2 emissions. Samples taken by GPSP personnel confirm the sulfur composition of the SNG is non-detectable. Therefore, no additional SO_2 control options are evaluated for the Package Boiler.

Finally, there have been previous issues at GPSP with H_2S scrubbing along with limited experience with operating H_2S scrubbing devices on flares, especially with low H_2S concentrations and those which do not operate at steady flow rates. Because of this and the safety concerns with operating backend equipment on pressure relief flare systems, no SO_2 control options will be evaluated for the Main Flare and Startup Flare.

9.2 ECONOMIC EVALUATION – NO_X CONTROLS

Based on the technical feasibility analysis completed as part of the first factor, it was determined that NOx control reduction is only feasible on the Riley Boilers and Superheaters. Table 9-1 presents the capital costs and annual operating costs associated with building and operating each control system for the three combined Riley Boilers or two combined Superheaters; annual emissions and pricing is not provided on an individual unit basis. Table 9-2 shows the average annual cost effectiveness for each control system. Additional cost details are provided in Appendix C.

Table 9-1. NO_X Control Cost Summary ($2018)

Unit (Note 1)	NO_X Control Option	Total Capital Investment $	Annual Capital Cost $/yr	Annualized Outage Cost $/yr	Annual Operating Cost $/yr	Total Annual Cost $/yr
Riley Boilers	TE-SCR	$178,542,000	$14,940,000	$3,515,000	$51,399,000	$69,854,000
Superheaters	Combustion Optimization	$1,7326,000	$144,000	$0	$85,000	$229,000

Note 1. Costs are provided for the combination of the three Riley Boilers or two Superheaters.

Table 9-2. NO_X Emissions Control System Cost Effectiveness ($2018)

Unit (Note 1)	NO_X Control Option	Total Annual Cost $/yr	Expected Emission Reduction tons NO_X/yr	Average Annual Cost Effectiveness (Note 2) $/ton NO_X removed
Riley Boilers	TE-SCR	$69,854,000	1,808	$38,639
Superheaters	Combustion Optimization	$229,000	10	$23,596

Note 1. Costs are provided for the combination of the three Riley Boilers or two Superheaters.
Note 2. Average cost effectiveness for each control option is the total annual cost divided by the expected emission reduction.

The costs indicate that the average annual cost effectiveness of the NO_X control options for the facility range from $23,596 per ton (Combustion Optimization on Superheaters) to $38,639 per ton (TE-SCR) NO_X removed.

The Combustion Optimization option is expected to achieve 5% NO_X reduction from long-term average baseline levels without impact to Superheater performance. This option can be implemented on both Superheaters with additional capital and minor operating costs for a total cost effectiveness is $23,596 per ton.

TE-SCR system costs have been included to remain consistent with the approach during the initial planning period (i.e., assuming technical feasibility and evaluating the control system for costs and cost effectiveness). Based on preliminary cost estimates, the cost effectiveness of a TE-SCR system is $38,639 per ton to treat the NOx from the three Riley Boilers.

10. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO)

The time necessary for compliance is generally defined as the time needed for full implementation of the evaluated control options identified in Table 5-3 and Table 6-4. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. Therefore, compliance deadlines must consider the time necessary for compliance by setting a compliance deadline that provides a reasonable amount of time for the source to implement the control measure.

Table 10-1 includes estimated timeframes needed to implement each of the control technologies. Notably, the estimated timeframes do not account for time needed for North Dakota to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve North Dakota's SIP.

Table 10-1. NO_X Emissions Control System Implementation Schedule

NO_X Control Option	Design / Specification / Procurement (months)	Detail Design / Fabrication (months)	Construction / Commissioning / Startup (months)	Total (months after SIP approval)
TE-SCR on Riley Boilers	10	18	24	Up to 60 months
Combustion Optimization on Superheaters	2	4	4	Up to 60 months

11. ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS (STATUTORY FACTOR THREE)

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal.

11.1 ENVIRONMENTAL IMPACTS

The Riley Boilers and Superheaters are currently equipped with a combination of LNB, FGR and OFA systems for NOx control and wet ammonia scrubber technology for SO_2 control. The ammonia reagent used in the ammonia-based FGD system reacts with SO_2 in the flue gas to form ammonium sulfate and ammonium sulfite solids. The solids are either recycled to the system for reuse or removed from the system and sold as fertilizer or disposed as nonhazardous solid waste. The existing WFGD system also requires water to quench the flue gas. Based on the design of the control system, the WFGD uses approximately 640 gpm of makeup water for SO_2 control. Collateral environmental impacts associated with the existing control systems include water consumption and increased solid waste generation. There were no collateral impacts associated with the combustion optimization or LNB/OFA/FGR systems previously implemented.

Based on a review of potential non-air quality environmental impacts, there are potentially significant collateral environmental impacts identified for and the NOx control options. The TE-SCR catalyst oxidizes some of the SO_2 to SO_3 in addition to catalyzing the reaction between NOx and ammonia. There could be the potential for increased SO_3 emissions with the use of a TE-SCR. The SO_3 will react with the moisture in the stack to form sulfuric acid emissions and react with the ammonia slip to form ABS. If it is determined a dry sorbent injection system is required for the reduction of SO_3 emissions prior to the WFGD, the system will increase the solid waste generated and may affect sales of the ammonium sulfate fertilizer. If fertilizer cannot be sold, it will need to be disposed of in a solid waste landfill. There would be some ammonia slip emissions from a TE-SCR in the range of 2 ppm, and there is no means to capture the ammonia slip emissions from the TE-SCR since it would be installed downstream of the WFGD. Finally, the TE-SCR system would require combustion of SNG in a duct burner to heat the flue gas. This would result in additional NOx, CO and VOC emissions.

Impacts from the incorporation of the combustion optimization system on the Superheaters are expected to be less significant than the TE-SCR. Based on tuning the combustion for minimizing NOx formation, there would be expected increases in CO emissions, since they have an inverse relationship with respect to combustion.

11.2 ENERGY IMPACTS

The facility relies on production of steam in the Riley Boilers, Superheaters, and Package Boiler as the heat energy for other processes within the gasification facility. Options that include changes to the combustion temperature for NOx control may result in sub-optimal steam production rates or quality. As such, if the combustion optimization systems may not able to maintain the desired boiler efficiency while tuning operating conditions for minimizing NOx production, additional fuel may have to be fired to maintain steam production rate and quality. As such, the measured efficiency of the boiler may decrease, and subsequently result in higher mass emission rates due to higher fuel throughput. The TE-SCR option would increase pressure drop through the control systems, and increase the electricity consumption of the facility.

Although several of the control options have energy impacts, none of the impacts are considered significant enough as to disqualify any of the options from consideration in the Four Factor Analysis. In order to account for potential energy impacts associated with each option, the electrical power cost associated with operating the control systems have been included as an annual operating cost in the economic impact assessment.

11.3 ENVIRONMENTAL / ENERGY IMPACTS SUMMARY

A summary of the Statutory Factor 3 environmental and energy impact analysis is provided in Table 11-1.

Table 11-1. Summary of Energy and Non-Air Quality Environmental Impacts

Control Option	Collateral Environmental & Energy Impacts
Baseline	➢ GPSP Riley Boilers are currently equipped with WFGD / WESP control systems for SO_2 control. The Riley Boilers and Superheaters are equipped with a combination of LNB, FGR, and OFA for NOx control. Existing collateral environmental and energy impacts include: ➢ Solid WFGD by-product management or disposal ➢ Increased water consumption ➢ Increased electrical power requirements
<u>NOx Control Options</u>	
Selective Catalytic Reduction (SCR) - Tail End Configuration (Riley Boilers)	➢ Increased electrical power requirements ➢ Increased ammonia slip emissions and potential for ABS emissions ➢ Potential increase in SO_3 emissions ➢ Additional solid waste disposal ➢ Additional NOx, CO, and VOC emissions from duct firing
Combustion Optimization (Superheaters)	➢ Potential decrease in boiler efficiency to reduce NOx emissions ➢ Potential increase in CO emissions

12. REMAINING USEFUL LIFE (STATUTORY FACTOR FOUR)

The evaluation of NO_X and SO_2 controls options should consider the source's "remaining useful life" in determining the costs of compliance. The remaining useful life is the difference between the date that controls would be put in place and the date that the facility permanently ceases operation. If the remaining useful life of the unit is shorter than the useful life of a particular control option, the remaining useful life should be used for annualizing costs. If the remaining useful life exceeds the useful life of the control options, the remaining useful life has no effect on the cost evaluation.

Under the current GPSP resource plan, the remaining useful life of the facility is expected to be greater than 20 years. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework. However, the implementation of additional controls has the potential to reduce the facility's minimal profit margin, which may adversely impact the facility's planned remaining life. In the event that occurs, GPSP would request an opportunity to reevaluate economic impacts and the facility's remaining useful life.

13. FOUR-FACTOR ANALYSIS SUMMARY

At the request of NDDH, a Four Factor Analysis was prepared for GPSP. The analysis identified SO_2 and NO_X control options for the three Riley Boilers, two Superheaters, auxiliary Package Boiler, Main Flare, and Startup Flare, and evaluated each of the control measures for the following four statutory factors:

1. The estimated cost of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

The technical feasibility evaluation concluded that there are no technically feasible options for further SO_2 control on the individual sources. The evaluation prepared for NO_X controls options indicates that that the average annual cost effectiveness for the facility ranges from $23,596 per ton (Combustion Optimization on Superheaters) to $38,639 per ton (TE-SCR on Riley Boilers) NO_X removed.

The time necessary for compliance for the NO_X control options, the time necessary for compliance ranges from 10 months (combustion optimization) to 52 months (TE-SCR); however, GPSP would expect that the state would allow up to 60 months to achieve compliance to be consistent with the first planning period.

An evaluation of energy impacts indicates that certain control options (e.g., TE-SCR) will increase electrical power requirements due to increased pressure drop. Use of a combustion optimization system for NOx control may also result in reduced boiler efficiency which would increase the amount of fuels fired to maintain steam generation. Collateral environmental impacts with regard to TE-SCR include an increase in solid waste generation due to sorbent injection; increases in other stack emission such as CO, VOC and ammonia slip; as well as additional power consumption.

Regarding remaining useful life, the GPSP owners do not have an enforceable or suggested remaining useful life that is less than 20 years. However, implementation of control technologies that eliminate any profitability for the facility may have an effect on the remaining life. Nevertheless, a 20 year remaining useful life is evaluated.

APPENDIX A

NORTH DAKOTA DEPARTMENT OF HEALTH LETTER

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

May 18, 2018

RECEIVED
MAY 24 2018
DAKOTA GASIFICATION

Mr. Daniel Whitley
Dakota Gasification Company
420 County Road 26
Beulah, ND 58523

Re: Regional Haze
Second Planning Period

Dear Mr. Whitley:

The Department of Health (Department) has begun work on the second planning period (Round 2) State Implementation Plan (SIP) for regional haze. In Round 1 of the regional planning process, the emphasis was on Best Available Retrofit Technology (BART) and making reasonable progress towards the national visibility goal. In Round 2, there are no BART requirements; therefore, we will focus on making reasonable progress. The reasonable progress analysis will be made using the four factors in Section 169A(g)(1) of the Clean Air Act:

The four factors are:

1. The cost of compliance
2. The time necessary to achieve compliance
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements

Guidance provided by the U.S. Environmental Protection Agency (Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period at https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf) indicates the Department must address 80% of the visibility impairment caused by in-state sources. Data from the IMPROVE monitoring sites at Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA) indicate that sulfates and nitrates continue to be the largest contributors to visibility impairment in these areas. The primary precursors of sulfates and nitrates are emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X).

The Great Plains Synfuels Plant has been identified as a significant source of SO_2 and NO_X emissions. Therefore, the Department requests that you prepare a "four factors" analysis for your facility. The analysis should be prepared using the draft EPA guidance noted above. The analysis should include all source units that emit through the main stack as well as the flares at the facility.

Environmental Health Section Chief's Office 701.328.5150
Division of Air Quality 701.328.5188
Division of Municipal Facilities 701.328.5211
Division of Waste Management 701.328.5166
Division of Water Quality 701.328.5210

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Preparation of the Round 2 Regional Haze SIP will require extensive planning and review of emission sources in North Dakota. The Department will be working with the Western Regional Air Partnership (WRAP) to prepare the Round 2 SIP. WRAP will be conducting air quality modeling of potential regional emissions reductions in early 2019. The Department asks that your "four factors" analysis be submitted by January 31, 2019.

If you have any questions, please contact David Stroh of my staff at (701)328-5188.

Sincerely.

Terry O'Clair

Terry L. O'Clair
Director
Division of Air Quality

TLO/TB:saj

APPENDIX B

GPSP BASELINE EMISSIONS

Great Plains Synfuels Plant
Reasonable Progress Four Factor Analysis
Baseline Emissions Estimates

Table 1. GPSP -- Baseline Emissions

Unit No.	Pollutant	Baseline Controls	Emissions		Heat Input	Capacity Factor	Notes
			lb/hr	tons/yr	MMBtu/yr	%	
Riley Boiler A, B, and S Combined Baseline	SO2	WFGD	671	2,757	13,691,041	68%	SO2 emissions based on 24-month annual average tpy for period January 1, 2016 – December 31, 2017
	NOx	Combustion tuning, LNB, OFA	517	2,260	14,265,939	71%	NOx emissions based on 24-month annual average tpy for period August 18, 2016 – August 17, 2018
Superheater A and B Combined Emissions	SO2	low-sulfur fuel	56	246	1,971,982	67%	Emissions based on 24-month annual average tpy for period May 1, 2016 – April 30, 2018.
	NOx	Combustion tuning & LNB	44	194	1,971,982	67%	
Rentech Package Boiler	SO2	low-sulfur fuel	non-detect	non-detect	1,265,958	45%	Emissions based on maximum 30-day rolling annual average for period December 20, 2017 – October 11, 2018. Annual emissions and annual heat input based on assuming similar operation for 12 months of the year to develop tpy.
	NOx	ULNB	4	19	1,265,958	45%	
Main Flare	SO2	n/a	75	327	2,462,437	n/a	Emissions based on annual average emission rate tpy for 2018.
	NOx	n/a	24	105	3,523,823	n/a	Emissions based annual average emission rate tpy for 2015.
Startup Flare	SO2	n/a	17	74	363,233	n/a	Emissions based on annual average emission rate tpy for 2015.
	NOx	n/a	3	12	363,233	n/a	

APPENDIX C

NO_X CONTROL COST EFFECTIVENESS ESTIMATES

Great Plains Synfuels Plant
NO_X Control Summary

Table 1. GPSP Operating Parameters

Parameter	Riley Boilers (3)	Superheaters (2)	Unit
Annual Average Heat Input	14,265,939	1,971,982	MMBtu/yr
Total Maximum Hourly Heat Input	2,289	338	MMBtu/hr
Average Capcity Factor	71%	67%	%

Table 2. Control Effectiveness

	Riley Boilers				Superheaters			
Control Technology	**Control Efficiency (%)**	**Expected Emissions (tons/yr)**	**Emission Rate (lb/hr)**	**Expected Emissions Reduction (tons/yr)**	**Control Efficiency (%)**	**Expected Emissions (tons/yr)**	**Emission Rate (lb/hr)**	**Expected Emissions Reduction (tons/yr)**
Tail-End SCR	80.0%	452	103	1,808				
Combustion Optimization					5.0%	184	42	10
Baseline		**2,260**	517			**194**	44	

Great Plains Synfuels Plant
NO_X Control Summary

Table 3. Cost Effectiveness Riley Boilers

Control Technology	Emissions (tons/yr)	Tons of NO_X Removed (tons/yr)	Total Capital Requirement ($)	Annualized Capital Cost ($/year)	Annualized Outage Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)
Tail-End SCR	452	1,808	$178,542,000	$14,940,000	$3,515,000	$51,399,000	$69,854,000	**$38,639**
Baseline	2,260	0	--	--	--	--	--	

Table 4. Cost Effectiveness Superheaters

Control Technology	Emissions (tons/yr)	Tons of NO_X Removed (tons/yr)	Total Capital Requirement ($)	Annualized Capital Cost ($/year)	Annualized Outage Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)
Combustion Optimization	184	10	$1,726,000	$144,000	$0	$85,000	$229,000	**$23,596**
Baseline	194	0	--	--	--	--	--	

GPSP Riley Boilers
NO_X Control Cost Evaluation
Tail-End SCR

NO_X Control Option Description	**Tail-End SCR**
Baseline NO_X Emissions, lb/hr	517
Post Upgrade NO_X Emissions, lb/hr	103
Capacity Factor used of Cost Estimates (%)	71%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$60,114,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$3,006,000	5% of Equipment/Material Cost
Freight	$3,006,000	5% of Equipment/Material Cost
Total PEC	$66,126,000	
Direct Installation Costs		
Labor	$43,531,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$1,088,000	2.5% of Labor
Mobilization / Demobilization	$653,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$2,177,000	5% of Labor
Total Direct Installation Costs	$47,449,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$113,575,000**	
Indirect Costs		
Contractor's General and Administration Expense	$11,358,000	10% of Total Direct Costs
Contractor's Profit	$5,679,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$9,086,000	8% of Total Direct Costs
Construction Management/Field Engineering	$4,543,000	4% of Total Direct Costs
S-U / Commissioning	$1,704,000	1.5% of Total Direct Costs
Spare Parts	$568,000	0.5% of Total Direct Costs
Owner's Cost	$2,272,000	2% of Total Direct Costs
Total Indirect Costs	**$35,210,000**	
Contingency	**$29,757,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$178,542,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0837	20 year life of equipment (years) @ 5.5% interest.
Annualized Capital Costs (CRF x TCI)	**$14,940,000**	
OUTAGE COSTS		
Outage Costs		
Standard Outage Duration (weeks/yr)	0	
Outage Duration due to Retrofit (weeks/yr)	6	Estimate for full facility (black-plant) outage for project tie-in
Lost Revenue due to Retrofit	**$42,000,000**	Based on GPSP facility net lost revenue from a black plant $1,000,000/day
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0837	20 year life of equipment (years) @ 5.5% interest.

GPSP Riley Boilers
NO_X Control Cost Evaluation
Tail-End SCR

NO_X Control Option Description	**Tail-End SCR**
Baseline NO_X Emissions, lb/hr	517
Post Upgrade NO_X Emissions, lb/hr	103
Capacity Factor used of Cost Estimates (%)	71%

Annualized Outage Costs (CRF x TCI)	**$3,515,000**	
OPERATING COSTS		
Operating & Maintenance Costs		
Variable O&M Costs		
Ammonia Reagent Cost	$197,000	Based on ammonia reagent cost of $275.18 per ton.
Hydrated Lime Cost	$1,066,000	Based on hydrated lime cost of $187 per ton.
Catalyst Replacement and Disposal Cost	$2,166,000	Based on catalyst cost of $8,000 per m3 and catalyst replacement cost of $1,000 per m3.
SNG Cost	$990,000	Based on an SNG sale rate of $3.14/MMBtu.
Lost Fertilizer Revenue	$36,010,000	Based on ammonia sulfate fertilizer sale price of $200/ton
Additional Solid Waste Cost	$786,000	Based on solid waste disposal cost of $4.20/ton
Electrical Power Cost	$881,000	Based on electricity cost of $41.16 per MWh
Total Variable O&M Costs	$42,096,000	

GPSP Riley Boilers
NO_X Control Cost Evaluation
Tail-End SCR

NO_X Control Option Description	**Tail-End SCR**
Baseline NO_X Emissions, lb/hr	517
Post Upgrade NO_X Emissions, lb/hr	103
Capacity Factor used of Cost Estimates (%)	71%

Fixed O&M Costs		
Additional Operators per Shift	1	
Operating Labor	$398,000	Assume $45.47/hr for each additional operator
Supervisor Labor	$60,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$1,704,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$2,162,000	
Indirect Operating Cost		
Property Taxes	$1,785,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,785,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$3,571,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$7,141,000	
Total Annual Operating Cost	**$51,399,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$14,940,000	
Annualized Outage Cost	$3,515,000	
Annual Operating Cost	$51,399,000	
Total Annual Cost	**$69,854,000**	

GPSP Superheaters
NO_X Control Cost Evaluation
Combustion Optimization

NO_X Control Option Description	**Combustion Optimization**
Baseline NO_X Emissions, lb/hr	44
Post Upgrade NO_X Emissions, lb/hr	42
Capacity Factor used of Cost Estimates (%)	67%

CAPITAL COSTS	**Cost (2018$)**	**Basis**
Direct Costs		
Purchased Equipment Costs (PEC)		
Equipment and Materials	$765,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	Included in equipment and materials cost
Sales Tax	$38,000	5% of Equipment/Material Cost
Freight	$38,000	5% of Equipment/Material Cost
Total PEC	$841,000	
Direct Installation Costs		
Labor	$235,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$6,000	2.5% of Labor
Mobilization / Demobilization	$4,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$12,000	5% of Labor
Total Direct Installation Costs	$257,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$1,098,000**	
Indirect Costs		
Contractor's General and Administration Expense	$110,000	10% of Total Direct Costs
Contractor's Profit	$55,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$88,000	8% of Total Direct Costs
Construction Management/Field Engineering	$44,000	4% of Total Direct Costs
S-U / Commissioning	$16,000	1.5% of Total Direct Costs
Spare Parts	$5,000	0.5% of Total Direct Costs
Owner's Cost	$22,000	2% of Total Direct Costs
Total Indirect Costs	**$340,000**	
Contingency	**$288,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$1,726,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0837	20 year life of equipment (years) @ 5.5% interest.
Annualized Capital Costs (CRF x TCI)	**$144,000**	
OPERATING COSTS		**Basis**
Operating & Maintenance Costs		
Variable O&M Costs		
Electrical Power Cost	$0	Based on electricity cost of $41.16 per MWh
Total Variable O&M Costs	$0	

GPSP Superheaters
NO_X Control Cost Evaluation
Combustion Optimization

NO_X Control Option Description	**Combustion Optimization**
Baseline NO_X Emissions, lb/hr	44
Post Upgrade NO_X Emissions, lb/hr	42
Capacity Factor used of Cost Estimates (%)	67%

Fixed O&M Costs		
Additional Operators per shift	$0	Assume no additional operators
Operating Labor	$0	N/A
Supervisor Labor	$0	N/A
Maintenance Materials	$16,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$16,000	
Indirect Operating Cost		
Property Taxes	$17,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$17,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$35,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$69,000	
Total Annual Operating Cost	**$85,000**	
TOTAL ANNUAL COST		
Annualized Capital Cost	$144,000	
Annual Operating Cost	$85,000	
Total Annual Cost	**$229,000**	

Appendix C – Supporting Modeling Data

C.1 – Normalization of Regional, State/Sector Source Apportionment Results

The purpose of this document is to outline a method which was used to normalize the 2028 CAMx model source apportionment results to the overall 2028 visibility projections for each Federal Class I Area. When normalized, the sum of all regional and state/sector apportionment model outputs will correspond to the overall 2028 visibility projections when reviewing the species-specific or total light extinction. *Currently, the regional (high-level) and the state/sector (low-level) model apportionment results are determined solely from the CAMx model output. Meaning, they will not correlate to the 2028 visibility projections until they are normalized.*

Annual average data is used in this document to provide a reasonable representation of the normalized regional, state, and/or sector specific contributions to light extinction in 2028.

Three steps were taken to perform this normalization.

Step 1

Determine species specific normalization factors. Take the 2028 visibility projection (2028 OTBa2EPA) for each species and divide by the 2028 CAMx source contribution model results (2028OTBa2).

The 2028 CAMx model results are found at the TSSv2 model product 1, indicated by the red box in Figure 1:

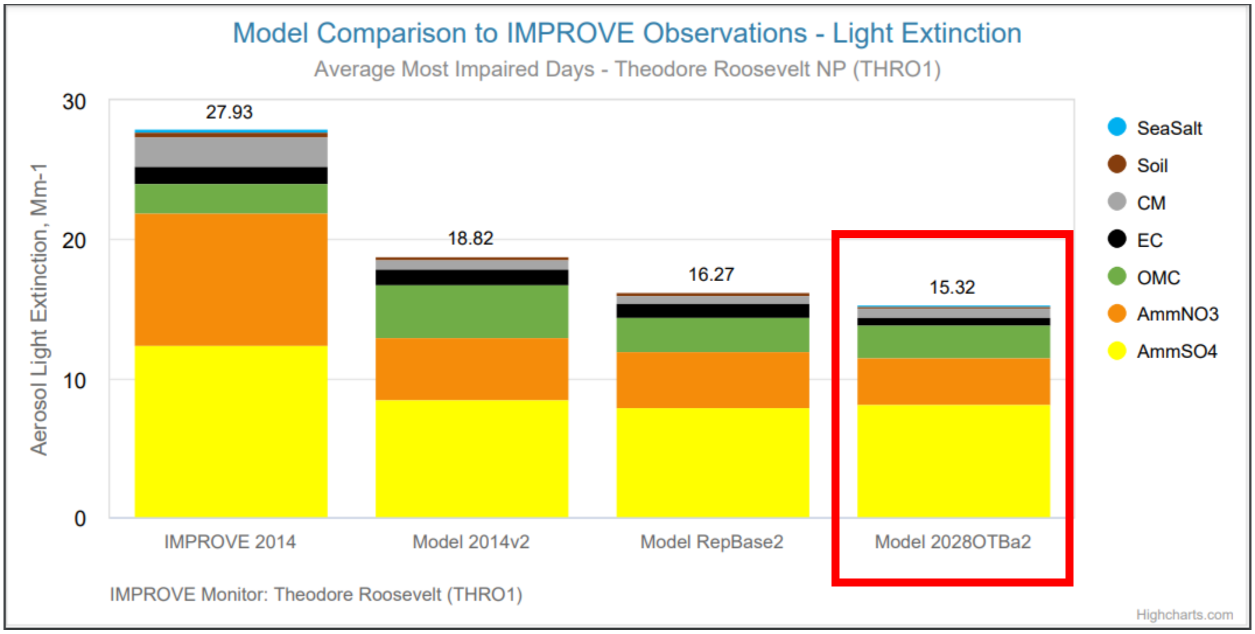

Figure 1: 2014 IMRPOVE data, 2014 Model Results, RepBase Model Results, and 2028 Source Contribution Model Results

The 2028 Visibility projections are found at the TSSv2 Model Product 3, indicated by the red box in Figure 2:

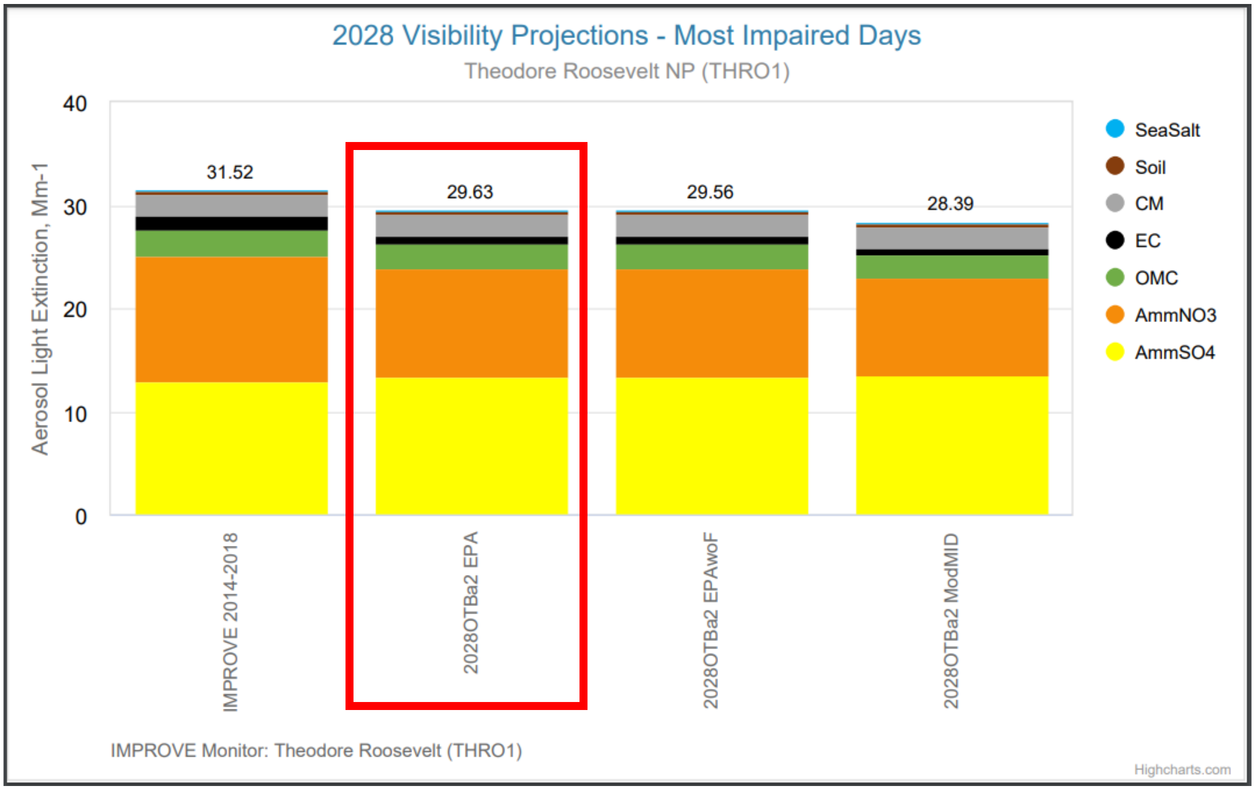

Figure 2: 2014-2018 IMPROVE data and 2028 Visibility Projections Using Different Scenarios

Table 1 shows the species-specific normalization factors for Theodore Roosevelt National Park on the most impaired days.

Table 1: 2028 Model Results, 2028 Visibility Projections, and Normalization Factors

	AmmNO3	AmmSO4	CM	EC	OMC	Sea Salt	Soil	**Total**	Notes
2028OTBa2 EPA	10.56	13.34	2.11	0.80	2.40	0.16	0.26	**29.6**	Model Product 3
Model 2028OTBa2	3.40	8.14	0.59	0.58	2.36	0.05	0.20	**15.3**	Model Product 1
Normalization Factor	**3.11**	**1.64**	**3.58**	**1.38**	**1.02**	**2.88**	**1.27**	-	MP3 ÷ MP1

AmmSO4 example: 13.34/8.14 = 1.64

Step 2

Use normalization factors to calculate regional contributions to the 2028 visibility Projection.

The annual regional source apportionment results can be found in TSSv2 model products 10, 11, and/or 12. Model Product 11 is displayed in Figure 3. The sum of all data in the Figure 3 equals the total modeled light extinction for 2028 (15.3 Mm^{-1}) from Table 1 at the end of Step 1.

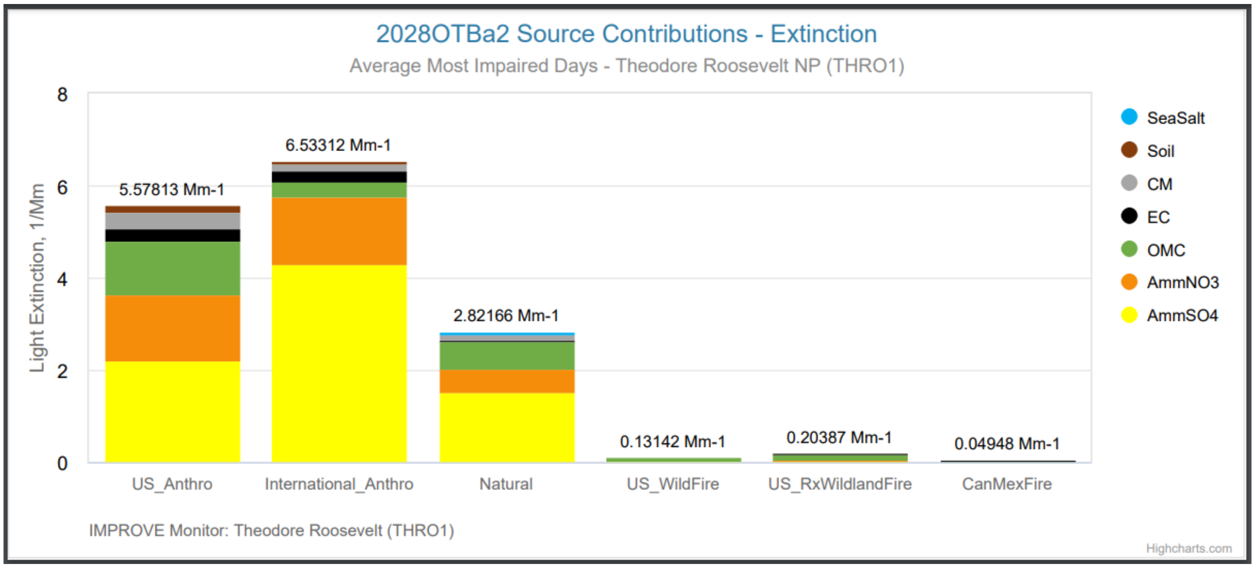

Figure 3:2028 Model Results of Regional Contribution to Light Extinction

15.3 Mm^{-1} can be normalized to the 2028 visibility projection (29.6 Mm^{-1} in Table 1) by applying each species normalization factor, shown in Table 2. Total AmmNO3 example: 3.43 x 3.11 = 10.67. US_Anthro AmmSO4 example: 2.21 x 1.64 = 3.63.

Table 2: 2028 Regional Apportionment Model Results, Species Multiplication Factors, and Normalized Regional Apportionment

Source Category	**AmmNO3**	**AmmSO4**	**CM**	**EC**	**OMC**	**Sea Salt**	**Soil**	**Total**
US_Anthro	1.42	2.21	0.35	0.29	1.15	0.00	0.15	**5.58**
Int_Anthro	1.45	4.30	0.14	0.24	0.34	0.00	0.06	**6.53**
Natural	0.52	1.51	0.11	0.02	0.61	0.06	0.00	**2.82**
US_RxWildlandFire	0.02	0.04	0.00	0.02	0.12	0.00	0.00	**0.20**
US_WildFire	0.02	0.02	0.00	0.02	0.07	0.00	0.00	**0.13**
CanMexFire	0.00	0.01	0.00	0.01	0.02	0.00	0.00	**0.05**
Total	**3.43**	**8.10**	**0.60**	**0.59**	**2.32**	**0.06**	**0.21**	**15.32**

Multiplied by

Site	**AmmNO3**	**AmmSO4**	**CM**	**EC**	**OMC**	**Sea Salt**	**Soil**
THRO1	3.11	1.64	3.58	1.38	1.02	2.88	1.27

Equals the normalized regional apportionment results

Source Category	**AmmNO3**	**AmmSO4**	**CM**	**EC**	**OMC**	**Sea Salt**	**Soil**	**Total**
US_Anthro	4.43	3.63	1.26	0.39	1.18	0.00	0.19	**11.07**
Int_Anthro	4.51	7.05	0.49	0.33	0.35	0.00	0.07	**12.81**

Source Category	**AmmNO3**	**AmmSO4**	**CM**	**EC**	**OMC**	**Sea Salt**	**Soil**	**Total**
Natural	1.61	2.47	0.40	0.03	0.62	0.16	0.00	**5.29**
US_RxWildlandFire	0.05	0.07	0.01	0.02	0.12	0.00	0.00	**0.28**
US_WildFire	0.07	0.03	0.00	0.02	0.07	0.00	0.00	**0.20**
CanMexFire	0.00	0.02	0.00	0.01	0.02	0.00	0.00	**0.07**
Total	**10.67**	**13.28**	**2.16**	**0.82**	**2.36**	**0.16**	**0.26**	**29.72**

The normalized regional apportionment results are shown in Figure 4. The sum of all data in the figure below equals the 29.7 Mm^{-1} (consistent with the above normalized data).

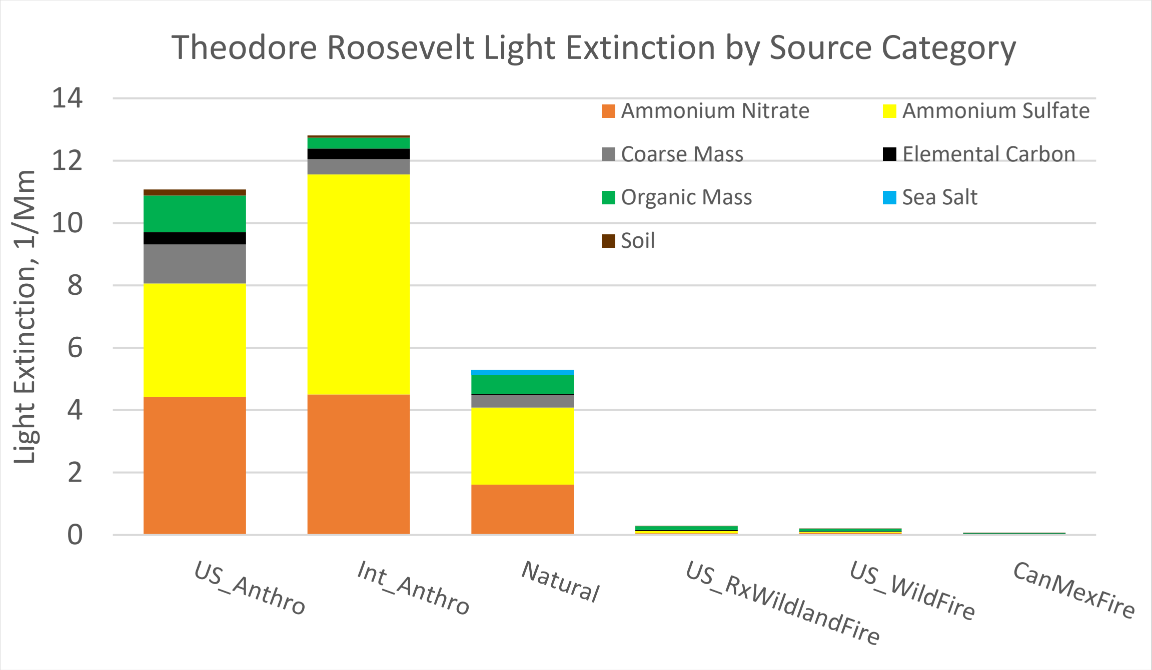

Figure 4: Source Contributions to Light Extinction Normalized to the 2028 Visibility Projection

This source contribution data now corresponds to the 2028 visibility projection. Confirmed by review of TSSv2 model product 4 when looking at the total light extinction projected for 2028. See the red box in Figure 5. The total light extinction projection for Theodore Roosevelt NP is 40.6 Mm^{-1} which consists of 29.72 Mm^{-1} of species extinction and approximately 11 Mm^{-1} of Rayleigh scattering.

Figure 5: Total Light Extinction Projection for 2028, Including Rayleigh

Therefore, 40.6 Mm^{-1} (total light extinction) minus approximately 11 Mm^{-1} (Rayleigh) equals 29.7 Mm^{-1}, consistent with the normalized regional data displayed in Figure 4 and listed in Table 2. With the normalized data, the information can now be discussed in both absolute and relative terms. In other words, for Theodore Roosevelt National Park, it can be said that 40.6 Mm^{-1} is the projected light extinction for 2028. Of the 40.6 Mm^{-1}, 11.1 Mm^{-1} (27%) are from US_Anthro emissions. Of the 11.1 Mm^{-1} from US_Anthro, 3.6 Mm^{-1} (9% overall) are from US_Anthro AmmSO4. In different context, of the 40.6 Mm^{-1}, 13.3 Mm^{-1} (33%) are from AmmSO4. Of the 13.3 Mm^{-1} from AmmSO4, 3.6 Mm^{-1} (9% overall) are from US_Anthro emissions.

Step 3

Use AmmNO3 normalization factors to calculate state/sector contributions to the 2028 light extinction. State/sector contributions to light extinction were only determined for AmmNO3 and AmmSO4. *(Repeat this process for AmmSO4)*

The AmmNO3 annual state/sector source apportionment results can be found in TSSv2 model product 9. Model Product 9 is show in Figure 6 for AmmNO3. The sum of all data in Figure 6 equals the 1.37 Mm^{-1}.

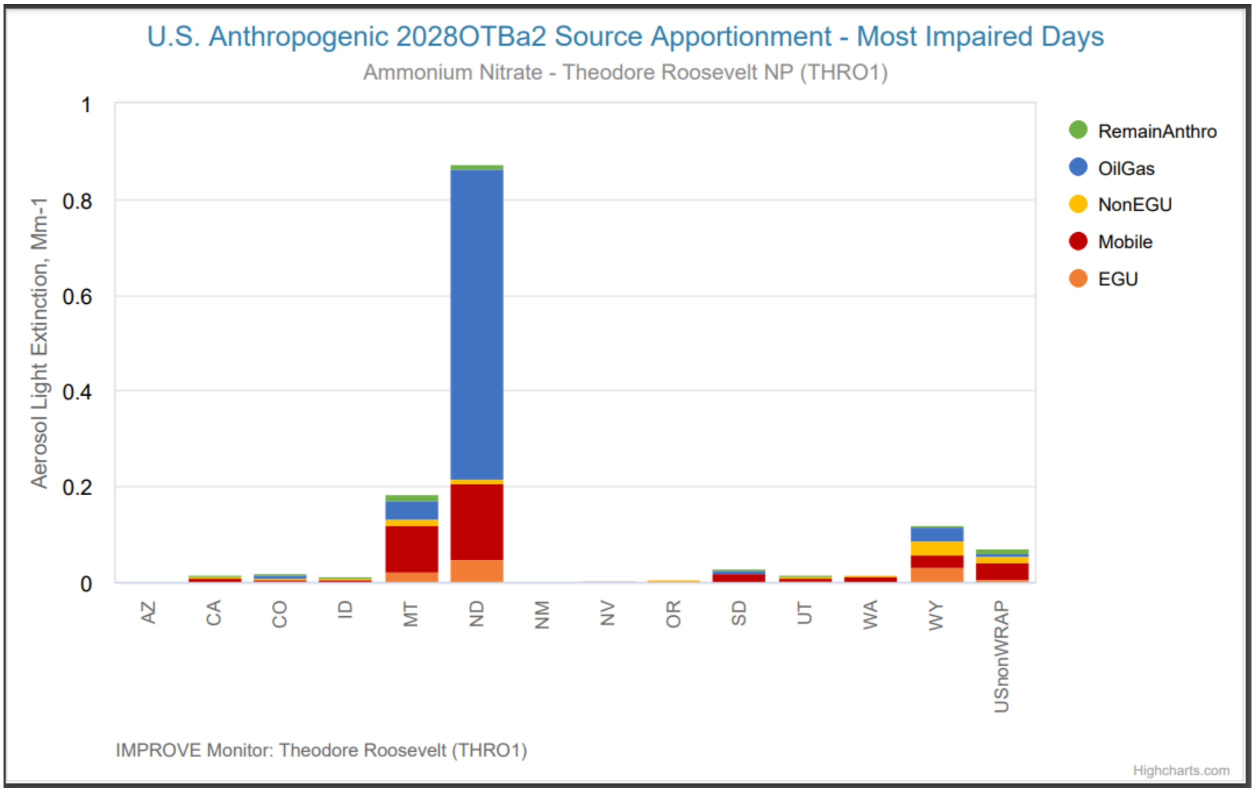

Figure 6: State and Sector Breakdown of AmmNO3 Light Extinction, US Anthropogenetic Sources Only

1.37 Mm^{-1} can be normalized to 4.3 Mm^{-1} by applying the AmmNO3 normalization factor to each of the state/sector values from Figure 6. This normalization is displayed in Table 3:

Table 3: 2028 State/Sector Apportionment Model Results, AmmNO3 Multiplication Factor, and Normalized State/Sector Apportionment

Row Labels	**EGU**	**OilGas**	**Mobile**	**NonEGU**	**RemainAnthro**	**Grand Total**
ND	0.05	0.65	0.16	0.01	0.01	0.87
AZ	0.00	0.00	0.00	0.00	0.00	0.00
CA	0.00	0.00	0.01	0.00	0.00	0.02
CO	0.00	0.01	0.00	0.00	0.00	0.02
ID	0.00	0.00	0.01	0.00	0.00	0.01
MT	0.02	0.04	0.09	0.01	0.01	0.18
NM	0.00	0.00	0.00	0.00	0.00	0.00

Row Labels	EGU	OilGas	Mobile	NonEGU	RemainAnthro	Grand Total
NV	0.00	0.00	0.00	0.00	0.00	0.00
OR	0.00	0.00	0.00	0.00	0.00	0.01
SD	0.00	0.01	0.02	0.00	0.00	0.03
UT	0.00	0.00	0.01	0.00	0.00	0.01
WA	0.00	0.00	0.01	0.00	0.00	0.02
WY	0.03	0.03	0.03	0.03	0.00	0.12
RemUS	0.01	0.01	0.04	0.01	0.01	0.07
Grand Total	**0.12**	**0.74**	**0.38**	**0.08**	**0.05**	**1.37**

Each value multiplied by

Site	Ammonium Nitrate
THRO1	3.11

Equals the normalized state/sector apportionment results

Row Labels	EGU	OilGas	Mobile	NonEGU	RemainAnthro	Grand Total
ND	0.15	2.02	0.49	0.03	0.03	2.71
AZ	0.00	0.00	0.00	0.00	0.00	0.00
CA	0.00	0.00	0.02	0.01	0.01	0.05
CO	0.01	0.02	0.02	0.01	0.01	0.06
ID	0.00	0.00	0.02	0.01	0.01	0.04
MT	0.07	0.12	0.29	0.04	0.05	0.57
NM	0.00	0.00	0.00	0.00	0.00	0.00
NV	0.00	0.00	0.01	0.00	0.00	0.01
OR	0.00	0.00	0.01	0.01	0.00	0.02
SD	0.00	0.02	0.06	0.01	0.01	0.09
UT	0.01	0.01	0.02	0.01	0.00	0.05
WA	0.00	0.00	0.03	0.01	0.01	0.05
WY	0.10	0.09	0.08	0.09	0.01	0.37
RemUS	0.02	0.03	0.12	0.03	0.02	0.22
Grand Total	**0.37**	**2.31**	**1.18**	**0.26**	**0.15**	**4.26**

The normalized state/sector AmmNO3 apportionment result is displayed in Figure 7. The sum of all data in the Figure 7 equals the 4.3 Mm^{-1}. 4.3 Mm^{-1} is slightly lower than the 4.4 Mm^{-1} listed in Table 2. The difference results from the exclusion of US Anthropogenic boundary conditions impacts. These boundary condition impacts accounted for 0.054 Mm^{-1} of the 2028 model results, an insignificant contribution.

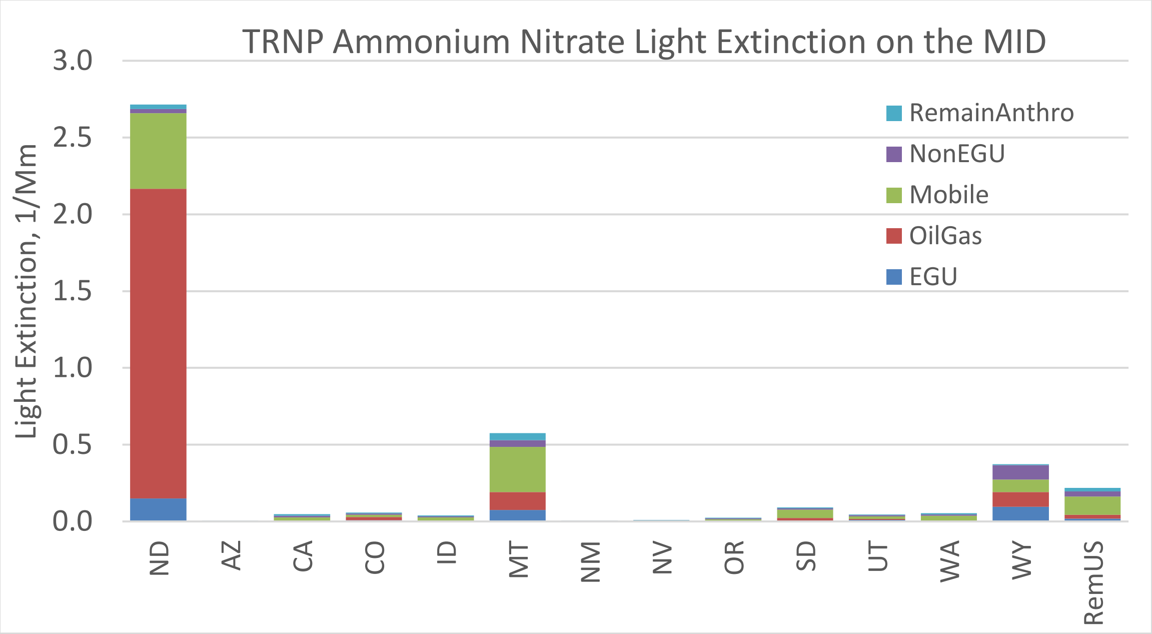

Figure 7: State and Sector Contributions to Light Extinction Normalized to the 2028 Visibility Projection

This state/sector AmmNO3 data now corresponds to the 2028 visibility projection for the US_Anthro component of light extinction. This is confirmed by review of normalized data displayed in Table 2.

The Normalized state/sector data can now be compared to TSSv2 model product 4, for both the total light extinction (Figure 5) and/or the AmmNO3 light extinction projection for 2028. See the red box in Figure 8. 10.6 Mm^{-1} is the total AmmNO3 light extinction.

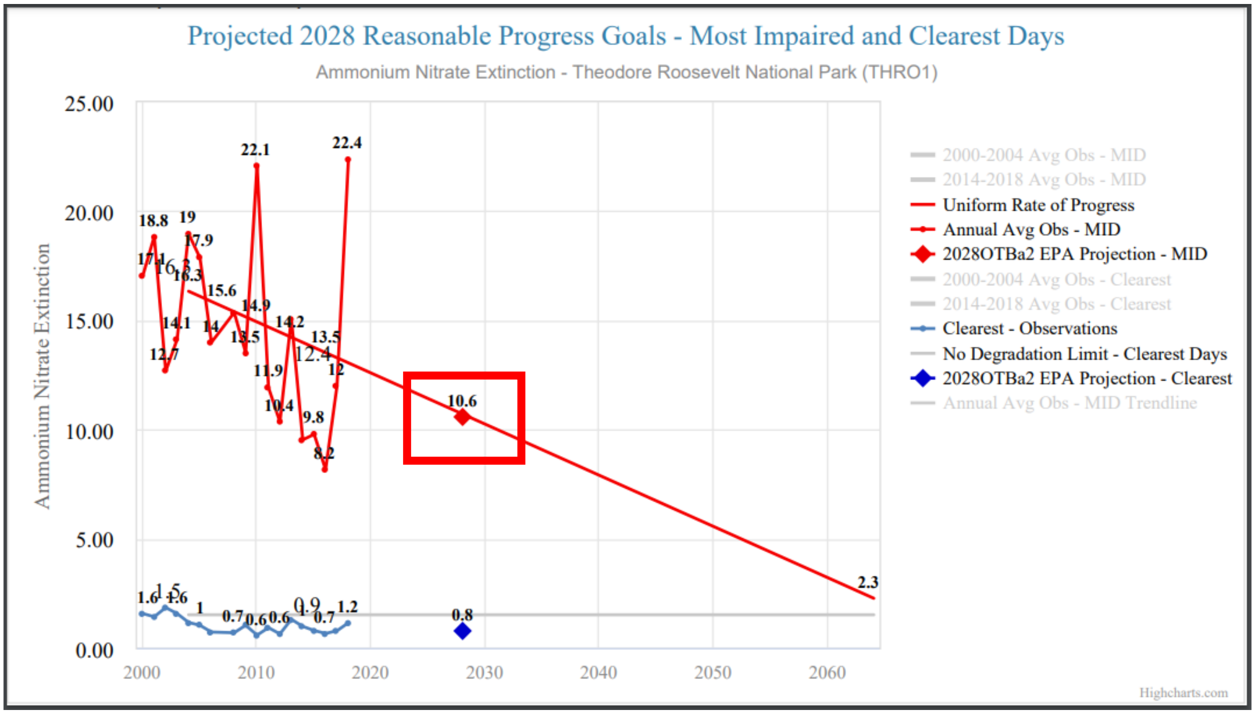

Figure 8: AmmNO3 Light Extinction Projection for 2028 (No Rayleigh)

The normalized state/sector results can now be discussed in absolute or relative terms. In other words, for Theodore Roosevelt National Park, 10.6 Mm^{-1} is the projected AmmNO3 light extinction for 2028, accounting for 26% of the total 2028 projected light extinction. Of the 10.6 Mm^{-1}, 4.3 Mm^{-1} (11% overall) are AmmNO3 from US_Anthro emissions (not including the US boundary conditions extinction, which is very small). Of the 4.3 Mm^{-1} of AmmNO3 light extinction from US_Anthro, 2 Mm^{-1} (5% overall) are from North Dakota Oil and Gas.

Conclusion

Table 4 provides all regional and the North Dakota sector percent contributions to light extinction. North Dakota's species light extinction contributions of coarse mass, elemental carbon, organic mass, sea salt and soil are included in the "Remaining US" row. The modeling was not performed for these species since they are of lesser concern due to small contributions to light extinction on the most impaired days.

Table 4: State Sector and Regional Percent Breakdown of Contributions to Light Extinction

Sector	AmmNO3	AmmSO4	Coarse Mass	Elemental Carbon	Organic Mass	Sea Salt	Soil	Total
ND EGU	0.4%	1.7%	--	--	--	--	--	2.1%
ND OilGas	5.0%	3.8%	--	--	--	--	--	8.8%
ND Mobile	1.2%	0.1%	--	--	--	--	--	1.3%
ND NonEGU	0.1%	0.1%	--	--	--	--	--	0.1%
ND RemainAnthro	0.1%	0.1%	--	--	--	--	--	0.1%
BCUS	0.4%	0.6%	--	--	--	--	--	1.0%
Remaining US	3.8%	2.6%	3.1%	1.0%	2.9%	0.0%	0.5%	13.8%
Int_Anthro	11.1%	17.3%	1.2%	0.8%	0.9%	0.0%	0.2%	31.5%
CanMexFire	0.0%	0.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.2%
Natural	4.0%	6.1%	1.0%	0.1%	1.5%	0.4%	0.0%	13.0%
US_RxWildlandFire	0.1%	0.2%	0.0%	0.1%	0.3%	0.0%	0.0%	0.7%
US_WildFire	0.2%	0.1%	0.0%	0.1%	0.2%	0.0%	0.0%	0.5%
Grand Total (non-Rayleigh)	26.2%	32.6%	5.3%	2.0%	5.8%	0.4%	0.6%	73.0%
Rayleigh	--	--	--	--	--	--	--	27.0%
					Source Plus Rayleigh			100%

The information from Table 4 is shown in Figure 9 as the vertical column. The gray dashed line is the unadjusted uniform rate of progress (glidepath). The black line is the adjusted glidepath. The orange line is the 5-year IMPROVE rolling average light extinction data. The blue line is the baseline light extinction from 2000–2004. The black diamond is the 2028 visibility projection. The column is the breakdown of the categories contributing to the 2028 visibility projection organized consistent with the legend from the top down.

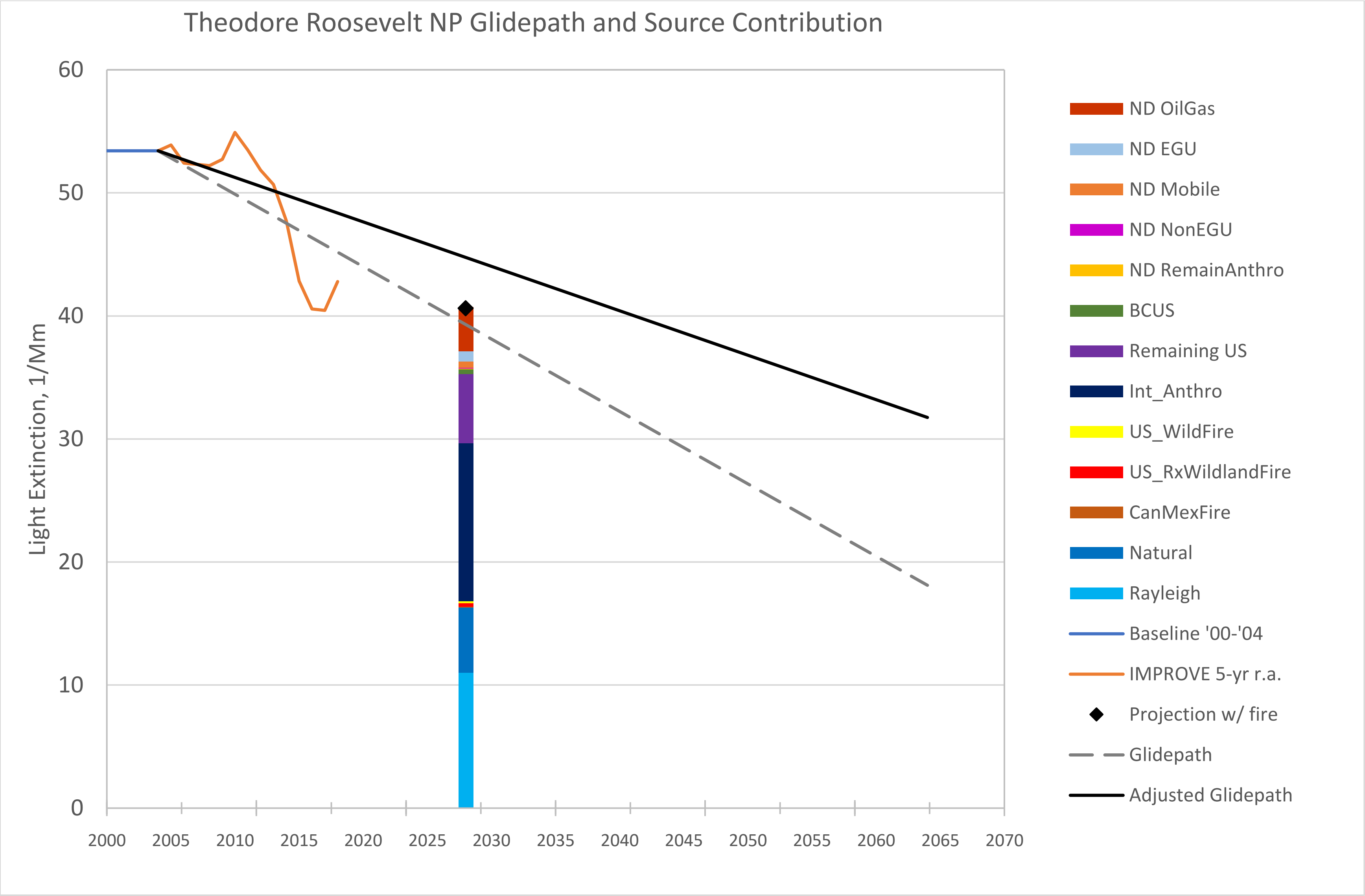

Figure 9: Theodore Roosevelt NP Normalized Apportionment Data Plotted with the 2028 Visibility Projection and Uniform Rate of Progress (with and without adjustment for International and Prescribed Wildland Fires)

C.2 – Regional, State/Sector Source Apportionment Results

1 International and Natural Impacts on North Dakota Visibility

This section contains the data from the high-level source apportionment results from the modeling performed by WRAP.[1] WRAP completed modeling to separate out the impacts of emissions from US anthropogenic sources (US_Anthro), international sources (Int_Anthro), natural sources (Natural), prescribed wildland burning (US_RxWildlandFire), US wildfires (US_WildFire), and Canadian Mexican Wildfire (CanMexFire). This modeling indicates that contributions from international sources significantly impair the visibility in North Dakota Class I areas. US anthropogenic sources also contribute significantly to the visibility impairment and natural sources also have a sizable influence on visibility. The categories of US wildfire, Canadian Mexican wildfire, and prescribed wildland burning typically had little impact on visibility impairment for the most impaired and/or clearest days. When looking at all monitor days or the haziest days, emissions from extreme episodic events (e.g. wildfires) tend to dominate the visibility impairment when impairment is at its highest levels, discussed in Section 3.3 of the main SIP document.

The high-level source apportionment results are discussed in Section 1.1 for the most impaired days and Section 1.2 for the clearest days. The data is further separated by source category and aerosol species contributing to light extinction in the respective subsections.

The aerosol species which contribute to light extinction are ammonium nitrate, ammonium sulfate, organic mass, elemental carbon, coarse mass, soil, and sea salt. The aerosol species of most significance to North Dakota Class I areas are ammonium nitrate and ammonium sulfate.

The modeling was completed for the Representative Baseline (RepBase) and the 2028 inventory projection (2028OTB). For details on RepBase and 2028OTB emission inventories, see Sections 4.1.4 and 4.1.6 of the main SIP document, respectively. Since there are limited expected changes in emissions between the RepBase and 2028 OTB emissions, the model results displayed in in Section 1.1 and Section 1.2 are for the 2028OTB emissions scenario. For both the most impaired days and the clearest days, the US_Anthro light extinction was modeled to be lower in the 2028OTB scenario than the RepBase scenario. These results, however, were not significantly different. The RepBase light extinction projections are available on the WRAP TSSv2.[2]

North Dakota shares a border with the Canadian Provinces of Manitoba and Saskatchewan. These provinces, along with the provinces of Alberta and British Columbia, are upwind of the prevailing wind direction causing North Dakota to be impacted by the airshed. Emissions from Canadian coal fired EGUs along with oil and gas development are significant and contribute to visibility impairment in North Dakota Class I areas. Emissions from nearby Canadian EGUs are discussed in Section 4.7.1 and emissions

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[1] Available at: https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/SourceApportionmentSpecifications_WRAP_RepBase2_and_2028OTBa2_High-LevelPMandO3_and_Low-Level_PM_andOptionalO3_Sept29_2020.pdf (Last visited February 22, 2021)

[2] Available at: https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx. See model products 10, 11, and 12 for “Most Impaired Days” and “Clearest Days” for model scenario “RepBase”. (Last visited March 9, 2021)

from oil and gas operations are discussed in Section 4.7.2 of the main SIP document. Canadian anthropogenic impairment accounts for 66% of the total international impairment projected for LWA and 50% at TRNP. The remaining international impairment is from international anthropogenic contributions from outside the CAMx 36-km domain boundary as defined by the GEOS-Chem global model (international boundary condition impacts). 32% of LWAs international anthropogenic impairment and 50% of TRNPs is from contributions outside the 36-km modeling domain.[3]

1.1 Most Impaired Days

1.1.1 Source Category Light Extinction on the Most Impaired Days

Figure 1 and Figure 2 display the 2028OTB source apportionment results for the average of the most impaired days for aerosol species within the five major source categories. The five major source categories are: US_Anthro, Int_Anthro, Natural, US_RxWildlandFire, US_WildFire, and CanMexFire. Table 1 and Table 2 display the numerical data corresponding to Figure 1 and Figure 2 for LWA and TRNP, respectively.

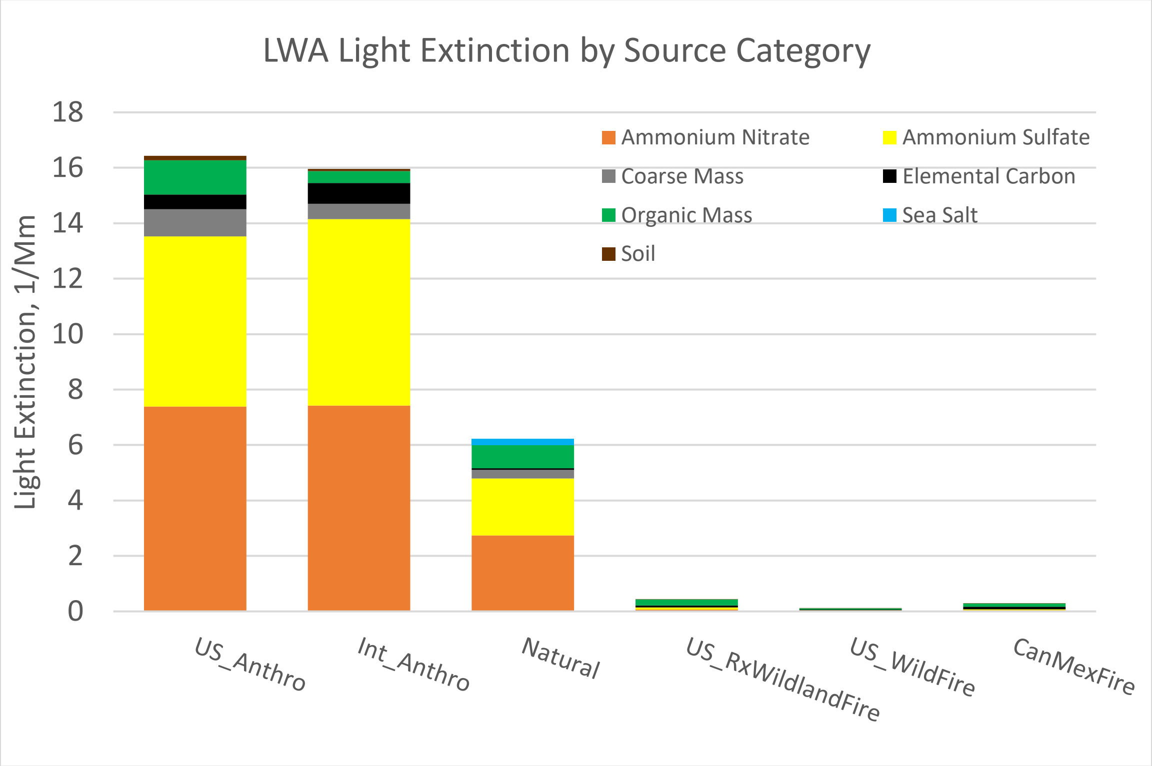

Figure 1: LWA 2028OTB Light Extinction on the Most Impaired Days by Source Category

Figure 1 shows approximately equal light extinction from US_Anthro and Int_Anthro for the species of ammonium nitrate and ammonium sulfate on the most impaired days at LWA. The total light extinction from US_Anthro and Int_Anthro is also very similar at LWA, with organic mass making up the largest

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[3] A complete breakdown of the modeled regional source group contributions can be found at: https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx. See model product 10 for "Most Impaired Days".

difference in impairment on the most impaired days. Impacts from Natural are the next largest category but are considerably less than US_Anthro and Int_Anthro. US_RxWildlandFire, US_WildFire, and CanMexFire are insignificant for the MID at LWA.

Table 1: LWA 2028OTB Light Extinction on the Most Impaired Days by Source Category

Source Category	**Ammonium Nitrate**	**Ammonium Sulfate**	**Coarse Mass**	**Elemental Carbon**	**Organic Mass**	**Sea Salt**	**Soil**	**Total**	**Percent of Total**
US_Anthro	7.39	6.14	0.98	0.53	1.23	0.00	0.16	**16.43**	42%
Int_Anthro	7.42	6.72	0.55	0.75	0.43	0.00	0.08	**15.96**	40%
Natural	2.75	2.05	0.32	0.06	0.83	0.23	0.00	**6.23**	16%
US_RxWildlandFire	0.06	0.08	0.01	0.07	0.22	0.00	0.00	**0.44**	1%
US_WildFire	0.01	0.03	0.00	0.02	0.05	0.00	0.00	**0.11**	0%
CanMexFire	0.04	0.04	0.01	0.09	0.11	0.00	0.00	**0.28**	1%
Total	**17.67**	**15.05**	**1.86**	**1.52**	**2.88**	**0.23**	**0.24**	**39.45**	**100%**

A review and breakdown of Table 1 shows the following significant contributors to light extinction. The US_Anthro source category accounts for 42% of the total light extinction on the most impaired days at LWA. Much of the total light extinction from US_Anthro is comprised of ammonium nitrate and ammonium sulfate. US_Anthro ammonium nitrate and ammonium sulfate account for 19% and 16% of the total light extinction, respectively. Int_Anthro accounts for 40% of the total light extinction on the most impaired days at LWA. Like US_Anthro, much of the Int_Anthro total light extinction is from ammonium nitrate and ammonium sulfate. Int_Anthro ammonium nitrate and ammonium sulfate account for 19% and 17% of the total light extinction, respectively. The only significant remaining category of total light extinction is Natural at 16%. Much of the total light extinction from Natural is also comprised of ammonium nitrates at 7% and ammonium sulfates at 5%.

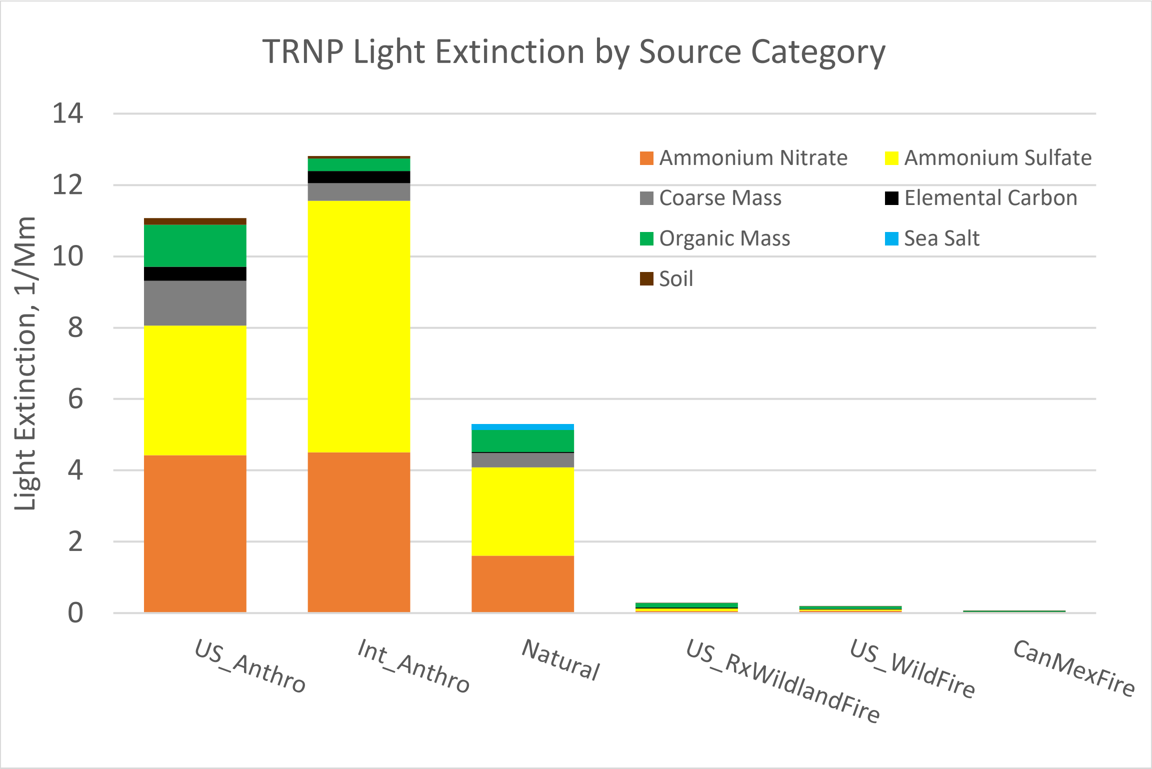

Figure 2: TRNP 2028OTB Light Extinction on the Most Impaired Days by Source Category

Figure 2 shows Int_Anthro ammonium sulfate light extinction is approximately two times the US_Anthro ammonium sulfate extinction on the most impaired days at TRNP. US_Anthro ammonium nitrate light extinction is approximately equal to Int_Anthro ammonium nitrate light extinction on the most impaired days. Combined, US_Anthro ammonium nitrate and ammonium sulfate light extinction is considerably less than the contribution from Int_Anthro. Higher contributions from organic mass and coarse mass from US_Anthro lessen the overall difference in impairment between US_Anthro and Int_Anthro. Impacts from Natural are the next largest category but are considerably less than US_Anthro and Int_Anthro. US_RxWildlandFire, US_WildFire, and CanMexFire are insignificant for the MID at TRNP.

Table 2: TRNP 2028OTB Light Extinction on the Most Impaired Days by Source Category

Source Category	Ammonium Nitrate	Ammonium Sulfate	Coarse Mass	Elemental Carbon	Organic Mass	Sea Salt	Soil	Total	Percent of Total
US_Anthro	4.43	3.63	1.26	0.39	1.18	0.00	0.19	**11.07**	37%
Int_Anthro	4.51	7.05	0.49	0.33	0.35	0.00	0.07	**12.81**	43%
Natural	1.61	2.47	0.40	0.03	0.62	0.16	0.00	**5.29**	18%
US_RxWildlandFire	0.05	0.07	0.01	0.02	0.12	0.00	0.00	**0.28**	1%
US_WildFire	0.07	0.03	0.00	0.02	0.07	0.00	0.00	**0.20**	1%
CanMexFire	0.00	0.02	0.00	0.01	0.02	0.00	0.00	**0.07**	0%
Total	**10.67**	**13.28**	**2.16**	**0.82**	**2.36**	**0.16**	**0.26**	**29.72**	**100%**

A review and breakdown of Table 2 shows the following significant contributors to light extinction. The US_Anthro source category accounts for 37% of the total light extinction on the most impaired days at TRNP. Much of the total light extinction from US_Anthro is comprised of ammonium nitrate and ammonium sulfate. US_Anthro ammonium nitrate and ammonium sulfate account for 15% and 12% of the total light extinction, respectively. Int_Anthro accounts for 43% of the total light extinction on the most impaired days at TRNP. Like US_Anthro, much of the Int_Anthro total light extinction is from ammonium nitrate and ammonium sulfate. Int_Anthro ammonium nitrate and ammonium sulfate account for 15% and 24% of the total light extinction, respectively. The only significant remaining category of total light extinction is Natural at 18%. Much of the total light extinction from Natural is also comprised of ammonium nitrates at 5% and ammonium sulfates at 8%.

1.1.2 Species Light Extinction on the Most Impaired Days

Figure 3 and Figure 4 display the 2028OTB source apportionment results for the average of the most impaired days for aerosol species within the five major source categories. The five major source categories are: US_Anthro, Int_Anthro, Natural, US_RxWildlandFire, US_WildFire, and CanMexFire. Table 3 and Table 4 display the numerical data corresponding to Figure 3 and Figure 4 for LWA and TRNP, respectively. The data in these figures and tables is the same as Section 1.1.1. The difference is how the data is displayed. The aerosol species are plotted along the x-axis and the light extinction contribution from the source category is separated by species.

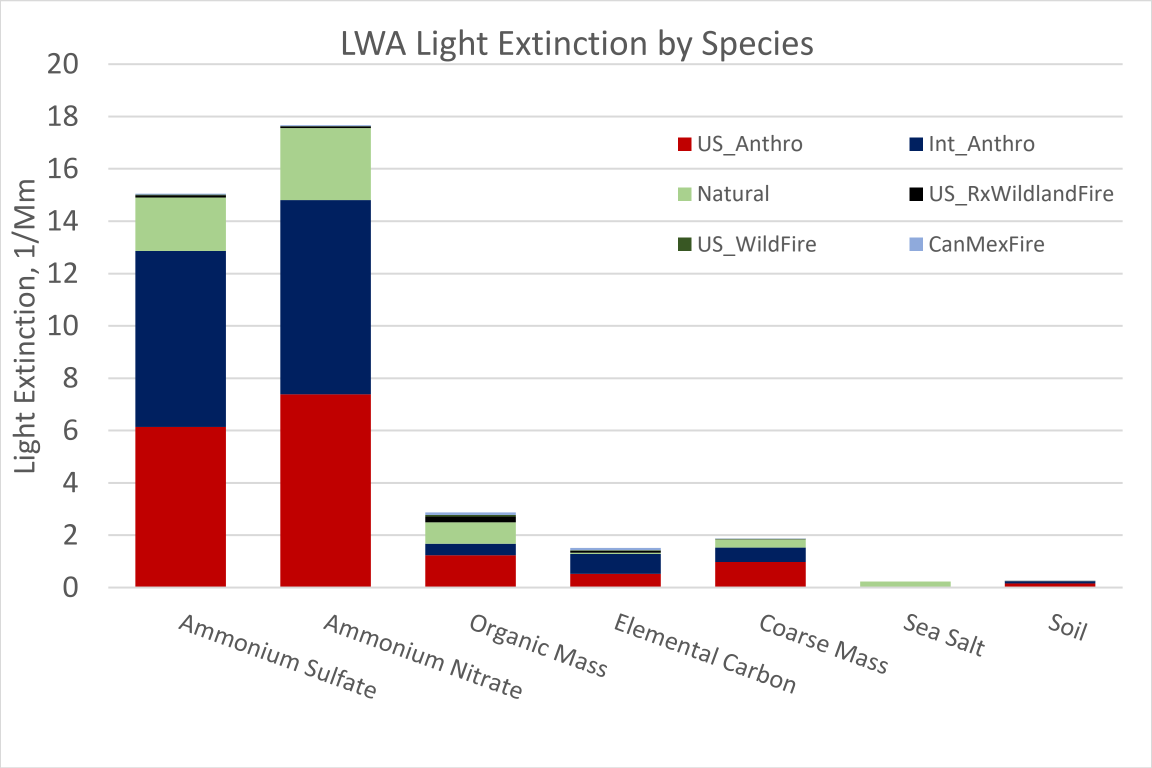

Figure 3: LWA 2028OTB Light Extinction on the Most Impaired Days by Species

Figure 3 emphasizes a few important items for LWA on the most impaired days. The most significant aerosol species contributing to light extinction are ammonium nitrate and ammonium sulfate. Light extinction from US_Anthro and Int_Anthro are nearly equal. The remaining species of light extinction: organic mass, elemental carbon, coarse mass, sea salt, and soil, are minimal.

Table 3: LWA 2028OTB Light Extinction on the Most Impaired Days by Species

Source Category	**US_ Anthro**	**Int_ Anthro**	**Natural**	**US_RxWild landFire**	**US_Wild Fire**	**CanMex Fire**	**Total**	**Percent of Total**
Ammonium Sulfate	6.14	6.72	2.05	0.08	0.03	0.04	**15.05**	38%
Ammonium Nitrate	7.39	7.42	2.75	0.06	0.01	0.04	**17.67**	45%
Organic Mass	1.23	0.43	0.83	0.22	0.05	0.11	**2.88**	7%
Elemental Carbon	0.53	0.75	0.06	0.07	0.02	0.09	**1.52**	4%
Coarse Mass	0.98	0.55	0.32	0.01	0.00	0.01	**1.86**	5%
Sea Salt	0.00	0.00	0.23	0.00	0.00	0.00	**0.23**	1%
Soil	0.16	0.08	0.00	0.00	0.00	0.00	**0.24**	1%
Total	**16.43**	**15.96**	**6.23**	**0.44**	**0.11**	**0.28**	**39.45**	**100%**

The light extinction contribution by species from Table 3 shows ammonium sulfate and ammonium nitrate are the most significant. Ammonium sulfate accounts for 38% of the total light extinction on the most impaired days at LWA. 17% of the total light extinction is caused by ammonium sulfate from Int_Anthro, 16% is from US_Anthro, and 5% is from Natural. Ammonium nitrate accounts for 45% of the total light extinction. 19% of the total light extinction is caused by ammonium nitrate from Int_Anthro, 19% is from US_Anthro, and 7% is from Natural. The remaining noteworthy species causing light extinction is organic mass, which contributes only 7% to the total light extinction.

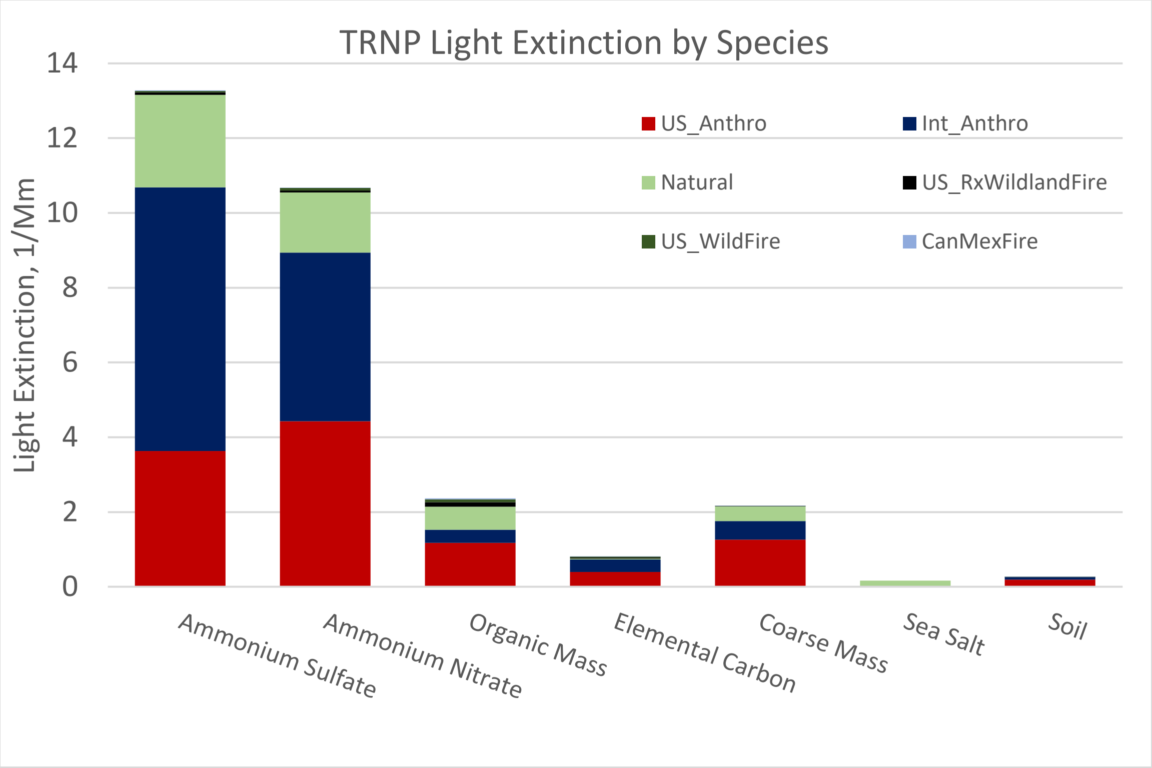

Figure 4: TRNP 2028OTB Light Extinction on the Most Impaired Days by Species

Figure 4 emphasizes a few important items for TRNP on the most impaired days. Light extinction from ammonium sulfate is the most significant aerosol species and Int_Anthro contributes the most to the overall light extinction. Int_Anthro ammonium sulfate light extinction is one and a half times larger than the next largest contributor to light extinction, which is ammonium nitrate from US_Anthro and Int_Anthro. US_Anthro and Int_Anthro light extinction from ammonium nitrate are nearly equal. The most significant remaining contributor to light extinction is US_Anthro ammonium sulfate. The remaining species of light extinction: organic mass, elemental carbon, coarse mass, sea salt, and soil, are much smaller in comparison to ammonium sulfate and ammonium nitrate.

Table 4: TRNP 2028OTB Light Extinction on the Most Impaired Days by Species

Source Category	**US_ Anthro**	**Int_ Anthro**	**Natural**	**US_RxWild landFire**	**US_Wild Fire**	**CanMex Fire**	**Total**	**Percent of Total**
Ammonium Sulfate	3.63	7.05	2.47	0.07	0.03	0.02	**13.28**	45%
Ammonium Nitrate	4.43	4.51	1.61	0.05	0.07	0.00	**10.67**	36%
Organic Mass	1.18	0.35	0.62	0.12	0.07	0.02	**2.36**	8%
Elemental Carbon	0.39	0.33	0.03	0.02	0.02	0.01	**0.82**	3%

Source Category	US_ Anthro	Int_ Anthro	Natural	US_RxWild landFire	US_Wild Fire	CanMex Fire	Total	Percent of Total
Coarse Mass	1.26	0.49	0.40	0.01	0.00	0.00	**2.16**	7%
Sea Salt	0.00	0.00	0.16	0.00	0.00	0.00	**0.16**	1%
Soil	0.19	0.07	0.00	0.00	0.00	0.00	**0.26**	1%
Total	**11.07**	**12.81**	**5.29**	**0.28**	**0.20**	**0.07**	**29.72**	**100%**

The light extinction contribution by species from Table 4 shows ammonium sulfate and ammonium nitrate are the most significant. Ammonium sulfate accounts for 45% of the total light extinction on the most impaired days at TRNP. 24% of the total light extinction is caused by ammonium sulfate from Int_Anthro, 12% is from US_Anthro, and 8% is from Natural. Ammonium nitrate accounts for 36% of the total light extinction. 15% of the total light extinction is caused by ammonium nitrate from Int_Anthro, 15% is from US_Anthro, and 5% is from Natural. The remaining noteworthy species causing light extinction is organic mass and coarse mass, which contribute 8% and 7% to the total light extinction, respectively.

1.1.3 Most Impaired Days Conclusion

In summary, the contributors to light extinction on the most impaired days for both LWA and TRNP come from four main areas: Int_Anthro ammonium sulfate, Int_Anthro ammonium nitrate, US_Anthro ammonium sulfate, and US_Anthro ammonium nitrate. Light extinction from Natural are smaller in comparison than US_Anthro and Int_Anthro at both LWA and TRNP, but still account for 16% and 18% of total light extinction, respectively.

The high-level source apportionment data presented in Sections 1.1.1 and 1.1.2 supports the Department's decision to use an adjusted glidepath for both LWA and TRNP to account for international anthropogenic emissions and wildland prescribed fires[4].

1.2 Clearest Days

1.2.1 Source Category Light Extinction on the Clearest Days

Figure 5 and Figure 6 display the 2028OTB source apportionment results for the average of the clearest days for aerosol species within the five major source categories. The five major source categories are: US_Anthro, Int_Anthro, Natural, US_RxWildlandFire, US_WildFire, and CanMexFire. Table 5 and Table 6 display the numerical data corresponding to Figure 5 and Figure 6 for LWA and TRNP, respectively.

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[4] 40 CFR 51.308(f)(1)(vi)(B)

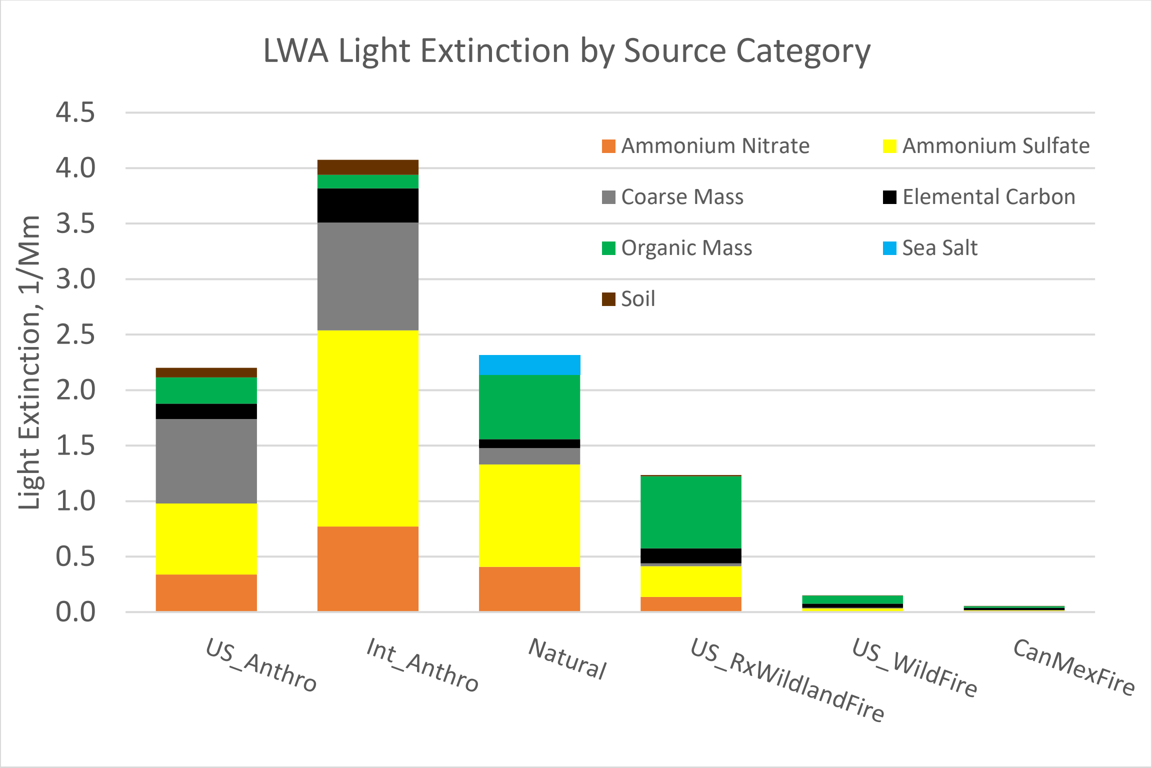

Figure 5: LWA 2028OTB Light Extinction on the Clearest Days by Source Category

Figure 5 shows significantly greater light extinction from Int_Anthro for the species of ammonium nitrate and ammonium sulfate on the Clearest days at LWA. Natural contributes more to total light extinction than US_Anthro sources and even more combined ammonium nitrate and ammonium sulfate light extinction. Prescribed wildland fires also contribute to light extinction on the clearest days where much of this impairment is from organic mass.

Table 5: LWA 2028OTB Light Extinction on the Clearest Days by Source Category

Source Category	Ammonium Nitrate	Ammonium Sulfate	Coarse Mass	Elemental Carbon	Organic Mass	Sea Salt	Soil	Total	Percent of Total
US_Anthro	0.34	0.64	0.76	0.14	0.24	0.00	0.08	**2.20**	22%
Int_Anthro	0.77	1.77	0.97	0.31	0.12	0.00	0.13	**4.08**	41%
Natural	0.41	0.92	0.15	0.08	0.58	0.18	0.00	**2.32**	23%
US_RxWildlandFire	0.14	0.28	0.03	0.14	0.65	0.00	0.01	**1.23**	12%
US_WildFire	0.00	0.03	0.01	0.04	0.07	0.00	0.00	**0.15**	1%
CanMexFire	0.01	0.01	0.00	0.02	0.01	0.00	0.00	**0.05**	1%
Total	**1.66**	**3.64**	**1.92**	**0.72**	**1.68**	**0.18**	**0.23**	**10.03**	**100%**

A review and breakdown of Table 5 shows the following significant contributors to light extinction. The US_Anthro source category accounts for 22% of the total light extinction on the clearest days at LWA. Much of the total light extinction from US_Anthro is comprised of coarse mass and ammonium sulfate.

US_Anthro coarse mass and ammonium sulfate account for 8% and 6% of the total light extinction, respectively. Int_Anthro accounts for 41% of the total light extinction on the clearest days at LWA. Much of the Int_Anthro total light extinction is from coarse mass, ammonium sulfate, and ammonium nitrate. Int_Anthro coarse mass, ammonium sulfate, and ammonium nitrate account for 10%, 18%, and 8% of the total light extinction, respectively. Unlike the most impaired days, Natural contributes to more impairment than US_Anthro on the clearest days, at 23%. Much of the total light extinction from Natural is comprised of ammonium nitrates at 4%, ammonium sulfates at 9%, and organic mass at 6%. Additionally, on the clearest days, prescribed wildland fires account for 12% of the total light extinction, 6% of which is from organic mass.

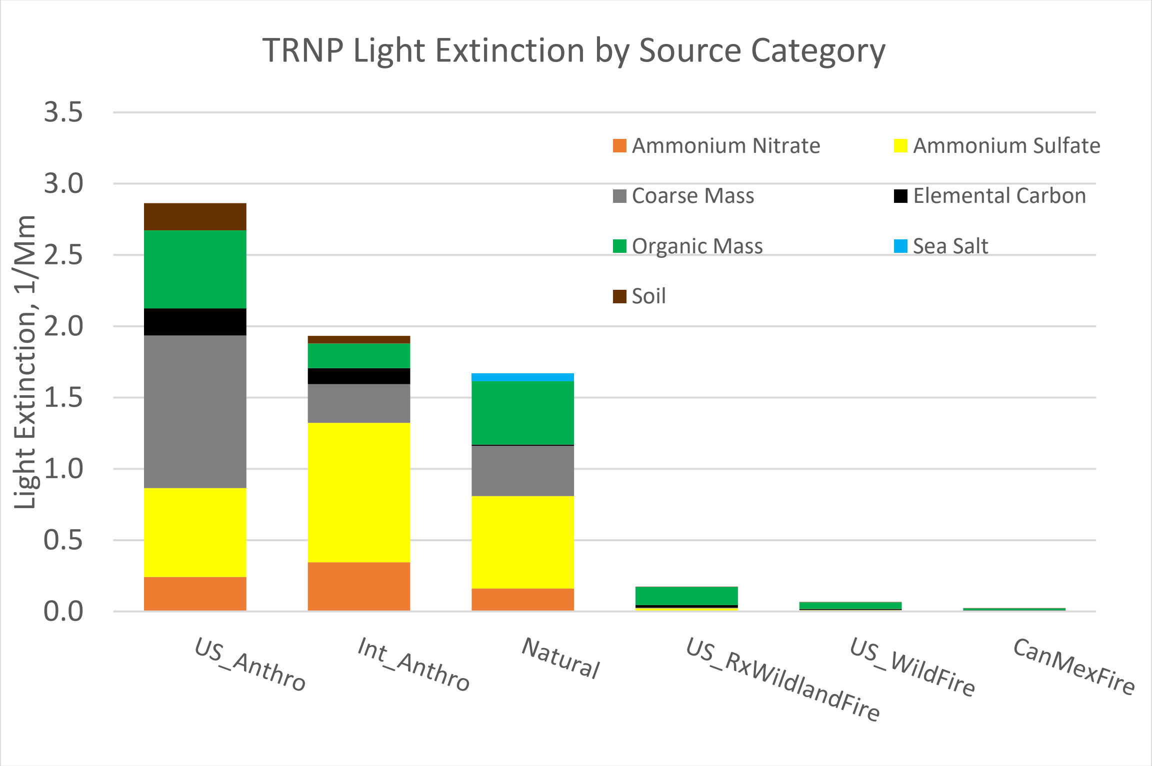

Figure 6: TRNP 2028OTB Light Extinction on the Clearest Days by Source Category

Figure 6 shows Int_Anthro ammonium sulfate light extinction is considerably higher than US_Anthro ammonium sulfate extinction on the clearest days at TRNP, this was also true for the most impaired days. US_Anthro ammonium nitrate light extinction is approximately the same as Int_Anthro on the clearest days. Overall, the light extinction from US_Anthro is the greatest, but a significant portion of the light extinction is from coarse mass and organic mass. Combined US_Anthro coarse mass and organic mass contribute more to light extinction on the clearest days than the combined ammonium sulfates and ammonium nitrates. US_Anthro ammonium nitrate and ammonium sulfate light extinction is also less than the contribution from Int_Anthro for these species. Additionally, Natural contributes significantly to the overall light extinction on the clearest days. Natural also contribute more to ammonium sulfate light extinction than US_Anthro sources and over half of the ammonium nitrate light extinction.

Table 6: TRNP 2028OTB Light Extinction on the Clearest Days by Source Category

Source Category	Ammonium Nitrate	Ammonium Sulfate	Coarse Mass	Elemental Carbon	Organic Mass	Sea Salt	Soil	Total	Percent of Total
US_Anthro	0.24	0.62	1.07	0.19	0.55	0.00	0.19	**2.86**	43%
Int_Anthro	0.35	0.98	0.27	0.11	0.17	0.00	0.05	**1.93**	29%
Natural	0.16	0.65	0.35	0.01	0.44	0.05	0.00	**1.67**	25%
US_RxWildlandFire	0.00	0.02	0.00	0.02	0.13	0.00	0.00	**0.17**	3%
US_WildFire	0.00	0.01	0.00	0.01	0.05	0.00	0.00	**0.07**	1%
CanMexFire	0.00	0.00	0.00	0.00	0.01	0.00	0.00	**0.02**	0%
Total	**0.75**	**2.28**	**1.70**	**0.34**	**1.35**	**0.05**	**0.25**	**6.73**	**100%**

A review and breakdown of Table 6 shows the following significant contributors to light extinction. The US_Anthro source category accounts for 43% of the total light extinction on the clearest days at TRNP. Only 13% of the total light extinction from US_Anthro is comprised of ammonium nitrates and ammonium sulfates, 4% and 9%, respectively. Meaning, 30% of the overall light extinction from US_Anthro on the clearest is from coarse mass, elemental carbon, organic mass, and soil. Int_Anthro accounts for 29% of the total light extinction on the clearest days at TRNP. Much of the total light extinction from Int_Anthro is comprised of ammonium nitrates and ammonium sulfates. Int_Anthro ammonium nitrate and ammonium sulfate account for 5% and 15% of the total light extinction, respectively. Natural also contribute a significant amount to impairment on the clearest days, at 25%. Much of the total light extinction from Natural is comprised of ammonium sulfates at 10%, coarse mass at 5%, and organic mass at 7%.

1.2.2 Species Light Extinction on the Clearest Days

Figure 7 and Figure 8 display the 2028OTB source apportionment results for the average of the clearest days for aerosol species within the five major source categories. Table 7 and Table 8 display the numerical data corresponding to Figure 7 and Figure 8 for LWA and TRNP, respectively. The data in these figures and tables is the same as Section 1.2.1. The difference is how the data is displayed. The aerosol species are plotted along the x-axis and the light extinction contribution from the source category is separated by species.

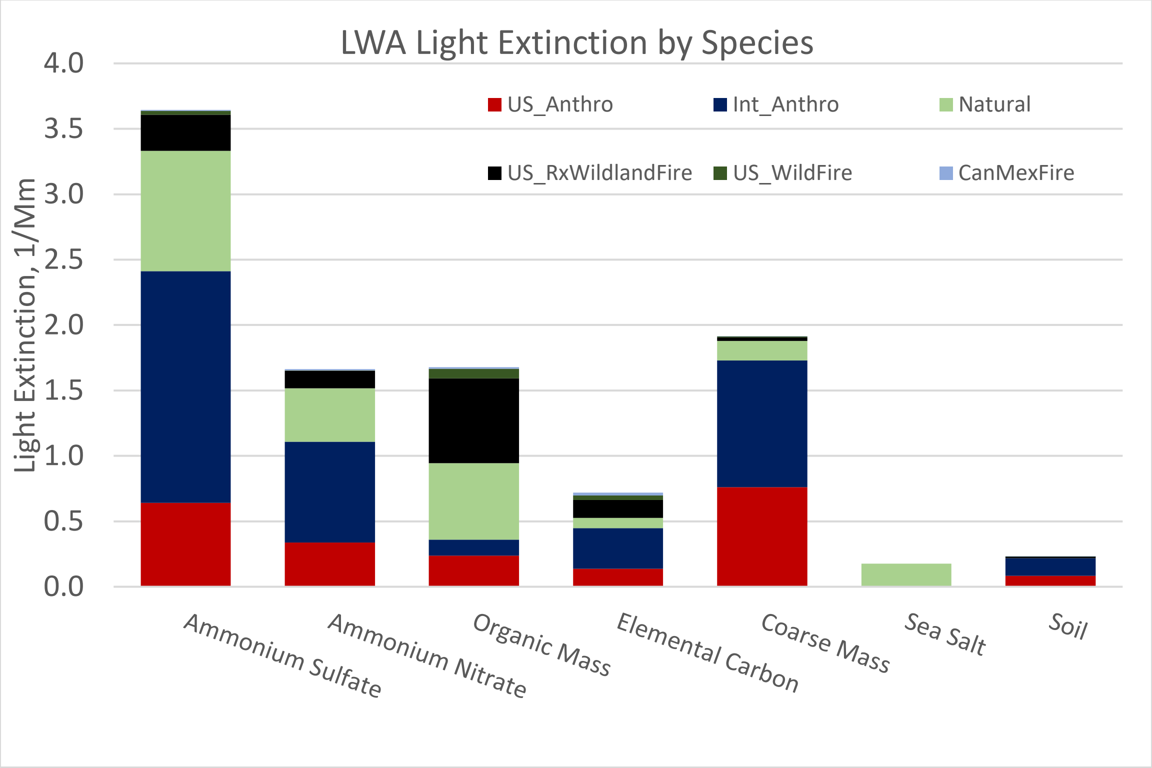

Figure 7: LWA 2028OTB Light Extinction on the Clearest Days by Species

Figure 7 emphasizes a few important items for LWA on the clearest days. Most of the total light extinction comes from ammonium sulfate, followed by ammonium nitrate, organic mass, and coarse mass. For ammonium sulfate and ammonium nitrate, Int_Anthro contributes greater to light extinction than US_Anthro. US_Anthro light extinction contributions from ammonium sulfate, ammonium nitrate, coarse mass, and organic mass are small, each below 1 Mm^{-1}. Natural also contributes significantly to impairment for ammonium sulfate, ammonium nitrate, and organic mass. As noted in the source category breakdown, prescribed wildland fires also account for a sizable portion of the light extinction on the clearest days.

Table 7: LWA 2028OTB Light Extinction on the Clearest Days by Species

Source Category	US_ Anthro	Int_ Anthro	Natural	US_RxWild landFire	US_Wild Fire	CanMex Fire	Total	Percent of Total
Ammonium Sulfate	0.64	1.77	0.92	0.28	0.03	0.01	**3.64**	36%
Ammonium Nitrate	0.34	0.77	0.41	0.14	0.00	0.01	**1.66**	17%
Organic Mass	0.24	0.12	0.58	0.65	0.07	0.01	**1.68**	17%
Elemental Carbon	0.14	0.31	0.08	0.14	0.04	0.02	**0.72**	7%

Source Category	US_ Anthro	Int_ Anthro	Natural	US_RxWild landFire	US_Wild Fire	CanMex Fire	Total	Percent of Total
Coarse Mass	0.76	0.97	0.15	0.03	0.01	0.00	**1.92**	19%
Sea Salt	0.00	0.00	0.18	0.00	0.00	0.00	**0.18**	2%
Soil	0.08	0.13	0.00	0.01	0.00	0.00	**0.23**	2%
Total	**2.20**	**4.08**	**2.32**	**1.23**	**0.15**	**0.05**	**10.03**	**100%**

A review and breakdown of Table 7 shows the following significant contributors to light extinction. Ammonium sulfate accounts for 36% of the total light extinction on the clearest days at LWA, where 18% of the total light extinction is from Int_Anthro, 6% is from US_Anthro, and 9% is from Natural. Coarse mass accounts for the largest species of light extinction after ammonium sulfate at 19% of overall light extinction. Coarse mass from Int_Anthro accounts for 10% and US_Anthro accounts for 8%. Ammonium nitrate accounts for 17% of the total light extinction, where 8% of the total light extinction is from Int_Anthro, 3% is from US_Anthro, and 4% is from Natural. Organic mass also accounts for 17% of the total light extinction, where 1% of the total light extinction is from Int_Anthro, 2% is from US_Anthro, 6% is from Natural, and 6% is from prescribed wildland fires.

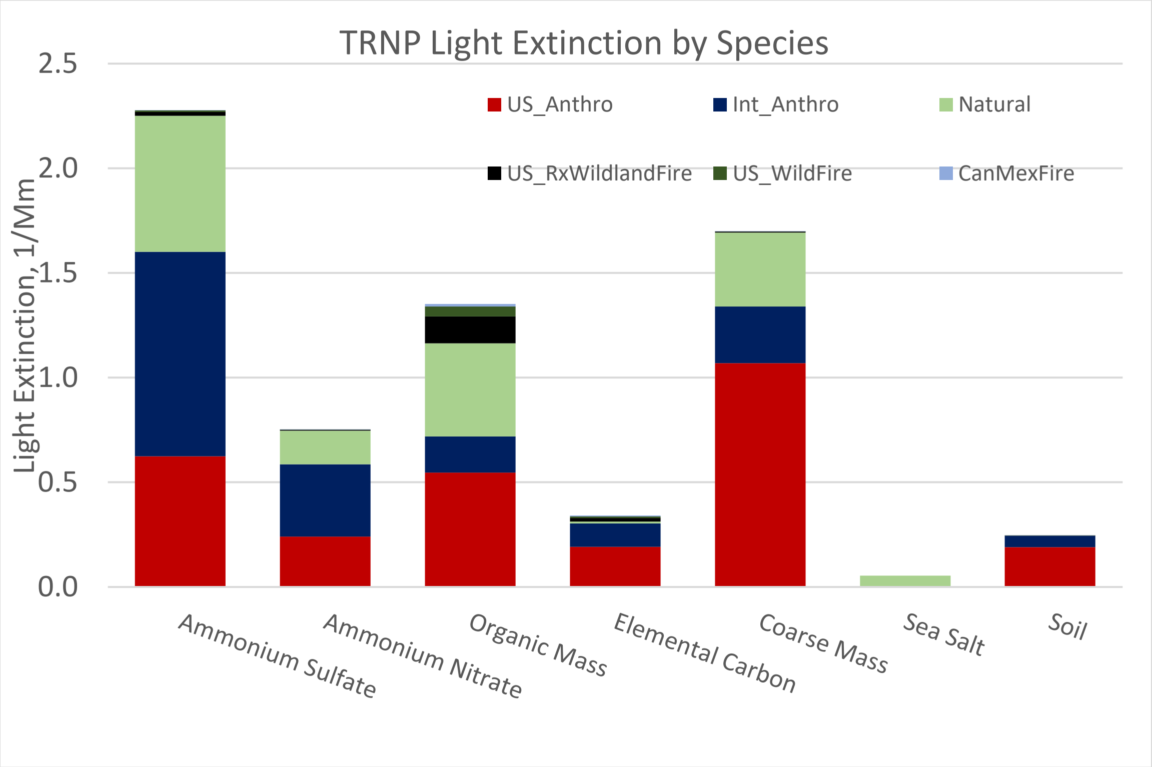

Figure 8: TRNP 2028OTB Light Extinction on the Clearest Days by Species

Figure 8 emphasizes a few important items for TRNP on the clearest days. Light extinction from ammonium sulfate is the most significant aerosol species and Int_Anthro, US_Anthro, and Natural are the primary contributors to the ammonium sulfate light extinction. Coarse mass and organic mass are the next largest contributors to light extinction on the clearest days and each of these species contributes more to light extinction than ammonium nitrate.

Table 8: TRNP 2028OTB Light Extinction on the Clearest Days by Species

Source Category	US_ Anthro	Int_ Anthro	Natural	US_RxWild landFire	US_Wild Fire	CanMex Fire	Total	Percent of Total
Ammonium Sulfate	0.62	0.98	0.65	0.02	0.01	0.00	**2.28**	34%
Ammonium Nitrate	0.24	0.35	0.16	0.00	0.00	0.00	**0.75**	11%
Organic Mass	0.55	0.17	0.44	0.13	0.05	0.01	**1.35**	20%
Elemental Carbon	0.19	0.11	0.01	0.02	0.01	0.00	**0.34**	5%
Coarse Mass	1.07	0.27	0.35	0.00	0.00	0.00	**1.70**	25%
Sea Salt	0.00	0.00	0.05	0.00	0.00	0.00	**0.05**	1%
Soil	0.19	0.05	0.00	0.00	0.00	0.00	**0.25**	4%
Total	**2.86**	**1.93**	**1.67**	**0.17**	**0.07**	**0.02**	**6.73**	**100%**

A review and breakdown of Table 8 shows the following significant contributors to light extinction. Ammonium sulfate accounts for 34% of the total light extinction on the clearest days at TRNP, where 15% of the total light extinction is from Int_Anthro, 9% is from US_Anthro, and 10% is from Natural. Coarse mass accounts for 25% of the total light extinction, where 4% of the total light extinction is from Int_Anthro, 16% is from US_Anthro, and 5% is from Natural. Organic mass accounts for 20% of the total light extinction, where 3% of the total light extinction is from Int_Anthro, 8% is from US_Anthro, and 7% is from Natural. Ammonium nitrate only accounts for 11% of the total light extinction on the clearest days, where 5% of the total light extinction is from Int_Anthro, 4% is from US_Anthro, and 2% is from Natural.

1.2.3 Clearest Days Conclusion

In summary, the contributors to light extinction on the clearest days for both LWA and TRNP come from six main areas: Int_Anthro ammonium sulfate, Int_Anthro ammonium nitrate, US_Anthro ammonium sulfate, US_Anthro ammonium nitrate, Natural ammonium sulfate, and Natural ammonium nitrate. Light extinction from coarse mass and organic mass are also more significant on the clearest days versus the most impaired days. Coarse mass accounts for 19% of the clearest days' total impairment at LWA and 25% of the clearest days' impairment at TRNP. Organic mass accounts for 17% of the clearest days' total impairment at LWA and 20% of the clearest days' total impairment at TRNP.

2 State and Sector Source Impacts on North Dakota Visibility

This section contains the data from the anthropogenic state and sector source apportionment results from the modeling performed by WRAP.[5] WRAP completed modeling to determine the visibility impacts from emissions of US anthropogenic sources by state and sector. This modeling was completed for the species of ammonium nitrates and ammonium sulfates. The sectors included in the modeling were: EGU, OilGas (oil and gas point and area sources with tribal oil and gas assigned to the state), NonEGU (all other point), Mobile (mobile on-road, non-road, rail, commercial marine vessels), and RemainAnthro (all remaining anthropogenic emissions including fugitive dust, agricultural, agricultural fire, residential wood combustion, and all other remaining nonpoint sources). Each of these sector's impairment contribution was determined on a state basis for the 13 continental WRAP states (no Hawaii or Alaska) and from the remaining continental US "RemUS".

The state and sector level source apportionment results are discussed in Section 2.1 for the most impaired days and Section 2.2 for the clearest days.

The aerosol species which contribute to light extinction are ammonium nitrate, ammonium sulfate, organic mass, elemental carbon, coarse mass, soil, and sea salt. The aerosol species of most significance to North Dakota Class I areas are ammonium nitrate and ammonium sulfate. The aerosol species of ammonium nitrate and ammonium sulfate were the only two species tracked for the state and sector breakdown.

The modeling was completed using the 2028 inventory projection (2028OTB). For details on the 2028OTB emission inventory, see Section 4.1.6 of the main SIP document.

2.1 Most Impaired Days

2.1.1 Ammonium Nitrate Light Extinction on the Most Impaired Days

Figure 9 and Figure 10 display the 2028OTB state and sector apportionment results for the average of the most impaired days at LWA and TRNP for aerosol species of ammonium nitrate within the five sector categories. Results are specific to US anthropogenic (US_Anthro) light extinction only. The five major source categories are: EGU, OilGas, NonEGU, Mobile, and RemainAnthro. Table 9 and Table 10 display the numerical data corresponding to Figure 9 and Figure 10 for LWA and TRNP, respectively.

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[5] Available at: https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/SourceApportionmentSpecifications_WRAP_RepBase2_and_2028OTBa2_High-LevelPMandO3_and_Low-Level_PM_andOptionalO3_Sept29_2020.pdf (Last visited February 22, 2021)

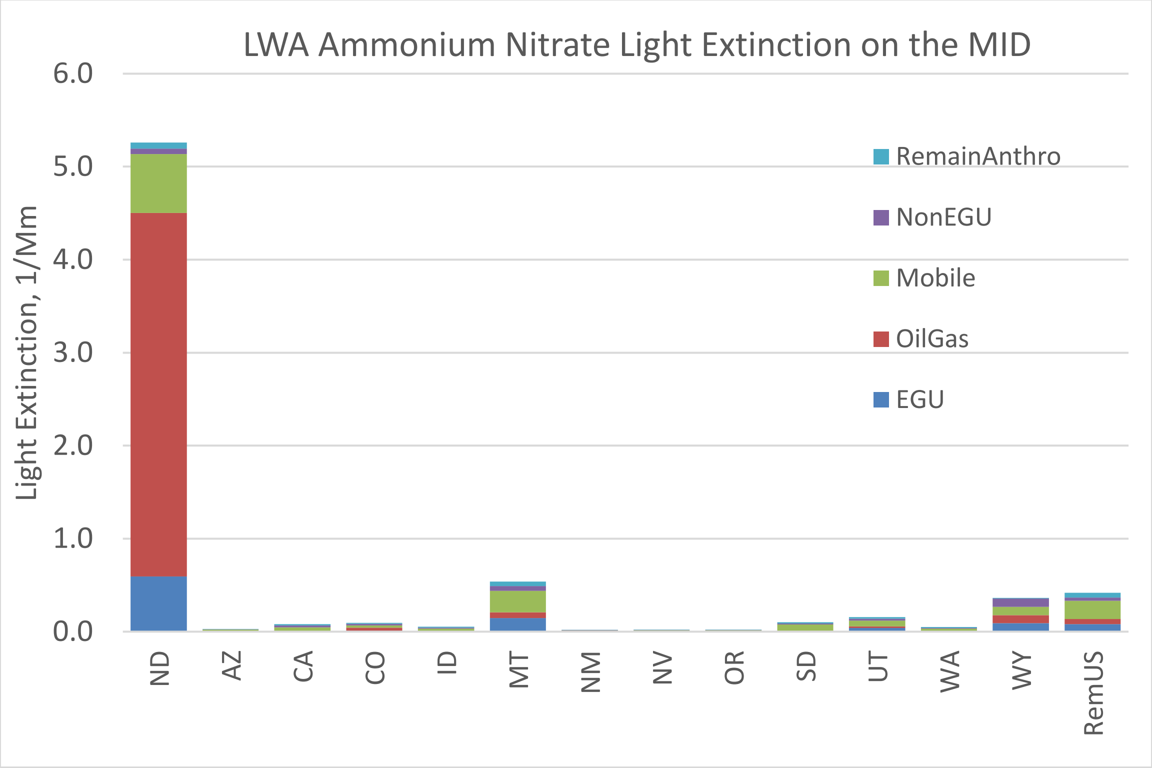

Figure 9: LWA Ammonium Nitrate light Extinction on the Most Impaired Days

Figure 9 shows that much of the projected US anthropogenic ammonium nitrate light extinction at LWA on the most impaired days comes from sources within North Dakota. The primary sectors contributing to the light extinction are OilGas, EGU and Mobile.

Table 9: LWA Ammonium Nitrate light Extinction on the Most Impaired Days

State	EGU	OilGas	Mobile	NonEGU	RemainAnthro	Total	Percent of Total
ND	0.59	3.91	0.63	0.06	0.07	**5.26**	73%
AZ	0.00	0.00	0.02	0.00	0.00	**0.03**	0%
CA	0.00	0.00	0.04	0.02	0.02	**0.08**	1%
CO	0.01	0.03	0.03	0.01	0.01	**0.09**	1%
ID	0.00	0.00	0.03	0.01	0.01	**0.05**	1%
MT	0.14	0.06	0.23	0.05	0.05	**0.54**	7%
NM	0.00	0.01	0.00	0.00	0.00	**0.02**	0%
NV	0.00	0.00	0.01	0.00	0.00	**0.02**	0%
OR	0.00	0.00	0.01	0.01	0.00	**0.02**	0%
SD	0.00	0.01	0.07	0.01	0.01	**0.10**	1%
UT	0.04	0.02	0.06	0.02	0.02	**0.16**	2%
WA	0.00	0.00	0.03	0.01	0.01	**0.05**	1%
WY	0.09	0.09	0.09	0.09	0.01	**0.36**	5%
RemUS	0.08	0.06	0.20	0.03	0.05	**0.42**	6%

State	EGU	OilGas	Mobile	NonEGU	RemainAnthro	Total	Percent of Total
Total	**0.98**	**4.19**	**1.45**	**0.34**	**0.26**	**7.21**	**100%**

Table 9 shows the state and source category breakdown of ammonium nitrate light extinction contributions on the most impaired days at LWA. North Dakota sources contribute 73% of the total US_Anthro ammonium nitrate light extinction at LWA on the most impaired days. The remaining 27% primarily comes from MT (7%), WY (5%), and RemUS (6%) with all other continental US WRAP states accounting for the remaining 9%. None of the impairment from US sources outside North Dakota is considered significant. The outside impairment is small on a relative or percentage basis, less than 10%. On an overall magnitude basis, US_Anthro impairment from outside of ND is also small. The highest state modeled impairment comes from MT and is 0.54 Mm^{-1}.

North Dakota's 73% contribution is mostly from three sectors, OilGas, EGU, and Mobile. Of the North Dakota contribution, OilGas accounts for 54% of the total US_Anthro light extinction, EGU accounts for 8%, and Mobile accounts for 9%. On a relative basis OilGas accounts for over half of the US_Anthro ammonium nitrate light extinction at LWA. However, the magnitude of the projected OilGas impairment is relatively small at only 3.91 Mm^{-1}, compared to the overall species light extinction of 39.45 Mm^{-1} (Section 1.1) or the total light extinction of 50.45 Mm^{-1} (Section 3.1 of the main SIP document). The magnitude of ammonium nitrate impairment from North Dakota EGUs and Mobile sources is even smaller, where EGUs contribute 0.59 Mm^{-1} of light extinction and Mobile contributes 0.63 Mm^{-1}.

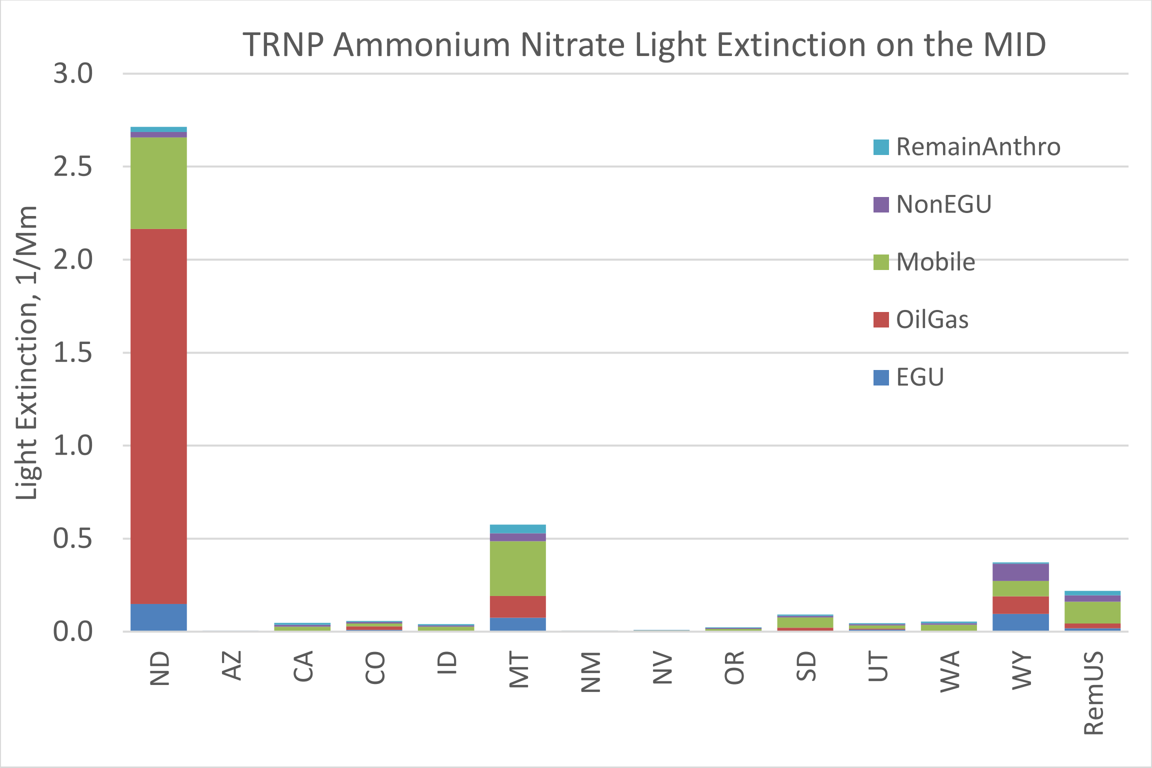

Figure 10: TRNP Ammonium Nitrate light Extinction on the Most Impaired Days

Similar to LWA, Figure 10 shows that the majority of projected US anthropogenic ammonium nitrate light extinction at TRNP on the most impaired days comes from sources within North Dakota. The primary sectors contributing to the light extinction are OilGas, EGU and Mobile.

Table 10: TRNP Ammonium Nitrate light Extinction on the Most Impaired Days

State	EGU	OilGas	Mobile	NonEGU	RemainAnthro	Total	Percent of Total
ND	0.15	2.02	0.49	0.03	0.03	**2.71**	64%
AZ	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
CA	0.00	0.00	0.02	0.01	0.01	**0.05**	1%
CO	0.01	0.02	0.02	0.01	0.01	**0.06**	1%
ID	0.00	0.00	0.02	0.01	0.01	**0.04**	1%
MT	0.07	0.12	0.29	0.04	0.05	**0.57**	13%
NM	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
NV	0.00	0.00	0.01	0.00	0.00	**0.01**	0%
OR	0.00	0.00	0.01	0.01	0.00	**0.02**	1%
SD	0.00	0.02	0.06	0.01	0.01	**0.09**	2%
UT	0.01	0.01	0.02	0.01	0.00	**0.05**	1%
WA	0.00	0.00	0.03	0.01	0.01	**0.05**	1%
WY	0.10	0.09	0.08	0.09	0.01	**0.37**	9%
RemUS	0.02	0.03	0.12	0.03	0.02	**0.22**	5%

State	EGU	OilGas	Mobile	NonEGU	RemainAnthro	Total	Percent of Total
Total	**0.37**	**2.31**	**1.18**	**0.26**	**0.15**	**4.26**	100%

Table 10 shows the state and source category breakdown of ammonium nitrate light extinction contributions on the most impaired days at TRNP. North Dakota sources contribute 64% of the total US_Anthro ammonium nitrate light extinction at TRNP on the most impaired days. The remaining 36% primarily comes from MT (13%), WY (9%), and RemUS (5%) with all other continental US WRAP states accounting for the remaining 9%. None of the impairment from US sources outside North Dakota is considered significant. On an overall magnitude basis, US_Anthro impairment from outside of ND is small. The highest state modeled impairment comes from MT and is 0.57 Mm^{-1}.

North Dakota's 64% contribution is mostly from three sectors, OilGas, EGU, and Mobile. Of the North Dakota contribution, OilGas accounts for 47% of the total US_Anthro light extinction, EGU accounts for 4%, and Mobile accounts for 12%. On a relative basis OilGas accounts for almost half of the US_Anthro ammonium nitrate light extinction at TRNP. However, the magnitude of the projected OilGas impairment is relatively small at only 2.02 Mm^{-1}, compared to the overall species light extinction of 29.72 Mm^{-1} (Section 1.1) or the total light extinction of 40.72 Mm^{-1} (Section 3.1 of the main SIP document). The magnitude of ammonium nitrate impairment from North Dakota EGUs and Mobile sources is even smaller, where EGUs contribute 0.15 Mm^{-1} of light extinction and Mobile contributes 0.49 Mm^{-1}.

2.1.2 Ammonium Sulfate Light Extinction on the Most Impaired Days

Figure 11 and Figure 12 display the 2028OTB state and sector apportionment results for the average of the most impaired days for aerosol species of ammonium sulfate within the five sector categories. Results are specific to modeled US anthropogenic light extinction only. The five major source categories are: EGU, OilGas, NonEGU, Mobile, and RemainAnthro. Table 11 and Table 12 display the numerical data corresponding to Figure 11 and Figure 12 for LWA and TRNP, respectively.

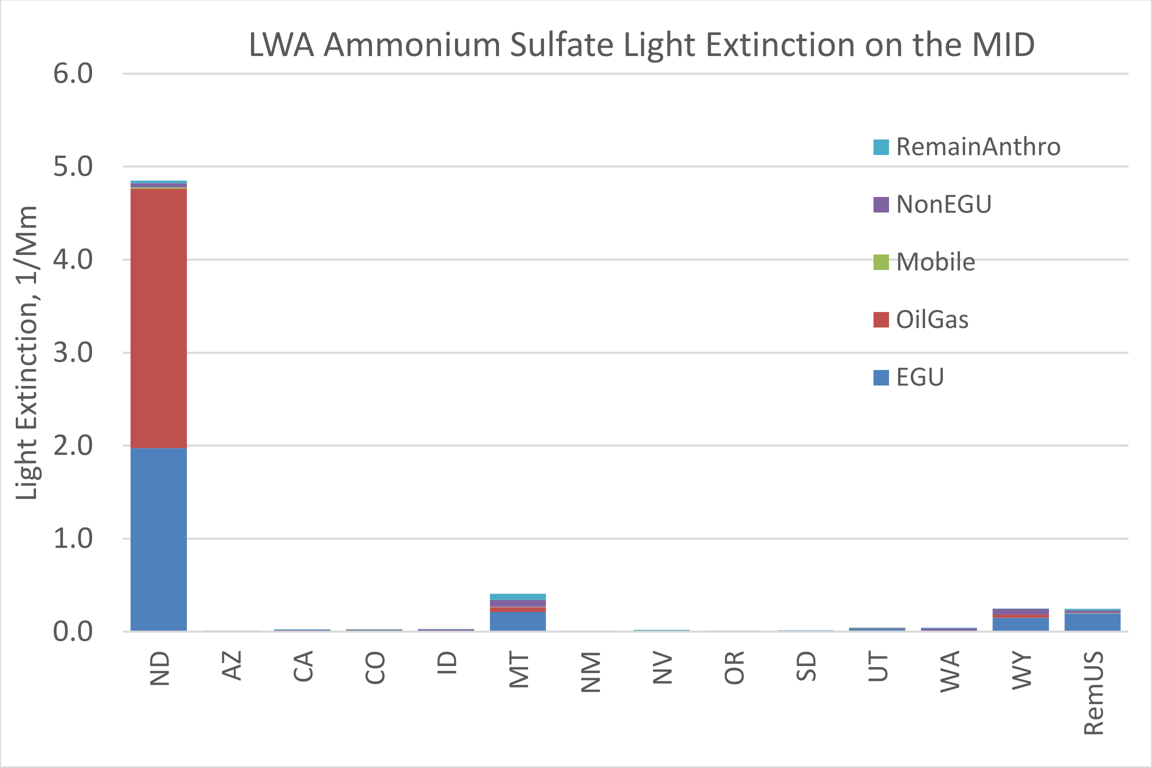

Figure 11: LWA Ammonium Sulfate light Extinction on the Most Impaired Days

Figure 11 shows that much of the modeled US anthropogenic ammonium sulfate light extinction at LWA on the most impaired days comes from sources within North Dakota. The primary sectors contributing to the light extinction are OilGas and EGU.

Table 11: LWA Ammonium Sulfate light Extinction on the Most Impaired Days

State	EGU	OilGas	Mobile	NonEGU	RemainAnthro	Total	Percent of Total
ND	1.97	2.79	0.01	0.05	0.03	**4.85**	81%
AZ	0.00	0.00	0.00	0.01	0.00	**0.01**	0%
CA	0.00	0.00	0.00	0.02	0.01	**0.03**	0%
CO	0.01	0.00	0.00	0.01	0.00	**0.02**	0%
ID	0.00	0.00	0.00	0.02	0.00	**0.03**	0%
MT	0.21	0.05	0.00	0.08	0.06	**0.41**	7%
NM	0.00	0.00	0.00	0.00	0.00	**0.01**	0%
NV	0.01	0.00	0.00	0.00	0.01	**0.02**	0%
OR	0.00	0.00	0.00	0.01	0.00	**0.01**	0%
SD	0.00	0.00	0.00	0.01	0.01	**0.02**	0%
UT	0.03	0.00	0.00	0.01	0.00	**0.04**	1%
WA	0.00	0.00	0.00	0.04	0.01	**0.04**	1%
WY	0.15	0.03	0.00	0.06	0.00	**0.25**	4%
RemUS	0.19	0.00	0.00	0.03	0.02	**0.25**	4%

State	EGU	OilGas	Mobile	NonEGU	RemainAnthro	Total	Percent of Total
Total	**2.59**	**2.89**	**0.03**	**0.32**	**0.15**	**5.98**	100%

Table 11 shows the state and source category breakdown of ammonium sulfate light extinction contributions on the most impaired days at LWA. North Dakota sources contribute 81% of the total US_Anthro ammonium sulfate light extinction at LWA on the most impaired days. The remaining 19% primarily comes from MT (7%), WY (4%), and RemUS (4%) with all other continental US WRAP states accounting for the remaining 4%. None of the impairment from US sources outside North Dakota is considered significant. The outside impairment is small on a relative or percentage basis, less than 10%. On an overall magnitude basis, US_Anthro impairment from outside of ND is small. The highest state modeled impairment comes from MT and is 0.41 Mm^{-1}.

North Dakota's 81% contribution is mostly from two sectors, OilGas and EGU. Of the North Dakota contribution, OilGas accounts for 47% of the total US_Anthro light extinction and EGU accounts for 33%. On a relative basis OilGas accounts for nearly half of the US_Anthro ammonium sulfate light extinction at LWA. However, the magnitude of the projected OilGas impairment is relatively small at only 2.79 Mm^{-1}, compared to the overall species light extinction of 39.45 Mm^{-1} (Section 1.1) or the total light extinction of 50.45 Mm^{-1} (Section 3.1 of the main SIP document). The magnitude of ammonium sulfate impairment from North Dakota EGUs is even smaller, where EGUs contribute 1.97 Mm^{-1} of light extinction.

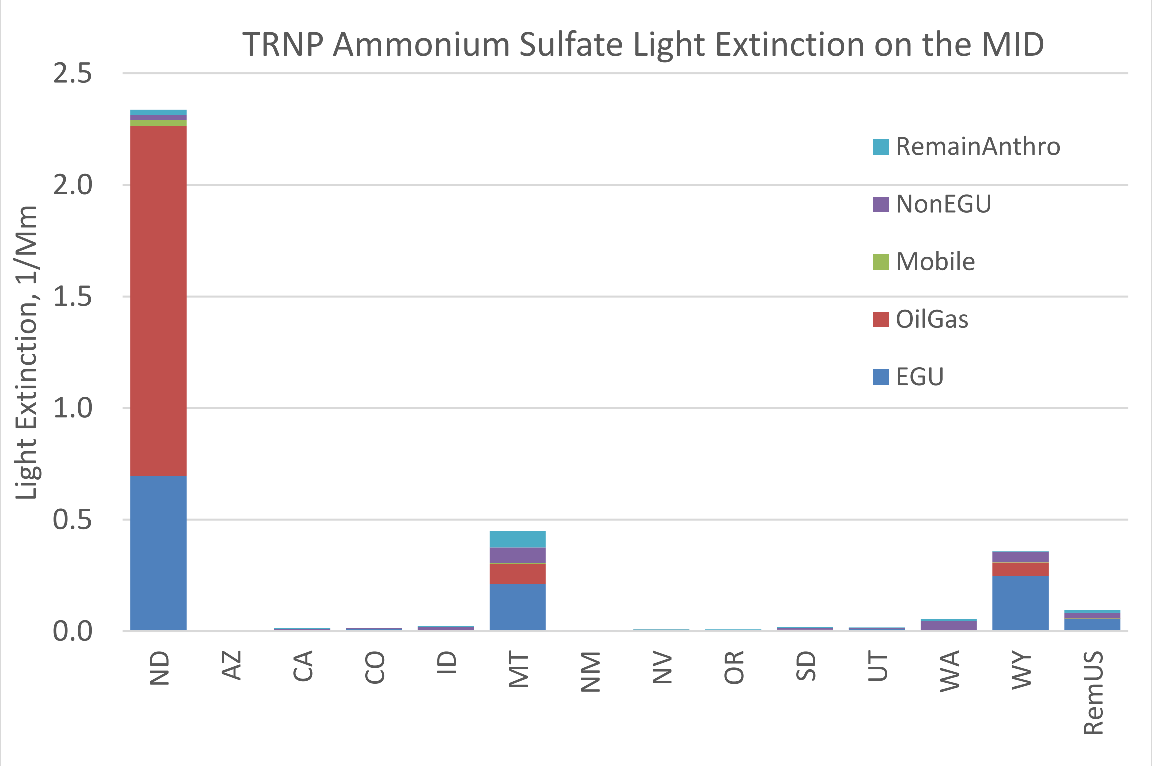

Figure 12: TRNP Ammonium Sulfate light Extinction on the Most Impaired Days

Figure 12 shows that the majority of projected US anthropogenic ammonium sulfate light extinction at TRNP on the most impaired days comes from sources within North Dakota. The primary sectors contributing to the light extinction are OilGas and EGU.

Table 12: TRNP Ammonium Sulfate light Extinction on the Most Impaired Days

State	EGU	OilGas	Mobile	NonEGU	RemainAnthro	Total	Percent of Total
ND	0.70	1.57	0.03	0.02	0.02	**2.34**	69%
AZ	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
CA	0.00	0.00	0.00	0.01	0.00	**0.01**	0%
CO	0.01	0.00	0.00	0.00	0.00	**0.02**	0%
ID	0.00	0.00	0.00	0.02	0.00	**0.02**	1%
MT	0.21	0.09	0.00	0.07	0.07	**0.45**	13%
NM	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
NV	0.01	0.00	0.00	0.00	0.00	**0.01**	0%
OR	0.00	0.00	0.00	0.00	0.00	**0.01**	0%
SD	0.00	0.01	0.00	0.01	0.00	**0.02**	1%
UT	0.01	0.00	0.00	0.00	0.00	**0.02**	0%
WA	0.00	0.00	0.00	0.04	0.01	**0.06**	2%
WY	0.25	0.06	0.00	0.05	0.00	**0.36**	11%
RemUS	0.06	0.00	0.00	0.02	0.01	**0.09**	3%
Total	**1.25**	**1.72**	**0.04**	**0.26**	**0.14**	3.40	100%

Table 12 shows the state and source category breakdown of ammonium sulfate light extinction contributions on the most impaired days at TRNP. North Dakota sources contribute 69% of the total US_Anthro ammonium sulfate light extinction at LWA on the most impaired days. The remaining 31% primarily comes from MT (13%), WY (11%), and RemUS (3%) with all other continental US WRAP states accounting for the remaining 4%. None of the impairment from US sources outside North Dakota is considered significant. On an overall magnitude basis, US_Anthro impairment from outside of ND is small. The highest state modeled impairment comes from MT and is 0.45 Mm^{-1}.

North Dakota's 69% contribution is mostly from two sectors, OilGas and EGU. Of the North Dakota contribution, OilGas accounts for 46% of the total US_Anthro light extinction and EGU accounts for 20%. On a relative basis OilGas accounts for nearly half of the US_Anthro ammonium sulfate light extinction at TRNP. However, the magnitude of the projected OilGas impairment is relatively small at only 1.57 Mm^{-1}, compared to the overall species light extinction of 29.72 Mm^{-1} (Section 1.1) or the total light extinction of 40.72 Mm^{-1} (Section 3.1 of the main SIP document). The magnitude of ammonium sulfate impairment from North Dakota EGUs is even smaller, where EGUs contribute 0.70 Mm^{-1} of light extinction.

2.1.3 North Dakota Sector Contribution on the Most Impaired Days

The impairment caused by North Dakota sectors can also be compared to the overall species light extinction projection for 2028. The following is a breakdown of species light extinction: US anthropogenic (US_Anthro), International anthropogenic (Int_Anthro), Natural, prescribed wildland fire (US_RxWildlandFire), US wildfire, and Canada Mexico Fires (CanMexFire) is discussed in detail and is included in Section 1.1. The following breakdown shows the impairment caused by the North Dakota sectors as compared to the species light extinction for the 2028OTB scenario. US_Anthro sources have been broken down into the following sectors: North Dakota electrical generating utilities (ND EGU); North Dakota Oil and Gas point and area sources including tribal Oil and Gas operation (ND OilGas); North Dakota mobile onroad, non-road, rail, and commercial marine vessels (ND Mobile); Other North Dakota point sources (ND NonEGU); all remaining anthropogenic emissions including fugitive dust, agriculture, agricultural fire, residential wood combustion, and all remaining nonpoint sources (ND RemainAnthro); all US_Anthro minus the North Dakota sectors (Remaining US); and the Boundary Conditions from US emissions (BCUS). The species breakdown for all US_Anthro sources and sectors was limited to ammonium nitrate and ammonium sulfate. Therefore, impairment from the species of coarse mass, elemental carbon, organic mass, sea salt, and soil for all US_Anthro sources (including North Dakota sources) are included in the “Remaining US” row for Table 13 and Table 14. Note that Tribal oil and gas emissions are assigned to the ND OilGas category.

Table 13: LWA Sector and Source Category Contributions to Species Light Extinction on MID

Source Category/Sector	Ammonium Nitrate	Ammonium Sulfate	Coarse Mass	Elemental Carbon	Organic Mass	Sea Salt	Soil	Grand Total
ND EGU	2%	5%	--	--	--	--	--	**7%**
ND OilGas	10%	7%	--	--	--	--	--	**17%**
ND Mobile	2%	0%	--	--	--	--	--	**2%**
ND NonEGU	0%	0%	--	--	--	--	--	**0%**
ND RemainAnthro	0%	0%	--	--	--	--	--	**0%**
Remaining US	5%	3%	2%	1%	3%	0%	0%	**15%**
BCUS	0%	0%	--	--	--	--	--	**1%**
Int_Anthro	**19%**	**17%**	**1%**	**2%**	**1%**	**0%**	**0%**	**40%**
CanMexFire	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**1%**
Natural	**7%**	**5%**	**1%**	**0%**	**2%**	**1%**	**0%**	**16%**
US_RxWildlandFire	**0%**	**0%**	**0%**	**0%**	**1%**	**0%**	**0%**	**1%**
US_WildFire	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Grand Total	**45%**	**38%**	**5%**	**4%**	**7%**	**1%**	**1%**	**100%**

Table 13 shows the percent breakdown of the total species light extinction contributions from different source categories and sectors at LWA. US_Anthro sources contribute to 42% of the total light extinction, with 19% and 16% attributed to ammonium nitrate and ammonium sulfate, respectively. ND sectors contribute to 26% of the total light extinction. The largest source category contributor is ND OilGas at

17%, with ND EGU being less than half of that at a 7% contribution. Similar to US_Anthro, Int_Anthro contributes 40% to the total light extinction. The only other significant contributor outside of these is Natural at 16%.

ND OilGas light extinction consists of North Dakota point and area sources and tribal oil and gas operations. North Dakota area oil and gas sources (upstream development and operation) consists of over 15,000 individual wells spread out amongst over 8,000 sites. Meaning the 17% combined ammonium nitrate and ammonium sulfate impairment comes from many individual sources, and a significant portion (tribal oil and gas) is outside of the State of North Dakota's control. The largest point sources emitters were evaluated under the four-factor analysis (Section 5.2 of the main SIP document).

Table 14: TRNP Sector and Source Category Contributions to Species Light Extinction on MID

Source Category/Sector	**Ammonium Nitrate**	**Ammonium Sulfate**	**Coarse Mass**	**Elemental Carbon**	**Organic Mass**	**Sea Salt**	**Soil**	**Grand Total**
ND EGU	1%	2%	--	--	--	--	--	**3%**
ND OilGas	7%	5%	--	--	--	--	--	**12%**
ND Mobile	2%	0%	--	--	--	--	--	**2%**
ND NonEGU	0%	0%	--	--	--	--	--	**0%**
ND RemainAnthro	0%	0%	--	--	--	--	--	**0%**
Remaining US	5%	4%	4%	1%	4%	0%	1%	**19%**
BCUS	1%	1%	--	--	--	--	--	**1%**
Int_Anthro	**15%**	**24%**	**2%**	**1%**	**1%**	**0%**	**0%**	**43%**
CanMexFire	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Natural	**5%**	**8%**	**1%**	**0%**	**2%**	**1%**	**0%**	**18%**
US_RxWildlandFire	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**1%**
US_WildFire	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**1%**
Grand Total	**36%**	**45%**	**7%**	**3%**	**8%**	**1%**	**1%**	**100%**

Table 14 shows the percent breakdown of the total species light extinction contributions from different source categories and sectors at TRNP. US_Anthro sources contribute to 37% of the total light extinction, with 15% and 12% attributed to ammonium nitrate and ammonium sulfate, respectively. ND sectors contribute to 17% of the total light extinction. The largest source category contributor is ND OilGas at 12%, with ND EGU being a quarter of that at a 3% contribution. Int_Anthro has a higher contribution than US_Anthro, contributing 43% to the total light extinction. The only other significant contributor outside of these is Natural at 18%.

2.2 Clearest Days

2.2.1 Ammonium Nitrate Light Extinction on the Clearest Days

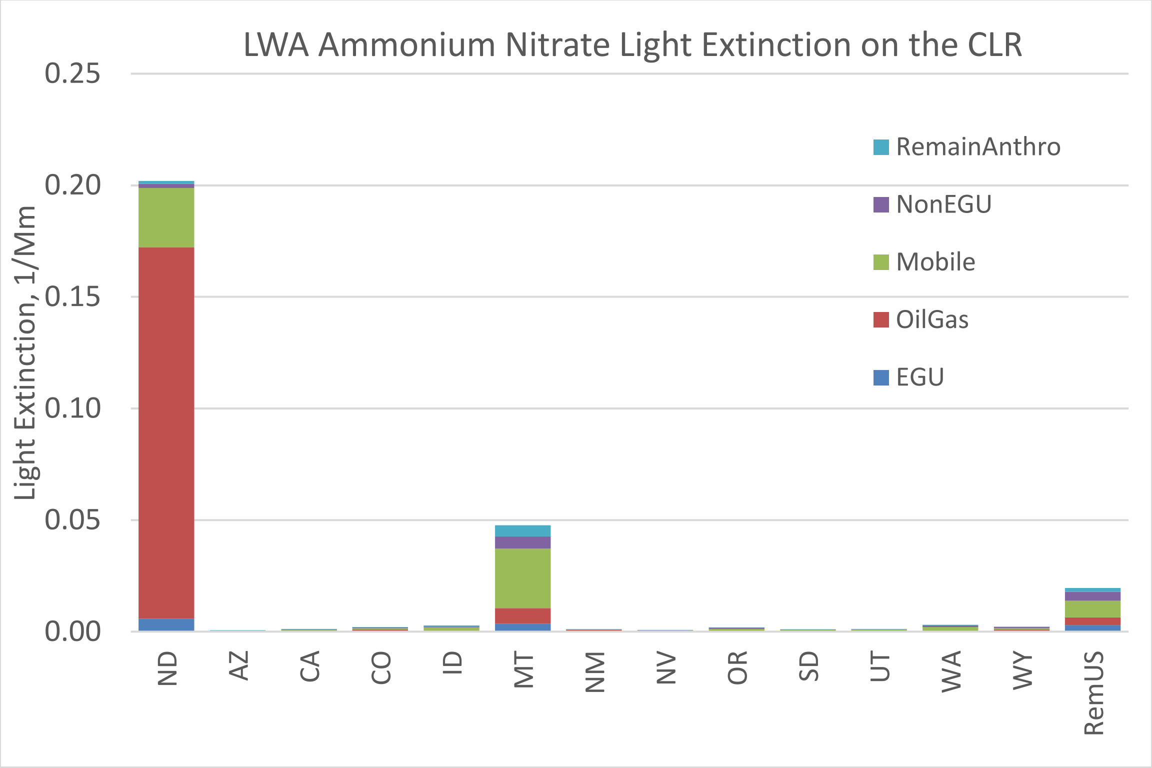

Figure 13: LWA Ammonium Nitrate light Extinction on the Clearest Days

Figure 13 shows that the majority of projected US anthropogenic ammonium nitrate light extinction at LWA on the clearest days comes from sources within North Dakota.

Table 15: LWA Ammonium Nitrate light Extinction on the Clearest Days

State	**EGU**	**OilGas**	**Mobile**	**NonEGU**	**RemainAnthro**	**Total**	**Percent of Total**
ND	0.01	0.17	0.03	0.00	0.00	**0.20**	70%
AZ	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
CA	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
CO	0.00	0.00	0.00	0.00	0.00	**0.00**	1%
ID	0.00	0.00	0.00	0.00	0.00	**0.00**	1%
MT	0.00	0.01	0.03	0.01	0.00	**0.05**	17%
NM	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
NV	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
OR	0.00	0.00	0.00	0.00	0.00	**0.00**	1%
SD	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
UT	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
WA	0.00	0.00	0.00	0.00	0.00	**0.00**	1%
WY	0.00	0.00	0.00	0.00	0.00	**0.00**	1%
RemUS	0.00	0.00	0.01	0.00	0.00	**0.02**	7%
Total	**0.01**	**0.18**	**0.07**	**0.01**	**0.01**	**0.29**	100%

Table 15 shows the state and source category breakdown of ammonium nitrate light extinction contributions on the clearest days at LWA. North Dakota sources contribute 70% of the total US_Anthro ammonium nitrate light extinction at LWA on the clearest days. The remaining 30% primarily comes from MT (17%) and RemUS (7%), with all other continental US WRAP states accounting for the remaining 6%. None of the impairment from US sources outside North Dakota is considered significant. On an overall magnitude basis, US_Anthro impairment from outside of ND is small. The highest state modeled impairment comes from MT and is 0.05 Mm^{-1}.

North Dakota's 70% contribution is mostly from two sectors, OilGas and Mobile. Of the North Dakota contribution, OilGas accounts for 58% of the total US_Anthro light extinction and Mobile accounts for 9%. On a relative basis OilGas accounts for over half of the US_Anthro ammonium nitrate light extinction at LWA on the clearest days. However, the magnitude of the projected OilGas impairment is small at only 0.17 Mm^{-1}. The magnitude of ammonium nitrate impairment from North Dakota Mobile is even smaller, where Mobile contributes 0.03 Mm^{-1} of light extinction.

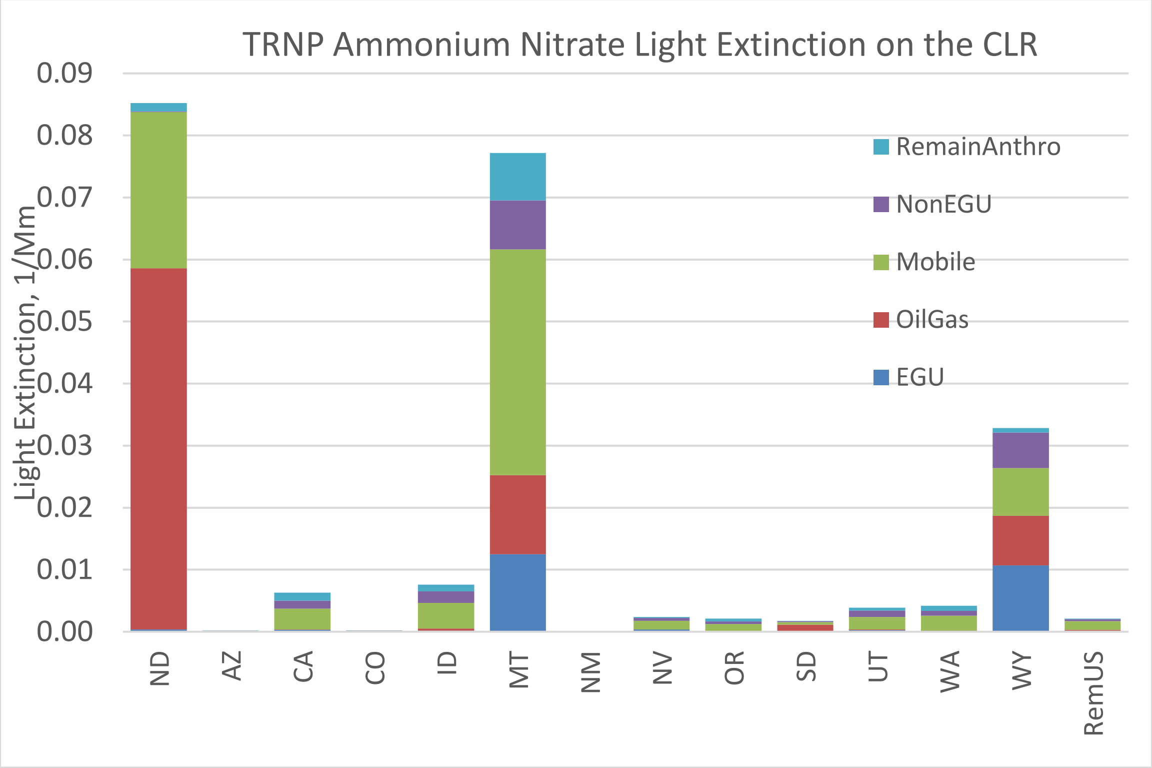

Figure 14: TRNP Ammonium Nitrate light Extinction on the Clearest Days

Figure 14 shows that the majority of projected US anthropogenic ammonium nitrate light extinction at TRNP on the clearest days comes from sources within North Dakota.

Table 16: TRNP Ammonium Nitrate light Extinction on the Clearest Days

State	**EGU**	**OilGas**	**Mobile**	**NonEGU**	**RemainAnthro**	**Total**	**Percent of Total**
ND	0.00	0.06	0.03	0.00	0.00	**0.09**	38%
AZ	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
CA	0.00	0.00	0.00	0.00	0.00	**0.01**	3%
CO	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
ID	0.00	0.00	0.00	0.00	0.00	**0.01**	3%
MT	0.01	0.01	0.04	0.01	0.01	**0.08**	34%
NM	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
NV	0.00	0.00	0.00	0.00	0.00	**0.00**	1%
OR	0.00	0.00	0.00	0.00	0.00	**0.00**	1%
SD	0.00	0.00	0.00	0.00	0.00	**0.00**	1%
UT	0.00	0.00	0.00	0.00	0.00	**0.00**	2%
WA	0.00	0.00	0.00	0.00	0.00	**0.00**	2%
WY	0.01	0.01	0.01	0.01	0.00	**0.03**	15%
RemUS	0.00	0.00	0.00	0.00	0.00	**0.00**	1%
Total	**0.03**	**0.08**	**0.09**	**0.02**	**0.01**	**0.23**	100%

Table 16 shows the state and source category breakdown of ammonium nitrate light extinction contributions on the clearest days at TRNP. North Dakota sources contribute 38% of the total US_Anthro ammonium nitrate light extinction at TRNP on the clearest days, with Montana sources contributing 34%. The remaining 28% primarily comes from WY (15%), with all other continental US WRAP states accounting for the remaining 13%. On an overall magnitude basis, US_Anthro impairment from outside of ND is small. The highest state modeled impairment from MT is 0.08 Mm^{-1}.

North Dakota's 38% contribution is mostly from two sectors, OilGas and Mobile. Of the North Dakota contribution, OilGas accounts for 26% of the total US_Anthro light extinction and Mobile accounts for 11%. The magnitude of the projected OilGas impairment is small at only 0.06 Mm^{-1}. The magnitude of ammonium nitrate impairment from North Dakota Mobile is even smaller, where Mobile contributes 0.03 Mm^{-1} of light extinction.

2.2.2 Ammonium Sulfate Light Extinction on the Clearest Days

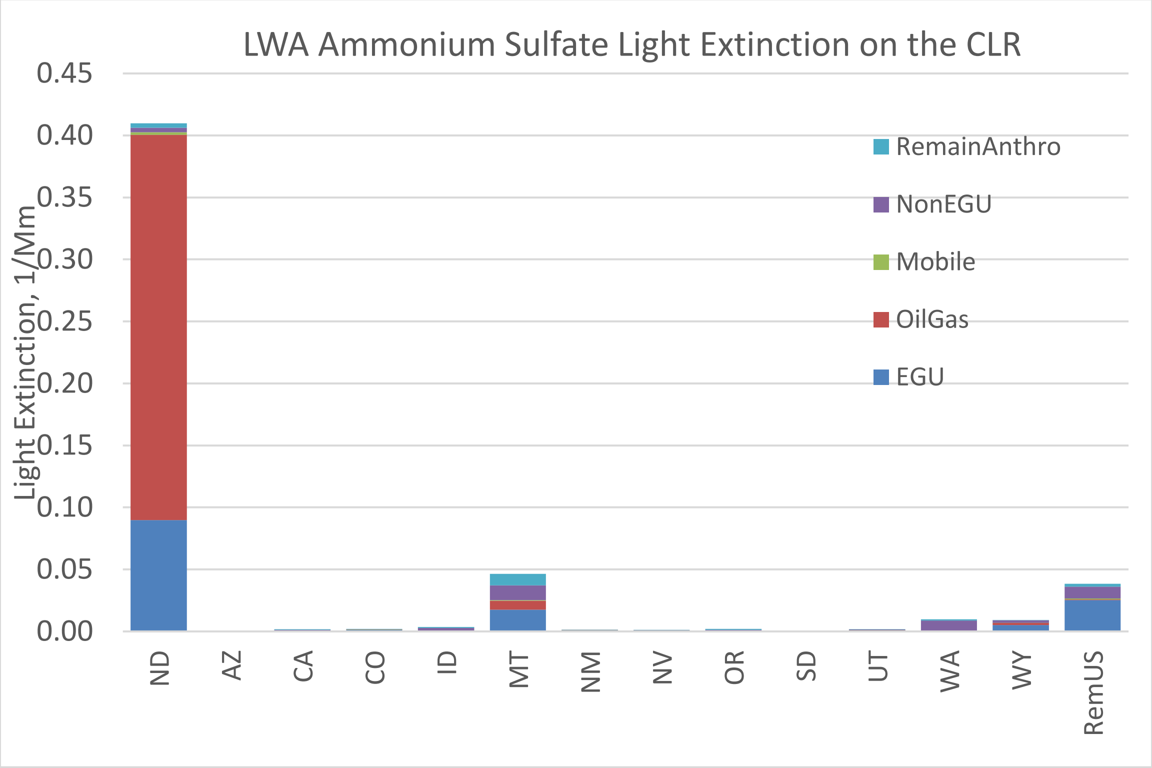

Figure 15: LWA Ammonium Sulfate light Extinction on the Clearest Days

Figure 15 shows that the vast majority of projected US anthropogenic ammonium sulfate light extinction at LWA on the clearest days comes from sources within North Dakota. The primary sectors contributing to the light extinction are OilGas and EGU.

Table 17: LWA Ammonium Sulfate light Extinction on the Clearest Days

State	EGU	OilGas	Mobile	NonEGU	RemainAnthro	Total	Percent of Total
ND	0.09	0.31	0.00	0.00	0.00	**0.41**	78%
AZ	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
CA	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
CO	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
ID	0.00	0.00	0.00	0.00	0.00	**0.00**	1%
MT	0.02	0.01	0.00	0.01	0.01	**0.05**	9%
NM	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
NV	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
OR	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
SD	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
UT	0.00	0.00	0.00	0.00	0.00	**0.00**	0%

State	EGU	OilGas	Mobile	NonEGU	RemainAnthro	Total	Percent of Total
WA	0.00	0.00	0.00	0.01	0.00	**0.01**	2%
WY	0.01	0.00	0.00	0.00	0.00	**0.01**	2%
RemUS	0.03	0.00	0.00	0.01	0.00	**0.04**	7%
Total	**0.14**	**0.32**	**0.00**	**0.04**	**0.02**	**0.53**	100%

Table 17 shows the state and source category breakdown of ammonium sulfate light extinction contributions on the clearest days at LWA. North Dakota sources contribute 78% of the total US_Anthro ammonium sulfate light extinction at LWA on the clearest days. The remaining 22% primarily comes from MT (9%) and RemUS (7%), with all other continental US WRAP states accounting for the remaining 6%. On an overall magnitude basis, US_Anthro impairment from outside of ND is small. The highest state modeled impairment from MT is 0.05 Mm^{-1}.

North Dakota's 38% contribution is mostly from two sectors, OilGas and EGU. Of the North Dakota contribution, OilGas accounts for 59% of the total US_Anthro light extinction and EGU accounts for 17%. The magnitude of the projected OilGas impairment is small at only 0.31 Mm^{-1}. The magnitude of ammonium sulfate impairment from North Dakota EGUs is even smaller, where EGUs contributes 0.09 Mm^{-1} of light extinction.

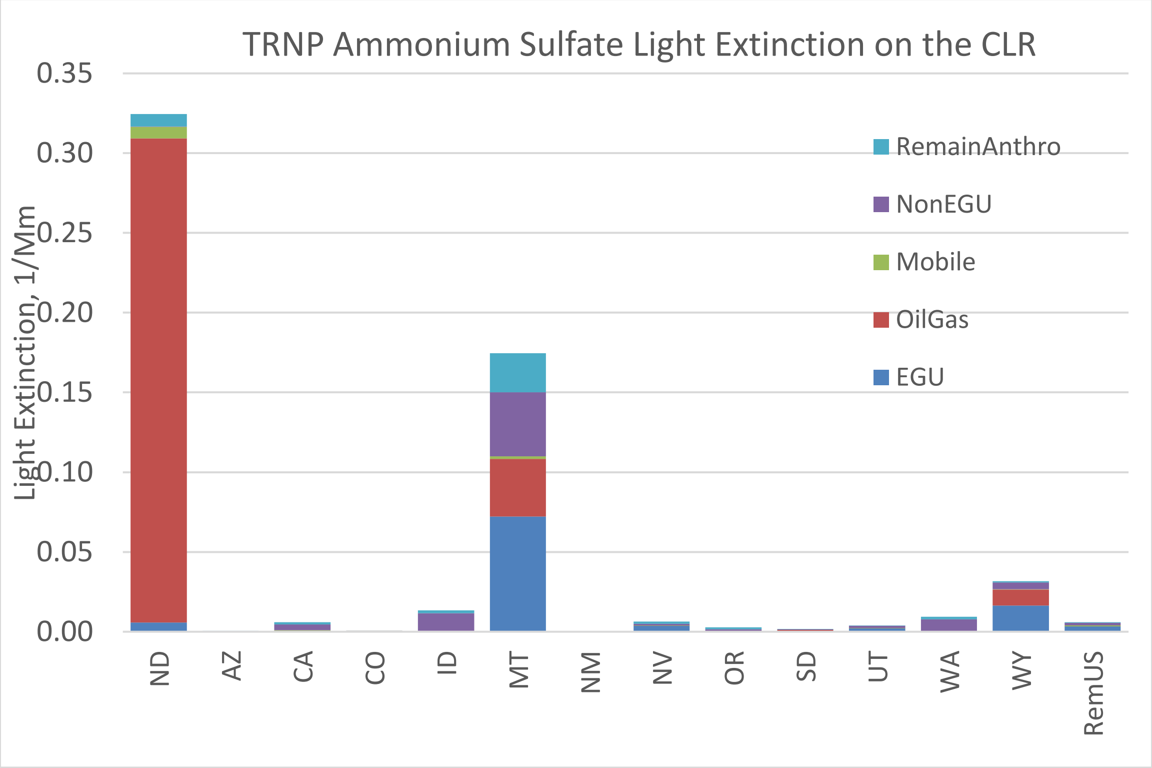

Figure 16: TRNP Ammonium Sulfate light Extinction on the Clearest Days

Figure 16 shows that the majority of projected US anthropogenic ammonium sulfate light extinction at TRNP on the clearest days comes from sources within North Dakota. The primary sector contributing to the light extinction is OilGas.

Table 18: TRNP Ammonium Sulfate light Extinction on the Clearest Days

State	EGU	OilGas	Mobile	NonEGU	RemainAnthro	Total	Percent of Total
ND	0.01	0.30	0.01	0.00	0.01	**0.32**	56%
AZ	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
CA	0.00	0.00	0.00	0.00	0.00	**0.01**	1%
CO	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
ID	0.00	0.00	0.00	0.01	0.00	**0.01**	2%
MT	0.07	0.04	0.00	0.04	0.02	**0.17**	30%
NM	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
NV	0.00	0.00	0.00	0.00	0.00	**0.01**	1%
OR	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
SD	0.00	0.00	0.00	0.00	0.00	**0.00**	0%
UT	0.00	0.00	0.00	0.00	0.00	**0.00**	1%
WA	0.00	0.00	0.00	0.01	0.00	**0.01**	2%
WY	0.02	0.01	0.00	0.00	0.00	**0.03**	5%
RemUS	0.00	0.00	0.00	0.00	0.00	**0.01**	1%
Total	**0.10**	**0.35**	**0.01**	**0.07**	**0.04**	**0.58**	100%

Table 18 shows the state and source category breakdown of ammonium sulfate light extinction contributions on the clearest days at TRNP. North Dakota sources contribute 56% of the total US_Anthro ammonium sulfate light extinction at TRNP on the clearest days, with Montana sources contributing 30%. The remaining 14% primarily comes from WY (5%), with all other continental US WRAP states accounting for the remaining 9%. On an overall magnitude basis, US_Anthro impairment from outside of ND is small. The highest state modeled impairment from MT is 0.17 Mm^{-1}.

North Dakota's 56% contribution is mostly from the OilGas sector. Of the North Dakota contribution, OilGas accounts for 52% of the total US_Anthro light extinction. The magnitude of the projected OilGas impairment is small at only 0.30 Mm^{-1}.

2.2.3 North Dakota Sector Contribution on the Clearest Days

The impairment caused by North Dakota sectors can also be compared to the overall species light extinction projection for 2028. The following is a breakdown of species light extinction: US anthropogenic (US_Anthro), International anthropogenic (Int_Anthro), Natural, prescribed wildland fire (US_RxWildlandFire), US wildfire, and Canada Mexico Fires (CanMexFire) is discussed in detail and is included in Section 1.2. The following breakdown shows the impairment caused by the North Dakota sectors as compared to the species light extinction for the 2028OTB scenario. US_Anthro sources have been broken down into the following sectors: North Dakota electrical generating utilities (ND EGU);

North Dakota Oil and Gas point and area sources (ND OilGas); North Dakota mobile onroad, non-road, rail, and commercial marine vessels (ND Mobile); Other North Dakota point sources (ND NonEGU); all remaining anthropogenic emissions including fugitive dust, agriculture, agricultural fire, residential wood combustion, and all remaining nonpoint sources (ND RemainAnthro); all US_Anthro minus the North Dakota sectors (Remaining US); and the Boundary Conditions from US emissions (BCUS). The species breakdown for all US_Anthro sources and sectors was limited to ammonium nitrate and ammonium sulfate. Therefore, impairment from the species of coarse mass, elemental carbon, organic mass, sea salt, and soil for all US_Anthro sources (including North Dakota sources) are included in the "Remaining US" row for Table 19 and Table 20. Note that Tribal oil and gas emissions are assigned to the ND OilGas category.

Table 19: LWA Sector and Source Category Contributions to Species Light Extinction on Clearest Days

Sector	Ammonium Nitrate	Ammonium Sulfate	Coarse Mass	Elemental Carbon	Organic Mass	Sea Salt	Soil	Grand Total
ND EGU	0%	1%	--	--	--	--	--	**1%**
ND OilGas	2%	3%	--	--	--	--	--	**5%**
ND Mobile	0%	0%	--	--	--	--	--	**0%**
ND NonEGU	0%	0%	--	--	--	--	--	**0%**
ND RemainAnthroND	1%	1%	--	--	--	--	--	**1%**
Remaining US	1%	1%	8%	1%	2%	0%	1%	**14%**
BCUS	0%	0%	--	--	--	--	--	**0%**
Int_Anthro	**8%**	**18%**	**10%**	**3%**	**1%**	**0%**	**1%**	**41%**
CanMexFire	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**1%**
Natural	**4%**	**9%**	**1%**	**1%**	**6%**	**2%**	**0%**	**23%**
US_RxWildlandFire	**1%**	**3%**	**0%**	**1%**	**6%**	**0%**	**0%**	**12%**
US_WildFire	**0%**	**0%**	**0%**	**0%**	**1%**	**0%**	**0%**	**1%**
Grand Total	**17%**	**36%**	**19%**	**7%**	**17%**	**2%**	**2%**	**100%**

Table 19 shows the percent breakdown of the total species light extinction contributions from different source categories and sectors at LWA. US_Anthro sources contribute to 22% of the total light extinction, with approximately 3% and 6% attributed to ammonium nitrate and ammonium sulfate, respectively. ND sectors contribute to 7% of the species light extinction. The largest source category contributor is ND OilGas at 5%, with ND EGU being approximately 1%. Int_Anthro contributes 41% to the species light extinction. The other significant contributors outside of these is Natural at 23% and prescribed fires at 12%.

Table 20: TRNP Sector and Source Category Contributions to Species Light Extinction on Clearest Days

Sector	Ammonium Nitrate	Ammonium Sulfate	Coarse Mass	Elemental Carbon	Organic Mass	Sea Salt	Soil	Grand Total
ND EGU	0%	0%	--	--	--	--	--	**0%**
ND OilGas	1%	5%	--	--	--	--	--	**5%**
ND Mobile	0%	0%	--	--	--	--	--	**0%**
ND NonEGU	0%	0%	--	--	--	--	--	**0%**
ND RemainAnthroND	0%	0%	--	--	--	--	--	**1%**
Remaining US	2%	4%	16%	3%	8%	0%	3%	**36%**
BCUS	0%	0%	--	--	--	--	--	**0%**
Int_Anthro	**5%**	**15%**	**4%**	**2%**	**3%**	**0%**	**1%**	**29%**
CanMexFire	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Natural	**2%**	**10%**	**5%**	**0%**	**7%**	**1%**	**0%**	**25%**
US_RxWildlandFire	**0%**	**0%**	**0%**	**0%**	**2%**	**0%**	**0%**	**3%**
US_WildFire	**0%**	**0%**	**0%**	**0%**	**1%**	**0%**	**0%**	**1%**
Grand Total	**11%**	**34%**	**25%**	**5%**	**20%**	**1%**	**4%**	**100%**

Table 20 shows the percent breakdown of the total species light extinction contributions from different source categories and sectors at TRNP. US_Anthro sources contribute to 42% of the species light extinction, with approximately 4% and 9% attributed to ammonium nitrate and ammonium sulfate, respectively. ND sectors only contribute to 7% of the species light extinction. The largest source category contributor is ND OilGas at 5%, with ND EGU being less than 1%. Int_Anthro contributes 29% to the species light extinction. The other significant contributor outside of these is Natural at 25%.

C.3 – Weighted Emissions Potential and Area of Influence Summary Results

1 Introduction and Background

Weighted Emissions Potential (WEP) and Area of Influence (AOI) products were made available for Regional Haze planning uses in the western U.S. The analysis was performed for the Most Impaired Days (MID) during each year of the 5-year period from 2014 through 2018 at 76 IMPROVE monitoring sites representing 116 Class I Areas (CIAs) in the 13 states of the contiguous WESTAR-WRAP region and neighboring states. The results were calculated for the 12WUS2 modeling domain aggregated to 36-kilometer resolution. Plots were provided for the 100m and 1000m trajectory heights and for a combined analysis in which data from all four trajectory heights were aggregated. For the purpose of this document the Department evaluated the combined analysis. Emissions originating from outside the 12WUS2 modeling domain were not included in this analysis. For example, the emissions from the nearby Canadian Electric Generating Units (EGU) are included but impacts from the Canadian oil sands are not. See Section 4.7 of the SIP for discussion on emissions from Canadian sources. International emissions were not placed into source categories and are only shown in Total Anthropogenic WEP figures.

The WEP is obtained by overlaying the extinction weighted residence time (EWRT) results with 2028 OTB emissions of light extinction precursors. The results were then normalized by the sum of the WEP for the total anthropogenic emissions. The dark green and light green isopleths in the WEP plots correspond to the 0.5 and 0.1 percent frequency, respectively, from the corresponding EWRT. This document shows the WEP analysis for nitrogen oxides (NO_x) and sulfur dioxide (SO_2) at each North Dakota and nearby CIA for five source sectors: Total Anthropogenic, Oil and Gas, EGUs, On-road mobile, and off highway mobile (Non-road). For each CIA, SO_2 for the on-road and off highway source sectors provided negligible results and were not included.

Complete species, including organic aerosol and elemental carbon, can be found for each western CIAs through the WRAP Technical Support System webpage.[1]

2 North Dakota

2.1 Theodore Roosevelt National Park

Figures 1 through 4 shows the WEP results for Theodore Roosevelt National Park.

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[1] Available at: https://views.cira.colostate.edu/tssv2/WEP-AOI/ (Last Visited December 30, 2020)

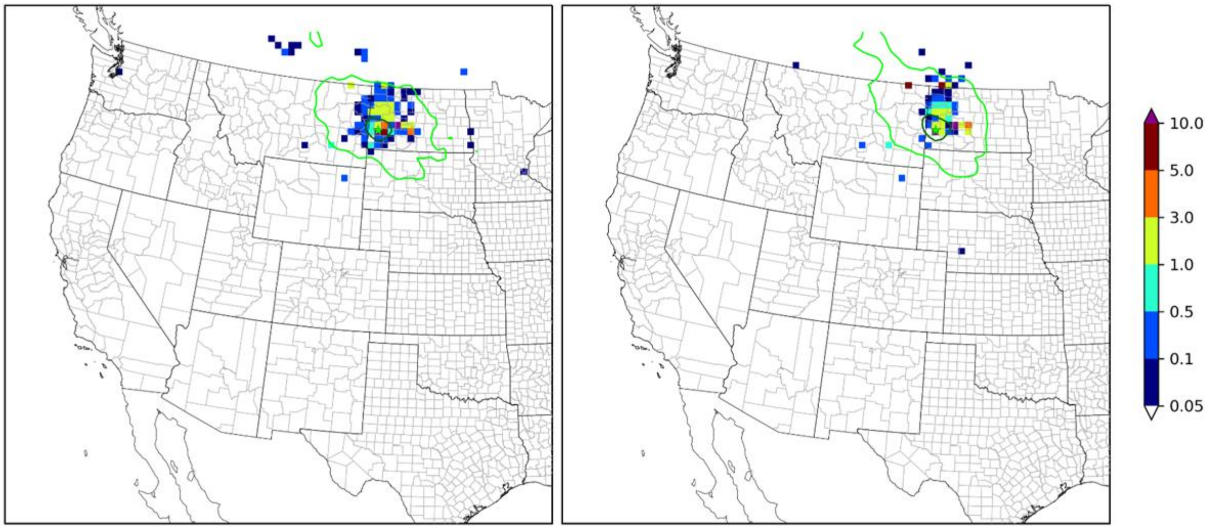

Figure 1: Total Anthropogenic WEP for NO_x (left) and SO_2 (right)

Figure 1 displays the NO_x and SO_2 WEP for total anthropogenic emissions. Most potential anthropogenic impairment comes from sources within North Dakota. A few areas outside of North Dakota show up at minimal levels, none of which were large enough to warrant additional review from North Dakota.

It is difficult to determine any individual sector impacts when looking at all source sectors combined, therefore, Figures 2 through 4 have been provided to show the results at the source category level for Theodore Roosevelt National Park.

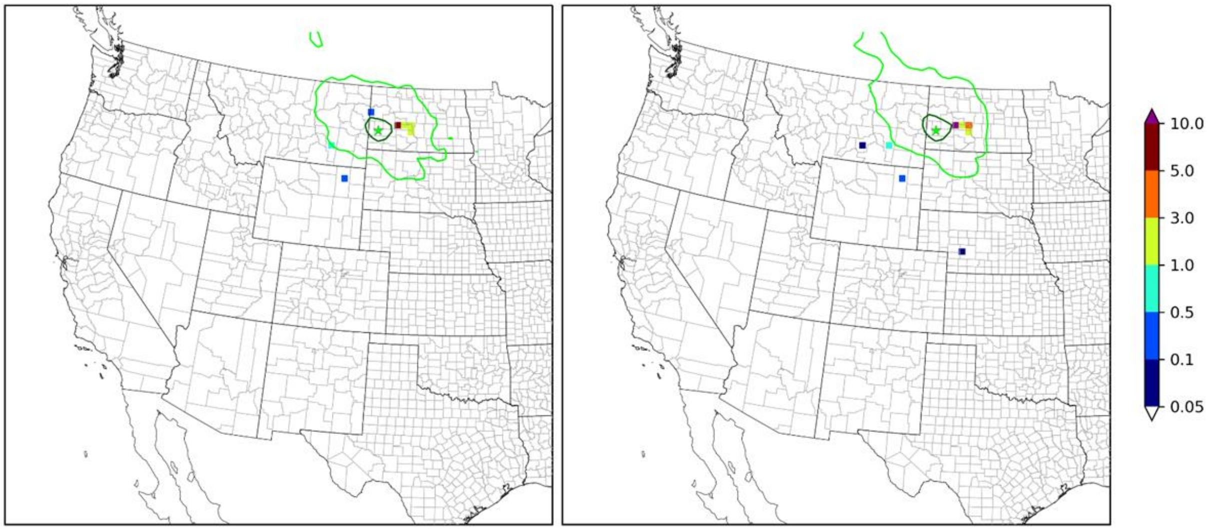

Figure 2: EGU WEP for NO_x (left) and SO_2 (right)

As displayed in Figure 2, most of the potential EGU impairment comes from sources within North Dakota. The potential impairment contribution from EGUs outside of the state were too minor to warrant further review from North Dakota during this planning period. Emissions from North Dakota EGU activity are included in Section 4.2.1 of the SIP.

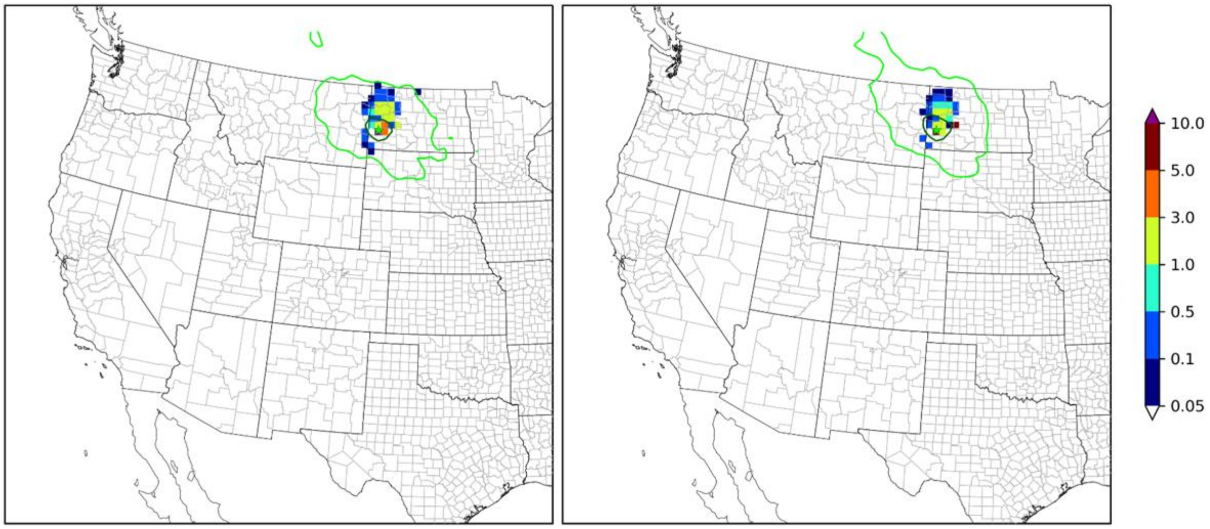

Figure 3: Oil and Gas WEP for NO_x (left) and SO_2 (right)

Figure 3 indicates that the potential impairment from the oil and gas sector comes from sources located within the state, with some very minor potential contributions along the Montana border. As such, oil and gas sources outside of the state did not warrant further review. Emissions from North Dakota oil and gas activity are included in Section 4.3.1 of the SIP. North Dakota is monitoring the development of the oil and gas field and will address impacts from this sector in future planning periods, as needed.

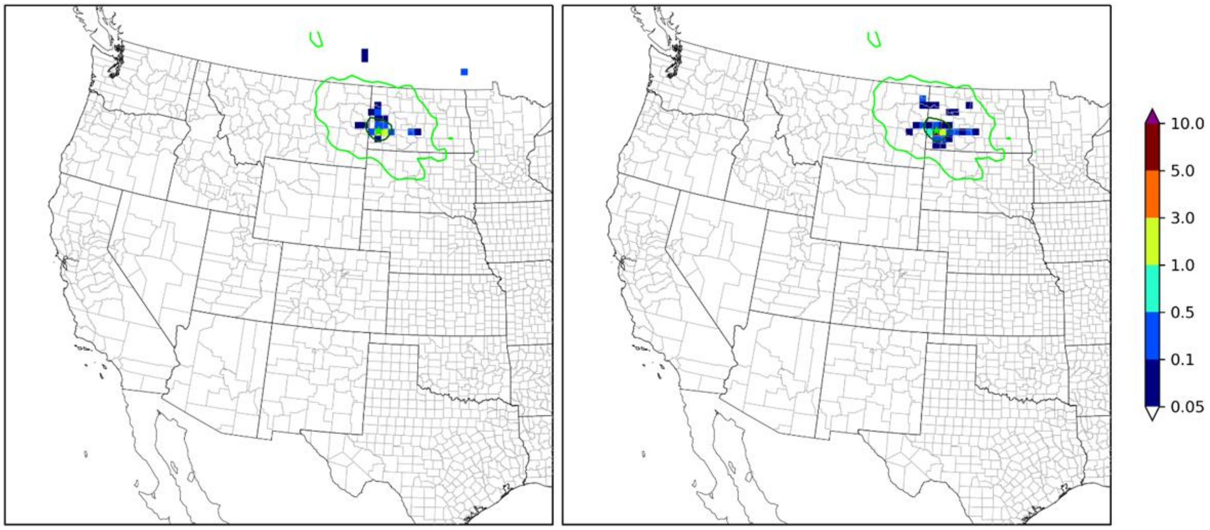

Figure 4: On-road (left) and Non-road (right) WEP for NO_x

Figure 4 shows that the contributions of the on-road and non-road sectors to potential impairment are minimal. As expected, much of the potential contribution follow the main transportation corridor in North Dakota, Interstate 94. Emissions from North Dakota non-road and on-road sectors are included in Section 4.4 and Section 4.5, respectively, in the SIP. The basis of the 2028 OTB mobile source emission inventories utilized both the WRAP 2014NEIv2 dataset as well as the 2014-2016 National Emissions

Modeling Collaborative 2016v1 future year 2028 inventory, with revisions per state agency input. North Dakota did not have any suggested changes to this dataset.

2.2 Lostwood National Wildlife Refuge

Figures 5 through 8 shows the WEP results for Lostwood National Wildlife Refuge.

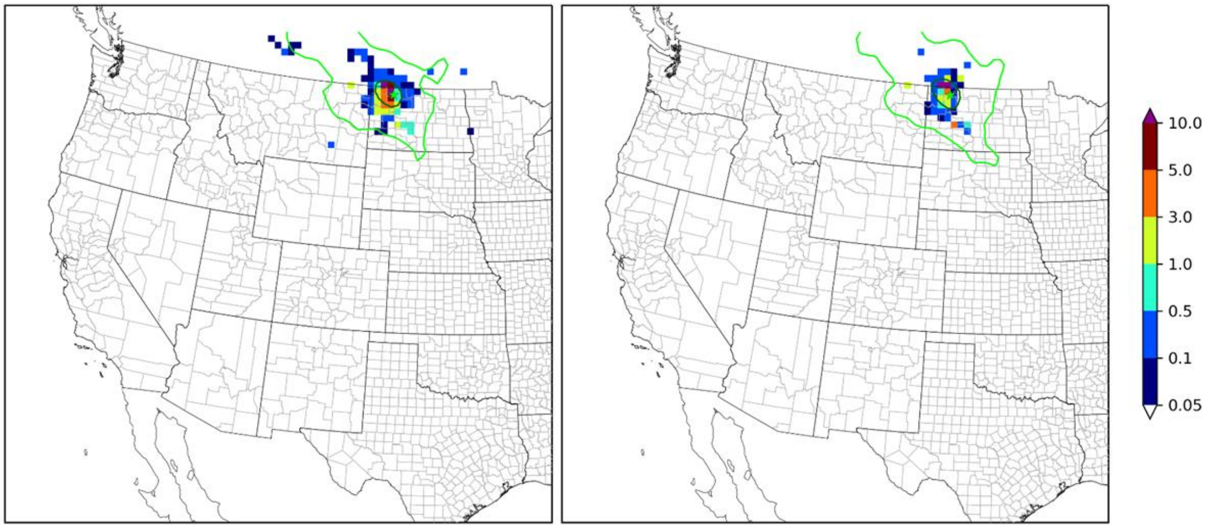

Figure 5: Total Anthropogenic WEP for NO_x (left) and SO_2 (right)

Figure 5 displays the NO_x and SO_2 WEP for total anthropogenic emissions. Most potential anthropogenic impairment comes from sources within North Dakota and just north of the Canadian border. International contributions are not able to be addressed. Potential impairment from Montana source's is minimal, not warranting additional review.

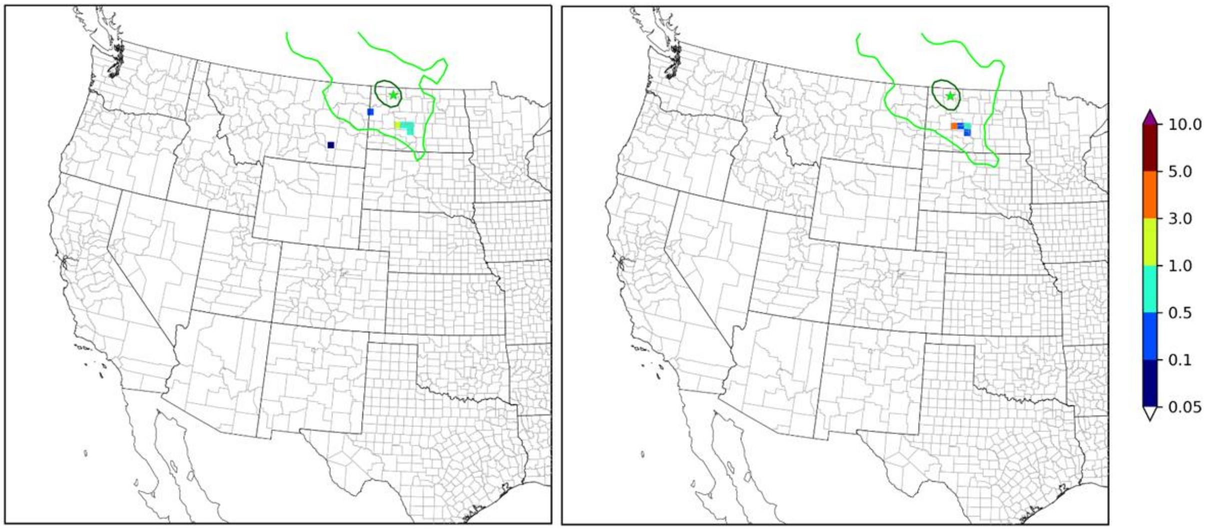

Figure 6: EGU WEP for NO_x (left) and SO_2 (right)

Figure 6 shows that the only EGU sources with an impairment potential that warrants review are located within North Dakota. The potential impairment contribution from EGUs outside of the state were too minor to warrant further review from North Dakota during this planning period. Emissions from North Dakota EGUs are included in Section 4.2.1 of the SIP.

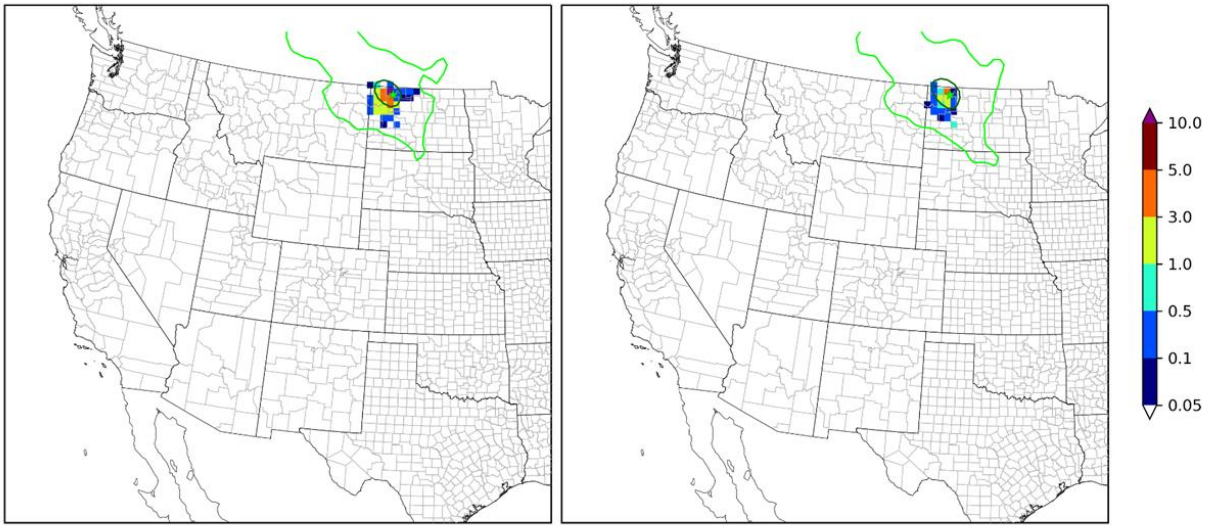

Figure 7: Oil and Gas WEP for NO_x (left) and SO_2 (right)

Figure 7 shows that no oil and gas area sources outside of the state have a significant potential to contribute to visibility impairment at Lostwood Wildlife Refuge. Emissions from North Dakota oil and gas activity are included in Section 4.3.1 of the SIP. North Dakota is monitoring the development of the oil and gas field and will address impacts from this sector in future planning periods, as needed.

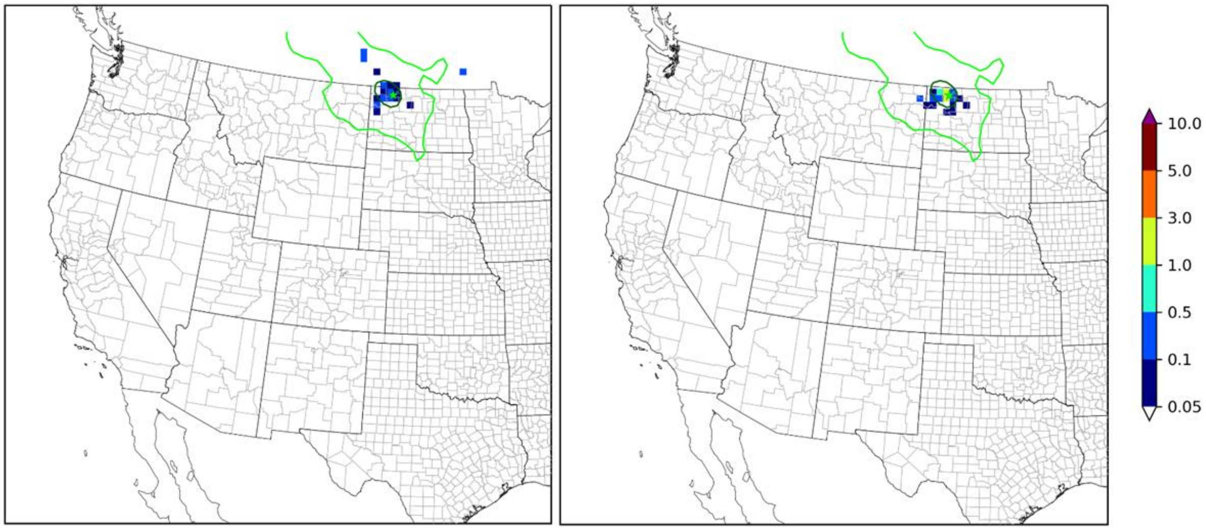

Figure 8: On-road (left) and Non-road (right) WEP for NO_x

Figure 8 shows that the contributions of the on-road and non-road sectors to impairment potentials are minimal and did not warrant review. Emissions from North Dakota non-road and on-road sectors are included in Section 4.4 and Section 4.5, respectively, in the SIP.

3 Minnesota

3.1 Voyageurs National Park

Figures 9 through 12 shows the WEP results for Voyageurs National Park. These results are also considered reflective of any potential impairment at Boundary Waters Canoe Area that emanates from North Dakota sources. This correlation was used since WEP results for Boundary Waters Canoe Area were not completed by WRAP. Additionally, Voyageurs National Park is located roughly 140 kilometers northwest of Boundary Waters Canoe Area. Therefore, Voyageurs National Park is closer to North Dakota and thus more likely to experience any potential impairment from North Dakota sources.

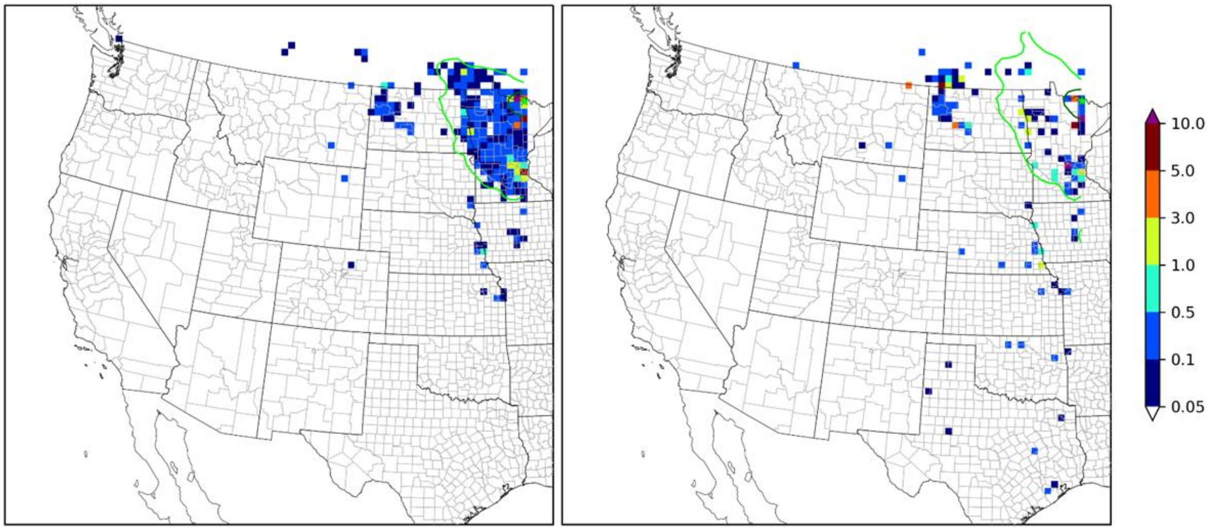

Figure 9: Total Anthropogenic WEP for NO_x (left) and SO_2 (right)

Figure 9 demonstrates that North Dakota sources have a minimal potential to impair visibility at Voyageurs National Park. The contributions along the northern border of North Dakota are Canadian contributions, which were not separated into source categories. Therefore, they are only shown in the Total Anthropogenic WEP.

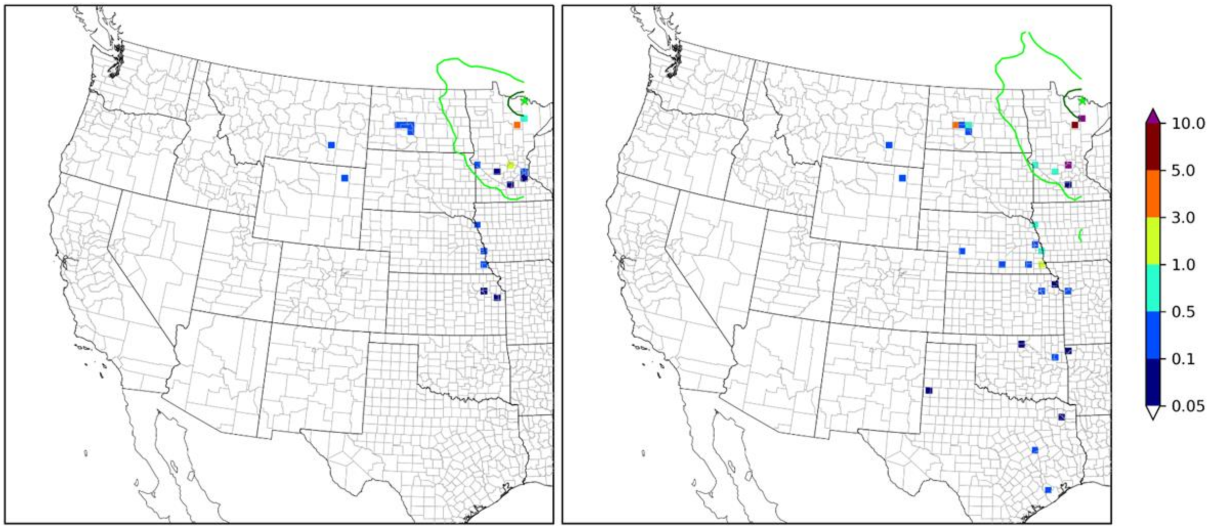

Figure 10: EGU WEP for NO_x (left) and SO_2 (right)

As stated before, Figure 10 shows that North Dakota sources have minimal contributions to impairment potentials at Voyageurs National Park. North Dakota EGU sources show some potential for impairment regarding SO_2, justifying the Department's consideration of additional controls for reasonable progress. The four-factor analyses can be found in Section 5.2, Appendix A, and Appendix B of the SIP.

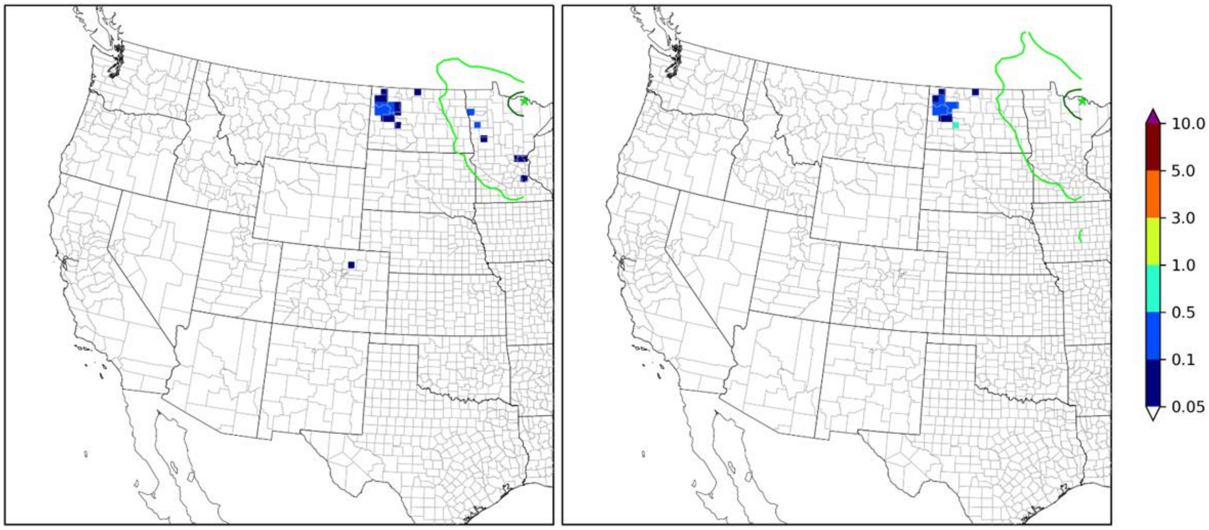

Figure 11: Oil and Gas WEP for NO_x (left) and SO_2 (right)

Figure 11 demonstrates that North Dakota oil and gas sources have a minimal impairment potential at Voyageurs National Park. Oil and gas activity is currently being monitored by the Department and is addressed in Section 5.2.11 of the SIP.

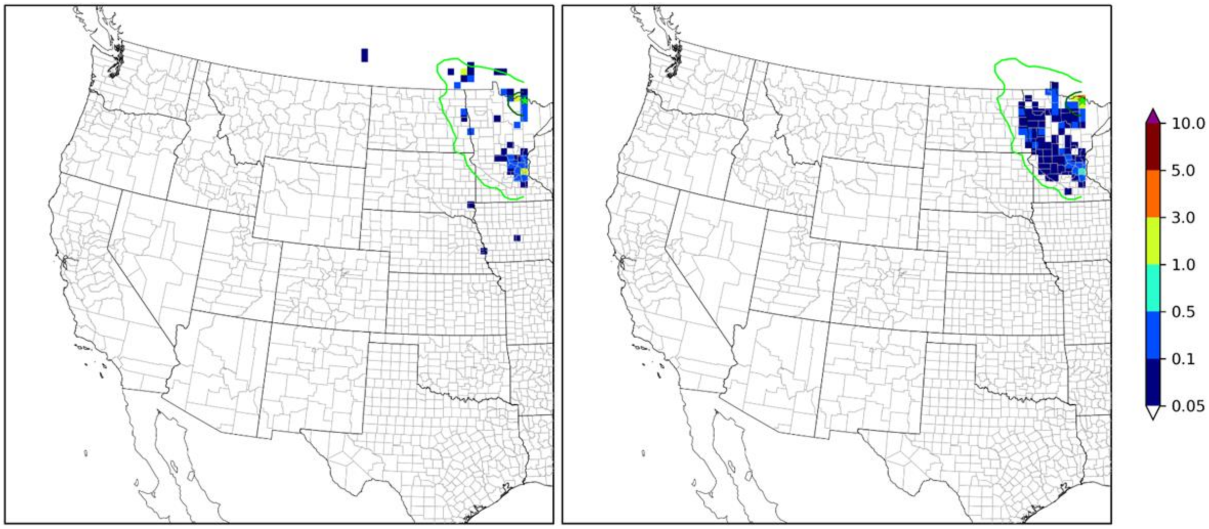

Figure 12: On-road (left) and Non-road (right) WEP for NO_x

As shown in Figure 12, much of the potential impairment from on-road and non-road sources comes from within Minnesota. On-road and non-road contributions to potential impairment at Voyageurs National Park are minimal along the North Dakota and Minnesota border and did not warrant review.

4 Montana

4.1 Medicine Lake Wilderness Area

Figures 13 through 16 shows the WEP results for Medicine Lake Wilderness Area.

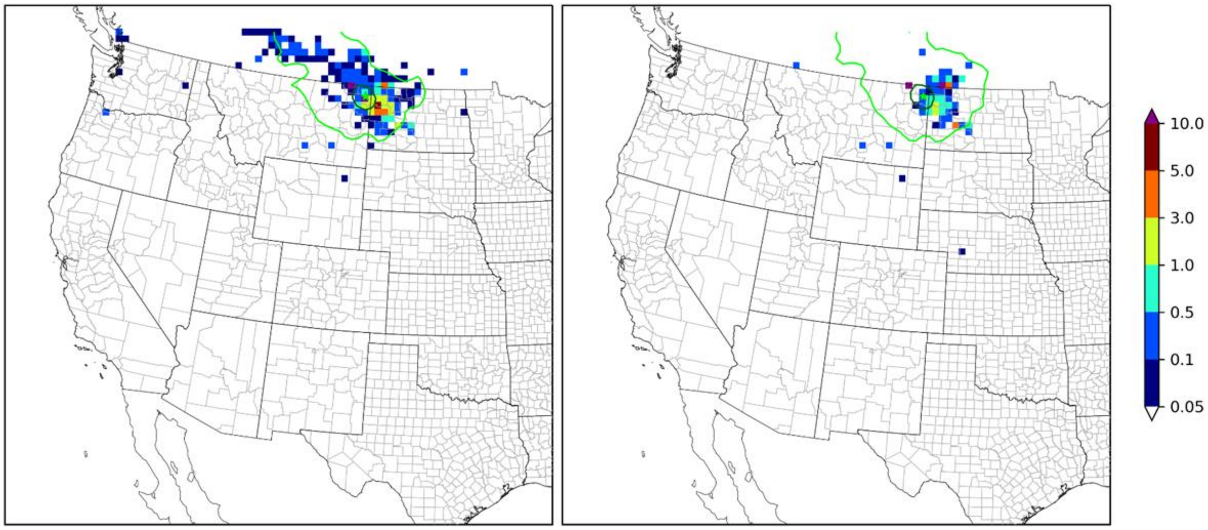

Figure 13: Total Anthropogenic WEP for NO_x (left) and SO_2 (right)

Figure 13 displays the NO_x and SO_2 WEP for total anthropogenic emissions. The following figures will demonstrate that North Dakota's contributions to impairment potential are limited to the EGU and oil and gas sectors, justifying the Department's consideration of additional controls for reasonable progress.

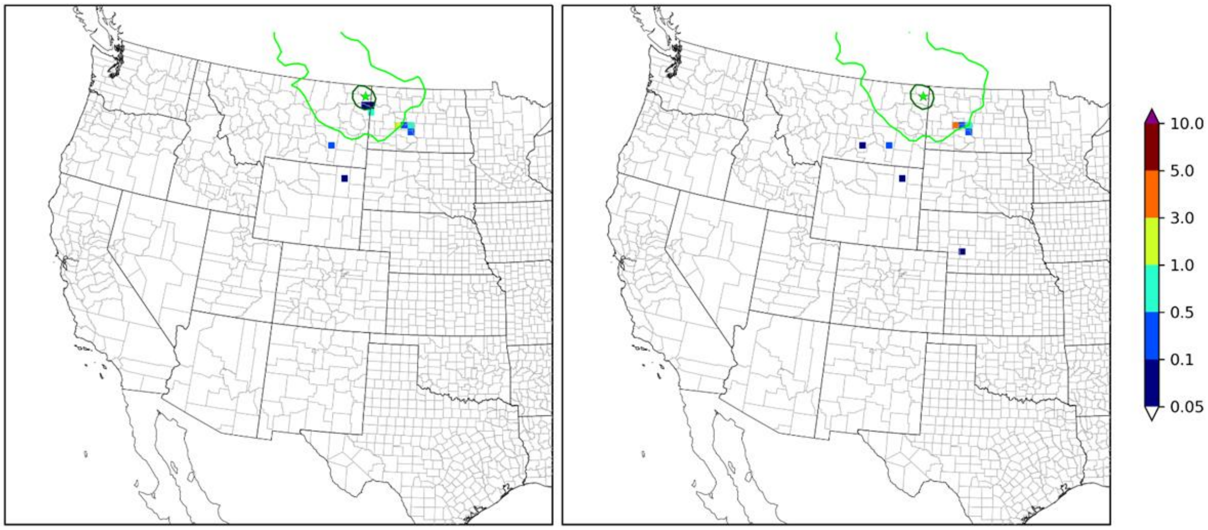

Figure 14: EGU WEP for NO_x (left) and SO_2 (right)

Figure 14 shows that North Dakota EGU sources have some potential for impairment regarding SO_2 and NO_X. This supports the Department's consideration of additional controls for reasonable progress on those sources, see SIP Section 5.2.

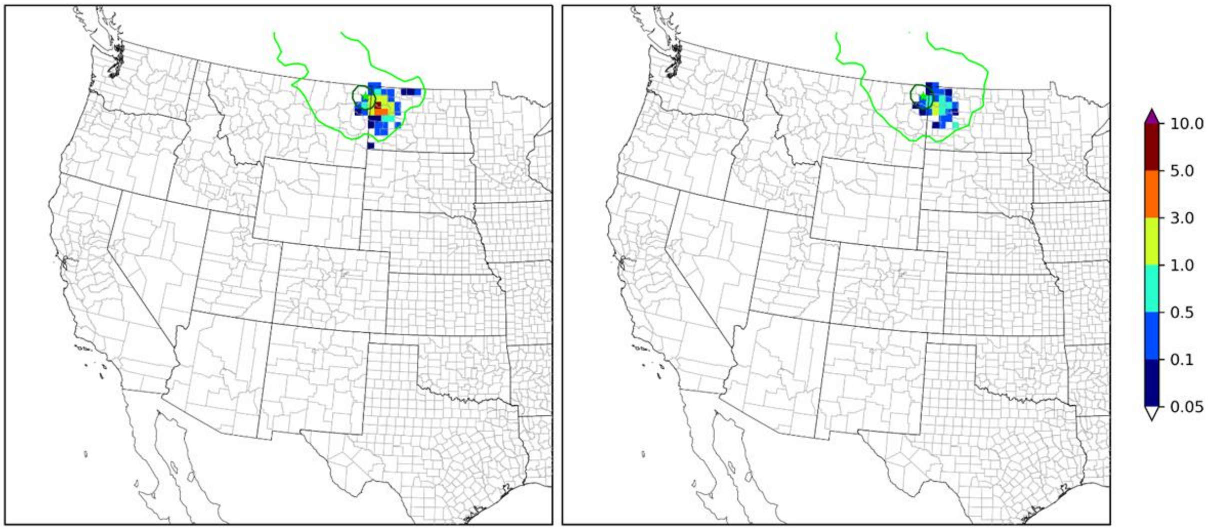

Figure 15: Oil and Gas WEP for NO_x (left) and SO_2 (right)

Figure 15 demonstrates the potential for impairment from North Dakota oil and gas sources, validating the Department's review of this activity. Oil and gas activity is currently being monitored by the Department and is addressed in Section 5.2.11 of the SIP.

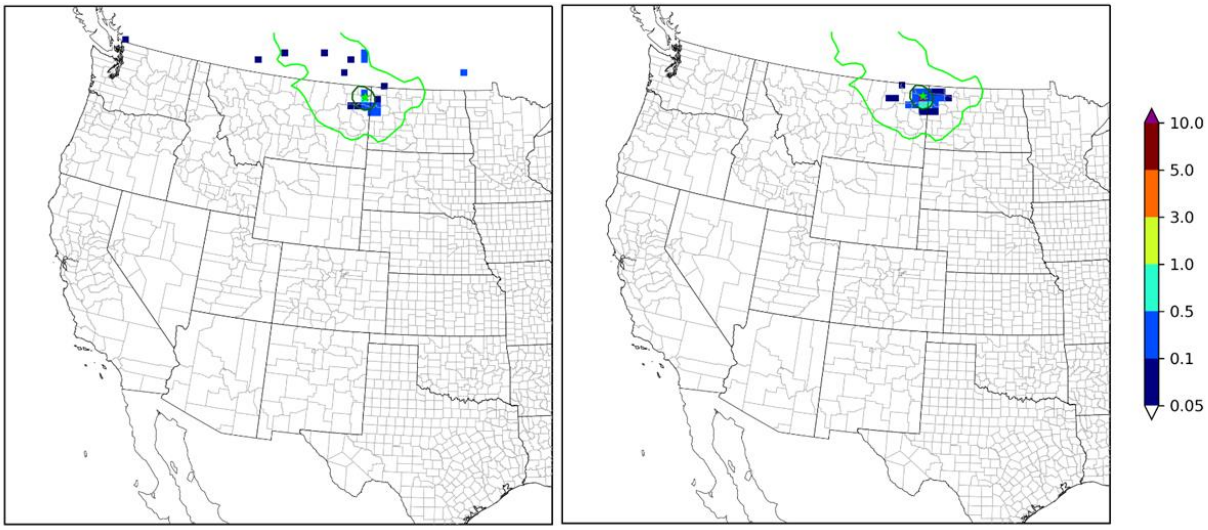

Figure 16: On-road (left) and Non-road (right) WEP for NO$_x$

Figure 16 indicates that the more significant potential impairment from on-road and non-road sources comes from Northeastern Montana and northwester North Dakota. Overall, on-road and non-road contributions to potential impairment at Medicine Lake Wilderness Area are minimal and did not warrant review.

4.2 UL Bend Wilderness Area

Figures 17 through 20 shows the WEP results for UL Bend Wilderness Area.

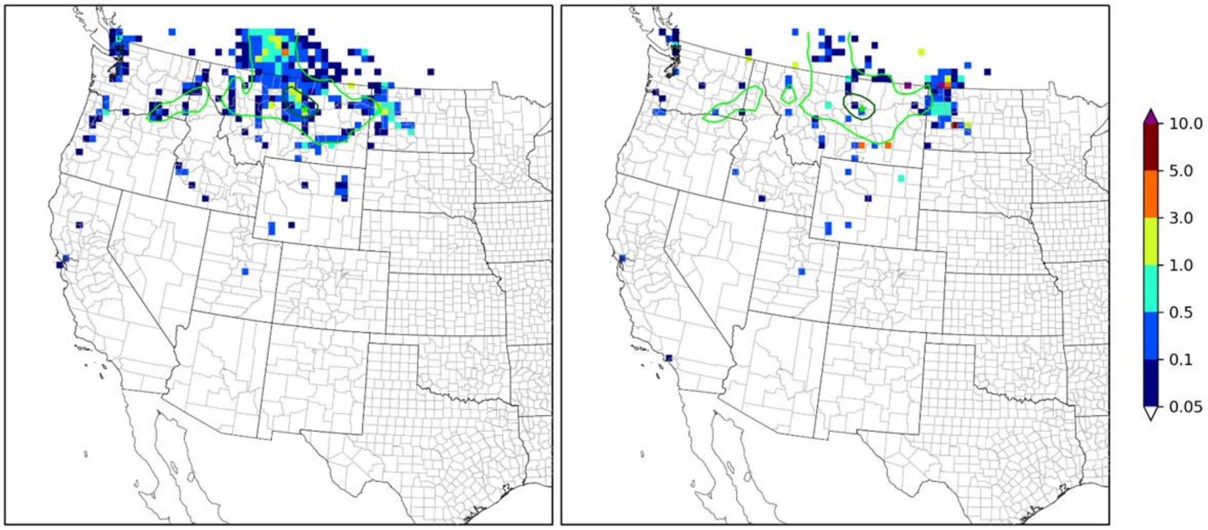

Figure 17: Total Anthropogenic WEP for NO$_x$ (left) and SO$_2$ (right)

Figure 17 displays the NO$_x$ and SO$_2$ WEP for total anthropogenic emissions. North Dakota contributions to the potential for impairment are minimal outside of the potential impact from EGU and oil and gas sectors.

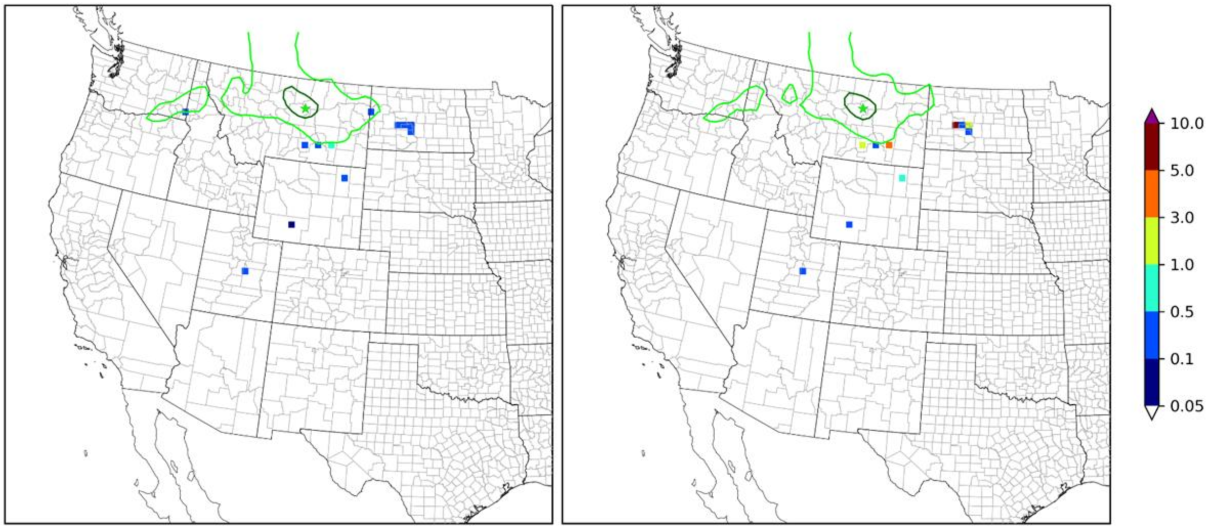

Figure 18: EGU WEP for NO_x (left) and SO_2 (right)

Figure 18 indicates that North Dakota EGU sources contribute to potential impairment regarding SO_2 at UL Bend Wilderness Area. This validates the consideration of additional controls for reasonable progress on those sources, see SIP Section 5.2.

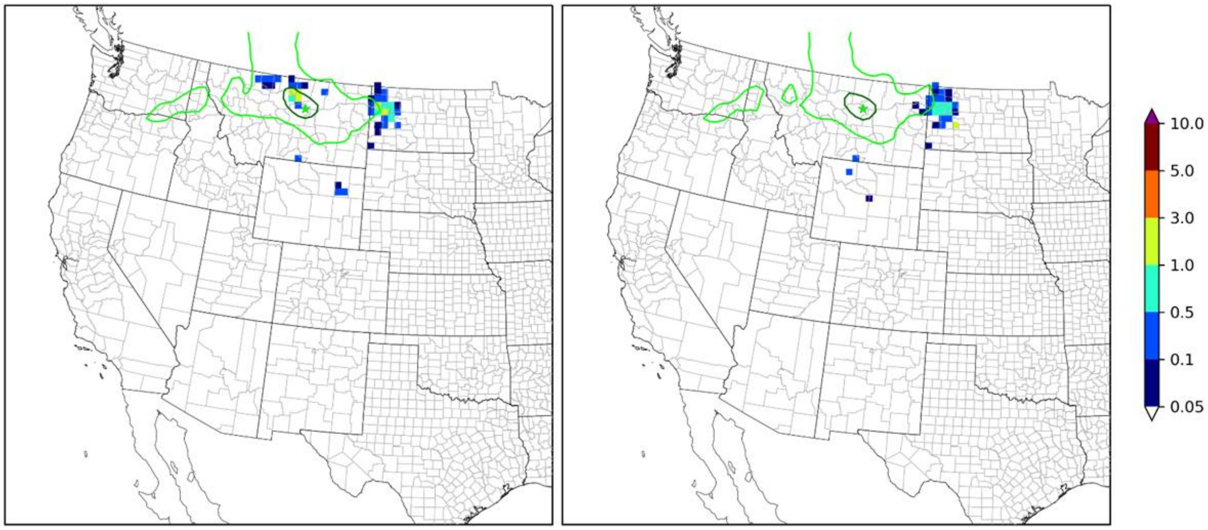

Figure 19: Oil and Gas WEP for NO_x (left) and SO_2 (right)

Figure 19 shows that North Dakota oil and gas sources have a minimal impairment potential at UL Bend Wilderness Area. Oil and gas activity is currently being monitored by the Department and is addressed in Section 5.2.11 of the SIP.

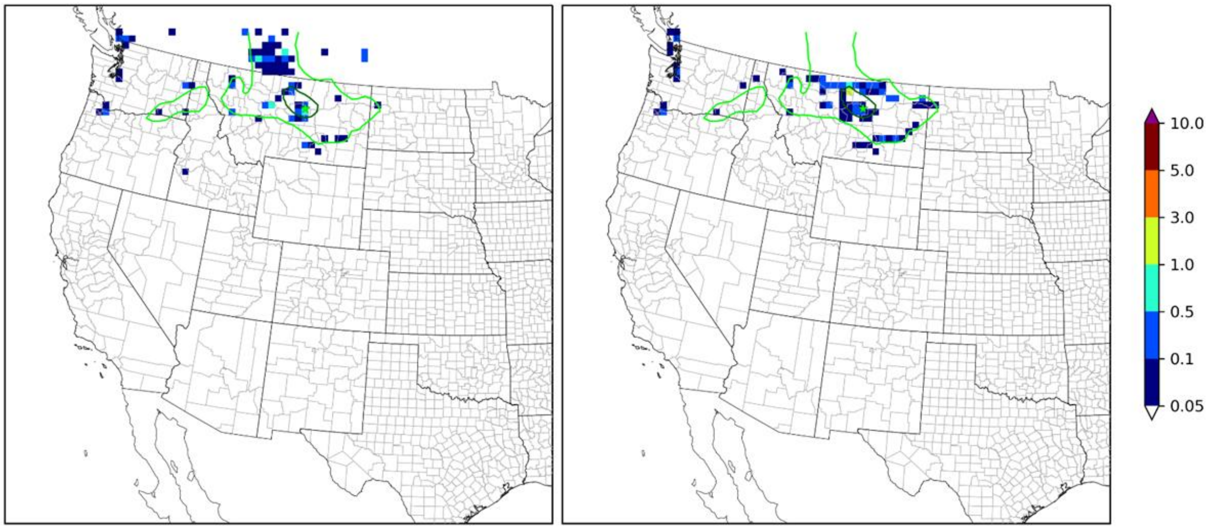

Figure 20: On-road (left) and Non-road (right) WEP for NO_x

Figure 20 indicates that the potential impairment from on-road and non-road sources at UL Bend Wilderness Area comes from within Montana. North Dakota on-road and non-road contributions to potential impairment are very minimal and did not warrant review.

5 South Dakota

5.1 Badlands National Park

Figures 21 through 24 shows the WEP results for Badlands National Park.

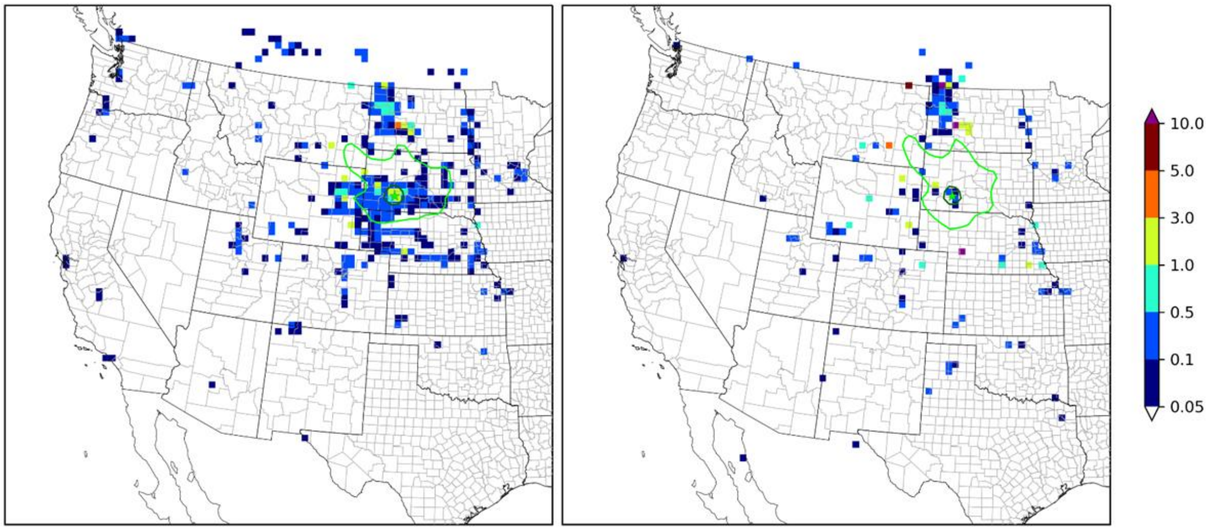

Figure 21: Total Anthropogenic WEP for NO_x (left) and SO_2 (right)

Figure 21 displays the NO_x and SO_2 WEP for total anthropogenic emissions. The following figures will demonstrate that North Dakota's contributions to impairment potential are limited to the EGU and oil and gas sectors, justifying the Department's consideration of additional controls for reasonable progress.

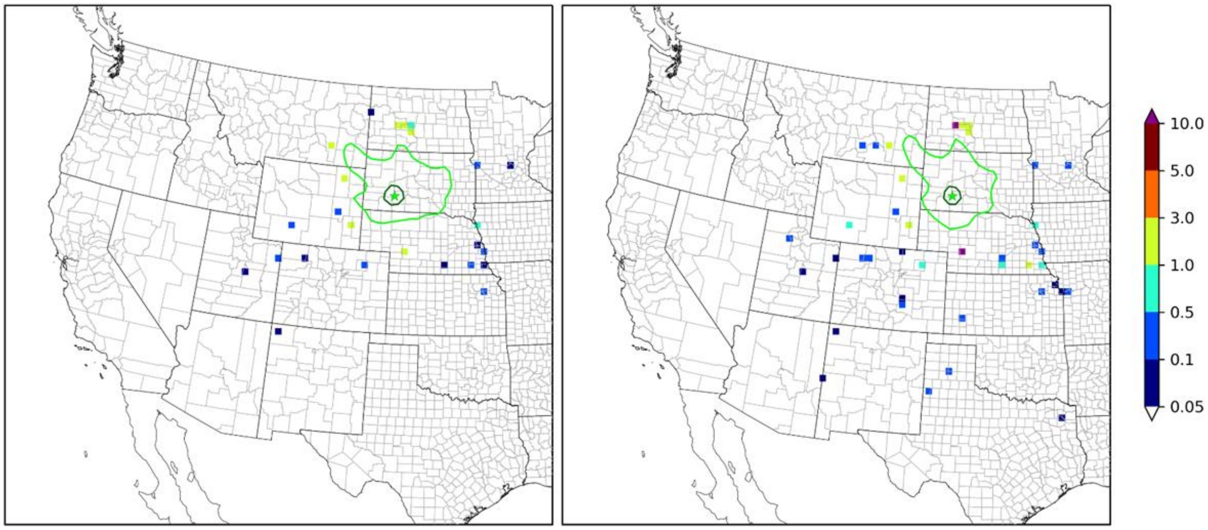

Figure 22: EGU WEP for NO_x (left) and SO_2 (right)

Figure 22 displays North Dakota EGU's impairment potential at Badlands National Park, supporting the consideration of additional controls for reasonable progress, see SIP Section 5.2.

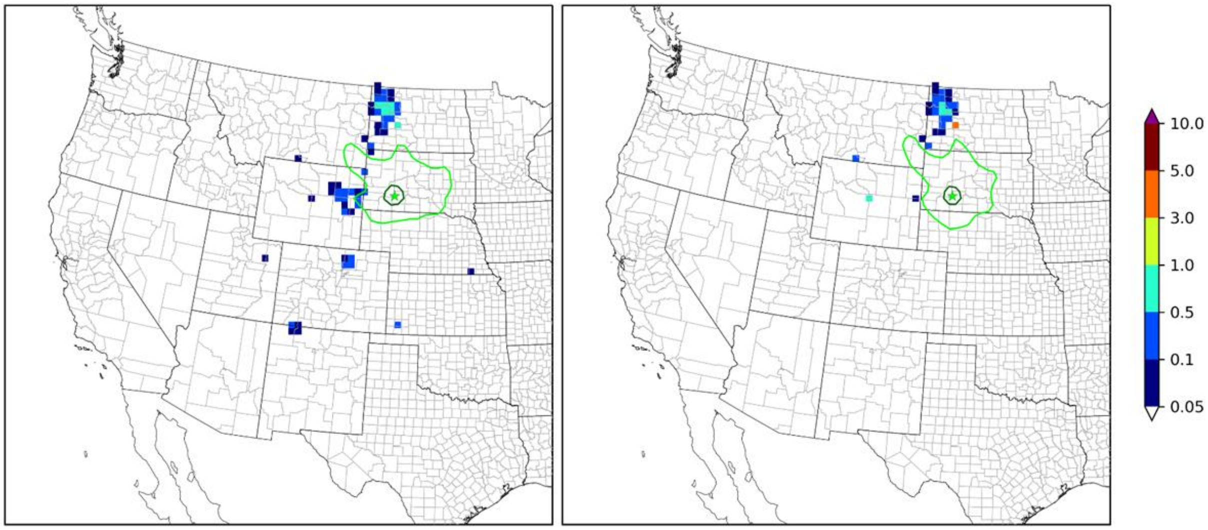

Figure 23: Oil and Gas WEP for NO_x (left) and SO_2 (right)

Figure 23 shows that North Dakota oil and gas sources have minimal impairment potential for NO_x, with some potential for SO_2. This supports the review of this sector. Oil and gas activity is currently being monitored by the Department and is addressed in Section 5.2.11 of the SIP.

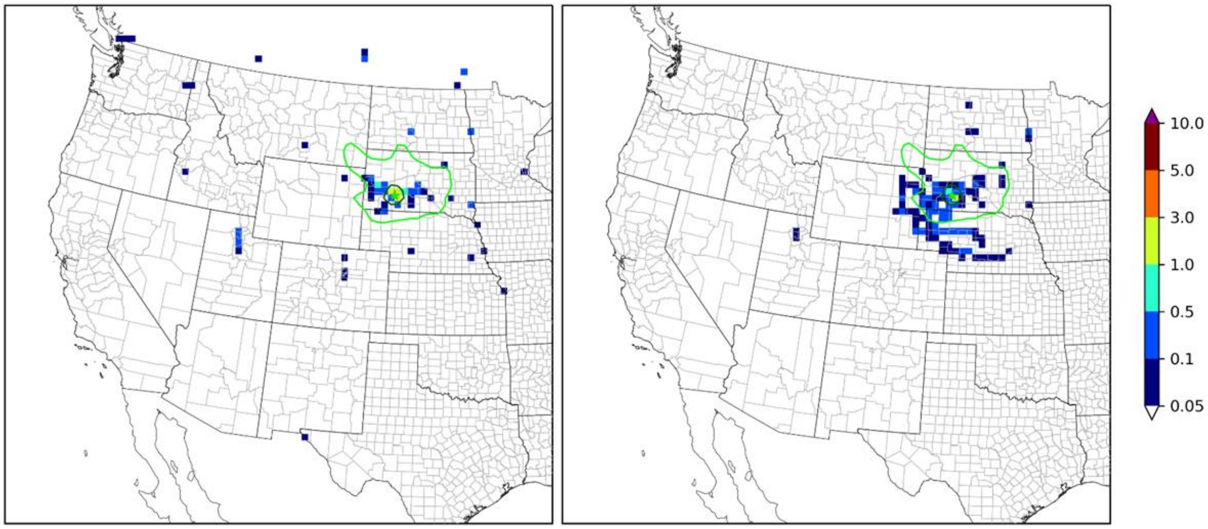

Figure 24: On-road (left) and Non-road (right) WEP for NO_x

Figure 24 indicates that the potential impairment from on-road and non-road sources at Badlands National Park largely comes from South Dakota, Wyoming and Nebraska. North Dakota on-road and non-road contributions to potential impairment at Badlands National Park are almost nonexistent and did not warrant review.

5.2 Wind Cave National Park

Figures 25 through 28 shows the WEP results for Wind Cave National Park.

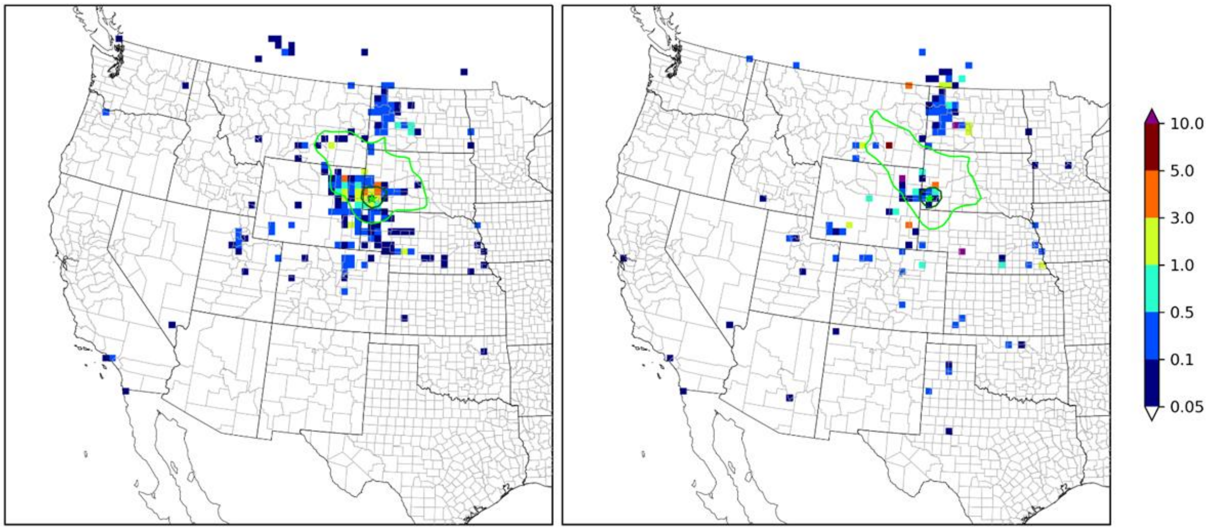

Figure 25: Total Anthropogenic WEP for NO_x (left) and SO_2 (right)

Figure 25 displays the NO_x and SO_2 WEP for total anthropogenic emissions. North Dakota contributions to the potential for impairment are minimal outside of the EGU and oil and gas sector.

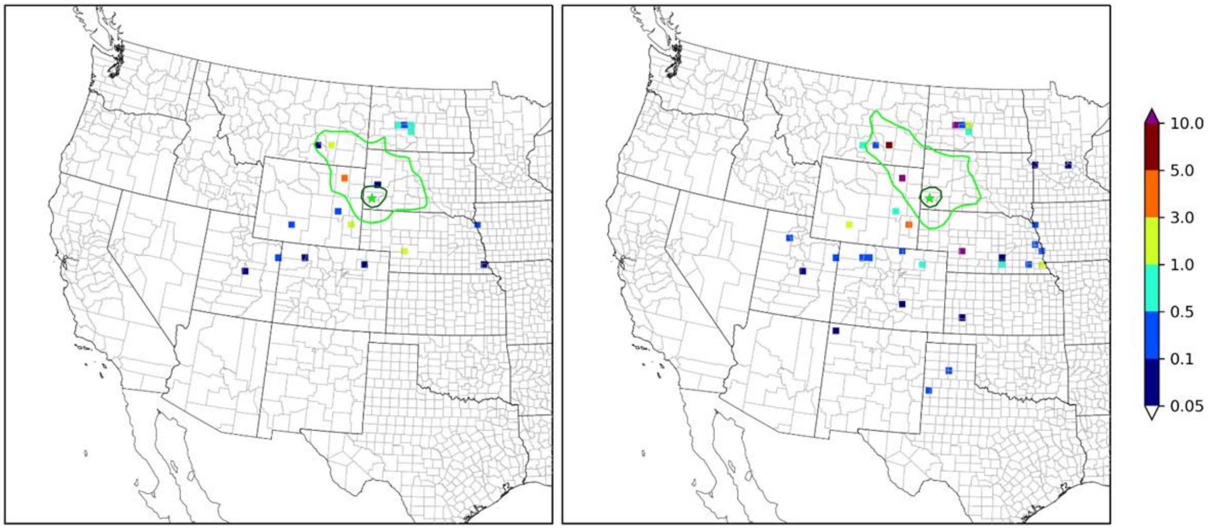

Figure 26: EGU WEP for NO_x (left) and SO_2 (right)

Figure 26 shows that North Dakota EGU sources contribute to potential impairment regarding SO_2 at Wind Cave National Park. This supports the consideration of additional controls for reasonable progress, see SIP Section 5.2.

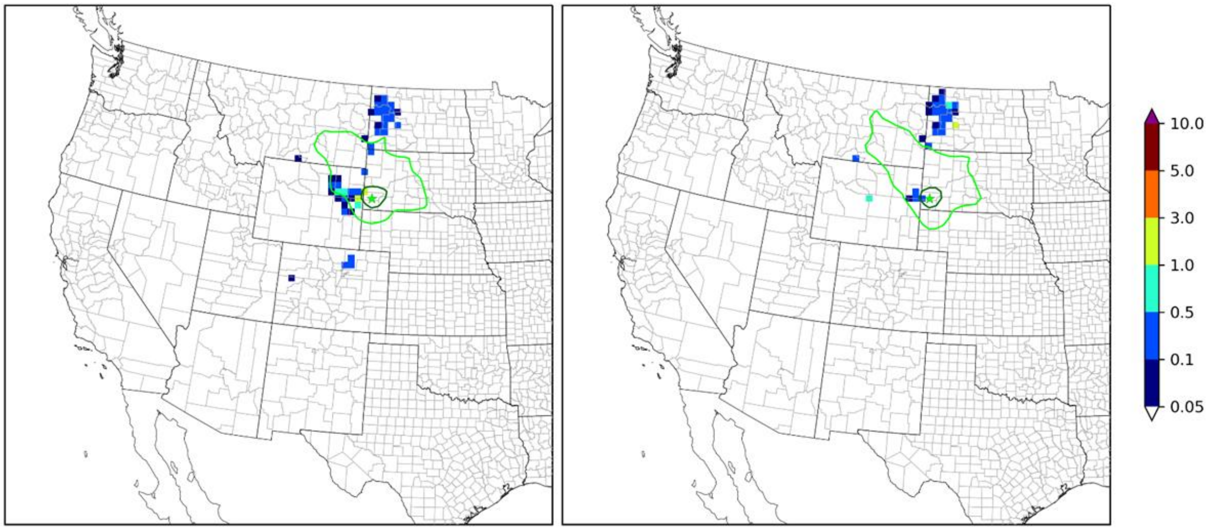

Figure 27: Oil and Gas WEP for NO_x (left) and SO_2 (right)

Figure 27 shows that North Dakota oil and gas sources have a minimal impairment potential at Wind Cave National Park. Oil and gas activity is currently being monitored by the Department and is addressed in Section 5.2.11 of the SIP.

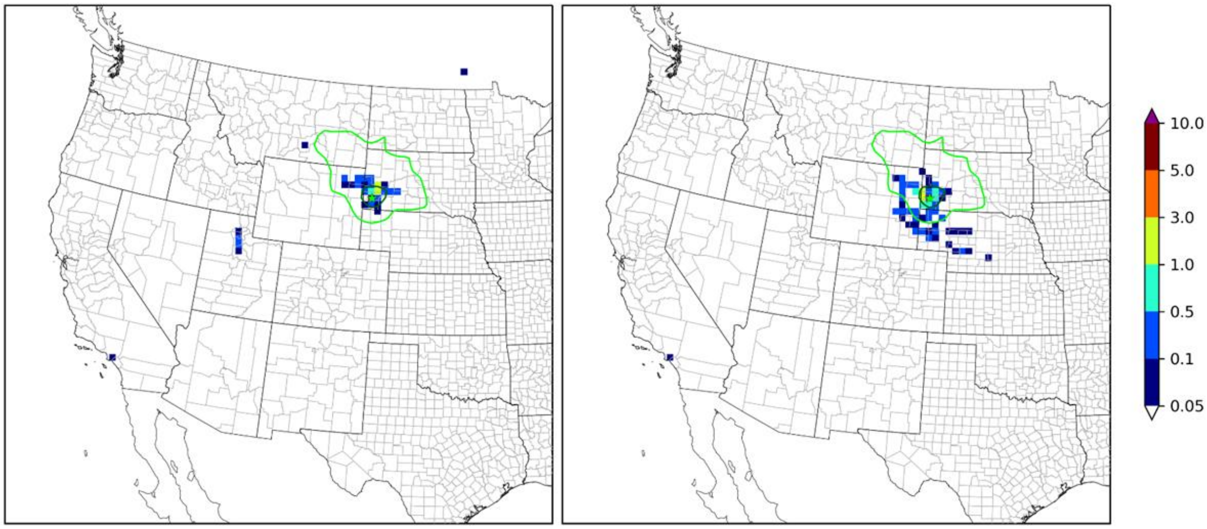

Figure 28: On-road (left) and Non-road (right) WEP for NO_x

Figure 28 indicates that the potential impairment from on-road and non-road sources at Wind Cave National Park largely comes from South Dakota, Wyoming and Nebraska. North Dakota has zero on-road and non-road contributions to potential impairment at Wind Cave National Park and did not warrant review.

6 Summary and Conclusions

The WEP analyses for Theodore Roosevelt National Park and Lostwood National Park support North Dakota's decision to evaluate the upstream oil and gas and EGU sources, as these are the major sectors that showed a potential for visibility impairment in the Class I areas. The WEP analyses also demonstrate that the potential impairment contribution from sources outside of North Dakota were minor and did not warrant further review from North Dakota during this planning period. The analyses of the nearby Montana, South Dakota, and Minnesota CIAs further support the decision to evaluate the oil and gas and EGU sources, as the potential for impairment was mostly limited to these sectors.

C.4 – WRAP Modeling Delays

February 8, 2021

To: WESTAR States and all WRAP member agencies

Re: Regional Haze modeling delays letter

Attached please find the letter from Ramboll U.S. Contracting - Environment and Health unit, detailing and explaining the reasons for delays in completing Regional Haze modeling under contract to WESTAR. The letter thoroughly describes the chronology of issues Ramboll experienced. The Regional Haze modeling effort for the 100+ Class I areas in the WESTAR-WRAP region is complex, involving a significant amount of data processing and assimilation from multiple data sources.

The modeling is largely complete at this point and Ramboll has made extra efforts to correct the cascade of problems at their expense. WESTAR-WRAP staff have been closely monitoring and sequencing the delivery of the modeling results for application in the Regional Haze SIPs and for the western regional modeling platform applications in the future. Ramboll is completing a comprehensive analysis to address western U.S. Regional Haze planning topics. As has been the case, WESTAR-WRAP staff are available to meet on the analysis and any issues with the delays.

The modeling effort has identified issues and lessons learned about the Regional Haze Rule requirements, affecting the process and timing of modeling for western U.S. Regional Haze planning:

- The delays in Summer and Fall 2019 prior to the Covid pandemic then cascaded into more delays in the 10 months from March 2020 to the present.
- To meet the Regional Haze Rule and planning guidance objectives to focus control strategies on U.S. anthropogenic emission contributions, the series of scenarios most affected by the issues in the letter (RepBase, 2028OTBa and 2002DynamicEvaluation) had to use those more computationally- and time-intensive source apportionment methods – that decision occurred in November 2019 in response to the national EPA modeling results. Those methods are necessary to separate fire and international anthropogenic emissions contributions at each Class I area for both the 2028 Reasonable Progress Goal visibility projections and to enable the “end-of-glidepath” adjustments. Those analyses now completed by Ramboll offer options for the Regional Haze SIP planners to analyze and consider in selecting Reasonable Progress Goals.
- WESTAR-WRAP members collaborated on the National Emissions Inventory Collaborative (the NEIC or “2016v1 + projections” modeling platform) at the same time the western Regional Haze modeling effort was underway. The two parallel processes certainly created some confusion and extra effort. While the NEIC data have utility in our modeling, mostly outside the WESTAR-WRAP region, for the overall required effort on Regional Haze modeling, the simultaneous projects were difficult to perfectly align, and issues emerged for individual states’ data.

Via E-Mail

February 8, 2021

Mary Uhl
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Western Air Resources Council (WESTAR)
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maryuhl@westar.org

Subject: Explanations for Delay in Western States Regional Haze Modeling

Dear Mary:

This letter documents and provides reasons for delays in the chronology of Ramboll's completion and delivery of the Regional Haze (RH) photochemical modeling results since late 2018, for the western states on the WRAP Technical Support System (TSS). The TSS is our delivery target since western states and other WRAP partners use it for Round 2 RH State Implementation Plans (SIPs) due July 2021. This work for WESTAR-WRAP has been done mainly under WESTAR Contract 19-01. First and foremost, I want to emphasize how much we value WESTAR-WRAP membership and the western states in particular as important clients and these delays in no way indicate a lack of commitment by Ramboll or us not placing this work as highest priority. This is the most important project that I and my staff have right now, and we are trying to finish delivery of high quality RH technical work products as quickly as we can.

The WRAP western state RH CAMx source apportionment is quite complex and complicated integrating numerous sources of data (e.g., 2014NEI, WRAP states data, EPA 2016v1 platform, natural and international emissions, data products of WRAP workgroups and projects etc.), because the vast majority of emissions affecting RH planning are out of the control of the states, but must be thoroughly assessed with photochemical modeling per EPA RH planning guidance. The work tasks in Contract 19-01 involved a lot of moving parts and pieces of data that needed to be properly implemented presenting multiple opportunities for mistakes. However, that is not an excuse as Ramboll has a reputation and track record on performing such complicated and high-quality air quality modeling studies.

In my over 40 years as an air quality consultant, I have never had a project that had so many setbacks for so many different reasons. Ramboll is not blameless in this as some delays are our fault and we have taken a financial penalty by all the re-running of modeling scenarios, not to mention the emotional and stressful aspects of these delays. But many of the delays have been unique and due to unforeseen circumstances that were out of our control, including:

- Federal government shut-down in December 2018 and January 2019 delayed getting EPA's 2014 modeling platform at the outset of the project.

- EPA's 2014 GEOS-Chem simulation that we planned to use for Boundary Conditions (BCs) was flawed with June & July SO2/SO4 overestimation and year-round ozone overestimation. As a result, we had to conduct our own unplanned 2014 GEOS-Chem simulation to correct it that took several months.

- Delays and data processing decisions at EPA in releasing the National Emissions Inventory Collaborative (NEIC) 2016v1 modeling platform and 2023 and 2028 future year emission projections caused delays in getting future year emissions, as well as errors in the data, as noted below.

- Ramboll modeling computer servers for this work are located in northern California. The Pacific Gas & Electric utility instituted Public Service Power Shutoffs (PSPS) to prevent wildfires that shut down the power to the computers doing the modeling during portions of September-October 2019.

- In November 2019, California Air Resources Board discovered errors in the 2014v2/RepBase fugitive dust emissions they provided that caused delays while we re-processed the emissions and re-ran model simulations.

- COVID-19 Shelter-in-place from March 2020 to the present disrupted and slowed down the modeling. It took a while to figure out how to work effectively remotely. Also with no one in the office, when a computer goes down, hangs or there is a need to mount a new disk to make disk space, there are longer delays than normal as someone has to make a trip to the office.

- In June 2020 we found that some anthropogenic state-controllable sources for RH planning were both incorrect and/or double-counted in the NEIC 2016v1 modeling platform data, in both of the key scenarios for RH planning, the already-completed RepBase and 2028OTBa projection scenarios in the WESTAR-WRAP modeling effort, that caused a 3-month delay (Jun-Jul-Aug 2020). The emissions had to be reviewed by Ramboll and the states for corrections, updated and fixed and SMOKE emissions modeling of re-done so new RepBase2 and 2028OTBa2 could be done.

- Because of the problems and reprocessing required for the NEIC 2016v1 and 2028 emissions, technical decisions were made by WESTAR-WRAP members in RH work groups, to change some of the emissions sector datasets to be used in the new RepBase2 and 2028OTBa2 scenarios from what was in Ramboll's contract necessitating re-processing and some additional delays. The effect of these decisions was non-zero in terms of Ramboll effort, but were timely and improved the representativeness of the RepBase2 and 2028OTBa2 modeling results for RH planning.

- Unprecedented wildfires in Northern California August through November 2020 interfered with staff working as $PM_{2.5}$ concentrations in excess of 200 $\mu g/m^3$ blanketed the region making going outdoors and travel dangerous. Many staff were on-call prepared for evacuation and worked much less efficiently under stressful conditions.

- Coding errors in the Ramboll CAMx model caused two re-runs of the CAMx RepBase2 and 2028OTBa2 source apportionment simulations in late 2020. As these runs take ~28 days to run, each re-run can cause a 1-2 month delay as we have to debug what the error is, fix it and re-run.

Ramboll was originally teamed with a Subcontractor whose role was to do most of the SMOKE emissions modeling. The same Subcontractor had a similar role when Ramboll developed the WRAP WestJumpAQMS 2008 and IWDW-WAQS 2011 modeling platforms and performed well.

Attachment 1 has a chronology of events that occurred and caused delays in delivering products on schedule. Below we discuss how some of these specific events delayed some of the key project deliverables.

- The schedule for the first big deliverable was WRAP-WAQS Shake-Out 2014v1 CMAQ and CAMx platforms, model evaluation and Close-Out meeting by March 2019. The Close-Out meeting occurred in April 2019 and delivery of the 2014v1 platform to IWDW in May. The causes for these delays are as follows:
    - Initial contract award was received December 11, 2018, affecting the proposed schedule from Ramboll. If we have started December 1, 2018 as originally planned we likely would have noticed the missing files for EPA's 2014 platform on their ftp site before the unexpected government shut-down.
    - Federal government shut-down December 22, 2018 through January 25, 2019 that delayed getting the EPA 2014 modeling platform by over a month as the EPA ftp site did not include all of the files and EPA staff were unavailable to provide them.
    - In February 2019 we found that the EPA 2014 GEOS-Chem had overestimation issues and in March 2019 EPA re-ran June and July to fix one of the problems so that final 2014v1 CMAQ/CAMx simulations, MPE and database transfer were delayed from the March target timeframe until April-May 2019.
- The next big deliverables, as identified in the May 29, 2019 WESTAR 19-01 Amendment#2 (A2), was 2014v2 emissions modeling, 2014 GEOS-Chem modeling and 2014v2 CMAQ/CAMx modeling to be completed by July 2019 and Representative Baseline (RepBase) modeling to be completed by August 2019. In reality, the first CAMx 2014v2 simulation was not completed until September 2019 and a series of emission updates were made so that the final 2014v2 CAMx base case was not completed until early December 2019. The first RepBase run was not completed until January 2020. The reasons for the delays of the final 2014v2 and initial RepBase simulations are as follows:
    - The July 2019 deadline for the 2014v2 platform was probably overly ambitious, but August should have been doable.
    - A key update in the 2014v2 platform was 2014 emissions for California that CARB provided to the SMOKE emissions Subcontractor in May 2019. In July the Subcontractor started asking questions and needing updates to the 2014 California inventory, so it appears they sat on and didn't look at the data for two months. 2014v2 SMOKE emissions processing was delayed as the Subcontractor's SMOKE modeler had many trips, such as to Korea (June), South America (July) and the EPA Emissions Inventory Conference in Dallas (August). Ramboll finally received the disk drive with the 2014v2 emissions on August 29, 2019. Note that Ramboll has worked very well with this Subcontractor in past studies (e.g., 2008 and 2011 platforms), but personnel

    changes appear to have affected their ability to deliver in a timely fashion. Ramboll ultimately took over the SMOKE emissions modeling so that it could be performed in a more timely manner.

  - Ramboll's initial CAMx 2014v2 simulation in September 2019 produced high ozone in northeast Wyoming that was traced to an emissions modeling error that allocated all the annual average O&G emissions to January in some counties.

  - The Subcontractor corrected the 2014v2 O&G emissions and a revised CAMx 2014v2 simulation was conducted in October 2019.

  - The California Air Resources Board informed us in November 2019 that there were errors in California's 2014v2/RepBase fugitive dust emissions and sent corrections that were incorporated into the RepBase emissions delaying the RepBase CAMx simulation until January 2020.

  - Also in November 2019, we discovered errors in the RepBase fire emissions files provided by the WRAP Fire & Smoke Work Group (FSWG) contractor that produced negative $PM_{2.5}$ emissions that had to be corrected by the FSWG contractor. Identification of these sort of issues for fire and many other source categories is a common and required task for assembly of air quality modeling scenarios in a platform. The evaluation and correction of the fire emissions files was another delay in the sequence to assemble RepBase.

  - Errors in EPA's proprietary and lightly documented AMET MPE Tool that EPA did not fix until January 2020 (and only EPA can fix), that we use to calculate performance statistics to be in compliance with EPA modeling guidance, meant that some of the model performance evaluation (MPE) products for the 2014v2 simulations were delayed.

- WESTAR Contract 19-01 Amendment#5 (A5) dated November 22, 2019 had several deliverables with the key ones as follows: (1) 2002 Dynamic Evaluation (2002DE) CAMx simulation completed by February 2020; (2) 2028OTB CAMx done by February 2020; and (3) CAMx 2028 source apportionment done by March 2020. There were numerous iterations in these simulations so that they were not finally completed until January 2021 for the following reasons:

  - After these milestones were set in the contract and in discussion with Regional Technical Operations Work Group Co-Chairs and WESTAR-WRAP staff and to meet objectives (e.g., obtain separate fire and U.S. anthropogenic emission contributions), the RepBase, 2028OTBa and 2002DE were turned into source apportionment simulations each of which takes ~28 days to run. Thus, the original schedule in A5 as the awarded contract required was physically impossible to meet given the changes in the run times from a CAMx standard model run (~5 days) to a source apportionment run (~28 days).

  - The delays in the 2014v2 and RepBase simulations meant that A5 modeling could not start until January 2020 instead of November 2019 as originally envisioned. This meant that the 2028OTB emissions and first CAMx 2028OTB simulations and visibility projections were completed in March-April instead of February 2020.

- In March 2020, shelter-in-place orders were mandated due to the COVID-19 pandemic that caused a slow-down in the modeling for several reasons:
    - People had to move their work stations from the office to home where they do not have as efficient a work space (e.g., copier machines, access to computers, etc.).
    - It took some time for people to figure out how to work from home effectively and efficiencies suffered.
    - Schools and day cares closed so parents had full time responsibility for their children and had to assist teaching from home.
    - When the high performance Linux computers in the office went down, hung or we needed to mount disks for backups to make more disk space, someone had to physically come in to the office and there were restrictions on how that could be done.
- The 2002 Dynamic Evaluation emissions development to backcast 2014 emissions to 2002 turned out to be a much bigger task than originally scoped by Ramboll and as awarded in the contract. It was deemed less critical than the 2028OTB modeling so was de-emphasized compared to getting the 2028 visibility projections done.
- How to treat fires in the 2028 MID projections caused some delays as there were modeled fires on some days in the IMPROVE MID; MID are selected in part to limit fire contributions.
- Double-counted and/or incorrect anthropogenic state-controllable sources for RH planning were discovered in the NEIC 2016v1 modeling platform due in part to EPA emissions processing of the 2016v1 files having O&G sources in the Non-EGU Point files instead of in the O&G files. Several WESTAR-WRAP region states also identified incorrect emissions rates in the 2016v1 files. This caused a series of state-by-state review and correction actions and a 3-4 month delay at a critical point in the regional haze modeling. This was probably the single biggest issue that caused delays in the project and required the following corrective action:
    - Ramboll conducts intensive review of the EPA 2016v1 platform emissions to identify the problems.
    - Western states review and update their RepBase and 2028OTBa emissions to now be RepBase2 and 2028OTBa2 inputs.
    - The WESTAR-WRAP project manager decides not to continue to use the NEIC 2028 projections for some source sectors (e.g., WRAP non-EGU Point), in response to requests from the WESTAR-WRAP region states, in 2028OTBa2 modeling and use 2014 instead.
    - Ramboll creates harmonized emission inventories for RepBase2 and 2028OTBa2 and conducts SMOKE modeling.
    - Re-run RepBase2 and 2028OTBa2 source apportionment simulations.

- WESTAR Contract 19-01 Amendment#10 (A10) provided funding for updating the RepBase2 and 2028OTBa2 emissions to address the EPA double counting issue and had a detailed schedule: (1) CAMx RepBase2 H-L SA run done by Nov 17, 2020; (2) CAMx 2028OTBa2 H-L SA run done by Nov 28, 2020; (3) CAMx 2028OTBa2 L-L SA run done by Dec 30, 2020. In reality, the final RepBase2 and 2028OTBa2 H-L SA runs were not done until January 2021 due to multiple re-runs:
    - The RepBase2 and 2028OTBa2 H-L SA simulations take approximately 28 days to run. The first RepBase2 and 2028OTBa2 H-L SA runs were completed within the A10 schedule (Nov 2020), but a series of issues were discovered that caused re-runs as follows:
        - The way lightning NOx emissions were treated was changed from millions of virtual point sources to a netCDF 3-D input to be more computationally efficient. However, a coding error in the CAMx v7.0 model caused the netCDF 3-D inputs not to work correctly and it adversely affected the source apportionment results necessitating going back to the virtual point source input approach.
        - The second round of RepBase2 H-L SA runs was performed in December 2020, but was invalid due to missing New Mexico Non-EGU Point emissions (Ramboll’s fault).
        - A third set of RepBase2 and 2028OTBa2 simulations were conducted the end of December 2020 into January 2021 and another coding error was discovered in CAMx v7.0 that dropped point source SO2 emissions.
        - The fourth set of RepBase2 and 2028OTBa2 H-L SA simulations finished in late January 2021 and were post-processed and transferred to the TSS by end of January.

I hope you find this letter useful in helping to explain why the regional haze modeling for the WESTAR-WRAP region is delayed. I believe these issues are behind us and the regional haze modeling results are now being populated onto the WRAP TSS. I do not foresee any remaining modeling or data delivery issues for the remaining tasks over the next 2-3 months, and Ramboll is closely coordinating with WESTAR-WRAP staff and the RTOWG Co-Chairs.

If you need more information or want me to personally talk to EPA or any of the States with WESTAR-WRAP staff in attendance, please let me know as I am always available and always try to live up to my commitments and responsibilities.

Best Regards,

Ralph E. Morris
Managing Principal
Central West Business Unit (CA-UT-CO)
Ramboll Environment and Health
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cc. Tom Moore

Attachment 1. Timeline of events that caused delays in the WRAP western states regional haze modeling.

Approximate Date	Event
Dec 11, 2018	Initial WESTAR Contract 18-12 to development 2014 Shake-Out platform was received 10 days after project start date (Dec 1, 2018)
Dec 2018-Jan 2019	Federal government shut-down Dec 22, 2018 – Jan 25, 2019 caused over a month plus delay in getting all files from EPA's 2014 modeling platform as the 2014 platform files on the EPA ftp site were incomplete.
Feb 2019	Found that EPA's 2014 GEOS-Chem run that was planned to be used for BCs was flawed as it had too high SO2/SO4 in Jun & Jul and overstated O3 year-round. This meant Ramboll had to perform an unplanned 2014 GEOS-Chem run that took several months to complete.
Mar 2019	EPA re-runs GEOS-Chem for Jun & Jul without volcano eruption fixing Jun & Jul SO2/SO4 overestimation problem in BCs but causing delays in delivering the 2014v1 Shake-Out modeling platform in March 2019.
Jun – Aug 2019	2014v2 SMOKE emissions modeling delayed 3 months due to unavailability of Subcontractors SMOKE modeler.
Sep 2019	Corrections needed for error in SMOKE emissions modeling of 2014v2 (overstates Wyoming Jan O&G emissions) caused another month delay.
Sep – Oct 2019	PG&E Public Service Power Shutoffs (PSPS) cut-off power to Ramboll's Linux computers in their Novato, CA office shutting down progress on 2014v2, RepBase2 and 2028OTB modeling.
Nov 2019	California Air Resources Board informs us that California Fugitive Dust emissions are in error in 2014v2/RepBase and sends update that caused delays.
Nov 2019	The RepBase fires from the FSWG have errors that produce negative $PM_{2.5}$ emission that need to be fixed
Dec 2019	EPA's AMET MPE tool does not work right and does not generate all the MPE products that are needed. EPA AMET contact goes on holiday and issue is not fixed until after they come back in Jan 2020.
Jan 2020	Modeling for 2028OTB and 2002DE that was supposed to start in November 2019 started in Jan 2020 instead due to delays and finishing up 2014v2 and RepBase modeling.
Mar 2020 - present	COVID-19 shelter-in-place disrupts modeling as people can no longer go to the office and must work from home. That reduces efficiency and modeling takes longer due to more computer down time.
Apr – May 2020	Extra time to determine how to treat modeled fires in visibility projections for the MID that are not supposed to have any episodic fire.
Jun – Sep 2020	Double counted sources in EPA's 2016v1 modeling platform caused a stop of the modeling and have Ramboll and the states re-work the emissions, fix them and redo the SMOKE modeling causing a 3-4 month delay.
Jun – Sep 2020	Given problems with EPA 2016v1 platform 2028 emission projections, WRAP decides to change what emissions are being used in 2028OTB emission scenarios from what was in Ramboll's contract.
Aug – Nov 2020	Massive wildfires in California caused extremely high $PM_{2.5}$ concentrations, limited travel in the region and caused inefficiencies in work.
Nov 2020	RepBase2 and 2028OTBa2 H-L SA runs have to be re-done due to coding error in CAMx v7.0 treatment of netCDF 3-D lighting NOx inputs.
Dec 2020	Second RepBase2 H-L SA run has to be re-done due to missing New Mexico non-EGU point source emissions.
Dec 2020 – Jan 2021	Third RepBase2 and 2028OTBa2 H-L SA runs have to be re-done due to coding error in source apportionment species mappings that dropped point source SO2 emissions.
Jan 2021	Fourth RepBase2 and 2028OTBa2 H-L SA runs have satisfied all the QA checks and appear correct so that 2028 visibility projections and other data will be transferred to the WRAP TSS by the end of January 2021.

Appendix D – (RESERVED)

Appendix E – Pre-Draft SIP revision State/FLM Communications

E.1 – Communications Log

Date	Method	Entities Involved	Topic/Problem	Outcome	Notes/Links	Added By:
6/12/2019	Phone (email setup)	NDDEQ/MTDEQ	informal coordination call for RH2 planning	ND/MT are taking similar approaches	20190612_MT-ND Regional Haze Call.pdf	David - 10/2/19
9/20/2019	Email	NDDEQ/NPS (Don S.)	North Dakota's Regional Haze progress and information	9/23 email	20190920_FW_ North Dakota's Regional Haze progress and information.pdf	David 12/4/19
9/20/2019	email	NDDEQ/EPAR8	ND RH progress and information	NDDEQ responsed via email	North Dakota's Regional Haze progress and information.pdf	David - 12/2/19
9/20/2019	email	NDDEQ/NPS (Don S.)	North Dakota's Regional Haze progress and information (follow-up)	N/A	20190920_RE North Dakota's Regional Haze progress and information.pdf	David 12/4/19
9/23/2019	Phone (email setup)	NDDEQ/SDDENR	informal call on RH2 4F work	SD 4F RH plan in line with ND stratagy	20190923_SD-ND Regional Haze Call (4F).pdf	David - 10/2/19
11/21/2019	email	NDDEQ/MPCA	MPCA email requst on 4F info	NDDEQ responsed via email	20191121_RE_ North Dakota 4-Factor Analysis(MPCA).pdf	David - 11/21/19
6/2/2020	Skype Meeting	NDDEQ/MTDEQ	Coordination call for RH2 planning	See Notes/Link	20200602_MT_ND State-to-State coordination call.pdf	David - 10/6/2020
9/30/2020	MS Teams Meeting	NDDEQ/EPAR8	ND RH progress and information	Shared PowerPoint	20201106 & 20201216_ North Dakota Regional Haze Round 2-EPApresentation.pdf	David - 10/6/2020
10/5/2020	MS Teams Meeting	NDDEQ/MTDEQ	RH SIP emissions inventory section discussion	Discussion on emission inventories in RH SIP	20201005_RH SIP emissions inventory section discussion.pdf	David - 10/6/2020
10/6/2020	MS Teams Meeting	NDDEQ/SDDENR	ND/SD RH progress and information	Shared PowerPoint	20201106 & 20201216_ North Dakota Regional Haze Round 2-EPApresentation.pdf	David - 10/6/2020
11/6/2020	MS Teams Meeting	NDDEQ/NPS (David P.)	ND RH progress and information	Shared PowerPoint	20201106 & 20201216_ North Dakota Regional Haze Round 2-EPApresentation.pdf	David - 11/6/2020
11/23/2020	MS Teams Meeting	NDDEQ/USFS	ND RH progress and information	Shared PowerPoint	'' (USFS attendees: Trent Wickman, Jill Webster)	David - 1/12/2021
12/15/2020	MS Teams Meeting	NDDEQ/NPS	ND RH progress and information	Shared PowerPoint	'' (NPS attendees: Kirsten King, Melanie Peters, Don Shepard, David Pohlman, Debra Miller, Andrea Stacy)	David - 1/12/2021
3/22/2021	MS Teams Meeting	NDDEQ/MPCA (Hassan Bouchareb)	ND and MN SIP revision progress and input	Discussed plans, estaimted timelines, and need for information exhange	Informal Discussion, no specific links	David - 4/5/2021
~Oct. 2020 - Current	Recurring MS Teams Meeting	NDDEQ/MTDEQ	ND and MT recurring discussions	Utilization of WRAP information and products for SIP revision	Informal Discussion, no specific links	David - 5/12/2021
6/9/2021	email	NDDEQ/MTDEQ	North Dakota's Regional Haze Determination on Impact of Facilities On North Dakota's Class I Area	Requested feedback on North Dakota RH SIP RPGs (no actions requested to date)	20210609_ND-to-MT-inputrequest.pdf	David - 6/15/2021
6/9/2021	email	NDDEQ/SDDENR	North Dakota's Regional Haze Determination on Impact of Facilities On North Dakota's Class I Area	Requested feedback on North Dakota RH SIP RPGs (no actions requested to date)	20210609_ND-to-SD-inputrequest.pdf	David - 6/15/2021
6/9/2021	email	NDDEQ/MPCA	North Dakota's Regional Haze Determination on Impact of Facilities On North Dakota's Class I Area	Requested feedback on North Dakota RH SIP RPGs (no actions requested to date)	20210609_ND-to-MN-inputrequest.pdf	David - 6/15/2021
7/8/2021	MS Teams Meeting	NDDEQ/EPAR8	ND RH progress update	Shared PowerPoint	20210708_RE_ North Dakota and EPA R8 Regional Haze Discussion.pdf	David - 8/23/2021

E.2 – Communications

Stroh, David E.

Subject: MT-ND Regional Haze Call
Location: 406-444-4647, access code: 6646861

Start: Wed 6/12/2019 11:00 AM
End: Wed 6/12/2019 12:00 PM

Recurrence: (none)

Meeting Status: Accepted

Organizer: Harbage, Rebecca

Hi all,

This is an informal coordination call between Montana and North Dakota to discuss regional haze topics that are of interest to both states. Specifically, we will talk about SIP work to-date as well as possible coordination on upstream O&G and international impacts.

I don't foresee us needing web access for the call, just the phone number and access code below.

……

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Join by phone

406-444-4647, access code: 6646861 (Helena Capitol Campus Region)

Find a local number

Conference ID: 6646861 (same as access code above)

Forgot your dial-in PIN? | Help

……

--
Rebecca Harbage
Air Quality Planner | 406-444-1472
P.O. Box 200901, Helena, MT 59620-0901
DEQ Montana Department of Environmental Quality

From: Stroh, David E. [mailto:deStroh@nd.gov]
Sent: Monday, June 03, 2019 9:10 AM
To: Harbage, Rebecca <RHarbage@mt.gov>
Cc: Bachman, Tom A. <tbachman@nd.gov>; Seligman, Angela N. <aseligman@nd.gov>; Semerad, Jim L. <jsemerad@nd.gov>
Subject: RE: Upcoming Regional Haze Webinar - Request

Rebecca,

North Dakota is interested in having a kick-off discussion with Montana per your email below. You are right, upstream O&G and international impacts are both very pertinent to ND and MT. A coordinated approach to address O&G from our states and others (CO/WY) would be ideal.

As a follow-up to our discussion, the morning June 12th works for us to have a kick-off meeting to discuss these topics plus anything else pertinent to RH.

If you would confirm with the MT RH staff this morning will work and respond with a proposed time – we will speak Wednesday, June 12th. Let me know if you want to discuss anything in advance of that date.

David Stroh
Environmental Engineer

701-328-5188 • destroh@nd.gov

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Be Legendary

918 E. Divide Ave. • Bismarck, ND 58501

From: Harbage, Rebecca <RHarbage@mt.gov>
Sent: Wednesday, May 29, 2019 5:46 PM
To: Stroh, David E. <deStroh@nd.gov>
Cc: Semerad, Jim L. <jsemerad@nd.gov>; Bachman, Tom A. <tbachman@nd.gov>
Subject: RE: Upcoming Regional Haze Webinar - Request

Thanks for the info, David.

As a follow-up, I have had “schedule call with North Dakota” on my to-do list for a while now. Would you all be interested in chatting with the Montana regional haze team at some point in the near future? We have had informal calls with both Idaho and Wyoming to check-in on progress and near-border Class I areas.

Specifically related to your email below, we’re interested in trying to coordinate with neighboring states on an approach for upstream oil and gas. We heard pretty strong feedback from the USFWS on our progress report that they expect something this round. From our conversations with Wyoming, I believe they’re also interested in some sort of coordinated approach. In addition – I know ND shares our concerns with international impacts from sources in Canada located very near the border and I would be interested in starting a conversation on that topic as well, although we don’t have a solid path forward developed yet (apart from waiting to see EPA’s modeling results).

If you're interested in getting a call on the calendar, let me know what works for you. If you're busy with Round 1 conversations right now and prefer to hold off, that works too.

Thanks again,
Rebecca

--
Rebecca Harbage
Air Quality Planner | 406-444-1472
Montana Department of Environmental Quality
P.O. Box 200901, Helena, MT 59620-0901

From: Stroh, David E. [mailto:deStroh@nd.gov]
Sent: Wednesday, May 29, 2019 1:06 PM
To: Harbage, Rebecca <RHarbage@mt.gov>
Cc: Semerad, Jim L. <jsemerad@nd.gov>; Bachman, Tom A. <tbachman@nd.gov>; Tom Moore <tmoore@westar.org>; Jay Baker <jbaker@utah.gov>; amber.potts@wyo.gov
Subject: RE: Upcoming Regional Haze Webinar - Request

Hello Rebecca,

Below is an email response on where North Dakota is at regarding the topics listed in your email (copied, as follows, with response in red text):

- Are you using Q/d as a screening tool? If so, what threshold are you using to determine which sources require further analysis? Did you include PM10 in your calculation of Q?
  - Yes, North Dakota used a Q/d of ~10 as the threshold for reaching out to sources. 10 sources were selected, 6 coal EGUs and 4 other facilities. The initial 4F request letters were sent in May 2018. (attached "Basin RH2 Letter.pdf" as example)
  - I checked North Dakota's selections vs the WRAP Q/d tool and it was in direct alignment with the sources selected.
  - PM10 was not included. ~80% of North Dakotas impairment is from sulfates and nitrates – so we had the sources focus on NOx and/or SOx (depending on the units which emit at their facilities).

- How many sources are "screened in" based on your selected threshold?
  - 10. No current plans to reach out to more.

- Are you focusing on any particular industrial sectors in this round of planning?
  - Not targeting anyone specifically, targeting those which are believed to impact Class I visibility.
    - North Dakota is hopeful to follow EPA/other states on addressing RH from the O&G upstream sector (wellsites).

  Sources selected:
  - 6 Coal EGUs (similar to Round 1).
  - 1 coal gasification facility
  - 1 NG compression facility (located near TRNP north unit "Class I" area)

    - 2 gas processing plants

- Have you contacted the screened sources to discuss the four-factor analysis?
    - Yes, started communications with letter in May 2018. Many phone conversations since then.

- How did you (or will you) determine which emitting units at a source require the full four-factor analysis?
    - Start with the emissions profile for the facility,
    - narrow down to the units of concern,
    - determine current “level of control” and whether or not additional controls need to be evaluated.

- Have you consulted informally with EPA, FLMs, or neighboring states/locals/tribes on your screening or analysis?
    - Not for Round 2. North Dakota is working with EPA (and just engaged FLMs) on a Round 1 revised SIP for a ND Coal EGU we are hoping to resolve in advance of Round 2 deadlines.

Feel free to share this information during the June 20th webinar.
Let me know if you have any questions/comments or want to discuss these in greater detail, thanks.

David Stroh
Environmental Engineer

701-328-5188 • destroh@nd.gov

918 E. Divide Ave. • Bismarck, ND 58501

From: Harbage, Rebecca <RHarbage@mt.gov>
Sent: Tuesday, May 28, 2019 5:16 PM
To: molly.birnbaum@alaska.gov; emerta@cabq.gov; Templeton.Ryan@azdeq.gov; christine.suarez-murias@arb.ca.gov; curtis.taipale@state.co.us; michael.madsen@doh.hawaii.gov; Pascale.Warren@deq.idaho.gov; bharprin@ndep.nv.gov; Mark.Jones@state.nm.us; Stroh, David E. <deStroh@nd.gov>; Orman.Michael@deq.state.or.us; rick.boddicker@state.sd.us; jhuy461@ecy.wa.gov
Cc: Amber Potts <amber.potts@wyo.gov>; Jay Baker <jbaker@utah.gov>; Tom Moore <tmoore@westar.org>
Subject: Upcoming Regional Haze Webinar - Request

Hi State/Local Leads –

The Coordination & Glide Path Subcommittee and the Regional Haze Planning Work Group co-chairs are working to plan our next milestone webinar. We plan to hold the webinar on Thursday, June 20 at 12:00-2:00pm Mountain Time (save-the-date email coming soon). Topics will include updates on fire emissions from the Fire & Smoke Work Group, an update from the Oil & Gas Work Group on their operator survey effort, and a discussion of point source emissions projection methodology for future year emission scenarios.

Following the last webinar in March, we’ve heard that folks found the brief status updates from states (we heard from CO, WA, AZ, and MT) very helpful and so I’m seeking volunteers for a similar “open mic”-type agenda item for this upcoming webinar.

Would you or someone else from your state be willing to give a five-minute update on your efforts to-date to establish a Q/d threshold, how many sources you're working with, whether there are any particular industries you are focused on in this round, and generally how things are going? I know many states shared updates on the Control Measures Subcommittee call last week and I think that would be great info to share with the webinar participants as well. If you're willing to share an update on the webinar, would you please respond by Friday 5/31 to let me know?

Specifically, some topics of interest include:

- Are you using Q/d as a screening tool? If so, what threshold are you using to determine which sources require further analysis? Did you include PM10 in your calculation of Q?
- How many sources are "screened in" based on your selected threshold?
- Are you focusing on any particular industrial sectors in this round of planning?
- Have you contacted the screened sources to discuss the four-factor analysis?
- How did you (or will you) determine which emitting units at a source require the full four-factor analysis?
- Have you consulted informally with EPA, FLMs, or neighboring states/locals/tribes on your screening or analysis?

Thanks in advance!
Rebecca

--

Rebecca Harbage
Air Quality Planner | 406-444-1472
P.O. Box 200901, Helena, MT 59620-0901
DEQ Montana Department of Environmental Quality

Stroh, David E.

From: Shepherd, Don <don_shepherd@nps.gov>
Sent: Tuesday, July 23, 2019 2:34 PM
To: Stroh, David E.
Subject: Re: [EXTERNAL] RE: ND facilities for potential RP analyses

David--thanks!

On Tue, Jul 23, 2019 at 12:34 PM Stroh, David E. <deStroh@nd.gov> wrote:

> Don,
>
> The Department has made this information available through our website at the following location:
>
> https://deq.nd.gov/AQ/planning/RegHaze.aspx
>
> At the bottom of the webpage under North Dakota's Progress, you can access the Regional Haze Files. Specifically, you will find:
>
> Round 1
>
> - communications regarding updated Great River Energy Coal Creek Station BART analysis (outstanding from the 1st round – 1st bullet)
> - 5 year progress report post round 1 (2nd bullet)
> - Other final documents from the 1st round of regional haze program (bullets 3 through 6)
>
> Round 2
>
> - four-factor requests, four-factor reports received, NDDEQ responses on four-factors (to date), and revised four-factor reports received
>   - this was requested in your email
>
> Let me know if you have any questions as you review the information.

> David
>
> **From:** Shepherd, Don
> **Sent:** Monday, July 22, 2019 3:19 PM
> **To:** Stroh, David E. <deStroh@nd.gov>
> **Cc:** Patricia Brewer <Patricia_F_Brewer@nps.gov>; Melanie Ransmeier <melanie_peters@nps.gov>; Dave Pohlman <david_pohlman@nps.gov>; d King <kirsten_king@nps.gov>; Andrea Stacy <andrea_stacy@nps.gov>; Bachman, Tom A. <tbachman@nd.gov>; Seligman, Angela N. <aseligman@nd.gov>; Semerad, Jim L. <jsemerad@nd.gov>; Thorton, Rhannon T. <rThorton@nd.gov>
> **Subject:** Re: [EXTERNAL] RE: ND facilities for potential RP analyses
>
> **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe.
>
> David, thanks for sharing this information. Would it also be feasible for you to share the industry response to your May 2018 request?
>
> On Mon, Jul 15, 2019 at 9:22 AM Stroh, David E. <deStroh@nd.gov> wrote:
>
> > Hi Don,
> >
> > Thank you for the email regarding source selection for four-factor analysis. The criteria/approach you used is consistent with what North Dakota did in May 2018. This is also consistent with the guidance and tool produced by WRAP for states to use for selection of sources potentially impacting visibility in Class I Areas. Here is a link to WRAP website containing tool and info on Q/d analysis: http://views.cira.colostate.edu/tssv2/Emissions/QDAnalysis.aspx
> >
> > As you indicate in the email, the guidance recommends states address 80% of the visibility impairment in Class I areas. Through the four-factor analysis, North Dakota is addressing approximately 80% of the visibility impairment (nitrates and sulfates) as determined by the IMPROVE monitoring network in North Dakota (http://vista.cira.colostate.edu/Improve/aqrv-summaries/). North Dakota sent four-factor request letters to the ten highest Q/d facilities in North Dakota, which addresses ~94% of the 2012-2016 emissions from stationary sources. Q/d for the sources selected in North Dakota ranged from 7 to 164. See attached "4 Factors Source Analysis Q over D" for a list of the sources North Dakota has selected for four-factor analysis. The list is consistent with the recommendations provided in your email attachment (North Dakota also included Northern Boarder Compression Station No. 4 for analysis).
> >
> > Additionally for your information, I have attached the four-factor request letters sent by North Dakota in May 2018. North Dakota has received responses from all the facilities and is in the process of reviewing the analysis for completeness and accuracy. Please let me know if you have any additional questions, comments, or would like to discuss.

David Stroh

Environmental Engineer

701-328-5188 • destroh@nd.gov

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918 E. Divide Ave. • Bismarck, ND 58501

From: Shepherd, Don
Sent: Friday, July 12, 2019 2:36 PM
To: Stroh, David E. <deStroh@nd.gov>
Cc: Patricia Brewer <Patricia_F_Brewer@nps.gov>; Melanie Ransmeier <melanie_peters@nps.gov>; Dave Pohlman <david_pohlman@nps.gov>; d King <kirsten_king@nps.gov>; Andrea Stacy <andrea_stacy@nps.gov>
Subject: ND facilities for potential RP analyses

Hello David,

I am sending the attached list of ND facilities for potential 4-factor RP analyses.Please accept this information as part of our discussion on how to address this task.

EPA's draft RP guidance recommends that states capture enough facilities for 4-factor RP analysis to account for 80% of the impact at each Class I area. I have used Q/d as a surrogate for impact (as allowed by EPA guidance). My calculation of "Q" includes only SO2 + NOx because i have discovered that PM is typically already very well controlled or, in the case of surface mines (e.g., copper, coal), their very large emissions can have a great impact on facility selection with essentially no way to further reduce PM emissions. (EPA's draft guidance advises not reviewing facilities that have little potential for additional control.) Also, Clean Air Markets Data (CAMD--now AMP) does not include PM. For "d," we calculated the distance to all facilities in the 2014 National Emissions Inventory (NEI) out to about 1000 km.

Our basic approach follows:

1. Extract from the 2014 NEI all facilities within about 1000 km of the NPS Class I area most-impacted by ND facilities.
    - Theodore Roosevelt NP (THRO)
2. Calculate Q/d.
3. Delete airports and rail yards because states have little regulatory authority.
4. Substitute more recent data for EGUs available from CAMD/AMP. Use projected/expected changes in EGU emissions for this planning period.
5. Rank the remaining facilities by Q/d and select those facilities contributing to 80% of impact (total Q/d) at each NPS Class I area.
6. Combine the sets of selected facilities for each NPS Class I area to produce combined lists based upon the highest impact at the NPS Class I areas.

Please feel free to comment or ask questions.

thanks,

--

Don Shepherd

National Park Service

Air Resources Division

12795 W. Alameda Pkwy.

Lakewood, CO 80228

Phone: 303-969-2075

Fax: 303-969-2822

E-Mail: don_shepherd@nps.gov

"the man who really counts in the world is the doer, not the mere critic" TR 1891

> --
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"the man who really counts in the world is the doer, not the mere critic" TR 1891

Year	Inventory	EIS ID	County	Facility Name	NAICS Code Description	Latitude	Longitude	State	NOX	SO2	Q	to NPS Class I Area	Q/d	NPS Class I Area
2018	CAMD	8086611	Mercer County	Coyote	Fossil Fuel Electric Power Generation	47.222	-101.814	ND	7,975	14,913	22,888	116	197.6	THRO
2018	CAMD	8086511	Mercer County	Antelope Valley	Fossil Fuel Electric Power Generation	47.371	-101.834	ND	3,589	12,037	15,626	109	143.5	THRO
2018	CAMD	8011011	McLean County	Coal Creek	Fossil Fuel Electric Power Generation	47.376	-101.157	ND	6,995	6,858	13,853	159	87.2	THRO
2018	CAMD	8087911	Oliver County	Milton R Young	Fossil Fuel Electric Power Generation	47.066	-101.214	ND	9,275	2,776	12,051	161	75.1	THRO
2014	NEI	8086711	Mercer	Great Plains Synfuels Plant	Natural Gas Distribution	47.361	-101.838	ND	3,235	3,818	7,053	109	64.6	THRO
2018	CAMD	8086311	Mercer County	Leland Olds	Fossil Fuel Electric Power Generation	47.282	-101.319	ND	4,664	1,704	6,368	149	42.7	THRO
2014	NEI	8013911	Williams	Tioga Gas Plant	Natural Gas Liquid Extraction	48.400	-102.914	ND	946	569	1,515	91	16.6	THRO
2014	NEI	8023811	Billings	Little Knife Gas Plant	Crude Petroleum and Natural Gas Extraction	47.298	-103.098	ND	24	526	550	35	15.8	THRO
2018	CAMD	8087011	Morton County	R M Heskett	Fossil Fuel Electric Power Generation	46.867	-100.884	ND	955	1,228	2,183	185	11.8	THRO

Stroh, David E.

From: Stroh, David E.
Sent: Friday, September 20, 2019 1:19 PM
To: 'Shepherd, Don'; Dave Pohlman
Cc: Bachman, Tom A.; Semerad, Jim L.; Thorton, Rhannon T.; Seligman, Angela N.
Subject: FW: North Dakota's Regional Haze progress and information
Attachments: Regional haze Q over D Analysis

Don and David,

I wanted to keep you informed of North Dakota's regional haze progress regarding Round 2 planning and Round 1 resolution efforts. See the email sent to EPA region 8 planning group yesterday (below) for more information and links to the information we have made available on our website.

Additionally, I extended an offer (highlighted in the email below) to EPA R8 for Great River Energy (GRE) – Coal Creek Station to present an overview of the recently submitted revised NOx BART analysis. EPA R8 is interested in this and we are in the process of coordinating a time for this to happen. Tentatively leaning toward an afternoon later next week (9/25-9/27).

I realize this is short notice, but if it something you would be in interested in attending - please let me know and I can keep you appraised of the date/time. If it wouldn't happen to work for you next week, we could look at doing something independent in the upcoming weeks.

Let me know if you have any questions or comments.

Regards,
David

David Stroh
Environmental Engineer

701-328-5188 • destroh@nd.gov

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918 E. Divide Ave. • Bismarck, ND 58501

From: Stroh, David E.
Sent: Thursday, September 19, 2019 4:17 PM
To: Worstell, Aaron <Worstell.Aaron@epa.gov>
Cc: Dobrahner, Jaslyn <Dobrahner.Jaslyn@epa.gov>; Jackson, Scott <Jackson.Scott@epa.gov>; Semerad, Jim L. <jsemerad@nd.gov>; Bachman, Tom A. <tbachman@nd.gov>; Seligman, Angela N. <aseligman@nd.gov>; Thorton, Rhannon T. <rThorton@nd.gov>
Subject: North Dakota's Regional Haze progress and information

Aaron,

As a follow-up to our call this morning. Here is the link to North Dakota's regional haze files for Round 1 resolution and Round 2 planning: https://deq.nd.gov/AQ/planning/RegHaze.aspx

Toward the bottom of the page, you'll find a "North Dakota's Progress" section. Within that section, "Regional Haze Round 1 Files" and "Regional Haze Round 2 Files" are contained. The first bullet under the "Round 1 Files" contains the GRE-CCS revised NOx BART analysis (received late last week) and correspondence associated with the development of that package. Under the "Round 2 Files", we have uploaded the: four-factor request letters, the four factor reports received to date, and formal communications between the facility and DEQ regarding our comments on the initial analysis received.

One other item I was going to mention/ask in our call. Prior to NDDEQ receiving the revised GRE NOx BART Analysis, GRE presented a PowerPoint overview of information contained in the report. I found this overview helpful as I have begun to thoroughly review the report. GRE offered to repeat this presentation/overview to you (and/or other EPA R8 staff). If this is something you think would be helpful, let me know and we can coordinate a time for this to happen.

Lastly, I have attached a NDDEQ internal Q/d email from May 2018 which outlines our original rational for the sources selected for four factor analysis. The attachment also includes spreadsheets summarizing the Q/d information.
Side note to Q/d info – here is a link to the NPS files sent to WESTAR-WRAP states regarding state sources for consideration of four factor analysis: https://www.wrapair2.org/RHP_Control.aspx. As you can see the NPS suggestions are in line with the sources already selected by NDDEQ.

I'd be happy to discuss any of this information after you get a chance to review.

Regards,
David Stroh
Environmental Engineer

701-328-5188 • destroh@nd.gov

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918 E. Divide Ave. • Bismarck, ND 58501

Stroh, David E.

From: Bachman, Tom A.
Sent: Wednesday, May 09, 2018 9:09 AM
To: O'Clair, Terry L.; Semerad, Jim L.; Stroh, David E.; Kautzman, Rheanna M.; Mills, Ryan D.; White, Rob J.
Subject: Regional haze Q over D Analysis
Attachments: 4 Factrors Source Analyssis Q over D.xlsx; Voyageurs Q ove D Analysis.xlsx

Hi all:

Attached is a spreadsheet that contains a Q/D (tons/km) analysis for Regional Haze Round 2. The analysis was done the same way we did it in Round 1(i.e. total SO2 plus NOx emissions for Title 5 sources divided by the distance to the nearest Class I area). As suspected, coal-fired EGUs dominate the Q/D analysis. Based on the average of 2012-2016 emissions, the coal-fired EGUs account for 86% of the emissions and 78% of the Q/D (EPA guidance suggests we address at least 80% of the impact from in-state sources). The Stanton Station is included in this analysis; but, as we all know, it is now shutdown. Please note the emissions do not include other minor point sources we track and area sources. Using the 2014 NEI, the coal-fired EGUs would only account for 39% of the total SO2 and NOx emissions. Of these other SO2 and NOx emissions in the 2014 NEI, only a small portion are controllable by us.

In the 2012-2016 emissions Q/D analysis, there is a very distinctive break point after the Northern Border No.4 station (Q/D of 8.7 versus 4.5 for the Grasslands Gas Plant). If you include DGC, the Tioga Gas Plant, the Little Knife Gas Plant, and Northern Border No.4 in the four factors analysis, you get 94% of the emissions and 93% of the Q/D. If you go down through the top ten sources in the Q/D analysis, you get 95% of the emissions and 96% of the Q/D. Some of the sources in the top ten, such as Hawkeye Compressor Station and Little Missouri Gas Plant, are very well controlled (recent PTCs); so, there is not much to gain from these sources. It is my understanding that the Fort Buford Compressor Station is now shut down. That leaves the Grasslands Gas Plant, Mandan Refinery and the Lignite Gas Plant. Perhaps these sources should be reviewed more closely to see if we can get some reductions from a four factors analysis.

The 2017 emissions are not quite complete yet; however, I was able to get emissions for the coal-fired EGUs and the top ten sources from the 2012-2016 Q/D analysis. The break point after Northern Border No.4 is still there. Once all of the 2017 emissions are available, I will complete the analysis for 2013-2017. I believe the 20117 emissions will not change our decision for which sources we want a four factors analysis.

I also conducted a Q/D analysis solely based on Voyageurs National Park for the coal-fired EGU's (see attached spreadsheet). Interesting that ACS has bigger Q/D than some power plants at Voyageurs. Perhaps this will be an issue with Minnesota.

We probably should have a meeting to decide what additional sources we want a four factors analysis. One other point to consider is the EPA guidance that indicates we must address more than 80% of the impact sources if we do not meet the glide path (we did not meet the glide path in Round 1).

If you have any questions, please see me.

Tom Bachman, P.E.
ND Dept. of Health
(701) 328-5188

Stroh, David E.

From: Worstell, Aaron <Worstell.Aaron@epa.gov>
Sent: Friday, September 20, 2019 9:59 AM
To: Stroh, David E.
Cc: Dobrahner, Jaslyn; Jackson, Scott; Semerad, Jim L.; Bachman, Tom A.; Seligman, Angela N.; Thorton, Rhannon T.
Subject: RE: North Dakota's Regional Haze progress and information

Follow Up Flag: Follow up
Flag Status: Completed

Hi David-

Thank you for the link to the RH files, as well as the round 2 Q/D materials.

Yes, it would be helpful for GRE to walk EPA through the Coal Creek Station NOx BART presentation. I'm available in the afternoon all days next week.

Thanks.

From: Stroh, David E. <deStroh@nd.gov>
Sent: Thursday, September 19, 2019 3:17 PM
To: Worstell, Aaron <Worstell.Aaron@epa.gov>
Cc: Dobrahner, Jaslyn <Dobrahner.Jaslyn@epa.gov>; Jackson, Scott <Jackson.Scott@epa.gov>; Semerad, Jim L. <jsemerad@nd.gov>; Bachman, Tom A. <tbachman@nd.gov>; Seligman, Angela N. <aseligman@nd.gov>; Thorton, Rhannon T. <rThorton@nd.gov>
Subject: North Dakota's Regional Haze progress and information

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I'd be happy to discuss any of this information after you get a chance to review.

Regards,
David Stroh
Environmental Engineer

701-328-5188 • destroh@nd.gov

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Be Legendary

918 E. Divide Ave. • Bismarck, ND 58501

Stroh, David E.

From: Shepherd, Don <don_shepherd@nps.gov>
Sent: Monday, September 23, 2019 12:10 PM
To: Stroh, David E.
Cc: Bachman, Tom A.
Subject: Re: [EXTERNAL] FW: North Dakota's Regional Haze progress and information
Attachments: BCS Permit 01092019.pdf; BuckinghamCompressorStationPermitApp (1).pdf

Follow Up Flag: Follow up
Flag Status: Flagged

David (and Tom),

Thanks for the update/heads-up. Yes, i would be interested sitting in on a presentation by GRE regarding CCS, and i would appreciate it if you would let me know when that might happen.

Regarding selection of facilities for four-factor analyses for the next phase of Regional Haze/Reasonable Progress work, i was very pleased to see how closely our lists matched. I have recently begun thinking about how we can address the impact of new source growth on Class I areas like Theodore Roosevelt National Park. For example, i saw that NDDEQ recently concluded a public review process for expansion of Targa Midstream's Little Missouri River Gas Plant a few kilometers from the Park. It is my understanding that this permit application did not trigger PSD or any BACT requirements. However, the resulting Q/d, if this facility is constructed as proposed, would easily exceed the thresholds NDDEQ used to trigger a four-factor RP analysis. Furthermore, we are aware of a similar project in VA with lower NOx emissions. The information contained in the attachments indicates that Dominion Energy's Buckingham County (VA) Compressor Station includes a Solar Centaur 50 compressor turbine (similar to the three CTs proposed by Targa) that is equipped with SoLoNOx and SCR to meet a NOx limit = 3.75 ppm (compared to 15 ppm at LMGP). Likewise, our comments on Meridian's Davis Refinery noted examples of similar emission units with lower permit limits. It is likely that there are several more similar situations where new source growth may need to be accounted for as we formulate strategies to make reasonable progress during this planning period. I would appreciate any additional thoughts you and Tom might have on this.

On Fri, Sep 20, 2019 at 12:20 PM Stroh, David E. <deStroh@nd.gov> wrote:

> Don and David,
>
> I wanted to keep you informed of North Dakota’s regional haze progress regarding Round 2 planning and Round 1 resolution efforts. See the email sent to EPA region 8 planning group yesterday (below) for more information and links to the information we have made available on our website.
>
> Additionally, I extended an offer (highlighted in the email below) to EPA R8 for Great River Energy (GRE) – Coal Creek Station to present an overview of the recently submitted revised NOx BART analysis. EPA R8 is interested in this and we

are in the process of coordinating a time for this to happen. Tentatively leaning toward an afternoon later next week (9/25-9/27).

I realize this is short notice, but if it something you would be in interested in attending - please let me know and I can keep you appraised of the date/time. If it wouldn't happen to work for you next week, we could look at doing something independent in the upcoming weeks.

Let me know if you have any questions or comments.

Regards,

David

David Stroh

Environmental Engineer

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From: Stroh, David E.
Sent: Thursday, September 19, 2019 4:17 PM
To: Worstell, Aaron <Worstell.Aaron@epa.gov>
Cc: Dobrahner, Jaslyn <Dobrahner.Jaslyn@epa.gov>; Jackson, Scott <Jackson.Scott@epa.gov>; Semerad, Jim L. <jsemerad@nd.gov>; Bachman, Tom A. <tbachman@nd.gov>; Seligman, Angela N. <aseligman@nd.gov>; Thorton, Rhannon T. <rThorton@nd.gov>
Subject: North Dakota's Regional Haze progress and information

Aaron,

As a follow-up to our call this morning. Here is the link to North Dakota's regional haze files for Round 1 resolution and Round 2 planning: https://deq.nd.gov/AQ/planning/RegHaze.aspx

Toward the bottom of the page, you'll find a "North Dakota's Progress" section. Within that section, "Regional Haze Round 1 Files" and "Regional Haze Round 2 Files" are contained. The first bullet under the "Round 1 Files" contains the GRE-CCS revised NOx BART analysis (received late last week) and correspondence associated with the development of that package. Under the "Round 2 Files", we have uploaded the: four-factor request letters, the four factor reports received to date, and formal communications between the facility and DEQ regarding our comments on the initial analysis received.

One other item I was going to mention/ask in our call. Prior to NDDEQ receiving the revised GRE NOx BART Analysis, GRE presented a PowerPoint overview of information contained in the report. I found this overview helpful as I have begun to thoroughly review the report. GRE offered to repeat this presentation/overview to you (and/or other EPA R8 staff). If this is something you think would be helpful, let me know and we can coordinate a time for this to happen.

Lastly, I have attached a NDDEQ internal Q/d email from May 2018 which outlines our original rational for the sources selected for four factor analysis. The attachment also includes spreadsheets summarizing the Q/d information.

Side note to Q/d info – here is a link to the NPS files sent to WESTAR-WRAP states regarding state sources for consideration of four factor analysis: https://www.wrapair2.org/RHP_Control.aspx. As you can see the NPS suggestions are in line with the sources already selected by NDDEQ.

I'd be happy to discuss any of this information after you get a chance to review.

Regards,

David Stroh

Environmental Engineer

701-328-5188 • destroh@nd.gov

918 E. Divide Ave. • Bismarck, ND 58501

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Don Shepherd
National Park Service
Air Resources Division
12795 W. Alameda Pkwy.
Lakewood, CO 80228
Phone: 303-969-2075
Fax: 303-969-2822
E-Mail: don_shepherd@nps.gov
"the man who really counts in the world is the doer, not the mere critic" TR 1891

From: Tom Moore <tmoore@westar.org>
Sent: Monday, September 23, 2019 10:25 AM
To: Boddicker, Rick; Stroh, David E.
Subject: RE: brief call to coordinate on 4factor analysis

Great, sorry for missing the mark on getting an appt. out earlier.

Tom Moore, WRAP Air Quality Program Manager
Western States Air Resources Council (WESTAR) | e: tmoore@westar.org | o: 970.491.8837
Western Regional Air Partnership | www.wrapair2.org

From: Boddicker, Rick <Rick.Boddicker@state.sd.us>
Sent: Monday, September 23, 2019 9:23 AM
To: Tom Moore <tmoore@westar.org>; destroh@nd.gov
Subject: RE: brief call to coordinate on 4factor analysis

It'll work for us. I have Kyrik with as well

From: Tom Moore <tmoore@westar.org>
Sent: Monday, September 23, 2019 10:21 AM
To: Boddicker, Rick <Rick.Boddicker@state.sd.us>; destroh@nd.gov
Subject: RE: [EXT] brief call to coordinate on 4factor analysis

Hi, Rick and David – so sorry, I forgot to send an appt. Would 930 MDT / 1030 CDT work? Will send an appt. now. Thanks.

Tom Moore, WRAP Air Quality Program Manager
Western States Air Resources Council (WESTAR) | e: tmoore@westar.org | o: 970.491.8837
Western Regional Air Partnership | www.wrapair2.org

From: Boddicker, Rick <Rick.Boddicker@state.sd.us>
Sent: Thursday, September 19, 2019 12:09 PM
To: Tom Moore <tmoore@westar.org>; destroh@nd.gov
Subject: RE: brief call to coordinate on 4factor analysis

Monday morning should work for us as well.

Thanks.

From: Tom Moore <tmoore@westar.org>
Sent: Thursday, September 19, 2019 12:22 PM
To: Boddicker, Rick <Rick.Boddicker@state.sd.us>; destroh@nd.gov
Subject: [EXT] brief call to coordinate on 4factor analysis

Hi, Rick and David – I didn't know if you guys have met, so I wanted to suggest a brief call to coordinate on SD's 4factor work with the "consistent WESTAR-WRAP states' effort" that David is leading.

Rick – we have some materials that David (or I could help) can walk through, and we'd like to learn more about the 2 sources you all are looking at.

Would you guys have some time on Monday the 23rd, say 900 AM MDT / 1000 AM CDT? I can send us an appt.

Thanks.

Tom Moore, WRAP Air Quality Program Manager
Western States Air Resources Council (WESTAR) | e: tmoore@westar.org | o: 970.491.8837
Western Regional Air Partnership | www.wrapair2.org

Stroh, David E.

From: Stroh, David E.
Sent: Thursday, November 21, 2019 11:30 AM
To: Bouchareb, Hassan (MPCA)
Subject: RE: North Dakota 4-Factor Analysis

Hi Hassan,

Here is the link to North Dakota's regional haze files for Round 1 resolution and Round 2 planning: https://deq.nd.gov/AQ/planning/RegHaze.aspx

Toward the bottom of the page, you'll find a "North Dakota's Progress" section. Within that section, "Regional Haze Round 1 Files" and "Regional Haze Round 2 Files" are contained.

The first bullet under the "Round 1 Files" contains the GRE-CCS revised NOx BART analysis (received in Sept. 2019) and correspondence associated with the development of that package.

Under the "Round 2 Files" – specific to what you requested, we have uploaded the: four-factor request letters, the four factor reports received to date, and formal communications between the facility and DEQ regarding our comments on the initial analysis received.

The NDDEQ is in the process of reviewing these reports and determining what is considered reasonable for round 2.

Let me know if you have any questions or comments, thanks!
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov

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From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Thursday, November 21, 2019 9:11 AM
To: Stroh, David E. <deStroh@nd.gov>
Subject: North Dakota 4-Factor Analysis

Good morning David,

If you remember, we both spoke at the Class of '85 State Meeting on Regional Haze. In your presentation, I think you had mentioned that you had already received some 4-factor analyses from some coal-fired EGUs? Are those analyses posted or available somewhere? I'm looking for what's available to try and gauge what levels of control utilities are looking at and what seems reasonable. If you can share those analyses I would appreciate it.

Feel free to contact me if you have any questions or if there is anything I can help you with as well.

Thank you!

Hassan M. Bouchareb | Engineer
Minnesota Pollution Control Agency (MPCA)
Environmental Analysis & Outcomes Division
520 Lafayette Road | St. Paul, MN | 55155
Office: (651) 757-2653 | Fax: (651) 296-8324
Pronouns: he/him/his
Hassan.Bouchareb@state.mn.us | www.pca.state.mn.us

MINNESOTA POLLUTION
CONTROL AGENCY

Our mission is to protect and improve the environment and human health.

Stroh, David E.

Subject: MT/ND State-to-State coordination call
Location: Skype Meeting

Start: Tue 6/2/2020 2:00 PM
End: Tue 6/2/2020 3:00 PM

Recurrence: (none)

Meeting Status: Accepted

Organizer: Payne, Rhonda

MATERIALS ADDED:

1) Agenda and background regulatory information
2) WEP-AOI Slides for discussion

Talk to you tomorrow!

Hi David,

MT would like to take this time to begin conversations with ND on a coordinated emissions management strategy to address potential interstate emissions impacts in our respective CIAs.

I am working on a packet of information for our discussion that I'll attach to this meeting request by the end of the week.

Our rough agenda is:

- Montana's schedule for submitting a draft SIP for FLM review by July 10.
- Consider guidance listed in Step 2: Determination of affected Class I areas in other states
- Current URPs for Medicine Lake, Lostwood, Teddy Roosevelt
- Current WEP/AOI results for Medicine Lake, Lostwood, Teddy Roosevelt

If there is anything else you'd like to add, please let me know!

Talk to you on Tuesday, June 2nd at 1:00pm MST.

Thanks,

Rhonda

……

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Join by phone

406-444-4647, access code: 136127 (Helena Capitol Campus Region)   English (United States)

Find a local number

Conference ID: 136127 (same as access code above)
Forgot your dial-in PIN? | Help

………

MT/ND State-to-State Informal Coordination Call
June 2, 2020

Agenda:

- Montana's schedule for submitting a draft SIP for FLM review by July 10.
- Consider guidance listed in Step 2: Determination of affected Class I areas in other states (see excerpt below)
- Current URPs for Medicine Lake, Lostwood, Teddy Roosevelt
- Current WEP/AOI results for Medicine Lake, Lostwood, Teddy Roosevelt

Excerpt from EPA's Guidance for RH SIP Development in the 2nd Planning Period (Pg. 8)

2. Step 2: Determination of affected Class I areas in other states

Section 51.308(f)(2) of the Regional Haze Rule requires each state to develop an LTS that includes the control measures necessary to make reasonable progress at each Class I area outside the state "that may be affected by emissions from the state."[1] This section addresses how a state determines which Class I areas in other states may be affected by its own emissions, so it knows which out-of-state Class I areas need to be considered in the development of its LTS. This linkage to specific Class I areas affects LTS development because baseline visibility impacts from individual sources and visibility benefits from possible emission control measures are specific to a Class I area. Also, section 51.308(f)(3) of the Regional Haze Rule provides that if a state contains sources whose emissions are reasonably anticipated to contribute to visibility impairment in a Class I area in another state for which the RPG is above the URP glidepath, the state must provide a "robust demonstration" that there are no additional emission reduction measures that would be reasonable to include in its own LTS.[19] [2]

As an initial matter, a state has the flexibility to use any reasonable method for quantifying the impacts of its own emissions on out-of-state Class I areas, and it may use any reasonable assessment for this determination. Additionally, since determinations of affected Class I areas were previously made for the first regional haze implementation period, states may consider retaining the same linkages and assumptions from those SIPs, but if states do so then they should consider whether the assumptions about source-receptor relationships have changed since those assessments.

States that are reassessing their linkages for the second implementation period may make this determination based on the state's recent emissions or anticipated emissions in 2028, which is the end of the second implementation period. Because visibility impairment is defined such that only anthropogenic emissions are considered to contribute to visibility impairment, all types of anthropogenic sources are to be included in this determination. States may also make this determination based on total statewide emissions.

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[1] Section 51.308(f)(2) of the Regional Haze Rule also requires each state to develop an LTS that includes the control measures necessary to make reasonable progress at each of its own Class I areas. The qualification regarding "may be affected" applies only to out-of-state Class I areas; the state preparing a SIP revision must develop an LTS that includes measures necessary to make reasonable progress at each of its own Class I areas regardless of the impact from its own sources' emissions on those areas.

[2] See Section II.B.7.c of this document for additional information regarding the requirement for a robust demonstration.

A variety of technical, quantitative approaches exist to assess which out-of-state Class I areas may be affected by aggregate emissions from a given state. The most common approach in the first implementation period was to use a photochemical transport model to track the contribution due to emissions from whole states to specific Class I areas. This approach may also be used in the second implementation period, or a state may use another reasonable approach (e.g., back trajectory-based approaches).

A state with a Class I area may advise another state that it considers its Class I area to be affected by emissions from the other state. However, each state is responsible for its determination of what Class I areas may be affected by its emissions, regardless of impacts that a neighboring state might or might not have identified.[3] This is also a suitable subject for interstate consultation. The Regional Haze Rule requires that states describe actions taken to resolve any disagreements and document interstate consultations.[4]

<u>Excerpt from RHR – 40 CFR (f)(2)(ii):</u>

(ii) The State must consult with those States that have emissions that are reasonably anticipated to contribute to visibility impairment in the mandatory Class I Federal area to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress.

(A) The State must demonstrate that it has included in its implementation plan all measures agreed to during state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement.

(B) The State must consider the emission reduction measures identified by other States for their sources as being necessary to make reasonable progress in the mandatory Class I Federal area.

(C) In any situation in which a State cannot agree with another State on the emission reduction measures necessary to make reasonable progress in a mandatory Class I Federal area, the State must describe the actions taken to resolve the disagreement. In reviewing the State's implementation plan, the Administrator will take this information into account in determining whether the plan provides for reasonable progress at each mandatory Class I Federal area that is located in the State or that may be affected by emissions from the State. All substantive interstate consultations must be documented.” 40 CFR 51.308(f)(3)(ii)(B) Reasonable progress goals “If a State contains sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another State for which a demonstration by the other State is required under (f)(3)(ii)(A), the State must demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in its own long-term strategy. The State must provide a robust demonstration, including documenting the criteria used to determine which sources or groups or sources were evaluated and how the four factors required by paragraph (f)(2)(i) were taken into consideration in selecting the measures for inclusion in its longterm strategy.”

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[3] If the state preparing a SIP revision has no Class I areas of its own and it has demonstrated that there are no out of-state Class I areas that may be affected by its sources’ emissions, we encourage the state to discuss this conclusion with their EPA Regional office.

[4] 40 CFR 51.308(f)(2)(ii)(C).

Excerpt from MT Proposed FIP

TABLE 149—MT SOURCES EXTINCTION CONTRIBUTION 2000–2004, 20% WORST DAYS

Class I area	Pollutant Species	Extinction (Mm^{-1})	Species contribution to particle extinction (%)	MT sources contribution to species extinction (%)[1]
Lostwood NWR	Sulfate	21.4	34	2
	Nitrate	22.94	36	9
	OC	11.05	18	17
	EC	2.84	5	12
	PM2.5	0.62	1	7
	PM10	3.93	6	11
	Sea Salt	0.26	0	----
Theodore Roosevelt NP	Sulfate	17.53	35	3
	Nitrate	13.74	27	15
	OC	10.82	21	49
	EC	2.75	5	33
	PM2.5	0.9	2	22
	PM10	4.82	10	25
	Sea Salt	0.07	0	----

[1] Contribution of sulfate and nitrate based on PSAT; OC, EC, $PM_{2.5}$, PM_{10}, and Sea Salt contribution based on WEP.

5. Consultation and Emissions Reduction for Other States' Class I Areas

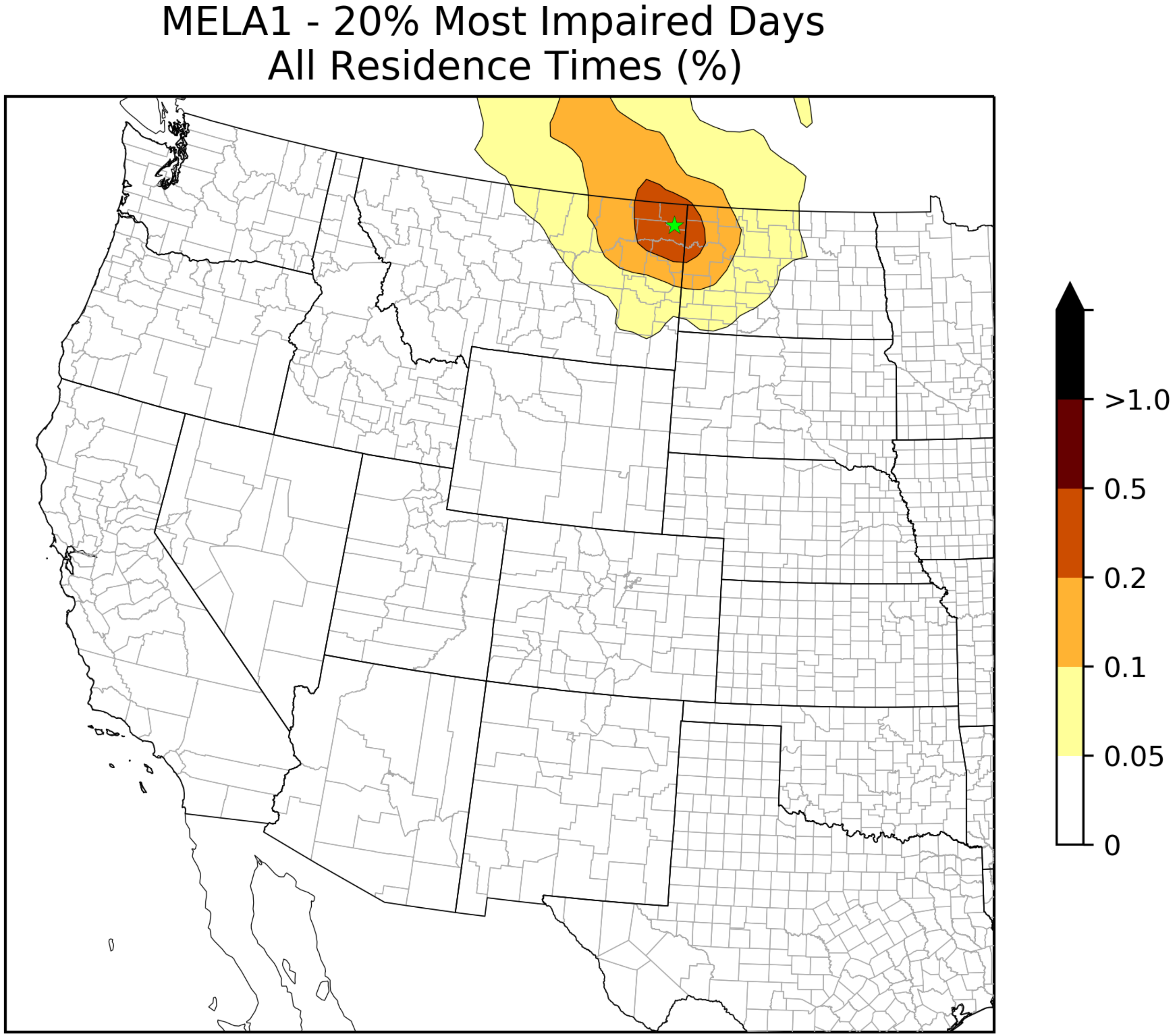
40 CFR 51.308(d)(3)(i) requires that EPA consult with another state if Montana's emissions are reasonably anticipated to contribute to visibility impairment at that state's Class I area(s), and that EPA consult with other states if those other states' emissions are reasonably anticipated to contribute to visibility impairment at Montana's Class I areas. EPA worked with other states and tribes through the WRAP process. EPA also accepts and incorporates the WRAP-developed visibility modeling into the Regional Haze FIP for Montana. This proposal contains the necessary measures to meet Montana's share of the reasonable progress goals for the other state's Class I areas. Table 149 above shows Montana's contribution to Class I areas in neighboring states. None of the neighboring states with Class I areas have indicated to EPA that specific reductions are necessary for this FIP. Therefore, EPA proposes that this FIP meets Montana's share of the reasonable progress goals for the other state's Class I areas.

WEP-AOI slides

MELA1, THRO1, LOST1

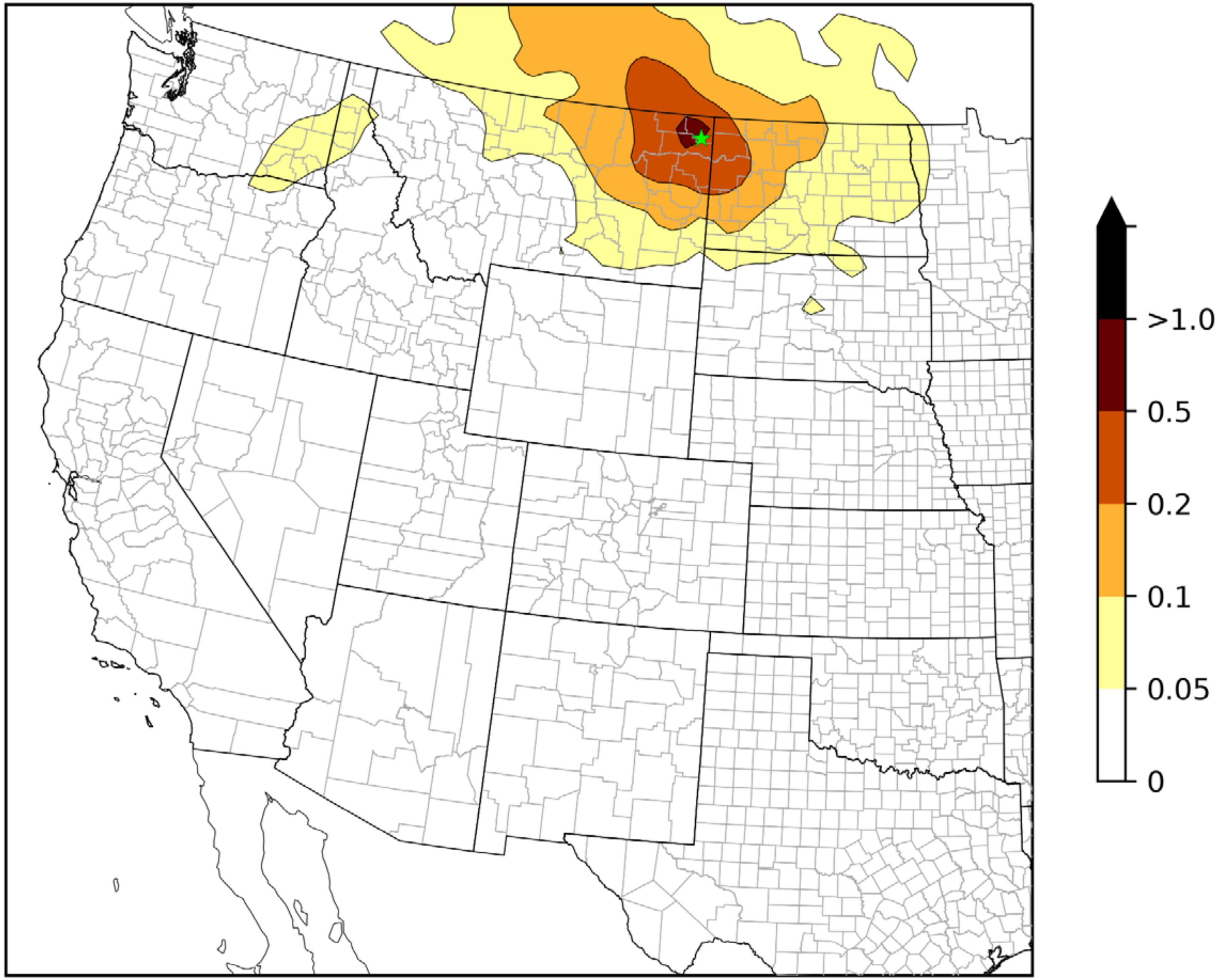
6/1/2020

MELA1



Area of Influence

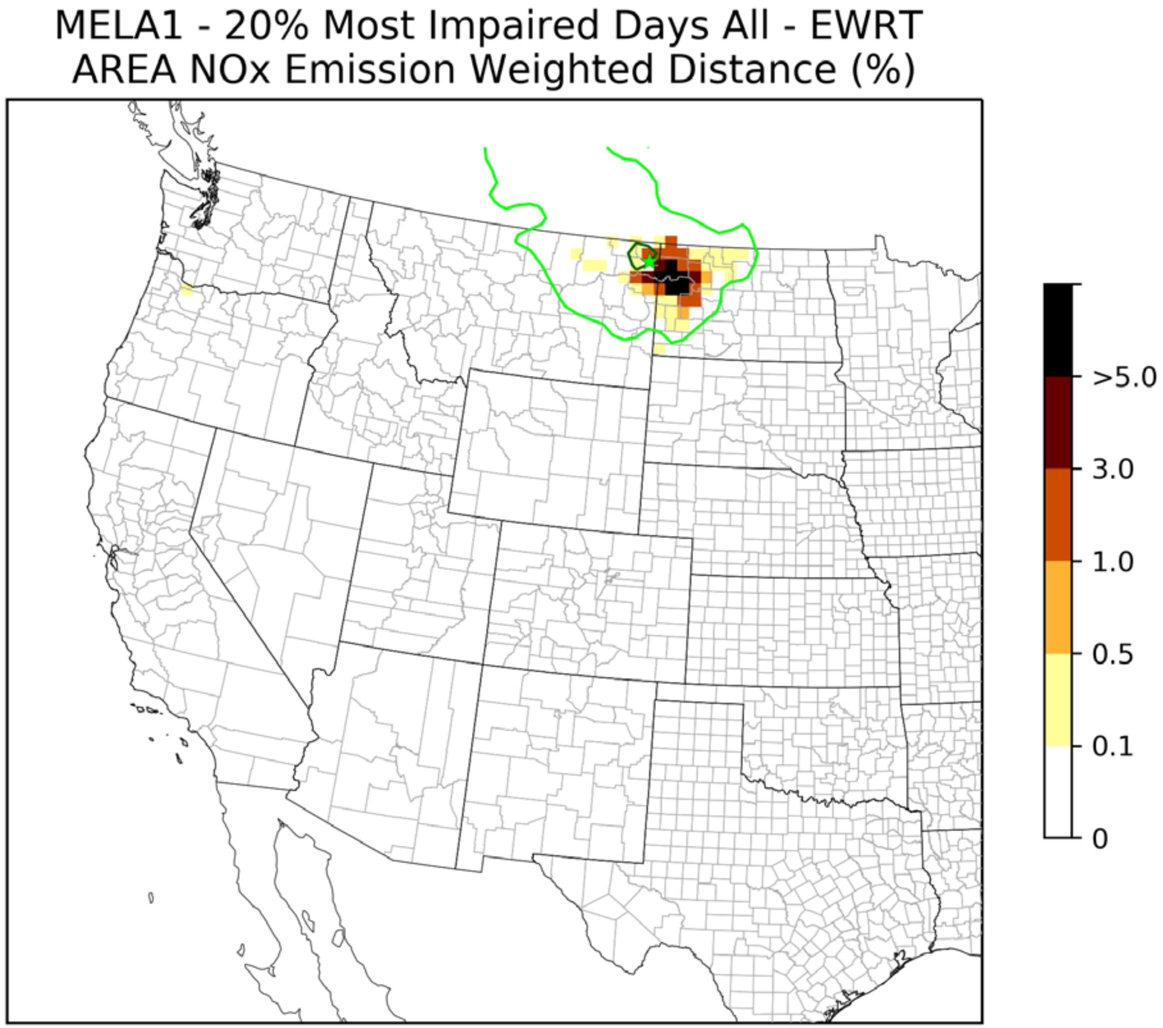
MELA1 - 20% Most Impaired Days
All Amm_NO3 Extinction Weighted Residence Times (%)



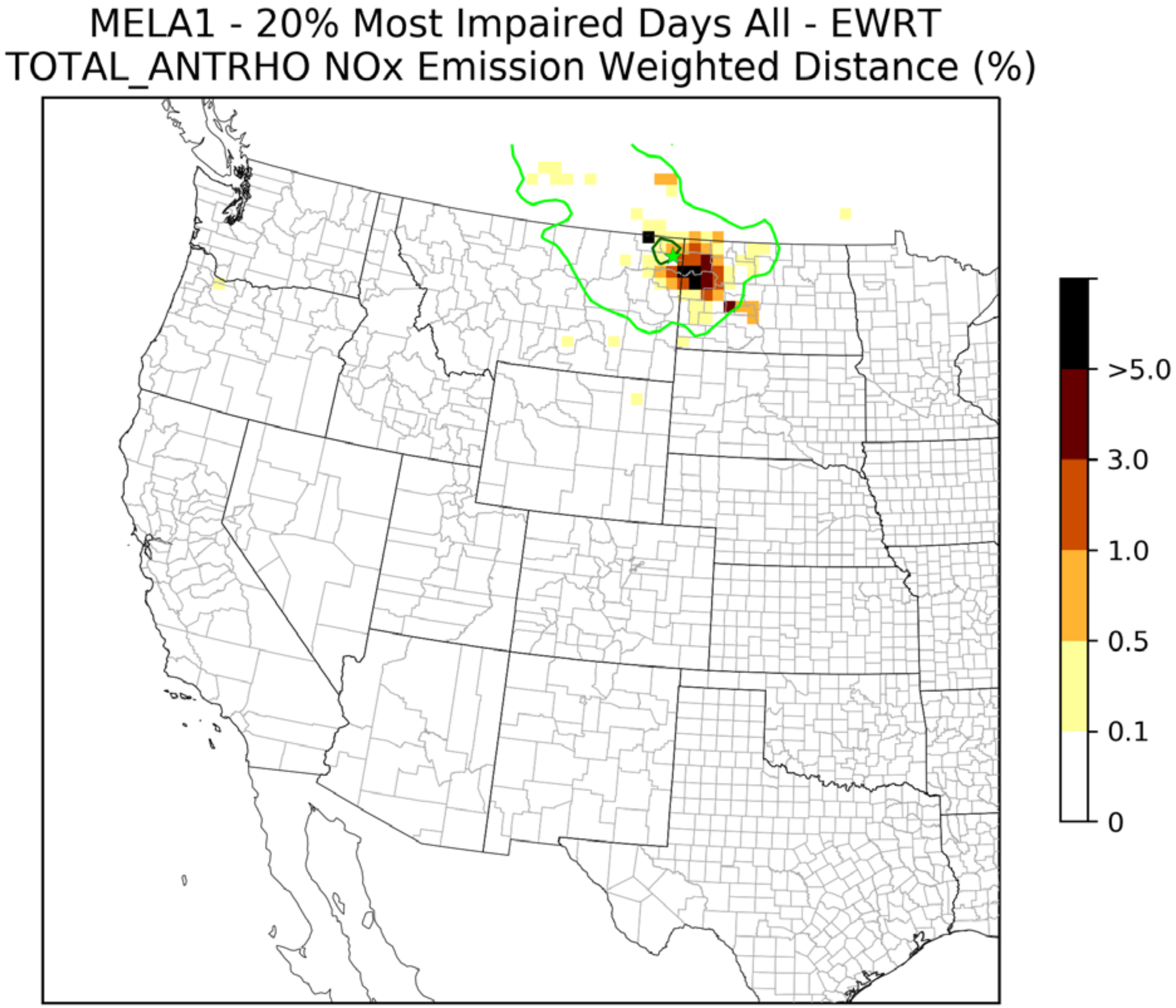
NOx

Extinction Weighted Residence Times

NOx

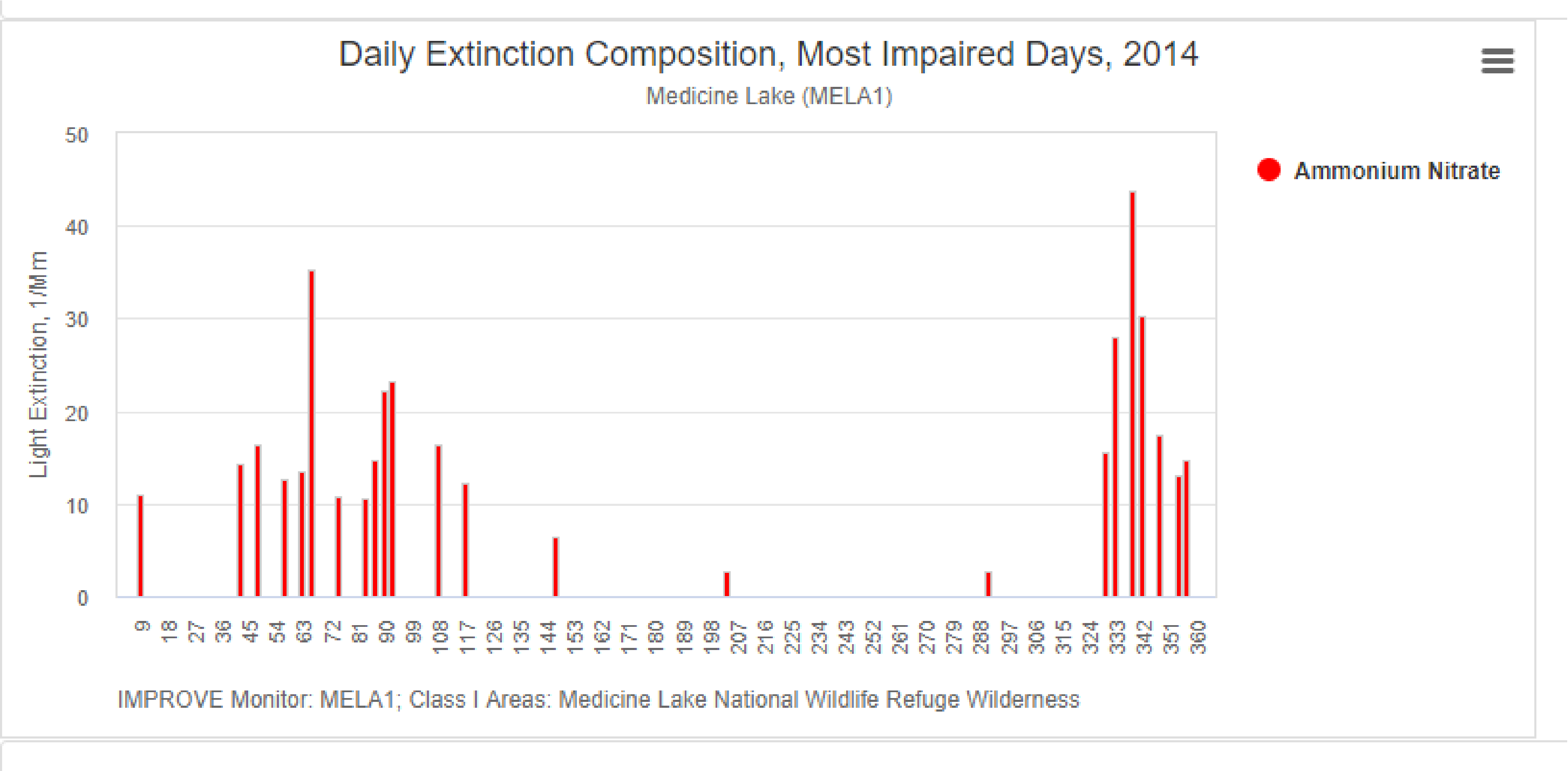


MELA1 - 20% Most Impaired Days All - EWRT
AREA NOx Emission Weighted Distance (%)



MELA1 - 20% Most Impaired Days All - EWRT
TOTAL_ANTRHO NOx Emission Weighted Distance (%)

MIDs in 2014


Daily Extinction Composition, Most Impaired Days, 2014
Medicine Lake (MELA1)
Light Extinction, 1/Mm
0
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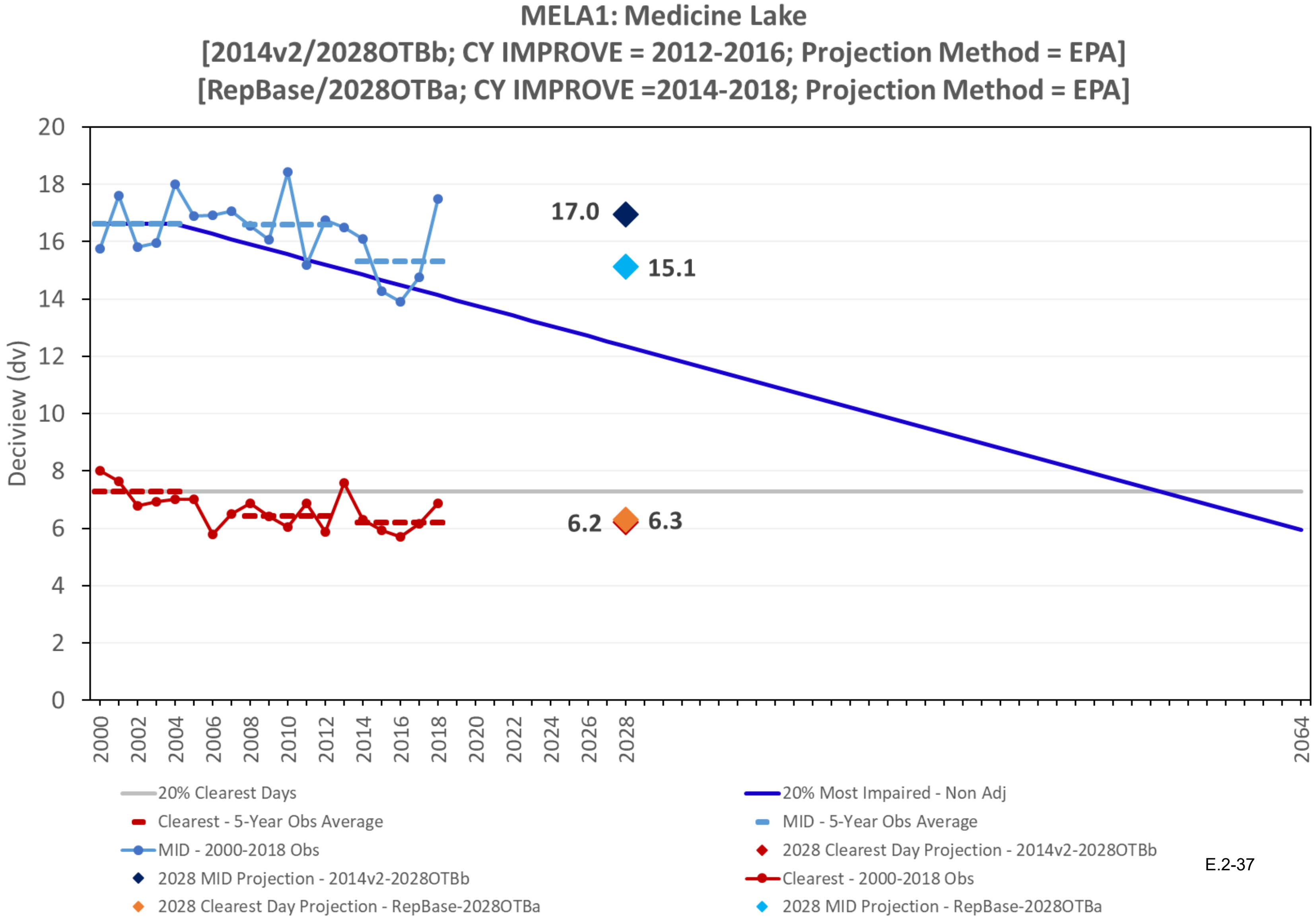
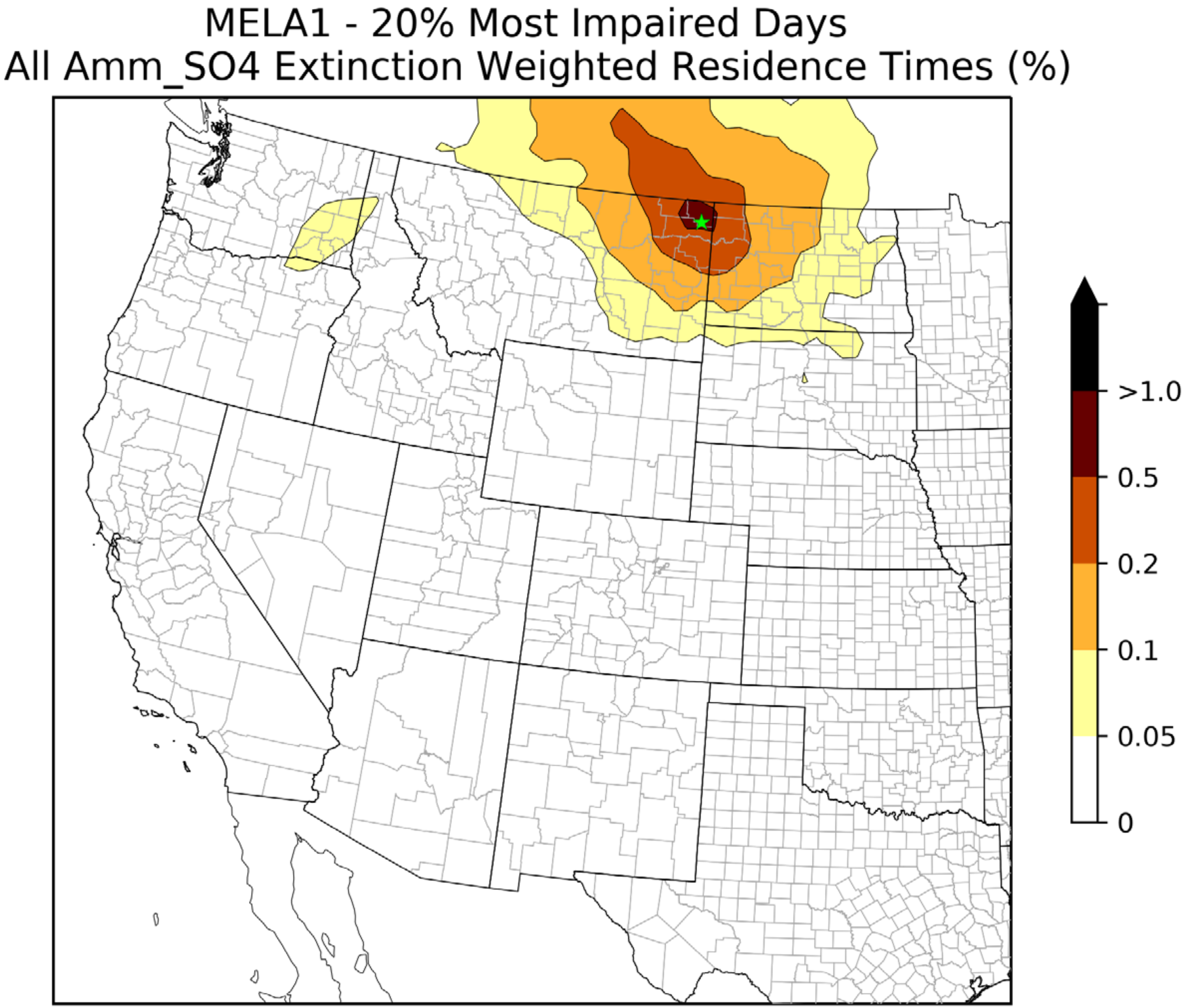
● Ammonium Nitrate
IMPROVE Monitor: MELA1; Class I Areas: Medicine Lake National Wildlife Refuge Wilderness

MELA URP & 2028 Projections

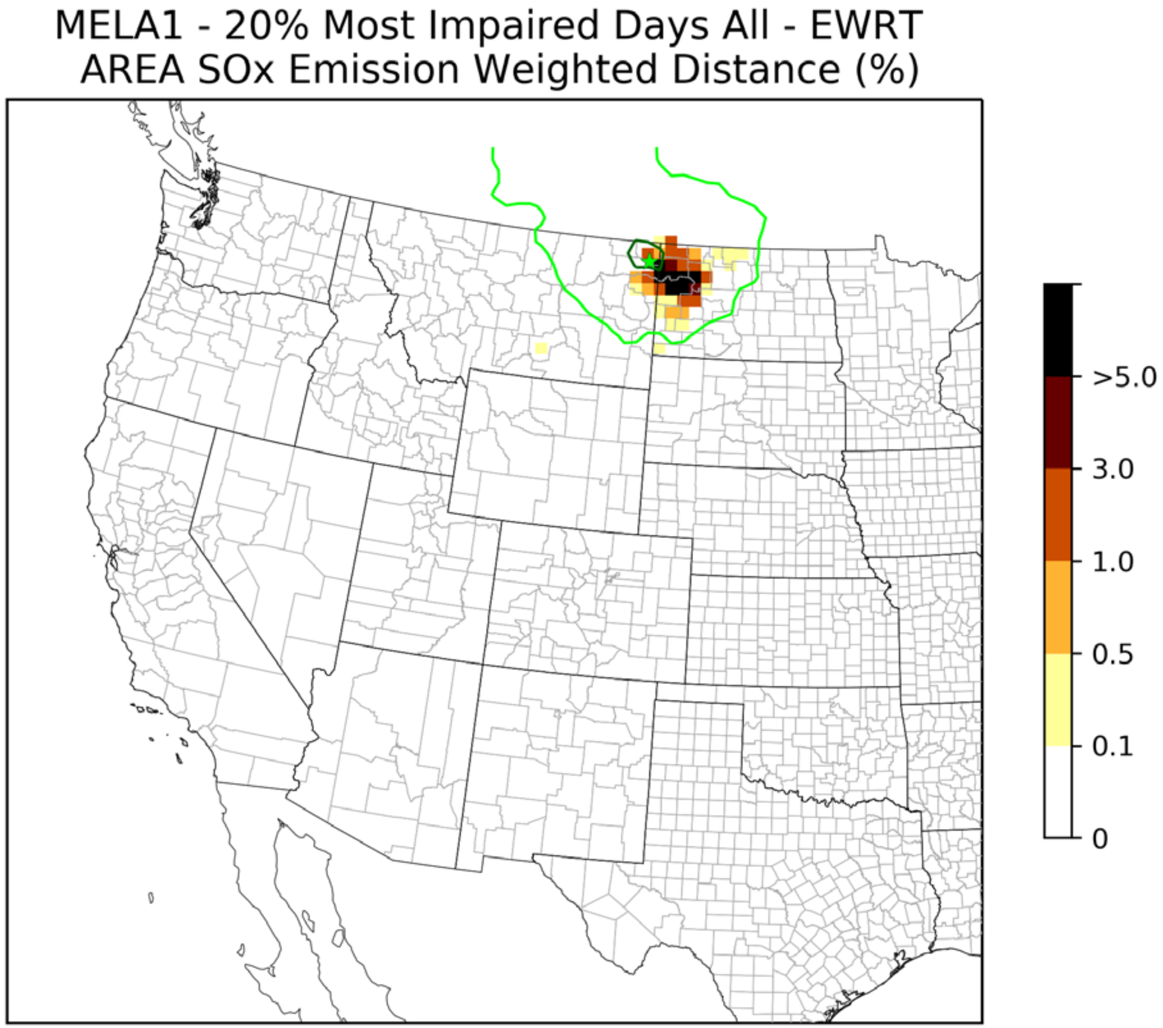

MELA1: Medicine Lake
[2014v2/2028OTBb; CY IMPROVE = 2012-2016; Projection Method = EPA]
[RepBase/2028OTBa; CY IMPROVE =2014-2018; Projection Method = EPA]

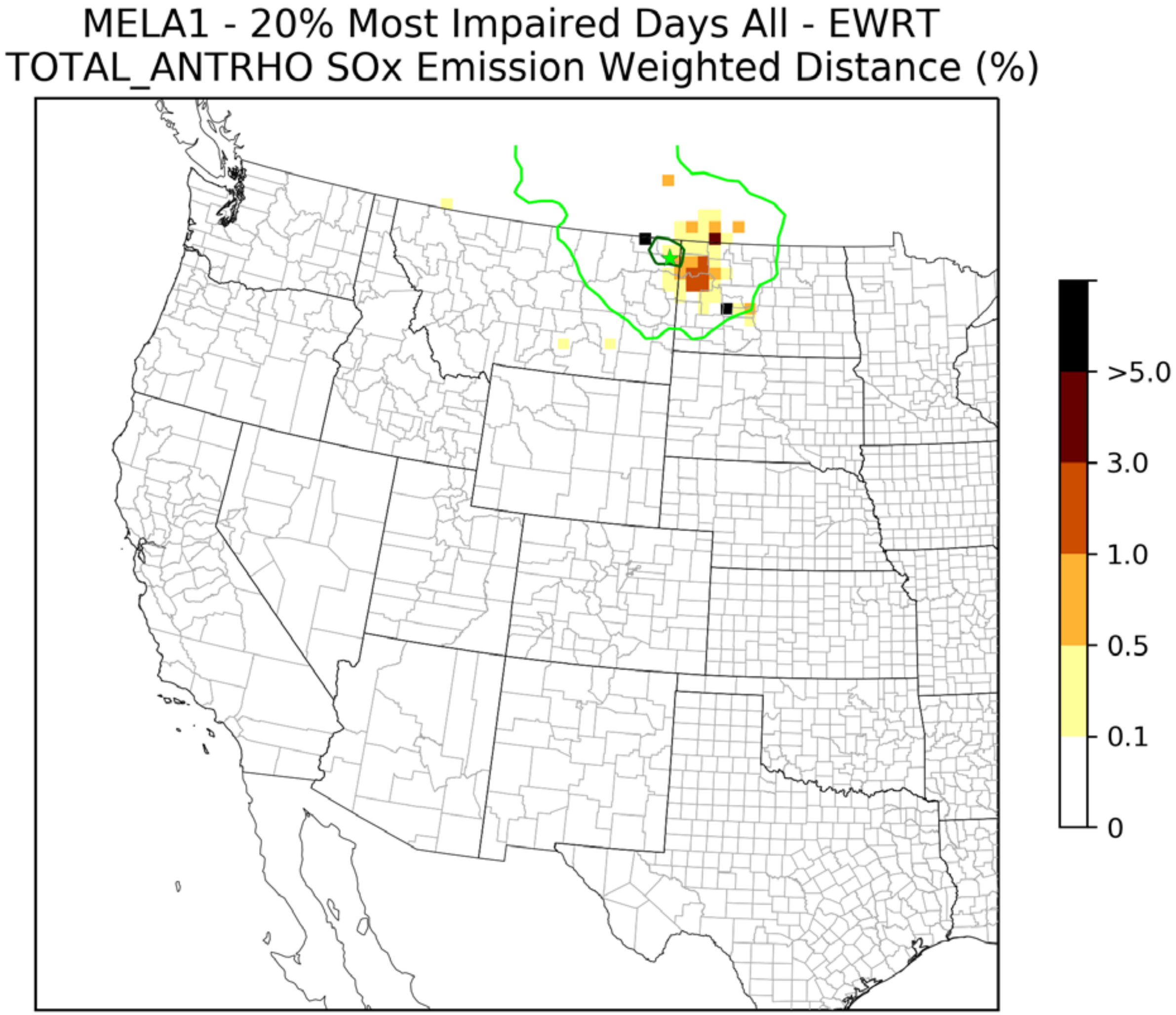


SOx

Extinction Weighted Residence Times

SOx


MELA1 - 20% Most Impaired Days All - EWRT
AREA SOx Emission Weighted Distance (%)
>5.0
3.0
1.0
0.5
0.1
0


MELA1 - 20% Most Impaired Days All - EWRT
TOTAL_ANTRHO SOx Emission Weighted Distance (%)
>5.0
3.0
1.0
0.5
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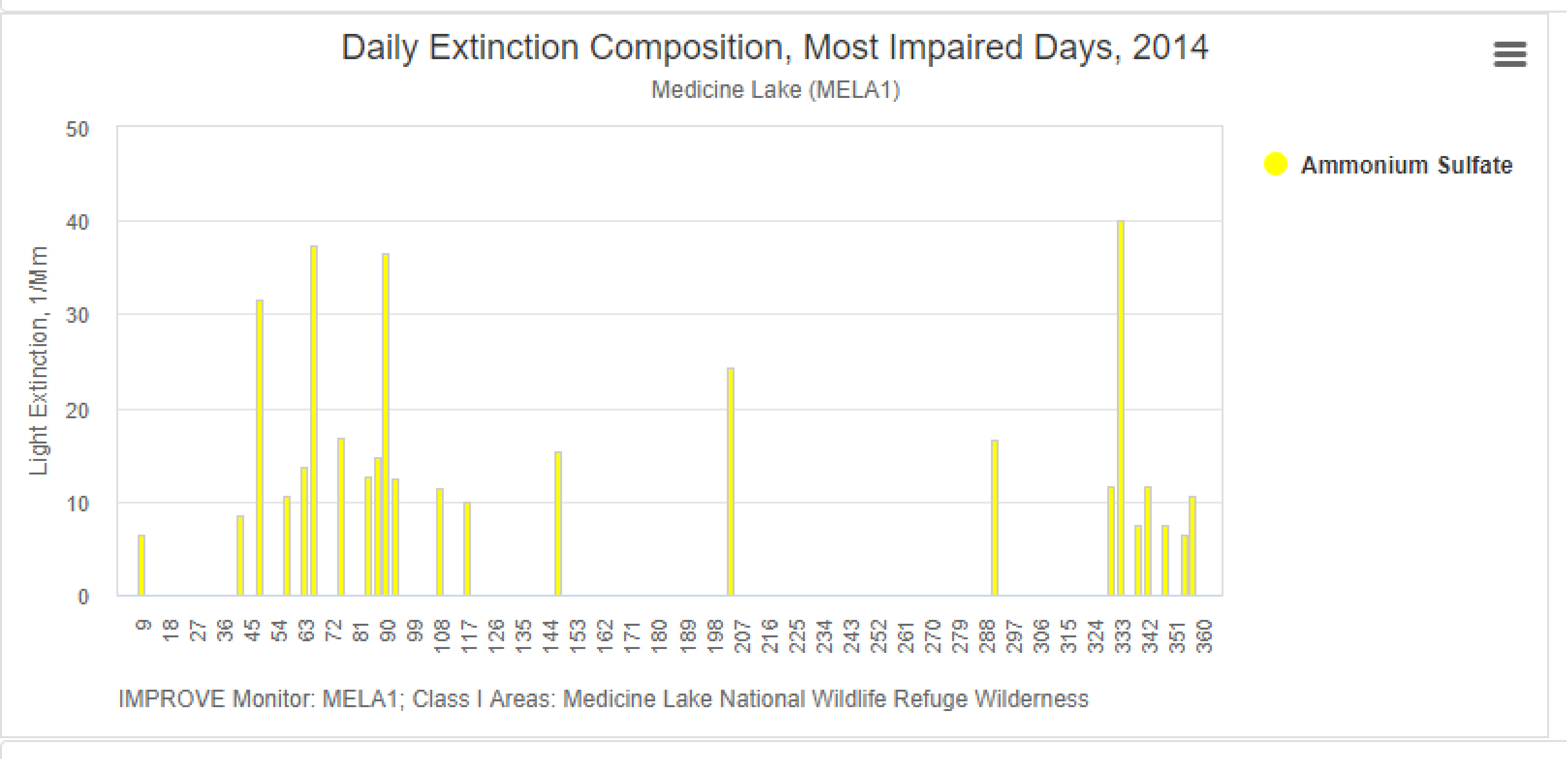
MIDs in 2014


Daily Extinction Composition, Most Impaired Days, 2014
Medicine Lake (MELA1)
Light Extinction, 1/Mm
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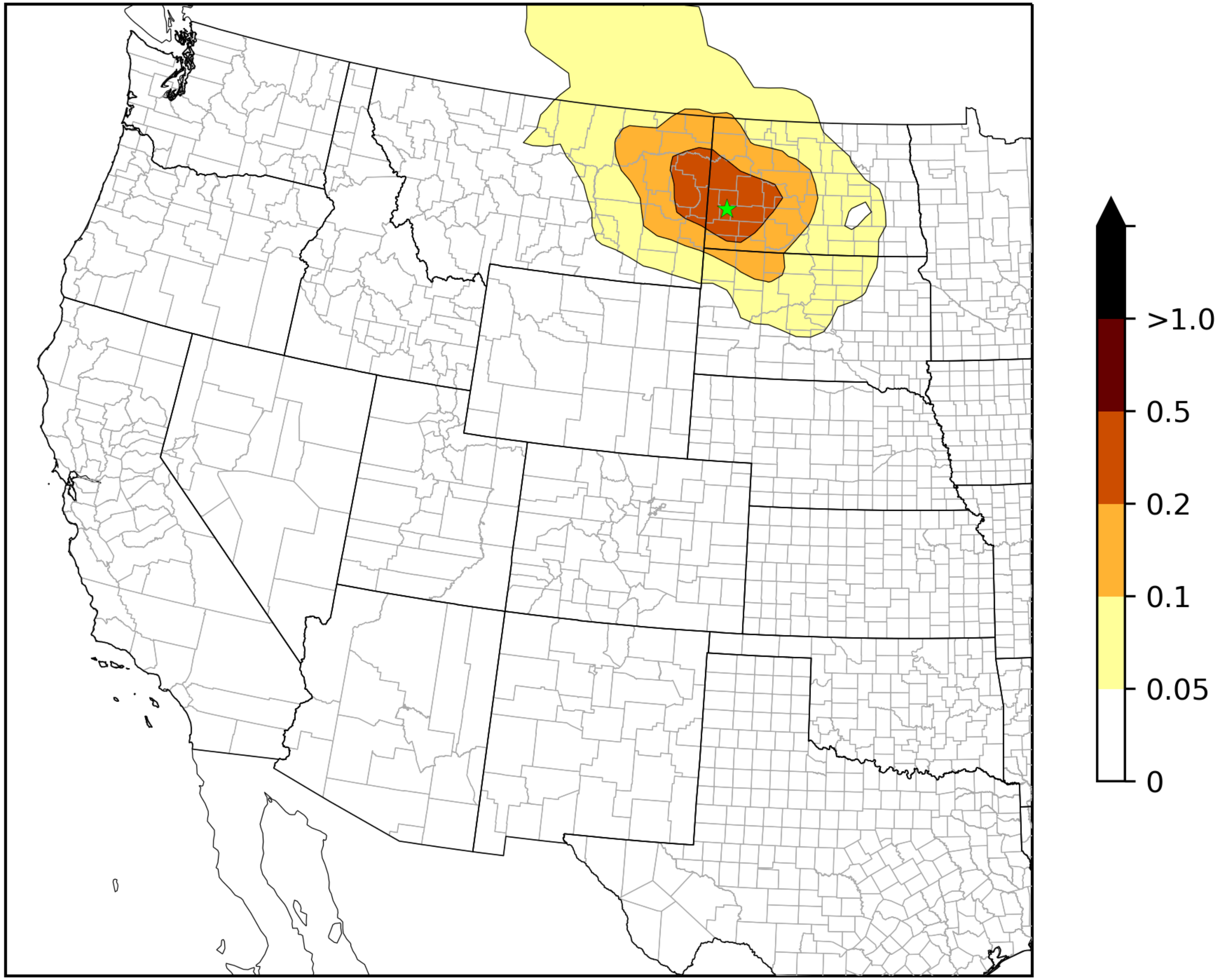
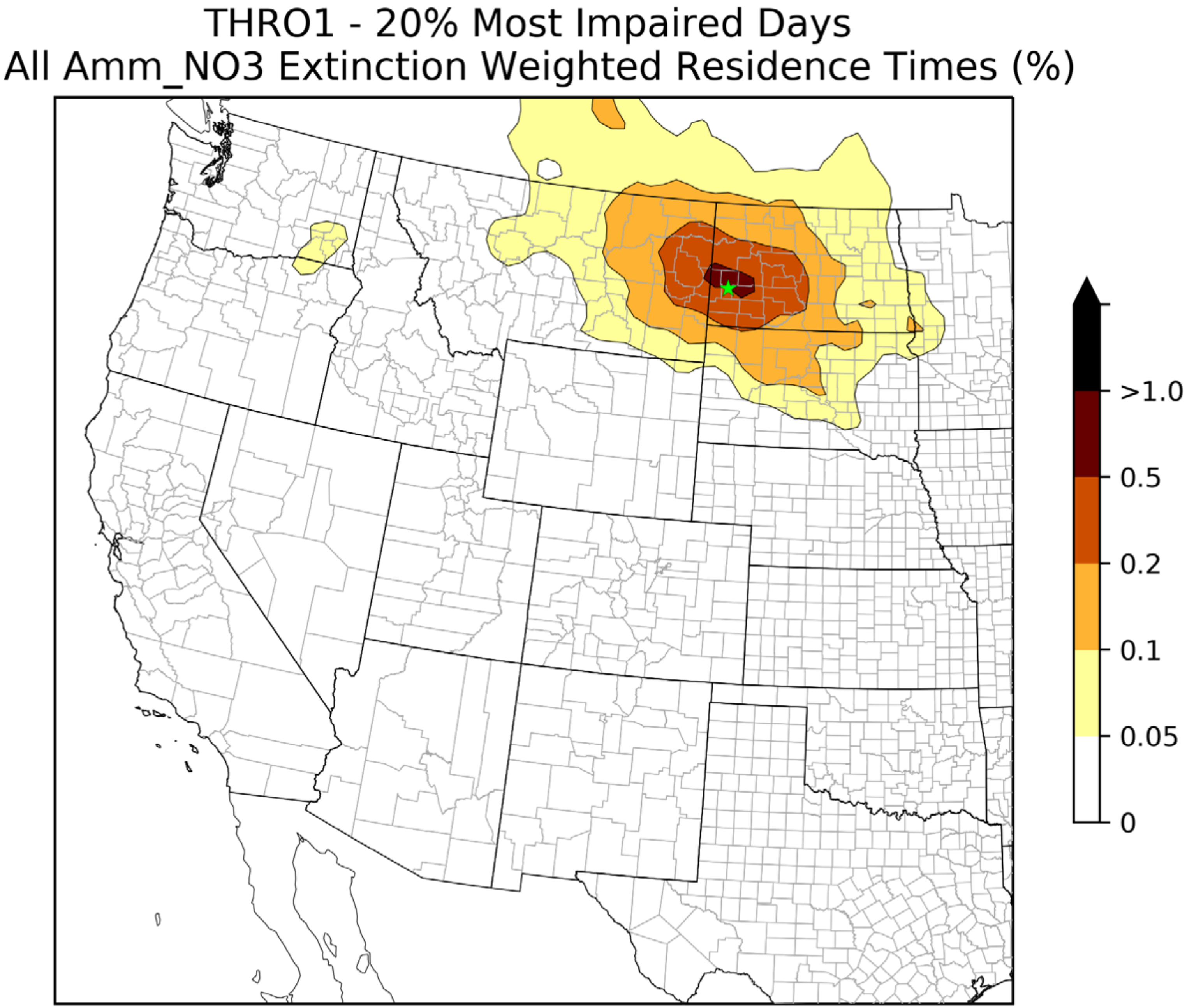
Ammonium Sulfate
IMPROVE Monitor: MELA1; Class I Areas: Medicine Lake National Wildlife Refuge Wilderness

THRO1

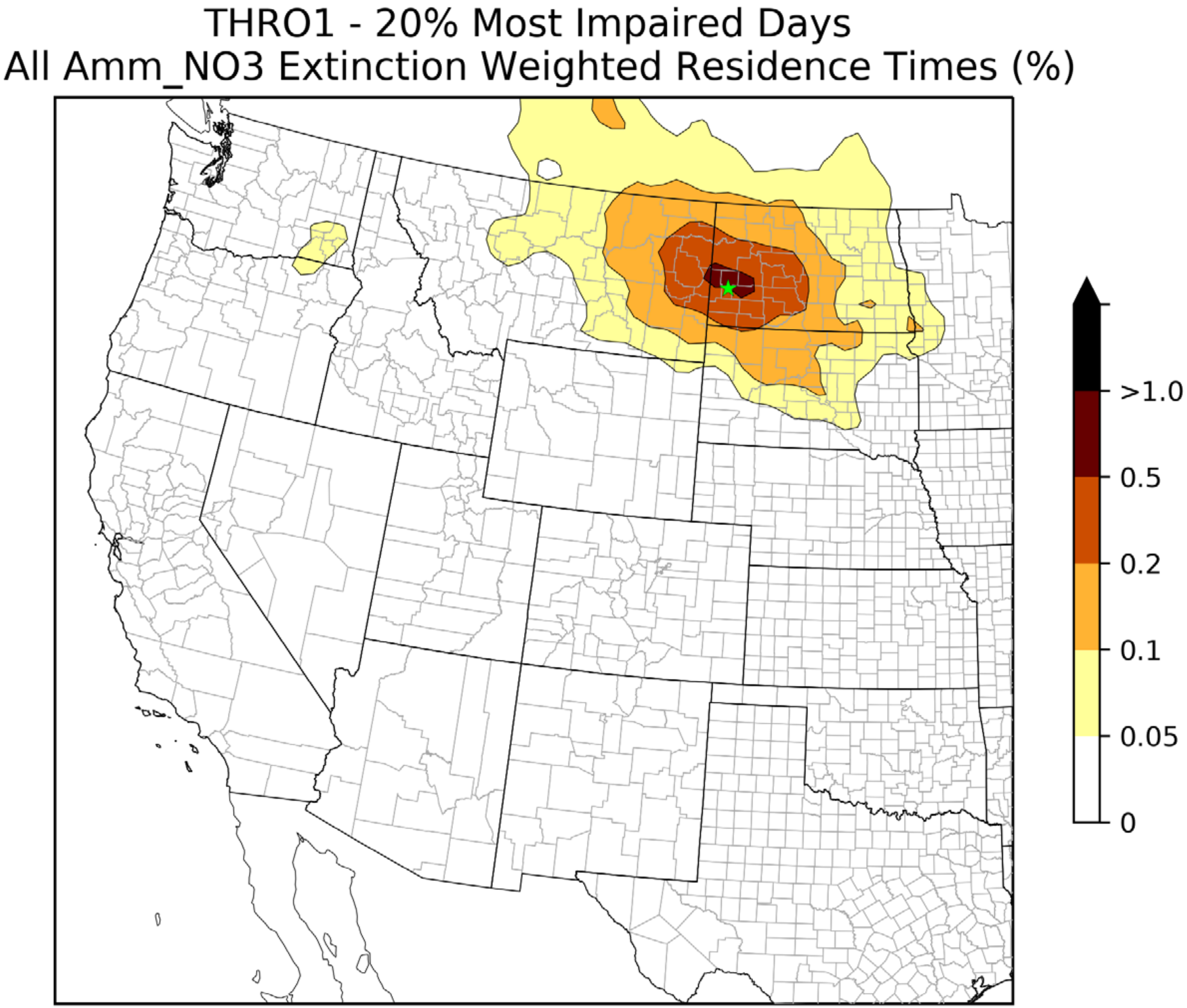
THRO1 - 20% Most Impaired Days All Residence Times (%)



Area of Influence



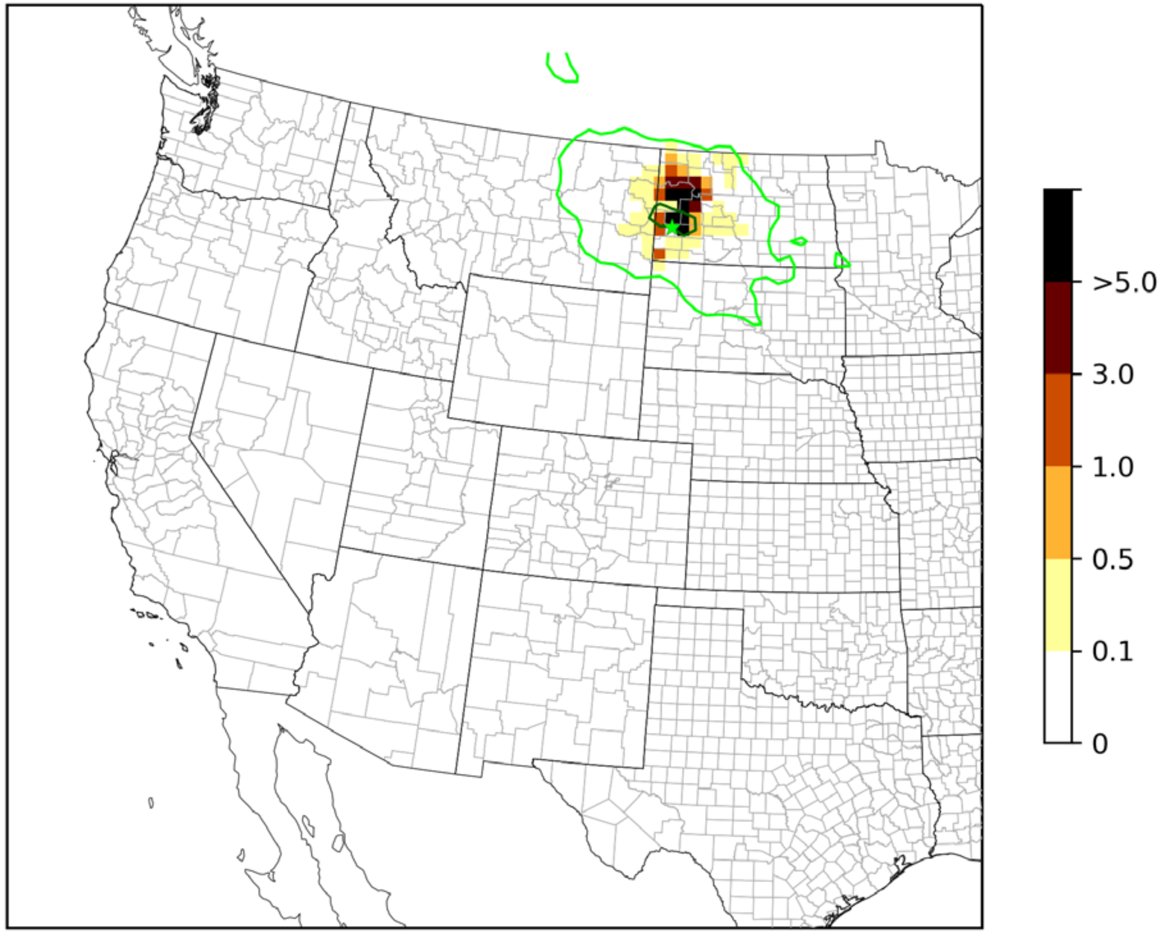
Area of Influence



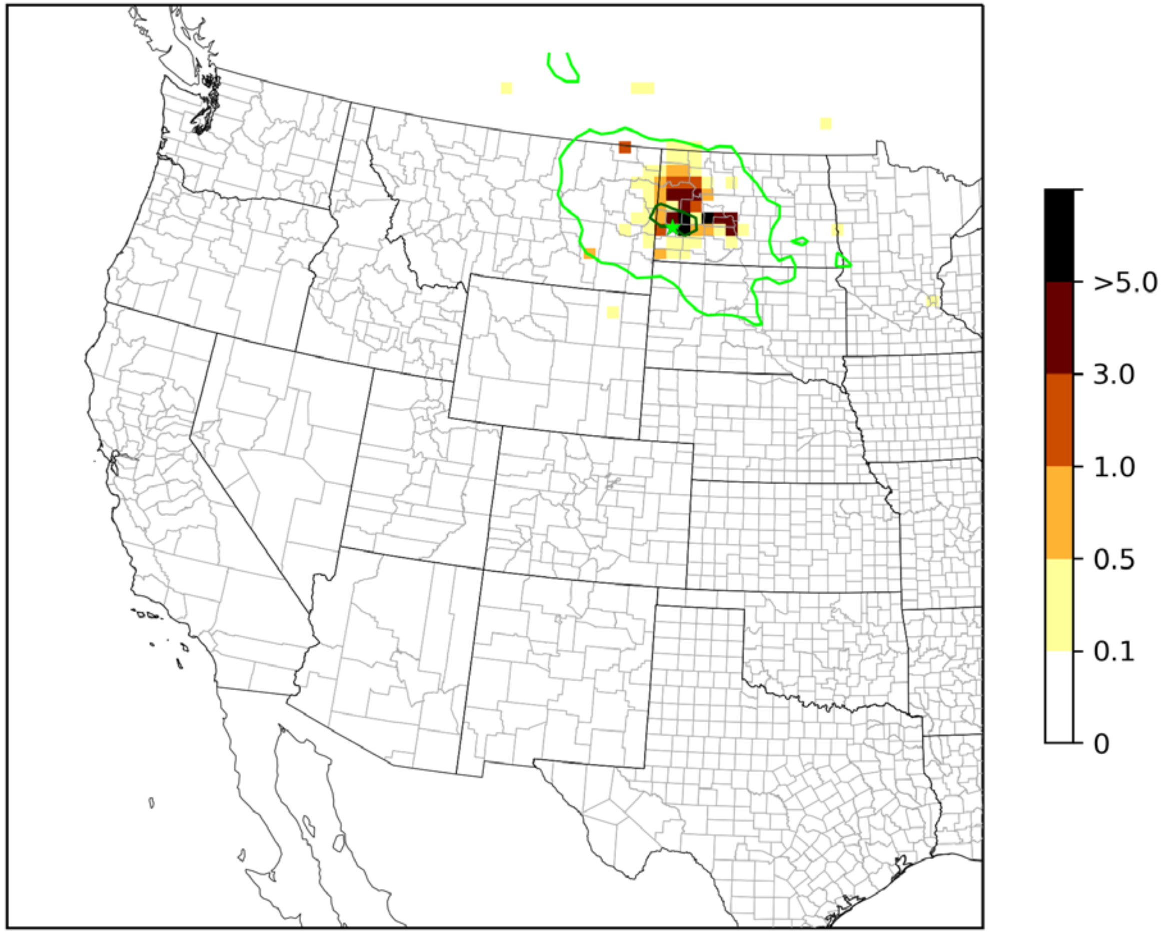
NOx

Extinction Weighted Residence Times

NOx

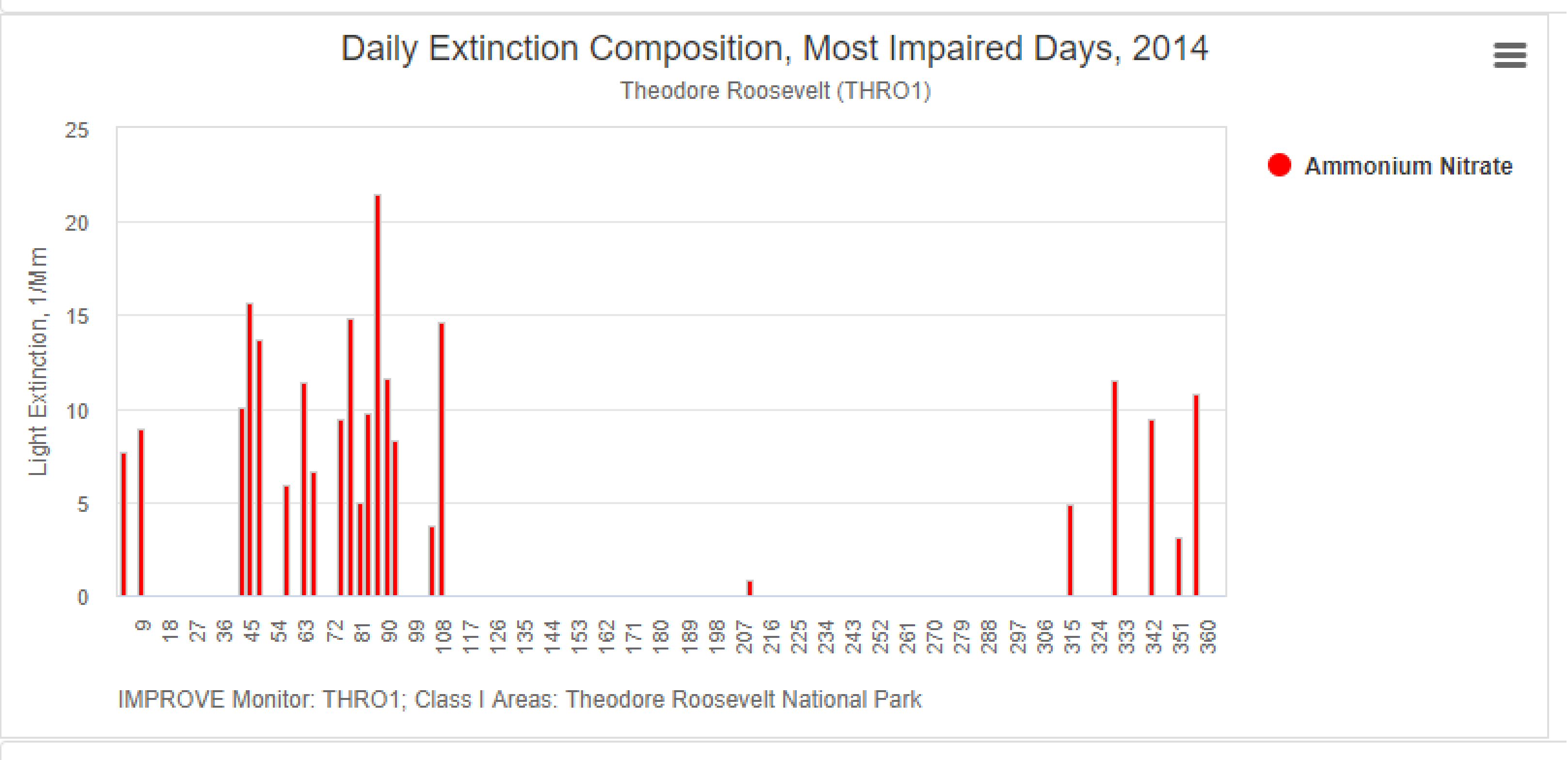


THRO1 - 20% Most Impaired Days All - EWRT
AREA NOx Emission Weighted Distance (%)



THRO1 - 20% Most Impaired Days All - EWRT
TOTAL_ANTRHO NOx Emission Weighted Distance (%)

MIDs in 2014


Daily Extinction Composition, Most Impaired Days, 2014
Theodore Roosevelt (THRO1)
● Ammonium Nitrate
Light Extinction, 1/Mm
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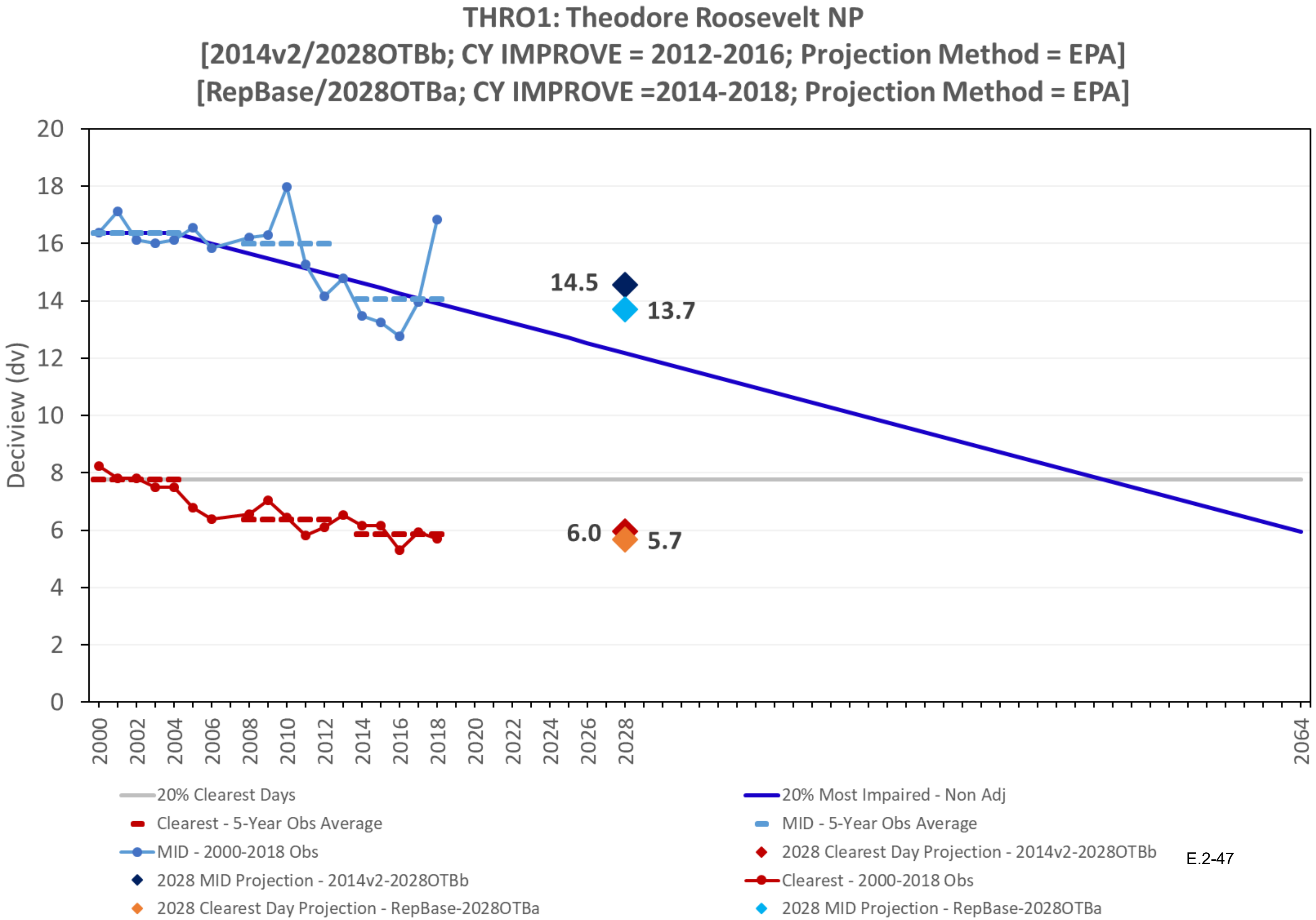
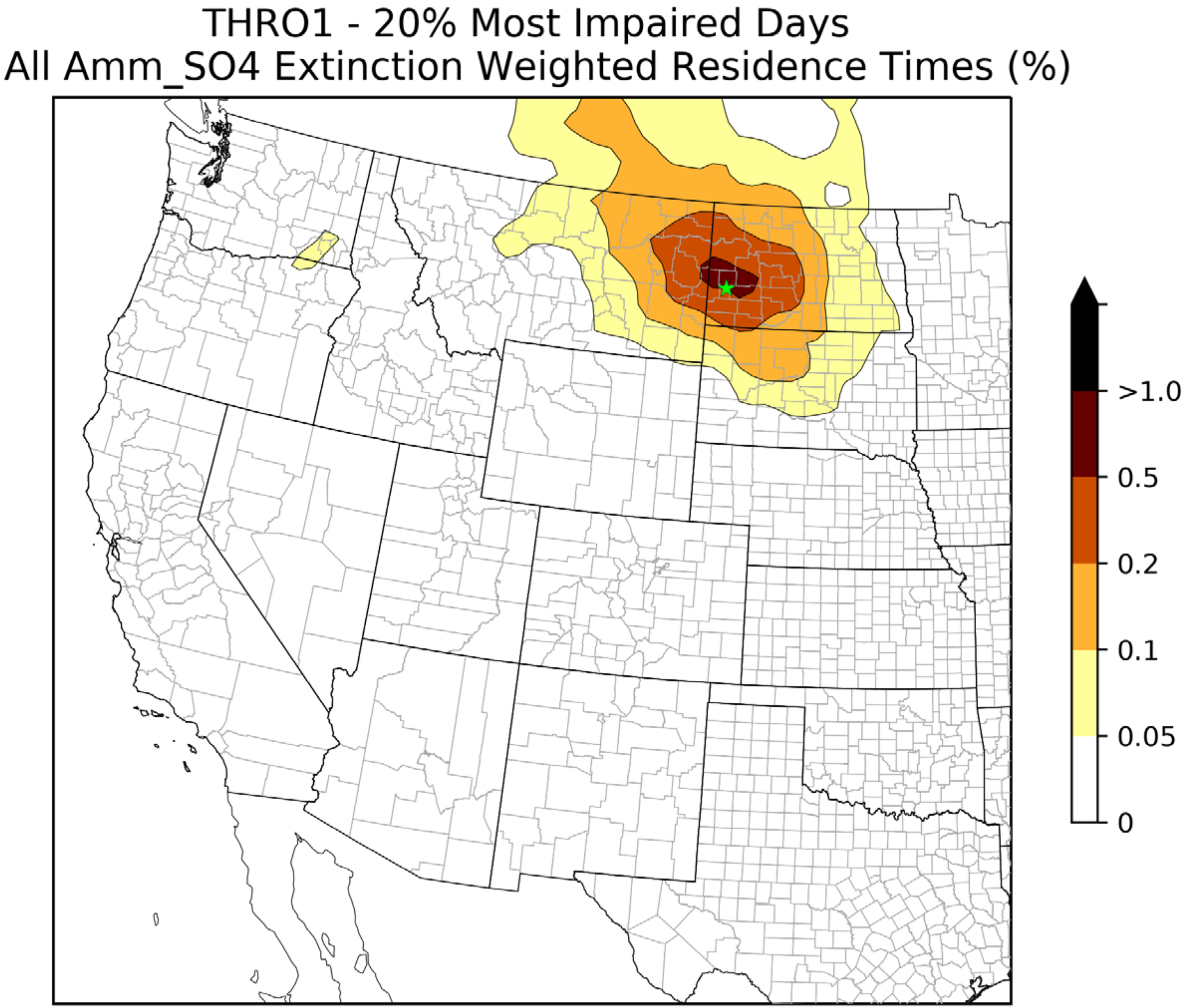
333
342
351
360
IMPROVE Monitor: THRO1; Class I Areas: Theodore Roosevelt National Park

THRO1 URP and 2028 Projections



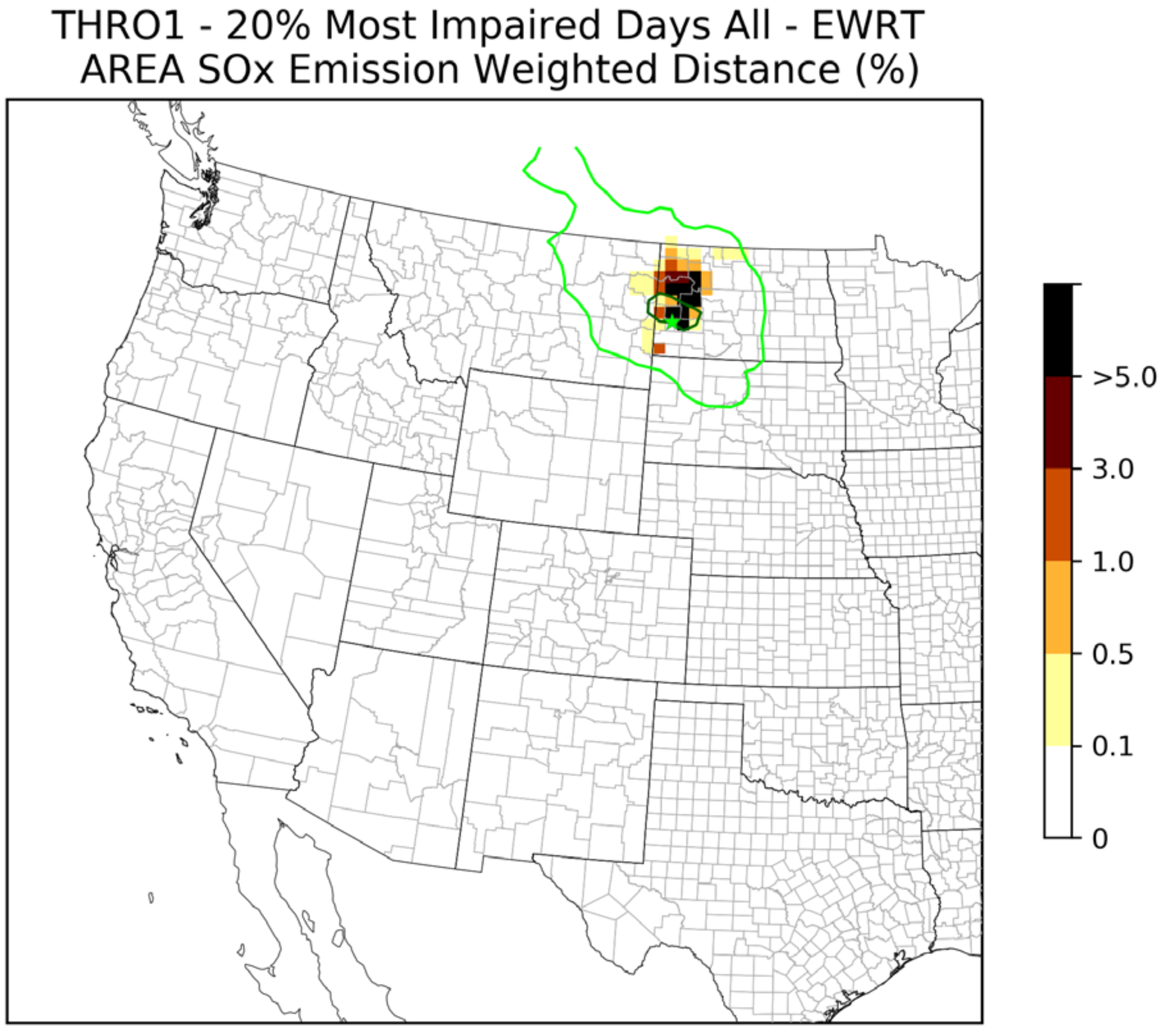
THRO1 - 20% Most Impaired Days
All Amm_SO4 Extinction Weighted Residence Times (%)

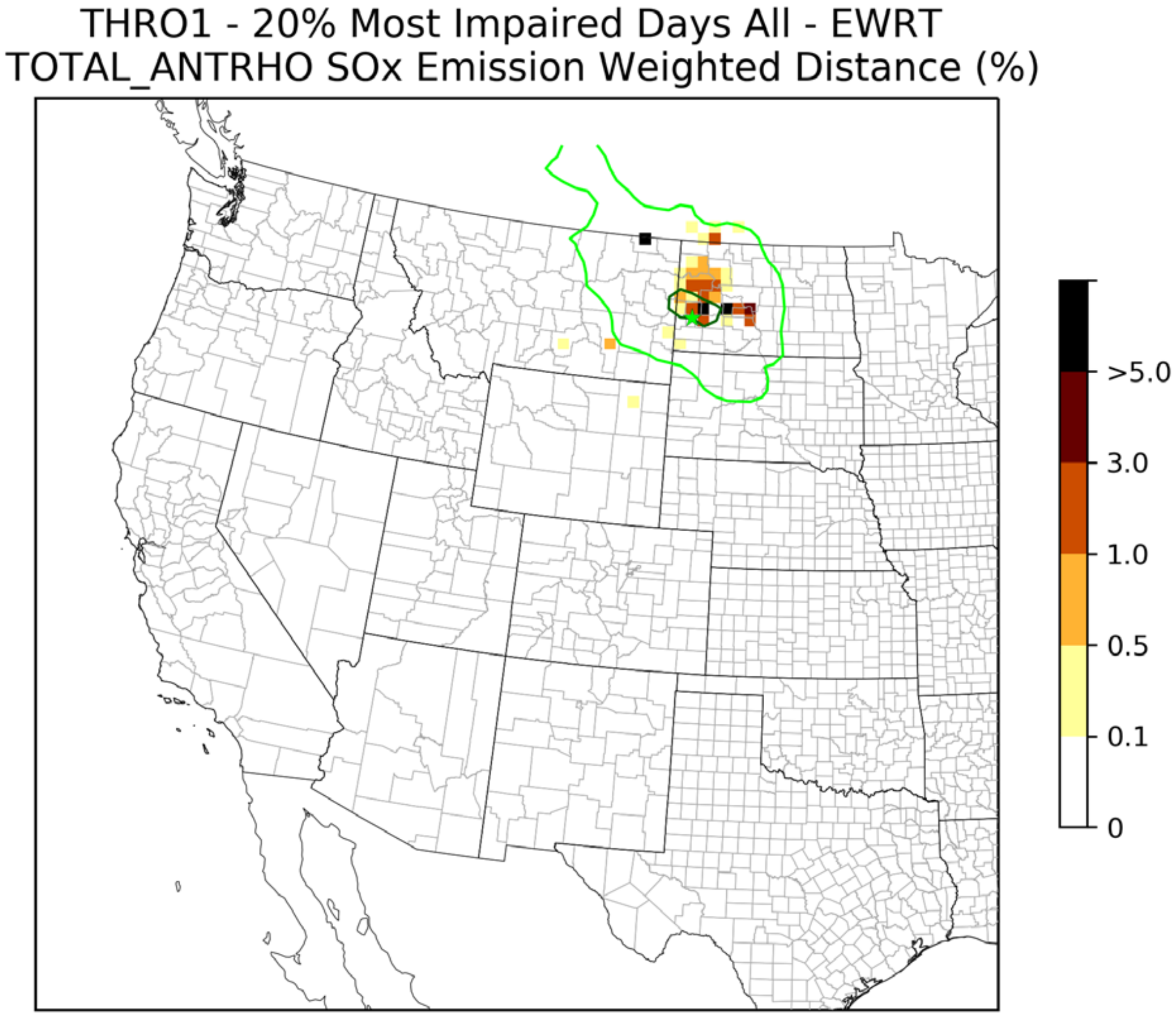


SOx

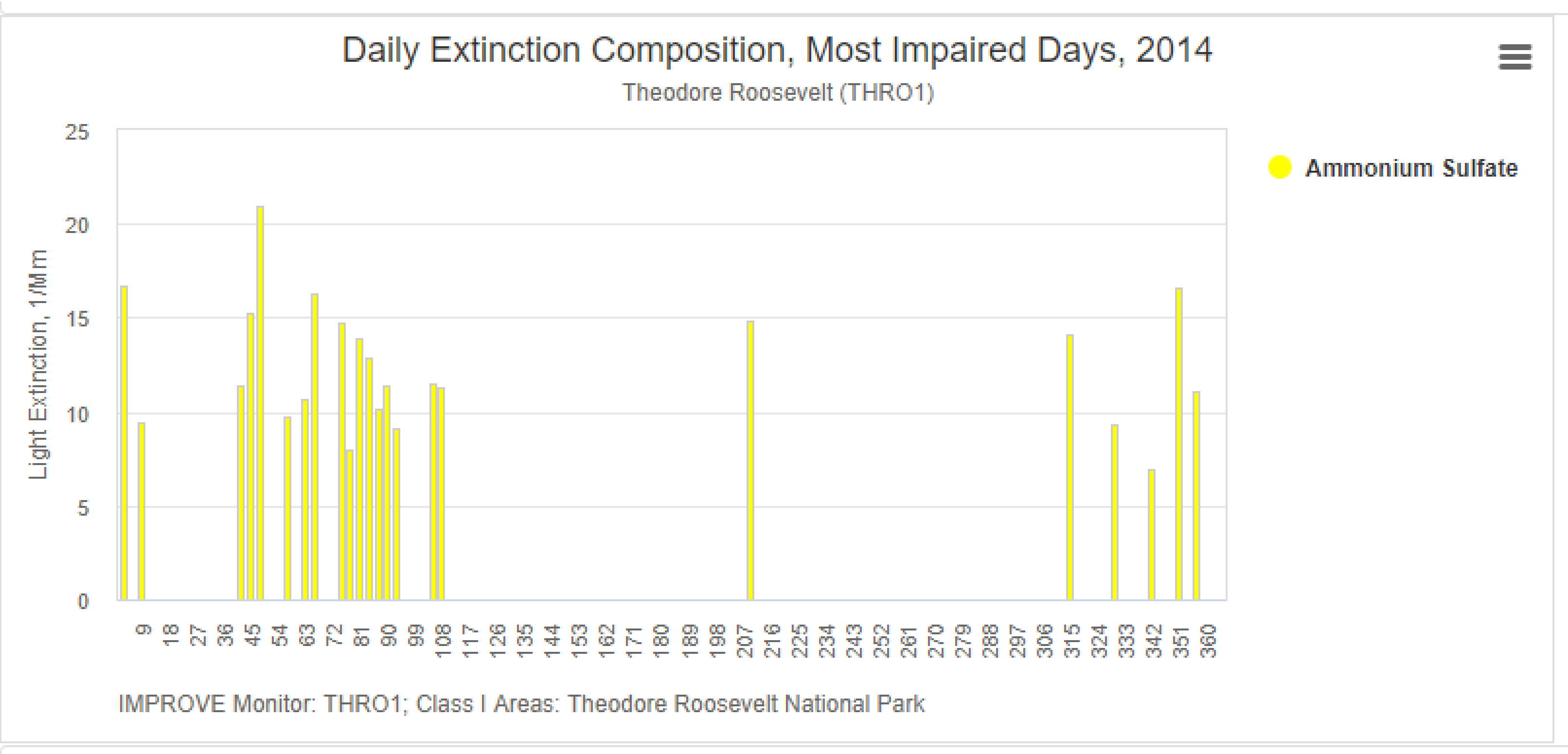
Extinction Weighted Residence Times

SOx

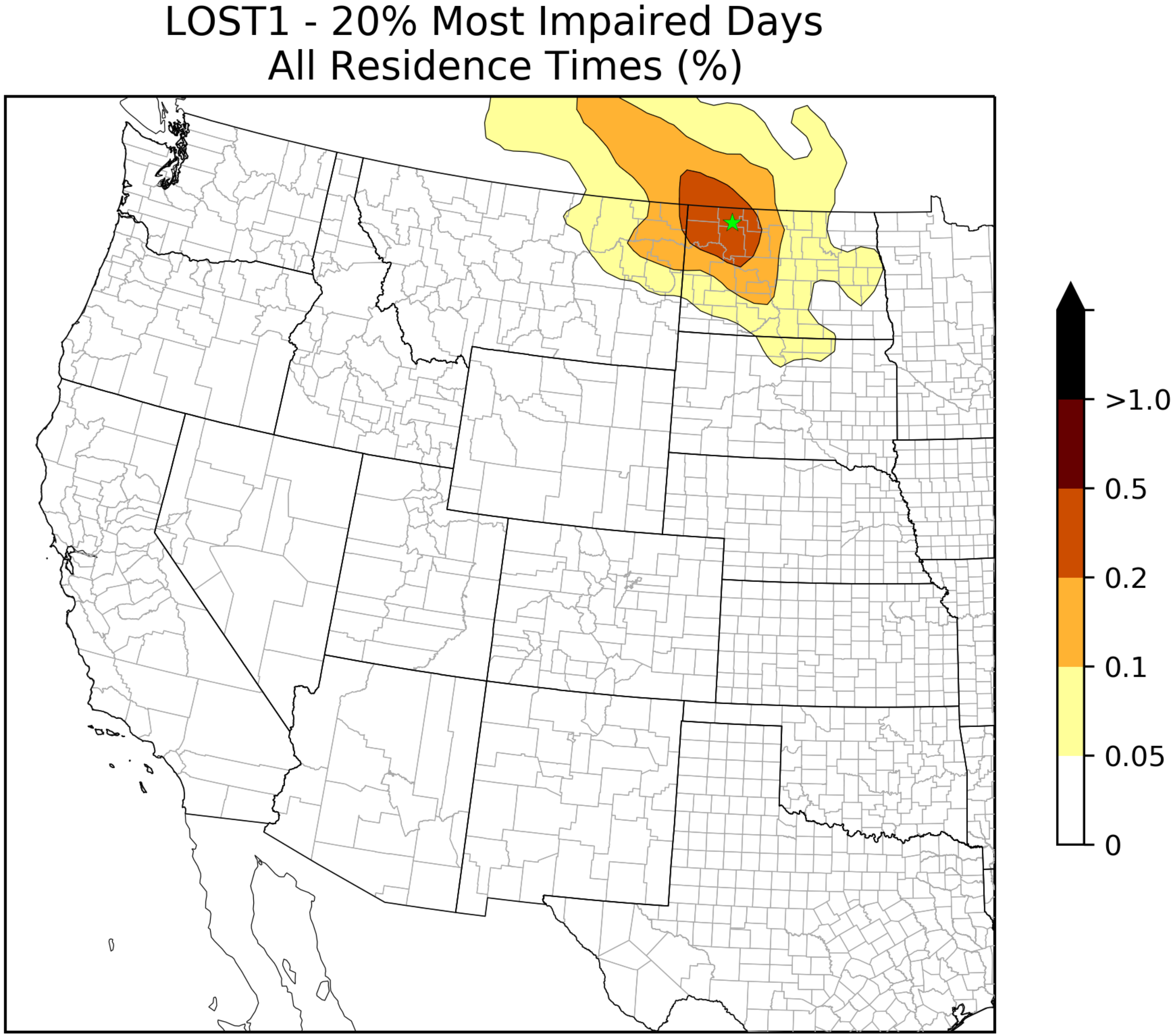

THRO1 - 20% Most Impaired Days All - EWRT
AREA SOx Emission Weighted Distance (%)
>5.0
3.0
1.0
0.5
0.1
0


THRO1 - 20% Most Impaired Days All - EWRT
TOTAL_ANTRHO SOx Emission Weighted Distance (%)
>5.0
3.0
1.0
0.5
0.1
0

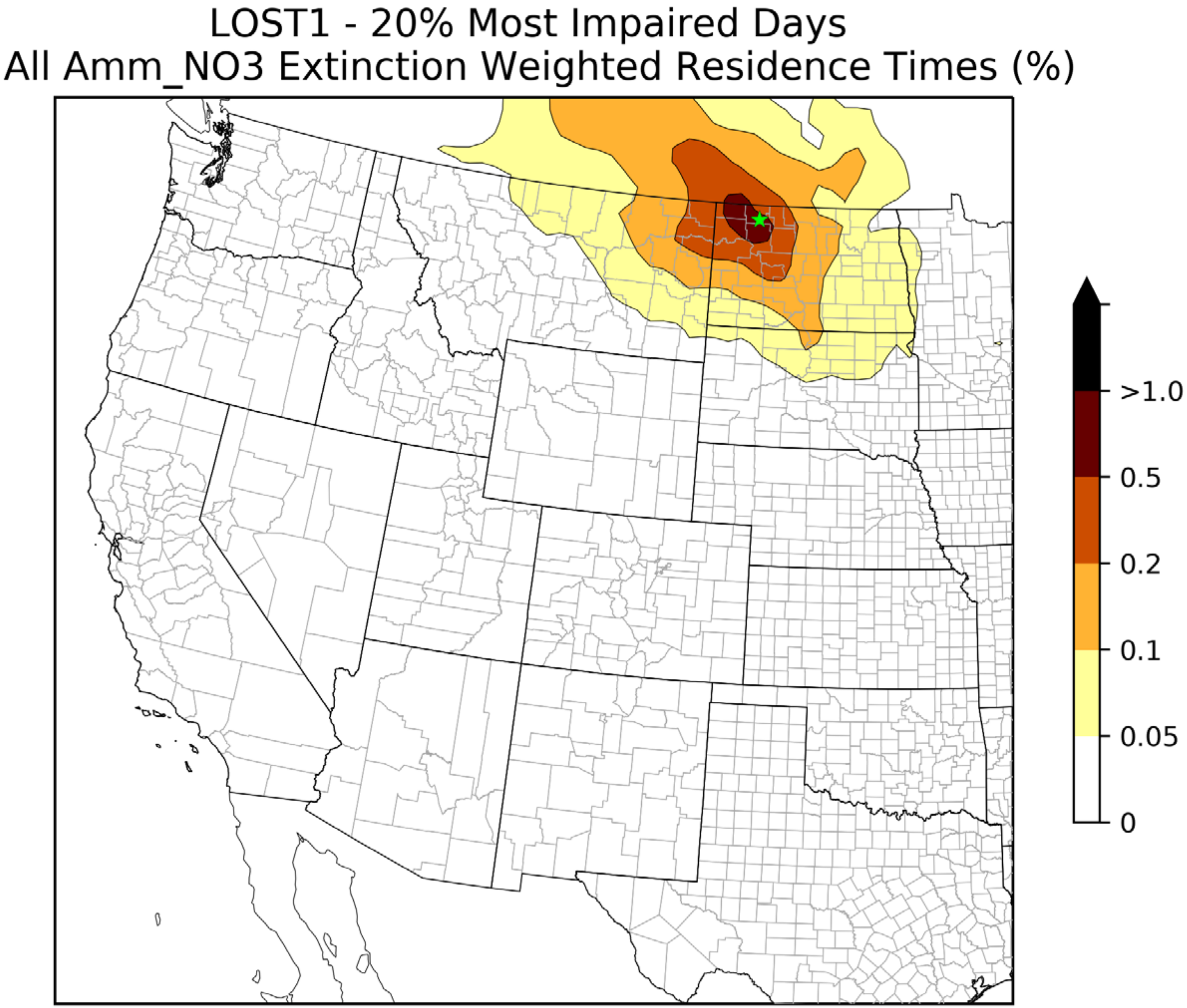
MIDs in 2014


Daily Extinction Composition, Most Impaired Days, 2014
Theodore Roosevelt (THRO1)
Light Extinction, 1/Mm
0
5
10
15
20
25
9
18
27
36
45
54
63
72
81
90
99
108
117
126
135
144
153
162
171
180
189
198
207
216
225
234
243
252
261
270
279
288
297
306
315
324
333
342
351
360
● Ammonium Sulfate
IMPROVE Monitor: THRO1; Class I Areas: Theodore Roosevelt National Park

LOST1



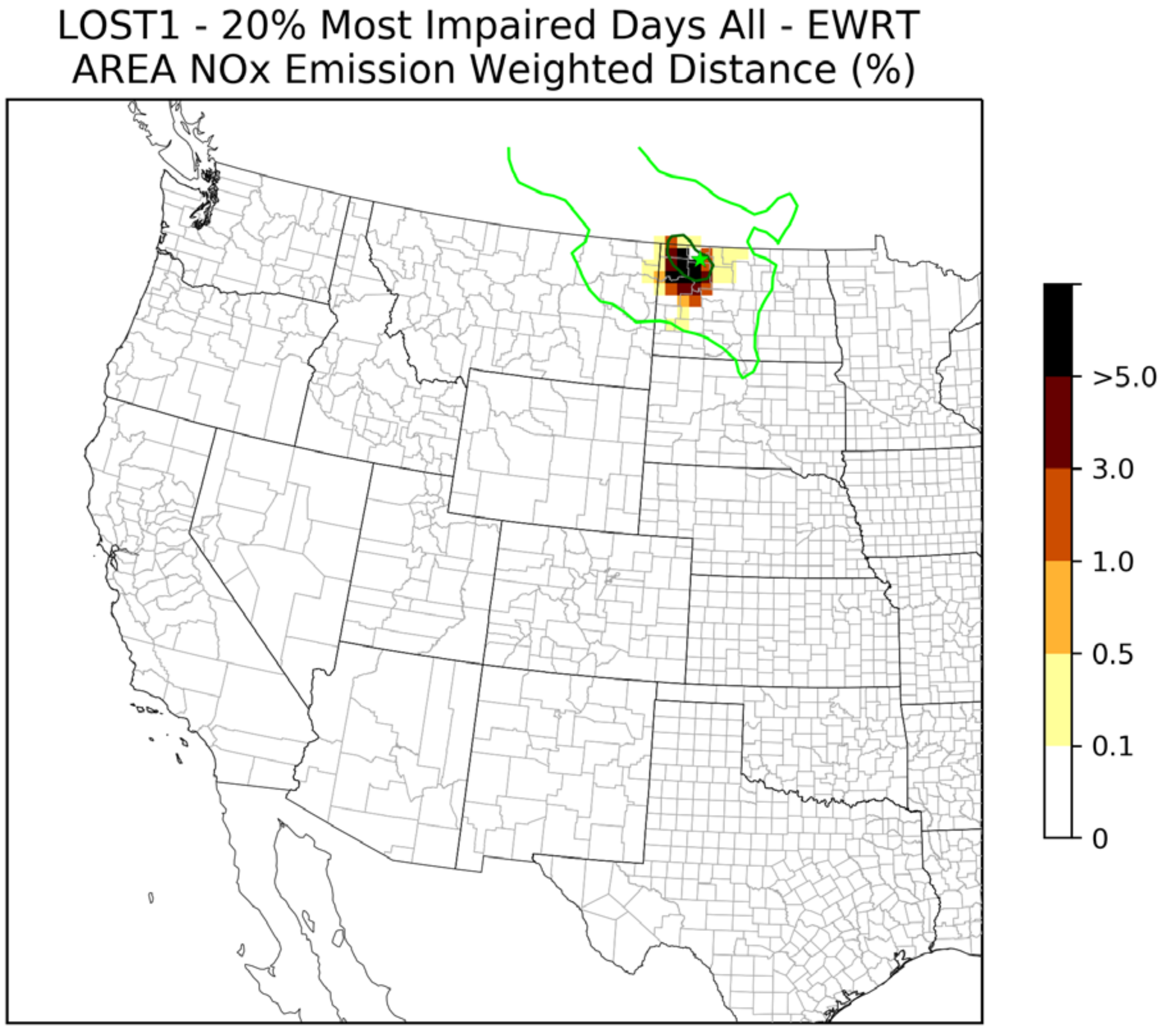
Area of Influence

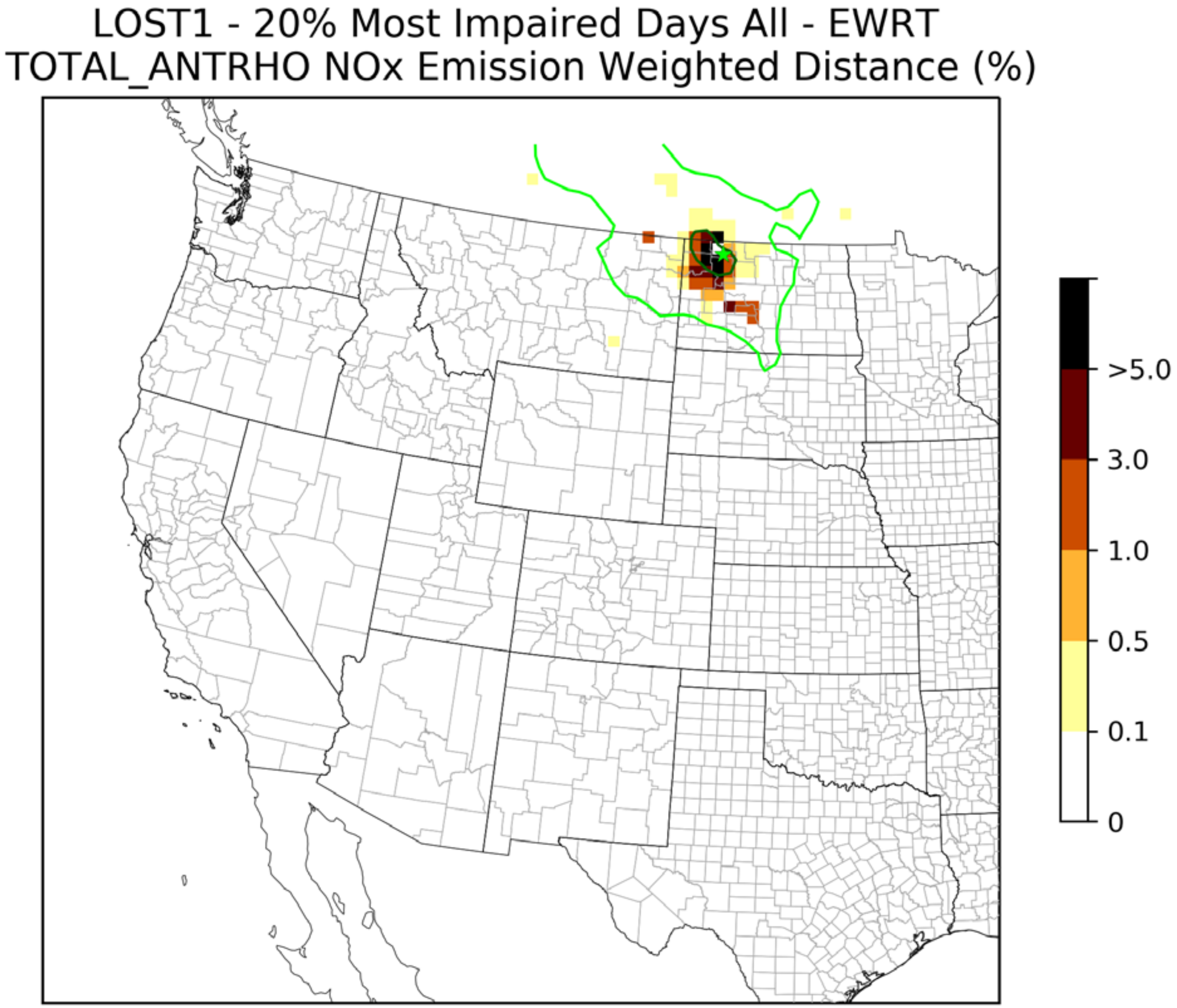


NOx

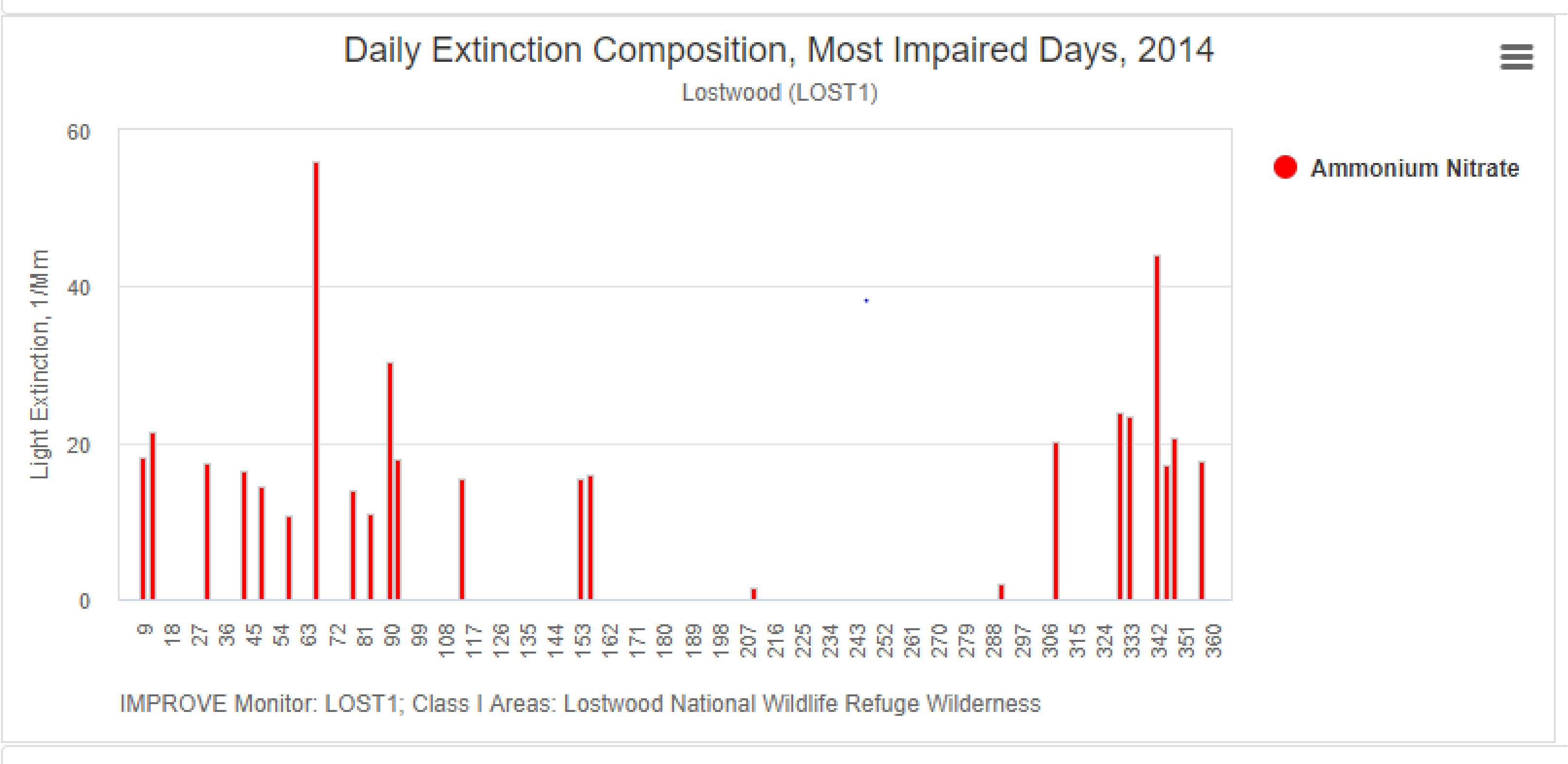
Extinction Weighted Residence Times

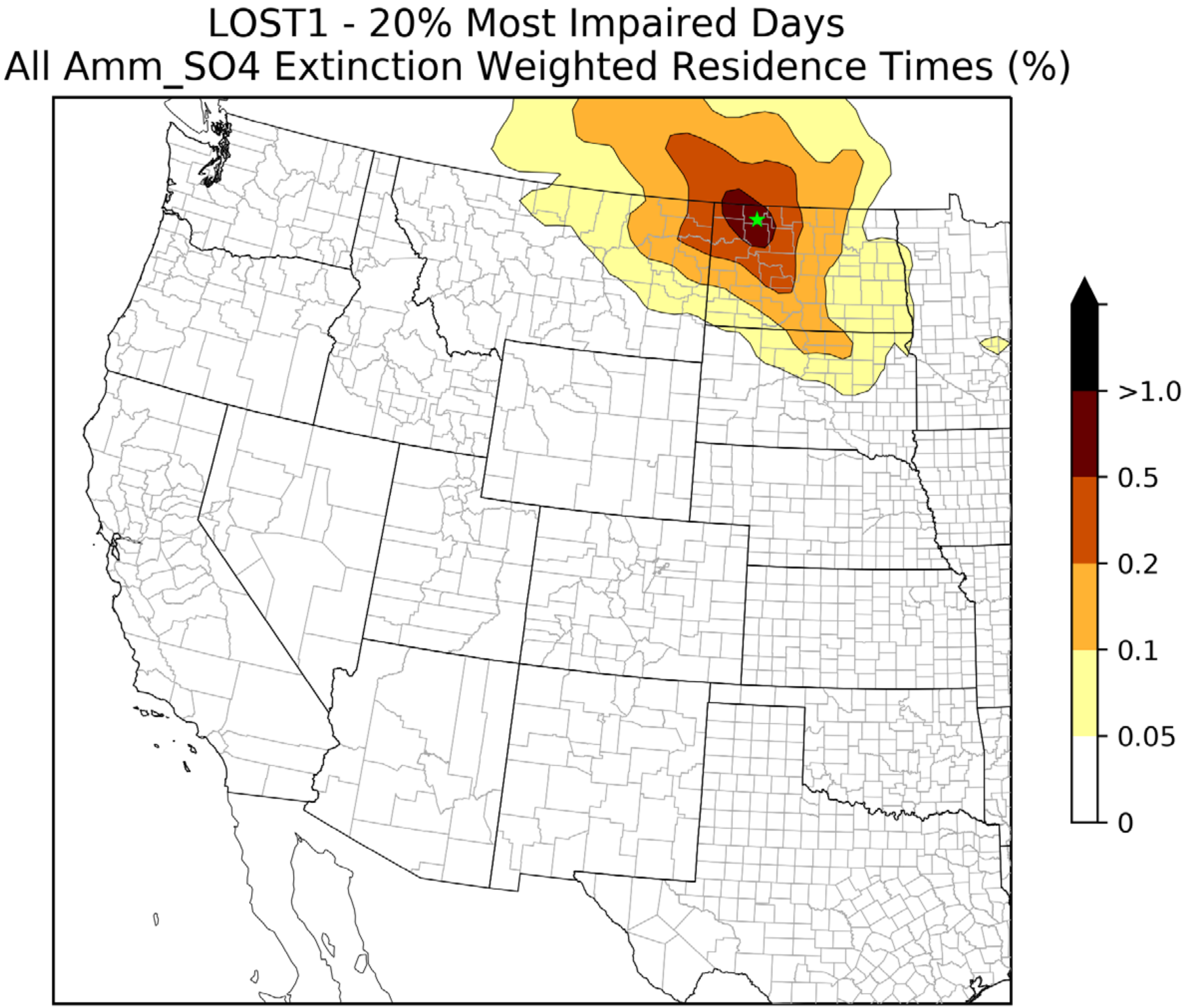
NOx


LOST1 - 20% Most Impaired Days All - EWRT
AREA NOx Emission Weighted Distance (%)
>5.0
3.0
1.0
0.5
0.1
0


LOST1 - 20% Most Impaired Days All - EWRT
TOTAL_ANTRHO NOx Emission Weighted Distance (%)
>5.0
3.0
1.0
0.5
0.1
0

MIDs in 2014

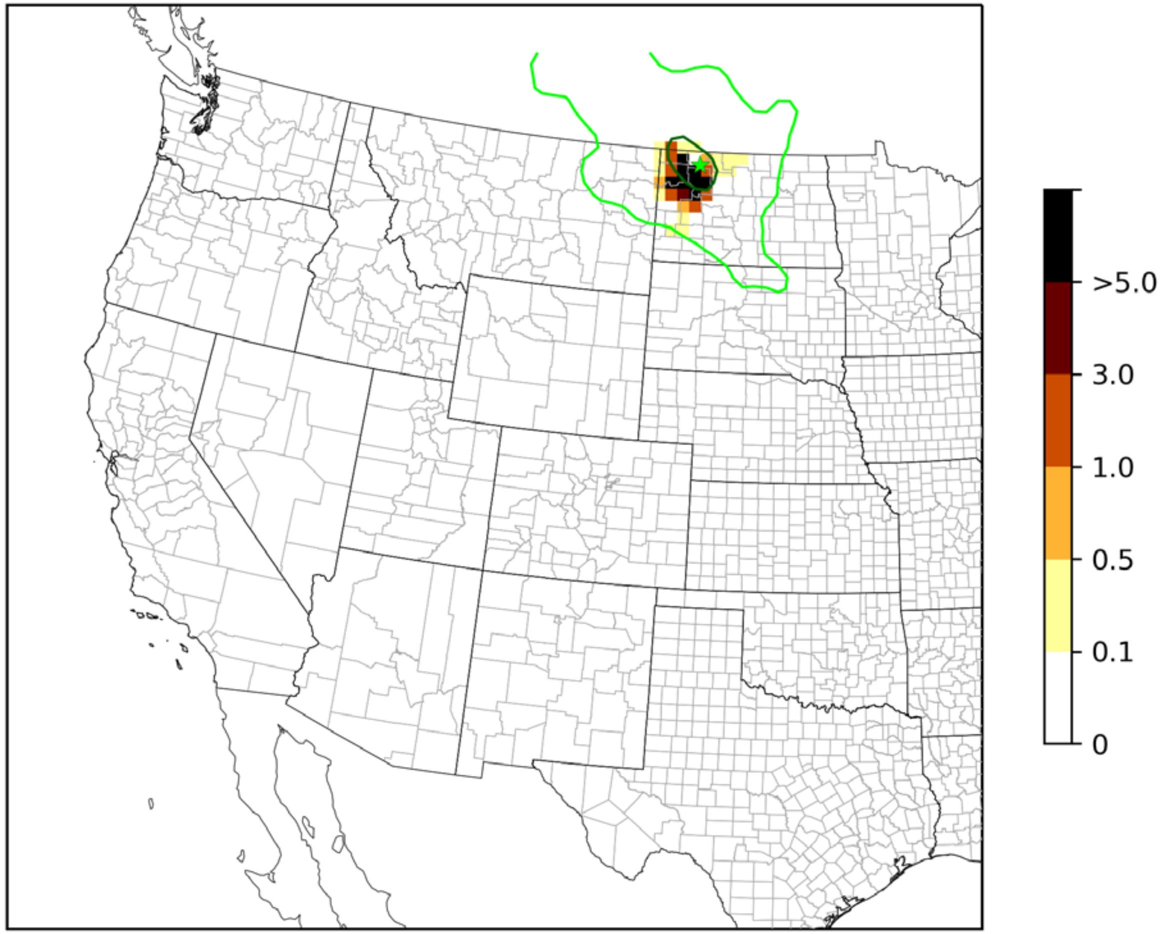

Daily Extinction Composition, Most Impaired Days, 2014
Lostwood (LOST1)
Light Extinction, 1/Mm
60
40
20
0
9
18
27
36
45
54
63
72
81
90
99
108
117
126
135
144
153
162
171
180
189
198
207
216
225
234
243
252
261
270
279
288
297
306
315
324
333
342
351
360
● Ammonium Nitrate
IMPROVE Monitor: LOST1; Class I Areas: Lostwood National Wildlife Refuge Wilderness



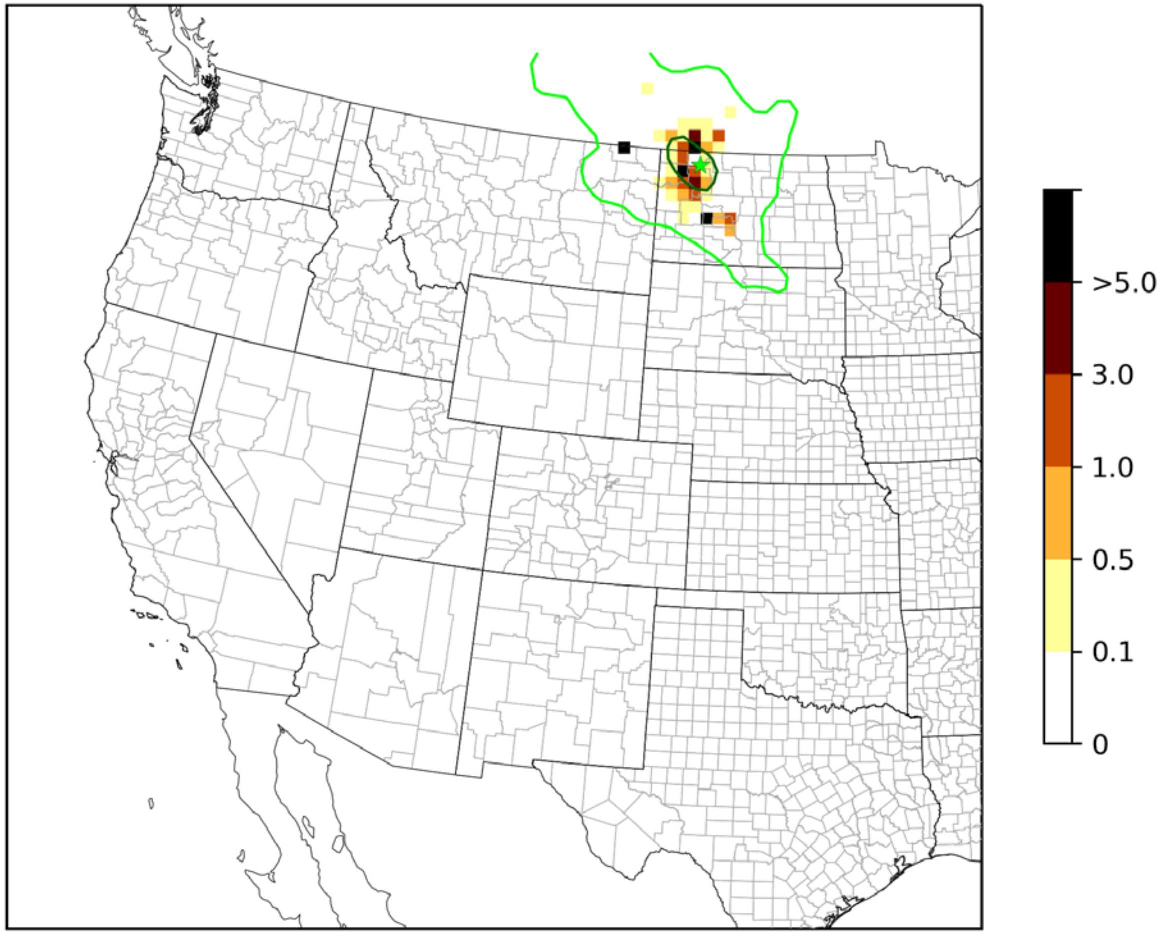
SOx

Extinction Weighted Residence Times

SOx

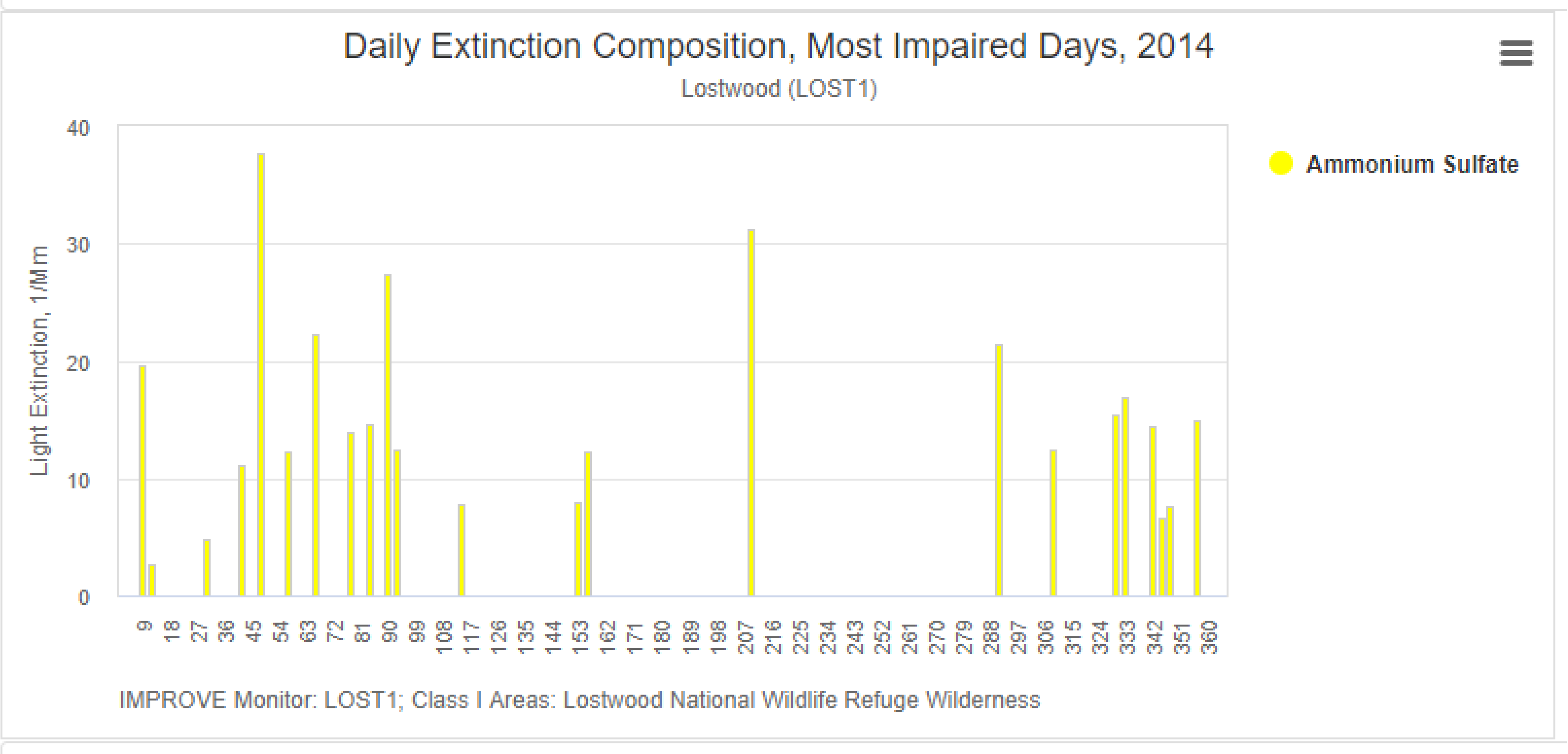


LOST1 - 20% Most Impaired Days All - EWRT
AREA SOx Emission Weighted Distance (%)

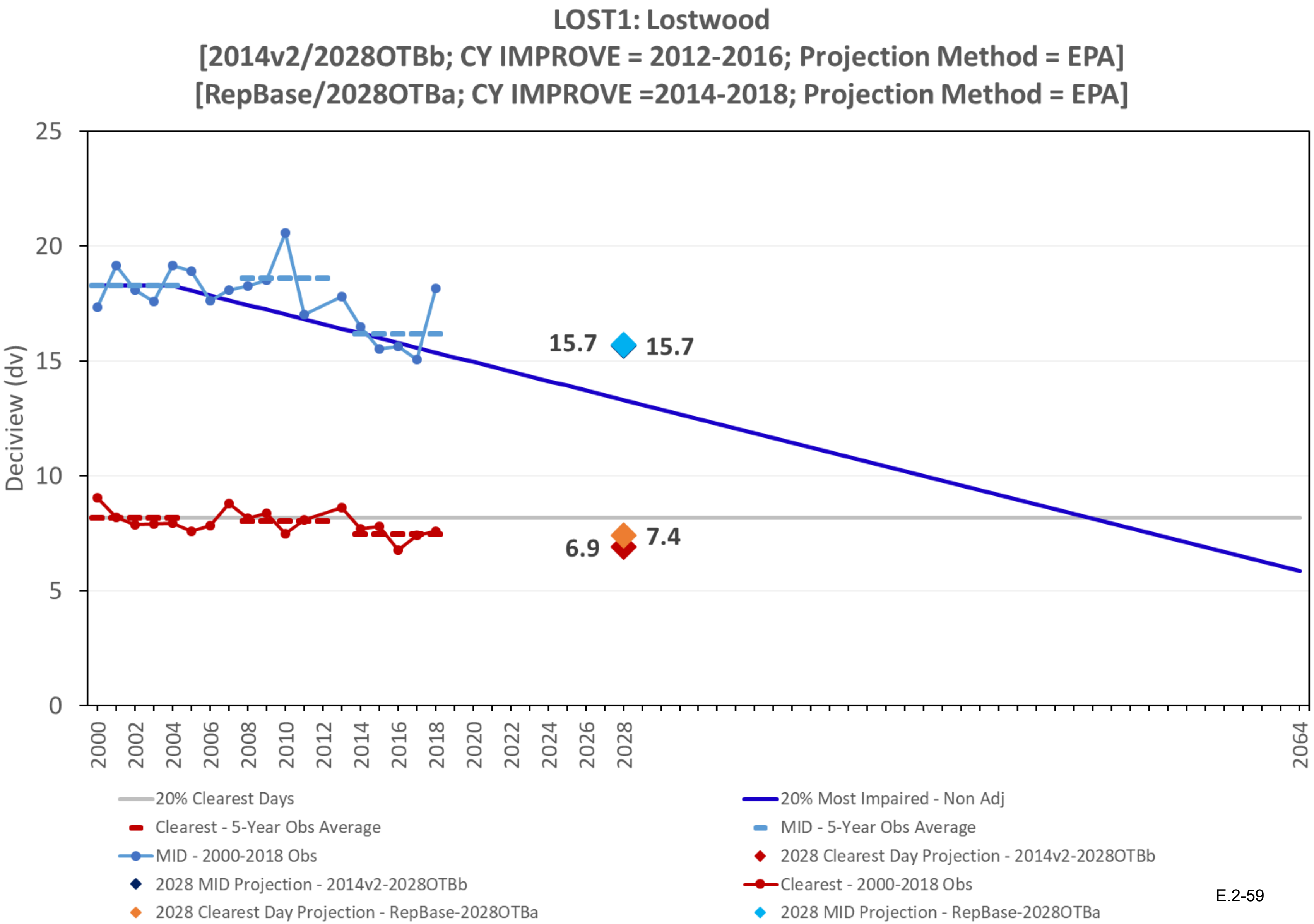


LOST1 - 20% Most Impaired Days All - EWRT
TOTAL_ANTRHO SOx Emission Weighted Distance (%)

MIDs in 2014


Daily Extinction Composition, Most Impaired Days, 2014
Lostwood (LOST1)
Light Extinction, 1/Mm
40
30
20
10
0
9
18
27
36
45
54
63
72
81
90
99
108
117
126
135
144
153
162
171
180
189
198
207
216
225
234
243
252
261
270
279
288
297
306
315
324
333
342
351
360
Ammonium Sulfate
IMPROVE Monitor: LOST1; Class I Areas: Lostwood National Wildlife Refuge Wilderness

LOST1 URP and 2028 Projections



Stroh, David E.

Subject:	RH SIP emissions inventory section discussion
Location:	Microsoft Teams Meeting
Start:	Mon 10/5/2020 2:30 PM
End:	Mon 10/5/2020 3:30 PM
Recurrence:	(none)
Meeting Status:	Accepted
Organizer:	Payne, Rhonda

CAUTION: This email originated from an outside source. Do not click links or open attachments unless you know they are safe.

UPDATE – Change to today? Hopefully this works!

I'd like to brainstorm with you about what the best way to organize the emissions inventory information into sections in the RH SIP.

The requirements for EIs are in this table:

RHR Requirements for an Emissions Inventory

RHR Rule Citation	RHR Description
Section 51.308(f)(2)(iii)	Identify the emissions information on which the state's strategies are based and explain how this information meets the RHR's requirements regarding the year(s) represented in the information to the NEI.
Section 51.308(f)(6)(v)	Requires states to submit a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in a Class I area. The inventory must include emissions for the most recent year for which data are available, and estimates for future projected emissions.
Paragraph 51.308(g)(4) of the Regional Haze Rule requires periodic progress reports to contain the following element:	An analysis tracking the change over the period since the period addressed in the most recent plan required under paragraph (f) of this section in emissions of pollutants contributing to visibility impairment from all sources and activities within the State.
Paragraph 51.308(g)(5) requires periodic progress reports to contain the following element:	An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred since the period addressed in the most recent plan required under paragraph (f) of this section including whether or not these changes in

RHR Rule Citation	RHR Description
	anthropogenic emissions were anticipated in that most recent plan and whether they have limited or impeded progress in reducing pollutant emissions and improving visibility.

There may be more requirements that I haven't listed.

Stroh, David E.

From: Stroh, David E.
Sent: Friday, November 6, 2020 11:02 AM
To: Dave Pohlman
Subject: North Dakota Regional Haze Round 2 Planning
Attachments: North Dakota Regional Haze Round 2-presentation.pdf

David,

Thanks again for the discussion regarding North Dakota regional haze round 2 planning. I have attached the slide deck we covered. Feel free to pass this along to the appropriate personnel. As discussed, I will be keeping in touch later this month to schedule additional meetings.

In the meantime, should you or others have questions/comments regarding the slide deck, let me know and I can provide more information.

David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov

NORTH
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Be Legendary.

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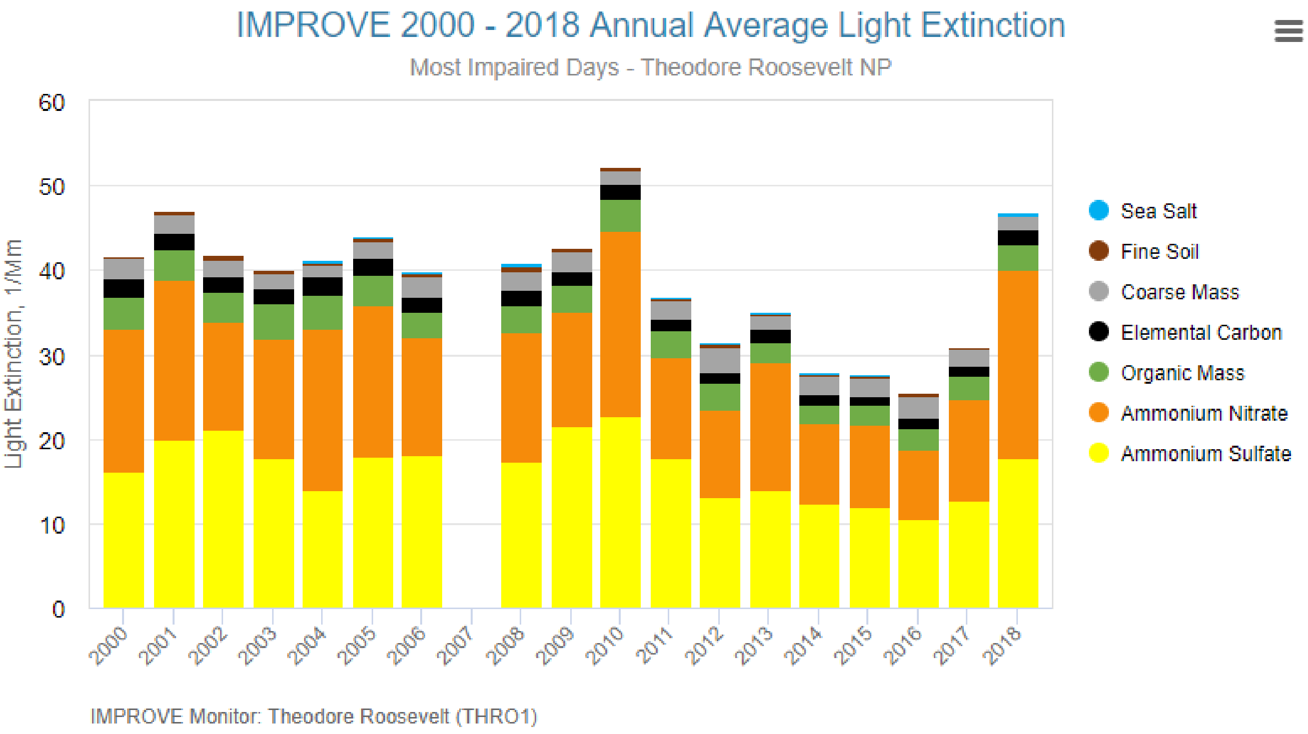
North Dakota Regional Haze Round 2

- Impairment Species
- Facilities and Four Factor Analysis
  - Cost of Compliance
- Impairment and Modeled Visibility
  - Glidepath and International Emissions
- Other Factors
  - Generation Trends
  - Economics

NORTH Dakota Be Legendary.™ | Environmental Quality

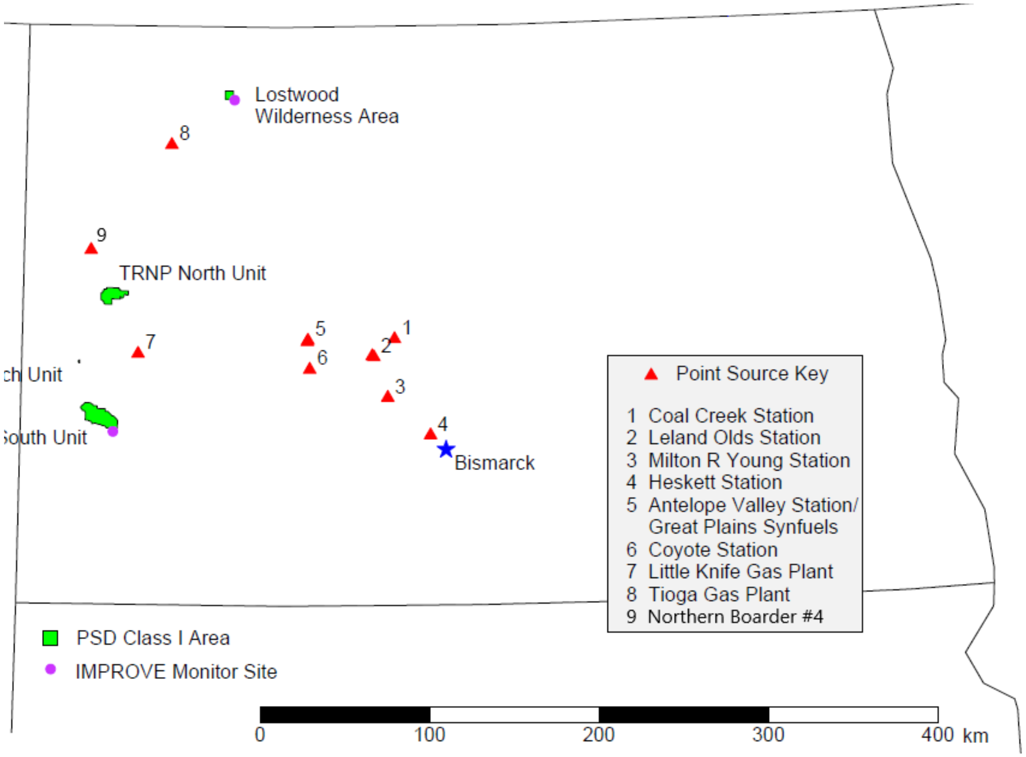
Most Impaired Species for ND

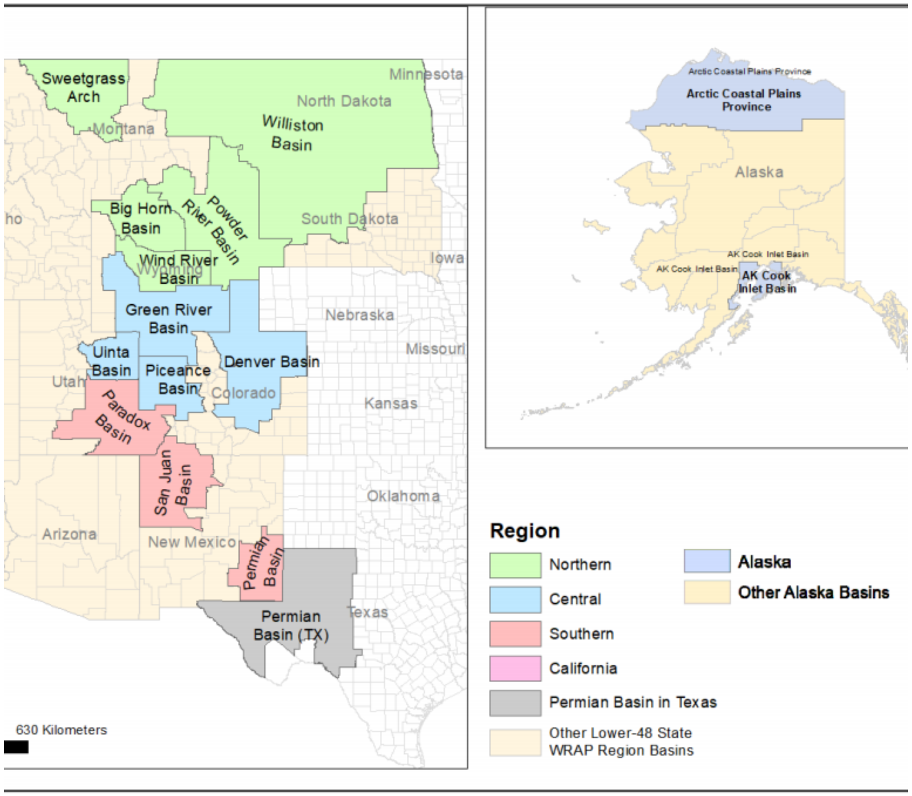
- Nitrates and Sulfates
  - NOx and SO2
- Graphic is for THRO, LOST looks nearly identical



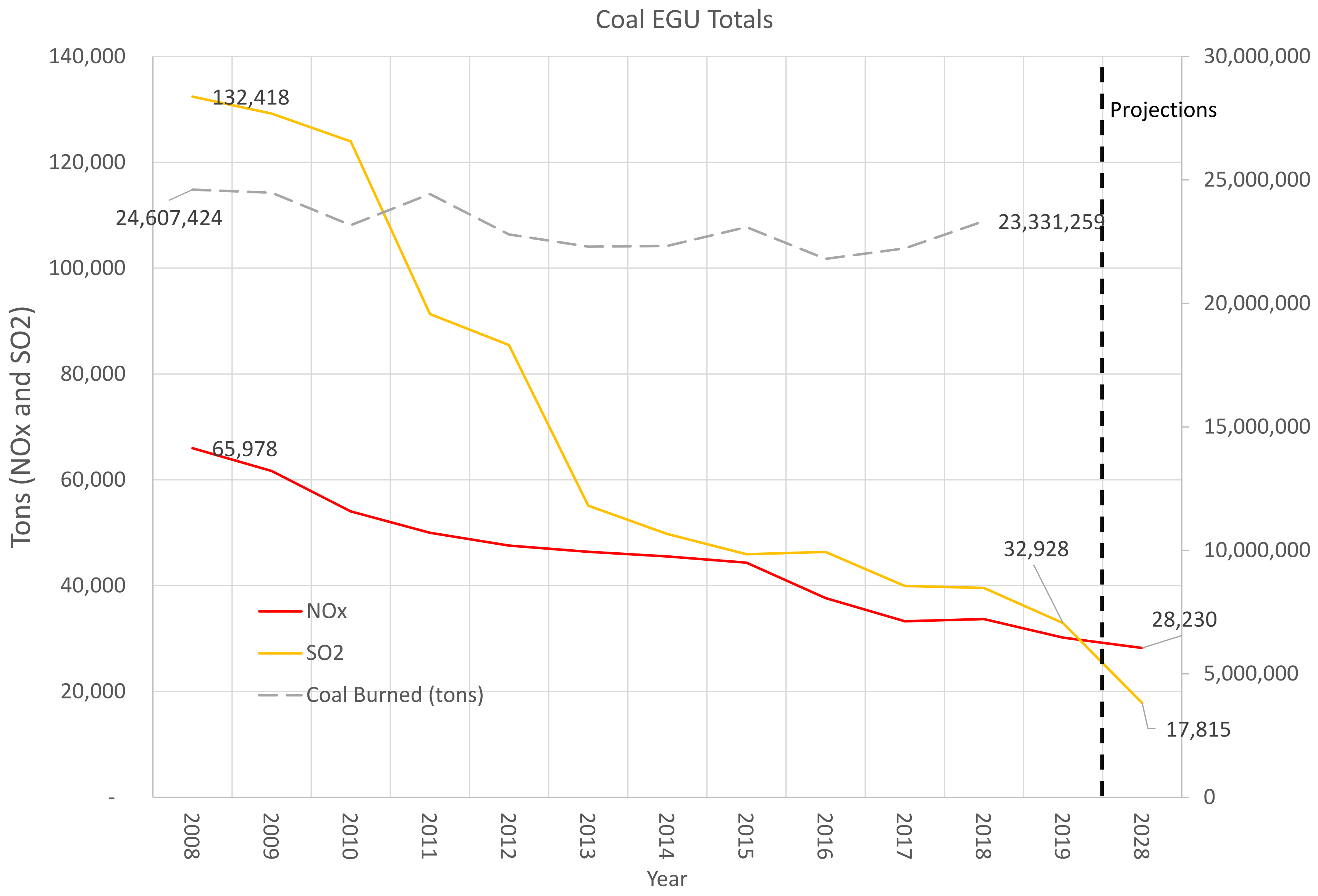
https://views.cira.colostate.edu/tssv2/

Sources Reviewed





https://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_DraftReport_11Oct2019a.pdf


Coal EGU Totals
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
Tons (NOx and SO2)
30,000,000
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
Tons Coal Burned
Projections
132,418
24,607,424
23,331,259
65,978
32,928
28,230
17,815
NOx
SO2
Coal Burned (tons)
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2028
Year

Coyote Station SO_2 (RP source)

Control Technology	Emission Rate (lb/MMBtu)	Reduction from Baseline	Projected Actual from ER & CF
DFGD/FF (Baseline)	0.85		12,963
DSI + Existing FGD	0.58	31.8%	8,845
FGD Improvements	0.50	41.2%	7,625
DSI + FGD Improvements	0.33	61.2%	5,033
Absorber Replacement	0.09	89.4%	1,373
WFGD	0.06	92.9%	915

Control Technology	Annual Emission Reduction (tpy)	Installed Capital Cost ($)	Annual O&M Cost ($)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost ($/ton)
DSI + Existing FGD	4,118	23,765,000	10,423,000	12,371,000	3,004	
FGD Stoich Improvements	5,338	526,000	2,042,000	2,085,000	391	(8,431)
DSI + FGD Improvements	7,930	24,292,000	12,465,000	14,456,000	1,823	4,772
Absorber Replacement	11,590	110,120,000	12,097,000	21,122,000	1,822	1,821
WFGD	12,048	324,742,000	22,481,000	49,094,000	4,075	61,139

Modeled for Potential Additional Controls

Coyote Station NO_x (RP source)

Unit	Control Technology	Emission Rate (lb/MMBtu)	Reduction from Baseline	Projected Actual from ER & CF
	SOFA (Baseline)	0.46		7,015
1	SOFA Optimization	0.42	8.7%	6,405
1	SNCR + Optimization	0.28	39.1%	4,270
1	SNCR + RRI + Optimization	0.20	56.5%	3,050

Control Technology	Annual Emission Reduction (tpy)	Installed Capital Cost ($)	Annual O&M Cost ($)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost ($/ton)
Combustion Optimization	610					
SNCR + CO	2,745	19,840,000	3,128,000	4,753,933	1,732	
SNCR + RRI + CO	3,965	56,864,000	8,030,000	12,690,135	3,200	6,505

Modeled for Potential Additional Controls

AVS SO_2 (RP source)

Unit	Control Technology	Emission Rate (lb/MMBtu)	Reduction from Baseline	Reduction from Uncontrolled	Projected Actual from ER & CF
1,2	DFGD/FF (Baseline)	0.36		87.6%	6,274
1,2	Station Work Practice	0.35	2.8%	87.9%	6,100
1,2	Ca:S Stoichiometry	0.2	44.4%	93.1%	3,486
1,2	DFGD (CDS/FF)	0.09	75.0%	96.9%	1,568
1,2	WFGD	0.07	80.6%	97.6%	1,220

Control Technology	Annual Emission Reduction (tpy)	Installed Capital Cost ($)	Annual O&M Cost ($)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost ($/ton)
Reduction in Allowable*	14,639					
DFGD/FF	Baseline					
Station Work Practice	174	0	135,000	135,000	775	
Ca:S Stoichiometry	2,788	9,698,000	1,144,000	1,938,773	695	690
DFGD (CDS/FF)	4,705	230,447,000	16,718,000	35,603,658	7,566	17,561
WFGD	5,054	272,384,000	16,945,000	39,267,491	7,770	10,512

Modeled for Potential Additional Controls

AVS NO_x (RP source)

Unit	Control Technology	Emission Rate (lb/MMBtu)	Reduction from Baseline	Projected Actual from ER & CF
1,2	SOFA/LNCFS (Limit)	0.17		2,963
1,2	SOFA/LNCFS (Operational)	0.11		1,896
1,2	SOFA/LNCFS (Baseline)	0.11		1,917
1,2	SNCR	0.09	18.2%	1,568
1,2	SCR-tail end configuration	0.05	54.5%	871

Control Technology	Annual Emission Reduction (tpy)	Installed Capital Cost ($)	Annual O&M Cost ($)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost ($/ton)
Reduction in Allowable*	1,046					
SOFA/LNCFS						
SNCR	349	16,356,000	1,945,000	3,285,412	9,426	
SCR-tail end configuration	1,046	221,396,000	18,201,000	36,344,908	34,758	47,424

*Plan to lower limit more in line with current operations

No Potential Additional Controls Modeled

Coal Creek Station (BART Source)

Current rates, two identical units:

- SO_2 rate: ~0.14 lb/MMBtu (WFGD)
- NO_X rate: ~0.13 lb/MMBtu (LNC3+)

Round 1: No approved NO_X BART

Round 2: Review indicates no reasonable additional controls (lower limits)

Facility future still uncertain (potential buyer)

Leland Olds Station (BART Source)

- Unit 1 – current rates
  - SO_2 rate: 0.088 lb/MMBtu (WFGD)
  - NO_X rate: 0.16 lb/MMBtu (SNCR)

- Unit 2 – current rates
  - SO_2 rate: 0.084 lb/MMBtu (WFGD)
  - NO_X rate: 0.29 lb/MMBtu (SNCR) (cyclone unit)

Four factor review indicates no reasonable additional controls

MR Young (BART Source)

- Unit 1 – current rates
  - SO_2 rate: 0.074 lb/MMBtu (WFGD)
  - NO_X rate: 0.33 lb/MMBtu (SNCR) (cyclone unit)

- Unit 2 – current rates
  - SO_2 rate: 0.126 lb/MMBtu (WFGD)
  - NO_X rate: 0.33 lb/MMBtu (SNCR) (cyclone unit)

Four factor review indicates no reasonable additional controls

Emissions Profile SO_2

Absorber Replacement

Facility	2014 Base Case	Representative Case	2028 OTB/OTW	2028 PAC1	2028 PAC2
Coyote Station	12,777	12,994	12,994	1,373	7,625
Basin AVS 1	5,809	6,279	6,279	3,405	6,279
Basin AVS 2	6,975	6,319	6,319	3,405	6,319
Basin LOS 1	412	636	636	636	636
Basin LOS 2	1,025	1,258	1,258	1,258	1,258
GRE CCS 1	7,885	3,458	2,740	2,384	2,384
GRE CCS 2	7,940	3,400	2,743	2,387	2,387
MR Young 1	361	766	766	766	766
MR Young 2	1,710	2,165	2,165	2,165	2,165
MDU Heskett 1	1,030	753	0	0	0
MDU Heskett 2	2,339	1,214	0	0	0
Stanton	2,591	0	0	0	0
Total EGU :	**50,852**	**39,242**	**35,900**	17,778	29,818
Hess TGP	569	740	740	740	740
DGC	3,818	3,904	3,904	3,904	3,904
Petro-Hunt LKGP	526	307	307	307	307
NB CS4	2	N/A	N/A	N/A	N/A
Total non-EGU:	**4,914**	**4,950**	**4,950**	4,950	4,950
Total:	**55,766**	**44,192**	**40,850**	22,728	34,768

FGD Improvement, both units

Emissions Profile NO_X

SNCR Reduction

Facility	2014 Base Case	Representative Case	2028 OTB/OTW	2028 PAC1	2028 PAC2
Coyote Station	11,374	7,363	7,363	4,270	7,363
Basin AVS 1	3,196	1,697	1,697	1,697	1,697
Basin AVS 2	6,052	1,708	1,708	1,708	1,708
Basin LOS 1	1,373	1,059	1,059	1,059	1,059
Basin LOS 2	5,202	4,192	4,192	4,192	4,192
GRE CCS 1	4,697	3,987	3,010	2,980	2,980
GRE CCS 2	3,287	3,010	3,010	2,983	2,983
MR Young 1	3,205	3,435	3,435	3,435	3,435
MR Young 2	5,004	5,735	5,735	5,735	5,735
MDU Heskett 1	351	209	0	0	0
MDU Heskett 2	995	978	0	0	0
Stanton	1,662	0	0	0	0
Total EGU :	**46,399**	**33,374**	**31,210**	28,059	31,152
Hess TGP	946	880	880	880	880
DGC	3,235	2,490	2,490	2,490	2,490
Petro-Hunt LKGP	24	21	21	21	21
NB CS4	97	110	124	124	124
Total non-EGU:	**4,301**	**3,501**	**3,515**	3,515	3,515
Total:	**50,700**	**36,875**	**34,725**	**31,574**	**34,667**

Modeled Reductions

Reductions	2028OTB/OTW - PAC1	Notes
SO_2	18,122	CS: Absorber Replacement AVS: Scrubber Improvements
NO_X	3,151	CS: SNCR (cyclone boiler)
Total	**21,273**	*

*Modeled by WRAP to determine the impact to visibility on the most impaired days

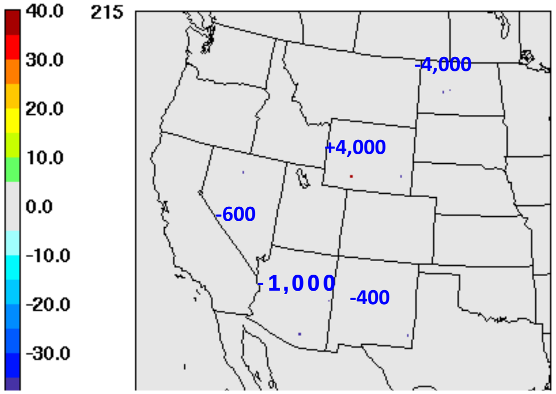
Glidepath and Adjustment

EGU and Non-EGU Point Sources

Changes (TPY)

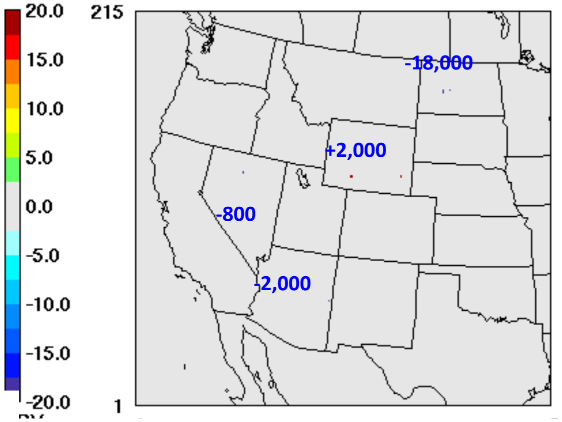
Delta_NOX

2028PAC1-2028OTB
Annual_Total_Diff:ptegu_wrap



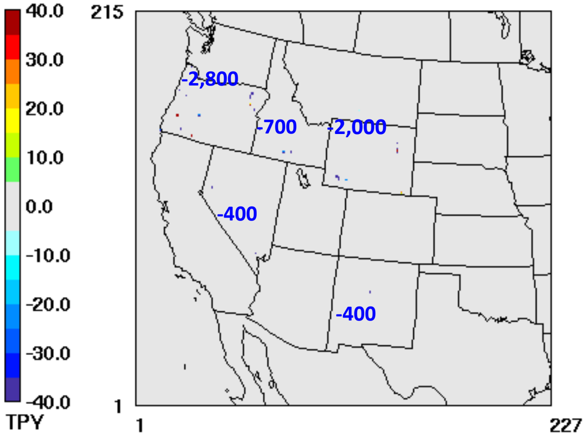
Delta_SO2g

2028PAC1-2028OTB
Annual_Total_Diff:ptegu_wrap



Delta_NOX

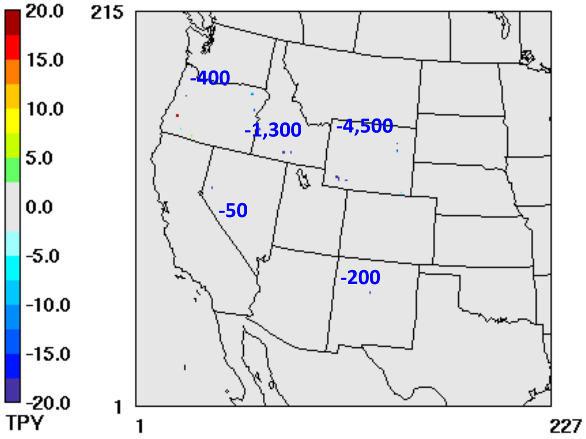
2028PAC1-2028OTB
Annual_Total_Diff:ptnonipm



April 1,2004 0:00:00
Min=-1438.7 at (112,124), Max=669.5 at (144,139)

Delta_SO2g

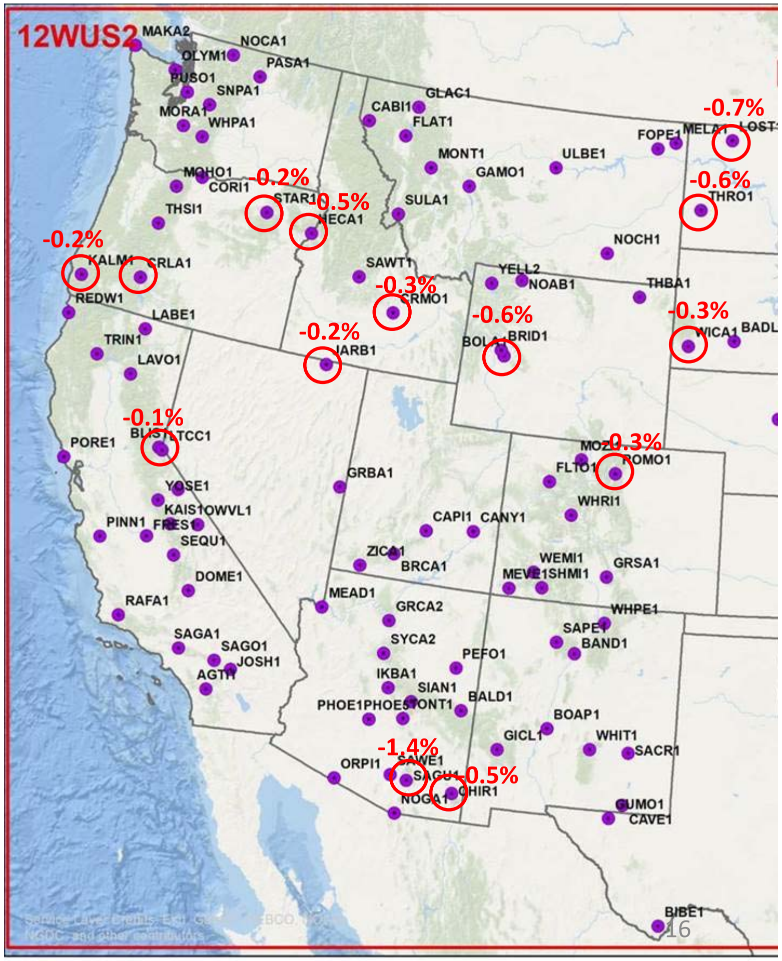
2028PAC1-2028OTB
Annual_Total_Diff:ptnonipm

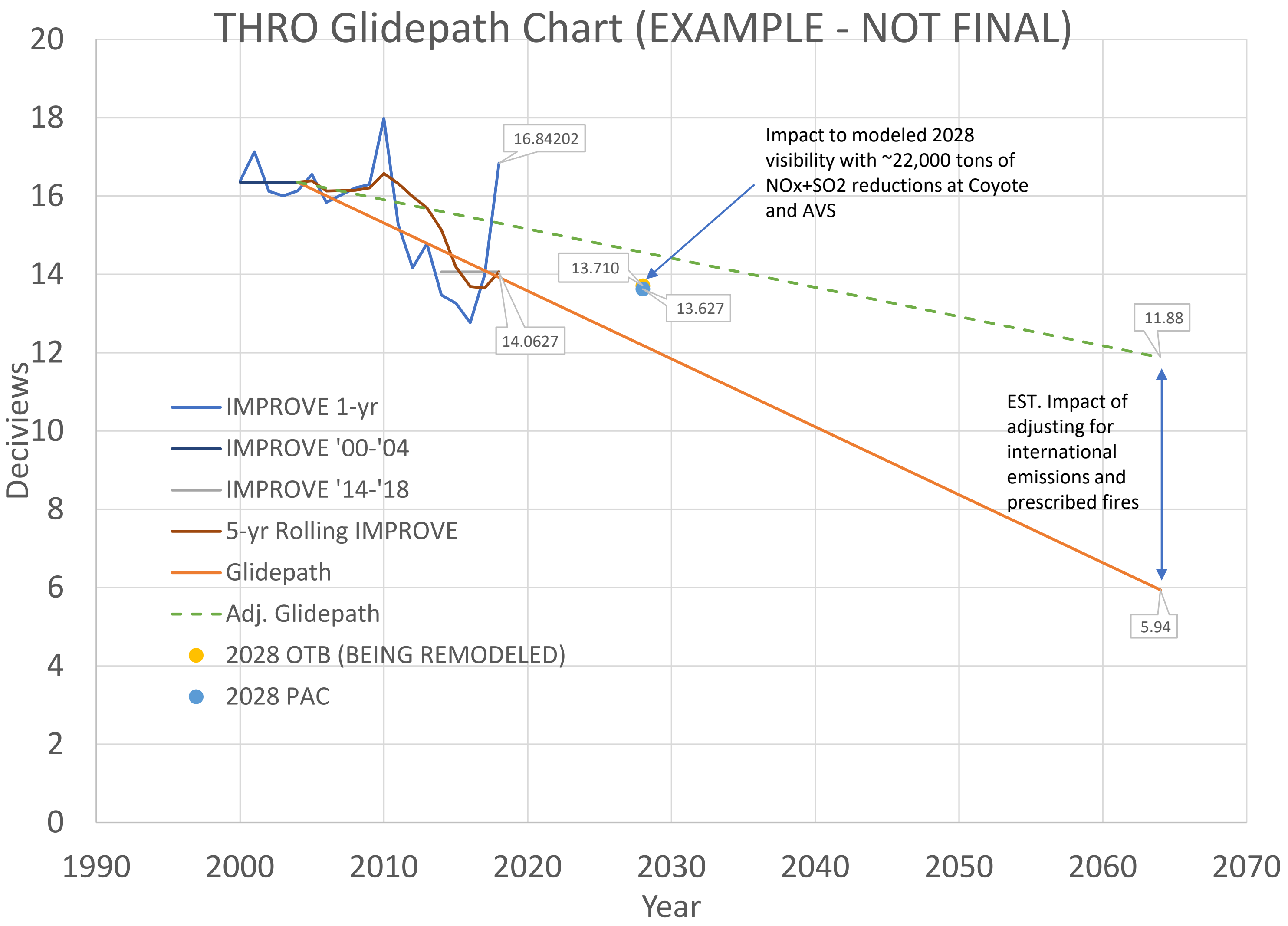


April 1,2004 0:00:00
Min=-3441.6 at (112,124), Max=70.1 at (24,158)

Percent Change in 2028 Visibility

(lower deciview value, better projected visibility in 2028)





THRO Glidepath Chart (EXAMPLE - NOT FINAL)

Impact to modeled 2028 visibility with ~22,000 tons of NOx+SO2 reductions at Coyote and AVS

EST. Impact of adjusting for international emissions and prescribed fires

Generated from data available at: https://views.cira.colostate.edu/tssv2/

EPA 2019 Modeling

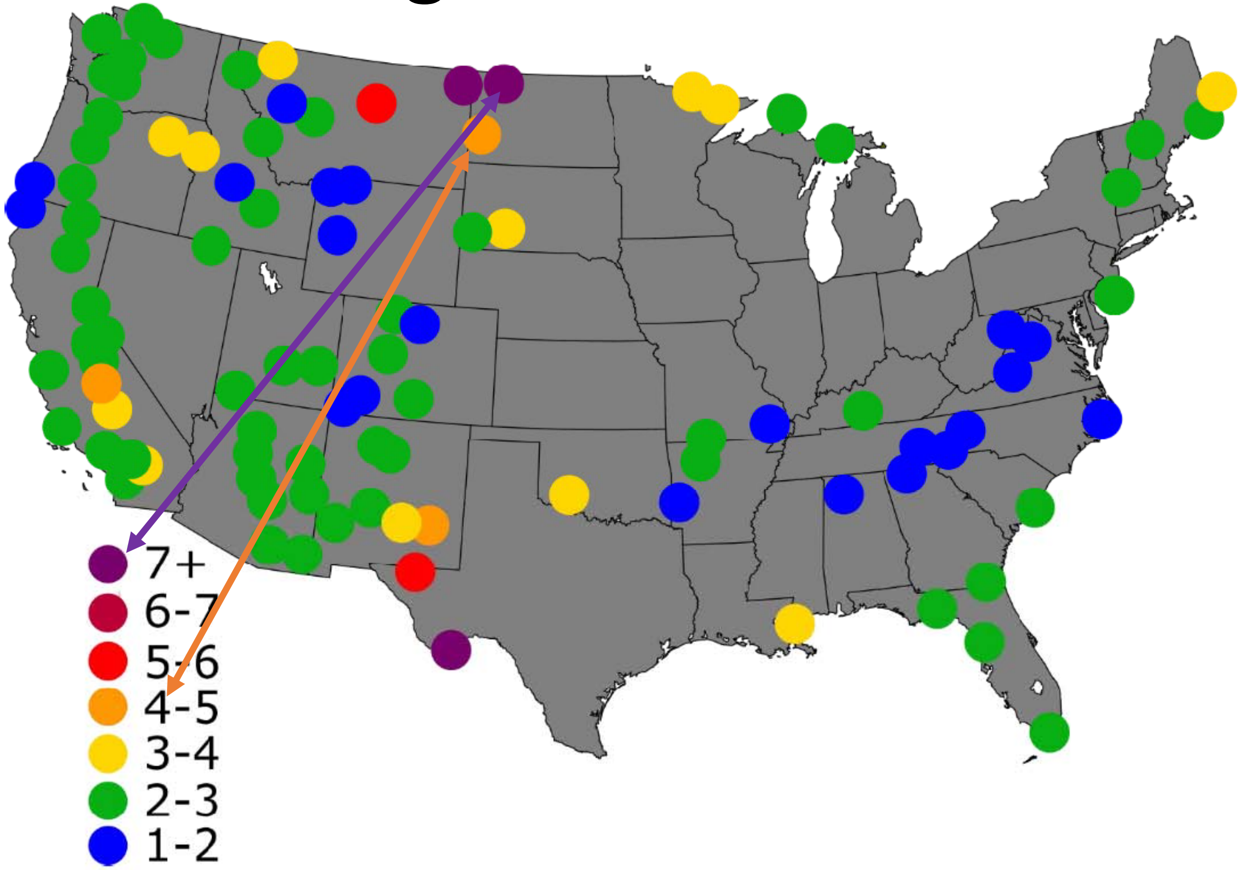


Figure 5-2 Adjustment to 2064 endpoint from international anthropogenic impacts on the 20% most impaired days (in deciviews)

https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf (page 66)

EPA 2019 Modeling

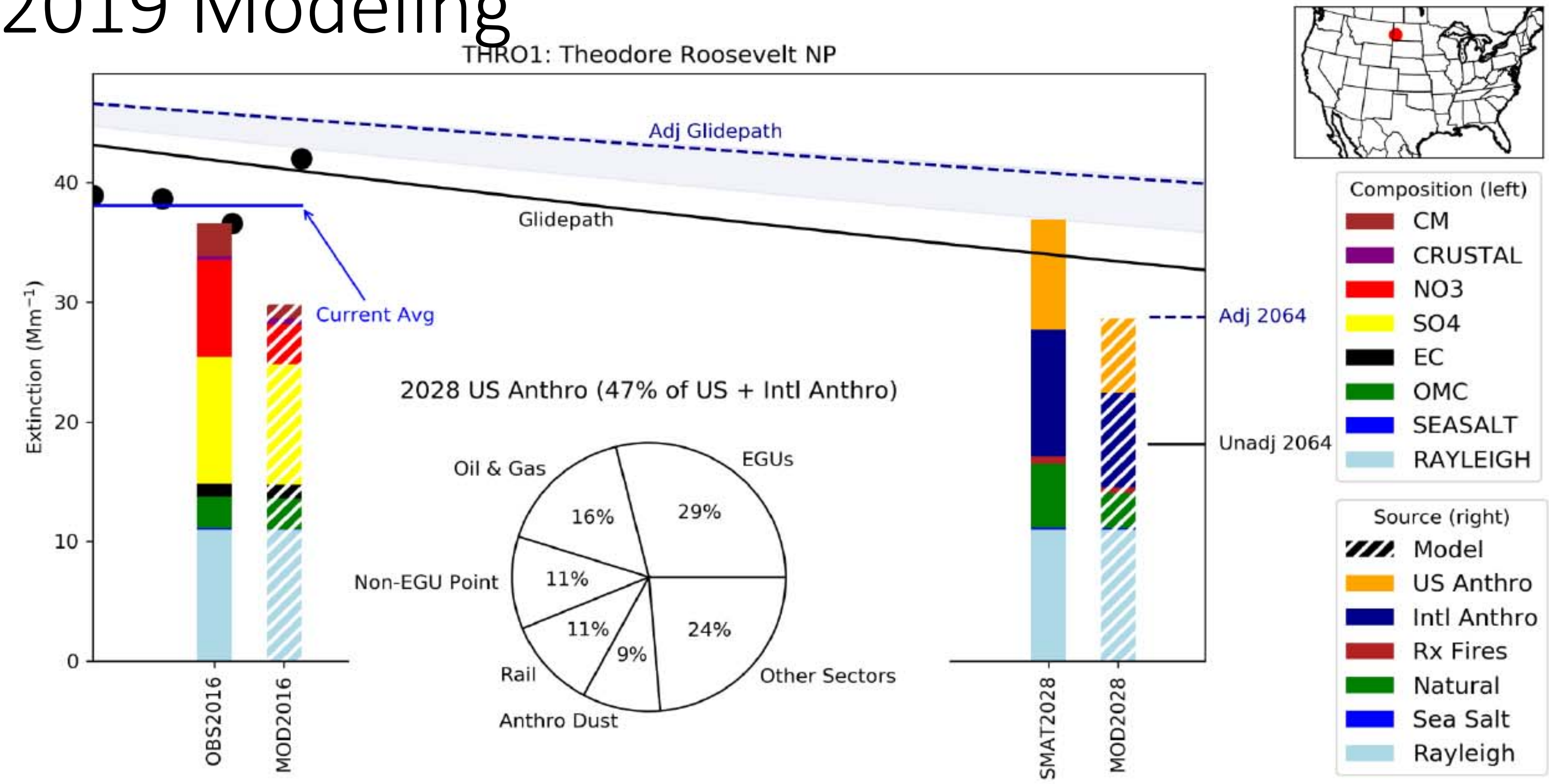


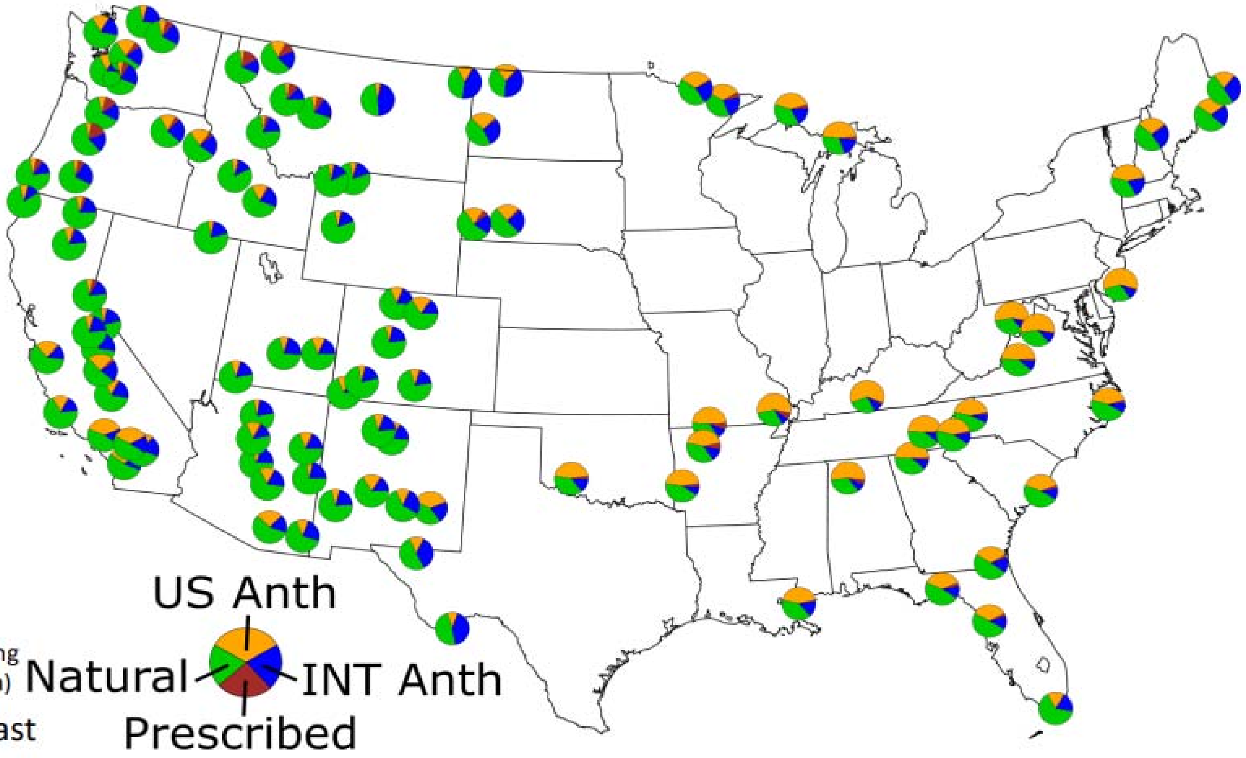
Figure 89: 2014-2017 IMPROVE observations, 2016 CAMx model predictions, 2028 modeled projection, and 2028 sector contributions at THRO1. Used for Class I areas: Theodore Roosevelt NP.

https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf (page B-92)

International Impacts

2028 Total Visibility Impairment Components (20% most impaired days)

2028 Visibility Impairment	Range (Mm-1)
US anthropogenic	0.98–45.68
International anthropogenic	2.88–19.33
Prescribed Fires	0.03-5.15
Modeled natural (including Rayleigh)	11.72-29.83

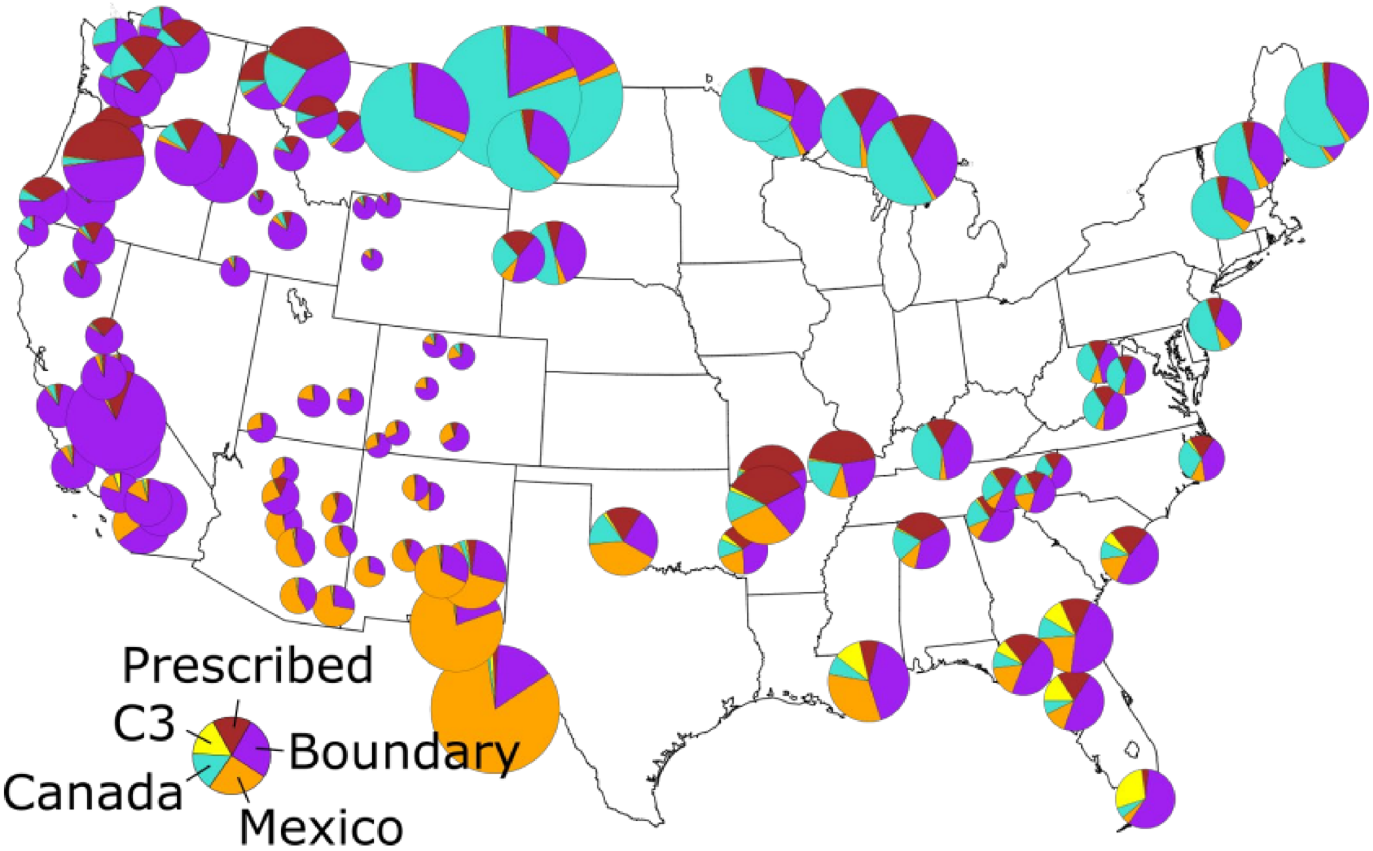


- Percentage of US anthropogenic higher in the East
- Percentage of natural higher in the West
- International anthropogenic contribution largest near border areas
- Prescribed fire contribution highest in the Northwest

https://www.epa.gov/sites/production/files/2019-10/documents/epa_rh_modeling_summary_101519-final_0.pdf (Slide 22)

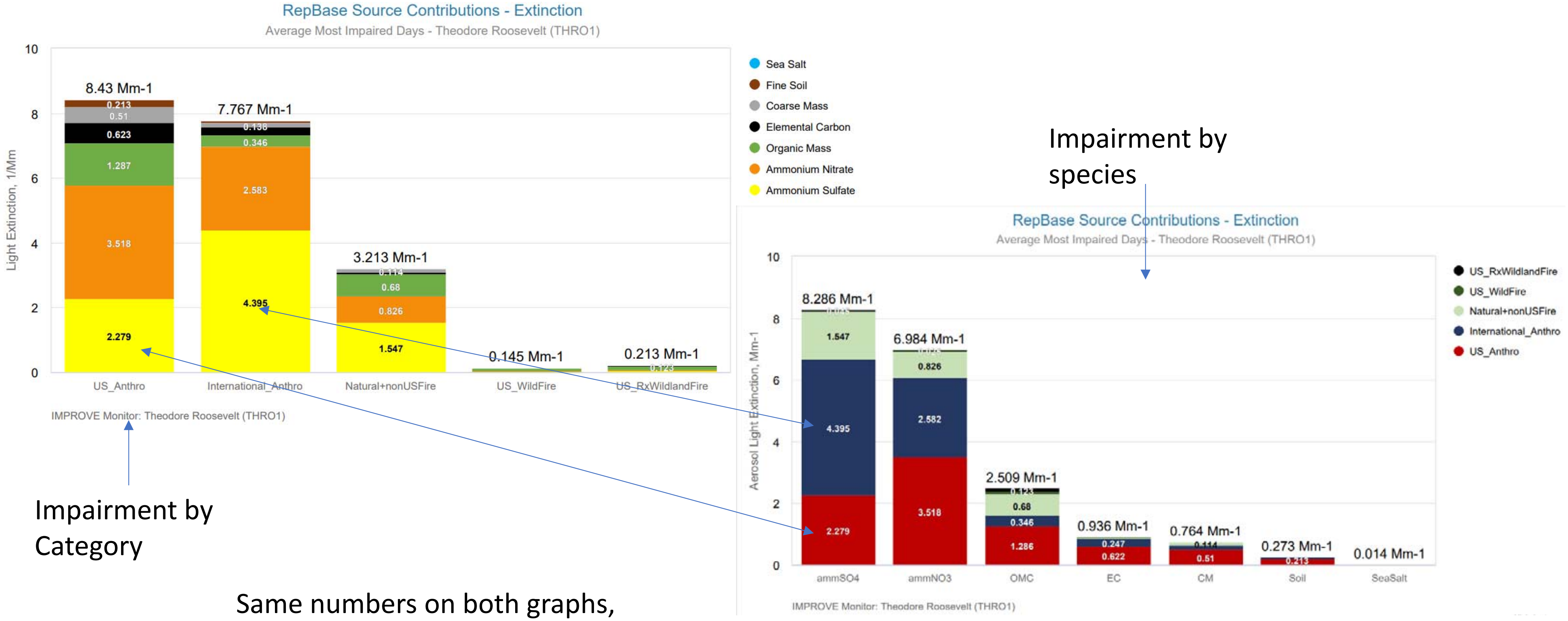
International Anthropogenic and Prescribed Fire Contributions (20% most impaired days)

Glidepath Adjustment components	Range (Mm-1)
Prescribed fires	0.03-5.15
C3 commercial marine outside the US ECA region	0-2.28
Canada anthropogenic	0.01–15.49
Mexico anthropogenic	0.02–14.39
International anthropogenic from outside the 36km domain (boundary conditions)	1.19–11.73



https://www.epa.gov/sites/production/files/2019-10/documents/epa_rh_modeling_summary_101519-final_0.pdf (Slide 22)

MID - International Contributions



Impairment by species

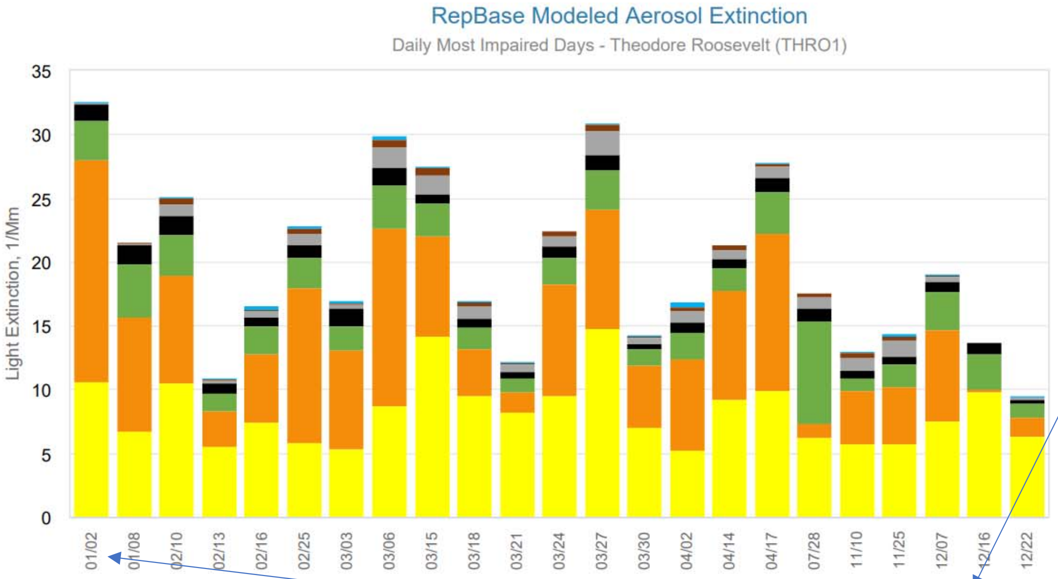
Impairment by Category

Same numbers on both graphs, displayed different to show:

1) species causing most impairment
2) significance of international

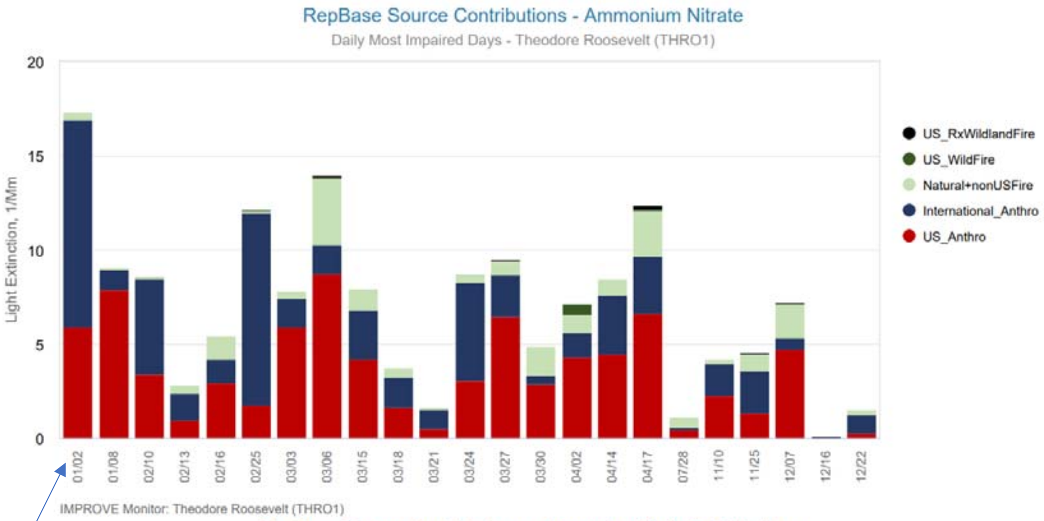
https://views.cira.colostate.edu/tssv2/

MID – US vs Int.

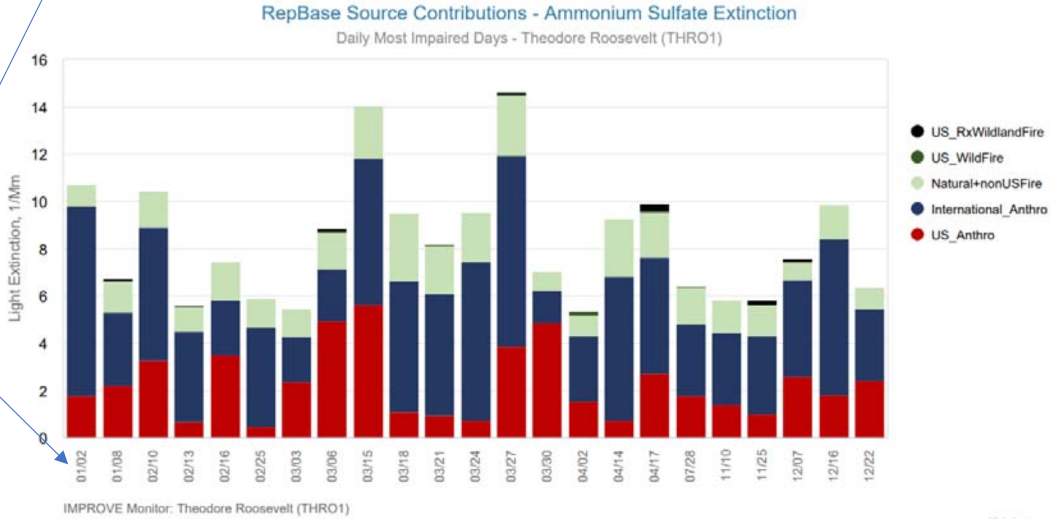

RepBase Modeled Aerosol Extinction
Daily Most Impaired Days - Theodore Roosevelt (THRO1)

Nitrate: 17.3
Sulfate: 10.7

Anthropogenic	Nitrates	Sulfates
US	5.91	1.75
International	11.00	8.04


RepBase Source Contributions - Ammonium Nitrate
Daily Most Impaired Days - Theodore Roosevelt (THRO1)

IMPROVE Monitor: Theodore Roosevelt (THRO1)


RepBase Source Contributions - Ammonium Sulfate Extinction
Daily Most Impaired Days - Theodore Roosevelt (THRO1)

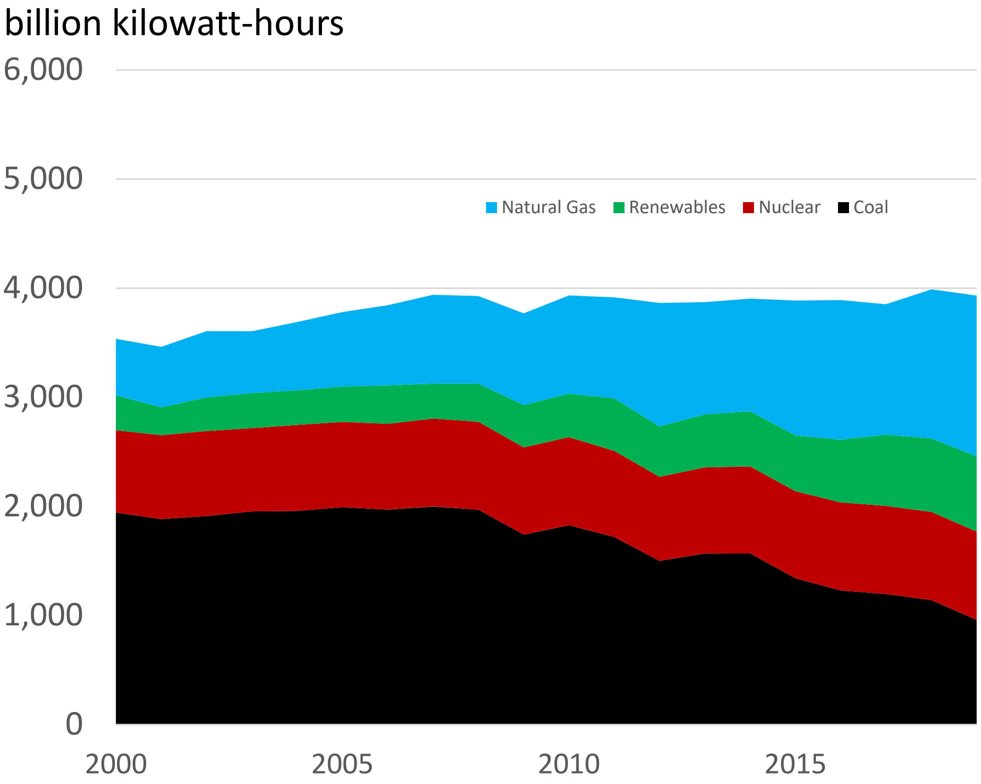
IMPROVE Monitor: Theodore Roosevelt (THRO1)

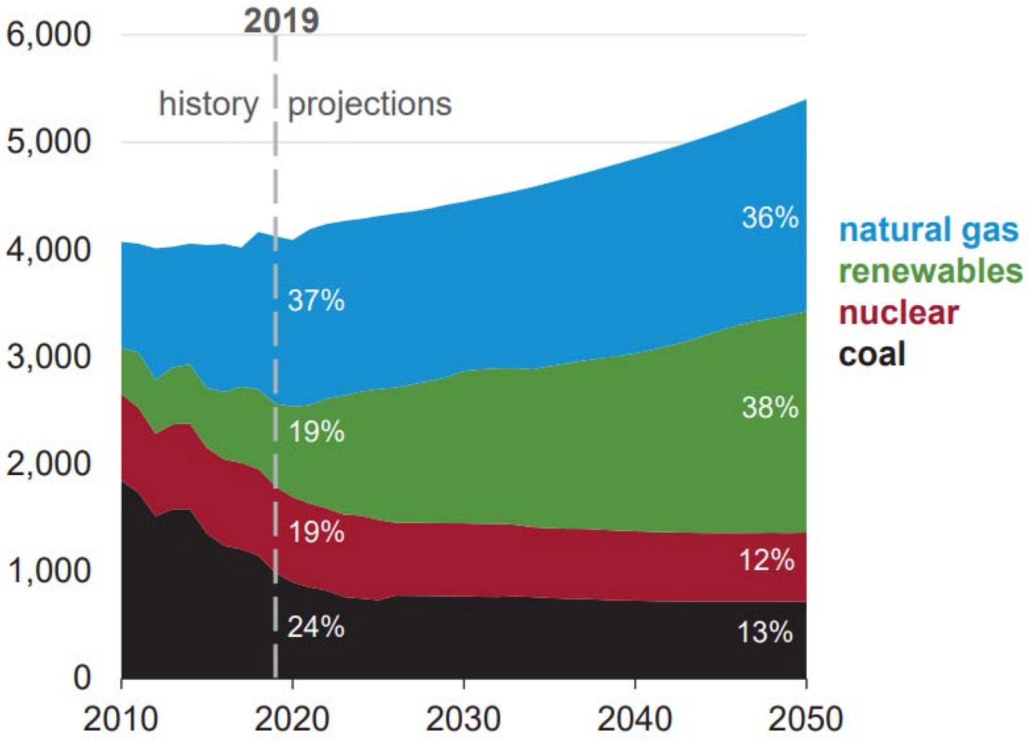
https://views.cira.colostate.edu/tssv2/

Other Factors

Generation Trends and Economics

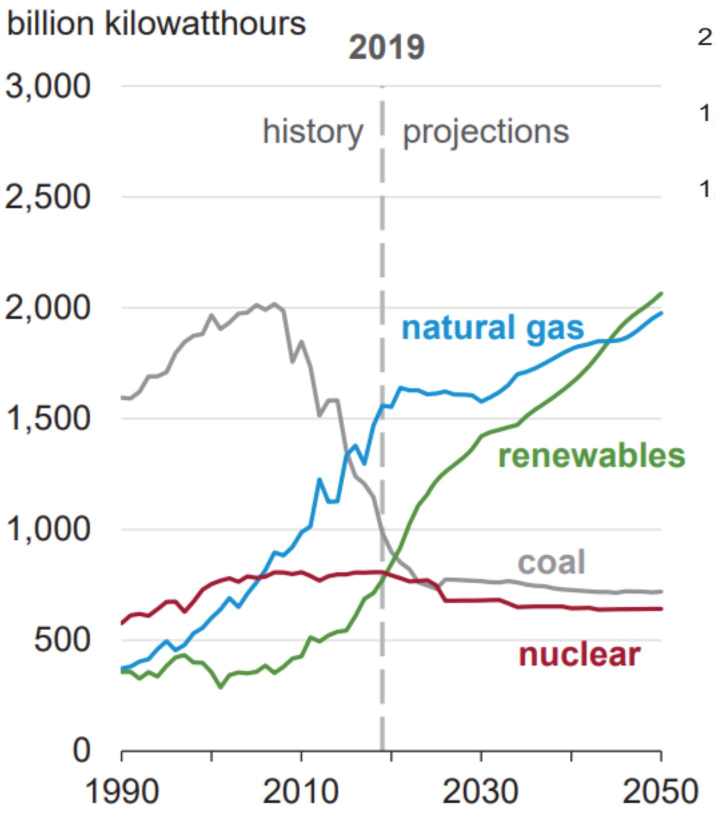
US Electrical Power Generation



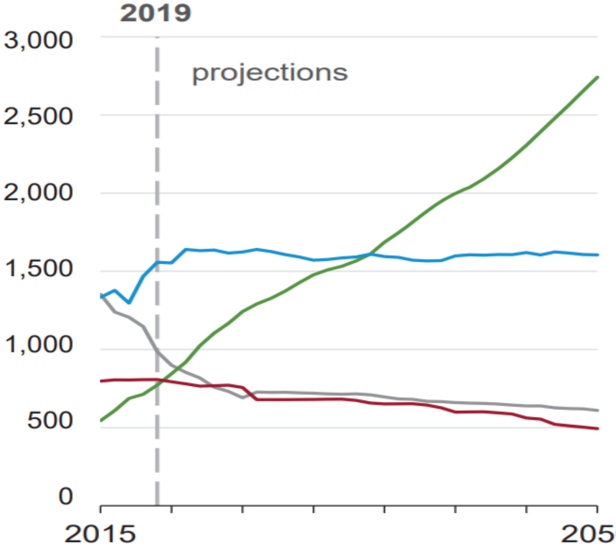


https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf (page 128)

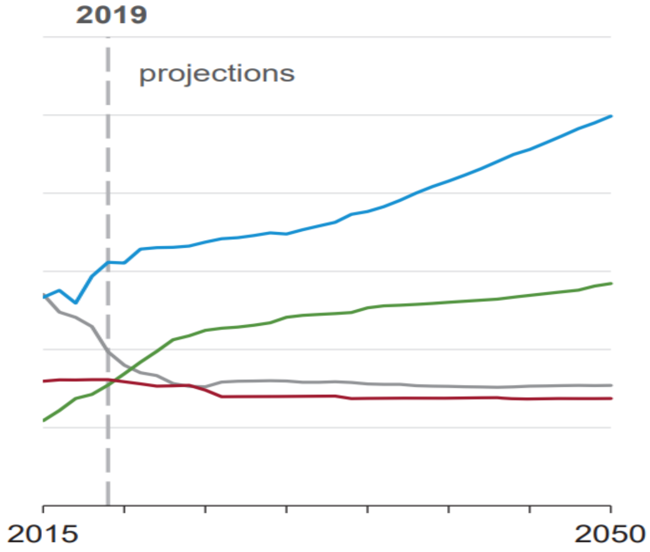
US Generation



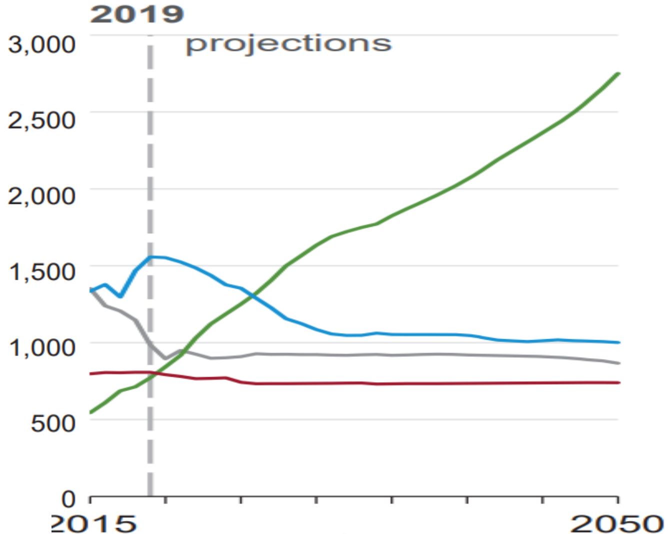
Reference case



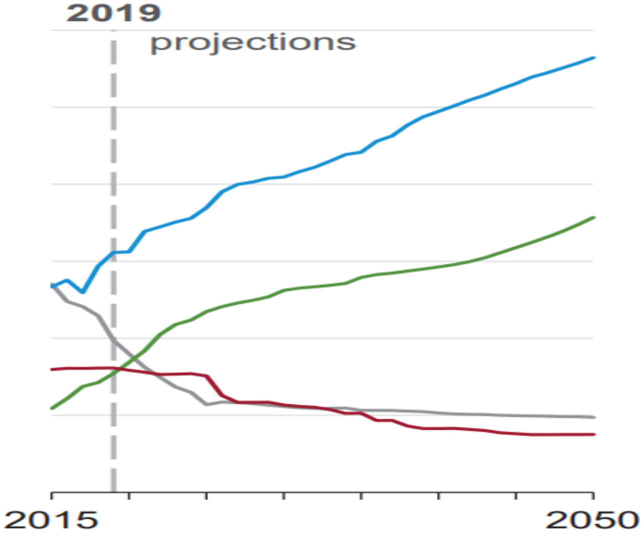
Low Renewables Cost case



High Renewables Cost case



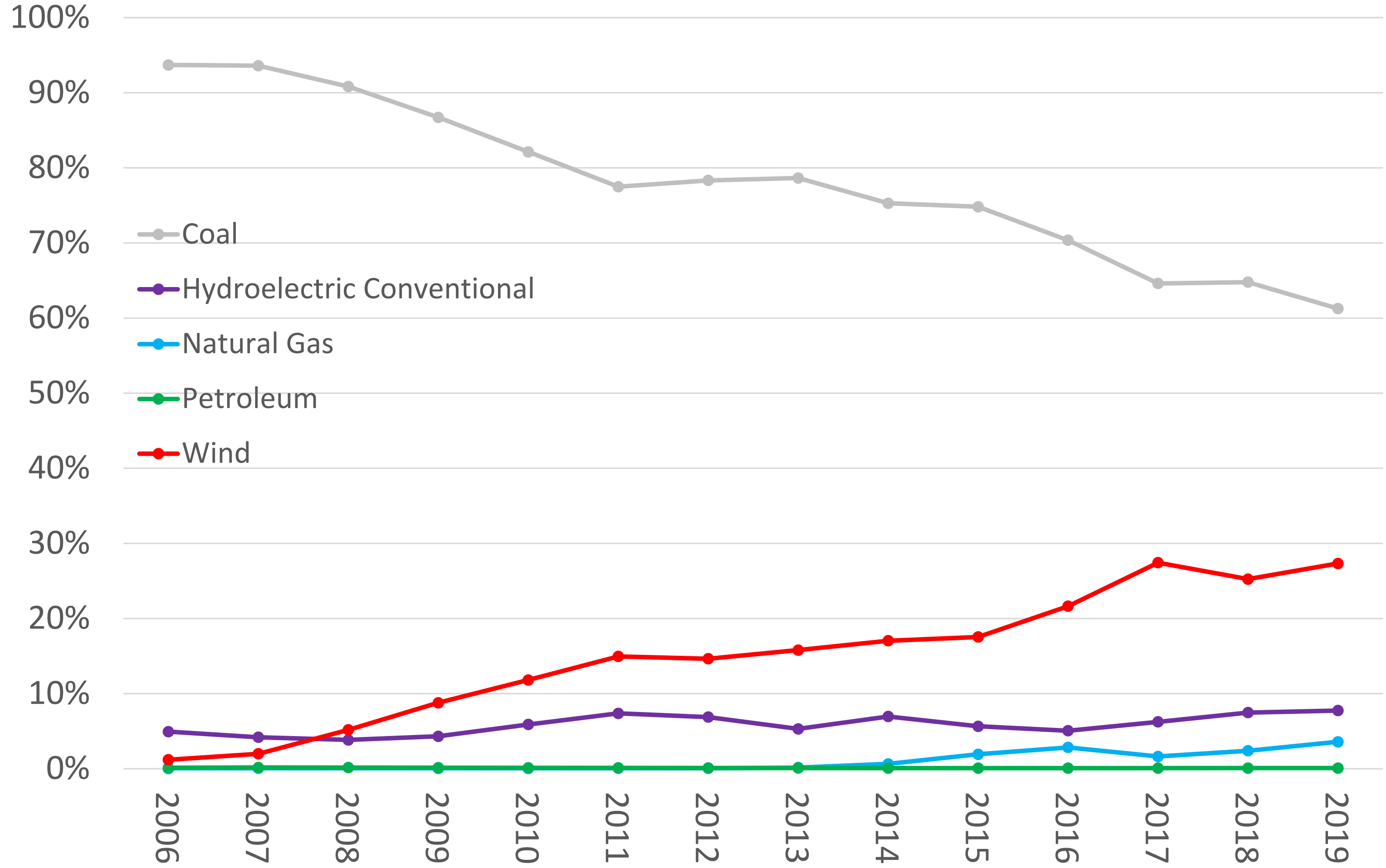
Low Oil and Gas Supply



High Oil and Gas Supply

https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Full%20Report.pdf

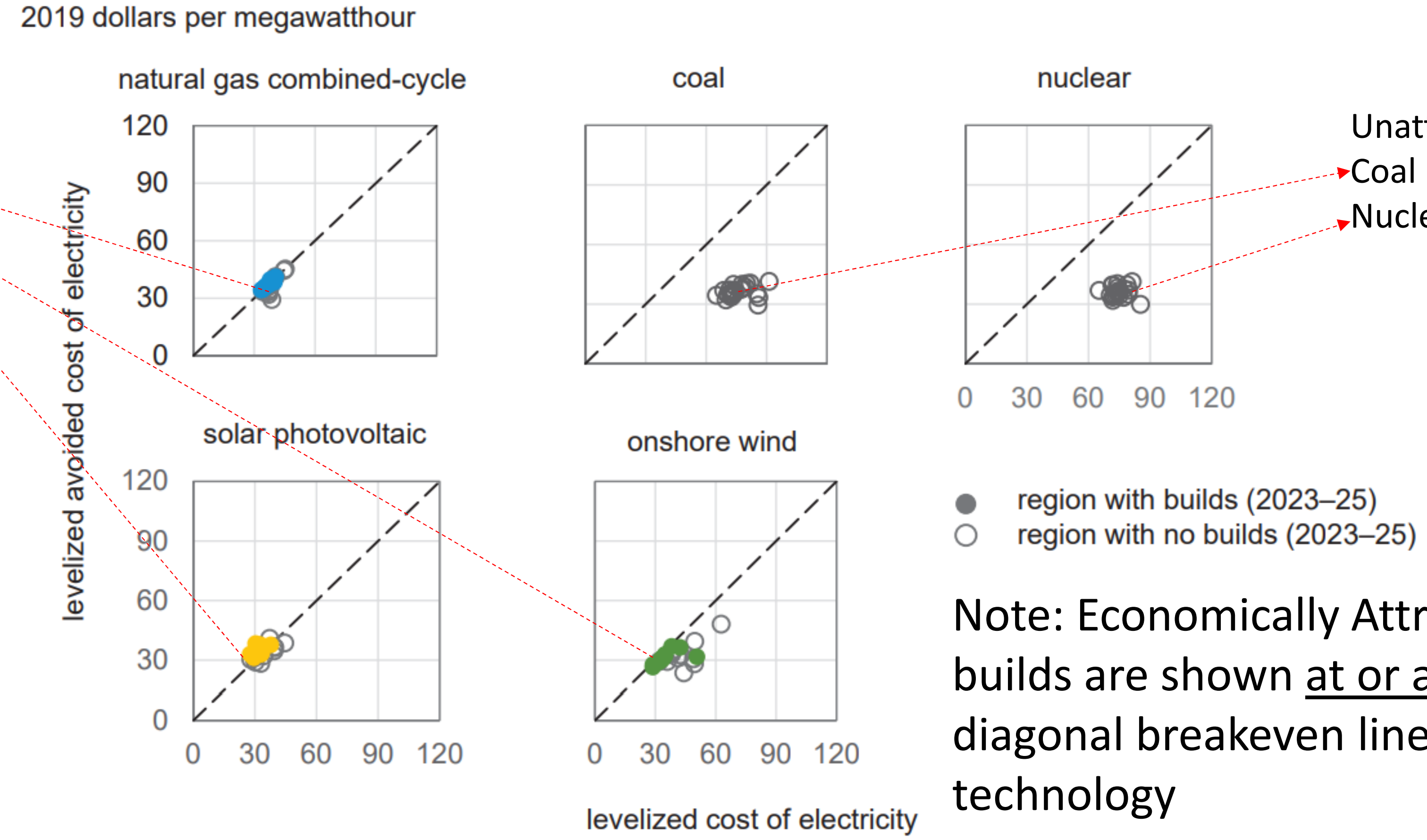
North Dakota Generation Trends



https://www.eia.gov/electricity/data/state/

Costs of Electricity – New Construction

Attractive:
NG
Wind
Solar



Unattractive:
Coal
Nuclear

Note: Economically Attractive builds are shown at or above the diagonal breakeven line for each technology

https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Full%20Report.pdf

Oil and Gas

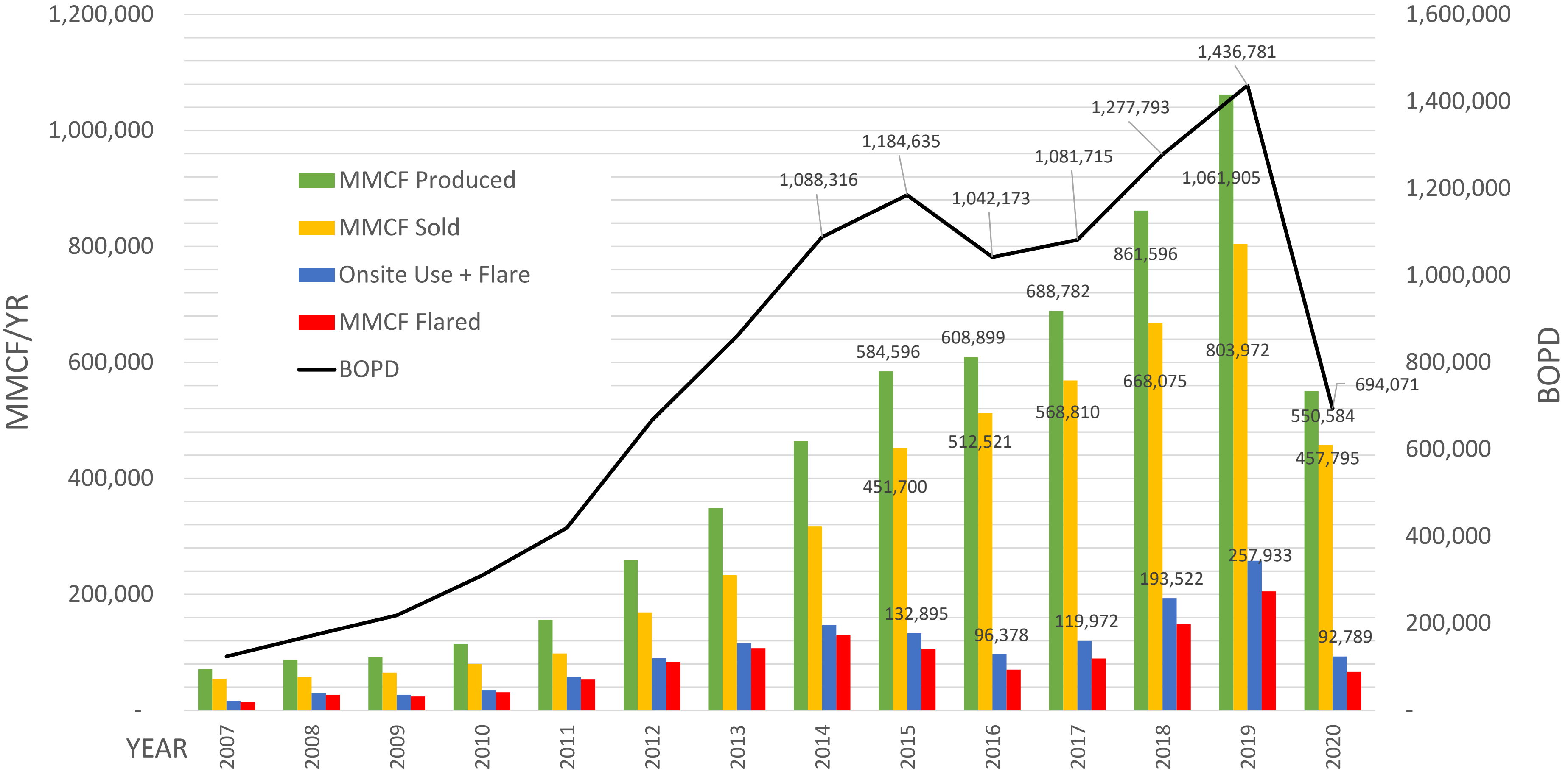
North Dakota Oil and Gas

- Statewide gas capture goal of 91% currently being met
  - June – 89%
  - July – 91%

July Breakdown*
Gas Capture Details:
Statewide………………. 91%
Statewide Bakken……… 92%
Non-FBIR Bakken…….. 93%
FBIR Bakken…………. 88%

- NSPS OOOO/OOOOa adopted
- Decline in activity due to COVID and OPEC
  - Expected to last until late 2022, at least

*https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2020-09-15.pdf



https://www.dmr.nd.gov/oilgas/stats/statisticsvw.asp

Stroh, David E.

From: Wickman, Trent R -FS <trent.wickman@usda.gov>
Sent: Tuesday, November 24, 2020 9:27 AM
To: Stroh, David E.; Webster, Jill - FS
Cc: Seligman, Angela N.; Thorton, Rhannon T.; Semerad, Jim L.; Bachman, Tom A.
Subject: RE: Regional Haze discussion follow-up

Thank you – will do

From: Stroh, David E. <deStroh@nd.gov>
Sent: Monday, November 23, 2020 4:39 PM
To: Wickman, Trent R -FS <trent.wickman@usda.gov>; Webster, Jill - FS <jill.webster@usda.gov>
Cc: Seligman, Angela N. <aseligman@nd.gov>; Thorton, Rhannon T. <rThorton@nd.gov>; Semerad, Jim L. <jsemerad@nd.gov>; Bachman, Tom A. <tbachman@nd.gov>
Subject: Regional Haze discussion follow-up

Trent and Jill,

Thank again for the discussion today and I apologize again for it taking ~2hrs versus the 1hr which was schedule for, but it was a great conversation!

Don't hesitate to reach out if you have any follow-up questions or comments. We look forward to working more with you as North Dakota's Round 2 Regional Haze SIP progresses.

Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov

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Stroh, David E.

From: Shepherd, Don <Don_Shepherd@nps.gov>
Sent: Wednesday, December 16, 2020 11:38 AM
To: Stroh, David E.
Cc: Peters, Melanie; King, Kirsten L; Stacy, Andrea; Miller, Debra C
Subject: Re: [EXTERNAL] North Dakota - Four Factor Analysis Update

Good morning, David,

Thanks for sending me the info on your updated web page--it is very helpful.

Again, thanks for the excellent presentation yesterday.

From: Stroh, David E. <deStroh@nd.gov>
Sent: Wednesday, December 16, 2020 10:10 AM
To: Shepherd, Don <Don_Shepherd@nps.gov>
Subject: [EXTERNAL] North Dakota - Four Factor Analysis Update

Hi Don,

As a follow-up to our discussion yesterday, I have made an update to the NDDEQ Regional Haze webpage. https://www.deq.nd.gov/AQ/planning/RegHaze.aspx

The update is specific to the North Dakota Progress section, Regional Haze Round 2 Files. Located toward the bottom of the webpage.

The data which used to be 2 separate Google drive folders has been consolidated into one document, Appendix B – Four Factor Information.
Direct link: https://www.deq.nd.gov/publications/AQ/Planning/RegionalHaze2/Appendix_B.pdf

Appendix B contains all the significant communications between NDDEQ and the sources regarding the four factor analysis. This Appendix is broken into 10 sections, B.1 – B.10. Each of these sections represents a facility which provided information per our request. These sections have been 'bookmarked' to ease navigation from report to report.

Of note per the discussion yesterday. Appendix B.1 contains the information received from Coyote Station. In 2020, the Department received 2 additional submittals from Coyote. One contains revisions to 'SNCR and RRI costs', and the other included revisions to the 'SO2 controls analysis'.

Let me know if you have any questions or trouble accessing this information. Thank again for the discussion yesterday.
Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov

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Subject: Regional Haze Consultation
Location: Microsoft Teams Meeting

Start: Mon 3/22/2021 10:00 AM
End: Mon 3/22/2021 11:00 AM
Show Time As: Tentative

Recurrence: (none)

Meeting Status: Not yet responded

Organizer: Stroh, David E.
Required Attendees Bouchareb, Hassan (MPCA)

Sounds great, Hassan.

Here is the invite for next Monday. Looking forward to the discussion.

Regards,
David

Microsoft Teams meeting

Join on your computer or mobile app
[Click here to join the meeting]

Join with a video conferencing device

teams@join.nd.gov
Video Conference ID: 118 591 122 8
Alternate VTC dialing instructions

Or call in (audio only)

+1 701-328-0950,,148072804# United States, Fargo

Phone Conference ID: 148 072 804#
Find a local number | Reset PIN

Enjoy your meeting

Learn More | Help | Meeting options

From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Wednesday, March 17, 2021 4:06 PM
To: Stroh, David E. <deStroh@nd.gov>
Subject: RE: Regional Haze Consultation

That works for me, thanks David!

Hassan M. Bouchareb | Engineer
Minnesota Pollution Control Agency (MPCA)
Office: (651) 757-2653 | Fax: (651) 296-8324
Pronouns: he/him/his
Hassan.Bouchareb@state.mn.us | www.pca.state.mn.us

From: Stroh, David E. <deStroh@nd.gov>
Sent: Wednesday, March 17, 2021 11:36 AM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Subject: RE: Regional Haze Consultation

Hi Hassan,

I also have good availability next Monday, can make most times work.

How does Monday, March 22nd @ 10:00am work?

If it works, I can send a Microsoft Teams meeting invite and we can get it on the calendar.

Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov

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From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Wednesday, March 17, 2021 10:52 AM

To: Stroh, David E. <deStroh@nd.gov>
Subject: RE: Regional Haze Consultation

Hi David,

I'd be happy to talk through regional haze topics with you. I'm generally available anytime this coming Monday if that works for you? If not, feel free to suggest some days/times.

Thanks!

Hassan M. Bouchareb | Engineer
Minnesota Pollution Control Agency (MPCA)
Office: (651) 757-2653 | Fax: (651) 296-8324
Pronouns: he/him/his
Hassan.Bouchareb@state.mn.us | www.pca.state.mn.us

From: Stroh, David E. <deStroh@nd.gov>
Sent: Thursday, March 4, 2021 2:49 PM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Subject: Regional Haze Consultation

Hi Hassan,

As a follow-up to my voicemail, I would like to gauge your interest in beginning state-to-state consultation. A couple items that come to mind are SIP submittal timelines and expectations, progress to date, and any input required from North Dakota to Minnesota or vise-versa for planning purposes.

Feel free to give me a call when you have time or respond via email and we can coordinate a time for discussion.

Hope you are doing well.
Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov

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Stroh, David E.

From: Payne, Rhonda <repayne@mt.gov>
Sent: Wednesday, June 9, 2021 12:41 PM
To: Stroh, David E.; Henrikson, Craig
Cc: McGuire, Brandon; Thorton, Rhannon T.
Subject: RE: North Dakota's Regional Haze Determination on Impact of Facilities On North Dakota's Class I Areas

Great, thank you, David. Also, thank you for sharing the modeling delays information.

Have a great weekend,

Rhonda

From: Stroh, David E. <deStroh@nd.gov>
Sent: Wednesday, June 9, 2021 7:48 AM
To: Payne, Rhonda <repayne@mt.gov>; Henrikson, Craig <CHenrikson@mt.gov>
Cc: McGuire, Brandon <BMcGuire@mt.gov>; Thorton, Rhannon T. <rThorton@nd.gov>
Subject: [EXTERNAL] North Dakota's Regional Haze Determination on Impact of Facilities On North Dakota's Class I Areas

Sending this email to correct the subject line.

I liked the subject line provided my Craig in Montana's request – so I copied it. Only I forgot to change it to ND. My apologies for any confusion.

David

From: Stroh, David E.
Sent: Tuesday, June 8, 2021 3:02 PM
To: repayne@mt.gov; Henrikson, Craig <CHenrikson@mt.gov>
Cc: BMcGuire@mt.gov; Thorton, Rhannon T. <rThorton@nd.gov>
Subject: Montana's Regional Haze Determination on Impact of Facilities On Montana's Class I Areas

Hi Craig and Rhonda,

Under various sections of the Regional Haze regulation, states with Class I areas are required to develop reasonable progress goals (RPG) for visibility improvement at their Class I areas. When developing each Class I area RPG, states are required to consult with other states which may reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. This email provides some general information and requests feedback from Montana.

Outside sources contributing to impairment in North Dakota Class I areas

Visibility in North Dakota's Class I areas is not significantly impaired by Montana sources on the most impaired days and Montana sources are not impeding North Dakota's ability to make reasonable progress during this planning period.

Therefore, North Dakota is not requesting the adoption of any controls or emission reduction measures from Montana during the second-planning period for the Regional Haze regulation.

North Dakota sources contributing to impairment in Montana Class I areas
North Dakota has reviewed the impacts our sectors have on visibility impairment in the Class I areas closest to North Dakota. This review indicated North Dakota sector contributions do not appear to be significantly impacting visibility in these Montana Class I areas (e.g. Medicine Lake "MELA1") on the most impaired days. We believe this determination is supported by the Source Apportionment Charts provided by WRAP, specifically the "WRAP State Source Group Contributions - U.S. Anthro" (Tool 9 on the TSSv2, https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx [views.cira.colostate.edu]). Should Montana disagree with this position, please notify North Dakota accordingly. Notification can be provided at any time, before or during the required public comment period.

This email provides an early opportunity for Montana to inform North Dakota of any expectations Montana has regarding North Dakota's Regional Haze SIP for round 2 of the planning process.

Thank you in advance for your participation in this consultation process.
Please contact me at 701-328-5229 or destroh@nd.gov should you require additional information on this matter.
Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov

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Stroh, David E.

From: Stroh, David E.
Sent: Wednesday, June 9, 2021 8:56 AM
To: rick.boddicker@state.sd.us; Anthony.Lueck@state.sd.us
Cc: Thorton, Rhannon T.
Subject: North Dakota's Regional Haze Determination on Impact of Facilities on North Dakota's Class I Area

Hi Rick and Anthony,

Under various sections of the Regional Haze regulation, states with Class I areas are required to develop reasonable progress goals (RPG) for visibility improvement at their Class I areas. When developing each Class I area RPG, states are required to consult with other states which may reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. This email provides some general information and requests feedback from South Dakota.

Outside sources contributing to impairment in North Dakota Class I areas
Visibility in North Dakota’s Class I areas is not significantly impaired by South Dakota sources on the most impaired days and South Dakota sources are not impeding North Dakota’s ability to make reasonable progress during this planning period. Therefore, North Dakota is not requesting the adoption of any controls or emission reduction measures from South Dakota during the second-planning period for the Regional Haze regulation.

North Dakota sources contributing to impairment in South Dakota Class I areas
North Dakota has reviewed the impacts our sectors have on visibility impairment in the Class I areas closest to North Dakota. This review indicated North Dakota sector contributions do not appear to be significantly impacting visibility in these South Dakota Class I areas (e.g. Badlands NP “BADL1”) on the most impaired days. We believe our determination is supported by the Source Apportionment Charts provided by WRAP, specifically the “WRAP State Source Group Contributions - U.S. Anthro” (Tool 9 on the TSSv2, https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx). Should South Dakota disagree with this position, please notify North Dakota accordingly. Notification can be provided at any time, before or during the required public comment period. This email provides an early opportunity for South Dakota to inform North Dakota of any expectations South Dakota has regarding North Dakota’s Regional Haze SIP for round 2 of the planning process.

Thank you in advance for your participation in this consultation process.
Please contact me at 701-328-5229 or destroh@nd.gov should you require additional information on this matter.
Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov

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Stroh, David E.

From: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Sent: Tuesday, June 15, 2021 1:41 PM
To: Stroh, David E.
Subject: RE: North Dakota's Regional Haze Determination on Impact of Facilities On North Dakota's Class I Area

Hi David,

Thanks for the voicemail and follow up email. No immediate updates yet, but I'm discussing with others here at MPCA and I'll get back to you when I have more information from those discussions.

Thanks!

Hassan M. Bouchareb | Engineer
Minnesota Pollution Control Agency (MPCA)
Office: (651) 757-2653 | Fax: (651) 296-8324
Pronouns: he/him/his
Hassan.Bouchareb@state.mn.us | www.pca.state.mn.us

From: Stroh, David E. <deStroh@nd.gov>
Sent: Wednesday, June 9, 2021 8:49 AM
To: Bouchareb, Hassan (MPCA) <hassan.bouchareb@state.mn.us>
Subject: North Dakota's Regional Haze Determination on Impact of Facilities On North Dakota's Class I Area

Hi Hassan,

Following up on my voicemail. Under various sections of the Regional Haze regulation, states with Class I areas are required to develop reasonable progress goals (RPG) for visibility improvement at their Class I areas. When developing each Class I area RPG, states are required to consult with other states which may reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. This email provides some general information and requests feedback from Minnesota.

<u>Outside sources contributing to impairment in North Dakota Class I areas</u>
Visibility in North Dakota's Class I areas is not significantly impaired by Minnesota sources on the most impaired days and Minnesota sources are not impeding North Dakota's ability to make reasonable progress during this planning period. Therefore, North Dakota is not requesting the adoption of any controls or emission reduction measures from Minnesota during the second-planning period for the Regional Haze regulation.

North Dakota sources contributing to impairment in Minnesota Class I areas

North Dakota has reviewed the impacts our sectors have on visibility impairment in the Class I areas closest to North Dakota. This review indicated North Dakota sector contributions do not appear to be significantly impacting visibility in these Minnesota Class I areas (e.g. Voyageurs NP “VOYA2”) on the most impaired days. We believe our determination is supported by the Source Apportionment Charts provided by WRAP, specifically the “WRAP State Source Group Contributions - U.S. Anthro” (Tool 9 on the TSSv2, https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx). Should Minnesota disagree with this position, please notify North Dakota accordingly. Notification can be provided at any time, before or during the required public comment period. This email provides an early opportunity for Minnesota to inform North Dakota of any expectations Minnesota has regarding North Dakota’s Regional Haze SIP for round 2 of the planning process.

Thank you in advance for your participation in this consultation process.
Please contact me at 701-328-5229 or destroh@nd.gov should you require additional information on this matter.

Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov

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Stroh, David E.

From: Stroh, David E.
Sent: Thursday, July 8, 2021 9:20 AM
To: Jackson, Scott; Worstell, Aaron; Dobrahner, Jaslyn; Thorton, Rhannon T.; Semerad, Jim L.
Subject: RE: North Dakota and EPA R8 Regional Haze Discussion
Attachments: July 2021_North Dakota Regional Haze Round 2.pptx

All,

I have attached the PP we will be covering today. I plan to screenshare, walkthrough the PP, and we can have an open discussion on the material.

Scott – thanks for the heads up

David

From: Jackson, Scott <Jackson.Scott@epa.gov>
Sent: Thursday, July 8, 2021 9:06 AM
To: Stroh, David E. <deStroh@nd.gov>; Worstell, Aaron <Worstell.Aaron@epa.gov>; Dobrahner, Jaslyn <Dobrahner.Jaslyn@epa.gov>; Thorton, Rhannon T. <rThorton@nd.gov>; Semerad, Jim L. <jsemerad@nd.gov>
Subject: RE: North Dakota and EPA R8 Regional Haze Discussion

Hi all,

I have a doctor's appt. during this time so I'm unable to make it. I will follow up with Jaslyn and Aaron to see how it went.

Scott

____
Scott Jackson
Air Quality Planning Branch Chief
U.S. EPA Region 8
(303) 312-6107

-----Original Appointment-----
From: Stroh, David E. <deStroh@nd.gov>
Sent: Wednesday, June 9, 2021 10:31 AM
To: Stroh, David E.; Worstell, Aaron; Dobrahner, Jaslyn; Jackson, Scott; Thorton, Rhannon T.; Semerad, Jim L.
Subject: North Dakota and EPA R8 Regional Haze Discussion
When: Thursday, July 8, 2021 10:00 AM-11:00 AM (UTC-07:00) Mountain Time (US & Canada).
Where: Microsoft Teams Meeting

Hi all,

Aaron and I spoke this morning regarding North Dakota, regional haze, and the upcoming work/SIP submittal (thanks for the good discussion, Aaron). We felt convening as a group to discuss North Dakota's current draft plan was a good idea. As your schedule allows, please join in the discussion set for July 8th. Feel free to pass along this invite to other EPA staff as you see fit.

I am planning to pull together some slides together for our discussion and will share the in advance of this call.

In the meantime, let me know if you have any questions or comments.
Regards,
David

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North Dakota Regional Haze Round 2 SIP Update

www.epa.gov/visibility/regional-haze-program

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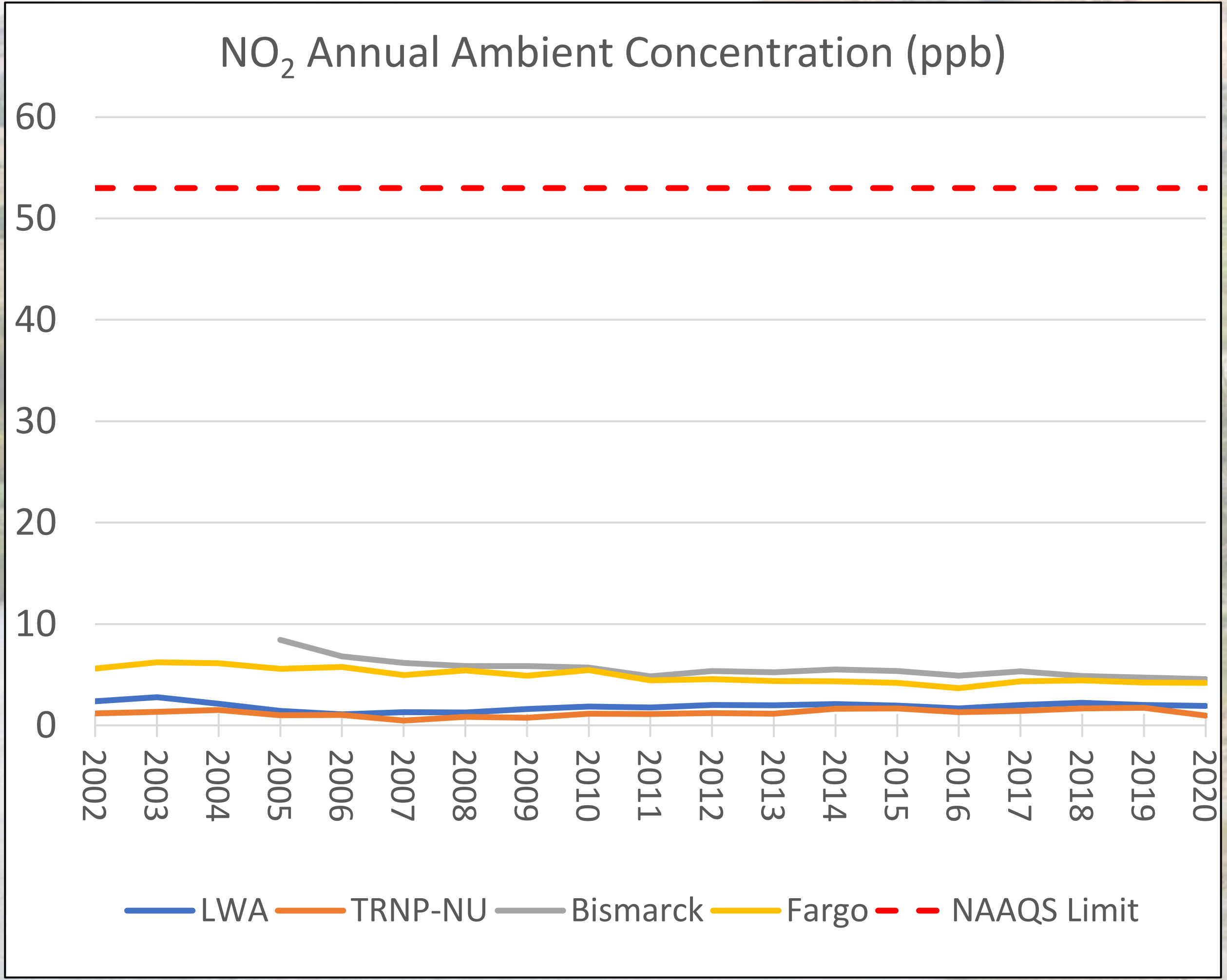
Draft Regional Haze Round 2 SIP Layout

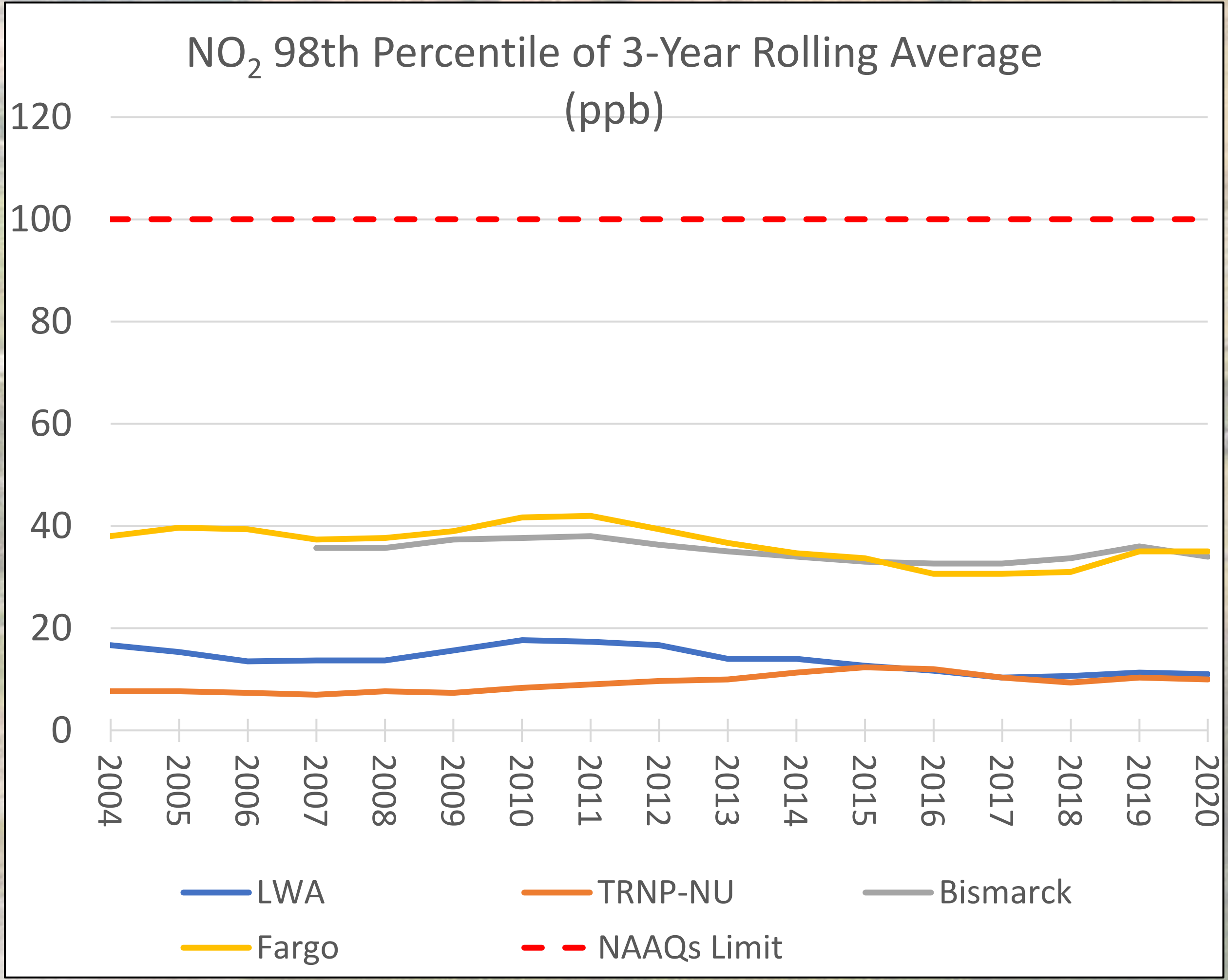
1) Background and Overview of RHR
2) SIP Development Process
3) Air Quality and Visibility Analysis
4) Emissions Inventories
5) Long-Term Strategy (LTS)
6) Modeling of LTS for Reasonable Progress Goals (RPGs)
7) Overview of WRAP Modeling
8) BART Requirements for Coal Creek Station NO_X Limits
9) Five-year Progress Report

Supporting Appendices

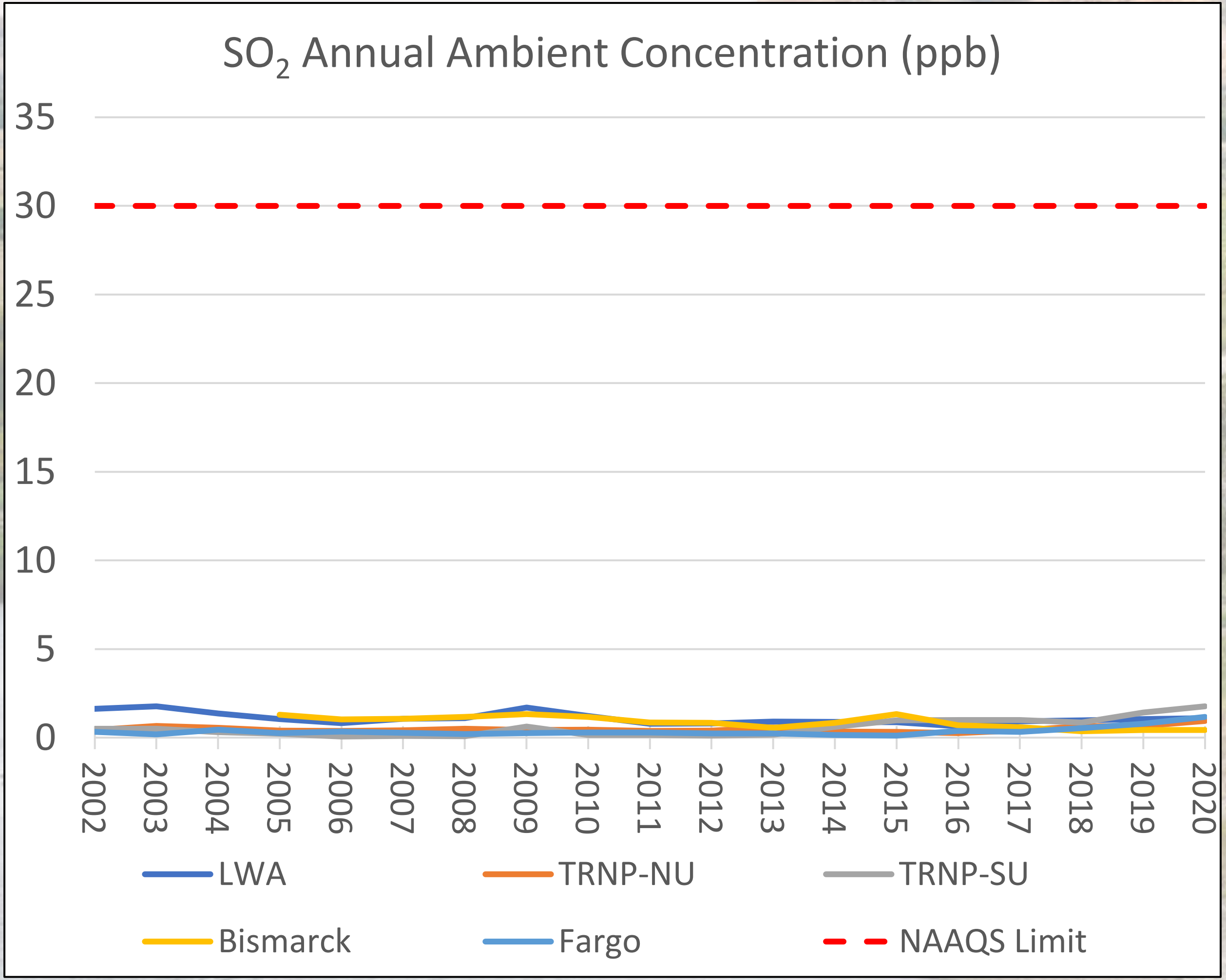
Teddy Roosevelt NP

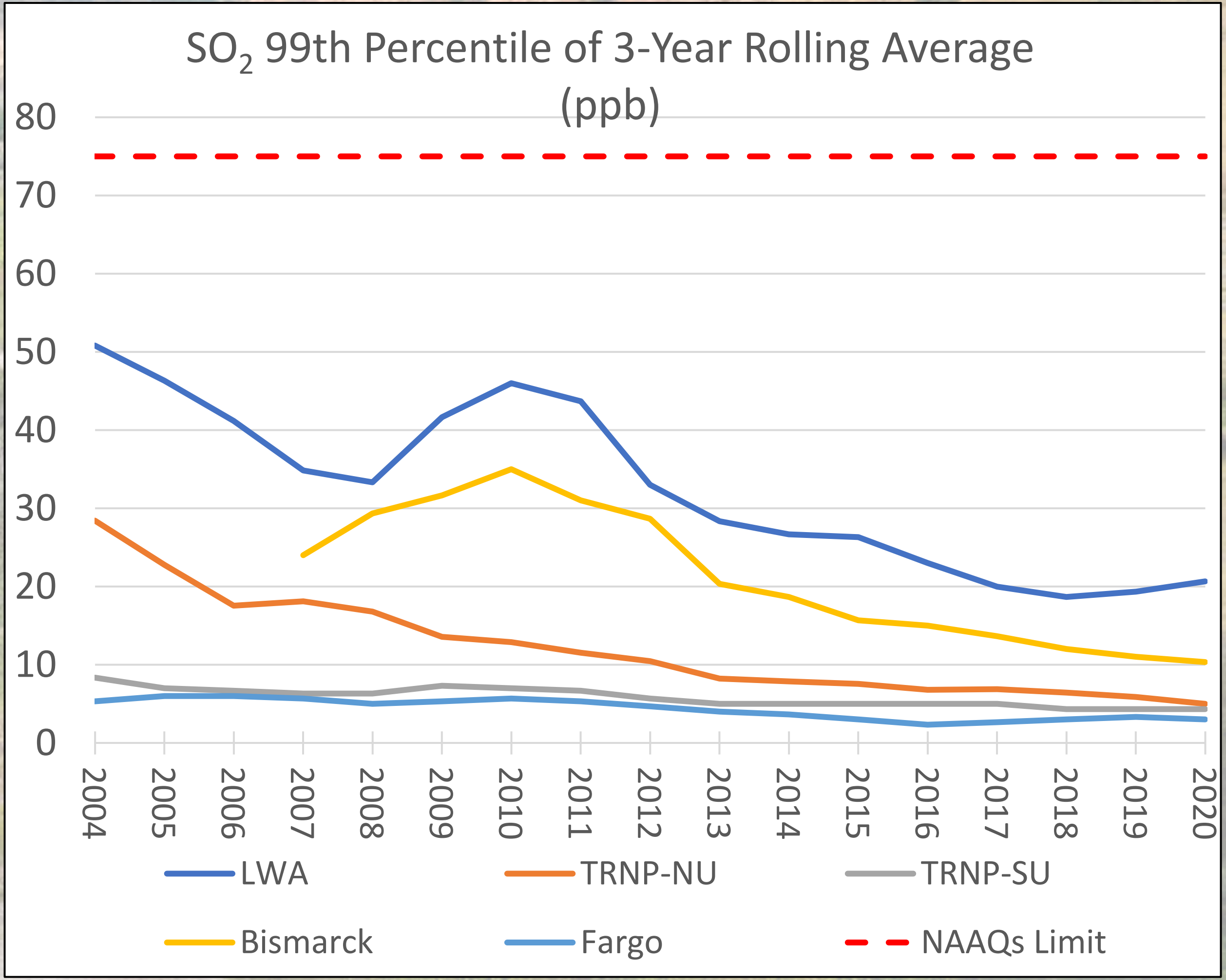
ND Air Quality



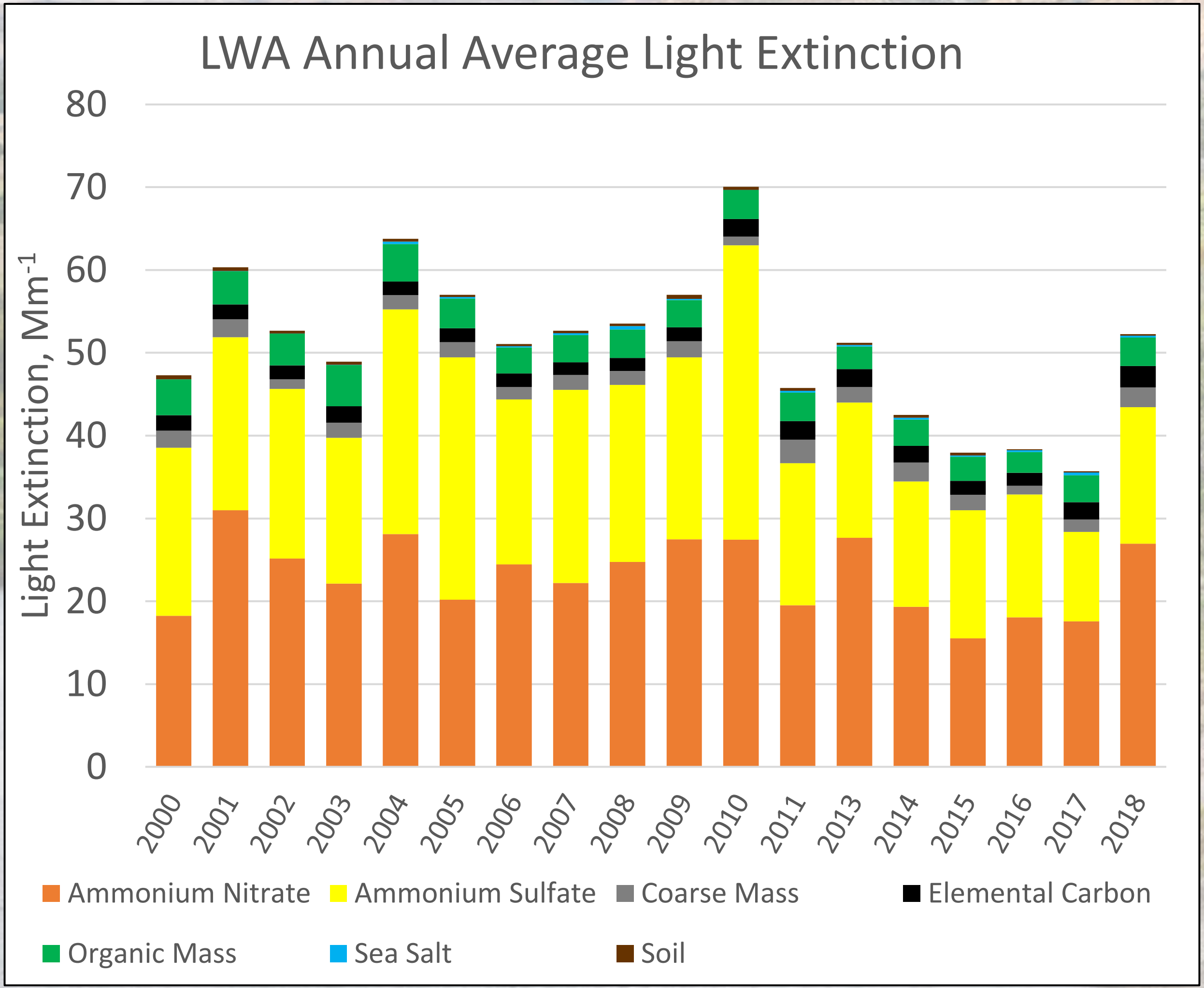


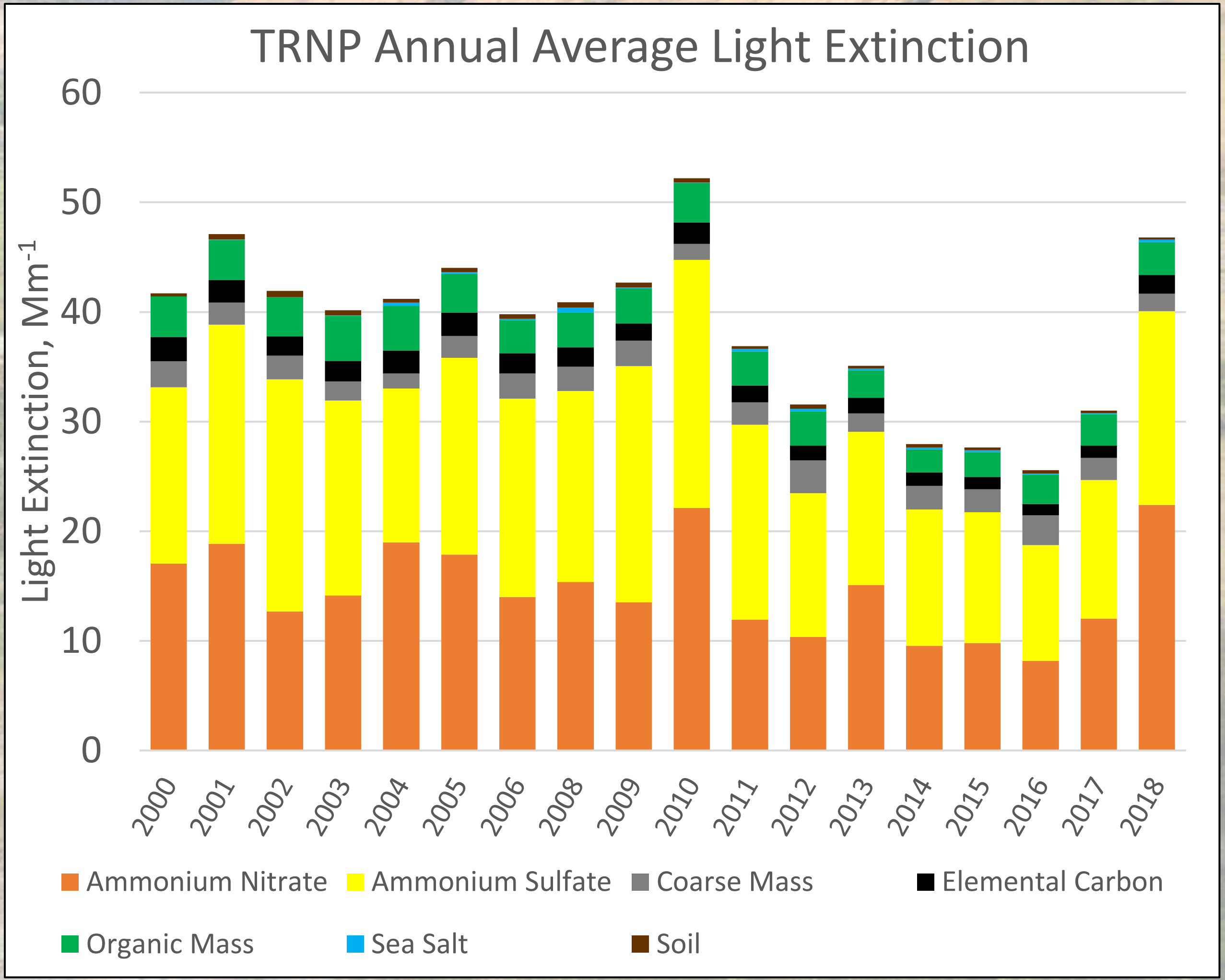
ND Air Quality



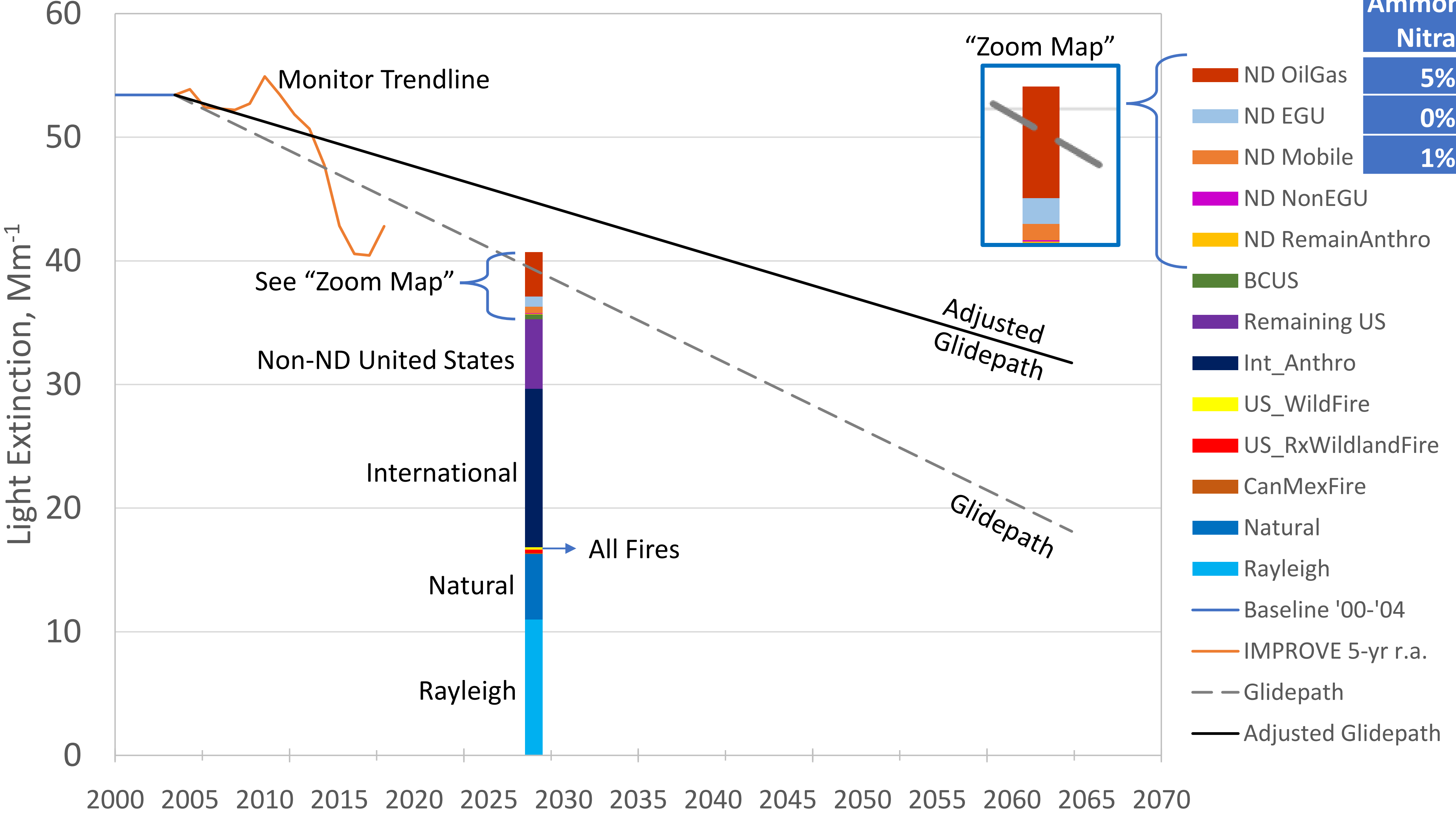


CIA Visibility - Most Impaired Days



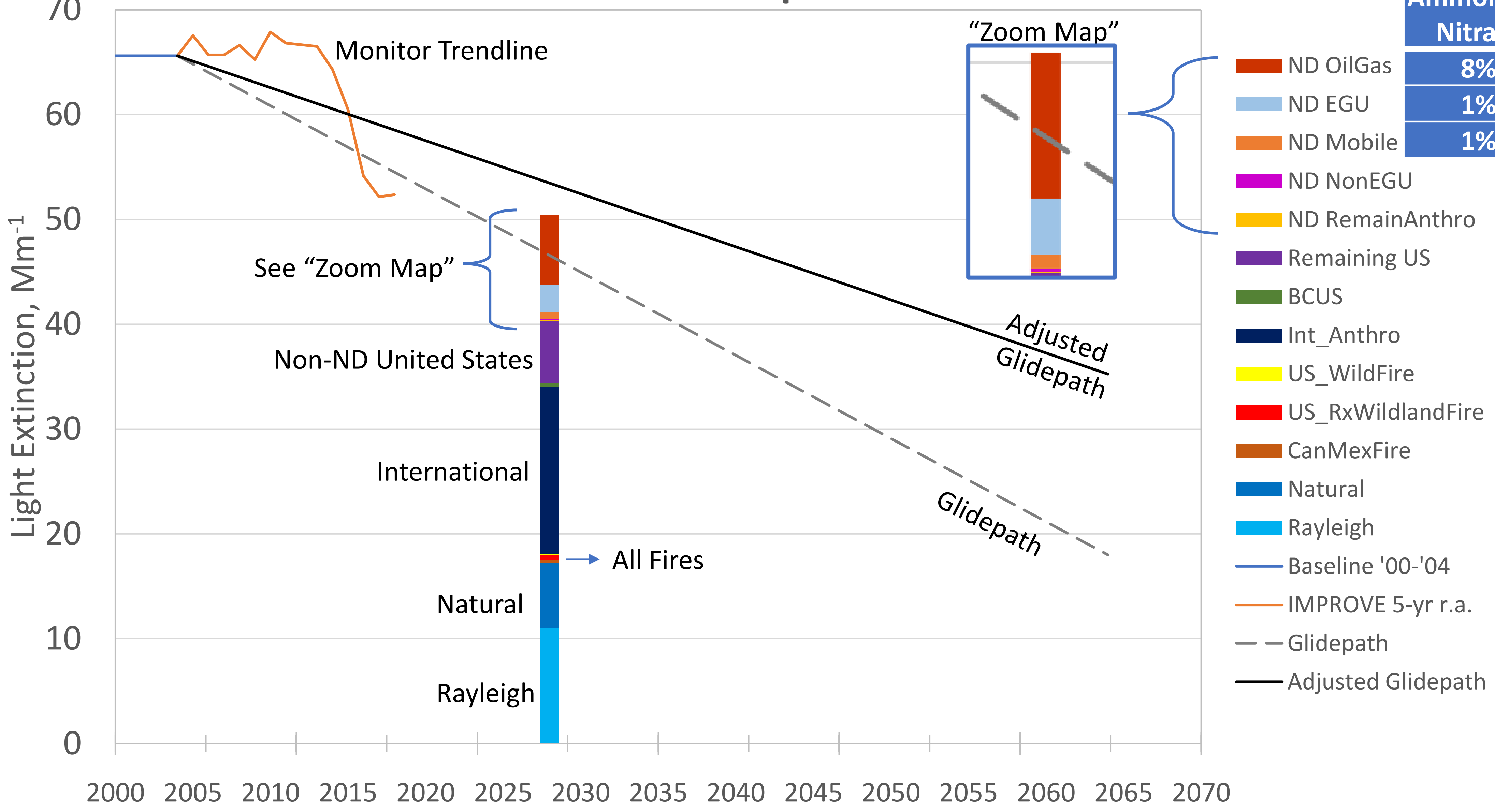


Theodore Roosevelt National Park Glidepath and Source Contribution



Ammonium Nitrate	Ammonium Sulfate
5%	4%
0%	2%
1%	0%

Lostwood Wilderness Area Glidepath and Source Contribution



Ammonium Nitrate	Ammonium Sulfate
8%	6%
1%	4%
1%	0%

Emissions Inventories for North Dakota

Representative Baseline Emissions Inventory (tons/year)

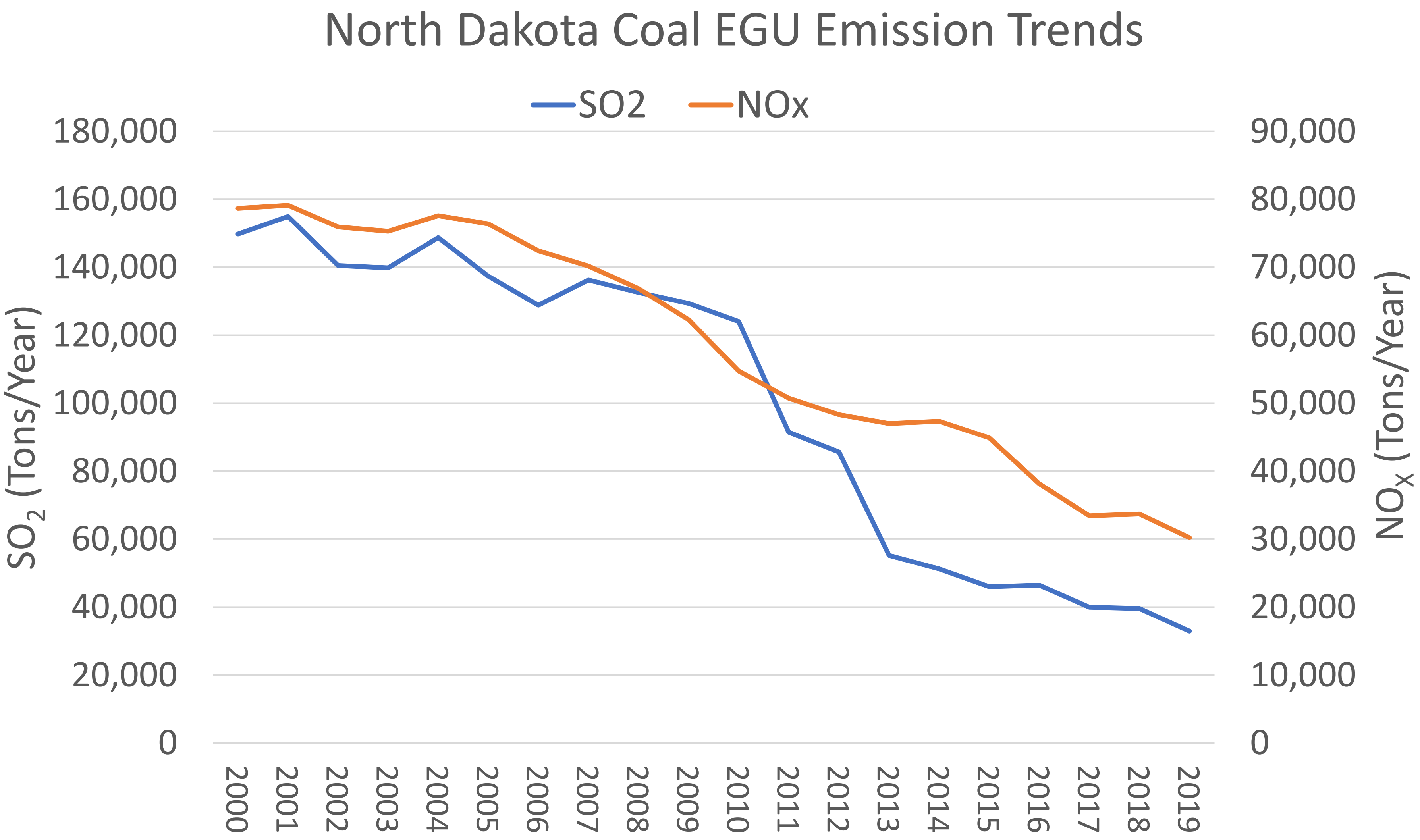
Sector	SO_2	NO_x	VOC	NH_3	PM_{10}	$PM_{2.5}$
Fugitive Dust (area-source)	0	0	0	0	186,929	32,975
Agricultural Operations	0	0	1,249	36,130	0	0
Agricultural Fire	403	1,188	1,655	6,399	5,253	3,459
Biogenic	0	44,573	179,876	0	0	0
Commercial Marine Vehicle	0	0	0	0	0	0
Lightning NOx	0	34,491	0	0	0	0
Remaining Nonpoint	171	1,194	17,144	133	878	778
Non-road Mobile	40	28,060	7,208	37	2,278	2,201
Non-US Fire	0	0	0	0	0	0
Oil & Gas Nonpoint	**9,391**	**62,190**	**400,646**	**0**	**1,116**	**1,116**
Sea Salt and DMS	0	0	0	0	0	0
Onroad Mobile	91	33,305	10,753	343	1,884	1,320
Electricity Generating Point	**39,323**	**33,712**	**633**	**172**	**3,575**	**2,553**
Industrial Point	2,856	4,517	2,885	112	2,044	1,554
Oil & Gas Point	**5,814**	**5,179**	**2,927**	**972**	**1,034**	**929**
Rail	9	14,758	749	8	468	430
Residential Wood	31	126	1,404	60	1,329	1,327
Prescribed Fire	214	593	6,605	279	2,542	2,369
Windblown Dust	0	0	0	0	3	1
Wildfire	60	221	1,518	55	564	541
Total	58,403	264,107	635,252	44,700	209,897	51,553

2028 Emissions Projections (tons/year)

Sector	SO_2	NO_x	VOC	NH_3	PM_{10}	$PM_{2.5}$
Fugitive Dust (area-source)	0	0	0	0	186,929	32,975
Agricultural Operations	0	0	1,249	36,130	0	0
Agricultural Fire	403	1,188	1,655	6,399	5,253	3,459
Biogenic	0	44,573	179,876	0	0	0
Commercial Marine Vehicle	0	0	0	0	0	0
Lightning NOx	0	34,491	0	0	0	0
Remaining Nonpoint	171	1,194	17,144	133	878	778
Non-road Mobile	32	12,200	4,762	38	852	819
Non-US Fire	0	0	0	0	0	0
Oil & Gas Nonpoint	**15,203**	**57,269**	**416,111**	**0**	**562**	**562**
Sea Salt and DMS	0	0	0	0	0	0
Onroad Mobile	53	8,051	3,831	259	808	308
Electricity Generating Point	**35,962**	**31,539**	**625**	**172**	**3,338**	**2,317**
Industrial Point	2,856	4,517	2,885	112	2,016	1,531
Oil & Gas Point	**5,814**	**5,179**	**2,857**	**972**	**1,034**	**929**
Rail	7	8,244	348	7	216	209
Residential Wood	31	126	1,404	60	1,329	1,327
Prescribed Fire	214	593	6,605	279	2,542	2,369
Windblown Dust	0	0	0	0	3	1
Wildfire	60	221	1,518	55	564	541
Total	60,806	209,385	640,870	44,616	206,324	48,125

Available on TSSv2: https://views.cira.colostate.edu/tssv2/Express/EmissionsTools.aspx

ND First Round EGU Reductions



ND EGU Emissions and Reductions

NO_x Emissions (tons)

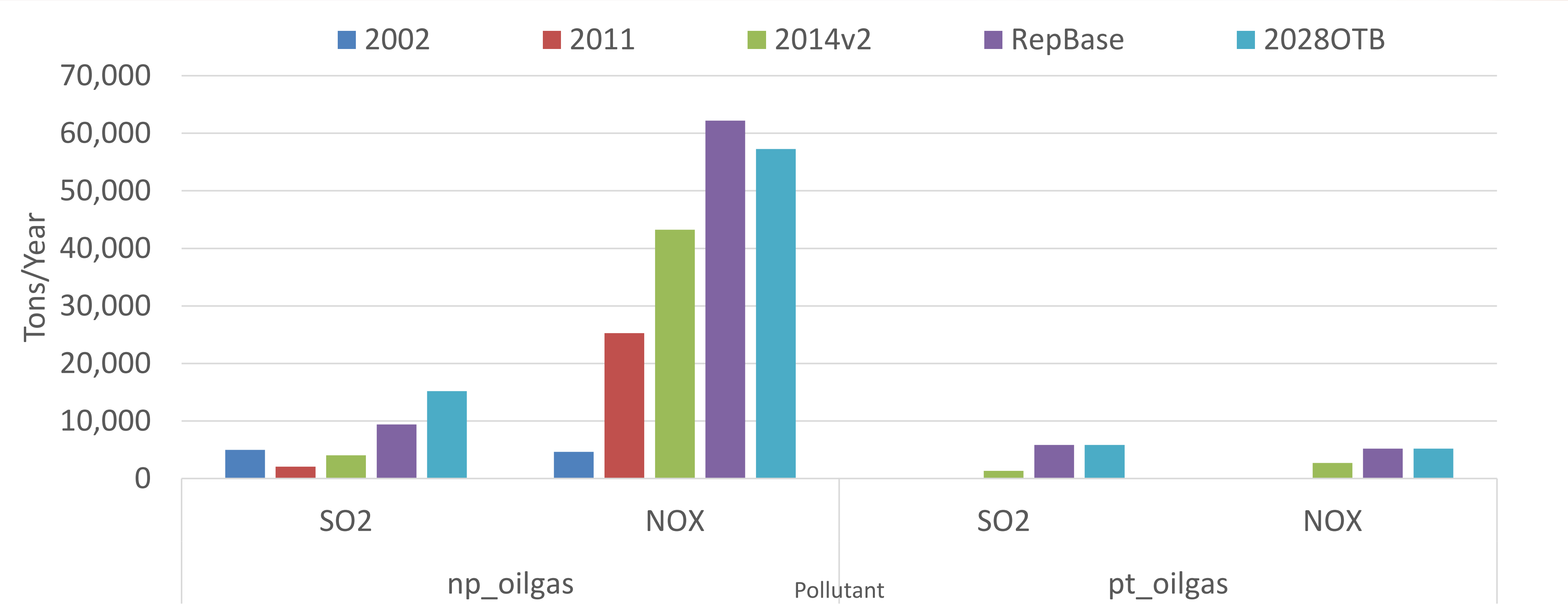
Facility	Unit	2002	RepBase	2028 OTB	Reduction*
Coyote	1	13,173	7,363	7,363	44%
Antelope Valley	1	5,840	1,697	1,697	71%
Antelope Valley	2	5,953	1,708	1,708	71%
Leland Olds	1	2,581	1,059	1,059	59%
Leland Olds	2	11,184	4,192	4,192	63%
Coal Creek	1	4,863	3,987	3,010	38%
Coal Creek	2	5,492	3,010	3,010	45%
Milton R. Young	1	8,510	3,435	3,435	60%
Milton R. Young	2	14,335	5,735	5,735	60%
RM Heskett Station	1	180	209		
RM Heskett Station	2	918	978		
Stanton Station	1	2,209			
Stanton Station	10	890			
	Total	76,127	33,373	31,209	59%

SO_2 Emissions (tons)

Facility	Unit	2002	RepBase	2028 OTB	Reduction*
Coyote	1	14,069	12,994	12,994	8%
Antelope Valley	1	6,580	6,279	6,279	5%
Antelope Valley	2	7,283	6,319	6,319	13%
Leland Olds	1	16,655	636	636	96%
Leland Olds	2	30,744	1,258	1,258	96%
Coal Creek	1	11,910	3,458	2,740	77%
Coal Creek	2	12,518	3,400	2,743	78%
Milton R. Young	1	19,858	766	766	96%
Milton R. Young	2	8,707	2,165	2,165	75%
RM Heskett Station	1	622	753		
RM Heskett Station	2	2,189	1,214		
Stanton Station	1	8,900			
Stanton Station	10	1,122			
	Total	141,156	39,242	35,900	75%

*Reduction from 2002 to 2028 Projections

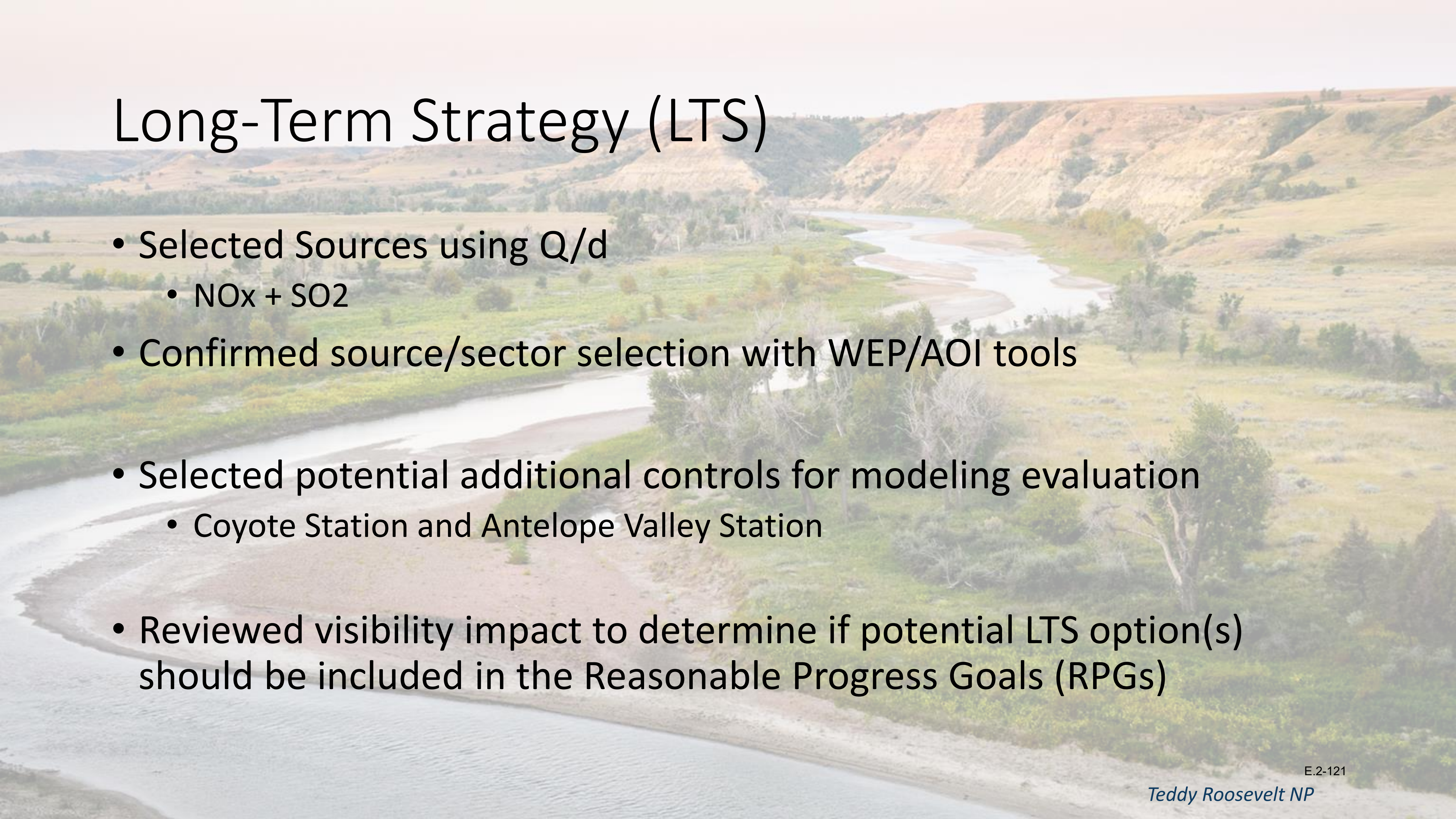
ND Oil and Gas Emissions



Sector	Pollutant	2002	2011	2014v2	RepBase	2028OTB
np_oilgas	SO_2	4,958	2,073	4,043	9,391	15,203
	NO_X	4,631	25,277	43,237	62,190	57,269
	VOC	7,740	252,920	664,297	400,646	416,111
pt_oilgas	SO_2	-	-	1,314	5,814	5,814
	NO_X	-	-	2,702	5,179	5,179
	VOC	-	-	2,025	2,927	2,857

Long-Term Strategy (LTS)

- Selected Sources using Q/d
  - NOx + SO2
- Confirmed source/sector selection with WEP/AOI tools
- Selected potential additional controls for modeling evaluation
  - Coyote Station and Antelope Valley Station
- Reviewed visibility impact to determine if potential LTS option(s) should be included in the Reasonable Progress Goals (RPGs)



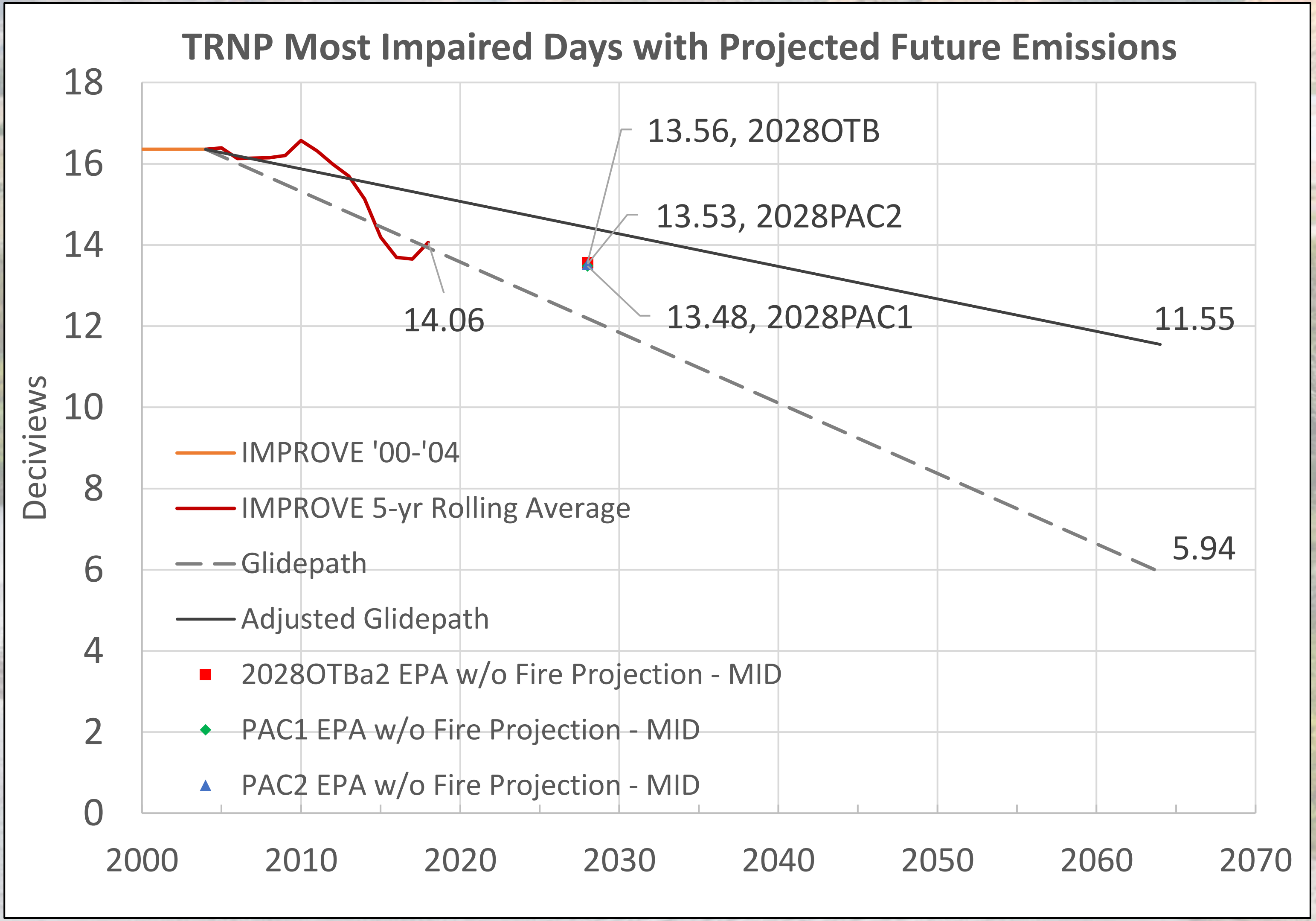
Teddy Roosevelt NP

Facility Modeled Emissions Reductions

Potential Additional Controls 1	Control Technology	Pollutant	Annual Emission Reduction (tpy)	Installed Capital Cost ($)	Annual O&M Cost ($)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
Coyote	Absorber Replacement	SO_2	11,621	110,120,000	12,097,000	21,122,000	1,818
	SNCR + Comb. Opt.	NO_x	3,093	19,840,000	3,128,000	4,753,933	1,537
AVS 1	Ca:S Stoichiometry	SO_2	2,874	9,698,000	1,144,000	1,938,773	675
AVS 2	Ca:S Stoichiometry	SO_2	2,914	9,698,000	1,144,000	1,938,773	665
CCS 1	*LNC3+*	*NO_x*	*1,034*	*N/A*	*N/A*	*N/A*	*N/A*
~~CCS 1 & 2~~	~~Scrubber Modification~~	~~SO_2~~	~~712~~	~~N/A~~	~~N/A~~	~~N/A~~	~~N/A~~

Potential Additional Controls 2	Control Technology	Pollutant	Annual Emission Reduction (tpy)	Installed Capital Cost ($)	Annual O&M Cost ($)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
Coyote	FGD Stoich Improvements	SO_2	5,369	526,000	2,042,000	2,085,000	388
CCS 1	*LNC3+*	*NO_x*	*1,034*	*N/A*	*N/A*	*N/A*	*N/A*
~~CCS 1 & 2~~	~~Scrubber Modification~~	~~SO_2~~	~~712~~	~~N/A~~	~~N/A~~	~~N/A~~	~~N/A~~

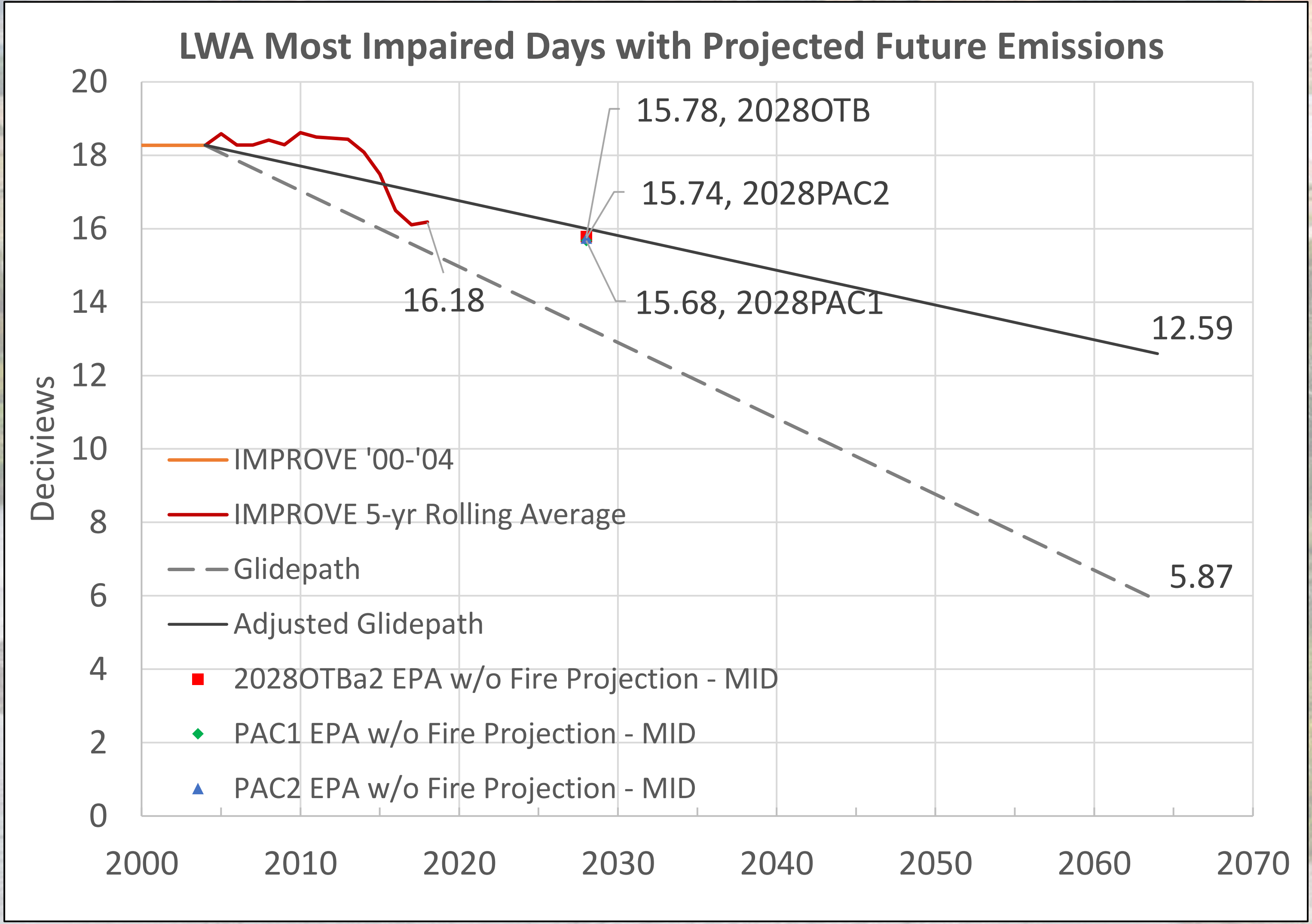
TRNP Reasonable Progress Goal



Scenario	SO_2	NO_X
2028OTB	35,900	32,186
2028PAC1	17,779	28,059
2028PAC2	29,819	31,152

EGU Reductions	SO_2	NO_X	Total
PAC 1	18,121	4,127	22,248
PAC2	6,081	1,034	7,115

LWA Reasonable Progress Goal



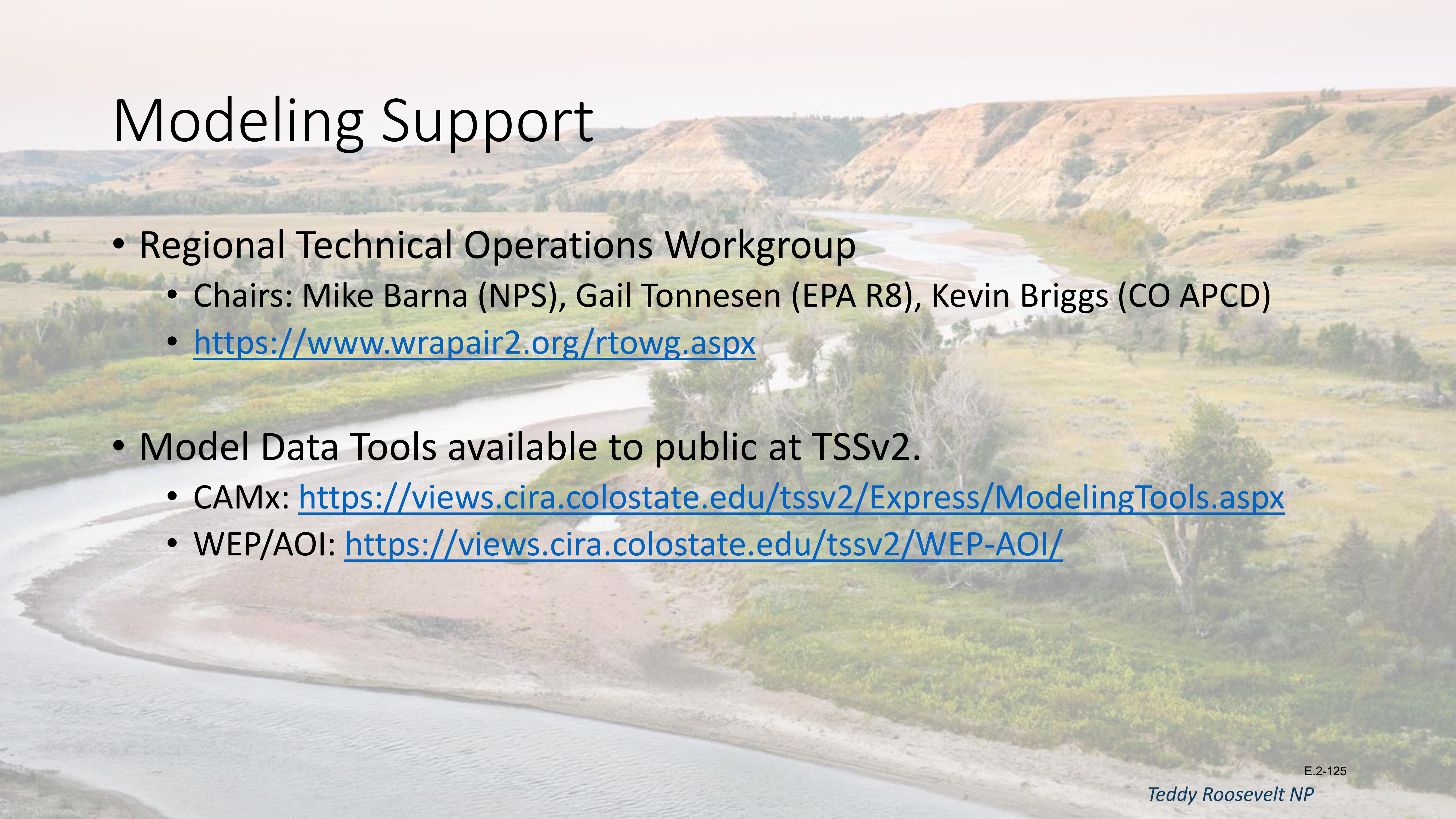
Scenario	SO_2	NO_X
2028OTB	35,900	32,186
2028PAC1	17,779	28,059
2028PAC2	29,819	31,152

EGU Reductions	SO_2	NO_X	Total
PAC 1	18,121	4,127	22,248
PAC2	6,081	1,034	7,115

Modeling Support

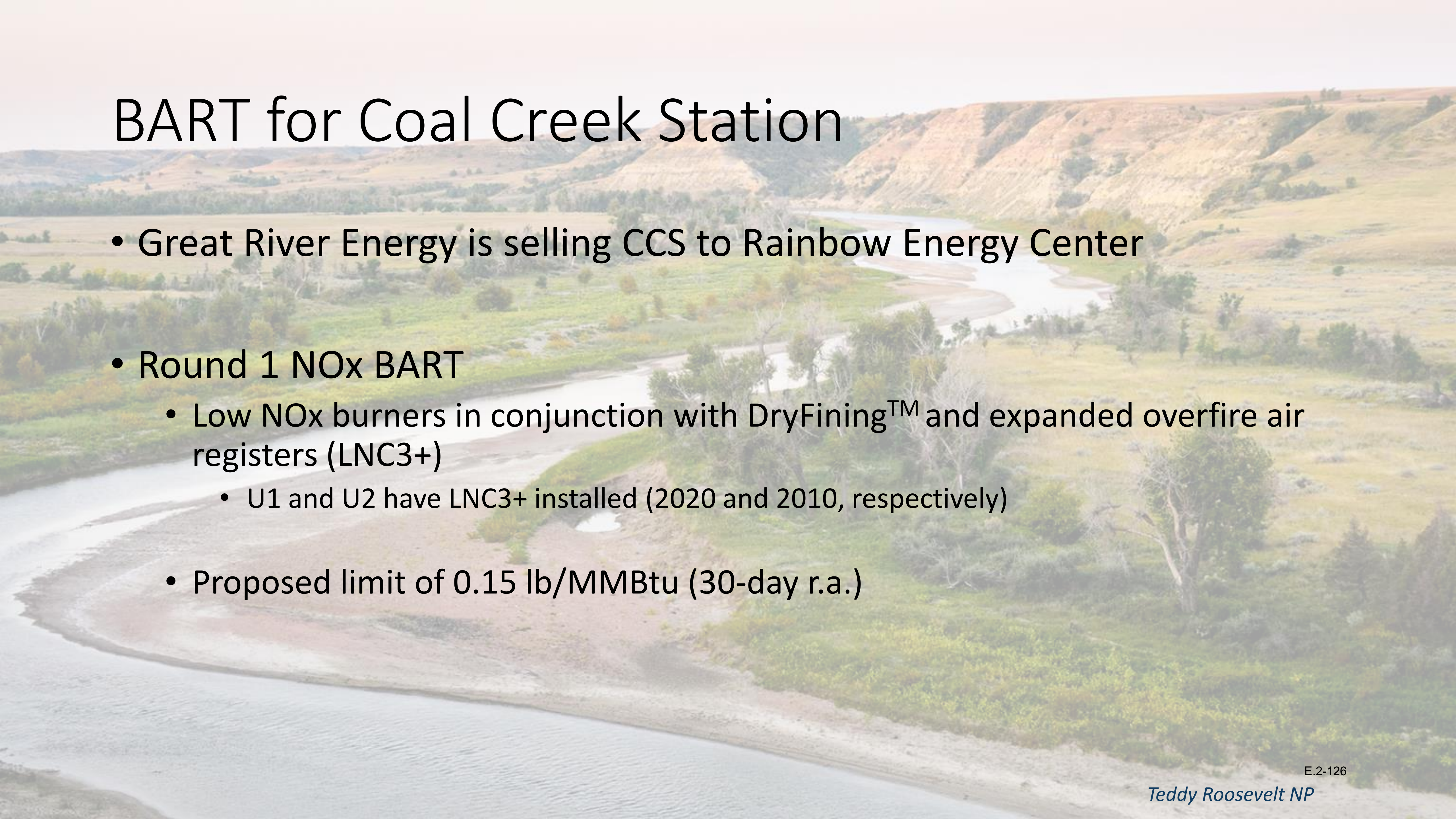
- Regional Technical Operations Workgroup
  - Chairs: Mike Barna (NPS), Gail Tonnesen (EPA R8), Kevin Briggs (CO APCD)
  - https://www.wrapair2.org/rtowg.aspx

- Model Data Tools available to public at TSSv2.
  - CAMx: https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx
  - WEP/AOI: https://views.cira.colostate.edu/tssv2/WEP-AOI/



Teddy Roosevelt NP

BART for Coal Creek Station



- Great River Energy is selling CCS to Rainbow Energy Center

- Round 1 NOx BART
  - Low NOx burners in conjunction with DryFining^{TM} and expanded overfire air registers (LNC3+)
    - U1 and U2 have LNC3+ installed (2020 and 2010, respectively)

  - Proposed limit of 0.15 lb/MMBtu (30-day r.a.)

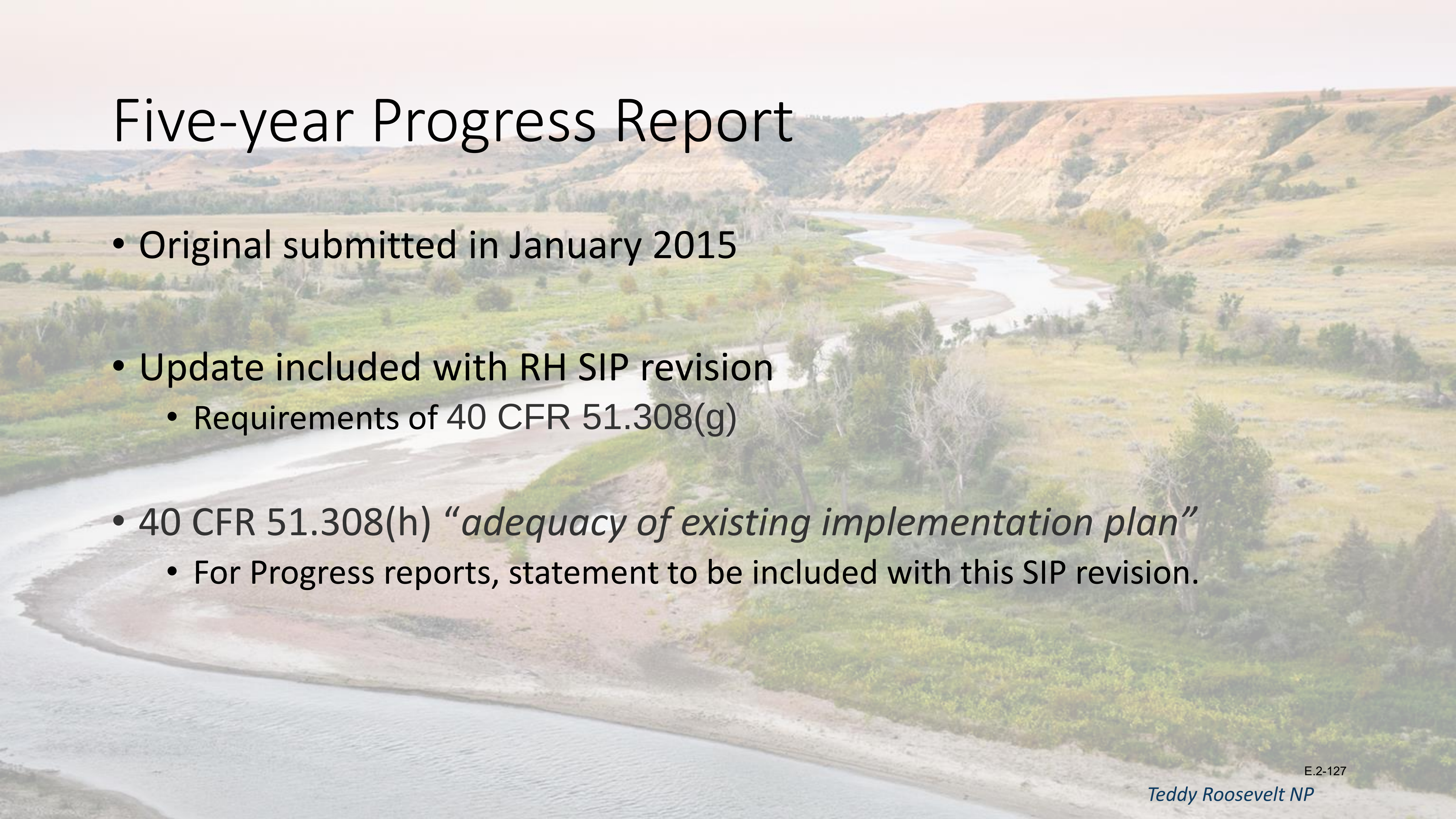
Teddy Roosevelt NP

Five-year Progress Report

- Original submitted in January 2015

- Update included with RH SIP revision
  - Requirements of 40 CFR 51.308(g)

- 40 CFR 51.308(h) *“adequacy of existing implementation plan”*
  - For Progress reports, statement to be included with this SIP revision.

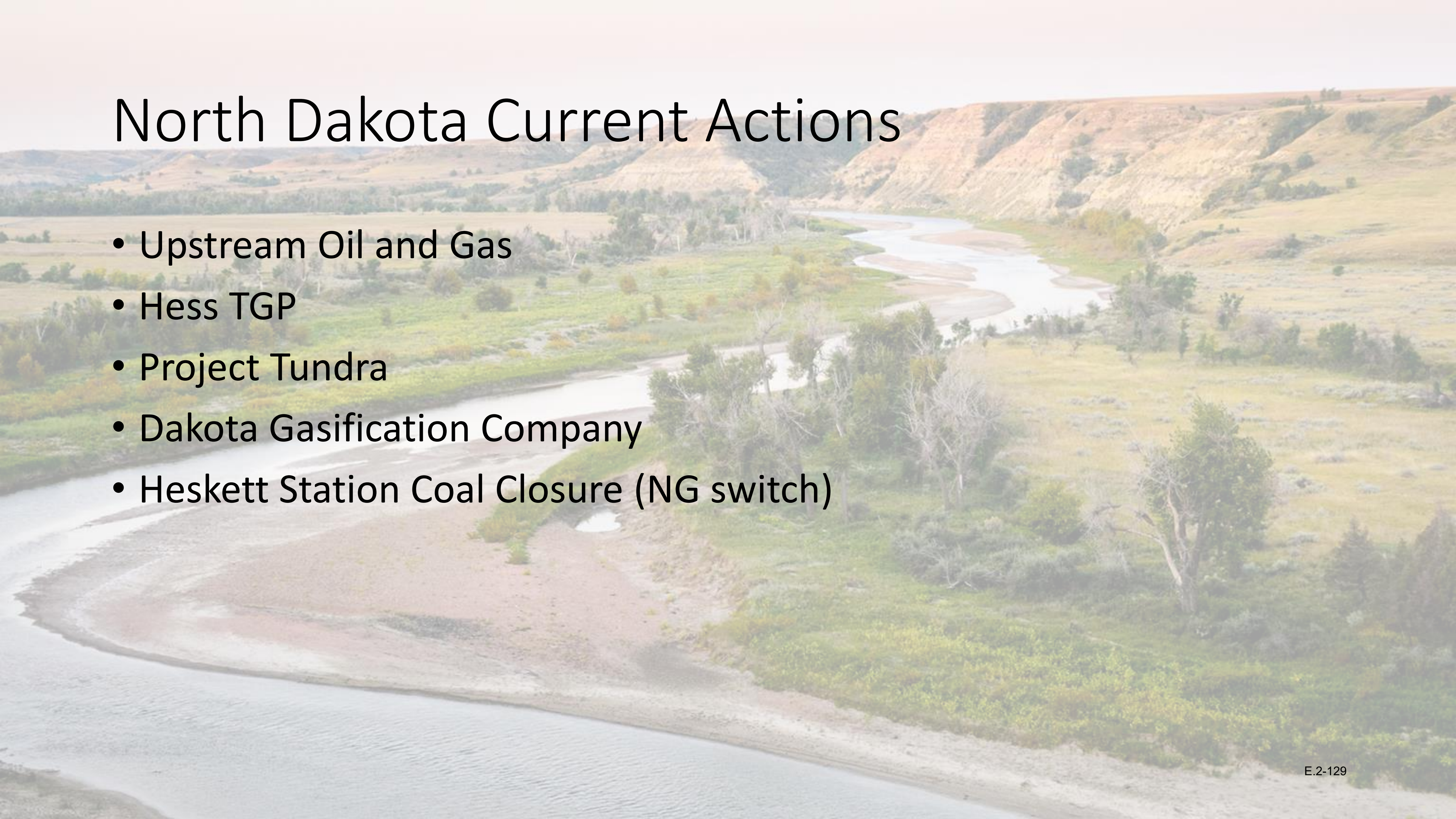


Teddy Roosevelt NP

Timeline and Next Steps

- Finish internal review
- 60-day formal FLM consultation period
  - Summarize/Incorporate comments
- 30-day public comment period
  - Hold public hearing
  - Respond to comments
- Route to Governor’s Office for signature
- Submit

Teddy Roosevelt NP



North Dakota Current Actions

- Upstream Oil and Gas
- Hess TGP
- Project Tundra
- Dakota Gasification Company
- Heskett Station Coal Closure (NG switch)

Appendix F – Coal Creek Station NOx BART

F.1 – NOx BART analysis for Coal Creek Station Unit 1 and Unit 2

1 Introduction and Representative Operations

Coal Creek Station (CCS) is a two-unit, approximately 1,200 gross MW mine-mouth power plant consisting primarily of two steam generators and associated coal and ash handling systems. Unit 1 and Unit 2 are identical Combustion Engineering boilers firing pulverized lignite coal tangentially. Unit 1 has a heat input capacity of 6,015 MMBtu/hr; Unit 2 has a heat input capacity of 6,022 MMBtu/hr.

Unit 1 began commercial operation in 1979. Unit 2 began commercial operation in 1980. The facility is located in south central McLean County about five miles south of the town of Underwood, North Dakota and three miles west of US Highway 83. CCS receives its lignite coal from the Falkirk Mine that is operated by the Falkirk Mining Company, which is a subsidiary of the North American Coal Corporation. The average annual amount of North Dakota lignite coal combusted from 2009 through 2018 was 7.2 million tons. See Table 1 for detailed information.

Table 1: Yearly Coal Combusted (tons)

Year	Unit 1 (tons)	Unit 2 (tons)
2009	4,095,584	3,941,997
2010	3,835,877	3,284,752
2011	4,371,455	4,801,722
2012	3,645,837	3,579,986
2013	3,623,564	3,304,313
2014	3,407,090	3,528,472
2015	3,439,201	3,446,814
2016	3,355,393	2,862,056
2017	2,752,937	3,394,443
2018	3,750,337	3,667,824
Average	**3,627,728**	**3,581,238**
Combined Average	**7,208,966**	

Over the same 10-year period (2009–2018), CCS operated at an 87% annual capacity factor, as determined on an actual heat input basis. Future operations are expected to be consistent with this 10-year period and the 87% annual capacity factor was used when calculating the baseline and future projected emissions discussed in Section 2.

Table 2 displays the operational information from 2009–2018. The Annual Capacity Factor is calculated by dividing the actual heat input by the maximum potential heat input for Unit 1 (52.69x10^6 MMBtu/yr) and Unit 2 (52.75x10^6 MMBtu/yr).

Table 2: Utilization and Annual Capacity Factor

Year	Unit 1 Heat Input MMBtu/yr	Unit 2 Heat Input MMBtu/yr	Unit 1Annual Capacity Factor	Unit 2 Annual Capacity Factor
2009	49,625,416	48,220,581	0.94	0.91
2010	49,409,811	41,998,558	0.94	0.80

Year	Unit 1 Heat Input MMBtu/yr	Unit 2 Heat Input MMBtu/yr	Unit 1Annual Capacity Factor	Unit 2 Annual Capacity Factor
2011	43,014,802	46,942,626	0.82	0.89
2012	48,676,811	47,951,409	0.92	0.91
2013	48,686,810	43,924,548	0.92	0.83
2014	46,286,312	46,530,063	0.88	0.88
2015	47,059,790	46,053,317	0.89	0.87
2016	45,437,239	38,498,049	0.86	0.73
2017	37,327,033	44,826,636	0.71	0.85
2018	48,250,097	47,761,484	0.92	0.91
Average	**46,377,412**	**45,270,727**	**0.88**	**0.86**
		Combined Average	**0.87**	

2 NOx Emissions Controls and History

2.1 Existing NOx Controls

The NOx controls currently installed at CCS Units 1 and 2 consist of the following:

1) LNC3 (combination of closed coupled overfired air, separated overfired air, and low NOx burners) is installed on Units 1 and 2. This technology is considered as part of the baseline emission calculation discussed in Section 2.2.

2) DryFining^{TM} technology has been installed and operating on Units 1 and 2 since 2010. DryFining^{TM} is an innovative technology developed by Great River Energy that reduces moisture and refines lignite coal. The technology increases the efficiency and performance of the fuel while reducing emissions. This technology is considered part of the baseline emissions discussed in Section 2.2. Units 1 and 2 have experienced approximately 0.02 lb NOx/MMBtu of reductions since completion of DryFining^{TM}.

3) LNC3+ (LNC3 with expanded overfired air registers in conjunction with DryFining^{TM}) was installed on Unit 2 in 2007. Expanded overfired air was completed in 2007 with DryFining^{TM} coming online in 2010. Collectively, LNC3+ became fully operational on Unit 2 in 2010. Unit 1 had expanded overfired air registers installed in the second quarter of 2020. Unit 1 is LNC3+ is expected to operate with a similar NOx profile as the LNC3+ on Unit 2.

2.2 Historical and Future Anticipated Emissions

For the purposes of this BART determination, the Department considered the operation of LNC3 with DryFining^{TM} technology as the baseline control technology for Units 1 and 2. Even though LNC3+ (expanded overfired air registers with DryFining^{TM}) has been operational on Unit 2 since 2010 and was installed on Unit 1 in 2020, the Department found it most appropriate to perform the BART determination as if LNC3+ is not installed on either unit. This is consistent with the EPA response to comments set forth in the Federal Implementation Plan created for North Dakota (77 FR 20893):

"We evaluate potential control options based on baseline conditions, not on ongoing revisions to a facility after the baseline period. It is not reasonable to consider controls installed after the baseline period in determining BART. Such an approach would tend to lead to higher cost effectiveness values for more effective controls and encourage sources to voluntarily install lesser controls to avoid installing more effective BART controls later." [1]

This above response is still applicable, but requires additional context given the amount of time which has passed and the reductions of NOx emissions from the source over this time. To demonstrate the impact LNC3+ had on the average NOx emissions for Unit 2, the Department reviewed the five-year annual average performance rates preceding the installation of LNC3+. From 2002 through 2006, the annual average NOx performance rate in pounds per MMBtu for Units 1 and 2 was 0.22 and 0.23, respectively. The similarity of this five-year average supports the notion that Unit 1 and Unit 2 operate nearly identically with similar controls. The differences in performance rates between Unit 1 and Unit 2 since that time period can be attributed to the installation of LNC3+. This also demonstrates that Unit 1 will be able to achieve a similar annual NOx performance as Unit 2.

CCS installed LNC3+ on Unit 2 in 2010 and on Unit 1 in 2020 in advance of being required through an approved regional haze SIP amendment. As a result of CCS installing LNC3+ on Unit 2, approximately 11,700 tons of NOx emissions reductions occurred at CCS from 2010–2018. These reductions would not have occurred without the installation of LNC3+. Table 3 displays this information.

Table 3: Annual NOx Emissions since 2010

Year	Unit 1 Configuration LNC3^A (NOx Tons)	Unit 2 Configuration LNC3+ (NOx Tons)	Difference
2010	5,199	3,473	1,726
2011	4,398	3,580	818
2012	5,102	3,556	1,547
2013	4,692	3,320	1,373
2014	4,697	3,287	1,410
2015	5,087	3,499	1,588
2016	4,327	2,564	1,763
2017	3,361	2,889	472
2018	3,985	3,010	976
Total NOx:	**40,848**	**29,176**	**11,673**

[A] LNC3 with DryFining™

Reducing NOx emissions through combustion upgrades (e.g. LNC3+) in advance of installing add-on post combustion controls (e.g. SNCR or SCR) is always recommended as the first step. Fundamentally, it is better to produce less NOx during the combustion process than it is to add-on post combustion pollution controls to remove NOx after formation. This reduces the equipment size and the associated operational and maintenance costs of the add-on controls. CCS has already taken

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[1] Available at: https://www.federalregister.gov/d/2012-6586/p-547

the step to install LNC3+ on both Units. As is described in the EPA response to comments above, the installation of LNC3+ was voluntary and not required by the Department. Therefore, it should not be used in the baseline emissions. However, LNC3+ may still be selected as the appropriate BART control for both Unit 1 and Unit 2. As this BART determination demonstrates, CCS installed NOx BART controls on Unit 2 in 2010 and installed NOx BART controls on Unit 1 in 2020 with the installation of LNC3+.

The 2016–2018 three-year annual average data from LNC3 (with DryFining^{TM}) on Unit 1 and LNC3+ on Unit 2 is displayed in Table 4. Table 4 LNC3 data for Unit 1 is used as the baseline performance rate in pounds of NOx per MMBtu for both units. Table 4 LNC3+ data for Unit 2 is used as the first option of additional controls for evaluation in the current BART determination for both units. This is unique from other BART determinations because the first option of additional control is based on actual performance data from Unit 2 and not on anticipated future performance rates (like the remaining add-on control options evaluated in Section 3.1).

Table 4: Three-year NOx performance rate in lb NOx/MMBtu

Year	Unit 1 (LNC3 with DryFining$^{TM)}$	Unit 2 (LNC3+)
2016	0.193	0.136
2017	0.182	0.130
2018	0.166	0.126
Average	**0.180**	**0.131**

As shown in Table 4, the 3-year average NOx performance rate from Unit 1 is 0.18 lb NOx/MMBtu; this is used as the baseline performance rate for Unit 1 and Unit 2. Also shown in Table 4, the Unit 2 LNC3+ 3-year average performance rate is 0.13 lb NOx/MMBtu; this is used as the performance rate for first option of BART controls.

A benefit to taking this approach is that the Department has actual operational data reflecting the impact LNC3+ has on reducing the formation of NOx emissions at CCS, relative to LNC3. Since Unit 1 and Unit 2 are identical units, the future anticipated performance rate for LNC3+ on Unit 1 is based on actual data from Unit 2. Table 5 displays the baseline NOx emissions scenario and the tons associated with the first control option (LNC3+). Note: values displayed are for a single unit.

Table 5: Unit 1 and Unit 2 Baseline Emissions and Control Option 1

Control Scenario	Control Technology	Emissions (tons/year)
Baseline	LNC3 with DryFining^{TM}	4,143
Option 1	LNC3+	2,980

3 NOx BART Determination for Unit 1 and Unit 2

The following determination was derived using combined average historical data for both units and using the data to make a single BART determination, which applies to both units. A single NOx BART determination is made because Unit 1 and Unit 2 are identical boilers and have historically operated consistently, as discussed in Section 2.2.

3.1 Step 1 – Identify All Available Retrofit Control Technologies

The BART controls that were evaluated for CCS are listed in Table 6. Each control technology is listed along with its associated performance rate and total expected emissions on a yearly basis. Expected emissions were calculated using the performance rate, the potential heat input, and the annual capacity factor (Table 2).

Table 6: NOx BART Control Options

Control Technology	Control Technology Abbreviation	Emission Rate (lb/MMBtu)	Emissions (tons/year)
low NOx burners with closed coupled overfired air	LNC3 [A]	0.18	4,143 [B]
LNC3 with expanded overfired air registers in conjunction with DryFining™	LNC3+	0.13	2,980
selective non-catalytic reduction	SNCR	0.10	2,293
selective catalytic reduction	SCR	0.08-0.06	1,830-1,380

[A] The emission rate for LNC3 includes the DryFining™ operation

[B] 0.18 lb NOx/MMBtu x 52.72×10^6 MMBtu/yr x 0.87 / 2000 = 4,140 tons NOx/year

LNC3+ was evaluated as an additional control option to reduce the formation of NOx during the combustion process. Selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) were both evaluated as potentially available add-on controls to reduce NOx emissions post combustion.

The control technologies evaluated in Table 6 for reducing NOx emissions are consistent with the technologies evaluated for the other North Dakota lignite-fired electrical generating utilities[2] and with the BART guidelines.[3]

3.2 Step 2 – Evaluate Technically Feasible Control Technologies

1) LNC3+ is technically feasible and is currently installed and operational on Unit 1 and Unit 2. LNC3+ was installed on Unit 2 in 2010 and was installed on Unit 1 in 2020.

2) SNCR is a type of post combustion add-on control equipment. SNCR is technically feasible for both units at CCS and was reviewed as a potential additional control option after LNC3+ installation.

3) SCR is a type of post combustion add-on control equipment. The technical feasibility of SCR is uncertain at CCS. SCR was reviewed as a potential additional control option after LNC3+ installation. SCR was evaluated based on two potential arrangements, including a "high-dust" and "low-dust" system. High-dust systems are located upstream of the particulate

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[2] Available at: https://www.federalregister.gov/documents/2012/04/06/2012-6586/approval-and-promulgation-of-implementation-plans-north-dakota-regional-haze-state-implementation

[3] 40 CFR Part 51 Appendix Y, Guidelines for BART Determinations under the Regional Haze Rule.

controls (electrostatic precipitator) and low-dust systems are located downstream of the particulate controls.

a. High-dust SCR systems have significant potential for catalyst surface plugging due to the high sodium concentrations in the lignite coal used at CCS. Additionally, without the completion of pilot testing, the SCR catalyst supplier was unable to ensure reliable performance and catalyst life given the significant uncertainty with potential plugging and catalyst deactivation.[4] For these reasons, a high-dust SCR system is determined to be technically infeasible. This is consistent with the Department's 2009 determination that high-dust SCR is not technically feasible for Units combusting North Dakota lignite coal.[5]

b. Low-dust SCR systems (including tail-end SCR) are located downstream of the electrostatic precipitator where most of the sodium-bearing fly ash particles are expected to be removed, potentially mitigating the issue of SCR catalyst plugging.[6] The catalyst vendor, IBDEM Ceram, and the SNCR/SCR vendor, Fuel Tech, both expressed overall concerns with North Dakota lignite coal impacts on the SCR catalyst plugging and fouling. Both independently recommended pilot scale testing be completed to obtain actual performance data and determine catalyst impacts.[7,8] Without consideration of the recommended pilot testing, a low-dust system potentially removes the concern with technical feasibility in relation to catalyst plugging. Therefore, a low-dust SCR system is determined to be technically feasible and is carried forward for further evaluation.[9]

3.3 Step 3 – Evaluate Control Effectiveness

The efficiency of the BART controls, anticipated performance rates, and the projected emission reductions for each control option are listed in Table 7. The projected emissions reductions listed in Table 7 would occur at each unit (e.g. SNCR would reduce NO_X emissions by 1,850 tons per year from both Unit 1 and Unit 2, totaling 3,700 tons per year, beyond the baseline emissions).

Table 7: Control Effectivenss and Emissions Reductions

Control Technology	Emission Rate (lb/MMBtu)	Control Efficiency	Emission Reduction (tons/year)
Baseline, LNC3[1]	0.18	--	--
LNC3+	0.13	28%	1,163
SNCR	0.10	45%	1,850
SCR	0.08-0.06	56%-67%	2,310-2,770

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[4] Appendix B.4.b, p. 16-19. PDF pages 596-599.

[5] Best Available Retrofit Technology – Selective Catalytic Reduction, Technical Feasibility Analysis for North Dakota Lignite. Division of Air Quality, ND Department of Health. July 2009.

[6] Appendix B.4.b, p. 16. PDF page 596.

[7] Appendix B.4.b, Attachment A, pages 2-15 to 2-17. PDF pages 642-644.

[8] Appendix B.4.b, Attachment A, Appendix E. PDF page 696.

[9] Appendix B.4.b, p. 17. PDF page 597.

Control Technology	Emission Rate (lb/MMBtu)	Control Efficiency	Emission Reduction (tons/year)

[1] The emission rate for LNC3 includes the DryFining™ operation

Within the Updated BART Analysis, a range of performance rates for SCR were evaluated, which is why the information in Table 7 includes a range of options for SCR. The performance rates evaluated are consistent with currently available information for units operating SCRs.[10] These anticipated performance rates ranged from 0.04 to 0.08 lb NO$_X$ per MMBtu. The performance rate of 0.04 lb NO$_X$ per MMBtu is not listed in Table 7 due to significant uncertainty that this rate could be achieved in practice and sustained for an extended timeframe.[11,12] Therefore, the Department will not evaluate SCR at a performance rate of 0.04 lb NO$_X$ per MMBtu for the purposes of this BART determination. Information presented throughout the remainder of this BART determination is specific to SCR at a performance rate of 0.06 and 0.08 lb NO$_X$ per MMBtu.

3.4 Step 4 – Evaluate Impacts

3.4.1 Cost of Compliance

The cost of compliance and incremental cost for the BART controls are listed in Table 8 for a single unit. The incremental costs displayed in Table 8 were determined from LNC3+ to SNCR and from LNC3+ to SCR. The incremental cost between SNCR and SCR is not shown in Table 8 due to the high annualized cost difference in conjunction with a limited improvement in emissions reduction.

Table 8: Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Level (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
Baseline, LNC3	0.18	--	--	--	--
LNC3+	0.13	1,162	793,418	683	--
LNC3+ w/ SNCR	0.10	1,850	6,194,244	3,348	7,850
LNC3+ w/ SCR	0.08	2,309	16,122,491	6,983	13,368
LNC3+ w/ SCR	0.06	2,767	17,391,169	6,284	10,339

A detailed breakdown of the costs listed in Table 8 can be found in the Updated BART Analysis.[13] The Department has reviewed these costs and believes them to be accurate.

As displayed in Table 8, the cost of compliance for the installation of LNC3+ at CCS is $700 per ton of NO$_X$ reduced. This represents a 0.05 lb NO$_X$ per MMBtu improvement over the baseline performance rate and results in an annual reduction of over 1,100 tons of NO$_X$ per unit.

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[10] Appendix B.4.b, p. 17-18. PDF pages 597-598.

[11] Appendix B.4.b, p. 18-19. PDF pages 598-599.

[12] Appendix B.4.b, Attachment A, page 2-12 and 3-1. PDF pages 639 and 649.

[13] Appendix B.4.b, PDF pages 690-694, 780-800, 923-946.

If SNCR is installed along with LNC3+, a performance rate improvement of 0.03 lb NO_X per MMBtu could be achieved. This equates to an additional reduction of approximately 700 tons of NO_X per year for each unit. To provide the most conservative cost of compliance (i.e., the lowest dollar per ton of pollutant reduction) for SNCR, Table 8 does not include additional costs associated with the treating of ammoniated fly-ash or the additional cost incurred due to the loss of a saleable by-product, which would result in an increase in fly-ash disposal.[14] There is also uncertainty in the amount of saleable by-product that would be lost and the limited commercial application of the treating process; both of which are required to better understand the impacts a treating system would have at CCS.[15] Without this information, the ultimate cost of SNCR is unknown. Without taking these costs into consideration, the cost of compliance to concurrently install LNC3+ with SNCR is $3,300 per ton of NO_X reduced.

To determine the appropriate BART controls when comparing between the installation of only LNC3+ and the installation of LNC3+ with SNCR, the Department calculated the stand-alone cost of installing SNCR after LNC3+ is installed. This stand-alone cost is referred to as the incremental cost of compliance or the incremental cost effectiveness in the BART guidelines.[16] Incremental cost is a key factor to consider when selecting BART controls since it details the cost effectiveness specific to the SNCR. The incremental cost of compliance was determined to be $7,800 per ton of NO_X reduced. Therefore, even though the cost of compliance for LNC3+ with SNCR listed in Table 8 appears reasonable at $3,300 per ton, it is more accurate to represent the cost of LNC3+ at $700 per ton and the cost of SNCR after the installation of LNC3+ at $7,800 per ton. The Department believes $7,800 is an unreasonably high cost, especially in consideration of the potential increased costs through the installation of a fly-ash treating system, lost fly-ash sales, and the technological uncertainty with the treating system viability at CCS. Between LNC3+ and LNC3+ with SNCR, LNC3+ is the most appropriate BART control from the perspective of cost feasibility.

All costs associated with the SCRs are provided for the high-dust arrangement. High-dust systems are generally considered more economical than low-dust systems since less equipment is required during operation. Exhaust gas re-heat and cooling systems are among the additional costs required with low-dust SCR systems.[17,18] The cost of compliance will increase significantly with the additional equipment needed for a low-dust SCR system.[19] Without taking these added costs into consideration, the cost to install LNC3+ concurrently with SCR is (at a minimum) $6,300 per ton of NO_X reduced. Using the same logic applied in the SNCR discussion in the above paragraph, the incremental cost to install SCR after LNC3+ is $10,300 per ton. Additionally, for consistency with the BART guidelines[20], the Department calculated the incremental cost between SNCR and SCR. This resulted in an incremental cost of $12,200 per ton. The Department believes all these costs are

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[14] Appendix B.4.b, p. 25-26. PDF pages 605-606.

[15] Appendix B.4.b, Attachment B. PDF page 837.

[16] 40 CFR Part 51 Appendix Y, Guidelines for BART Determinations under the Regional Haze Rule

[17] Appendix B.4.b, p. 17 and 23. PDF pages 597 and 603.

[18] Appendix B.4.b, Attachment A, page 2-16. PDF page 643.

[19] Appendix B.4.b, Attachment A, Appendix B. PDF page 684.

[20] Calculate the incremental cost effectiveness for each dominant option, which is the difference in total annual costs between that option and the next most stringent option, divided by the difference in emissions, after controls have been applied, between those two control options.

unreasonably high, especially in consideration of the technological uncertainty with SCR and the added costs associated with the exhaust reheat and cooling systems.

3.4.2 Energy and Non-air Quality Environmental Impacts

LNC3+ is determined to have negligible energy and/or non-air quality environmental impacts. LNC3+ technology reduces the formation of NO_X during the combustion process and does not affect items such as: auxiliary power consumption, water usage, potential fly ash sales, and/or ammonia slip, which are all potential impacts associated with SNCR and/or SCR.

The largest potential non-air quality environmental impact with SNCR is the potential for producing ammoniated fly-ash, which could inhibit or severely limit CCS from selling fly-ash for beneficial use (e.g. concrete additive).[21] This ammoniated fly-ash has the largest impact on non-air quality environmental impacts since ammoniated fly-ash not being sold for beneficial use could end up significantly increasing the amount of fly-ash disposed of in landfills. The production of ammoniated fly-ash also reduces any economic benefit CCS receives from selling this by-product. SNCR also requires a significant increase in water consumption for the injection skid. Additionally, ammonia slip from the SNCR will likely result in nitrogen being carried through the scrubber water that is routed to the evaporation ponds, causing potential issues with pond maintenance.[22]

Low-dust SCR has the same potential non-air quality environmental impacts as SNCR regarding increased water consumption and ammonia slip. There is also increased power and fuel consumption required with SCR related equipment and from the gas reheat and cooling systems.[23]

The non-air quality environmental impacts for SNCR and SCR are significant, but not significant enough to eliminate them as a control option.

3.4.3 Remaining Useful Life

Coal Creek Station is expected to operate beyond the life of the control equipment[24], therefore, remaining useful life was not considered.

3.5 Step 5 – Evaluate Visibility Impacts

CCS conducted dispersion modeling to assess the potential visibility improvement from the use of add-on NO_X controls. The modeling was conducted in accordance with the “Protocol for BART-Related Visibility Impairment Modeling Analysis, Great River Energy Coal Creek Station” approved by EPA Region 8 on August 7, 2019.[25]

The first modeled scenario (Model Scenario 0) in Table 9 was performed to establish the baseline visibility impairment on North Dakota’s Class I Areas from 2000–2002 (pre-BART controls for all pollutants). Model Scenario 1 reflects the post-SO_2 BART approved controls and associated emission rates. The remaining modeling scenarios (Model Scenarios 2 through 6) reflect the application of the potential NO_X BART controls evaluated in this BART Determination.[26] It is important to note that CCS

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[21] Appendix B.4.b, Attachment B. PDF page 837.
[22] Appendix B.4.b, Attachment A, p. 4-23. PDF page 674.
[23] Appendix B.4.b, Attachment A, p. 4-23. PDF page 674.
[24] Appendix B.4.b, p. 27. PDF page 607.
[25] Appendix B.4.b, Attachment E. PDF pages 911-917.
[26] Appendix B.4.b, p. 27-28. PDF pages 607-608.

was required to perform modifications to the wet gas scrubber in order to reduce sulfur dioxide (SO_2) emissions as required by the earlier partially approved Regional Haze SIP.[27] No particulate matter (PM) controls were required in the partially approved Regional Haze SIP; however, the enhanced SO_2 controls had a beneficial impact on reducing PM emissions. This information is summarized in Table 9.

Table 9: Emissions Rates Modeled for Determination of Visibility Impact

Modeling Scenario	**NO_X Control Technology**	**NO_X Emissions Rate (lb/hr)^A**	**SO_2 Control Technology**	**SO_2 Emissions Rate (lb/hr)^A**	**PM Emissions Rate (lb/hr)^{A,B}**
0	LNC3	1797	Pre-BART	5351	233
1	LNC3 (with DryFining^{TM})	1233	Post-BART	967	90
2	LNC3+	898	Post-BART	967	90
3	LNC3+ w/ SNCR	695	Post-BART	967	90
4	LNC3+ w/ SCR (0.06)$^{C, D}$	415	Post-BART	967	199
5	LNC3+ w/ SCR (0.06)$^{C, E}$	415	Post-BART	967	141
6	LNC3+ w/ SCR (0.06)$^{C, F}$	415	Post-BART	967	90

^{A} Maximum 24-hour emissions rate in pounds, averaged between both units
^{B} No particulate matter controls were selected as BART, decrease from Scenario 0 to 1 resulted from SO_2 BART
^{C} Refers to an anticipated annual NO_X performance level of 0.06 lb/MMBtu
^{D} Additional 109 lb/hr PM results from anticipated sulfuric acid formation from SCR; 5% SO_2 to SO_3 oxidation rate
^{E} Additional 51 lb/hr PM results from anticipated sulfuric acid formation from SCR; 2.5% SO_2 to SO_3 oxidation rate
^{F} No anticipated sulfuric acid formation from SCR; 0% SO_2 to SO_3 oxidation rate

In Table 9, the reason for the increase in PM emissions from Model Scenario 3 to 4 is from the anticipated sulfuric acid mist formation from SCR application. This anticipated increase results from an SO_2 to SO_3 oxidation rate of 5%.[28] The reason for the high oxidation rate is due to the uncertainty regarding the technical feasibility of SCR on units that combust North Dakota lignite coal and the high boiler flue gas temperatures at CCS. Given the uncertainty, the Department believes the 5% oxidation rate provided by the SCR catalyst vendor is the most appropriate value to use for this BART determination. However, since the 5% SO_2 to SO_3 oxidation rate is outside the range of what is typically expected[29], a recommendation was made to conduct additional modeling using more conservative (lower) SO_2 to SO_3 oxidation rates. Therefore, CCS conducted additional modeling using lower SO_2 to SO_3 oxidation rates of 0% and 2.5%. This modeling was performed to evaluate the potential change in visibility by lowering the SO_2 to SO_3 oxidation rate. This additional modeling was provided to the Department in a report dated February 27, 2020, "Coal Creek Station BART for NO_X Emissions – Visibility Impairment Modeling Results for Additional SCR SO_2 Oxidation Scenarios",

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[27] Available at: https://www.federalregister.gov/documents/2012/04/06/2012-6586/approval-and-promulgation-of-implementation-plans-north-dakota-regional-haze-state-implementation
[28] Appendix B.4.b, Attachment A, Appendix E, p. 2. PDF page 697.
[29] Appendix B.4.b, Attachment H-1, p. 3-2. PDF page 968.

which is included as Appendix F.3. This report also provides additional technical details that support the uncertainty of the SO_2 to SO_3 oxidation rate.

As discussed in Section 3.3, the performance level for SCR installation on North Dakota lignite-fired units is uncertain and was provided at three performance rates (0.04, 0.06, and 0.08 lb NO_X per MMBtu). Due to the uncertainty in sustaining the 0.04 lb NO_X per MMBtu performance rate, the Department did not consider the visibility results from the modeling associated with this rate. For informational purposes, these results are available in Appendix F.3.[30] With the information currently available, the Department has determined 0.06 lb NO_X per MMBtu as the lowest sustainable performance rate for SCR at CCS. In turn, modeling the projected maximum pounds of NO_X emitted per 24-hours in association with the performance rate of 0.06 lb NO_X per MMBtu will result in the largest potential improvement on visibility (i.e. 0.08 lb NO_X per MMBtu modeling would only show less of a visibility improvement).

Before determining the potential visibility improvements for the NO_X BART controls evaluated, baseline visibility impairment was established. A baseline visibility impairment was established for Model Scenarios 0 and 1. As is shown in Table 9, Model Scenario 0 uses pre-BART emissions data for NO_X, SO_2¸and PM. Model Scenario 1 uses post-SO_2 BART SO_2 and PM emissions data in addition to the collective impact DryFining™ had on SO_2, PM, and NO_X emissions. Model Scenario 0 visibility impairment is shown in Table 10 and Model Scenario 1 visibility impairment is shown in Table 11. These Tables show the maximum impairment on visibility for the 98th percentile at each of the North Dakota Class I Areas. The Class I areas in North Dakota are Theodore Roosevelt National Park (TRNP) and Lostwood National Wildlife Refuge (Lostwood). TRNP consists of the South Unit, the North Unit, and the Elkhorn Ranch.

Table 10: Model Scenario 0 Baseline Visibility Impairment in Deciviews

Year	TRNP South Unit	TRNP North Unit	TRNP Elkhorn Ranch	Lostwood
2000	1.96	1.78	1.41	2.16
2001	1.65	1.38	1.63	2.84
2002	3.13	2.69	2.17	1.98

As shown in Table 10, the maximum potential visibility impairment for Model Scenario 0 occurs in calendar year 2002 and is 3.13 deciviews at TRNP South Unit. This is the pre-BART and pre-DryFining™ controls baseline.

Table 11: Model Scenario 1 Baseline Visibility Impairment in Deciviews

Year	TRNP South Unit	TRNP North Unit	TRNP Elkhorn Ranch	Lostwood
2000	0.66	0.65	0.60	0.92
2001	0.47	0.57	0.53	0.87
2002	1.28	1.15	0.99	0.69

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[30] Appendix F.3, Tables 1 through 12a.

As shown in Table 11, the maximum potential visibility impairment for Model Scenario 1 occurs in calendar year 2002 and is 1.28 deciviews at TRNP South Unit. The largest difference in visibility impairment from Model Scenario 0 to 1 is in year 2001 at Lostwood and is a difference of 1.97 deciviews. The difference of 1.97 deciviews is the maximum calculated visibility improvement resulting from SO_2 BART controls in conjunction with DryFining™. Model Scenario 1 is the current baseline scenario.

Once the current baseline visibility impairment was established, the potential visibility improvements, in deciviews, were determined. The potential difference in visibility impairment between model scenarios is the calculated visibility improvement associated with the implementation of the NO_X control technology. The visibility improvements for the BART controls evaluated in Table 9 have been summarized for each year (2000, 2001, and 2002) in Table 12, Table 13, and Table 14, respectively. The average visibility improvements from 2000–2002 are shown in Table 15. Each table shows the maximum improvement in visibility for the 98th percentile at each of the North Dakota Class I Areas. The row displaying Model Scenario 1 results depicts the visibility improvement resulting from SO_2 BART and DryFining™ (i.e. the difference between Model Scenario 0 and 1). The remaining model scenarios depict the visibility improvements between Model Scenario 1 and the respective model scenario. For example, the Model Scenario 4 results display the visibility change between Model Scenario 1 and Model Scenario 4. Results from Model Scenario 2 through Model Scenario 6 are used to evaluate the potential visibility improvement resulting from the NO_X BART controls evaluated in this BART determination.

Table 12: Combined Unit 1 and 2 98th Percentile Deciview Improvement for Year 2000

Modeling Scenario	**TRNP South Unit**	**TRNP North Unit**	**TRNP Elkhorn Ranch**	**Lostwood**
1[A]	*1.30*	*1.13*	*0.81*	*1.24*
2	0.11	0.11	0.10	0.19
3	0.15	0.17	0.16	0.28
4	0.07	0.10	0.15	0.07
5	0.16	0.17	0.20	0.23
6	0.23	0.25	0.25	0.39

[A] Displayed for informational purposes, shows impact of SO_2 BART and DryFining™

Table 13: Combined Unit 1 and 2 98th Percentile Deciview Improvement for Year 2001

Modeling Scenario	**TRNP South Unit**	**TRNP North Unit**	**TRNP Elkhorn Ranch**	**Lostwood**
1[A]	*1.18*	*0.81*	*1.10*	*1.97*
2	0.06	0.07	0.08	0.13
3	0.08	0.15	0.13	0.16
4	-0.02	0.01	0.05	-0.10
5	0.06	0.13	0.11	0.06
6	0.11	0.24	0.16	0.21

[A] Displayed for informational purposes, shows impact of SO_2 BART and DryFining™

Table 14: Combined Unit 1 and 2 98th Percentile Deciview Improvement for Year 2002

Modeling Scenario	TRNP South Unit	TRNP North Unit	TRNP Elkhorn Ranch	Lostwood
1[A]	*1.85*	*1.55*	*1.19*	*1.29*
2	0.23	0.18	0.18	0.12
3	0.37	0.30	0.28	0.19
4	0.23	0.31	0.17	-0.01
5	0.40	0.40	0.28	0.13
6	0.55	0.48	0.43	0.26

[A] Displayed for informational purposes, shows impact of SO_2 BART and DryFining^{TM}

Table 15: Average Combined Unit 1 and 2 98th Percentile Deciview Improvement from 2000–2002

Modeling Scenario	TRNP South Unit	TRNP North Unit	TRNP Elkhorn Ranch	Lostwood
1[A]	*1.44*	*1.16*	*1.03*	*1.50*
2	0.13	0.12	0.12	0.15
3	0.20	0.21	0.19	0.21
4	0.09	0.14	0.12	-0.02
5	0.20	0.23	0.20	0.14
6	0.30	0.33	0.28	0.29

[A] Displayed for informational purposes, shows impact of SO_2 BART and DryFining^{TM}

As is shown for Model Scenario 1 of Table 12 through Table 15, the maximum improvement SO_2 BART in conjunction with DryFining^{TM} had on visibility was 1.97 deciviews in year 2001, with an average of 1.50 deciviews of improvement from 2000–2002. Both improvements occurred at Lostwood. The maximum of 1.97 with an average of 1.50 deciviews represents a significant modeled improvement on visibility as a result of SO_2 BART in conjunction with DryFining^{TM}.

For the reasons outlined earlier in this Section, the Department believes the most accurate information to use when evaluating visibility improvement for the NO_X controls evaluated is shown in Model Scenarios 2 through 4 of Table 12 through Table 15.

Model Scenario 2 displays the deciview improvement from the installation of LNC3+. Average Model Scenario 2 visibility improvements ranged from 0.12 to 0.15 deciviews, with a combined average visibility improvement of 0.13 deciviews. A maximum improvement of 0.23 deciviews was modeled at TRNP South Unit in the year 2002.

Model Scenario 3 displays the deciview improvement from the installation of LNC3+ with SNCR. Average Model Scenario 3 visibility improvements ranged from 0.19 to 0.21 deciviews with a combined average visibility improvement of 0.20 deciviews. A maximum improvement of 0.37 deciviews was modeled at TRNP South Unit in the year 2002.

Model Scenario 4 displays the deciview improvement from the installation of LNC3+ with SCR at the vendor expected 5% SO_2 to SO_3 oxidation rate. Average Model Scenario 4 visibility improvements ranged from -0.02 to 0.14 deciviews with a combined average visibility improvement of 0.09 deciviews.[31] A maximum improvement of 0.31 deciviews was modeled at TRNP North Unit in the year 2002.

The maximum modeled visibility improvement for all the NO_X controls evaluated comes from the Model Scenario 6, which is the hypothetical 0% SO_2 to SO_3 oxidation rate. Average Model Scenario 6 visibility improvements ranged from 0.28 to 0.33 deciviews with a combined average visibility improvement of 0.30 deciviews. A maximum improvement of 0.55 deciviews was modeled at TRNP South Unit in the year 2002. These results are representative of the expected cumulative visibility improvement from Unit 1 and Unit 2 due to the installation of SCR with an annual performance level of 0.06 lb NO_X per MMBtu and a 0% SO_2 to SO_3 oxidation rate. Even with this conservative methodology, these modeled visibility improvements are minimal.

None of the NO_X BART controls modeled were shown to have a significant impact on improving visibility in North Dakota's Class 1 Areas. Therefore, when determining the appropriate NO_X BART controls, visibility did not contribute significantly to the BART selection.

3.6 Step 6 – Select BART

In consideration of the BART related factors addressed in Section 3.1 through 3.5, the Department has determined the appropriate NO_X BART technology for CCS Units 1 and 2 to be a combination of closed coupled overfired air, separated overfired air, and low-NO_X burners with expanded overfired air registers in conjunction with DryFining™. This has been referred to as LNC3+ throughout this BART determination. LNC3+ technology is currently installed on Unit 1 and Unit 2 at Coal Creek Station.

The selection of LNC3+ as BART is supported in this BART determination due to the following reasons:

- Cost feasible at $700 per ton of NO_X reduced while providing a 28% reduction from the baseline emissions rate (See Table 7 and Table 8)
- Has negligible energy and non-air quality environmental impacts (See Section 3.4.2)

The selection of SNCR as BART is not supported in this BART determination due to the following reasons:

- Not cost feasible due to an incremental cost of $7,800 per ton of NO_X reduced relative to LNC3+, while only providing an additional 17% reduction in NO_X (See Table 7 and Table 8)
- Has potentially significant non-air quality environmental impacts (See Section 3.4.2)
- Has a minimal average visibility improvement of 0.07 deciviews beyond the improvement achieved by the installation of LNC3+ (See Table 15)

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[31] The -0.02 represents additional modeled impairment to be expected with SCR installation resulting from the additional PM (as sulfuric acid mist).

The selection of SCR as BART is not supported in this BART determination due to the following reasons:

- Technical feasible concerns without undertaking of pilot scale testing (See Section 3.2)
- Not cost feasible at an incremental cost of $10,300 per ton of NO_X reduced relative to LNC3+ (See Table 7)
- Has potentially significant non-air quality environmental impacts (See Section 3.4.2)
- Has a minimal average visibility improvement of 0.17 deciviews beyond the improvement achieved by the installation of LNC3+ (See Table 15)

Recent performance data for LNC3+ on Unit 2, as outlined in Table 4, indicates a sustained annual average performance rate of approximately 0.13 lb NO_X per MMBtu. This annual average performance rate should not be misconstrued as achievable on a shorter-term basis (e.g. 30-day rolling average). There is inherent variability with shorter-term operations due to unit load swings and variable sodium concentrations in North Dakota lignite coal.[32,33] To account for this variability, the Department is proposing a BART NO_X emissions limit on Unit 1 and Unit 2 of 0.15 lb NO_X per MMBtu on a 30-day rolling average basis. The 30-day rolling average limits are consistent with the BART guidelines[34], and a limit of 0.15 lb NO_X per MMBtu on a 30-day rolling average is achievable in practice. A 5–15% upward adjustment from an annual average to establish a shorter-term limit is consistent with Department and EPA experience.[35]

The proposed limit of 0.15 lb NO_X per MMBtu on a 30-day rolling average is less than the presumptive BART limit established in Table 1 of the BART guidelines for tangential-fired lignite units. Table 1 of the guidelines indicates a presumptive BART limit of 0.17 lb NO_X per MMBtu on a 30-day rolling average.[36]

4 Permit to Construct

The emission limits, monitoring, recordkeeping and reporting requirements will be included in a federally enforceable Air Pollution Control Permit to Construct that will be issued to the owner/operator of the facility. Monitoring for NO_X will be accomplished by using the continuous emission monitors required by 40 CFR 75 for the Acid Rain Program. The owner/operator will be required to conduct recordkeeping and reporting as required by NDAC 33.1-15-14-06, Title V Permit to Operate and NDAC 33.1-15-21, Acid Rain Program (40 CFR 72, 75 and 76).

Permit to Construct No. PTC21001 is included in Appendix F.2.

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[32] Appendix B.4.b., p. 3 and 34-35. PDF page 583 and 615-615.

[33] Appendix B.4.b., Attachment D. PDF page 904-909.

[34] 40 CFR Part 51 Appendix Y, Guidelines for BART Determinations under the Regional Haze Rule

[35] Available at: https://www.federalregister.gov/documents/2012/04/06/2012-6586/approval-and-promulgation-of-implementation-plans-north-dakota-regional-haze-state-implementation#p-426

[36] 40 CFR Part 51 Appendix Y, Guidelines for BART Determinations under the Regional Haze Rule

F.2 – Coal Creek Station NOx BART Permit to Construct

AIR POLLUTION CONTROL
PERMIT TO CONSTRUCT

Pursuant to the Air Pollution Control Rules of the State of North Dakota (North Dakota Administrative Code Article 33.1-15, Chapter 33.1-15-14 and Chapter 33.1-15-25), the North Dakota Department of Environmental Quality hereby issues a Permit to Construct for the following source:

I. **General Information**:

A. **Permit to Construct Number**: PTC21001

B. **Source**:

1. **Name**: Coal Creek Station

2. **Location**: 2875 Third Street SW
Underwood, ND 58576-9596

3. **Source Type**: Fossil-fuel fired steam electric plant (EGU) with a nominal generating capacity of over 1,200 megawatts

4. **Equipment at the Facility Subject to NO_X BART**:

Unit 1 - Coal-fired boiler (nominal 6,015 x 10^6 Btu/hour heat input)

Unit 2 - Coal-fired boiler (nominal 6,022 x 10^6 Btu/hour heat input)

C. **Owner/Operator**:

1. **Name**: Rainbow Energy Center

2. **Address**: TBD

II. **Permit Conditions**:

The Permit to Construct only establishes the emission limits and other requirements if, and when, EPA approves those limits as part of the Regional Haze SIP. The source shall be operated in accordance with the terms of this Permit to Construct and the Title V Permit to Operate until a revised Title V Permit to Operate is issued. The source is subject to all applicable rules, regulations, and orders now or hereafter in effect of the North Dakota Department of Environmental Quality and to the conditions specified below:

A. **Special Conditions**:

1. **Definitions**: Terms not defined below shall have the meaning given them in the Clean Air Act or EPA's regulations implementing the Clean Air Act. For purposes of this permit:

   a. *Boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the EGU. It is not necessary for fuel to be combusted for the entire 24-hour period.

   b. *Continuous emission monitoring system or CEMS* means the equipment required by this permit to sample, analyze, measure and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of NO_x emissions, other pollutant emissions, diluent or stack gas volumetric flow rate.

   c. *NO_x* means nitrogen oxides.

   d. *Unit* means any of the EGU's identified in section I.B.

   e. *30-day rolling average*, as used in this permit, shall be determined by calculating an arithmetic average of all hourly rates for the current boiler operating day and the previous 29 boiler operating days. A new 30-day rolling average shall be calculated for each boiler operating day. Each 30-day rolling average rate shall include start-up, shutdown, emergency and malfunction periods unless those periods are exempt by this permit. The 30-day rolling average emission rate is calculated as follows:

      - Calculate the hourly average emission rate for any hour in which any fuel is combusted in the boiler.

      - Calculate the 30-day rolling average emission rate as the arithmetic average of all valid hourly average emission rates for the 30 successive boiler operating days.

2. **Emission Limits**: Coal Creek Station Unit 1 and Unit 2 shall not emit or cause to be emitted NO_x in excess of 0.15 pounds per million British Thermal Units (0.15 lb/10^6 Btu) averaged over a 30-day period (30-day rolling average). The emission limit applies to both units at all times including startup, shutdown, emergency and malfunction.

3. **Compliance Date**: Compliance with the emission limits and other requirements of this permit is required when the U.S. Environmental Protection Agency approves this permit as a part of the Regional Haze SIP.

4. **Continuous Emission Monitoring (CEM)**: The emissions from each unit shall each be measured by continuous emission monitors (CEM) for NO_x, CO_2 and flow. The monitoring requirements under Condition II.A.5 shall be the compliance determination method for NO_x.

5. **Monitoring Requirements and Conditions**:

   a. Compliance determination: At all times Coal Creek Station shall maintain, calibration and operate a CEMS, in full compliance with the requirements found at 40 CFR Part 75, to accurately measure NO_x, diluent and stack gas volumetric flow rate from each unit. The CEMS shall be used to determine compliance with the emission limits in Section II.A.2.

   b. Methods:

      1. For any hour in which fuel is combusted in a unit, Coal Creek Station shall calculate the hourly average NO_x concentration in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75. At the end of each boiler operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from the arithmetic average of all valid hourly emission rates from the CEMS for the current boiler operating day and the previous 29 successive boiler operating days.

      2. An hourly average NO_x emission rate in lb/MMBtu is valid only if the minimum number of data points, as specified in 40 CFR Part 75, is acquired by both the NOx pollutant concentration monitor and the diluent monitor (O_2 or CO_2).

      3. Data reported to meet the requirements of this section shall not include data substituted using the missing data substitution procedures of Subpart D of 40 CFR Part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75.

4. The Department may require additional performance audits of the CEM systems.

5. Coal Creek Station shall maintain and operate air pollution control monitoring equipment in a manner consistent with the manufacturer's recommended Operations and Maintenance (O&M) procedures, or a site-specific O&M procedure (developed from the manufacturer's recommended O&M procedures). Coal Creek Station shall have the O&M procedures available on-site and provide the Department with a copy when requested.

5. **Recordkeeping Requirements**:

Coal Creek Station shall maintain the following records for at least five years:

a. All CEMS data, including the date, place and time of sampling or measurement; parameters sampled or measured and results.

b. Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Part 75.

c. Records of all major maintenance activities conducted on emission units, air pollution control equipment and CEMS.

d. Any other records required by 40 CFR Part 75.

6. **Reporting**:

a. Coal Creek Station shall submit quarterly excess emissions reports no later than the 30th day following the end of each calendar quarter. Excess emissions means emissions that exceed the emissions limits specified in Section II.A.2. The reports shall include the magnitude, date(s) and duration of each period of excess emissions, specific identification of each period of excess emissions that occurs during startups, shutdown and malfunctions of the unit, the nature and cause of any malfunction (if known) and corrective action taken or preventative measures adopted.

b. Coal Creek Station shall submit quarterly CEMS performance reports, to include dates and duration of each period during which the CEMS was inoperative (except for zero and span adjustments and calibration checks), reason(s) why the CEMS was inoperative and steps taken to prevent recurrence, any CEMS repairs or adjustments and results of any CEMS performance tests required by 40 CFR Part 75 (Relative Accuracy Test Audits, Relative Accuracy Audits and Cylinder Gas Audits).

c. When no excess emissions have occurred or the CEMS has not been inoperative, repaired or adjusted during the reporting period, such information shall be stated in the report.

d. Coal Creek Station shall submit a semi-annual report for all monitoring records required under Condition II.A.5 on forms supplied or approved by the Department. All instances of deviations from the permit must be identified in the report. A monitoring report shall be submitted within 45 days after June 30 and December 31 of each year.

e. Coal Creek Station shall submit an annual compliance certification report within 45 days after December 31 of each year on forms supplied or approved by the Department.

f. Coal Creek Station shall submit an annual emission inventory report on forms supplied or approved by the Department. This report shall be submitted by March 15 of each calendar year. Insignificant units/activities listed in this permit do not need to be included in the annual emission inventory report.

B. **General Conditions**:

1. Nothing in this section shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with requirements of this section if the appropriate performance or compliance test procedures or method had been performed.

2. This permit shall in no way permit or authorize the maintenance of a public nuisance or danger to public health or safety.

3. Coal Creek Station shall comply with all State and Federal environmental laws and rules. In addition, Coal Creek Station shall comply with all local building, fire, zoning, and other applicable ordinances, codes, rules and regulations.

4. Coal Creek Station shall at all times, including periods of startup, shutdown, and malfunction, maintain and operate Unit 1 and Unit 2 and all other emission units including associated air pollution equipment and fugitive dust suppression operations in a manner consistent with good air pollution control practices for minimizing emissions.

5. Any duly authorized officer, employee or agent of the North Dakota Department of Environmental Quality may enter and inspect any property, premise or place at which the source listed in Item I.B. of this permit is or will be located at any time for the purpose of ascertaining the state of compliance with the North Dakota Air Pollution Control Rules and the conditions of this permit.

6. Any violation of a condition issued as part of this approval to construct is regarded as a violation of construction authority and is subject to enforcement action.

7. The conditions of this permit herein become, upon the effective date of this permit, enforceable by the Department pursuant to any remedies it now has or may in the future have, under the North Dakota Air Pollution Control Law, NDCC Chapter 23.1-06. Each and every condition of this permit is a material part thereof and is not severable.

FOR THE NORTH DAKOTA DEPARTMENT
OF ENVIRONMENTAL QUALITY

Date:__________________________ By:____

F.3 – Coal Creek Station BART Support

February 27, 2020

VIA ELECTRONIC MAIL

David Stroh
North Dakota Department of Environmental Quality
918 E. Divide Ave., 2nd Floor
Bismarck, ND 58501-1947

RE: Coal Creek Station BART for NOx Emissions – Visibility Impairment Modeling Results for Additional SCR SO_2 Oxidation Scenarios

Dear Mr. Stroh:

Pursuant to recent conversations with you and Great River Energy (GRE) staff, GRE understands that the US EPA Region 8 and federal land managers provided feedback to you on the September 2019 NOx BART report concerning the estimated degree of sulfur dioxide (SO_2) oxidation resulting from the selective catalytic reduction (SCR) technology control scenario. This letter provides additional technical information regarding SO_2 oxidation resulting from the SCR control scenario at Coal Creek Station. Additionally, Barr Engineering Co. (Barr) has prepared supplemental dispersion modeling analyses of visibility impacts for the SCR control scenario at different levels of SCR-related SO_2 oxidation for informational purposes.

The September 2019 NOx BART report included technical documents from Barr and from Black and Veatch as well as expert information provided by other third parties. Both of the engineering consulting firms concluded that low-dust SCR as a retrofit technology at Coal Creek Station has considerable technical challenges, is not cost-effective, and would result in additional energy impacts and combustion impacts from its use.[1] Notwithstanding these conclusions pursuant to the first four BART factors, modeling analyses relevant to the fifth BART factor of evaluating visibility impacts were also conducted. As the two engineering consulting firms disagreed on the demonstrable and sustained NOx performance level for SCR at Coal Creek Station, two SCR emissions scenarios – Scenario #4A at 0.04 lb/MMBtu and Scenario #4B at 0.06 lb/MMBtu – were modeled for the change in visibility impairment.

Inputs to the visibility impacts analysis include emission rates of SO_2, NOx, and PM_{10} with its speciated components of coarse particulate, fine particulate, secondary organic aerosols, elemental carbon, and sulfate (SO_4). This last modeled component of sulfate is affected by application of SCR technology due to oxidation of SO_2 to SO_3, which is a precursor of sulfuric acid mist (SAM or H_2SO_4).

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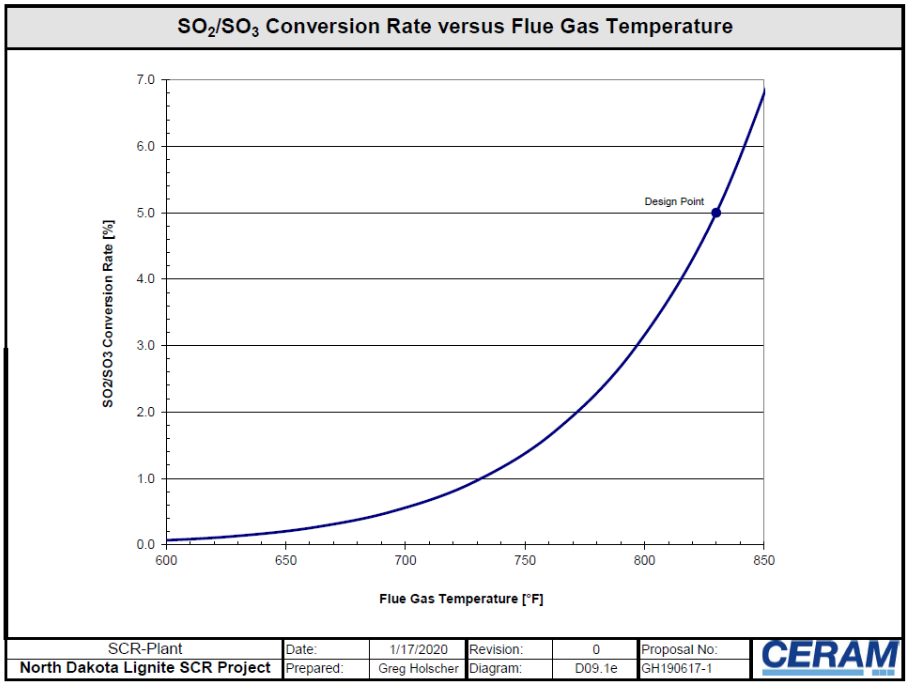
[1] High-dust SCR technology was also evaluated by these firms and was deemed technically and economically infeasible as a retrofit technology at Coal Creek Station.

The SO_2 oxidation rate due to SCR used by Barr in the modeling analysis is 5%. This oxidation rate comes from IBIDEN Ceram, an SCR catalyst vendor. It was determined by IBIDEN Ceram to be most appropriate design value based on their examination of site-specific characteristics at Coal Creek Station and with respect to their considerable experience with SCR catalysts.[2]

As follow-up to our conversations in January 2020, GRE reached out again to IBIDEN Ceram for additional technical information regarding the 5% SO_2 oxidation rate. They provided the illustration below, noting that catalyst design temperature for the GRE project is 830° F and the SO_2 to SO_3 oxidation rate is a large function of temperature. At baseload operation the flue gas exiting the economizer fluctuates between 800° and 830° F which is dependent upon coal quality and soot blowing. IBIDEN Ceram also stated that they are experienced with SCR systems that operate at elevated temperatures and that oxidation rate is exponential to temperature, regardless of fuel type.



Notwithstanding IBIDEN Ceram's analysis and since North Dakota lignite fueled units do not operate with SCR technology, there is no empirical data specific to these installations at a utility scale that can definitively conclude the SO_2 oxidation rate due to SCR at Coal Creek Station. Additionally, Electric Power Research Institute (EPRI) describes several additional variables that impact the rate of SCR-related SO_2 oxidation (i.e., fuel sulfur content, fly ash alkalinity, catalyst material and volume) as well as related measurement uncertainties between laboratory tests and field trials.[3] Because of these

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[2] See the September 2019 NOx BART analysis at Attachment 1, Appendix E, for IBIDEN Ceram's analysis and their reference list of SCR projects.

[3] EPRI's report, "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," March 2018, is found in Attachment H-1 of the September 2019 NOx BART report.

considerations, Barr has calculated the sulfuric acid mist generated by SCR at an SO_2 oxidation rate of 0% and 2.5% in addition to the 5% level used in the September 2019 report.

The 0% rate is hypothetical only and is not technically supportable, but it is provided for informational purposes to assess the theoretical visibility impairment level if no additional sulfuric acid mist was created due to SCR. The corresponding PM_{10} emissions rate for this scenario is the same as that used in Emissions Control Scenarios #1 through #3 of 90.2 lb/hr for Unit 1 and 90.3 lb/hr for Unit 2.

The 2.5% rate is chosen as a mid-point between 0% and 5%, which is representative of the range provided in EPRI's report based on other types of coals but does not recognize the specific fuel and operational considerations at Coal Creek Station in IBIDEN Ceram's analysis. Correspondingly, the 2.5% rate is used in the modeling analysis to assess the theoretical visibility impairment level at a reduced level of sulfuric acid mist formation due to SCR compared to that at 5% oxidation. The resulting generation of sulfuric acid mist at 2.5% oxidation is 51 lb/hr, compared to the 109 lb/hr generated at 5% oxidation. The corresponding PM_{10} emissions rate for this scenario is the same as that used in Emissions Control Scenarios #1 through #3 of 141.2 lb/hr for Unit 1 and 141.3 lb/hr for Unit 2.

The 0% and 2.5% oxidation rates are incorporated into individual modeling runs for Emissions Control Scenarios #4A and #4B. In summary, the results of these model sensitivity runs do not appreciably change the visibility impairment at the Class I areas, being on the order of ~0.1 delta-deciview per unit improvement.

Several tables have been updated to reflect the additional 0% and 2.5% oxidation rates for Scenarios #4A and #4B. These tables are identified and numbered in the same manner as that presented in Greg Archer's email to you on November 1, 2019.

The first sets of tables entail modeling the control options for one unit while holding the other unit at the facility at a fixed emission rate so that total facility emissions are accounted for in the model chemistry. Two potential configurations are evaluated – one holding the non-evaluated unit at Scenario 1 rates (LNC3, DryFining™, SO_2 BART – **Tables 1 to 6**), and the other holding the non-evaluated unit at Scenario 2 rates (LNC3+, DryFining™, SO_2 BART – **Tables 7 to 12**).

Modified versions of Tables 3-5 through 3-7 from the BART report are also included as **Tables 3-5a through 3-7a**, with the columns for modeled days over 1.0 and 0.5 deciviews replaced by net improvement in visibility versus Scenario 1 emissions. This provides a common basis for comparing emission controls between all tables.

Alternatively, attached is another version of tables 7 to 12 (tagged as **Tables 7a to 12a**) which calculates the net improvement versus Scenario 2 rather than versus Scenario 1. This provides a clearer comparison of control effectiveness versus LNC3+ emissions, and this approach also aligns with the expected emissions as of mid-2020 for evaluating additional controls.

Notably, the deciviews are negative in instances where SCR at the 5% oxidation rate has more of an impact as compared to Scenario 3, with SNCR. This is understandably a function of the increase in PM.

Much like SCR 0.04 and 0.06 sensitivity (Scenarios #4A and #4B, respectively), which did not materially change the conclusions, the oxidation rate sensitivity also does not materially change the conclusions.

Please contact Deb Nelson at 763-445-5208 if you have any questions regarding the four-factor analysis or wish to discuss any of the above.

Sincerely,

GREAT RIVER ENERGY

Mary Jo Roth

Mary Jo Roth
Manager, Environmental Services

c: Deb Nelson, Great River Energy
Greg Archer, Great River Energy
Joel Trinkle, Barr Engineering Co.

Attachments

Table 1: Unit 1 Visibility Modeling Results for Year 2000 (Unit 2 Emissions Held Constant at Scenario 1 Levels)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	Oxidation Rate	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV
#1: LNC3, DryFining™, SO_2 BART	-	0.660	-	0.647	-	0.599	-	0.916	-
#2: LNC3+, DryFining™, SO_2 BART	-	0.609	0.051	0.595	0.052	0.552	0.047	0.824	0.092
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	0.575	0.085	0.564	0.083	0.522	0.077	0.767	0.149
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.525	0.135	0.502	0.145	0.461	0.138	0.676	0.240
	2.5%	0.563	0.097	0.522	0.125	0.482	0.117	0.723	0.193
	5.0%	0.607	0.053	0.565	0.082	0.505	0.094	0.813	0.103
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.532	0.128	0.522	0.125	0.481	0.118	0.694	0.222
	2.5%	0.581	0.079	0.542	0.105	0.501	0.098	0.762	0.154
	5.0%	0.626	0.034	0.579	0.068	0.525	0.074	0.844	0.072

Table 2: Unit 1 Visibility Modeling Results for Year 2001 (Unit 2 Emissions Held Constant at Scenario 1 Levels)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	**Oxidation Rate**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**
#1: LNC3, DryFining™, SO_2 BART	-	0.474	-	0.571	-	0.526	-	0.873	-
#2: LNC3+, DryFining™, SO_2 BART	-	0.433	0.041	0.567	0.004	0.486	0.040	0.802	0.071
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	0.423	0.051	0.527	0.044	0.461	0.065	0.759	0.114
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.402	0.072	0.447	0.124	0.412	0.114	0.723	0.150
	2.5%	0.425	0.049	0.471	0.100	0.434	0.092	0.794	0.079
	5.0%	0.465	0.009	0.519	0.052	0.460	0.066	0.875	-0.002
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.409	0.065	0.473	0.098	0.428	0.098	0.734	0.139
	2.5%	0.432	0.042	0.497	0.074	0.450	0.076	0.805	0.068
	5.0%	0.471	0.003	0.533	0.038	0.476	0.050	0.886	-0.013

Table 3: Unit 1 Visibility Modeling Results for Year 2002 (Unit 2 Emissions Held Constant at Scenario 1 Levels)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	Oxidation Rate	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV
#1: LNC3, DryFining™, SO_2 BART	-	1.279	-	1.145	-	0.987	-	0.689	-
#2: LNC3+, DryFining™, SO_2 BART	-	1.164	0.115	1.070	0.075	0.890	0.097	0.628	0.061
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	1.097	0.182	1.016	0.129	0.835	0.152	0.590	0.099
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.961	0.318	0.889	0.256	0.745	0.242	0.519	0.170
	2.5%	1.005	0.274	0.929	0.216	0.802	0.185	0.564	0.125
	5.0%	1.055	0.224	0.974	0.171	0.866	0.121	0.615	0.074
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	1.005	0.274	0.930	0.215	0.775	0.212	0.538	0.151
	2.5%	1.049	0.230	0.970	0.175	0.831	0.156	0.582	0.107
	5.0%	1.099	0.180	1.015	0.130	0.895	0.092	0.633	0.056

Table 4: Unit 2 Visibility Modeling Results for Year 2000 (Unit 1 Emissions Held Constant at Scenario 1 Levels)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	**Oxidation Rate**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**
#1: LNC3, DryFining™, SO_2 BART	-	0.660	-	0.647	-	0.599	-	0.916	-
#2: LNC3+, DryFining™, SO_2 BART	-	0.609	0.051	0.592	0.055	0.549	0.050	0.823	0.093
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	0.575	0.085	0.560	0.087	0.519	0.080	0.765	0.151
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.523	0.137	0.495	0.152	0.459	0.140	0.670	0.246
	2.5%	0.564	0.096	0.515	0.132	0.479	0.120	0.719	0.197
	5.0%	0.608	0.052	0.564	0.083	0.503	0.096	0.814	0.102
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.529	0.131	0.516	0.131	0.478	0.121	0.693	0.223
	2.5%	0.580	0.080	0.536	0.111	0.499	0.580	0.080	0.536
	5.0%	0.626	0.034	0.579	0.068	0.522	0.077	0.845	0.071

Table 5: Unit 2 Visibility Modeling Results for Year 2001 (Unit 1 Emissions Held Constant at Scenario 1 Levels)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	Oxidation Rate	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV
#1: LNC3, DryFining™, SO_2 BART	-	0.474	-	0.571	-	0.526	-	0.873	-
#2: LNC3+, DryFining™, SO_2 BART	-	0.434	0.040	0.567	0.004	0.484	0.042	0.801	0.072
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	0.423	0.051	0.527	0.044	0.458	0.068	0.757	0.116
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.402	0.072	0.447	0.124	0.406	0.120	0.724	0.149
	2.5%	0.425	0.049	0.471	0.100	0.430	0.096	0.795	0.078
	5.0%	0.464	0.010	0.521	0.050	0.457	0.069	0.876	-0.003
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.409	0.065	0.473	0.098	0.423	0.103	0.734	0.139
	2.5%	0.432	0.042	0.497	0.074	0.446	0.080	0.806	0.067
	5.0%	0.471	0.003	0.535	0.036	0.473	0.053	0.887	-0.014

Table 6: Unit 2 Visibility Modeling Results for Year 2002 (Unit 1 Emissions Held Constant at Scenario 1 Levels)

Description		**Visibility Impairment**							
		TRNP South Unit		**TRNP North Unit**		**TRNP Elkhorn Ranch**		**Lostwood Wilderness Area**	
Emissions Control Scenario	**Oxidation Rate**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**
#1: LNC3, DryFining™, SO_2 BART	-	1.279	-	1.145	-	0.987	-	0.689	-
#2: LNC3+, DryFining™, SO_2 BART	-	1.161	0.118	1.069	0.076	0.890	0.097	0.628	0.061
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	1.092	0.187	1.011	0.134	0.834	0.153	0.590	0.099
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.953	0.326	0.880	0.265	0.732	0.255	0.521	0.168
	2.5%	0.998	0.281	0.921	0.224	0.800	0.187	0.564	0.125
	5.0%	1.050	0.229	0.968	0.177	0.864	0.123	0.613	0.076
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.998	0.281	0.922	0.223	0.769	0.218	0.538	0.151
	2.5%	1.043	0.236	0.963	0.182	0.829	0.158	0.582	0.107
	5.0%	1.095	0.184	1.010	0.135	0.894	0.093	0.631	0.058

Table 7: Unit 1 Visibility Modeling Results for Year 2000 (Unit 2 Emissions Held Constant at Scenario 2 Levels for Scenarios 2 through 4B)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	Oxidation Rate	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV
#1: LNC3, DryFining™, SO_2 BART	-	0.660	-	0.647	-	0.599	-	0.916	-
#2: LNC3+, DryFining™, SO_2 BART	-	0.552	0.108	0.540	0.107	0.501	0.098	0.729	0.187
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	0.528	0.132	0.509	0.138	0.471	0.128	0.687	0.229
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.477	0.183	0.447	0.200	0.409	0.190	0.577	0.339
	2.5%	0.515	0.145	0.476	0.171	0.430	0.169	0.646	0.270
	5.0%	0.559	0.101	0.541	0.106	0.454	0.145	0.735	0.181
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.495	0.165	0.467	0.180	0.429	0.170	0.616	0.300
	2.5%	0.534	0.126	0.487	0.160	0.450	0.149	0.684	0.232
	5.0%	0.578	0.082	0.550	0.097	0.473	0.126	0.766	0.150

Table 8: Unit 1 Visibility Modeling Results for Year 2001 (Unit 2 Emissions Held Constant at Scenario 2 Levels for Scenarios 2 through 4B)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	Oxidation Rate	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV
#1: LNC3, DryFining™, SO_2 BART	-	0.474	-	0.571	-	0.526	-	0.873	-
#2: LNC3+, DryFining™, SO_2 BART	-	0.416	0.058	0.502	0.069	0.443	0.083	0.745	0.128
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	0.405	0.069	0.462	0.109	0.418	0.108	0.729	0.144
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.384	0.090	0.381	0.190	0.388	0.138	0.695	0.178
	2.5%	0.413	0.061	0.422	0.149	0.414	0.112	0.768	0.105
	5.0%	0.462	0.012	0.482	0.089	0.439	0.087	0.849	0.024
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.391	0.083	0.407	0.164	0.389	0.137	0.708	0.708
	2.5%	0.414	0.061	0.436	0.135	0.414	0.112	0.778	0.708
	5.0%	0.463	0.011	0.497	0.074	0.444	0.082	0.860	0.013

Table 9: Unit 1 Visibility Modeling Results for Year 2002 (Unit 2 Emissions Held Constant at Scenario 2 Levels for Scenarios 2 through 4B)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	**Oxidation Rate**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**
#1: LNC3, DryFining™, SO_2 BART	-	1.279	-	1.145	-	0.987	-	0.689	-
#2: LNC3+, DryFining™, SO_2 BART	-	1.048	0.231	0.970	0.175	0.806	0.181	0.566	0.123
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	0.981	0.298	0.907	0.238	0.761	0.226	0.531	0.158
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.844	0.435	0.779	0.366	0.653	0.334	0.467	0.222
	2.5%	0.889	0.390	0.819	0.326	0.725	0.262	0.520	0.169
	5.0%	0.945	0.334	0.865	0.280	0.793	0.194	0.584	0.105
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.888	0.391	0.820	0.325	0.688	0.299	0.491	0.198
	2.5%	0.933	0.346	0.860	0.285	0.758	0.229	0.538	0.151
	5.0%	0.983	0.296	0.906	0.239	0.823	0.164	0.591	0.098

Table 10: Unit 2 Visibility Modeling Results for Year 2000 (Unit 1 Emissions Held Constant at Scenario 2 Levels for Scenarios 2 through 4B)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	Oxidation Rate	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV
#1: LNC3, DryFining™, SO_2 BART	-	0.660	-	0.647	-	0.599	-	0.916	-
#2: LNC3+, DryFining™, SO_2 BART	-	0.552	0.108	0.540	0.107	0.501	0.098	0.729	0.187
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	0.527	0.133	0.508	0.139	0.471	0.128	0.687	0.229
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.477	0.183	0.442	0.205	0.409	0.190	0.573	0.343
	2.5%	0.516	0.144	0.476	0.171	0.430	0.169	0.645	0.271
	5.0%	0.560	0.100	0.540	0.107	0.453	0.146	0.737	0.179
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.496	0.164	0.463	0.184	0.429	0.170	0.613	0.303
	2.5%	0.535	0.125	0.485	0.162	0.450	0.149	0.684	0.232
	5.0%	0.578	0.082	0.549	0.098	0.473	0.126	0.769	0.147

Table 11: Unit 2 Visibility Modeling Results for Year 2001 (Unit 1 Emissions Held Constant at Scenario 2 Levels for Scenarios 2 through 4B)

Description		**Visibility Impairment**							
		TRNP South Unit		**TRNP North Unit**		**TRNP Elkhorn Ranch**		**Lostwood Wilderness Area**	
Emissions Control Scenario	**Oxidation Rate**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**
#1: LNC3, DryFining™, SO_2 BART	-	0.474	-	0.571	-	0.526	-	0.873	-
#2: LNC3+, DryFining™, SO_2 BART	-	0.416	0.058	0.502	0.069	0.443	0.083	0.745	0.128
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	0.405	0.069	0.462	0.109	0.417	0.109	0.729	0.144
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.384	0.090	0.381	0.190	0.387	0.139	0.696	0.177
	2.5%	0.413	0.061	0.422	0.149	0.413	0.113	0.768	0.105
	5.0%	0.461	0.013	0.484	0.087	0.440	0.086	0.850	0.023
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.391	0.083	0.407	0.164	0.389	0.137	0.708	0.165
	2.5%	0.414	0.060	0.437	0.134	0.414	0.112	0.779	0.094
	5.0%	0.462	0.012	0.499	0.072	0.443	0.083	0.860	0.013

Table 12: Unit 2 Visibility Modeling Results for Year 2002 (Unit 1 Emissions Held Constant at Scenario 2 Levels for Scenarios 2 through 4B)

Description		**Visibility Impairment**							
		TRNP South Unit		**TRNP North Unit**		**TRNP Elkhorn Ranch**		**Lostwood Wilderness Area**	
Emissions Control Scenario	**Oxidation Rate**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**
#1: LNC3, DryFining™, SO_2 BART	-	1.279	-	1.145	-	0.987	-	0.689	-
#2: LNC3+, DryFining™, SO_2 BART	-	1.048	0.231	0.970	0.175	0.806	0.181	0.566	0.123
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	0.979	0.300	0.905	0.240	0.758	0.229	0.531	0.158
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.838	0.441	0.773	0.372	0.645	0.342	0.465	0.224
	2.5%	0.885	0.394	0.815	0.330	0.720	0.267	0.520	0.169
	5.0%	0.946	0.333	0.862	0.283	0.793	0.194	0.585	0.104
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.884	0.395	0.815	0.330	0.682	0.305	0.490	0.199
	2.5%	0.930	0.349	0.857	0.288	0.757	0.230	0.538	0.151
	5.0%	0.982	0.297	0.904	0.241	0.822	0.165	0.591	0.098

Table 3-5a: Year 2000 Visibility Modeling Results

Description			Visibility Impairment							
			TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	Units	Oxidation Rate	98th % Δ-dV	Visibility Improvement Δ-dV	98th % Δ-dV	Visibility Improvement Δ-dV	98th % Δ-dV	Visibility Improvement Δ-dV	98th % Δ-dV	Visibility Improvement Δ-dV
#0: LNC3	1 & 2	-	1.959	-	1.780	-	1.412	-	2.155	-
#1: LNC3, DryFining™, SO_2 BART	1 & 2	-	0.660	-	0.647	-	0.599	-	0.916	-
#2: LNC3+, DryFining™, SO_2 BART	1 & 2	-	0.552	0.108	0.54	0.107	0.501	0.098	0.729	0.187
#3: LNC3+, DryFining™, SO_2 BART, SNCR	1 & 2	-	0.506	0.154	0.476	0.171	0.44	0.159	0.637	0.279
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	1 & 2	0%[1]	0.389	0.271	0.375	0.272	0.302	0.297	0.516	0.400
		2.5%	0.467	0.193	0.426	0.221	0.358	0.241	0.639	0.277
		5%	0.555	0.105	0.513	0.134	0.411	0.188	0.774	0.142
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	1 & 2	0%[1]	0.427	0.233	0.394	0.253	0.352	0.247	0.525	0.391
		2.5%	0.505	0.155	0.478	0.169	0.398	0.201	0.685	0.231
		5%	0.592	0.068	0.550	0.097	0.445	0.154	0.850	0.066

[1] 0% rate is hypothetical only and is not technically supportable, but it is provided for informational purposes to assess the theoretical visibility impairment level if no additional sulfuric acid mist was created due to SCR.

Table 3-6a: Year 2001 Visibility Modeling Results

Description			Visibility Impairment							
			TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	**Units**	**Oxidation Rate**	**98th % Δ-dV**	**Visibility Improvement Δ-dV**	**98th % Δ-dV**	**Visibility Improvement Δ-dV**	**98th % Δ-dV**	**Visibility Improvement Δ-dV**	**98th % Δ-dV**	**Visibility Improvement Δ-dV**
#0: LNC3	1 & 2	-	1.653	-	1.378	-	1.626	-	2.842	-
#1: LNC3, DryFining™, SO_2 BART	1 & 2	-	0.474	-	0.571	-	0.526	-	0.873	-
#2: LNC3+, DryFining™, SO_2 BART	1 & 2	-	0.416	0.058	0.502	0.069	0.443	0.083	0.745	0.128
#3: LNC3+, DryFining™, SO_2 BART, SNCR	1 & 2	-	0.394	0.080	0.422	0.149	0.392	0.134	0.713	0.160
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	1 & 2	0%[1]	0.352	0.122	0.299	0.272	0.341	0.185	0.645	0.228
		2.5%	0.398	0.076	0.408	0.163	0.392	0.134	0.792	0.081
		5.0%	0.462	0.012	0.53	0.041	0.450	0.076	0.956	-0.083
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	1 & 2	0%[1]	0.365	0.109	0.329	0.242	0.362	0.164	0.667	0.206
		2.5%	0.412	0.062	0.438	0.133	0.415	0.111	0.813	0.060
		5.0%	0.492	-0.018	0.560	0.011	0.476	0.050	0.976	-0.103

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[1] 0% rate is hypothetical only and is not technically supportable, but it is provided for informational purposes to assess the theoretical visibility impairment level if no additional sulfuric acid mist was created due to SCR.

Table 3-7a: Year 2002 Visibility Modeling Results

Description			Visibility Impairment							
			TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	**Units**	**Oxidation Rate**	**98th % Δ-dV**	**Visibility Improvement Δ-dV**	**98th % Δ-dV**	**Visibility Improvement Δ-dV**	**98th % Δ-dV**	**Visibility Improvement Δ-dV**	**98th % Δ-dV**	**Visibility Improvement Δ-dV**
#0: LNC3	1 & 2	-	3.131	-	2.692	-	2.173	-	1.980	-
#1: LNC3, DryFining™, SO_2 BART	1 & 2	-	1.279	-	1.145	-	0.987	-	0.689	-
#2: LNC3+, DryFining™, SO_2 BART	1 & 2	-	1.048	0.231	0.97	0.175	0.806	0.181	0.566	0.123
#3: LNC3+, DryFining™, SO_2 BART, SNCR	1 & 2	-	0.911	0.368	0.841	0.304	0.706	0.281	0.504	0.185
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	1 & 2	0%[1]	0.678	0.601	0.578	0.567	0.482	0.505	0.393	0.296
		2.5%	0.841	0.438	0.662	0.483	0.631	0.356	0.535	0.154
		5.0%	1.010	0.269	0.790	0.355	0.744	0.243	0.667	0.022
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	1 & 2	0%[1]	0.733	0.546	0.663	0.482	0.555	0.432	0.429	0.260
		2.5%	0.882	0.397	0.746	0.399	0.703	0.284	0.560	0.129
		5.0%	1.050	0.229	0.839	0.306	0.822	0.165	0.698	-0.009

[1] 0% rate is hypothetical only and is not technically supportable, but it is provided for informational purposes to assess the theoretical visibility impairment level if no additional sulfuric acid mist was created due to SCR.

Table 7a: Unit 1 Visibility Modeling Results for Year 2000 (Unit 2 Emissions Held Constant at Scenario 2 Levels)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	**Oxidation Rate**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**
#2: LNC3+, DryFining™, SO$_2$ BART	-	0.552	-	0.540	-	0.501	-	0.729	-
#3: LNC3+, DryFining™, SO$_2$ BART, SNCR	-	0.528	0.024	0.509	0.031	0.471	0.030	0.687	0.042
#4A: LNC3+, DryFining™, SO$_2$ BART, SCR@0.04	0%[1]	0.477	0.075	0.447	0.093	0.409	0.092	0.577	0.152
	2.5%	0.515	0.037	0.476	0.064	0.430	0.071	0.646	0.083
	5.0%	0.559	-0.007	0.541	-0.001	0.454	0.047	0.735	-0.006
#4B: LNC3+, DryFining™, SO$_2$ BART, SCR@0.06	0%[1]	0.495	0.057	0.467	0.073	0.429	0.072	0.616	0.113
	2.5%	0.534	0.018	0.487	0.053	0.450	0.051	0.684	0.045
	5.0%	0.578	-0.026	0.550	-0.010	0.473	0.028	0.766	-0.037

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[1] 0% rate is hypothetical only and is not technically supportable, but it is provided for informational purposes to assess the theoretical visibility impairment level if no additional sulfuric acid mist was created due to SCR.

Table 8a: Unit 1 Visibility Modeling Results for Year 2001 (Unit 2 Emissions Held Constant at Scenario 2 Levels)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	Oxidation Rate	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV
#2: LNC3+, DryFining™, SO_2 BART	-	0.416	-	0.502	-	0.443	-	0.745	-
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	0.405	0.011	0.462	0.040	0.418	0.025	0.729	0.016
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.384	0.032	0.381	0.121	0.388	0.055	0.695	0.050
	2.5%	0.413	0.003	0.422	0.080	0.414	0.029	0.768	-0.023
	5.0%	0.462	-0.046	0.482	0.020	0.439	0.004	0.849	-0.104
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.391	0.025	0.407	0.095	0.389	0.054	0.708	0.037
	2.5%	0.414	0.003	0.436	0.066	0.414	0.029	0.778	-0.033
	5.0%	0.463	-0.047	0.497	0.005	0.444	-0.001	0.860	-0.115

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[1] 0% rate is hypothetical only and is not technically supportable, but it is provided for informational purposes to assess the theoretical visibility impairment level if no additional sulfuric acid mist was created due to SCR.

Table 9a: Unit 1 Visibility Modeling Results for Year 2002 (Unit 2 Emissions Held Constant at Scenario 2 Levels)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	Oxidation Rate	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV
#2: LNC3+, DryFining™, SO_2 BART	-	1.048	-	0.970	-	0.806	-	0.566	-
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	0.981	0.067	0.907	0.063	0.761	0.045	0.531	0.035
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.844	0.204	0.779	0.191	0.653	0.153	0.467	0.099
	2.5%	0.889	0.159	0.819	0.151	0.725	0.081	0.520	0.046
	5.0%	0.945	0.103	0.865	0.105	0.793	0.013	0.584	-0.018
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.888	0.160	0.820	0.150	0.688	0.118	0.491	0.075
	2.5%	0.933	0.115	0.860	0.110	0.758	0.048	0.538	0.028
	5.0%	0.983	0.065	0.906	0.064	0.823	-0.017	0.591	-0.025

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[1] 0% rate is hypothetical only and is not technically supportable, but it is provided for informational purposes to assess the theoretical visibility impairment level if no additional sulfuric acid mist was created due to SCR.

Table 10a: Unit 2 Visibility Modeling Results for Year 2000 (Unit 1 Emissions Held Constant at Scenario 2)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	Oxidation Rate	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV
#2: LNC3+, DryFining™, SO_2 BART	-	0.552	-	0.540	-	0.501	-	0.729	-
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	0.527	0.025	0.508	0.032	0.471	0.030	0.687	0.042
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.477	0.075	0.442	0.098	0.409	0.092	0.573	0.156
	2.5%	0.516	0.036	0.476	0.064	0.430	0.071	0.645	0.084
	5.0%	0.560	-0.008	0.540	0.000	0.453	0.048	0.737	-0.008
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.496	0.056	0.463	0.077	0.429	0.072	0.613	0.116
	2.5%	0.535	0.017	0.485	0.055	0.450	0.051	0.684	0.045
	5.0%	0.578	-0.026	0.549	-0.009	0.473	0.028	0.769	-0.040

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[1] 0% rate is hypothetical only and is not technically supportable, but it is provided for informational purposes to assess the theoretical visibility impairment level if no additional sulfuric acid mist was created due to SCR.

Table 11a: Unit 2 Visibility Modeling Results for Year 2001 (Unit 1 Emissions Held Constant at Scenario 2 Levels)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	Oxidation Rate	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV	98th Percentile Δ-dV	Visibility Improvement Δ-dV
#2: LNC3+, DryFining™, SO$_2$ BART	-	0.416	-	0.502	-	0.443	-	0.745	-
#3: LNC3+, DryFining™, SO$_2$ BART, SNCR	-	0.405	0.011	0.462	0.040	0.417	0.026	0.729	0.016
#4A: LNC3+, DryFining™, SO$_2$ BART, SCR@0.04	0%[1]	0.384	0.032	0.381	0.121	0.387	0.056	0.696	0.049
	2.5%	0.413	0.003	0.422	0.080	0.413	0.030	0.768	-0.023
	5.0%	0.461	-0.045	0.484	0.018	0.440	0.003	0.850	-0.105
#4B: LNC3+, DryFining™, SO$_2$ BART, SCR@0.06	0%[1]	0.391	0.025	0.407	0.095	0.389	0.054	0.708	0.037
	2.5%	0.414	0.002	0.437	0.065	0.414	0.029	0.779	-0.034
	5.0%	0.462	-0.046	0.499	0.003	0.443	0.000	0.860	-0.115

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[1] 0% rate is hypothetical only and is not technically supportable, but it is provided for informational purposes to assess the theoretical visibility impairment level if no additional sulfuric acid mist was created due to SCR.

Table 12a: Unit 2 Visibility Modeling Results for Year 2002 (Unit 1 Emissions Held Constant at Scenario 2 Levels)

Description		Visibility Impairment							
		TRNP South Unit		TRNP North Unit		TRNP Elkhorn Ranch		Lostwood Wilderness Area	
Emissions Control Scenario	**Oxidation Rate**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**	**98th Percentile Δ-dV**	**Visibility Improvement Δ-dV**
#2: LNC3+, DryFining™, SO_2 BART	-	1.048	-	0.970	-	0.806	-	0.566	-
#3: LNC3+, DryFining™, SO_2 BART, SNCR	-	0.979	0.069	0.905	0.065	0.758	0.048	0.531	0.035
#4A: LNC3+, DryFining™, SO_2 BART, SCR@0.04	0%[1]	0.838	0.210	0.773	0.197	0.645	0.161	0.465	0.101
	2.5%	0.885	0.163	0.815	0.155	0.720	0.086	0.520	0.046
	5.0%	0.946	0.102	0.862	0.108	0.793	0.013	0.585	-0.019
#4B: LNC3+, DryFining™, SO_2 BART, SCR@0.06	0%[1]	0.884	0.164	0.815	0.155	0.682	0.124	0.490	0.076
	2.5%	0.930	0.118	0.857	0.113	0.757	0.049	0.538	0.028
	5.0%	0.982	0.066	0.904	0.066	0.822	-0.016	0.591	-0.025

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[1] 0% rate is hypothetical only and is not technically supportable, but it is provided for informational purposes to assess the theoretical visibility impairment level if no additional sulfuric acid mist was created due to SCR.