DRAFT for PUBLIC COMMENT

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 Environmental Quality
Adopted: **DRAFT**

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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 clearest days over the same period. This SIP revision analyzes the current rate of progress needed to attain natural visibility in 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. For all such sources, potential additional emission reductions are determined through identification of available and technically feasible control measures. These available and technically feasible controls are further examined in consideration of the four statutory factors. The four factors are: 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 to analyze for additional potential emission reduction measures as part of North Dakota's development of its four-factor analysis. Each source was required to submit a report North Dakota detailing the additional emissions reduction measures that are available and technically feasible for implementation, in consideration of the four factors. These measures were reviewed by North Dakota and used by North Dakota to determine what is necessary to demonstrate reasonable progress in consideration of the four statutory factors. 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 emissions from North Dakota sources. 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 emission levels.

Of the three non-BART EGU sources, one retired in early 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 in consideration of the four factors, the source's existing level of control, recent NO_X and SO_2 emission rates, and costs of controls as compared to round 1 costs incurred by similar sources (adjusted to 2018 dollars). In short, the four factor controls selected for modeling evaluation 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 uniform rate of progress[1] (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 (non-Rayleigh[2]) 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). With the glidepath adjustment, the baseline 2028 visibility condition projections[3] for CIAs in and around North Dakota indicates that all areas are expected to meet the 2028 planning goals.

Modeling the projected 2028 visibility conditions with additional emissions reduction measures selected from the four-factor analysis sources (Antelope Valley Station and Coyote Station) did not show a reduction in anthropogenic visibility impairment[4] from the projected baseline 2028 visibility conditions for the most impaired days[5]. The additional emissions reduction measures modeling was conducted using two scenarios determined from the four-factor analyses. 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 baseline 2028 visibility of 0.1 deciview[6] 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 baseline 2028 visibility of 0.04 deciview at Lostwood Wilderness

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[1] Uniform rate of progress is the linear improvement in visibility from the baseline visibility conditions to natural visibility conditions for the most impaired days.

[2] Rayleigh refers to the light scattering of the natural gases in the atmosphere.

[3] Baseline 2028 visibility conditions are projected using expected 2028 emissions projections without additional emissions reduction measures selected from the four factors.

[4] Anthropogenic visibility impairment means any humanly perceptible difference due to air pollution from anthropogenic sources between actual visibility and natural visibility on one or more days. Because natural visibility can only be estimated or inferred, visibility impairment also is estimated or inferred rather than directly measured.

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

[6] A deciview is the unit of measurement on the deciview index scale for quantifying in a standard manner human perceptions of visibility.

Area and 0.03 deciviews at Theodore Roosevelt National Park. Neither additional emissions reduction measures scenario indicated the North Dakota CIAs would experience a reduction in anthropogenic visibility impairment from the installation of these potential control measures. The modeling analysis also indicated there will be no degradation during the clearest days[7] projection of the baseline 2028 visibility conditions.

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 emissions reduction measures selected upon four-factor consideration will not provide for a reduction in anthropogenic visibility impairment on the most impaired days visibility projections for 2028. Therefore, the Department determined that it is not reasonable to require these additional control measures 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 the additional emission reduction measures selected for review in consideration of the four factors are not reasonable for implementation during this planning period (second round of the RHR).

The RHR also 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. In addition to these requirements, North Dakota chose to consult with Tribal partner stakeholders in and near North Dakota. Doing so allowed 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 additional emissions reduction measures review in consideration of the

[7] Clearest days means the twenty percent of monitored days in a calendar year with the lowest values of the deciview index.

four factors, the sources selected, and North Dakota current strategy based on the information available. Documentation is included in Appendix E.

North Dakota held an early engagement consultation period for the FLMs, and other stakeholders listed above, from September 20, 2021, through November 19, 2021. In addition to the early consultation, a video conference meeting was held on November 10, 2021. The objective of the meeting was to discuss the proposed SIP revision. Attendees included the NDDEQ, National Park Service, U.S. Forest Service, and EPA region 8. This engagement provided the stakeholders with a formal opportunity to review and comment on North Dakota's proposed SIP revision. Comments were received from the National Parks Service and the U.S. Forest Service in November 2021 and are included in Appendix D.2. A response to the FLM comments is included in Appendix D.2.c. Additional text explaining the North Dakota's SIP development process has been included in Section 2.1 to address FLM feedback.

Comments were received from EPA Region 8 on January 13, 2022, and are included in Appendix D.4. EPA comments received will be addressed upon conclusion of the public comment period.

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".[8] 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."[9] In North Dakota, the North Dakota Department of Environmental Quality (NDDEQ) is the agency that designs and implements State and Federal air quality programs.[10] 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).[11] 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.[12]

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.

[8] General Motors Corp. v. United States, 496 U.S. 530, 532 (1990)
[9] 42 U.S.C. § 7401(a)(3)
[10] N.D.C.C. section 23.1-06 and N.D.A.C Article 33.1-15.
[11] Available at: https://www3.epa.gov/airquality/greenbook/ancl.html (Last visited July 21, 2021)
[12] 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.[13]
- $PM_{2.5}$
  - Primary 1-year. Annual mean averaged over 3-years. Standard of 12 micrograms per meter cubed ($\mu g/m^3$).
  - Primary and Secondary 24-hour. 98th percentile of 24-hour average, averaged over 3-years. Standard of 35 $\mu g/m^3$.
- Ozone
  - Primary and Secondary 8-hour. Annual 4th highest daily maximum 8-hour concentration averaged over 3-years. Standard of 70 ppb.

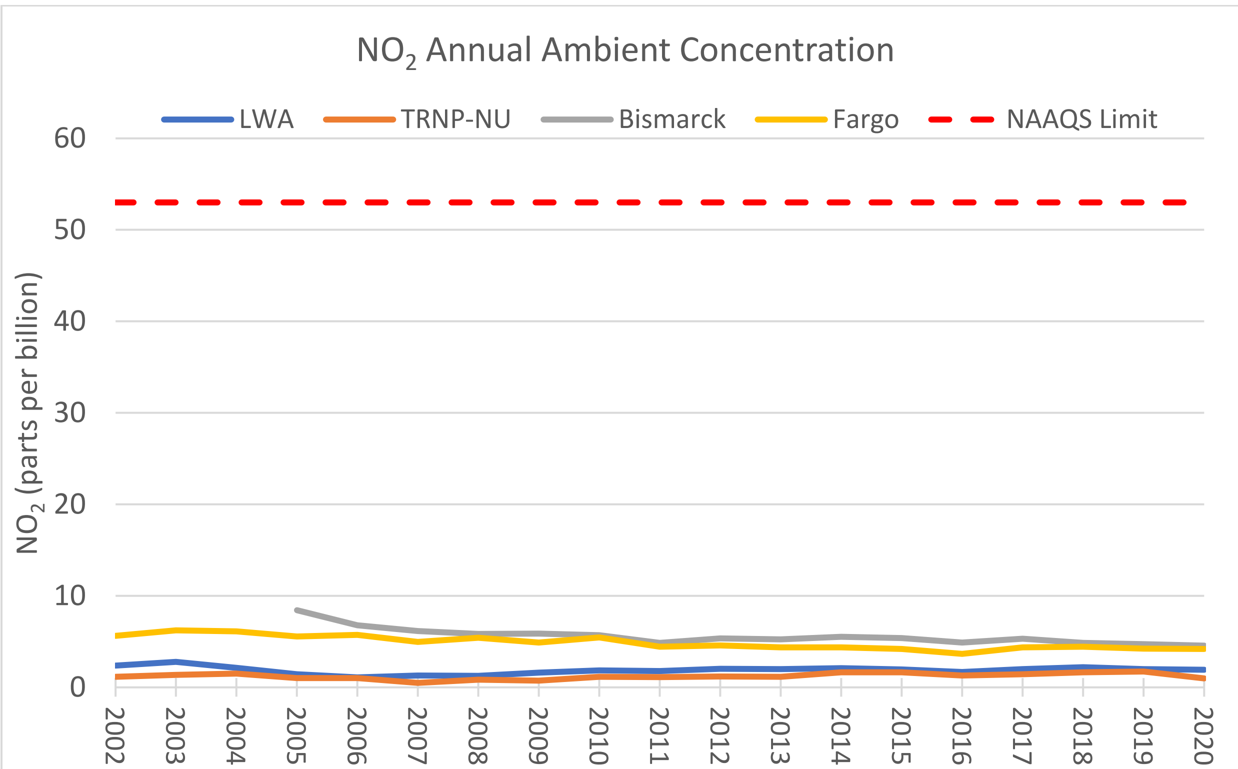

Figure 1: NO_2 Annual Average Ambient Concentrations

[13] 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).

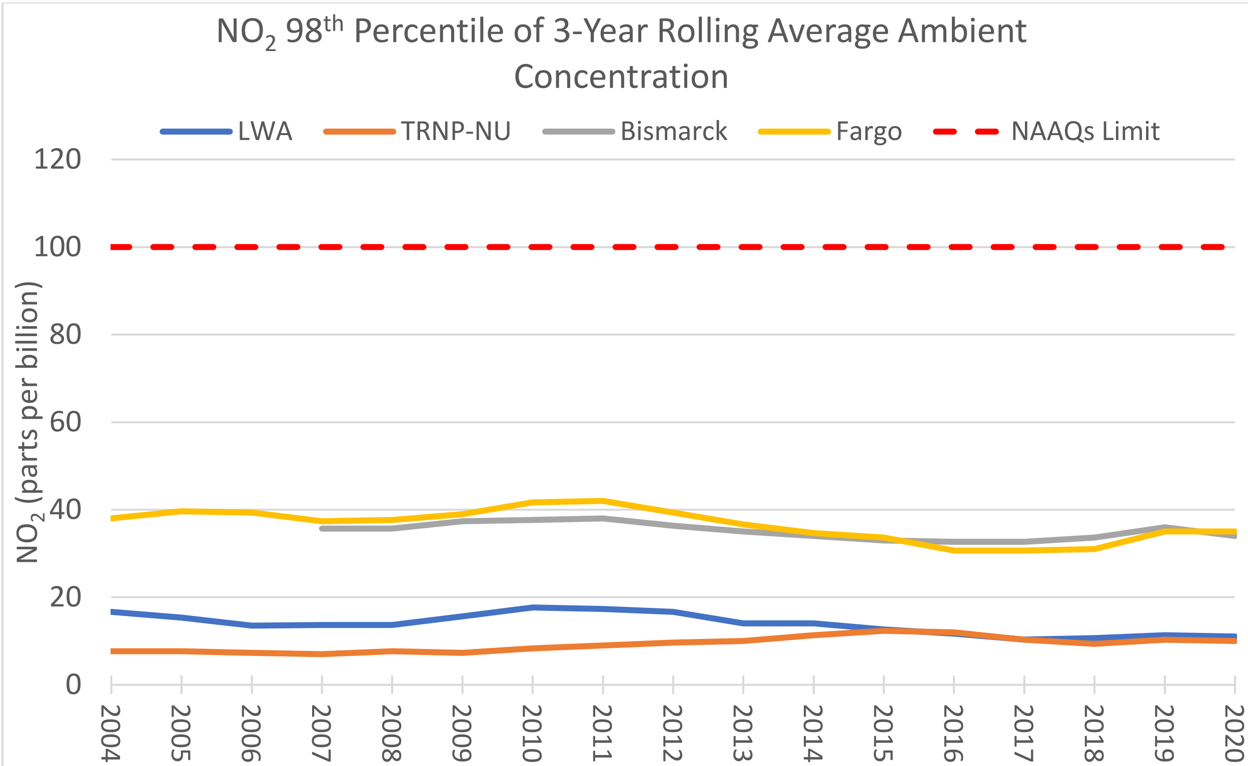

Figure 2: NO_2 98th Percentile of Daily Maximum 1-hour Concentration

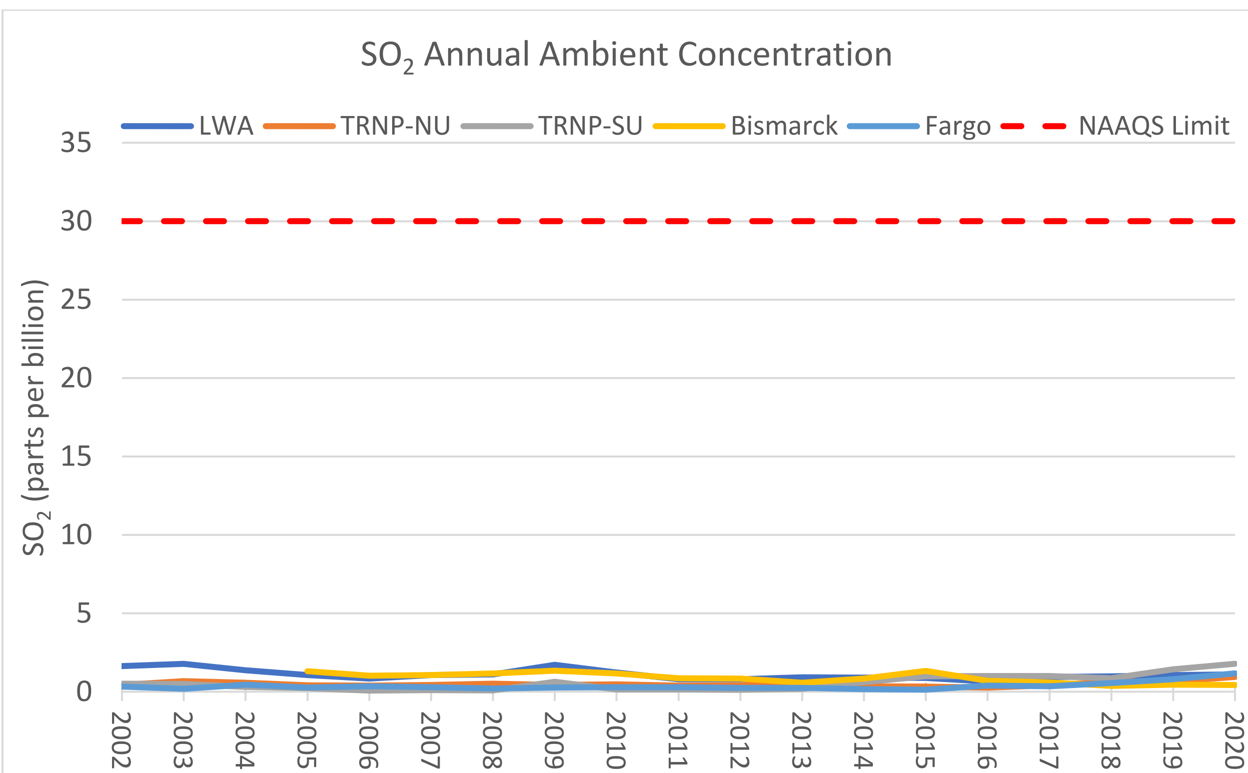

Figure 3: SO_2 Annual Average Ambient Concentrations

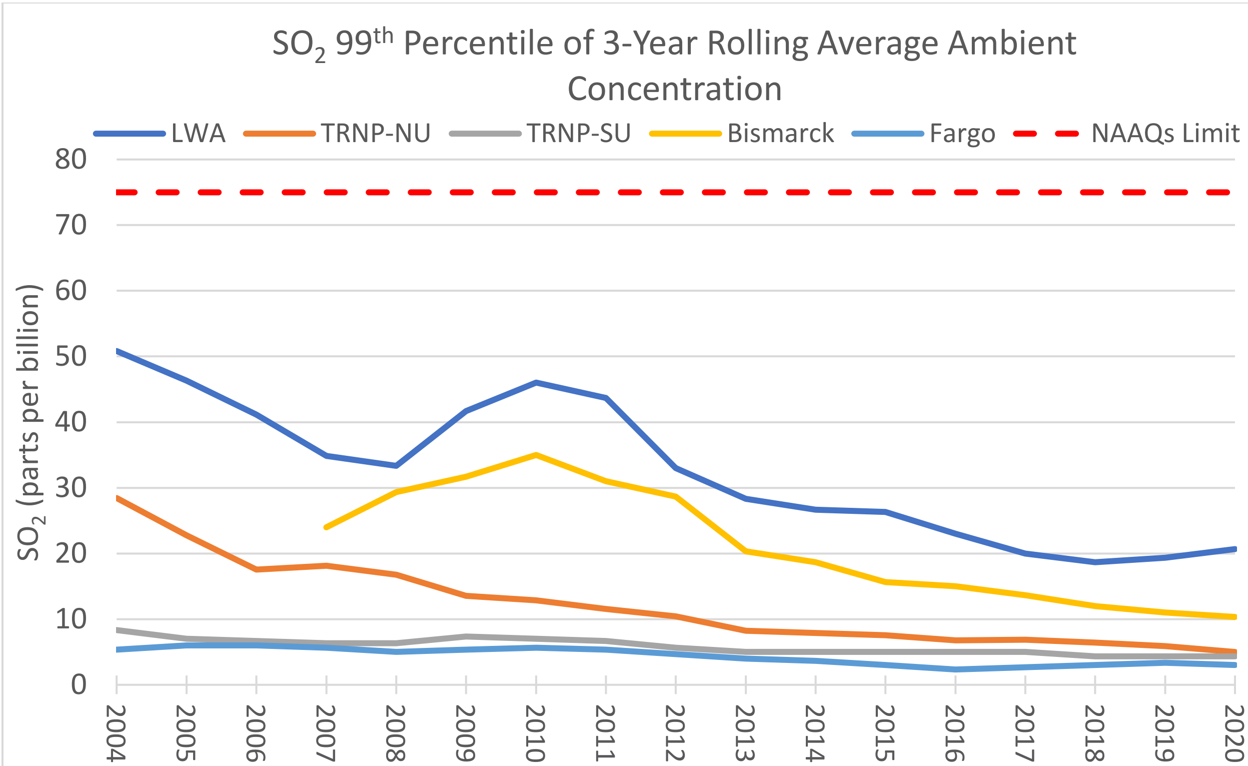

Figure 4: SO_2 99th Percentile of Daily Maximum 1-hour Concentration

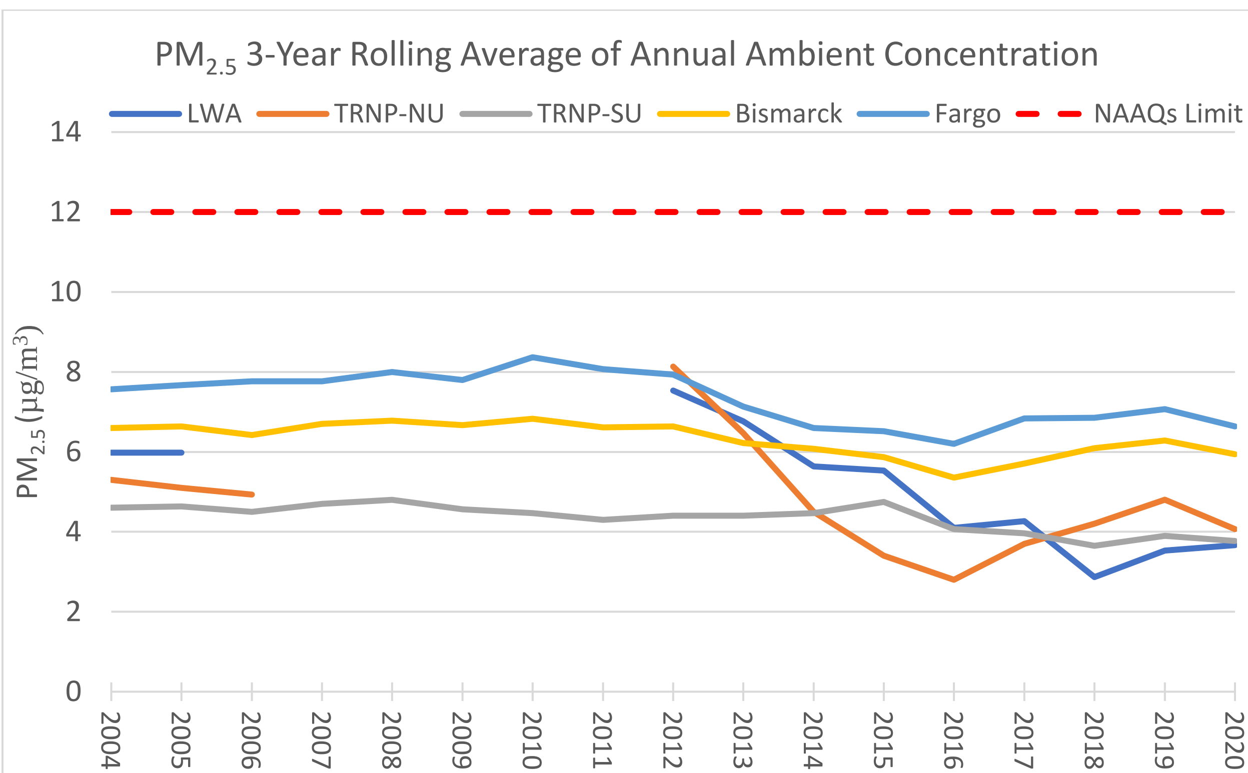

Figure 5: $PM_{2.5}$ Annual Average Ambient Concentration

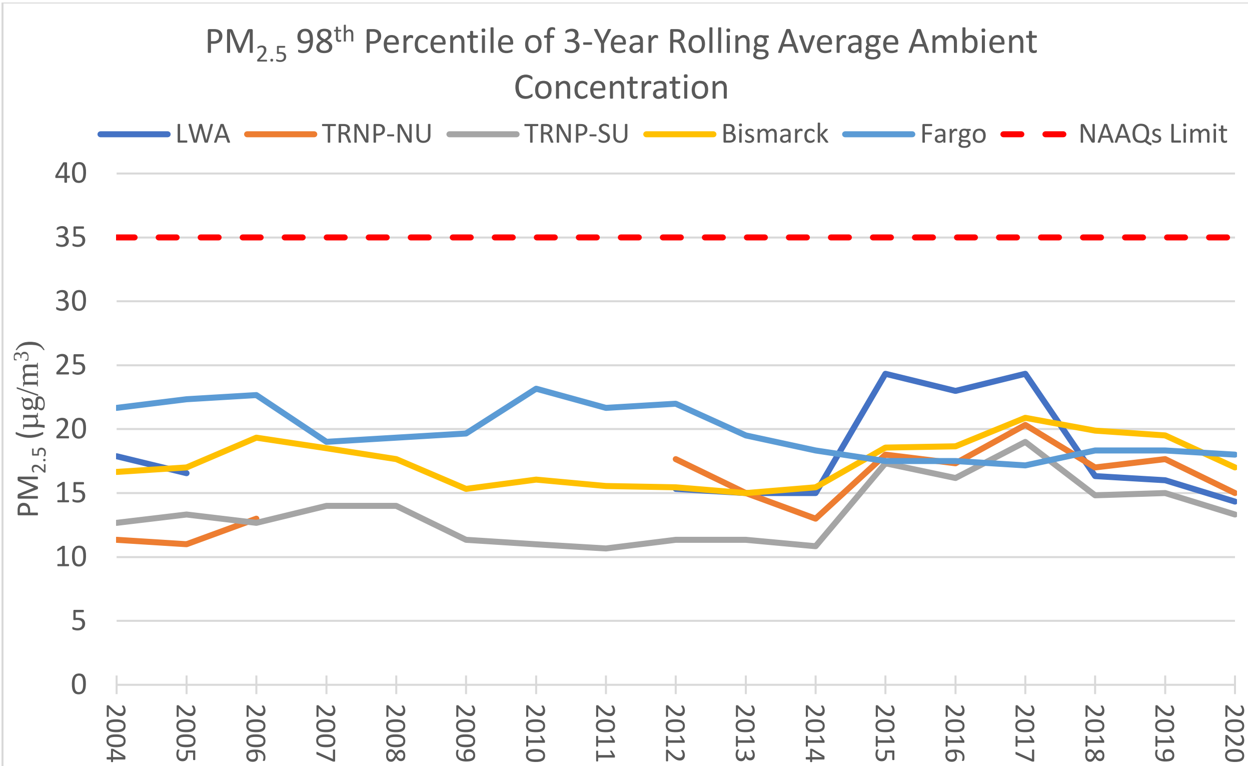

Figure 6: $PM_{2.5}$ 98^{th} Percentile of Average 24-hour Concentration

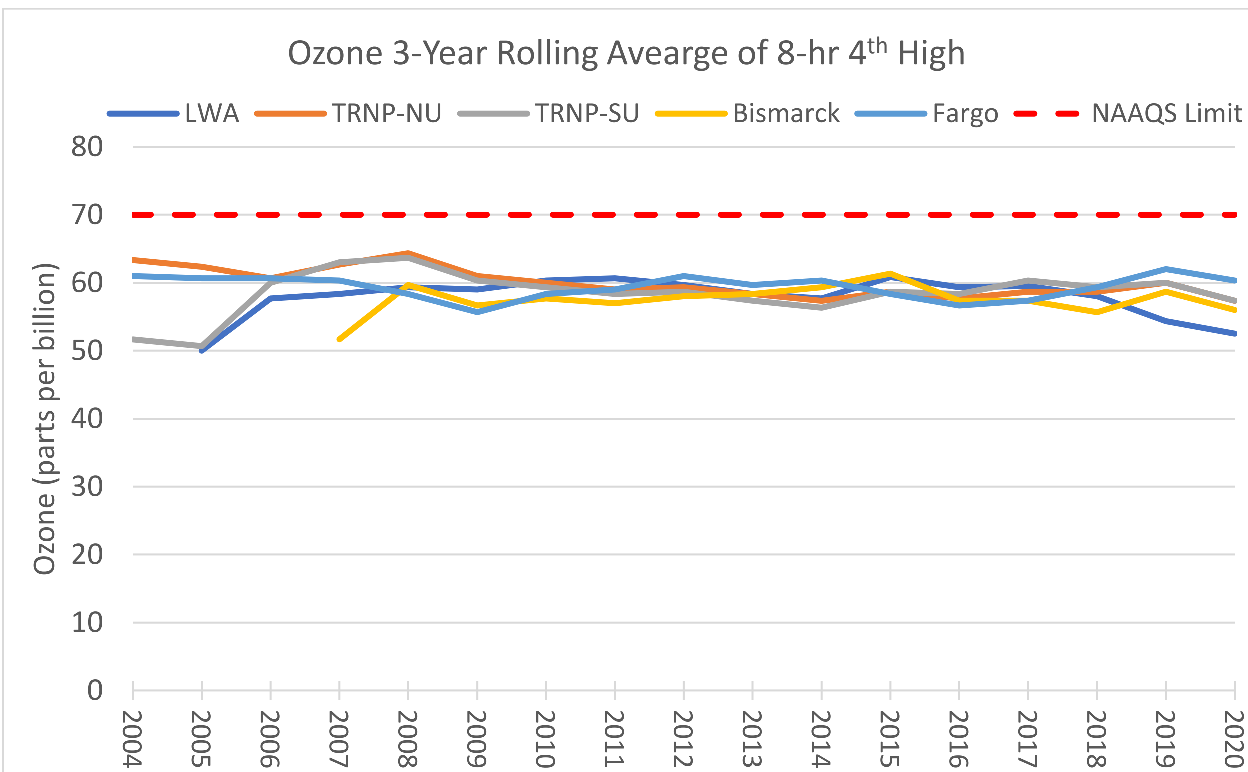

Figure 7: Ozone 4^{th} High of 8-hour Concentration

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 µg/m^3 or lower, significantly below the 12 µg/m^3 standard.
- Figure 6, LWA, TRNP-NU, and TRNP-SU have an averaged 98th percentile of daily maximum concentrations of 18 µg/m^3, 16 µg/m^3, and 14 µg/m^3, respectively, significantly below the 35 µg/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)[14] 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 clearest days. 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[15]

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[14] 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.

[15] 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.[16] 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.[17] On April 26, 2018 EPA proposed to approve North Dakota's BART determination for Coal Creek.[18] 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:

- 40 CFR 51.308(a) What is the purpose of this section? This section establishes the requirements for RH SIP, these requirements are included throughout this RH SIP.
- 40 CFR 51.308(b) When are the first implementation plans due under the regional haze program? Completed for first round of regional haze, no action required under this RH SIP.
- 40 CFR 51.308(c) [Reserved], no action.
- 40 CFR 51.308(d) What are the core requirements for the implementation plan for regional haze?
    - 40 CFR 51.308(d)(1) Reasonable progress goals, Section 3.1 and Section 6.
    - 40 CFR 51.308(d)(2) Calculations of baseline and natural visibility conditions, Section 3.2.1 and 3.2.2.
    - 40 CFR 51.308(d)(3) Long-term strategy for regional haze, Section 5

[16] Available at: https://www.govinfo.gov/content/pkg/FR-2012-04-06/pdf/2012-6586.pdf (Last visited June 7, 2021)
[17] Available at: https://caselaw.findlaw.com/us-8th-circuit/1644956.html (Last visited February 23, 2021)
[18] 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)

    - 40 CFR 51.308(d)(4) Monitoring strategy and other implementation plan requirements, Section 6.8.
- 40 CFR 51.308(e) Best Available Retrofit Technology (BART) requirements for regional haze visibility impairment, Section 8 and Appendix F.
- 40 CFR 51.308(f) Requirements for periodic comprehensive revisions of implementation plans for regional haze
    - 40 CFR 51.308(f)(1) Calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress, Section 3.2.
    - 40 CFR 51.308(f)(2) Long-term strategy for regional haze, Section 5.
    - 40 CFR 51.308(f)(3) Reasonable progress goals, Section 3.1 and Section 6.
    - 40 CFR 51.308(f)(4) "additional monitoring to assess reasonably attributable visibility impairment", Section 6.6.
    - 40 CFR 51.308(f)(5) "plan revision to serve as progress report", Section 6.7
    - 40 CFR 51.308(f)(6) Monitoring strategy and other implementation plan requirements, Section 6.8.
- 40 CFR 51.308(g) Requirements for periodic reports describing progress towards the reasonable progress goals, Section 9.
- 40 CFR 51.308(h) Determination of the adequacy of existing implementation plan, Section 5.2, Section 5.3, and Section 6.1
- 40 CFR 51.308(i) What are the requirements for State and Federal Land Manager coordination?, 2.1.1.

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.

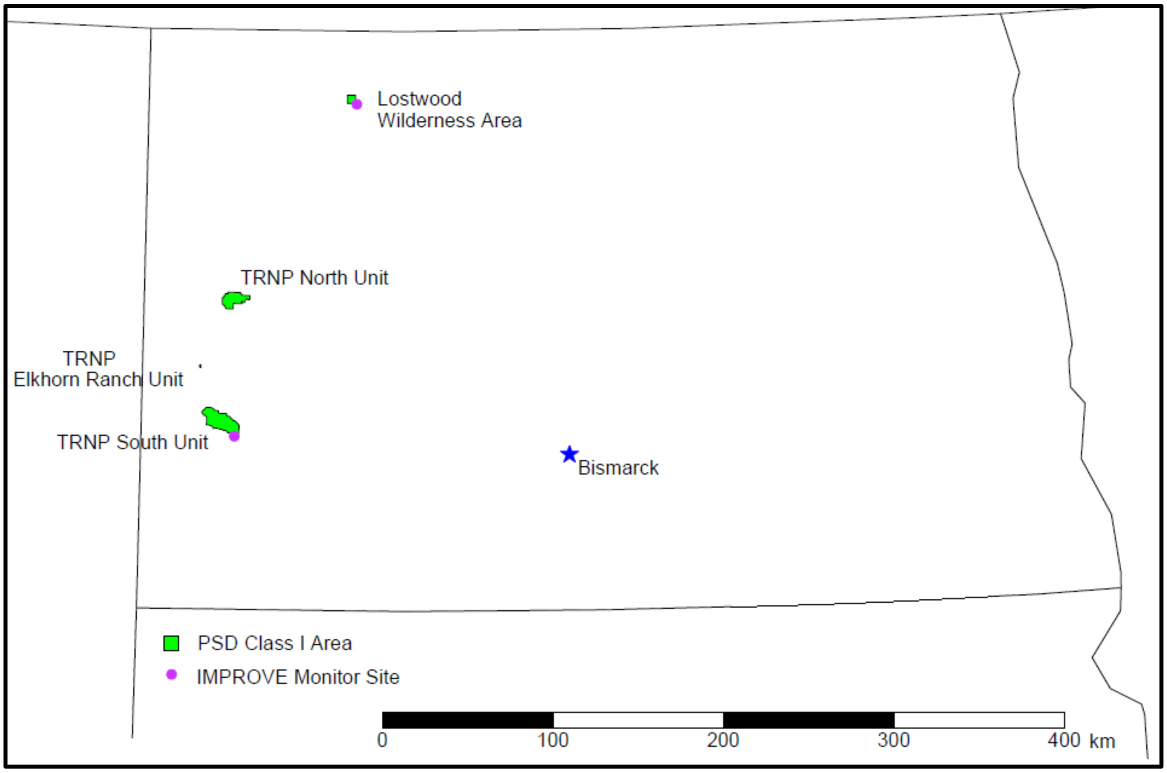

Figure 9: Class I areas in North Dakota

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[19] 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.

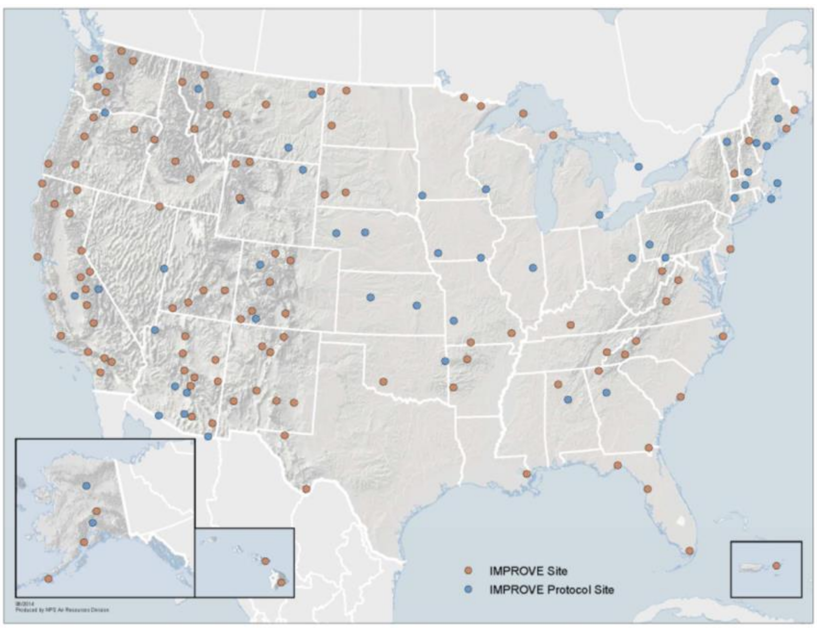

Figure 10: Locations of IMPROVE monitoring sites.[20]

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

[20] 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.

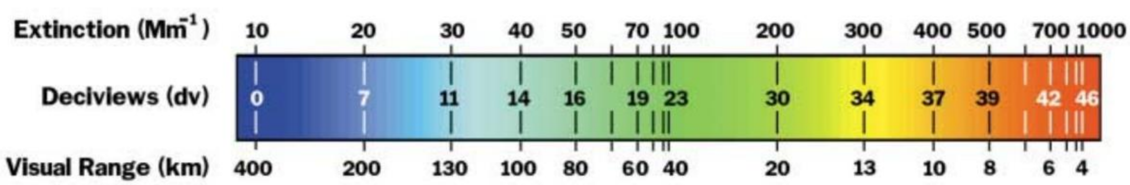

Figure 11: Comparison of extinction (Mm^{-1}), deciview (dv), and visual range (km) [21]

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.

[21] 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[22]. These reductions are depicted in Figure 12 and listed in Table 2.

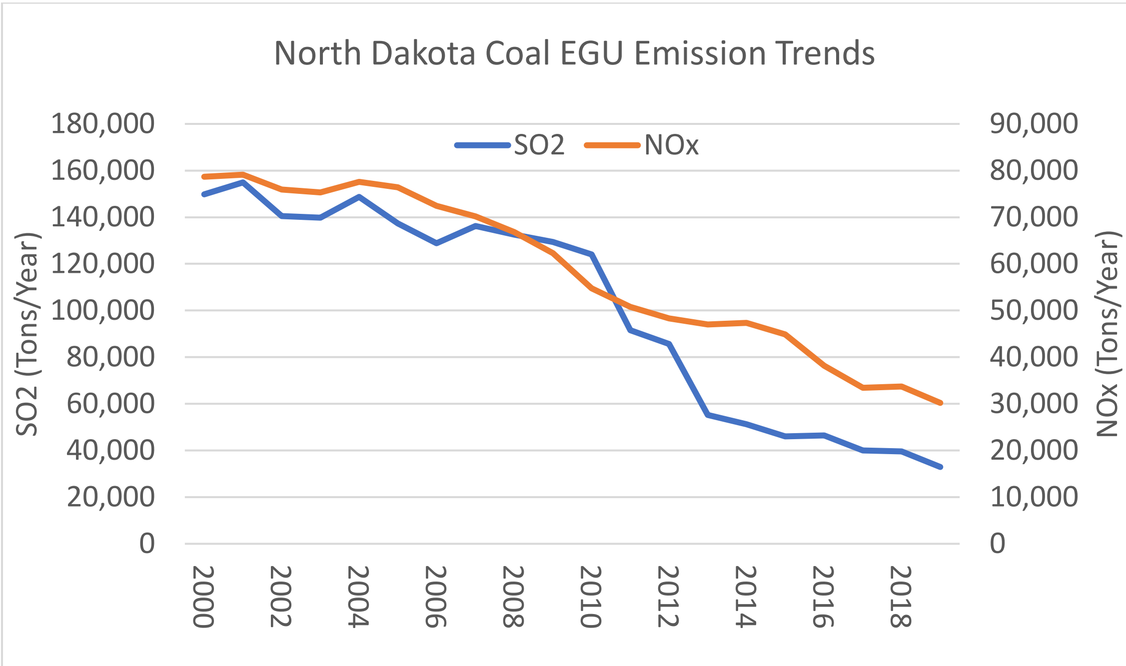

Figure 12: North Dakota Coal Fired EGU Emissions since from 2002-2019.

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%***

[22] 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[23] at TRNP and compared the visitation to the EPA selected Most Impaired Days (MID)[24] 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".[25]

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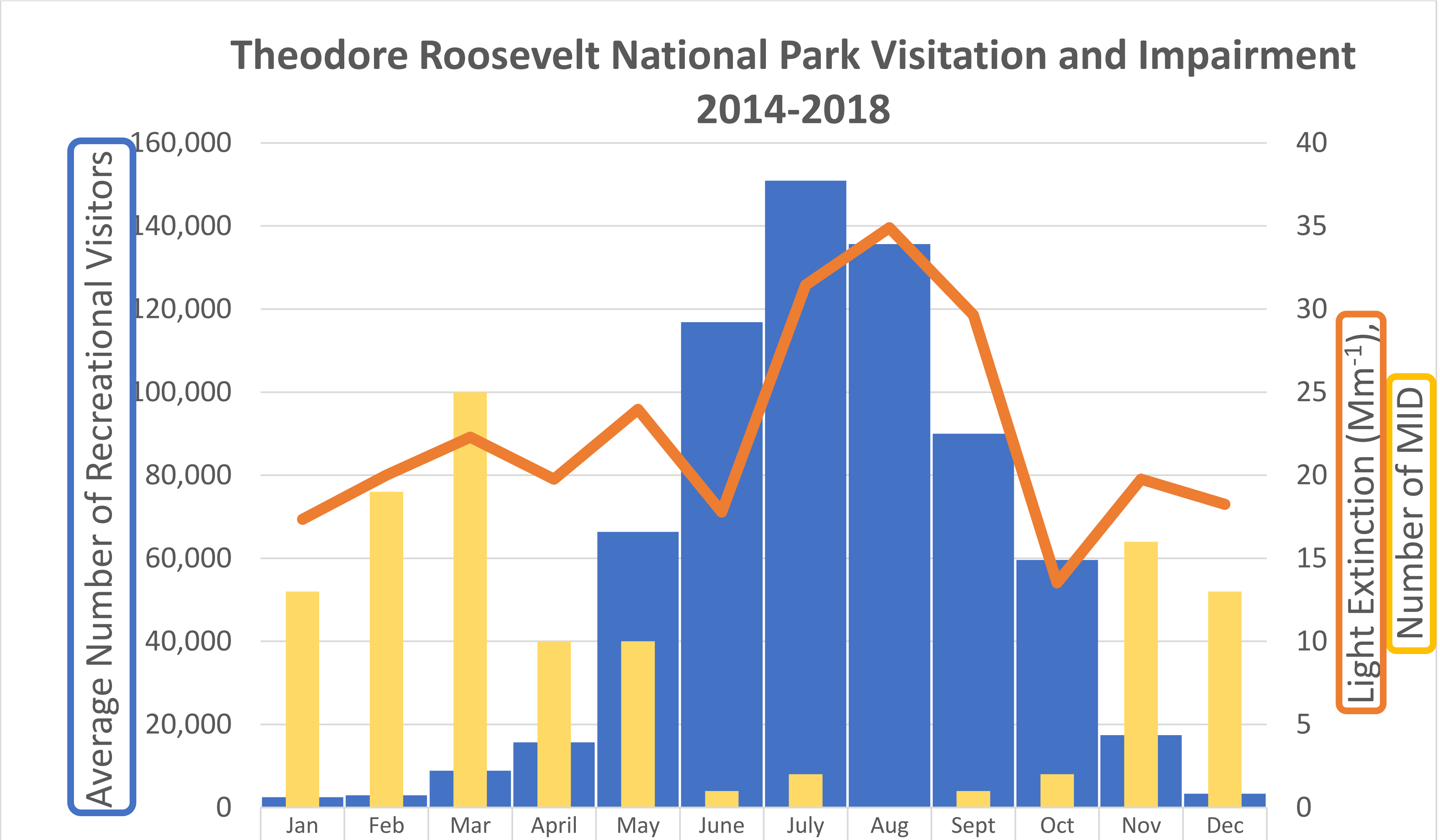
[23] Available at: https://irma.nps.gov/STATS/SSRSReports/Park%20Specific%20Reports/Visitation%20by%20Month (Last visited July 21, 2021)

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

[25] 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 was completed. 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

(RESERVED) 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

In development of this proposed RH SIP revision, the Department relied on a significant amount of work completed through collaboration with the Western Regional Air Partnership (WRAP) regional planning organization. 40 CFR §51.308(f)(2)(iii) and 40 CFR §51.308(d)(3)(iii) both state, in part, "*The State must document the technical basis,…The State may meet this requirement by relying on technical analyses developed by a regional planning process and approved by all State participants.*" The technical analysis and support provided by WRAP are detailed in Section 2.2, Section 7, and Appendix C. This information is also publicly available through the WRAP website[26] and the Technical Support System website[27].

In addition, the Department independently evaluated sources and sectors of significance in North Dakota following the requirements of CAA Section 169A, 40 CFR §51.308(d)(1), and 40 CFR §51.308(f)(2). Evaluations were performed to determine potential emission reduction measures which may be necessary when identifying what is required to show reasonable progress. Section 4.1.7 contains the cumulative emissions reductions identified in consideration of the four factors. Section 5.2 contains an overview of the long-term strategy review process for each source evaluated.[28] Section 6 contains the Department's discussion and determination of the reasonable progress goals set for this planning period. The emission reduction measures evaluations contain four factors which must be taken into consideration. These factors are costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment.[29]

In determining reasonable progress, North Dakota can consider visibility and projected visibility improvements. Utilizing its discretion, the Department chose to consider visibility and the modeled

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[26] https://www.wrapair2.org/
[27] https://views.cira.colostate.edu/tssv2/
[28] Appendix A and Appendix B contain the information used in support of the statements included in Section 5.2.
[29] CAA Section 169A(g), 40 CFR §51.308(d)(1), and 40 CFR §51.308(f)(2)

visibility improvements projected to result from the implementation of any emission reduction measures prior to finalizing any measure for inclusion in the long-term strategy.

The Department identified three potential emission reduction strategies from the four-factor analyses to determine the resulting modeled visibility improvement. The results of the modeling evaluation were used by the Department to inform its decision as to which potential emissions reduction measures are appropriate and necessary to include in the long-term strategy. In other words, the proposed reasonable progress goal for each Class I area was determined by North Dakota based on its evaluation of three unique potential long-term strategies. Upon consideration of the three long-term strategies and associated modeled visibility conditions, the Department determined that the long-term strategy necessary to meet the statutory reasonable progress requirement was the baseline 2028 strategy. North Dakota's long-term strategy and the reasonable progress goals comply with the requirement of 40 CFR §51.308(f)(3)(i) to provide for an improvement on the most impaired days since the baseline period and ensure no degradation in visibility for the clearest days since the baseline period. Section 3.1, Section 3.2.7, and Section 6.1 contain the information demonstrating North Dakota's Class I areas are meeting the reasonable progress requirements.

Of note, 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.[30] The modeling was completed and made available for state use in March 2021. On April 1, 2021, a results meeting was held to present the final data needed for incorporation into the SIP revision.[31] 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.

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[30] Available at: https://www.wrapair2.org/pdf/2018-2019%20WRAP%20Workplan%20update%20Board%20Approved%20April.3.2019.pdf (Last visited June 1, 2021)
[31] Available at: https://www.wrapair2.org/RHPWG.aspx. See April 1, 2021 – Meeting 8. (Last visited June 1, 2021)

2.1 §51.308(i) – Consultation with Federal Land Managers (FLM), Neighboring States, and Tribes

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[32]). 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.

Once an initial draft of North Dakota's RH SIP revision was completed, the Department held an early engagement consultation period for the FLMs from September 20, 2021, through November 19, 2021. In addition to the early consultation, a video conference meeting was held on November 10, 2021.[33] The objective of the meeting was to discuss the draft RH SIP revision and to receive to feedback from the FLMs. Attendees included the NDDEQ, National Park Service, U.S. Forest Service, and EPA Region 8. This engagement period provided the stakeholders with an early opportunity to review and comment on North Dakota's initial draft RH SIP revision. Feedback was received from the National Parks Service on November 19, 2021, and from the U.S. Forest Service on November 17, 2021.

Feedback was received from the FLMs on the following topics: correlation between park visitation and visibility impairment; cost thresholds for additional source controls; the uniform rate of progress toward natural visibility conditions; the impact to visibility conditions when considering the four statutory factors; visibility trends and impacts to out of state Class I areas; costs in the four factor evaluations; feasibility of selective catalytic reduction on North Dakota lignite sources; North Dakota upstream oil and gas industry; and increased future prescribed fire emissions. The FLM comments have been included in Appendix D.2.a and D.2.b. The Department's response can be found in Appendix D.2.c.

As required by §51.308(i)(4), the Department will continue to coordinate and consult the FLMs during the development of future progress reports and RH SIP revisions, as well as during the implementation of programs having the potential to contribute to visibility impairment in CIAs. The progress reports and RH SIP revisions are to occur at five-year intervals, see Section 1.4.1. This consultation process shall provide on-going and timely opportunities to address the status of the control programs identified in this RH SIP revision, the development of future assessments of sources and impacts, and the development of

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

[33] Consultation slides can be found in Appendix D.2.a, page D.2.a-119.

additional control programs. The consultation will include the status of the following specific implementation items:

1. Implementation of emissions strategies identified in the RH SIP revision as contributing to achieving improvement on the most impaired days.
2. Summary of major new permits issued.
3. Status of State actions to meet commitments for completing any future assessments or rulemaking on sources identified as likely contributors to visibility impairment, but not directly addressed in the most recent RH SIP revision.
4. Any changes to the monitoring strategy or monitoring stations status that may affect tracking of reasonable progress.
5. Work underway for preparing the progress reports and periodic RH SIP revisions.
6. Summary of topic discussions (meetings, emails, other records) covered in ongoing communication between the State and FLMs regarding implementation of the visibility program.

2.1.2 Minnesota

Per 40 CFR §51.308(f)(2)(ii), the Department consulted with Minnesota. On March 22, 2021, the Department met with Minnesota to discuss the status of the proposed 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

Per 40 CFR §51.308(f)(2)(ii), the Department consulted with Montana. The Department also 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 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

Per 40 CFR §51.308(f)(2)(ii), the Department consulted with South Dakota. The Department also 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. No comments were received from North Dakota's Tribal partners during the early engagement consultation period held from September 20, 2021, through November 19,2021.

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.[34]

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.

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*

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

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. North Dakota utilized the technical data in considering and developing Section 3: 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, Section 7: Overview of WRAP Modeling Scenarios, and Section 9: §51.308(g) – 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 Participation and Review Process

The Public Hearing Record will be included in Appendix D.3.

2.5.1 Public Comment Period and Hearing Information

NDDEQ will hold a public comment period and public hearing for this proposed SIP revision at the following time and location:

The public comment period ends on June 1, 2022. Direct comments, in writing, to the North Dakota Department of Environmental Quality, Division of Air Quality, 4201 Normandy Street, Bismarck North Dakota, 58503 or AirQuality@nd.gov, Re: Regional Haze SIP Revision. Please note that, to be considered, comments submitted by email must be sent to the email address listed. Comments must be received by 11:59 PM central time on the last day of the public comment period to be considered in the final determination.

A public hearing to address the proposed changes to the SIP revision will be held at 9:00am CDT on May 31, 2022, at 4201 Normandy Street, Bismarck North Dakota, 58503.

An electronic version of this proposed Regional Haze SIP Revision and Appendices can be found at the Departments Website: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx, https://www.deq.nd.gov/AQ/PublicCom.aspx, and https://www.deq.nd.gov/PublicNotice.aspx.

2.5.2 Summary of Comments Received during Public Comment Period/Hearing

(RESERVED) This section will be completed upon the conclusion of the public comment period.

2.5.3 Response to Public Comments

(RESERVED) This section will be completed upon the conclusion of the public comment 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).

2.7 Revisions to the State Implementation Plan

(RESERVED) This section will be completed upon the conclusion of the public comment period.

3 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. This section satisfies the requirements of 40 CFR 51.308(f)(1) and 40 CFR 51.308(d)(2).

3.1 Visibility Summary

3.1.1 Most Impaired Days 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[35]), 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.[36] This helps show the most controllable portion of visibility impairment from North Dakota anthropogenic sources.

[35] 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.

[36] 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.

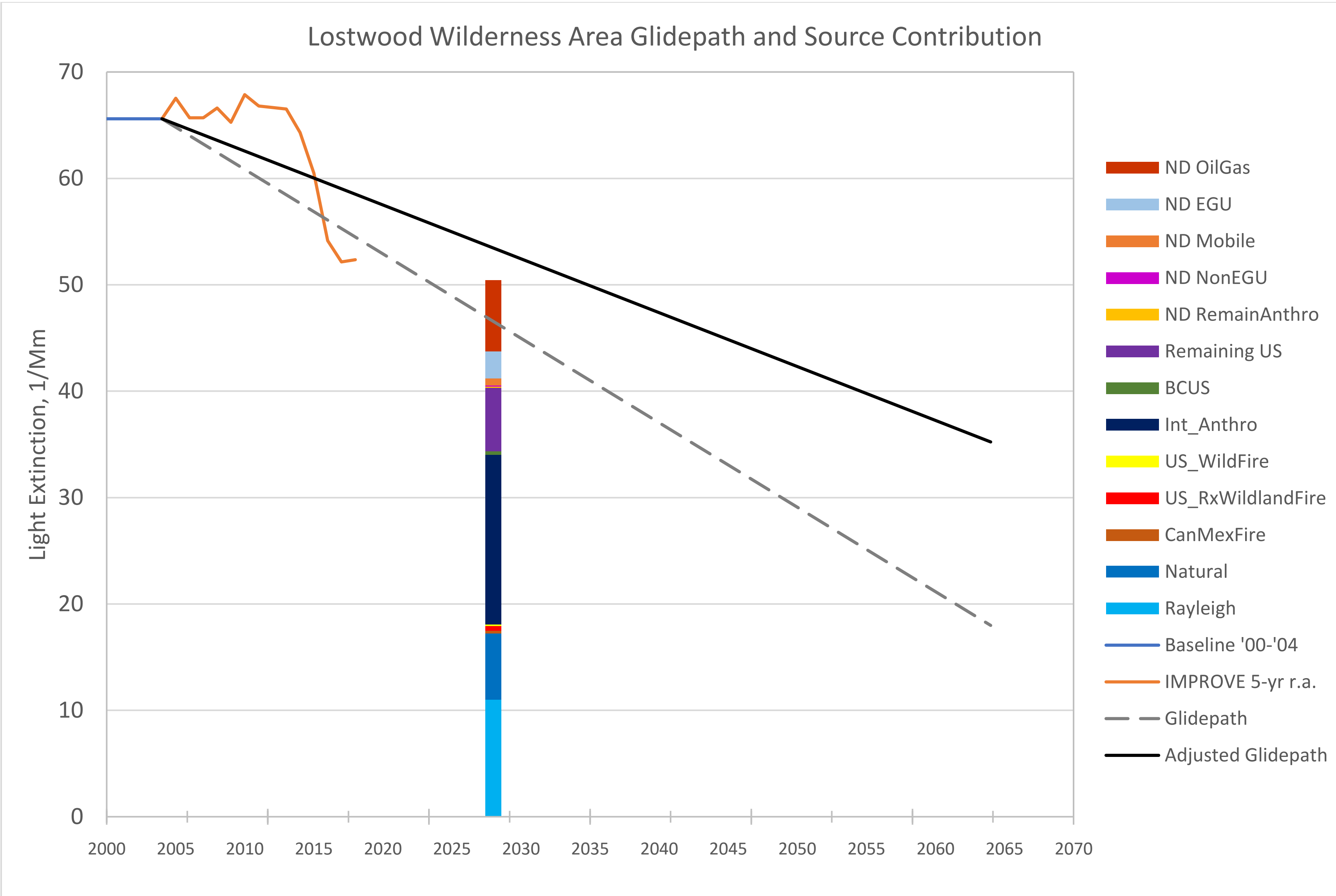

Figure 14: LWA contributors to visibility impairment, overall progress since baseline period, and 2028 projection

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.

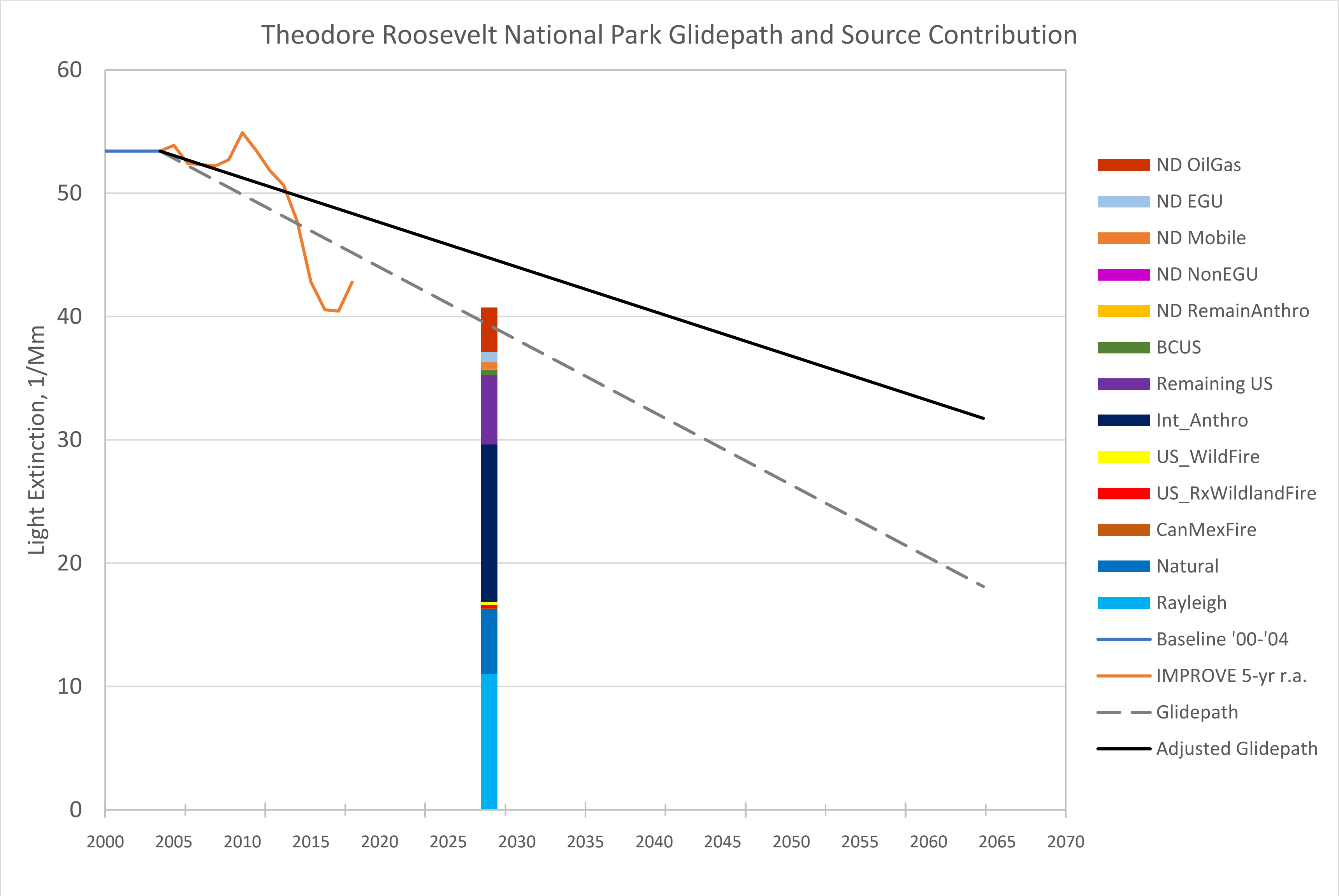

Figure 15: TRNP contributors to visibility impairment, overall progress since baseline period, and 2028 projection

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.[37] 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.

[37] 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.[38] 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.[39] 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. These events are not shown in Figure 14 nor Figure 15 since these figures remove wildfires by only focusing on the most impaired days as defined in 40 CFR §51.301.

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 (PGM) results have been scaled to correlate to the 2028 visibility projections. Where the 2028 visibility projections were determined following EPA recommended methodology.[40] 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.

3.1.2 Clearest Days Visibility Summary

Visibility on the clearest days at LWA and TRNP is adversely impacted by many different sources, most of which are outside of North Dakota's ability to regulate. 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 projection 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

[38] Note: Remaining US sources includes impairment from all US_Anthro species minus ammonium nitrates and ammonium sulfate from the North Dakota sectors.
[39] Note: Remaining US sources includes impairment from all US_Anthro species minus ammonium nitrates and ammonium sulfate from the North Dakota sectors.
[40] Available at: https://www.wrapair2.org/pdf/2028_Vis_Proj_Glidepath_Adj_2021-03-01draft_final.pdf, page 5. (Last Visited May 17, 2021)

light extinction of 10 Mm^{-1} and 6.7 Mm^{-1}, respectively.[41] The 2014–2018 IMPROVE data can be found in Section 5.1.1.2.[42] The IMPROVE data and 2028 visibility projections are displayed in Figure 16.

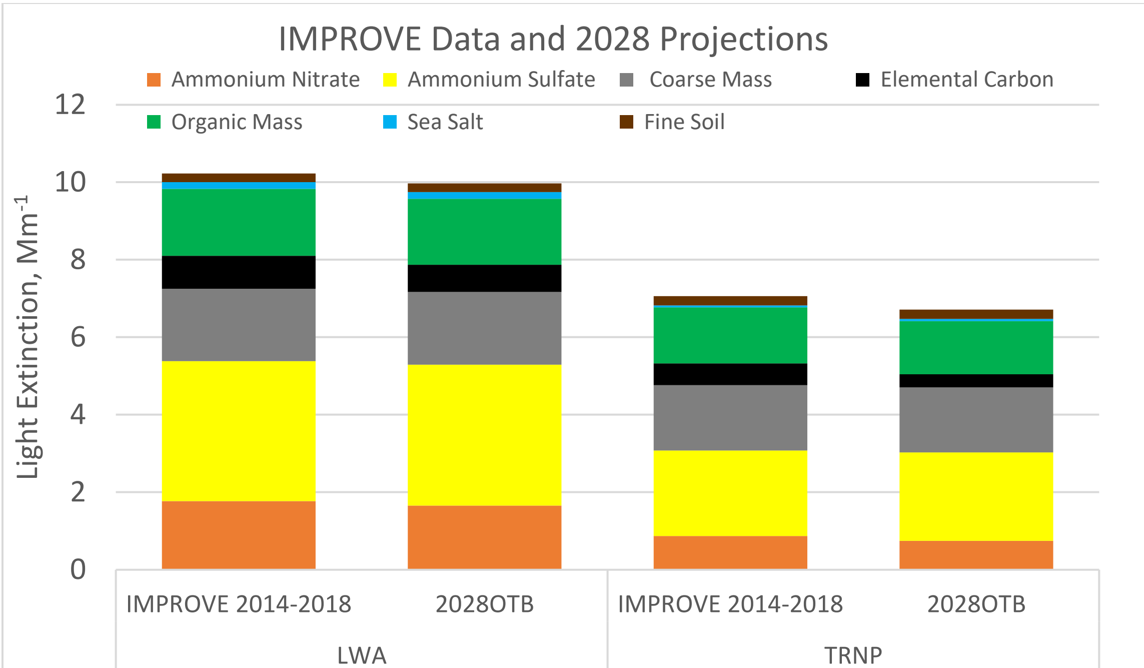

Figure 16: LWA and TRNP IMPROVE Data and 2028 Visibility Projections

The source and sector breakdown of the 2028 visibility projection information displayed in Figure 16 can be found in Appendix C.2.

[41] Available at: https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx. See Model Results Product 3.
[42] Also available at: https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx. See Charts Product 2.

3.2 §51.308(f)(1) 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.[43] 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.[44] 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.

[43] Final Rule: Protection of Visibility: Amendments to Requirements for State Plans, 82 FR 3101, January 10, 2017.
[44] 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[45]

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.

[45] 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[46]	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

[46] 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/Visibilityprogress (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.[47] This data was used for this SIP revision.

3.2.6.1 Most Impaired Data

Figure 17 and Figure 18 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.

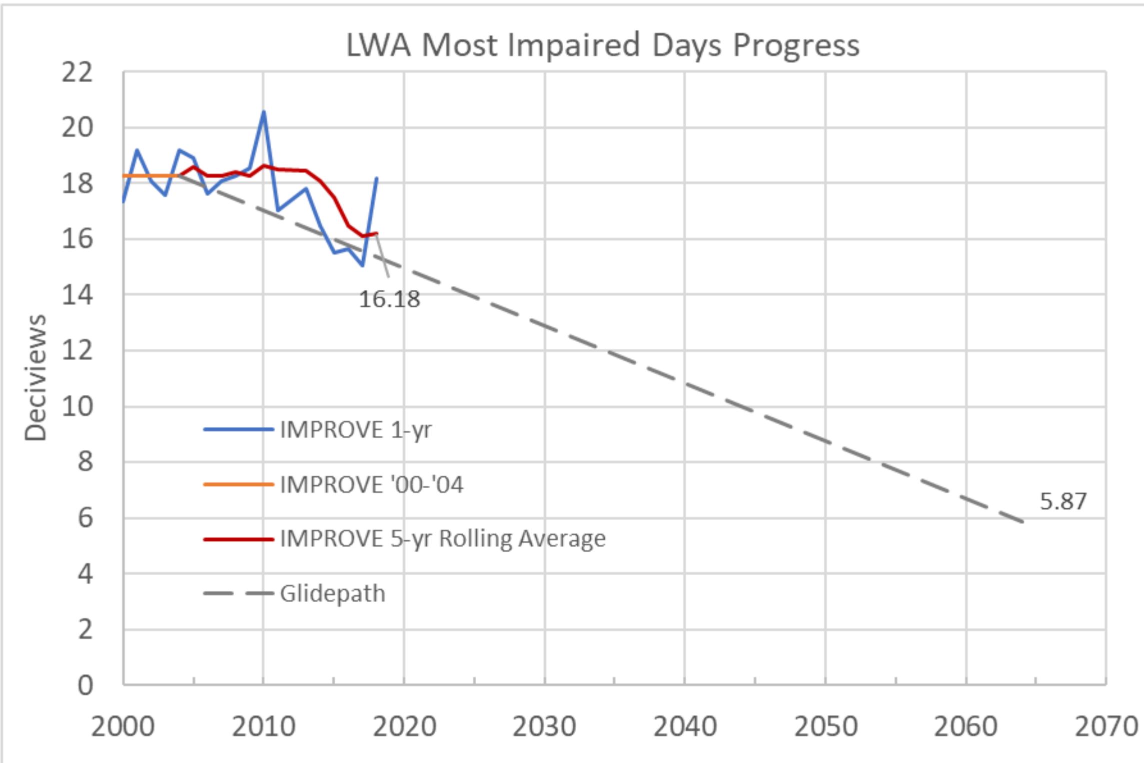

Figure 17: LWA Most Impaired Days Progress from 2000–2018

Figure 17 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 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.

[47] 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)

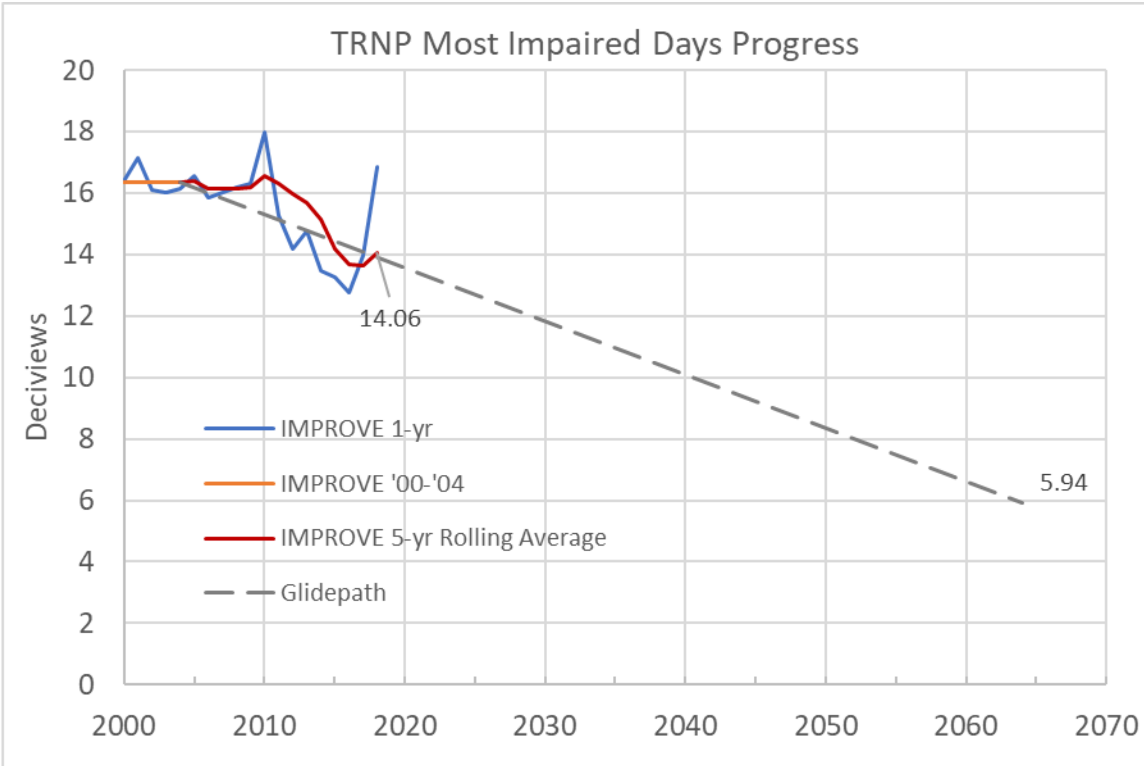

Figure 18: TRNP Most Impaired Days Progress from 2000–2018

Figure 18 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 18 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 19 and Figure 20 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.

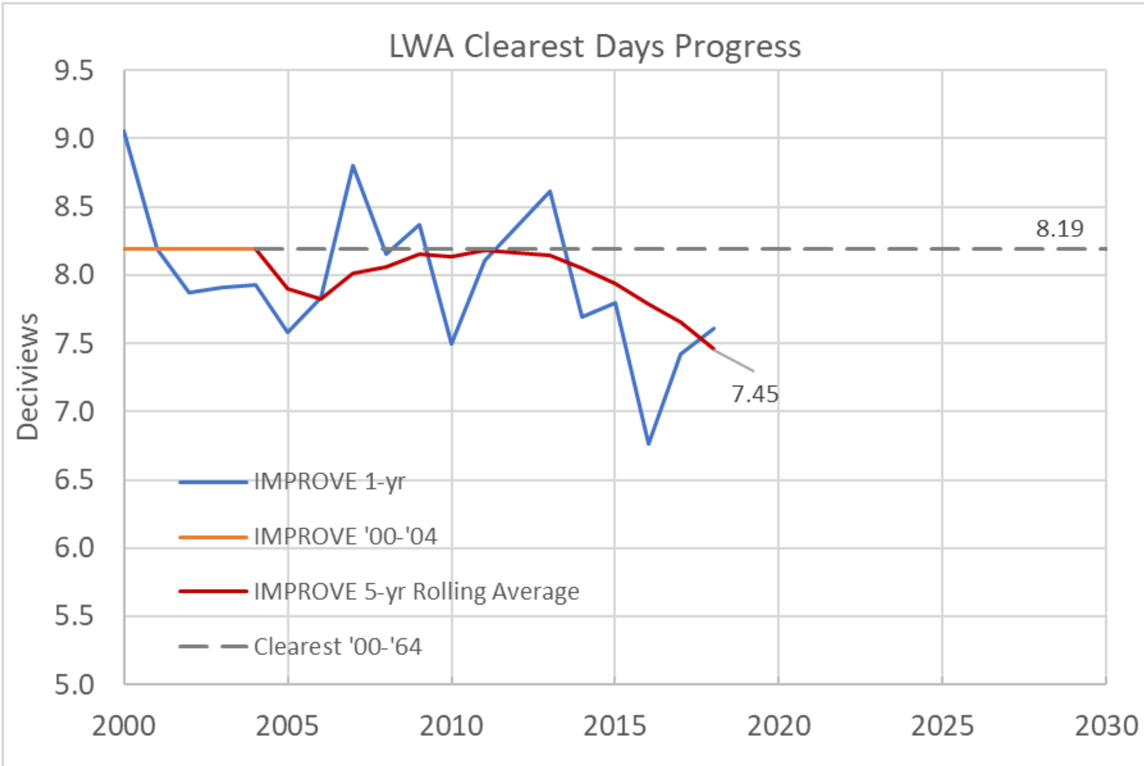

Figure 19: LWA Clearest Days Progress from 2000–2018

Figure 19 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.

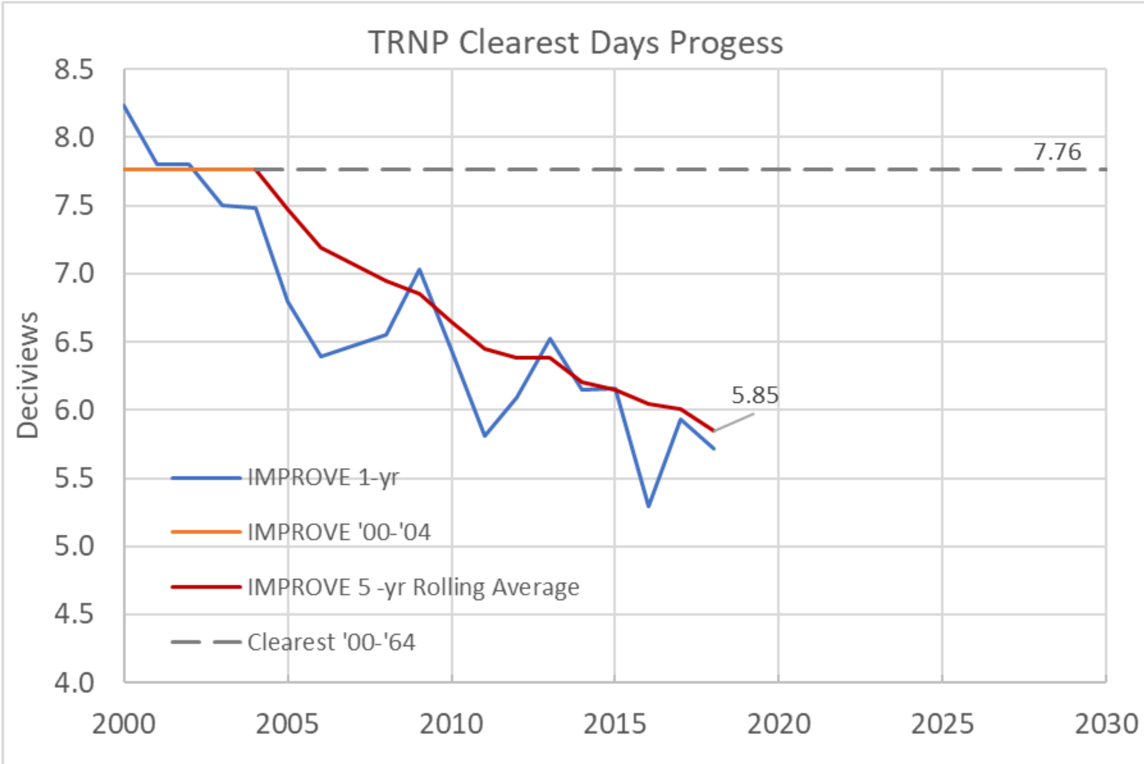

Figure 20: TRNP Clearest Days Progress from 2000–2018

Figure 20 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.[48] 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.[49] 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.

[48] 40 CFR 51.308(f)(1)(vi)(B)

[49] 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 21 and Figure 22 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.

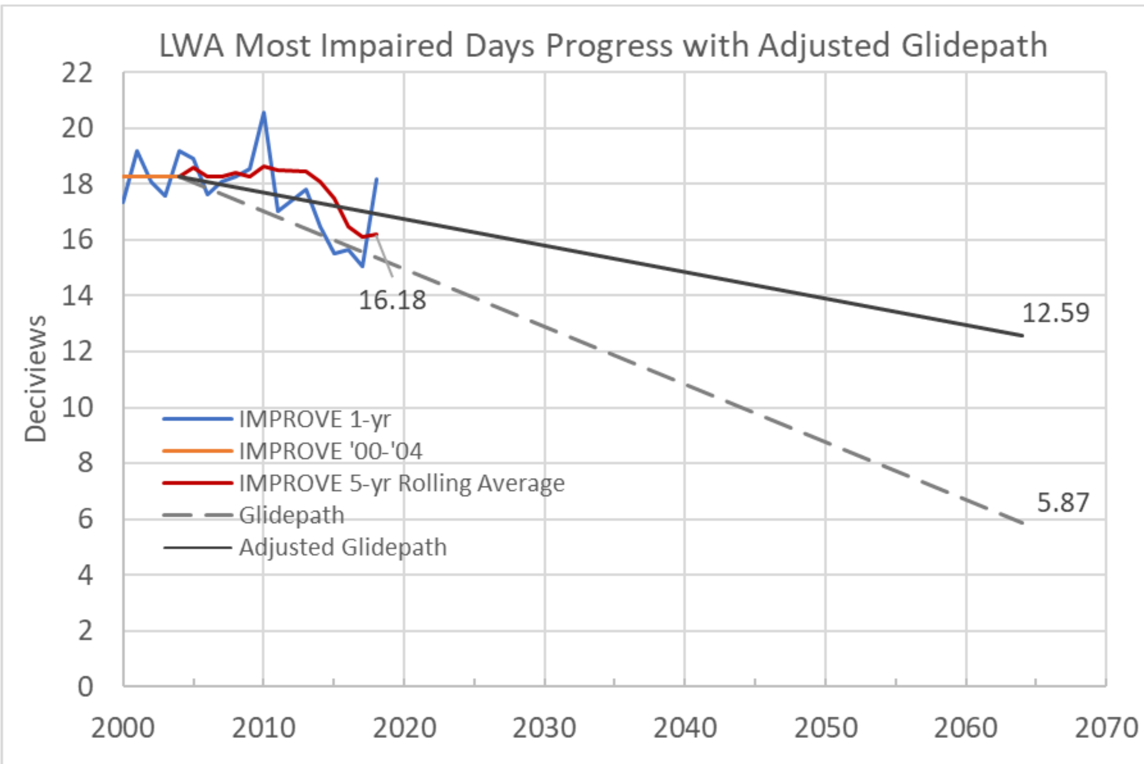

Figure 21: LWA Most Impaired Days Progress with Adjusted Glidepath from 2000–2018

Figure 21 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 21 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.

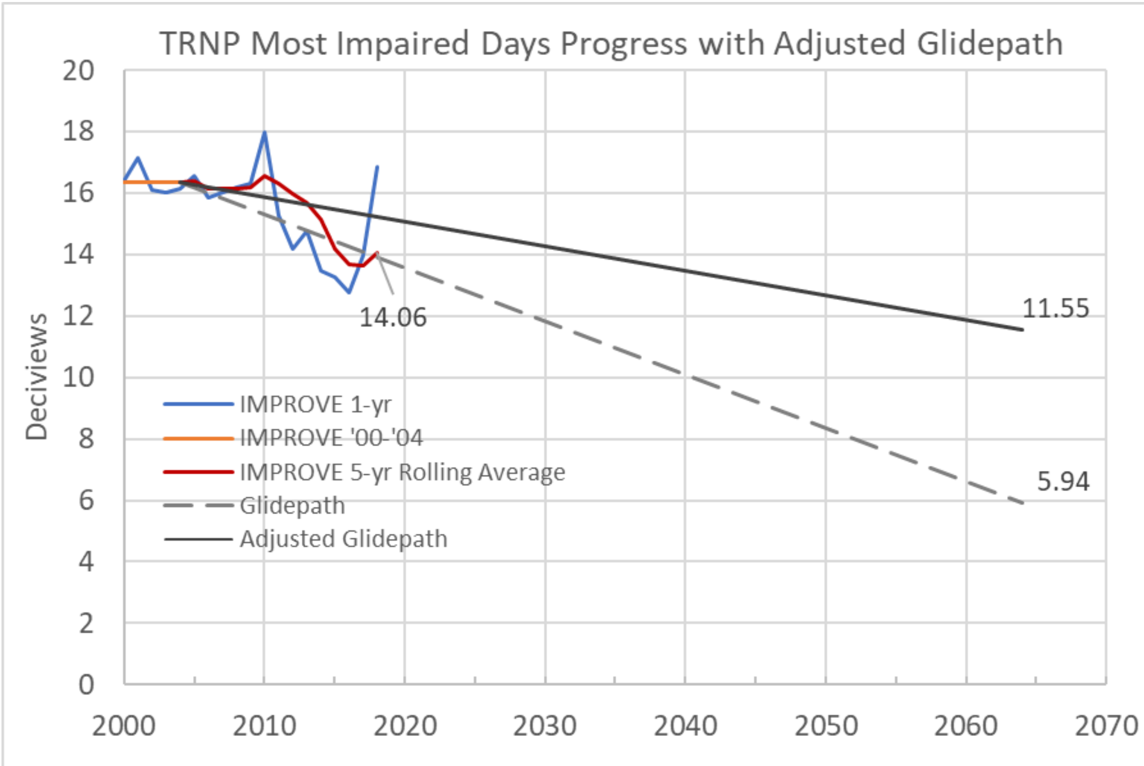

Figure 22: TRNP Most Impaired Days Progress with Adjusted Glidepath from 2000–2018

Figure 22 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 22 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[50,51] causing visibility impairment throughout much of the United States[52], 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.[53,54,55] 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.[56] Due to the extreme drought conditions throughout much of the western united states, this trend is likely to continue.[57] 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 23 and Figure 24 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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[50] Available at: https://www.nytimes.com/interactive/2020/09/24/climate/fires-worst-year-california-oregon-washington.html (Last visited December 29, 2020)
[51] Available at: https://www.washingtonpost.com/weather/2020/09/30/western-wildfire-nasa-satellite/ (Last visited December 29, 2020)
[52] Available at: https://earthobservatory.nasa.gov/images/event/146855/2020-fire-season-in-the-western-us (Last visited December 29, 2020)
[53] Available at: https://deq.nd.gov/PressReleases/2018-08-17-Wildfire-Smoke.pdf (Last visited December 29, 2020)
[54] Available at: https://deq.nd.gov/PressReleases/2018-08-09-Wildfire-Smoke.pdf (Last visited December 29, 2020)
[55] Available at: https://www.deq.nd.gov/AQ/News/2019-05-29WildfireSmokePR.pdf (Last visited December 29, 2020)
[56] Available at: https://deq.nd.gov/PressReleases/2021-07-14-637622872677570278.pdf (Last visited July 21, 2021)
[57] Available at: https://earthobservatory.nasa.gov/images/148419/western-soils-and-plants-are-parched (Last visited July 21, 2021)

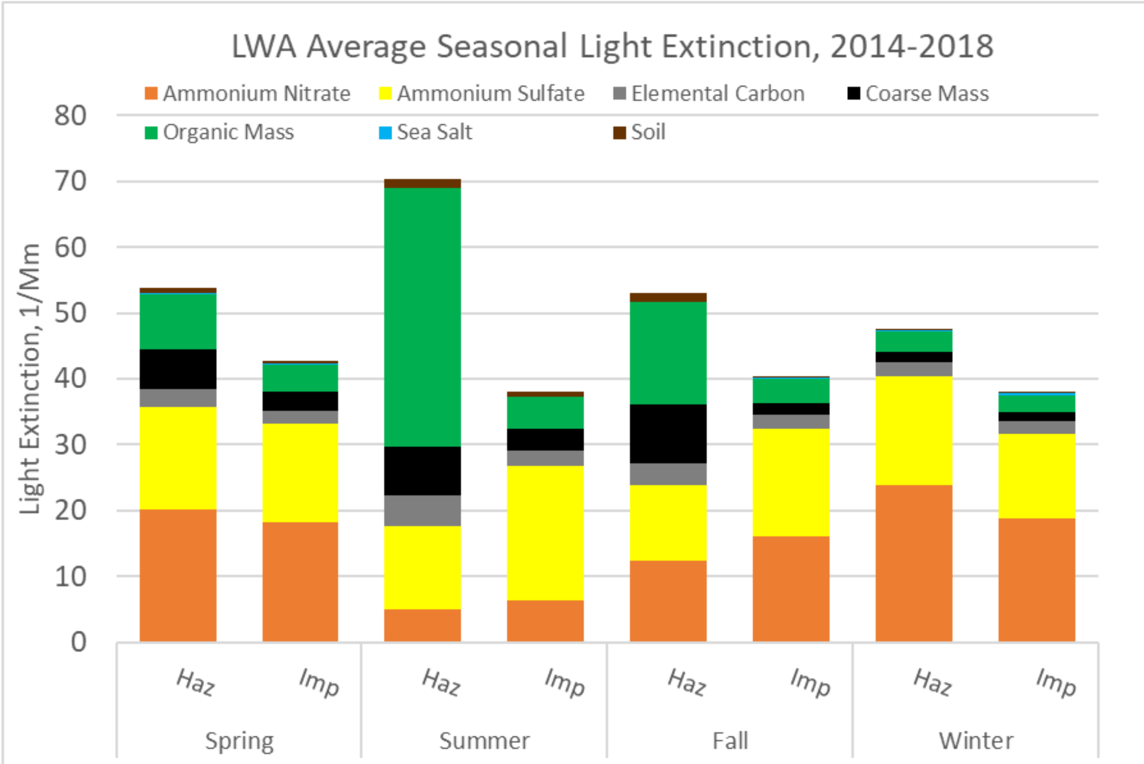

Figure 23: 2014–2018 Average Seasonal Haziest Days (Haz) and Most Impaired Days (Imp) data for LWA

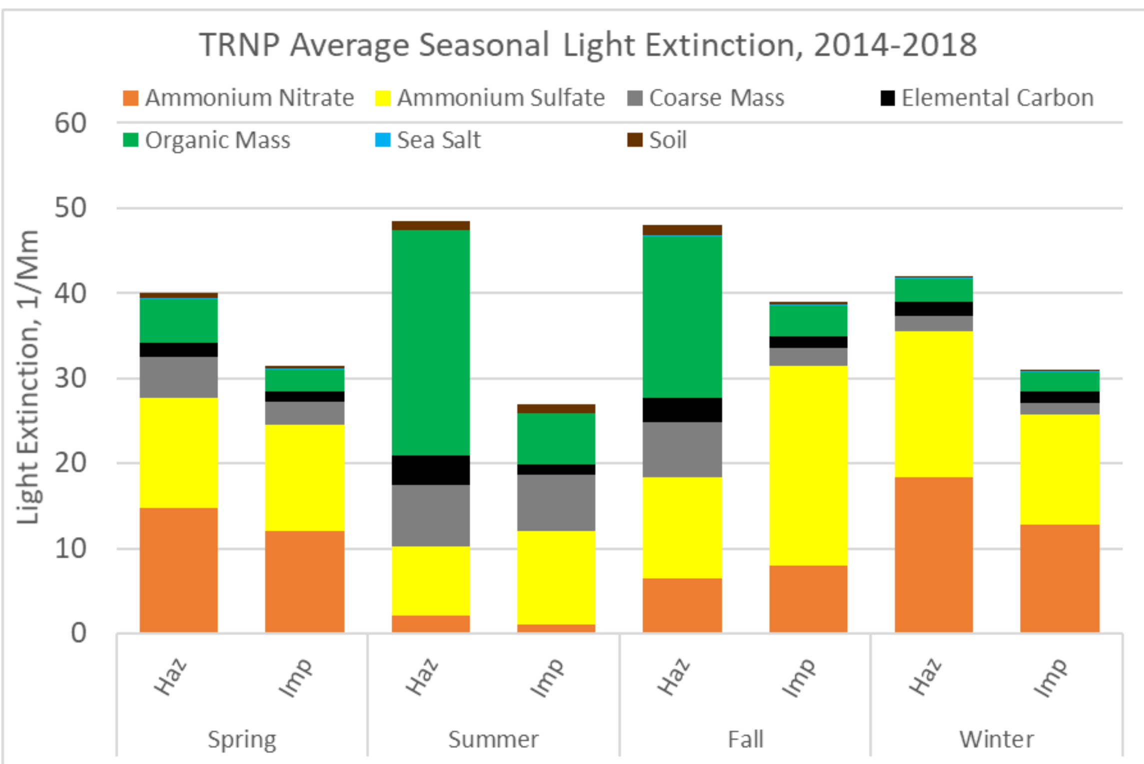

Figure 24: 2014–2018 Average Seasonal Haziest Days (Haz) and Most Impaired Days (Imp) data for TRNP

There is no distinction between a diminished visual experience caused by anthropogenic sources or natural events[58], 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.[59,60] 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).

[58] 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.
[59] 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)
[60] 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.[61] 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.[62] 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
Wildfire	17	32	600	45	288	242
Total	**63,965**	**256,235**	**899,707**	**45,070**	**211,097**	**52,204**

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

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

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[63] (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.[64] 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
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**

[63] 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.

[64] Available at:
https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/RepBase_2028_CAMx_v3.pdf

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 25.

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)

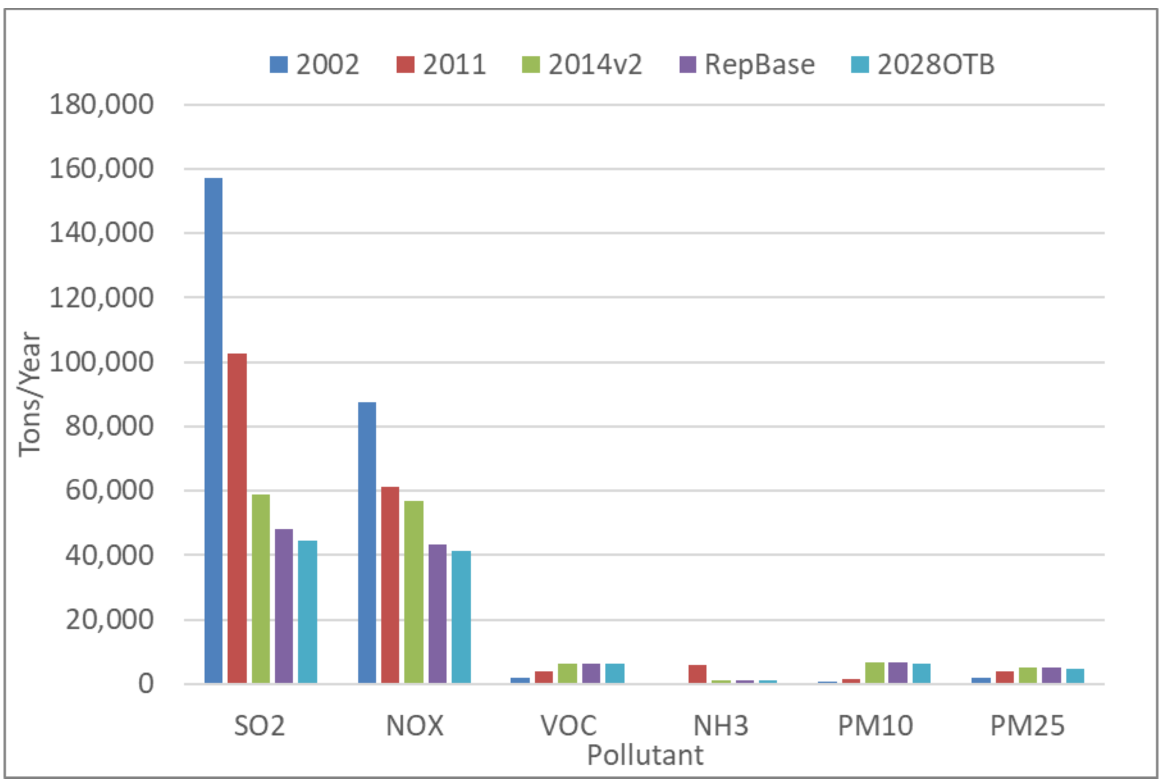

Figure 25: North Dakota Point Source Emissions

As displayed in Table 19 and in Figure 25, 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
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 26 displays the significant progress North Dakota has made to reduce impacts from these pollutants.

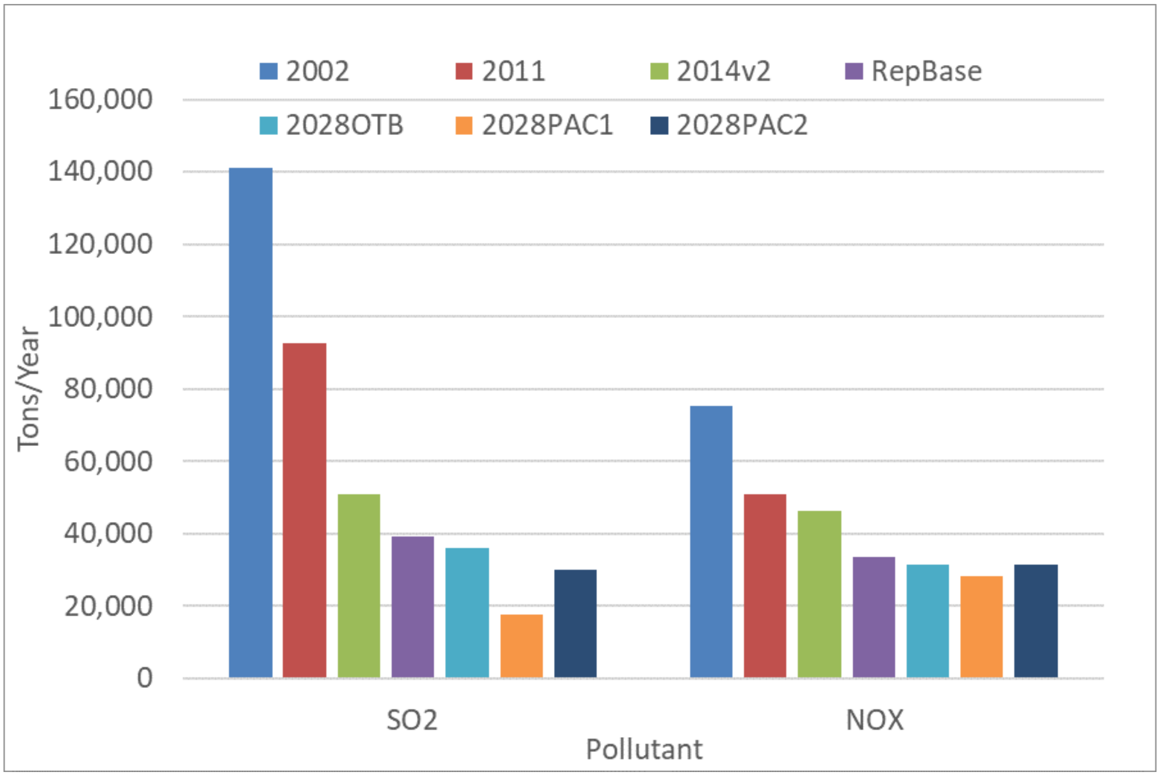

Figure 26: North Dakota coal fired EGU NO_X and SO_2 Emissions

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
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

Facility	Unit	2028 Projected Emissions (tons) [A]	Representative Annual Performance Rate (lb/MMBtu)	Emissions Limit [B]	Control Device
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™
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
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 27.

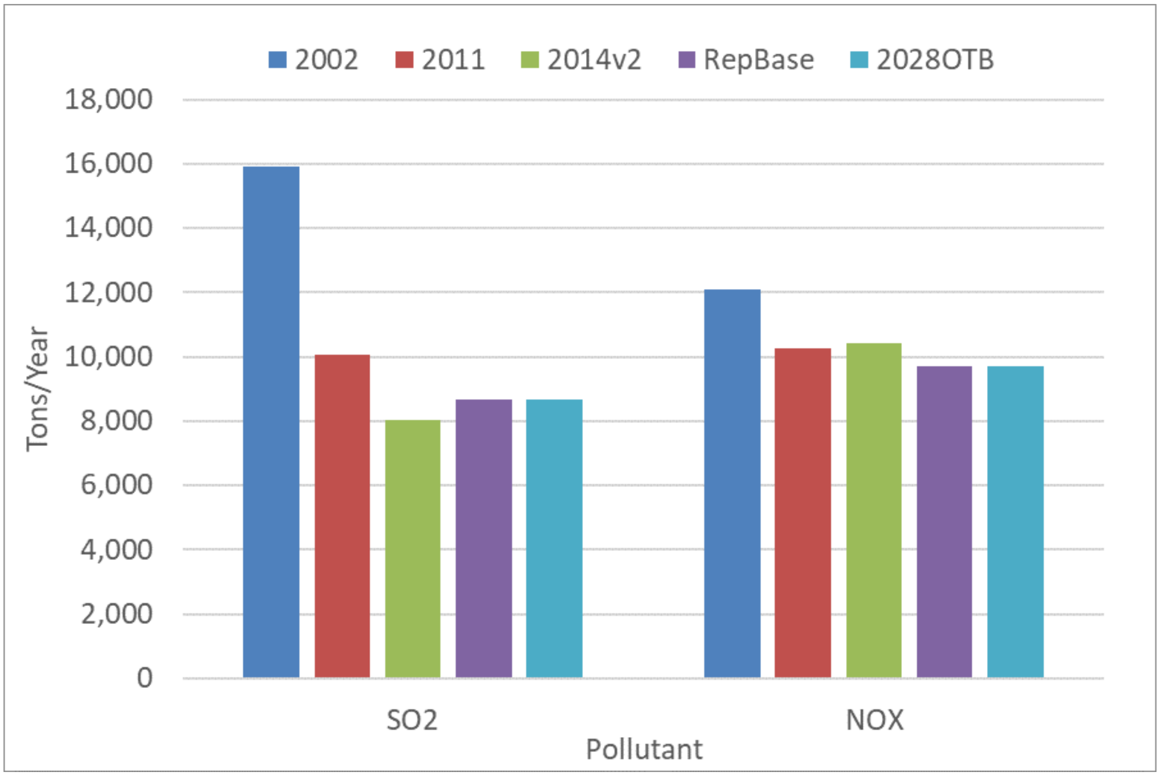

Figure 27: North Dakota non-EGU Point Source NO_X and SO_2 Emissions

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 28.

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, $PM_{2.5} \approx$ FPM
[C] For 2002 and 2011, $PM_{10} \approx$ CPM

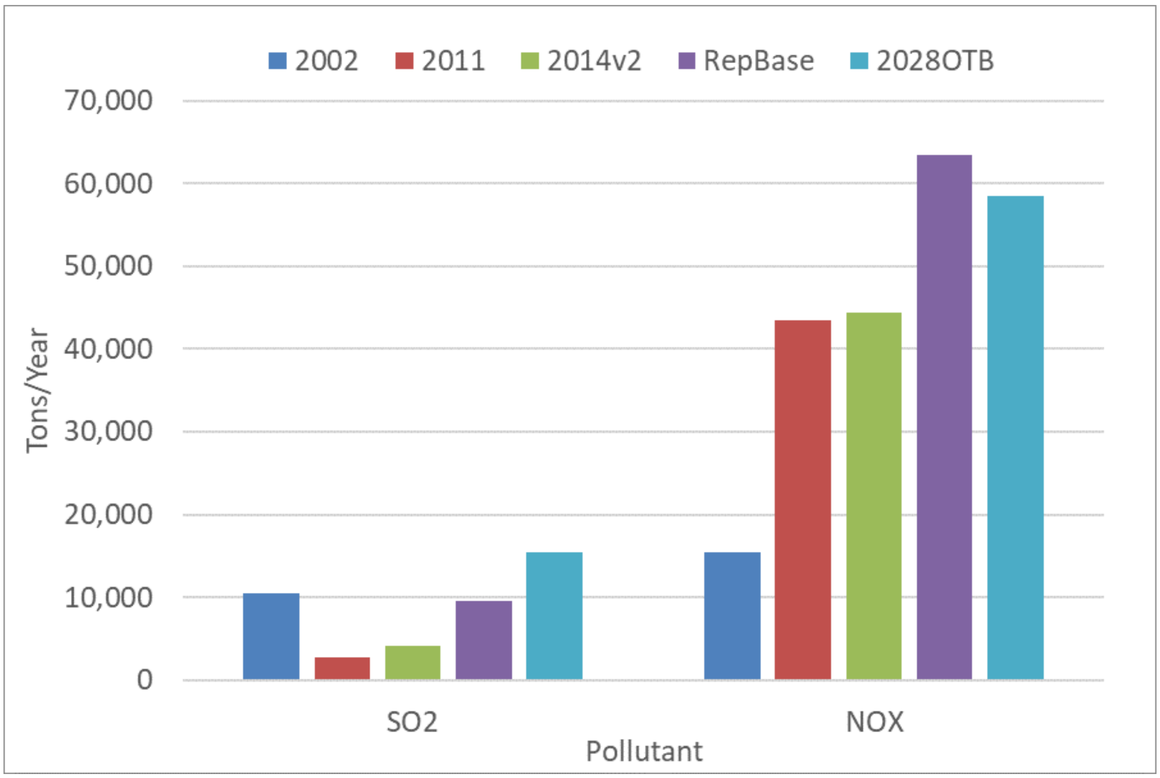

Figure 28: North Dakota Area and Non-Point Source NO_X and SO_2 Emissions

As detailed in Section 4.3.1 and as shown in Figure 29, 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.

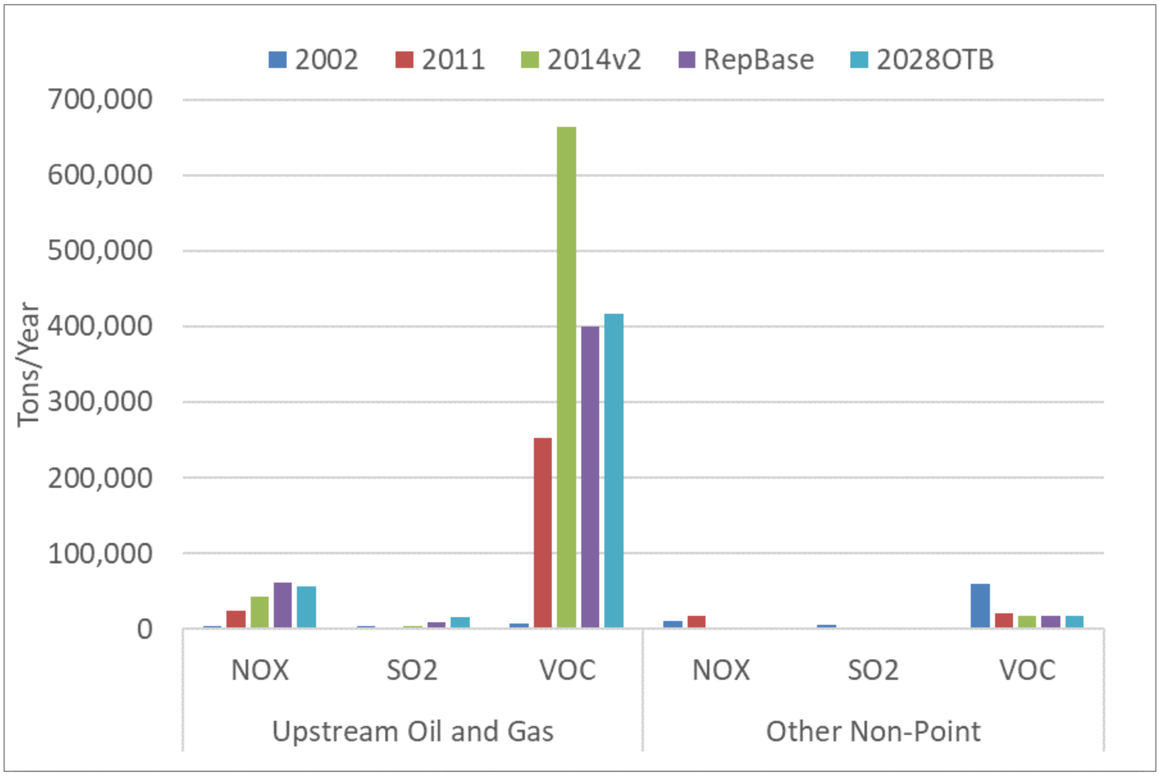

Figure 29: North Dakota Upstream Oil and Gas and Other Non-Point Emissions

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 30. 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 30.

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.

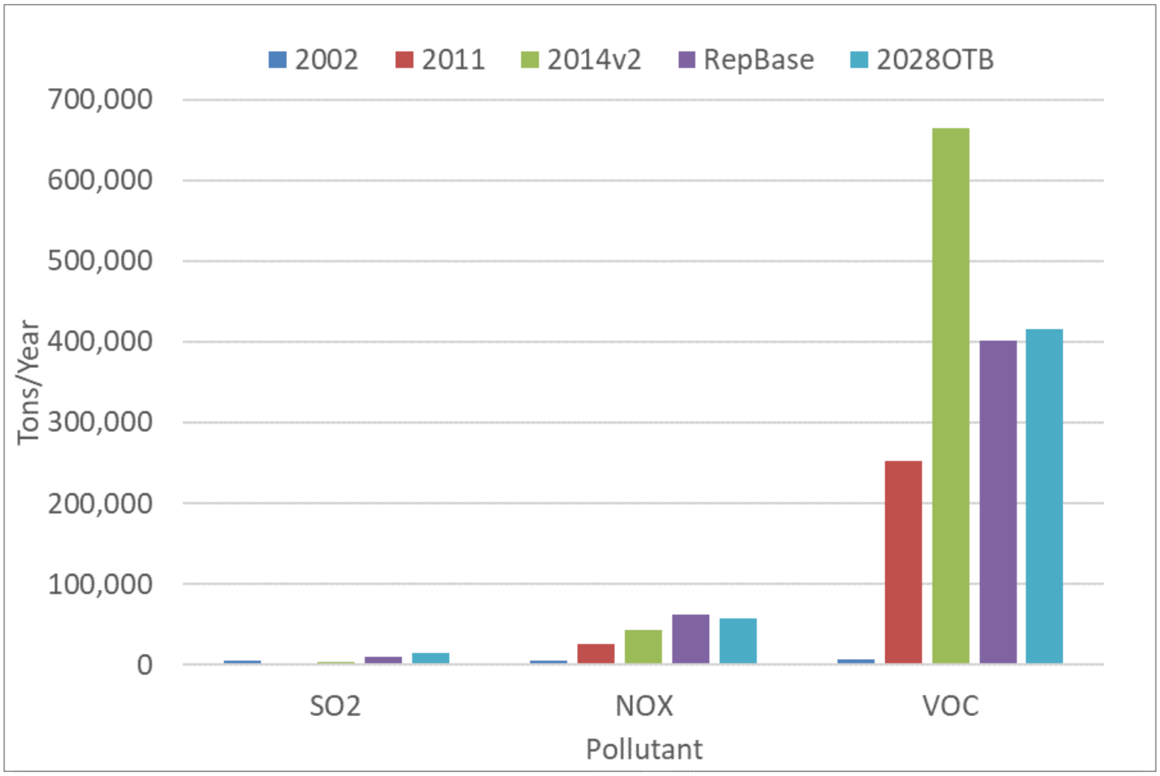

Figure 30: North Dakota Upstream Oil and Gas SO_2, NO_X, and VOC Emissions

As is displayed in Table 27 and Figure 30, 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 31. 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."*[65] A memorandum which discusses detailed information regarding the baseline inventory and future year inventory was also developed to support the WRAP states.[66] 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.

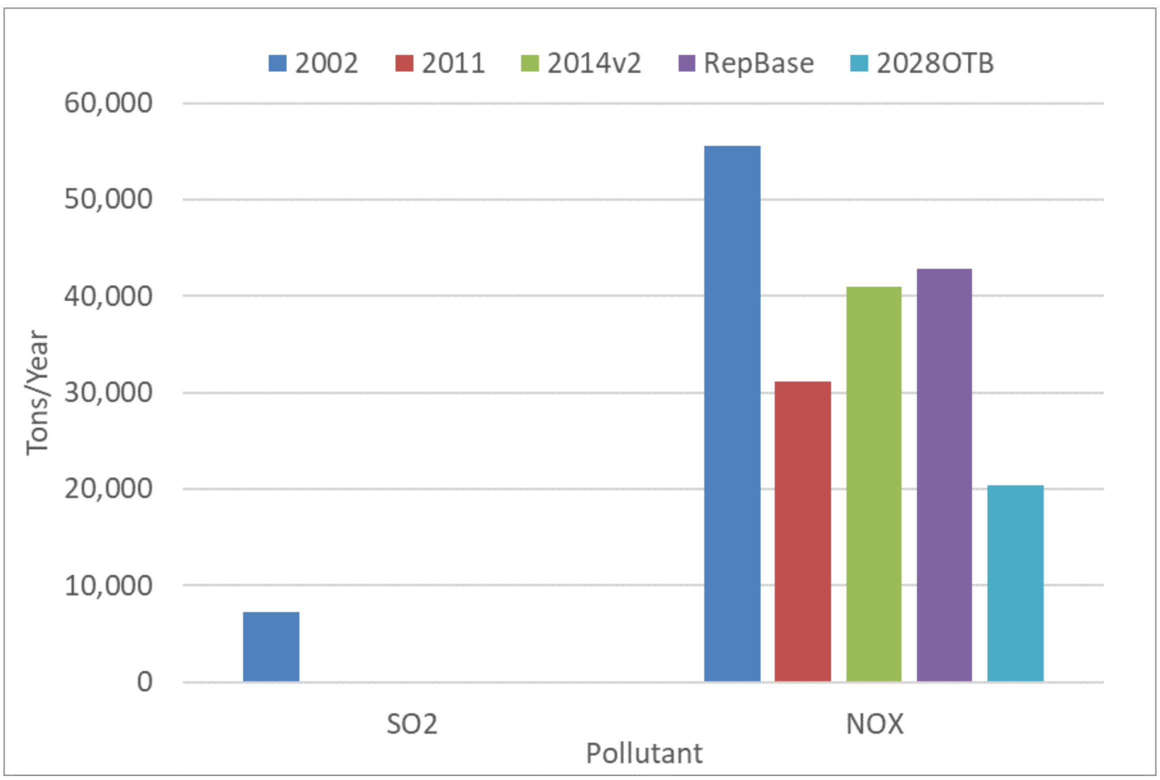

Figure 31: North Dakota Non-Road Mobile NO_X and SO_2 Emissions

[65] Available at: http://views.cira.colostate.edu/wiki/wiki/11203/mobile-source-emissions-inventory-projections-project (Last visited December 28, 2020)
[66] 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 31. 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 32. This information was prepared by WRAP for use in regional haze planning and modeling.[67] A memorandum which discusses detailed information regarding the baseline inventory and future year inventory was also developed to support the WRAP states.[68] 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

[67] Available at: http://views.cira.colostate.edu/wiki/wiki/11203/mobile-source-emissions-inventory-projections-project (Last visited December 28, 2020)
[68] Available at: https://views.cira.colostate.edu/docs/wrap/mseipp/WRAP_MSEI_Summary_Memo_13Mar2020.pdf (Last visited December 28, 2020)

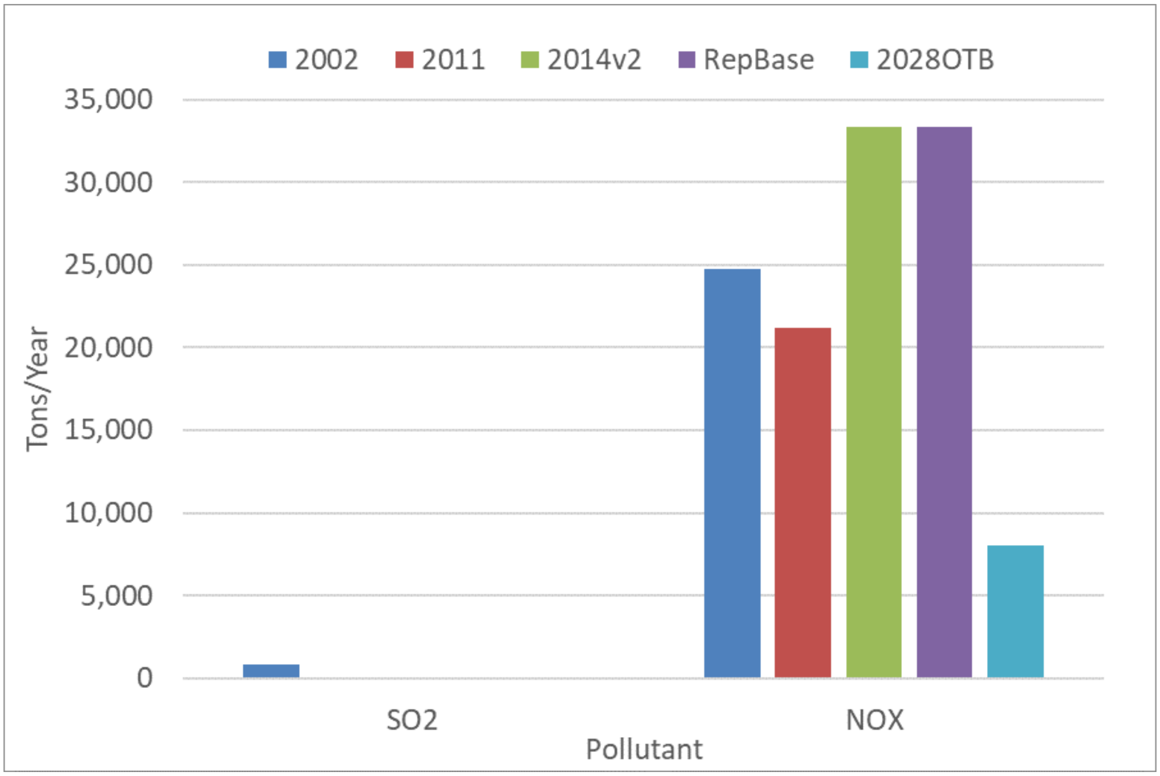

Figure 32: North Dakota On-Road Mobile NO_X and SO_2 Emissions

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 32. 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 33. 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.[69]

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**

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

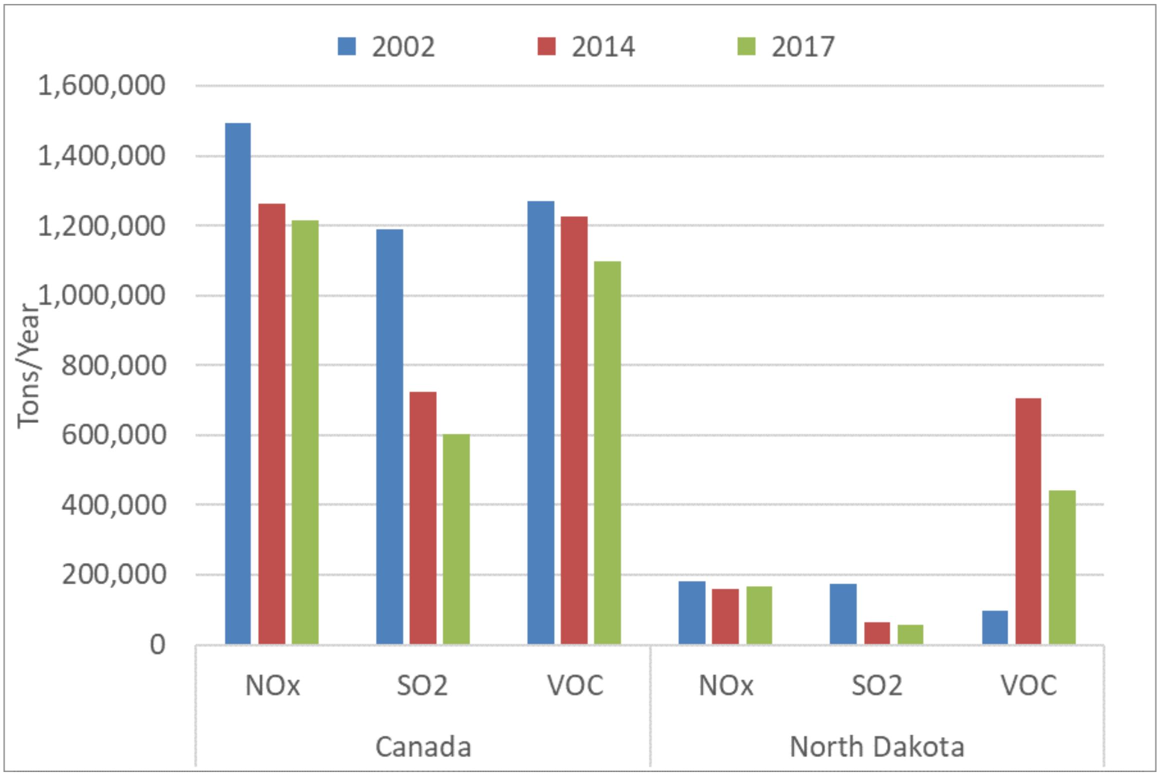

Figure 33: Anthropogenic Emissions from the Four Combined Canadian Provinces and North Dakota

4.7.1 Nearby Canadian Coal fired EGUs

Table 31 and Figure 34 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 35 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 34 shows the magnitude of the reductions achieved in North Dakota since 2002 as compared to the Canadian EGUs.

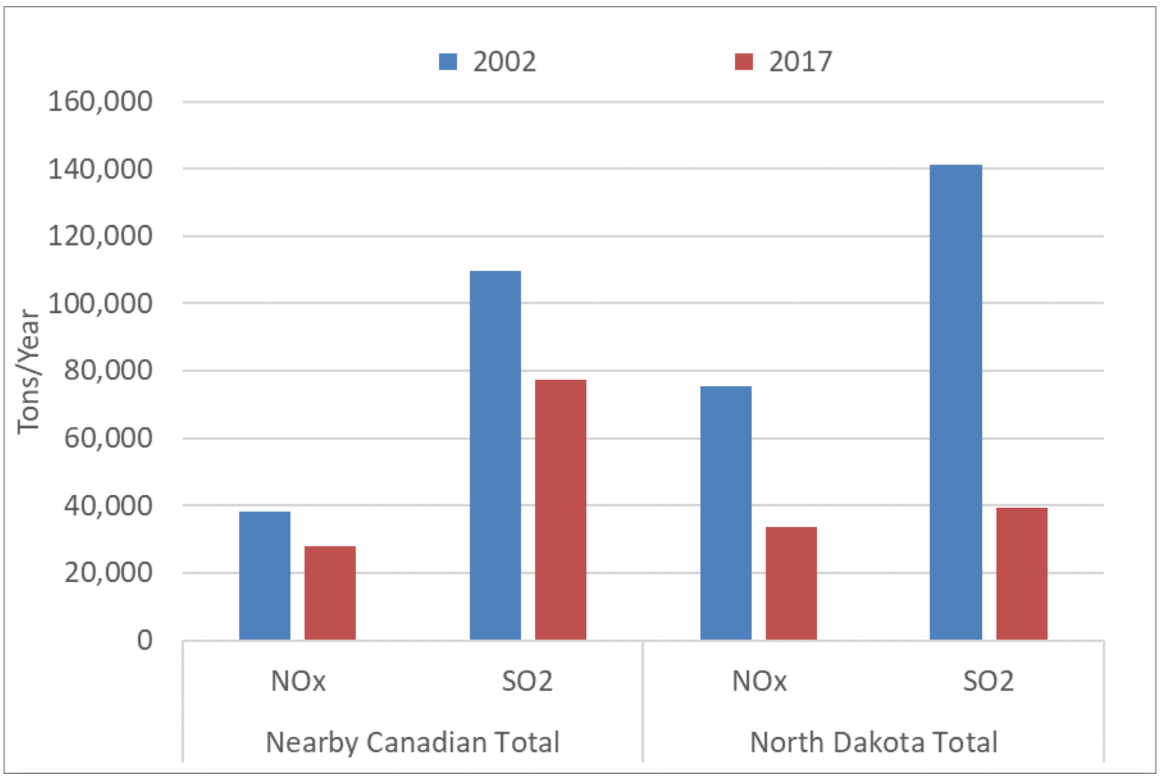

Figure 34: Nearby Canadian and North Dakota Coal fired EGU Emissions (tons/year)

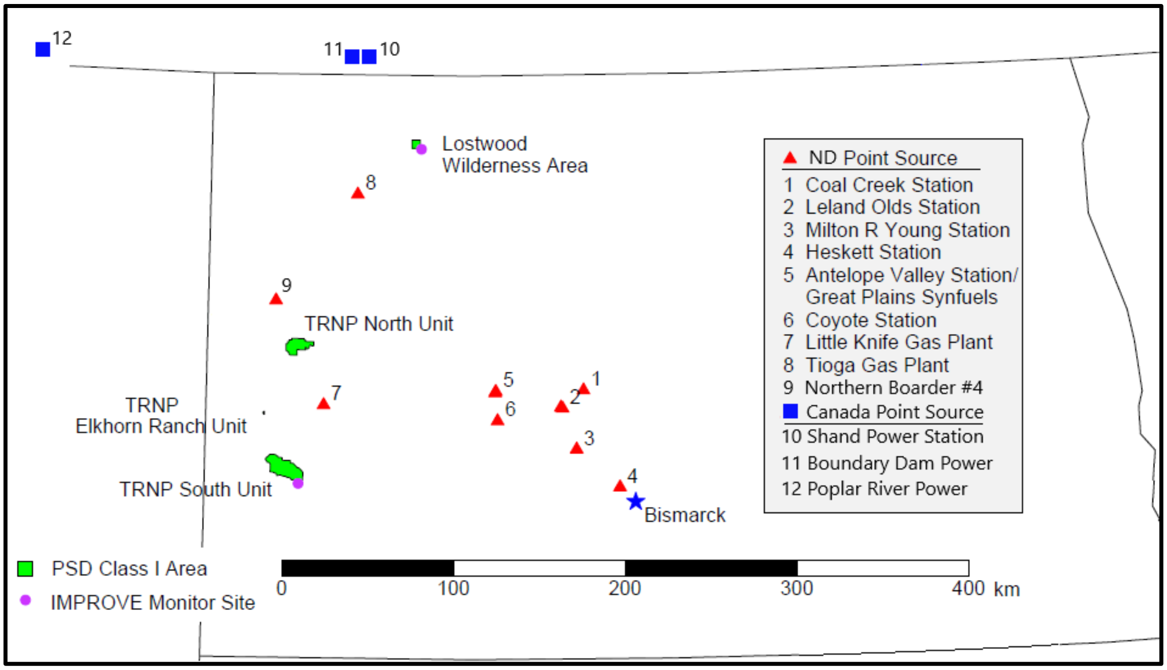

Figure 35: North Dakota Four Factor Sources and Nearby Canadian Coal fired Power Plants

4.7.2 Canadian Upstream Oil and Gas

Table 32 and Figure 36 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.[70] 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.

[70] 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.[71] The oil sands are primarily located in Alberta, northeast of Edmonton.[72]

[71] Available at: https://www.nrcan.gc.ca/our-natural-resources/energy-sources-distribution/clean-fossil-fuels/what-are-oil-sands/18089
[72] Available at: http://history.alberta.ca/energyheritage/sands/origins/the-geology-of-the-oil-sands/the-location-of-oil-sands.aspx

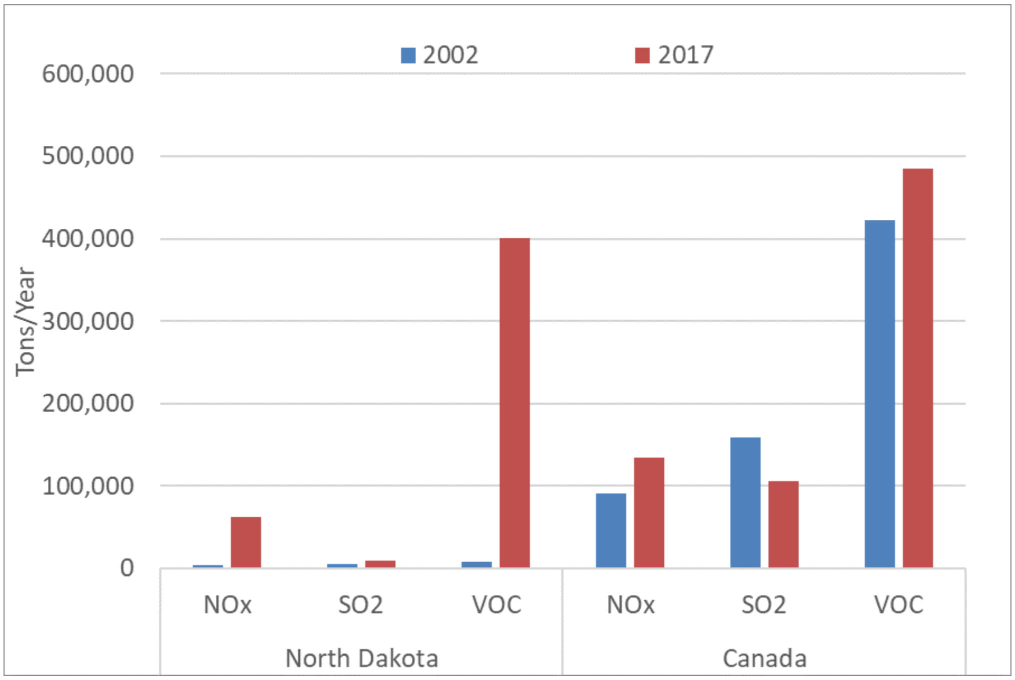

Figure 36: Canadian and North Dakota Upstream Oil and Gas Emissions (tons/year)

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.[73] 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.[74]

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 37. Figure 37 includes $PM_{2.5}$ from both the 2014v2 and RepBase inventories. When comparing 2014v2 to RepBase fire emission inventories, it is easily noticed that 2014 was a low fire activity year and the RepBase inventory

[73] Available at: ftp://newftp.epa.gov/air/nei/2014/doc/2014v2_supportingdata/wild_and_prescribed_fires/ (Last visited August 23, 2018)
[74] Available at: https://www.wrapair2.org/pdf/fswg_rhp_fire-ei_final_report_20200519_FINAL.PDF (Last visited December 30, 2020)

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

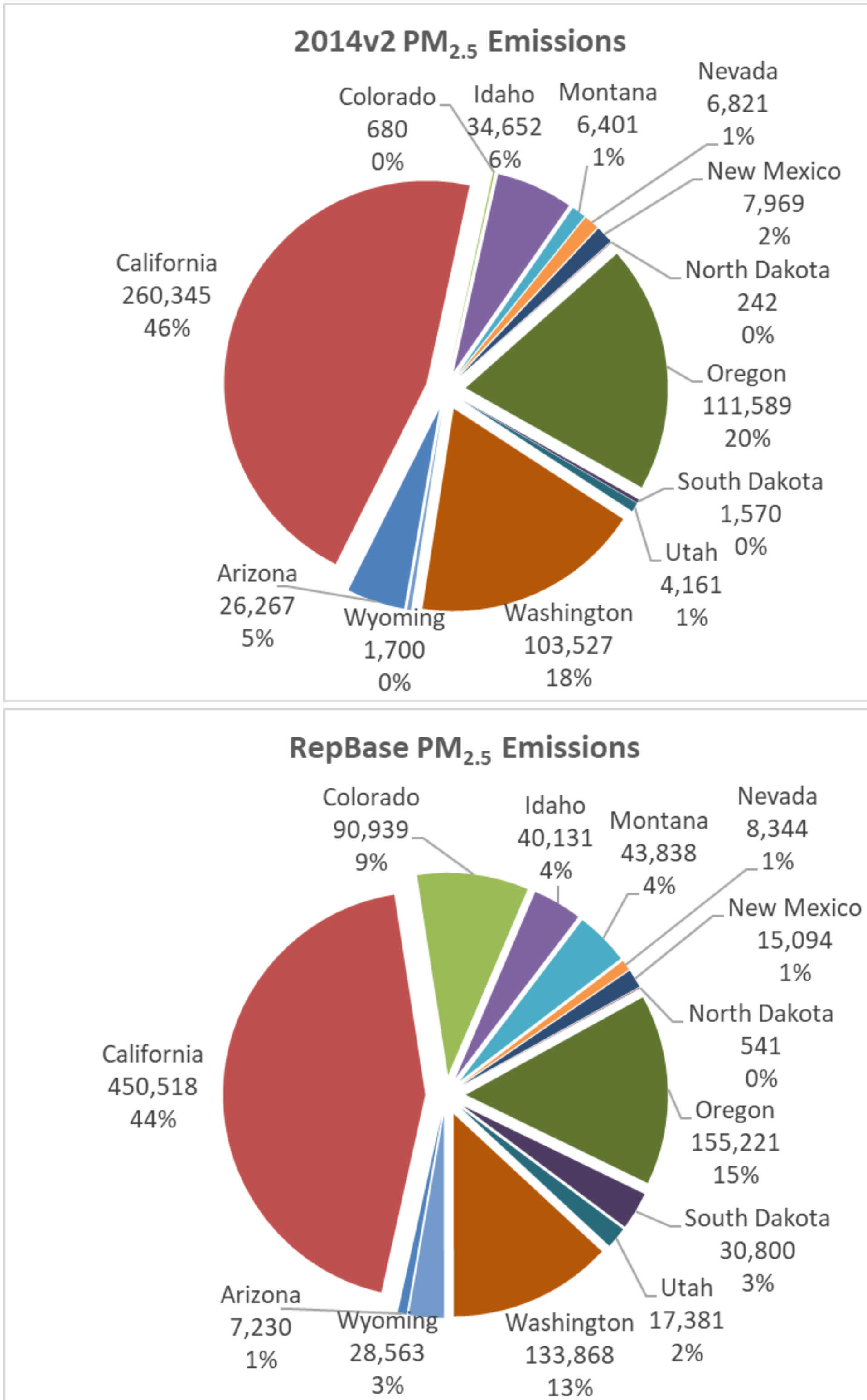

Figure 37: $PM_{2.5}$ Emissions, in Tons, from WRAP States. The Top Pie Chart Contains 2014v2 Emissions. The Bottom Pie Chart Contains RepBase Emissions.

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 on the MIDs (Section 5.1.1). 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 (Section 5.2.1 through Section 5.2.10). 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.[75] These products supported 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 38 displays the annual average light extinction information for LWA and Figure 39 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.

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

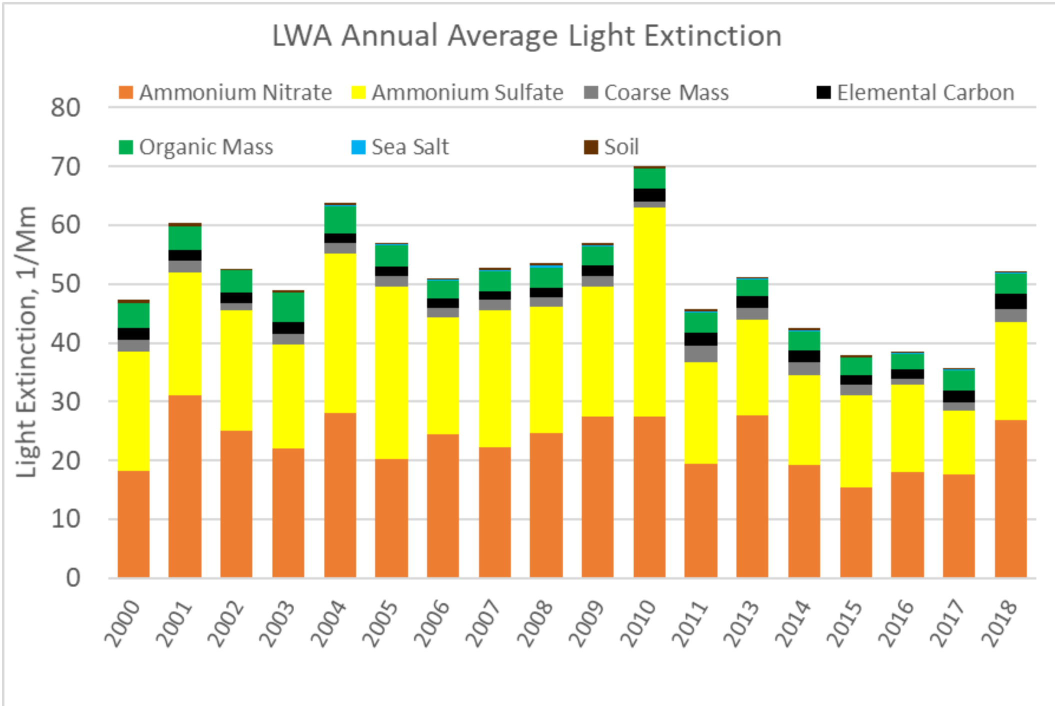

Figure 38: Annual Average Light Extinction at LWA for the Most Impaired Days from 2000–2018.[76]

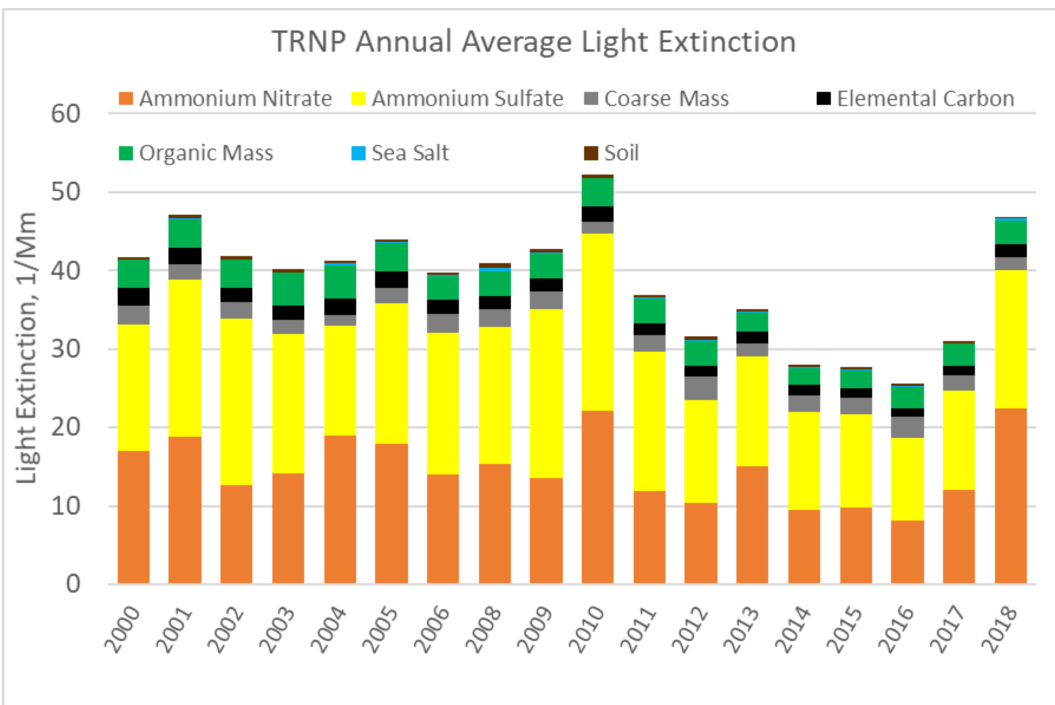

Figure 39: Annual Average Light Extinction at TRNP for the Most Impaired Days from 2000–2018.[77]

[76] Available at: https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx
[77] 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 40 displays this information for LWA and Figure 41 displays this information for TRNP.

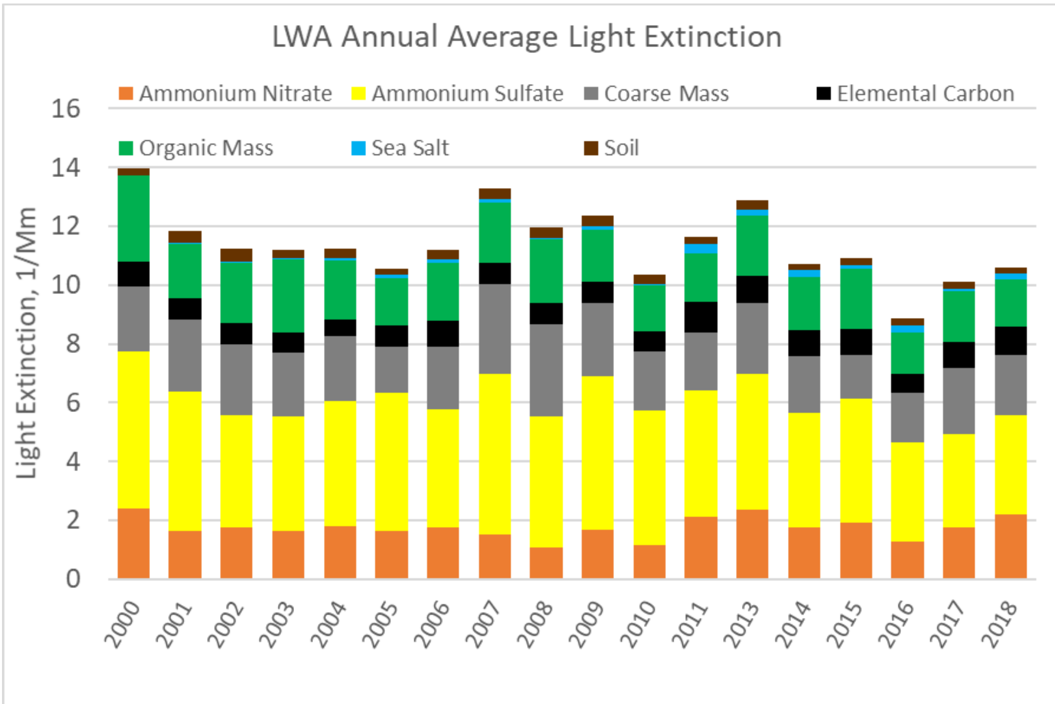

Figure 40: Annual Average Light Extinction at LWA for the Clearest Days from 2000–2018.[78]

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

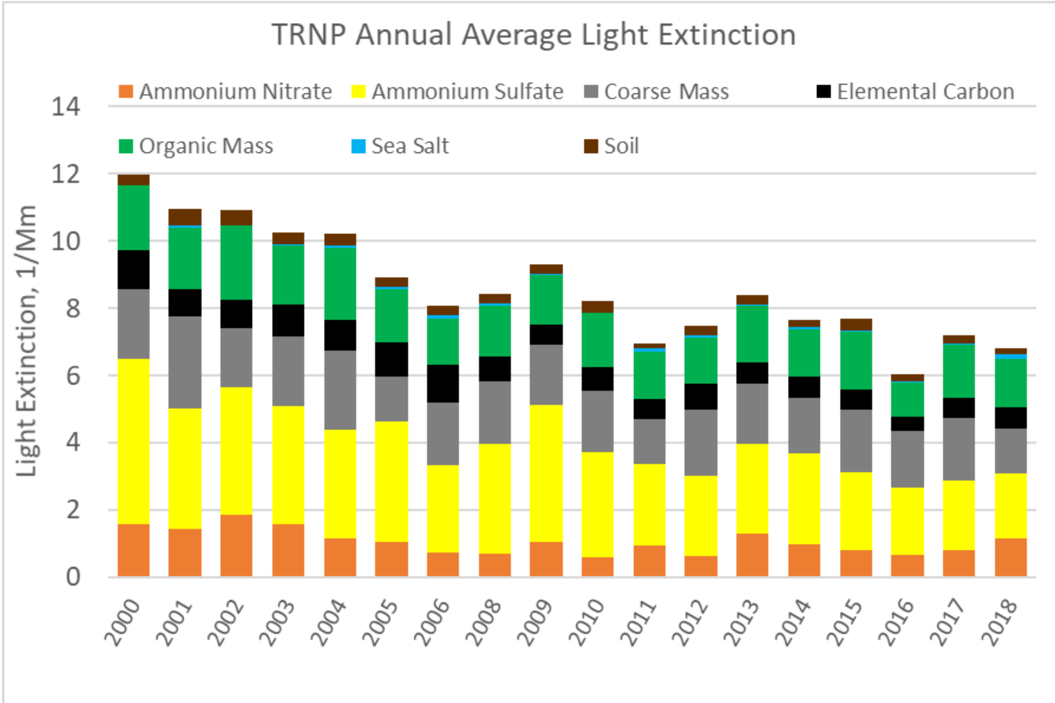

Figure 41: Annual Average Light Extinction at TRNP for the Clearest Days from 2000–2018.[79]

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 report detailing available emissions reduction measures in consideration of the four statutory factors. The facilities required to submit these reports were selected based on 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 chosen based on their proximity to CIAs and 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 report detailing available emissions reduction measures. 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 report detailing available emissions reduction measures 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 report 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

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

down on May 1, 2017. Therefore, a letter requesting a report was not 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 report 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 report on emissions reductions measures was sent

[E] No letter requesting a report on emissions reductions measures 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 42 submitted a report on emissions reductions measures in consideration of the four statutory factors 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 this report. 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).

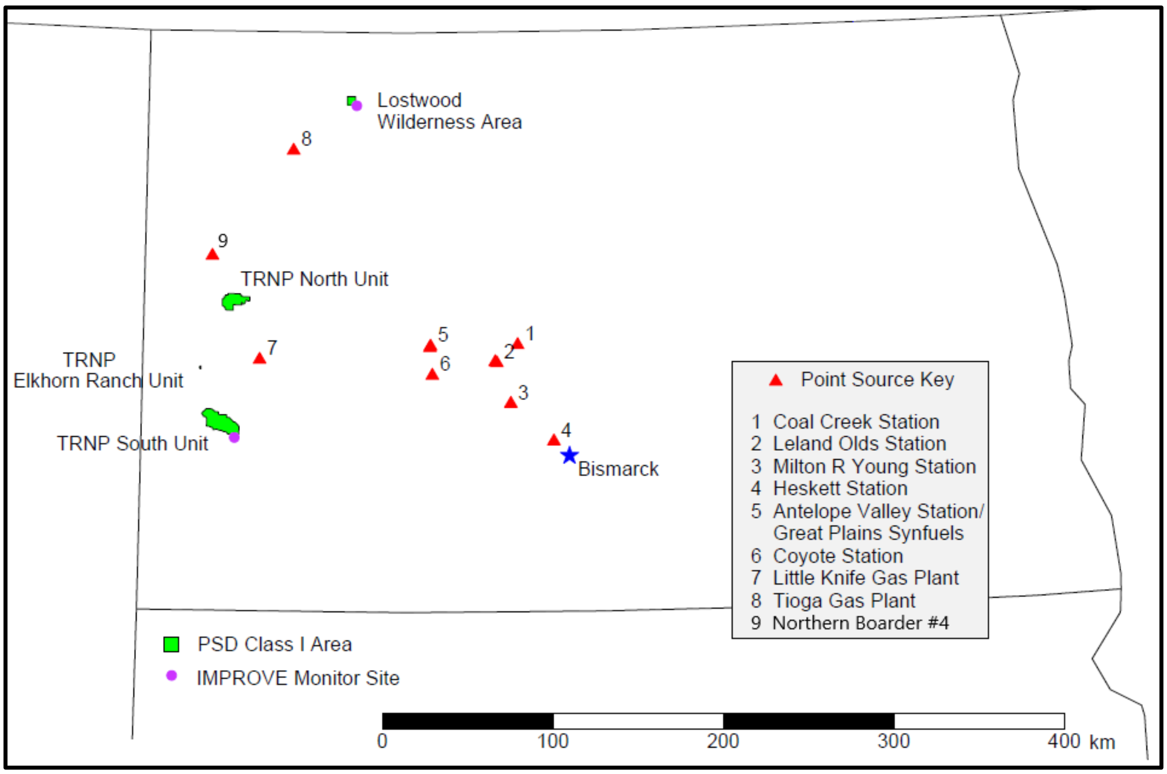

Figure 42: Locations of the point sources that submitted a four factors analysis as part of North Dakota's long-term strategy planning.

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 an evaluation of additional potential control measures.[80] The letter required that the report be submitted to the Department on or before January 31, 2019. Otter Tail Power Company submitted their original report to the Department on January 30, 2019. The Department submitted comments regarding areas of concern in the report to Otter Tail Power Company on March 20, 2019.[81] A revised report was provided by Otter Tail Power Company on May 10, 2019. An additional report from Otter Tail Power Company was submitted to the Department on January 6, 2020, containing an update to the costs for the installation and operation of selected non-catalytic reduction (SNCR) and rich reagent injection (RRI). A final Otter Tail Power Company report was submitted to the Department on June 8, 2020, containing an update to 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.

The Department evaluated the information submitted by Otter Tail Power Company and conducted its own independent four factor analysis to determine the appropriate control requirements for Coyote Station. Based on the Department's evaluation of all sources of information, future operations and emissions profiles are expected to remain consistent with current conditions. Additionally, the control cost estimations presented in the Department's four-factor analysis are accurate and consistent with Department experience based on past analysis of source control costs. The Department's four-factor analysis of Coyote Station's additional control measures evaluation can be found in Appendix A.1.

The Department's consideration and application of the four factors (as set forth in Appendix A.1) are summarized as follows. Time necessary for compliance was determined not to be significant enough to discount any control measures. Energy and non-air quality environmental impacts were determined not to be significant enough to eliminate any of the control measures. Remaining useful life was determined by the Department to not eliminate any control measures. Therefore, cost of compliance was most heavily considered by the Department in selection of additional controls for modeling review and to determine if these controls are appropriate and necessary to demonstrate reasonable progress.

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 consideration of the four factors. 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 2028 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

[80] Appendix B.1.a.
[81] Appendix B.1.c.

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

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 3.1 and 6.1.1), 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 an evaluation of additional potential control measures.[82] The letter required that the report be submitted to the Department on or before January 31, 2019. Basin's original report was submitted to the Department on January 31, 2019.[83] The Department provided comments to address areas of concern in Basin's report on June 20, 2019.[84] Basin submitted a response to the Department's comments on July 12, 2019.[85] A copy of each submittal by Basin AVS can be found in Appendix B.2.b.

The Department evaluated the information submitted by Basin and conducted its own independent four factor analysis to determine the appropriate control requirements for AVS. Based on the Department's evaluation of all sources of information, future operations and emissions profiles are expected to remain consistent with current conditions. Additionally, the control cost estimations presented in the Department's four-factor analysis are accurate and consistent with Department experience based on past analysis of source control costs. The Department's four-factor analysis of Basin AVS's additional control measures evaluation can be found in Appendix A.2.

The Department's consideration and application of the four factors (as set forth in Appendix A.2) are summarized as follows. Time necessary for compliance was determined not to be significant enough to discount any control options. Energy and non-air quality environmental impacts were determined not to be significant enough to eliminate any of the control options. Remaining useful life was determined by the Department to not eliminate any control options. Therefore, cost of compliance was most heavily considered by the Department in selection of additional controls for modeling review and to determine if these controls are appropriate and necessary to demonstrate reasonable progress.

Additional SO_2 controls were selected to be included in the 2028 potential additional controls visibility modeling based on the Department's consideration of the four factors. 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 2028 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.

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[82] Appendix B.2.a.
[83] Appendix B.2.b.
[84] Appendix B.2.c.
[85] Appendix B.2.c.

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 3.1 and 6.1.1), 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 an evaluation of additional potential control measures. [86] The letter required that Basin's report be submitted to the Department on or before January 31, 2019. Basin's original report was submitted to the Department on January 31, 2019.[87] The Department provided comments to address areas of concern in Basin's report on April 15 and April 22, 2019.[88] Basin submitted a response to the Department's comments on July 26, 2019.[89] On November 20, 2019, Basin submitted an update to the steam costs that were used to develop the operating costs for the technically feasible NO_X reduction technologies.[90] A copy of each submittal by Basin LOS can be found in Appendix B.3.b.

The Department evaluated the information submitted by Basin and conducted its own independent four factor analysis to determine the appropriate control requirements for LOS. Based on the Department's evaluation of all sources of information, future operations and emissions profiles are expected to remain

[86] Appendix B.3.a.
[87] Appendix B.3.b.
[88] Appendix B.3.c.
[89] Appendix B.3.c.
[90] Appendix B.3.b., PDF page 504.

consistent with current conditions. Additionally, the control cost estimations presented in the Department's four-factor analysis are accurate and consistent with Department experience based on past analysis of source control costs. The Department's four-factor analysis of Basin LOS's additional control measures evaluation can be found in Appendix A.3.

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.[91] The Department's consideration and application of the four factors (as set forth in Appendix A.3) are summarized as follows. Time necessary for compliance was determined not to be significant enough to discount any control options. Energy and non-air quality environmental impacts were determined not to be significant enough to eliminate any of the control options. Remaining useful life was determined by the Department to not eliminate any control options. Therefore, cost of compliance was most heavily considered by the Department in selection of additional controls for modeling review and to determine if these controls are appropriate and necessary to demonstrate reasonable progress. The Department's 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 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.

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 an evaluation of additional potential control measures.[92] The letter required that Great River Energy's report be

[91] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, Appendix B.4.
[92] Appendix B.4.a., PDF page 573.

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.[93] On September 12, 2019, Great River Energy submitted an updated BART analysis associated with the first round of Regional Haze planning.[94]

5.2.4.1 CCS SO_2 Emissions

After submission of the updated NOx BART analysis (Section 8), Great River Energy CCS completed an evaluation of additional potential control measures. CCS submitted the report for the second round of Regional Haze planning on December 23, 2019.[95] Both SO_2 and NOx were addressed in the submittal.

The Department evaluated the information submitted by CCS and conducted its own independent four factor analysis to determine the appropriate control requirements for CCS. Based on the Department's evaluation of all sources of information, future operations and SO_2 emissions profiles are expected to remain consistent with current conditions. Additionally, the control cost estimations presented in the Department's four-factor analysis are accurate and consistent with Department experience based on past analysis of source control costs. The Department's four-factor analysis of CCS's additional control measures evaluation can be found in Appendix A.4.

As outlined in CCS's submittal and as requested, 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 pending change in ownership the improvements are no longer being considered with this SIP revision.[96] These potential improvements were voluntary and are not necessary since the Department 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

[93] Appendix B.4.c., PDF page 1082.
[94] Appendix B.4.b., PDF page 576.
[95] Appendix B.4.b., PDF page 1038
[96] See Section 8 for details on ownership change.

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 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 an evaluation of additional potential control measures.[97] The letter required that Minnkota's report be submitted to the Department on or before January 31, 2019. Minnkota's original report was submitted to the Department on January 31, 2019.[98] The Department provided comments regarding areas of concern in the report to Minnkota on March 18, 2019.[99] Minnkota submitted a response to the Department's comments, along with a revised report, on May 29, 2019.[100] A copy of each submittal by MRYS can be found in Appendix B.5.b.

The Department evaluated the information submitted by Minnkota and conducted its own independent four factor analysis to determine the appropriate control requirements for MRYS. Based on the Department's evaluation of all sources of information, future operations and emissions profiles are expected to remain consistent with current conditions. Additionally, the control cost estimations presented in the Department's four-factor analysis are accurate and consistent with Department experience based on past analysis of source control costs. The Department's four-factor analysis of Minnkota's additional control measures evaluation can be found in Appendix A.5.

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.[101] 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.[102,103] 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.[104] 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.

The Department's consideration and application of the four factors (as set forth in Appendix A.5) are summarized as follows. Time necessary for compliance was determined not to be significant enough to

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[97] Appendix B.5.a.
[98] Appendix B.5.b.
[99] Appendix B.5.c.
[100] Appendix. B.5.b.
[101] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 74.
[102] Available at: https://www.epa.gov/enforcement/minnkota-power-cooperative-and-square-butte-electric-cooperative-settlement (Last visited December 28, 2020)
[103] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, Appendix B.4, p.16-19.
[104] North Dakota State Implementation Plan for Regional Haze, March 3, 2010, p. 71.

discount any control options. Energy and non-air quality environmental impacts were determined not to be significant enough to eliminate any of the control options. Remaining useful life was determined by the Department to not eliminate any control options. Therefore, cost of compliance was most heavily considered by the Department in selection of additional controls for modeling review and to determine if these controls are appropriate and necessary to demonstrate reasonable progress. The Department's 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 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 an evaluation of potential additional control measures.[105] The letter required that MDU's report be submitted to the Department on or before January 31, 2019. MDU submitted the report to the Department on January 31, 2019.[106] A copy of the submittal by Heskett can be found in Appendix B.6.b.

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.[107] MDU plans to replace Unit 1 and Unit 2 with a new natural gas unit in early 2023. The Department issued MDU a permit to construct for the new natural gas unit. The Department determined that it was not necessary to conduct a four-factor analysis due to the announced shutdown of the Unit 1 and Unit 2 at Heskett. 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 received notice on March 9, 2022, that Unit 1 and Unit 2 at Heskett station have been permanently retired and will undergo decommissioning. Unit 1 shut down February 25, 2022, and Unit 2 shut down on January 31, 2022.[108]

[105] Appendix B.6.a.
[106] Appendix B.6.b.
[107] Appendix B.6.c.
[108] Appendix A.6.

The Department included the emissions reductions from Heskett in this proposed SIP as a result of the retirement 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 an evaluation of additional control measures.[109] The letter required that Petro-Hunt's report 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.[110] 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.[111] Petro-Hunt submitted an updated report to the Department on January 25, 2019.[112] A copy of each submittal by LKGP can be found in Appendix B.7.b.

The Department evaluated the information submitted by Petro-Hunt and conducted its own independent four factor analysis to determine the appropriate control requirements for LKGP. Based on the Department's evaluation of all sources of information, future operations and emissions profiles are expected to remain consistent with current conditions. Additionally, the control cost estimations presented in the Department's four-factor analysis are accurate and consistent with Department experience in evaluating source control costs. The Department's four-factor analysis of Petro-Hunts's additional control measures evaluation can be found in Appendix A.7.

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. The Department's consideration and application of the four factors (as set forth in Appendix A.7) are summarized as follows. Time necessary for compliance was determined not to be significant enough to discount any control options. Energy and non-air quality environmental impacts were determined not to be significant enough to eliminate any of the control options. Remaining useful life was determined by the Department to not eliminate any control options. Therefore, cost of compliance was most heavily considered by the Department in selection of additional controls for modeling review and to determine if these controls are appropriate and necessary to demonstrate reasonable progress. The Department's four-factor analysis confirms LKGP has effective controls already in place. Therefore, no additional

[109] Appendix B.7.a.
[110] Appendix B.7.c.
[111] Appendix B.7.c.
[112] Appendix B.7.b.

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.[113] 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 an evaluation of additional potential control measures.[114] The letter required that Hess's report be submitted to the Department on or before January 31, 2019. Hess's original report was submitted to the Department on December 20, 2018.[115] The Department provided comments to Hess regarding areas of concern in the report on January 16, 2019.[116] Hess submitted a revised report on March 13, 2019.[117] A copy of each submittal by TGP can be found in Appendix B.8.b.

The Department evaluated the information submitted by Hess and conducted its own independent four factor analysis to determine the appropriate control requirements for TGP. Based on the Department's evaluation of all sources of information, future operations and emissions profiles are expected to remain consistent with current conditions. Additionally, the control cost estimations presented in the Department's four-factor analysis are accurate and consistent with Department experience in evaluating source control costs. The Department's four-factor analysis of Hess's additional control measures evaluation can be found in Appendix A.8.

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 (Clark Engines). On January 10, 2022, the Department and Hess TGP entered into an administrative consent agreement, Case No. 21-169 APC, to remove the non-retrofitted Clark engines before July 1, 2024, and to remove the retrofitted Clark engines from service before June 30, 2025.[118] This agreement will significantly reduce NO_X emissions from the facility. The Department's administrative consent agreement will ensure continued compliance with the 1-hour NO_2 NAAQS standards. This administrative consent agreement will also provide collateral benefits

[113] Representative emissions from Coyote, AVS, LOS, Coal Creek, and MRYS on a per unit basis.
[114] Appendix B.8.a.
[115] Appendix B.8.b.
[116] Appendix B.8.c.
[117] Appendix B.8.b.
[118] Appendix A.8

to visual air quality since emissions of NO_X will be significantly reduced. The 2028OTB emissions did not consider these reductions since they were not enforceable at the time the projections were provided and used in the various modeling exercises. The NO_X reductions from this agreement supersede the information addressed in the Department's NO_X four-factor analysis.

For regional haze purposes, based on the Department's SO_2 four-factor analysis and TGP having effective controls already in place, no additional SO_2 controls for the TGP were selected to include in the first or second additional controls modeling scenario. Of note, the magnitude of SO_2 reductions available from this source is minimal when compared to a typical North Dakota coal fired EGU.[119] 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 an evaluation of additional control measures since CS4's Q/d was sufficiently close to the Q/d threshold and CS4 is located only 18 km from the nearest CIA. The Department sent a letter to Northern Border on May 2, 2018, requesting a report for CS4.[120] The letter required that Northern Border's report be submitted to the Department on or before January 31, 2019. Northern Border's original report was submitted to the Department on December 10, 2018.[121] The Department submitted comments regarding areas of concern in the report to Northern Border on December 28, 2018.[122] Northern Border submitted a response to the Department's comments on March 1, 2019.[123] A copy of each submittal by CS4 can be found in Appendix B.9.b.

The Department evaluated the information submitted by Northern Border and conducted its own independent four factor analysis to determine the appropriate control requirements for CS4. Based on the Department's evaluation of all sources of information, future operations and emissions profiles are expected to remain consistent with current conditions. Additionally, the control cost estimations presented in the Department's four-factor analysis are accurate and consistent with Department experience in evaluating source control costs. The Department's four-factor analysis of CS4's additional control measures evaluation can be found in Appendix A.9.

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[119] Representative emissions from Coyote, AVS, LOS, Coal Creek, and MRYS on a per unit basis.
[120] Appendix B.9.a.
[121] Appendix B.9.b.
[122] Appendix B.9.c.
[123] Appendix B.9.b. and Appendix B.9.c.

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. The Department's consideration and application of the four factors (as set forth in Appendix A.9) are summarized as follows. Time necessary for compliance was determined not to be significant enough to discount any control options. Energy and non-air quality environmental impacts were determined not to be significant enough to eliminate any of the control options. Remaining useful life was determined by the Department to not eliminate any control options. Therefore, cost of compliance was most heavily considered by the Department in selection of additional controls for modeling review and to determine if these controls are appropriate and necessary to demonstrate reasonable progress. The Department evaluated controls for this turbine but determined controls were not necessary for installation during this planning period due to excessive cost and limited expected reduction in mass-based emissions.

Based on the Department's four-factor analysis and conclusions presented above, no additional controls for CS4 were selected to include in the first or second additional controls modeling scenario. Additionally, the magnitude of NO_X reductions available from this source is minimal when compared to a typical North Dakota coal fired EGU.[124] 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 an evaluation of additional control measures based on the four factors for the GPSP.[125] The letter required that DGC's report be submitted to the Department on or before January 31, 2019. DGC's report was submitted to the Department on January 31, 2019.[126] The Department

[124] Representative emissions from Coyote, AVS, LOS, Coal Creek, and MRYS on a per unit basis.
[125] Appendix B.10.a.
[126] Appendix B.10.b.

found no areas of concern in the report received from DGC. A copy of the submittal by DGC can be found in Appendix B.10.b.

The Department evaluated the information submitted by DGC and conducted its own independent four factor analysis to determine the appropriate control requirements for GPSP. Based on the Department's evaluation of all sources of information, future operations and emissions profiles are expected to remain consistent with current conditions. Additionally, the control cost estimations presented in the Department's four-factor analysis are accurate and consistent with Department experience in evaluating source control costs. The Department's four-factor analysis and determination of GPSP's additional control measures evaluation can be found in Appendix A.10.

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's determination from its four-factor analysis are summarized as follows. Time necessary for compliance was determined not to be significant enough to discount any control options. Energy and non-air quality environmental impacts were determined not to be significant enough to eliminate any of the control options. Remaining useful life was determined by the Department to not eliminate any control options. Cost of compliance was considered in selection of additional controls for modeling review and to determine if these controls are appropriate and necessary to demonstrate reasonable progress. However, the Department's four-factor analysis confirmed that GPSP's 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 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.[127] 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 facilities 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.

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

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. 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.[128]

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.[129] 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.[130] 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

[128] Additional details available at: https://www.wrapair2.org/ogwg.aspx (Last visited December 28, 2020)
[129] Available at: https://www.wrapair2.org/pdf/WRAP_OGWG_ARCS_Memo_23Mar2020.pdf (Last visited June 14, 2021)
[130] Available at: https://www.wrapair2.org/pdf/WRAP_OGWG_ARCS_Memo_23Mar2020.pdf (last visited June 14, 2021)

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 incentivizes the investment in gas capture infrastructure.[131] 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.[132] 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 43. 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.[133]

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

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

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

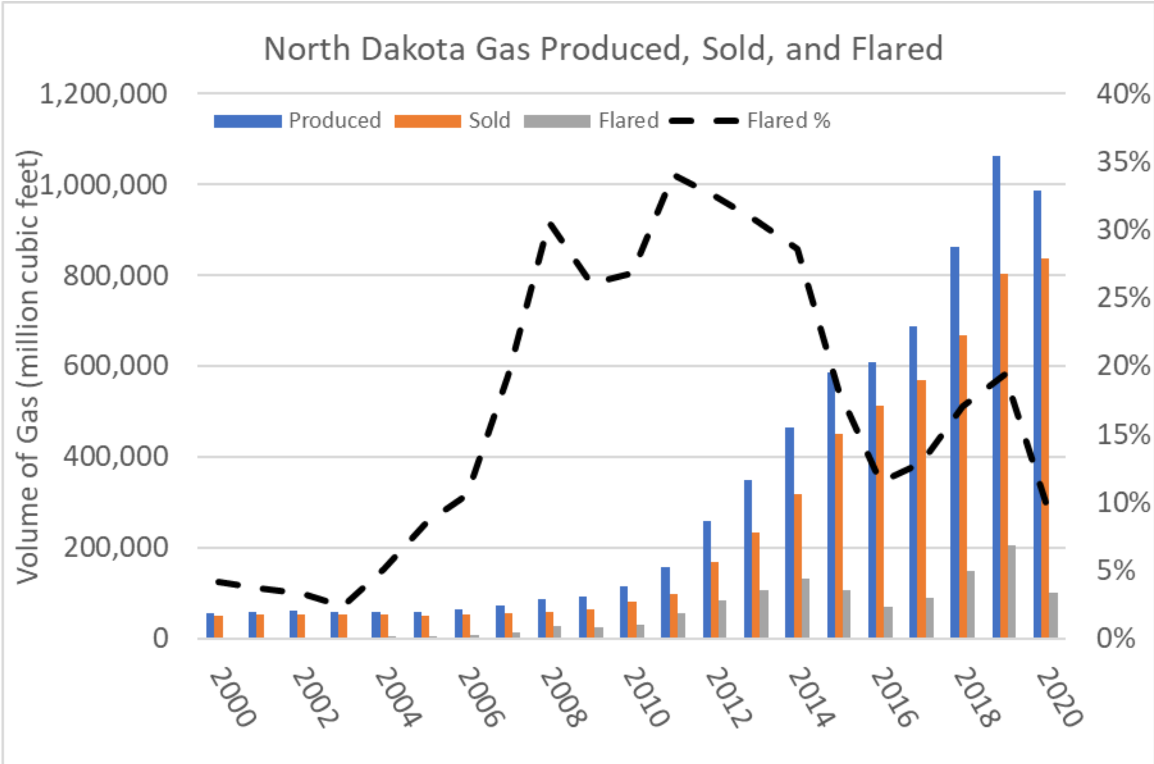

Figure 43: Volume of Gas Produced, Sold, Flared, and Flared Percent from 2000–2020.

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, 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 44.

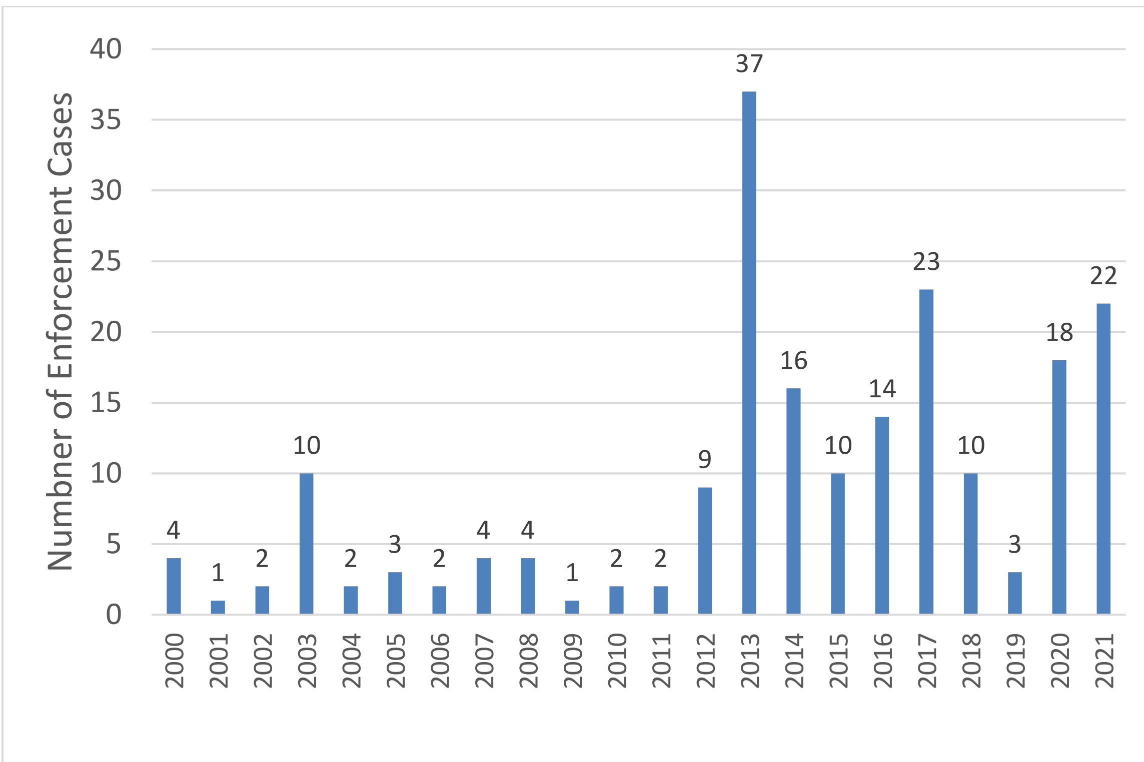

Figure 44: NDDEQ Air Quality Enforcement Actions from 2000 through June 30, 2021.

Figure 44 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.[134] 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.[135] 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.[136] 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.*

[134] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-02.pdf?20150602082326
[135] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-03.pdf?20150202141005
[136] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-04.pdf?20150202141022

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.[137] 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.[138] 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.

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.[139] 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.[140] 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.[141] 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.

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[137] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-05.pdf?20150202141044
[138] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-06.pdf?20150202141137
[139] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-07.pdf?20150202141202
[140] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-08.pdf?20150202141225
[141] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-12.pdf?20150202141441

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.[142] 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.[143] 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 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.[144] 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.[145] 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."*

[142] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-13.pdf?20150202141536
[143] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-14.pdf?20150202141623
[144] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-15.pdf?20150202141650
[145] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-17.pdf?20150202142045

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[146], 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.

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.[147] 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.[148] 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.

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[146] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-19.pdf?20150202142145
[147] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-20.pdf?20150202142208
[148] Available at: https://www.legis.nd.gov/information/acdata/pdf/33.1-15-21.pdf?20150202142230

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.[149]

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[150] and implements the BART provisions of the federal RHR.[151] 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.

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.

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

[150] 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.

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

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.[152] 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

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

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 45 shows NO_X emissions across the continental United States in 1990 relative to 2019. Figure 46 shows the same for SO_2 emissions. It should be noted that Figure 45 and Figure 46 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.

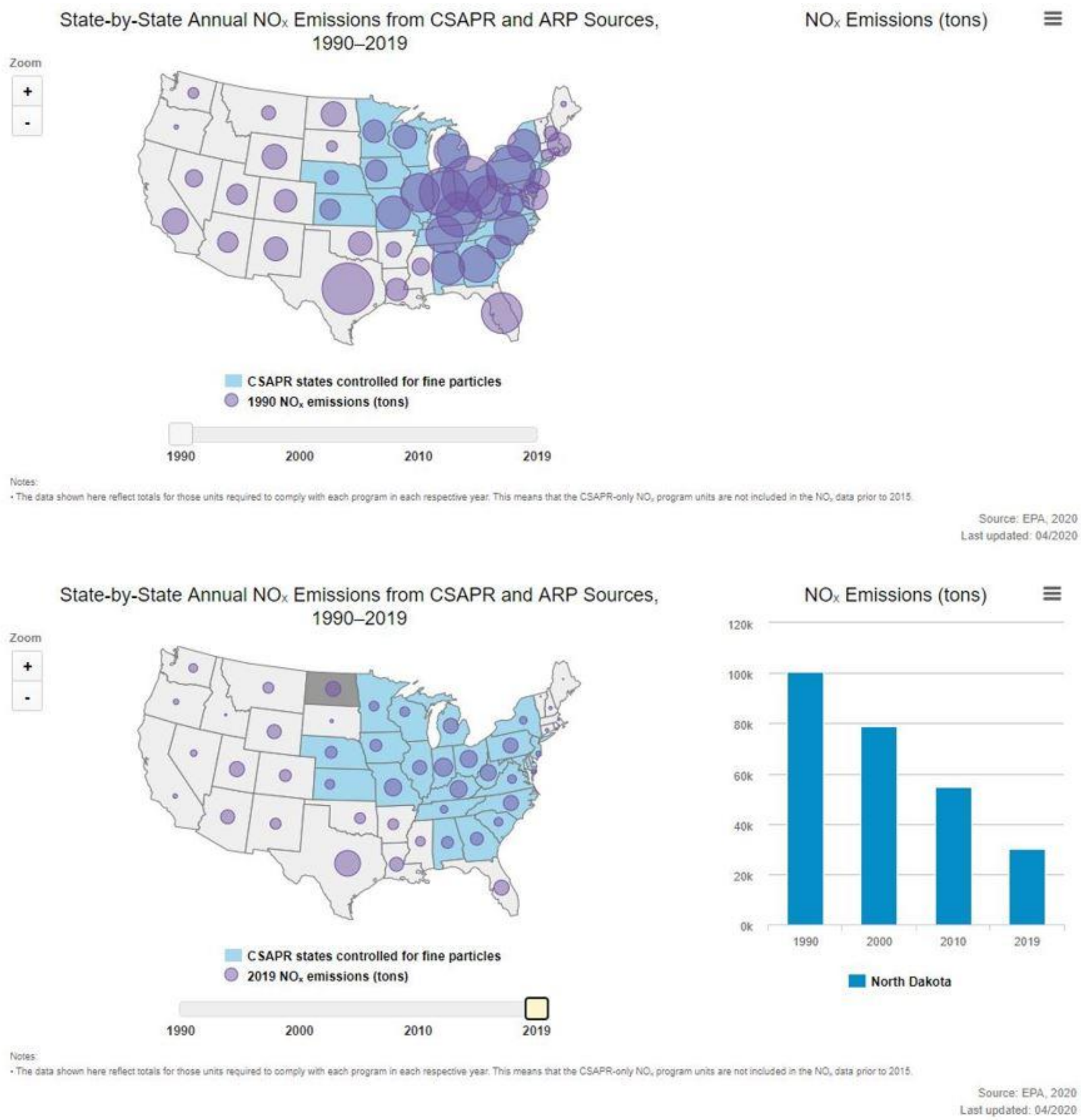

Figure 45: Annual NO_X reductions across the continental United States from 1990–2019. The size of the circle over each state represents a relative scale of emissions. NO_X emissions from North Dakota sources from 1990–2019 is also shown.

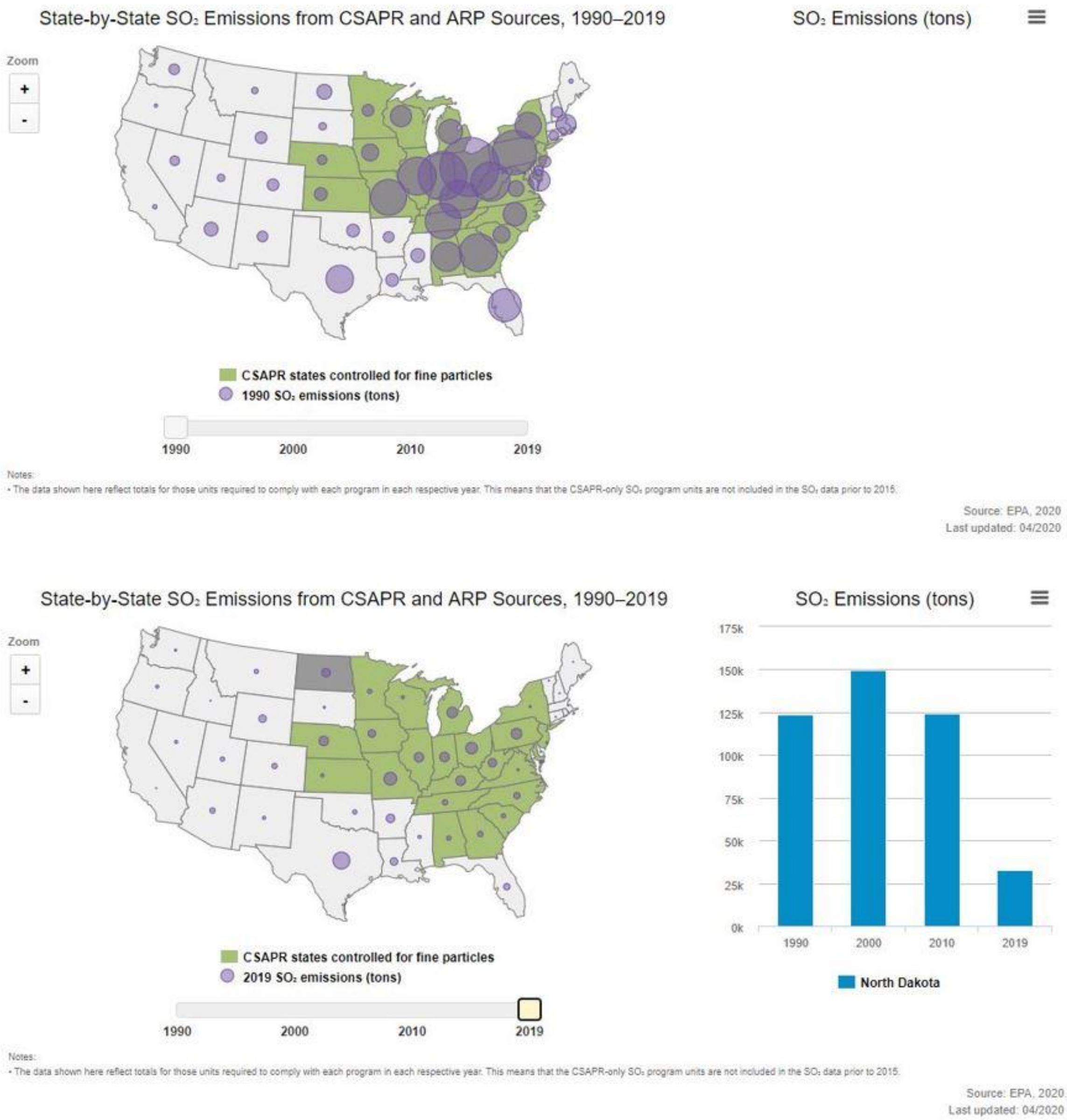

Figure 46: SO_2 reductions across the continental United States from 1990–2019. The size of the circle over each state represents a relative scale of emissions. SO_2 emissions from North Dakota sources from 1990–2019 is also shown.

5.3.1.2.4 Tier 3 Motor Vehicle Emission and Fuel Standards

Tier 3 vehicle standards were established in 2014.[153] 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

[153] 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.[154] 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.[155] 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).[156]

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

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

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

requesting comments on the CTI.[157] 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.[158] The rule has been updated several times, with the most recent update being finalized in 2020.[159]

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

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

[159] 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[160] and restoration of the site has since been completed[161].

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. Unit 1 and Unit 2 shutdown in January and February of 2022.[162]

In May of 2020, Great River Energy announced that the 99 MWe Spiritwood Station will be modified to be fueled by only natural gas.[163] Unit 1 has a nominal heat input capacity of 1,280 MMBtu/hr and can be currently fired with coal, natural gas, or propane. As documented in Table 35, the average annual

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

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

[162] See Appendix A.6.

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

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.[164] 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 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

[164] 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)

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 6.1, and the visibility projections are covered in Sections 3.1 and 6.1.1.

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 resulting from the long-term strategy (LTS). The LTS contains the measures adopted upon consideration of the four factors 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.[165]

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.[166] 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*."[167] 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 emissions reduction measures 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*".[168] 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, however, a useful metric for evaluating progress. The Department believes the current rate of visibility improvement projected by the end of the planning period is

[165] Available at: https://www.epa.gov/visibility/visibility-guidance-documents (Last visited January 27, 2021)
[166] 40 CFR 51.308(f)(3)
[167] 64 FR 35731
[168] 64 FR 35731

reasonable for 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 to occur during this planning period. The Department came to this conclusion in consideration of the four factors and through the WRAP PGM modeling of current and potential additional controls. 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 were appropriate or necessary 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 and no degradation of visibility for the clearest days over the implementation plan. The 2028 visibility projections for the MIDs and clearest days 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.[169] 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 (or 2028 baseline), 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 (2028OTB, 2028PAC1, and 2028PAC2), how sensitive is the model to the magnitude of reductions evaluated and will this meaningfully impact future visibility conditions on the MID?

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

[169] 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.

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 47 and Figure 48 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 47 and Figure 48 only show the 2028 visibility projections and glidepath adjustment produced using the recommended procedures by the WRAP RTO.[170]

Figure 47 and Figure 48 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

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

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".

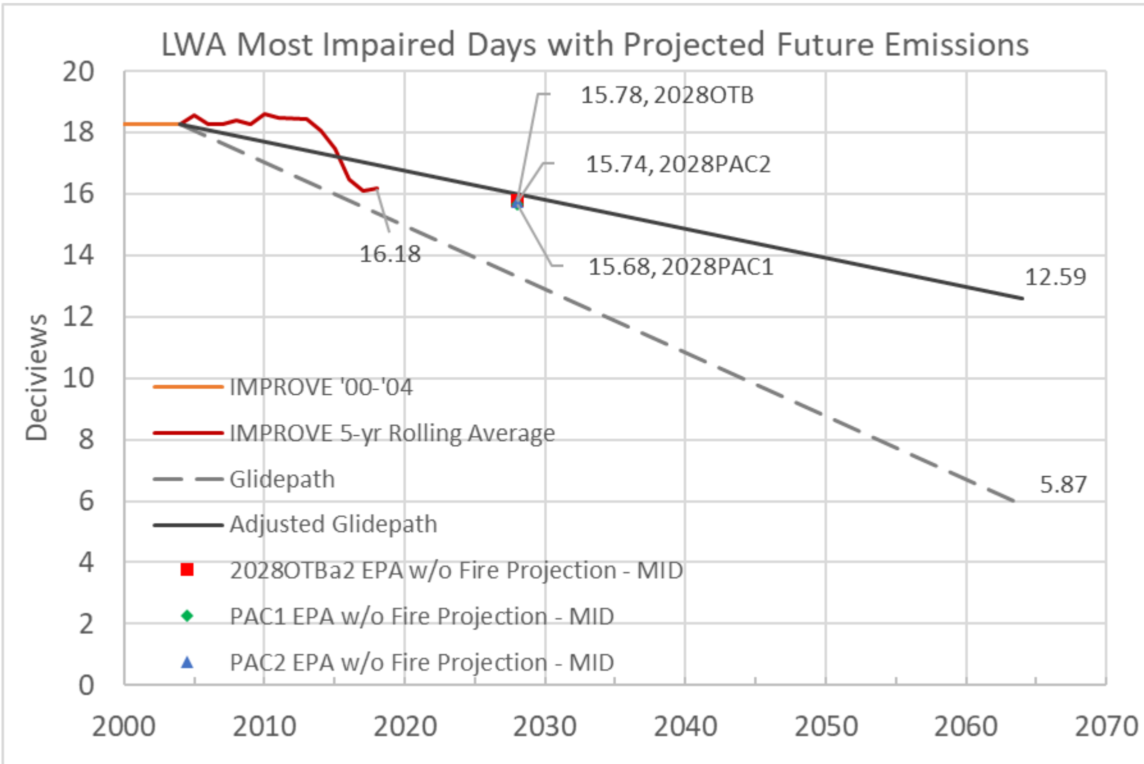

Figure 47: LWA Visibility Projection for the Most Impaired Days with 2028 Emissions Scenarios

The 2028OTB projection in Figure 47 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 reduction measures 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-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 47 also displays the impact to visibility from the additional controls selected for modeling evaluation resulting from consideration of the four factors 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 2028PAC1 projection in Figure 47 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 reducing anthropogenic visibility impairment, as defined in §51.301, on the MIDs visibility projection for 2028.

The 2028PAC2 projection in Figure 47 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 reduction in anthropogenic visibility impairment, as defined in §51.301, on the MIDs visibility projection for 2028. Although the cost for this scenario is considerably lower than 2028PAC1, there is also no projected improvement in anthropogenic visibility impairment 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 projected improvement in anthropogenic visibility conditions, 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.

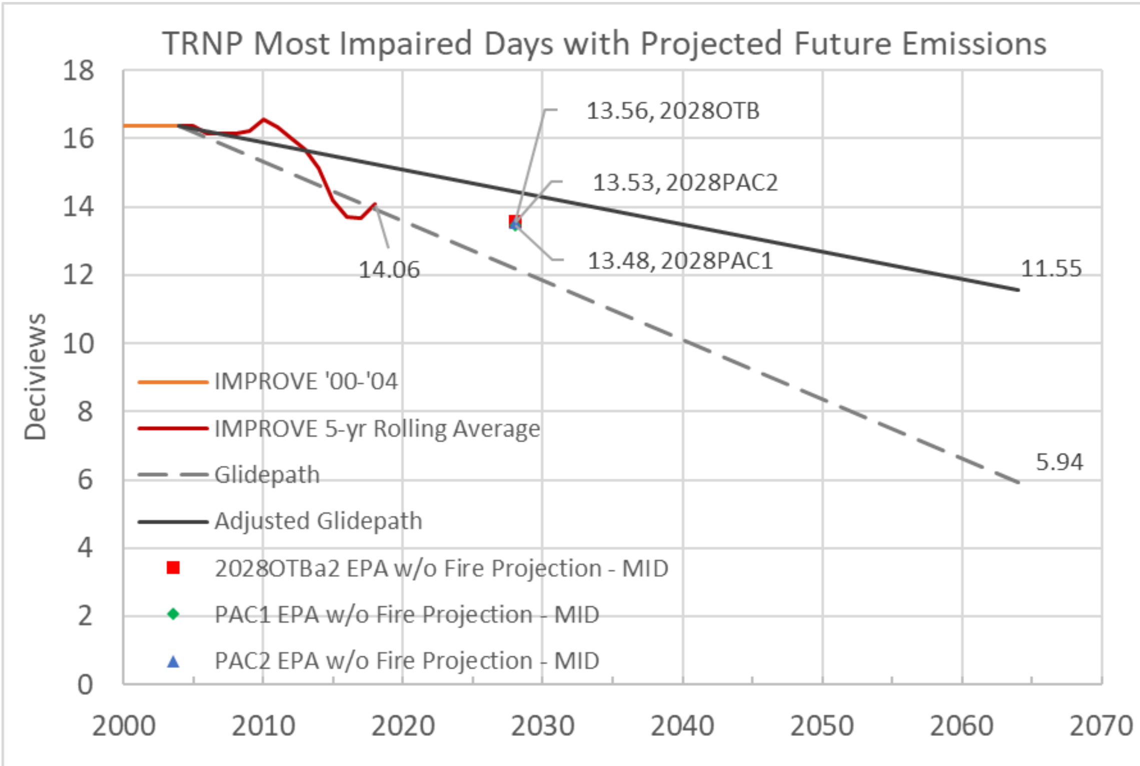

Figure 48: TRNP Visibility Projection for the Most Impaired Days with 2028 Emissions Scenarios

The 2028OTB projection in Figure 48 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 reduction measures 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 48 also displays the impact to visibility from the additional controls selected for modeling evaluation resulting from consideration of the four factors 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 2028PAC1 projection in Figure 48 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 reducing anthropogenic visibility impairment, as defined in §51.301, on the MIDs visibility projection for 2028.

The 2028PAC2 projection in Figure 48 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 reduction in anthropogenic visibility impairment, as defined in §51.301, on the MIDs visibility projection for 2028. Although the cost for this scenario is considerably lower than 2028PAC1, there is also no projected improvement in anthropogenic visibility impairment 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 projected improvement in anthropogenic visibility conditions, 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)

Same requirement as §51.308(d)(4)(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)

Same requirement as §51.308(d)(4)(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)

Same requirement as §51.308(d)(4)(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)

Same requirement as §51.308(d)(4)(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)

Similar to requirement under §51.308(d)(4)(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)

Same requirement as §51.308(d)(4)(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. WRAP also developed a document titled "WRAP Technical Support System for Regional Haze Planning: Modeling Methods, Results, and References". This document describes the WRAP emissions and modeling analyses and illustrates how the technical support system products can be applied to support the 2028 visibility progress demonstrations for western U.S. Class I areas. This document has been included in Appendix C.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.[171] 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

[171] 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)

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 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".[172]

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.2. 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.[173]

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-

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

[173] 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)

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.

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.3. 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 §51.308(e) – 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.[174] On September 12, 2019, Great River Energy submitted an updated BART analysis associated with the first round of Regional Haze planning.[175] Great River Energy announced plans to retire Coal Creek in the second half of 2022 on May 7, 2020.[176] 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.[177] 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 this new

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[174] Appendix B.4.c., PDF page 1082.
[175] Appendix B.4.b., PDF page 576.
[176] 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)
[177] Available at: https://greatriverenergy.com/rainbow-energy-center-to-purchase-coal-creek-station/ (Last visited July 6, 2021)

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[178] 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.[179]. 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™ 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.

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

[179] 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.[180]

[180] 40 CFR Part 51 Appendix Y, Guidelines for BART Determinations under the RHR

9 §51.308(g) – 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.[181]

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).

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

[181] 86 FR 14055. Available at: https://www.govinfo.gov/content/pkg/FR-2021-03-12/pdf/2021-04402.pdf

- 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. North Dakota's 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%

State	Class I Area	Total Light Extinction (Mm^{-1})	North Dakota Ammonium Nitrate	North Dakota Ammonium Sulfate
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.[182] A significant portion of the increase in attributable to the support needed for the operation of the Bakken in the western North Dakota.

[182] 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)

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".[183] 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.[184] This policy has been helpful in reducing the percentage of produced gas being flared. Figure 43 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 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).

[183] Available at: https://www.deq.nd.gov/publications/AQ/policy/PC/20110502_OilGas_Permitting_Guidance.pdf (Last visited December 22, 2020)
[184] Available at: https://www.dmr.nd.gov/oilgas/112018GuidancePolicyNorthDakotaIndustrialCommissionorder24665_2.pdf (Last visited December 22, 2020)

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.