Appendix D – FLM Consultation and Public Record

D.1 – Notice of Opportunity for Early Consultation

Stroh, David E.

From: Stroh, David E.
Sent: Wednesday, September 15, 2021 10:03 AM
To: Pohlman, David C.; King, Kirsten L; Peters, Melanie; Shepherd, Don
Cc: Thorton, Rhannon T.; Semerad, Jim L.
Subject: North Dakota - DRAFT Regional Haze SIP for Consultation
Attachments: 20210915_NationalParkService Ltr.pdf

David, Kirsten, Melanie, Don,

Attached is a signed electronic notice for the North Dakota Department of Environmental Quality (NDDEQ) DRAFT regional haze state implementation plan (RH SIP) revision. This plan is being made available to provide you with an early opportunity to comment on NDDEQ's current DRAFT RH SIP Revision.

The location of the material available for review is included in the attached notice and can be found at:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx
(note: webpage and material will be updated prior to Sept. 20th)

Comments can be sent through the mail or electronically to: AirQuality@nd.gov
If electronic comments are provided, please include "Regional Haze Consultation Comments" in the subject line.

Please review the attached and reach out with any comments or questions. We look forward to engaging with you in the next steps of the regional haze process.

Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov
4201 Normandy St., Bismarck, ND 58503-1324

North Dakota | Environmental Quality
Be Legendary

NORTH
Dakota | Environmental Quality
Be Legendary.™

September 15, 2021

Sent via Email to david_pohlman@nps.gov, kirsten_king@nps.gov, melanie_peters@nps.gov and Don_Shepherd@nps.gov

David Pohlman, Kirsten King, Melanie Peters, and Don Sheperd:

In accordance with provisions of the federal Regional Haze Rule (RHR) under 40 Code of Federal Regulations, Part 51, Subpart P, §51.308(i)(2), the State of North Dakota is hereby offering the opportunity for consultation on the draft Regional Haze State Implementation Plan (RH SIP) revision.

The draft RH SIP revision has been uploaded to the North Dakota Department of Environmental Quality, Division of Air Quality's Regional Haze webpage:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx

A 60-day consultation period for North Dakota's draft RH SIP revision will be held from September 20, 2021 through November 19, 2021. Written comments can be mailed to the North Dakota Department of Environmental Quality, Division of Air Quality, 4201 Normandy Street, Bismarck, ND 58503-1324 or emailed to AirQuality@nd.gov. Comments sent via email should include "Regional Haze Consultation Comments" in the subject line.

Upon completion of the consultation period, North Dakota will include a description of how comments provided by the appropriate stakeholders were addressed. Only comments received from appropriate stakeholders will be added during this consultation period.

If you are unable to access the draft RH SIP revision online, require a hardcopy or prefer the information through other means, contact David Stroh at (701)328-5229 or destroh@nd.gov.

If you wish to schedule an in-person or video conference meeting to discuss the draft RH SIP revision, contact David Stroh.

If you have any general questions about this process, please contact David Stroh or myself at (701)328-5188.

Sincerely,

Jim Semerad
Director
Division of Air Quality

JS/DES:saj

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office 701-328-5150
Division of Air Quality 701-328-5188
Division of Municipal Facilities 701-328-5211
Division of Waste Management 701-328-5166
Division of Water Quality 701-328-5210
Division of Chemistry 701-328-6140 2635 East Main Ave Bismarck ND 58501

Stroh, David E.

From: Stroh, David E.
Sent: Wednesday, September 15, 2021 10:03 AM
To: tim_allen@fws.gov
Cc: Thorton, Rhannon T.; Semerad, Jim L.
Subject: North Dakota - DRAFT Regional Haze SIP for Consultation
Attachments: 20210915_Fish&Wildlife Ltr.pdf

Hi Tim,

Attached is a signed electronic notice for the North Dakota Department of Environmental Quality (NDDEQ) DRAFT regional haze state implementation plan (RH SIP) revision. This plan is being made available to provide you with an early opportunity to comment on NDDEQ's current DRAFT RH SIP Revision.

The location of the material available for review is included in the attached notice and can be found at:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx
(note: webpage and material will be updated prior to Sept. 20th)

Comments can be sent through the mail or electronically to: AirQuality@nd.gov
If electronic comments are provided, please include "Regional Haze Consultation Comments" in the subject line.

Please review the attached and reach out with any comments or questions. We look forward to engaging with you in the next steps of the regional haze process.

Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov
4201 Normandy St., Bismarck, ND 58503-1324

NORTH Dakota | Environmental Quality
Be Legendary

NORTH
Dakota | Environmental Quality
Be Legendary.™

September 15, 2021

Sent via Email to Tim_Allen@fws.gov

Tim Allen:

In accordance with provisions of the federal Regional Haze Rule (RHR) under 40 Code of Federal Regulations, Part 51, Subpart P, §51.308(i)(2), the State of North Dakota is hereby offering the opportunity for consultation on the draft Regional Haze State Implementation Plan (RH SIP) revision.

The draft RH SIP revision has been uploaded to the North Dakota Department of Environmental Quality, Division of Air Quality's Regional Haze webpage:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx

A 60-day consultation period for North Dakota's draft RH SIP revision will be held from September 20, 2021 through November 19, 2021. Written comments can be mailed to the North Dakota Department of Environmental Quality, Division of Air Quality, 4201 Normandy Street, Bismarck, ND 58503-1324 or emailed to AirQuality@nd.gov. Comments sent via email should include "Regional Haze Consultation Comments" in the subject line.

Upon completion of the consultation period, North Dakota will include a description of how comments provided by the appropriate stakeholders were addressed. Only comments received from appropriate stakeholders will be added during this consultation period.

If you are unable to access the draft RH SIP revision online, require a hardcopy or prefer the information through other means, contact David Stroh at (701)328-5229 or destroh@nd.gov.

If you wish to schedule an in-person or video conference meeting to discuss the draft RH SIP revision, contact David Stroh.

If you have any general questions about this process, please contact David Stroh or myself at (701)328-5188.

Sincerely,

Jim Semerad
Director
Division of Air Quality

JS/DES:saj

Stroh, David E.

From:	Stroh, David E.
Sent:	Wednesday, September 15, 2021 10:03 AM
To:	'Webster, Jill - FS'; 'bret.a.anderson@usda.gov'
Cc:	Thorton, Rhannon T.; Semerad, Jim L.
Subject:	North Dakota - DRAFT Regional Haze SIP for Consultation
Attachments:	20210915_ForrestService Ltr.pdf

Jill and Bret,

Attached is a signed electronic notice for the North Dakota Department of Environmental Quality (NDDEQ) DRAFT regional haze state implementation plan (RH SIP) revision. This plan is being made available to provide you with an early opportunity to comment on NDDEQ's current DRAFT RH SIP Revision.

The location of the material available for review is included in the attached notice and can be found at:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx
(note: webpage and material will be updated prior to Sept. 20th)

Comments can be sent through the mail or electronically to: AirQuality@nd.gov
If electronic comments are provided, please include "Regional Haze Consultation Comments" in the subject line.

Please review the attached and reach out with any comments or questions. We look forward to engaging with you in the next steps of the regional haze process.

Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov
4201 Normandy St., Bismarck, ND 58503-1324

North Dakota | Environmental Quality
Be Legendary

NORTH Dakota | Environmental Quality
Be Legendary.™

September 15, 2021

Sent via Email to jill.webster@usda.gov and bret.a.anderson@usda.gov

Jill Webster and Bret Anderson:

In accordance with provisions of the federal Regional Haze Rule (RHR) under 40 Code of Federal Regulations, Part 51, Subpart P, §51.308(i)(2), the State of North Dakota is hereby offering the opportunity for consultation on the draft Regional Haze State Implementation Plan (RH SIP) revision.

The draft RH SIP revision has been uploaded to the North Dakota Department of Environmental Quality, Division of Air Quality's Regional Haze webpage:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx

A 60-day consultation period for North Dakota's draft RH SIP revision will be held from September 20, 2021 through November 19, 2021. Written comments can be mailed to the North Dakota Department of Environmental Quality, Division of Air Quality, 4201 Normandy Street, Bismarck, ND 58503-1324 or emailed to AirQuality@nd.gov. Comments sent via email should include "Regional Haze Consultation Comments" in the subject line.

Upon completion of the consultation period, North Dakota will include a description of how comments provided by the appropriate stakeholders were addressed. Only comments received from appropriate stakeholders will be added during this consultation period.

If you are unable to access the draft RH SIP revision online, require a hardcopy or prefer the information through other means, contact David Stroh at (701)328-5229 or destroh@nd.gov.

If you wish to schedule an in-person or video conference meeting to discuss the draft RH SIP revision, contact David Stroh.

If you have any general questions about this process, please contact David Stroh or myself at (701)328-5188.

Sincerely,

Jim Semerad
Director
Division of Air Quality

JS/DES:saj

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office	Division of Air Quality	Division of Municipal Facilities	Division of Waste Management	Division of Water Quality	Division of Chemistry
701-328-5150	701-328-5188	701-328-5211	701-328-5166	701-328-5210	701-328-6140 2635 East Main Ave Bismarck ND 58501

Stroh, David E.

From: Stroh, David E.
Sent: Wednesday, September 15, 2021 10:03 AM
To: Worstell, Aaron; Dobrahner, Jaslyn
Cc: Thorton, Rhannon T.; Semerad, Jim L.; Gregory, Kate (she/her); Jackson, Scott
Subject: North Dakota - DRAFT Regional Haze SIP for Consultation
Attachments: 20210915_EPAR8 Ltr.pdf

Aaron and Jaslyn,

Attached is a signed electronic notice for the North Dakota Department of Environmental Quality (NDDEQ) DRAFT regional haze state implementation plan (RH SIP) revision. This plan is being made available to provide you with an early opportunity to comment on NDDEQ's current DRAFT RH SIP Revision.

The location of the material available for review is included in the attached notice and can be found at:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx
(note: webpage and material will be updated prior to Sept. 20th)

Comments can be sent through the mail or electronically to: AirQuality@nd.gov
If electronic comments are provided, please include "Regional Haze Consultation Comments" in the subject line.

Please review the attached and reach out with any comments or questions. We look forward to engaging with you in the next steps of the regional haze process.

Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov
4201 Normandy St., Bismarck, ND 58503-1324

NORTH Dakota | Environmental Quality
Be Legendary

NORTH **Dakota** | Environmental Quality

Be Legendary.™

September 15, 2021

Sent via Email to Worstell.Aaron@epa.gov and Dobrahner.Jaslyn@epa.gov

Aaron Worstell and Jaslyn Dobrahner:

In accordance with provisions of the federal Regional Haze Rule (RHR) under 40 Code of Federal Regulations, Part 51, Subpart P, §51.308(i)(2), the State of North Dakota is hereby offering the opportunity for consultation on the draft Regional Haze State Implementation Plan (RH SIP) revision.

The draft RH SIP revision has been uploaded to the North Dakota Department of Environmental Quality, Division of Air Quality's Regional Haze webpage:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx

A 60-day consultation period for North Dakota's draft RH SIP revision will be held from September 20, 2021 through November 19, 2021. Written comments can be mailed to the North Dakota Department of Environmental Quality, Division of Air Quality, 4201 Normandy Street, Bismarck, ND 58503-1324 or emailed to AirQuality@nd.gov. Comments sent via email should include "Regional Haze Consultation Comments" in the subject line.

Upon completion of the consultation period, North Dakota will include a description of how comments provided by the appropriate stakeholders were addressed. Only comments received from appropriate stakeholders will be added during this consultation period.

If you are unable to access the draft RH SIP revision online, require a hardcopy or prefer the information through other means, contact David Stroh at (701)328-5229 or destroh@nd.gov.

If you wish to schedule an in-person or video conference meeting to discuss the draft RH SIP revision, contact David Stroh.

If you have any general questions about this process, please contact David Stroh or myself at (701)328-5188.

Sincerely,

Jim Semerad
Director
Division of Air Quality

JS/DES:saj

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office	Division of Air Quality	Division of Municipal Facilities	Division of Waste Management	Division of Water Quality	Division of Chemistry
701-328-5150	701-328-5188	701-328-5211	701-328-5166	701-328-5210	701-328-6140 2635 East Main Ave Bismarck ND 58501

Stroh, David E.

From: Stroh, David E.
Sent: Wednesday, September 15, 2021 10:03 AM
To: Bouchareb, Hassan (MPCA); margaret.mccourtney@state.mn.us
Cc: Thorton, Rhannon T.; Semerad, Jim L.
Subject: North Dakota - DRAFT Regional Haze SIP for Consultation
Attachments: 20210915_MN Ltr.pdf

Hi Hassan and Margaret,

Attached is a signed electronic notice for the North Dakota Department of Environmental Quality (NDDEQ) DRAFT regional haze state implementation plan (RH SIP) revision. This plan is being made available to provide you with an early opportunity to comment on NDDEQ's current DRAFT RH SIP Revision.

The location of the material available for review is included in the attached notice and can be found at:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx
(note: webpage and material will be updated prior to Sept. 20th)

Comments can be sent through the mail or electronically to: AirQuality@nd.gov
If electronic comments are provided, please include "Regional Haze Consultation Comments" in the subject line.

Please review the attached and reach out with any comments or questions. We look forward to engaging with you in the next steps of the regional haze process.

Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov
4201 Normandy St., Bismarck, ND 58503-1324

North Dakota | Environmental Quality
Be Legendary

NORTH
Dakota | Environmental Quality
Be Legendary.™

September 15, 2021

Sent via Email to hassan.bouchareb@state.mn.us and margaret.mccourtney@state.mn.us

Hassan Bouchareb and Margaret McCourtney:

In accordance with provisions of the federal Regional Haze Rule (RHR) under 40 Code of Federal Regulations, Part 51, Subpart P, §51.308(i)(2), the State of North Dakota is hereby offering the opportunity for consultation on the draft Regional Haze State Implementation Plan (RH SIP) revision.

The draft RH SIP revision has been uploaded to the North Dakota Department of Environmental Quality, Division of Air Quality's Regional Haze webpage:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx

A 60-day consultation period for North Dakota's draft RH SIP revision will be held from September 20, 2021 through November 19, 2021. Written comments can be mailed to the North Dakota Department of Environmental Quality, Division of Air Quality, 4201 Normandy Street, Bismarck, ND 58503-1324 or emailed to AirQuality@nd.gov. Comments sent via email should include "Regional Haze Consultation Comments" in the subject line.

Upon completion of the consultation period, North Dakota will include a description of how comments provided by the appropriate stakeholders were addressed. Only comments received from appropriate stakeholders will be added during this consultation period.

If you are unable to access the draft RH SIP revision online, require a hardcopy or prefer the information through other means, contact David Stroh at (701)328-5229 or destroh@nd.gov.

If you wish to schedule an in-person or video conference meeting to discuss the draft RH SIP revision, contact David Stroh.

If you have any general questions about this process, please contact David Stroh or myself at (701)328-5188.

Sincerely,

Jim Semerad
Director
Division of Air Quality

JS/DES:saj

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office	Division of Air Quality	Division of Municipal Facilities	Division of Waste Management	Division of Water Quality	Division of Chemistry
701-328-5150	701-328-5188	701-328-5211	701-328-5166	701-328-5210	701-328-6140 2635 East Main Ave Bismarck ND 58501

Stroh, David E.

From:	Stroh, David E.
Sent:	Wednesday, September 15, 2021 10:03 AM
To:	repayne@mt.gov
Cc:	Thorton, Rhannon T.; Semerad, Jim L.; Brandon McGuire; Henrikson, Craig
Subject:	North Dakota - DRAFT Regional Haze SIP for Consultation
Attachments:	20210915_MT Ltr.pdf

Hi Rhonda,

Attached is a signed electronic notice for the North Dakota Department of Environmental Quality (NDDEQ) DRAFT regional haze state implementation plan (RH SIP) revision. This plan is being made available to provide you with an early opportunity to comment on NDDEQ's current DRAFT RH SIP Revision.

The location of the material available for review is included in the attached notice and can be found at:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx
(note: webpage and material will be updated prior to Sept. 20th)

Comments can be sent through the mail or electronically to: AirQuality@nd.gov
If electronic comments are provided, please include "Regional Haze Consultation Comments" in the subject line.

Please review the attached and reach out with any comments or questions. We look forward to engaging with you in the next steps of the regional haze process.

Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov
4201 Normandy St., Bismarck, ND 58503-1324

North Dakota | Environmental Quality
Be Legendary

NORTH
Dakota | Environmental Quality
Be Legendary.™

September 15, 2021

Sent via Email to repayne@mt.gov

Rhonda Payne:

In accordance with provisions of the federal Regional Haze Rule (RHR) under 40 Code of Federal Regulations, Part 51, Subpart P, §51.308(i)(2), the State of North Dakota is hereby offering the opportunity for consultation on the draft Regional Haze State Implementation Plan (RH SIP) revision.

The draft RH SIP revision has been uploaded to the North Dakota Department of Environmental Quality, Division of Air Quality's Regional Haze webpage:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx

A 60-day consultation period for North Dakota's draft RH SIP revision will be held from September 20, 2021 through November 19, 2021. Written comments can be mailed to the North Dakota Department of Environmental Quality, Division of Air Quality, 4201 Normandy Street, Bismarck, ND 58503-1324 or emailed to AirQuality@nd.gov. Comments sent via email should include "Regional Haze Consultation Comments" in the subject line.

Upon completion of the consultation period, North Dakota will include a description of how comments provided by the appropriate stakeholders were addressed. Only comments received from appropriate stakeholders will be added during this consultation period.

If you are unable to access the draft RH SIP revision online, require a hardcopy or prefer the information through other means, contact David Stroh at (701)328-5229 or destroh@nd.gov.

If you wish to schedule an in-person or video conference meeting to discuss the draft RH SIP revision, contact David Stroh.

If you have any general questions about this process, please contact David Stroh or myself at (701)328-5188.

Sincerely,

Jim Semerad
Director
Division of Air Quality

JS/DES:saj

Stroh, David E.

From:	Stroh, David E.
Sent:	Wednesday, September 15, 2021 10:03 AM
To:	rick.boddicker@state.sd.us
Cc:	Thorton, Rhannon T.; Semerad, Jim L.; Anthony.Lueck@state.sd.us
Subject:	North Dakota - DRAFT Regional Haze SIP for Consultation
Attachments:	20210915_SD Ltr.pdf

Hi Rick,

Attached is a signed electronic notice for the North Dakota Department of Environmental Quality (NDDEQ) DRAFT regional haze state implementation plan (RH SIP) revision. This plan is being made available to provide you with an early opportunity to comment on NDDEQ's current DRAFT RH SIP Revision.

The location of the material available for review is included in the attached notice and can be found at:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx
(note: webpage and material will be updated prior to Sept. 20th)

Comments can be sent through the mail or electronically to: AirQuality@nd.gov
If electronic comments are provided, please include "Regional Haze Consultation Comments" in the subject line.

Please review the attached and reach out with any comments or questions. We look forward to engaging with you in the next steps of the regional haze process.

Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov
4201 Normandy St., Bismarck, ND 58503-1324

North Dakota | Environmental Quality
Be Legendary

NORTH
Dakota | Environmental Quality
Be Legendary.™

September 15, 2021

Sent via Email to rick.boddicker@state.sd.us

Rick Boddicker:

In accordance with provisions of the federal Regional Haze Rule (RHR) under 40 Code of Federal Regulations, Part 51, Subpart P, §51.308(i)(2), the State of North Dakota is hereby offering the opportunity for consultation on the draft Regional Haze State Implementation Plan (RH SIP) revision.

The draft RH SIP revision has been uploaded to the North Dakota Department of Environmental Quality, Division of Air Quality's Regional Haze webpage:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx

A 60-day consultation period for North Dakota's draft RH SIP revision will be held from September 20, 2021 through November 19, 2021. Written comments can be mailed to the North Dakota Department of Environmental Quality, Division of Air Quality, 4201 Normandy Street, Bismarck, ND 58503-1324 or emailed to AirQuality@nd.gov. Comments sent via email should include "Regional Haze Consultation Comments" in the subject line.

Upon completion of the consultation period, North Dakota will include a description of how comments provided by the appropriate stakeholders were addressed. Only comments received from appropriate stakeholders will be added during this consultation period.

If you are unable to access the draft RH SIP revision online, require a hardcopy or prefer the information through other means, contact David Stroh at (701)328-5229 or destroh@nd.gov.

If you wish to schedule an in-person or video conference meeting to discuss the draft RH SIP revision, contact David Stroh.

If you have any general questions about this process, please contact David Stroh or myself at (701)328-5188.

Sincerely,

Jim Semerad
Director
Division of Air Quality

JS/DES:saj

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office 701-328-5150 | Division of Air Quality 701-328-5188 | Division of Municipal Facilities 701-328-5211 | Division of Waste Management 701-328-5166 | Division of Water Quality 701-328-5210 | Division of Chemistry 701-328-6140 2635 East Main Ave Bismarck ND 58501

NORTH
Dakota | Environmental Quality
Be Legendary.™

September 16, 2021

Nathan Davis, Director
North Dakota Indian Affairs Commission
Sent via email only to nathan.davis@nd.gov

Dear Mr. Davis:

The North Dakota Department of Environmental Quality (NDDEQ), Division of Air Quality recently completed a draft Regional Haze State Implementation Plan (RH SIP) revision. This draft RH SIP revision is required under 40 CFR Part 51, Subpart P, §51.308 (https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-51/subpart-P/section-51.308).

As part of NDDEQ's coordination efforts, we have made the draft RH SIP revision available for review and comment to our tribal partners at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx

The review/comment period is set to run from September 20, 2021, through November 19, 2021.

We wanted to make you aware of the outreach NDDEQ has made toward this effort in the event you receive questions/comments on the matter. I have attached the letters sent to our tribal partners (the Mandan, Hidatsa and Arikara Nation; the Standing Rock Sioux; the Turtle Mountain Band of Chippewa; the Sisseton Wahpeton Oyate; and the Spirit Lake Nation) offering the opportunity for consultation with NDDEQ on this draft RH SIP revision.

Should you receive feedback from any of our tribal partners regarding this matter and/or if there is a desire to schedule an in-person or teleconference meeting to review the draft RH SIP revision, please reach out to David Stroh at destroh@nd.gov or 701-328-5229 to coordinate.

Sincerely,

L. David Glatt
Director
Environmental Quality

LDG/DES:saj
Enc:
xc: Jim Semerad
Reice Haase

NORTH
Dakota | Environmental Quality
Be Legendary.™

September 15, 2021

Tribal Chairman Mark Fox
Mandan, Hidatsa & Arikara Nation
Environmental Division
MHA TERO/Energy Complex, 1st Floor
305 4th Avenue, Suite 1300
New Town, ND 58763:

Dear Chairman Fox:

In accordance with provisions of the federal Regional Haze Rule (RHR) under 40 Code of Federal Regulations, Part 51, Subpart P, §51.308(i)(2), the State of North Dakota is hereby offering the opportunity for consultation on the draft Regional Haze State Implementation Plan (RH SIP) revision.

The draft RH SIP revision has been uploaded to the North Dakota Department of Environmental Quality, Division of Air Quality's Regional Haze webpage:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx

A 60-day consultation period for North Dakota's draft RH SIP revision will be held from September 20, 2021 through November 19, 2021. Written comments can be mailed to the North Dakota Department of Environmental Quality, Division of Air Quality, 4201 Normandy Street, Bismarck, ND 58503-1324 or emailed to AirQuality@nd.gov. Comments sent via email should include "Regional Haze Consultation Comments" in the subject line.

Upon completion of the consultation period, North Dakota will include a description of how comments provided by the appropriate stakeholders were addressed. Only comments received from appropriate stakeholders will be added during this consultation period.

If you are unable to access the draft RH SIP revision online, require a hardcopy or prefer the information through other means, contact David Stroh at (701)328-5229 or destroh@nd.gov.

If you wish to schedule an in-person or video conference meeting to discuss the draft RH SIP revision, contact David Stroh.

If you have any general questions about this process, please contact David Stroh or myself at (701)328-5188.

Sincerely,

Jim Semerad
Director
Division of Air Quality

JS/DES:saj

NORTH
Dakota | Environmental Quality
Be Legendary.™

September 15, 2021

Chairman Douglas Yankton, Sr.
Spirit Lake Tribe
P.O. Box 359
Fort Totten, ND 58335

Dear Chairman Yankton:

In accordance with provisions of the federal Regional Haze Rule (RHR) under 40 Code of Federal Regulations, Part 51, Subpart P, §51.308(i)(2), the State of North Dakota is hereby offering the opportunity for consultation on the draft Regional Haze State Implementation Plan (RH SIP) revision.

The draft RH SIP revision has been uploaded to the North Dakota Department of Environmental Quality, Division of Air Quality's Regional Haze webpage:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx

A 60-day consultation period for North Dakota's draft RH SIP revision will be held from September 20, 2021 through November 19, 2021. Written comments can be mailed to the North Dakota Department of Environmental Quality, Division of Air Quality, 4201 Normandy Street, Bismarck, ND 58503-1324 or emailed to AirQuality@nd.gov. Comments sent via email should include "Regional Haze Consultation Comments" in the subject line.

Upon completion of the consultation period, North Dakota will include a description of how comments provided by the appropriate stakeholders were addressed. Only comments received from appropriate stakeholders will be added during this consultation period.

If you are unable to access the draft RH SIP revision online, require a hardcopy or prefer the information through other means, contact David Stroh at (701)328-5229 or destroh@nd.gov.

If you wish to schedule an in-person or video conference meeting to discuss the draft RH SIP revision, contact David Stroh.

If you have any general questions about this process, please contact David Stroh or myself at (701)328-5188.

Sincerely,

Jim Semerad

Jim Semerad
Director
Division of Air Quality

JS/DES:saj

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office 701-328-5150 | Division of Air Quality 701-328-5188 | Division of Municipal Facilities 701-328-5211 | Division of Waste Management 701-328-5166 | Division of Water Quality 701-328-5210 | Division of Chemistry 701-328-6140 2635 East Main Ave Bismarck ND 58501

NORTH
Dakota | Environmental Quality
Be Legendary.™

September 15, 2021

Chairman Mike Faith
Standing Rock Sioux Tribe
1 Standing Rock Avenue
Fort Yates, ND 58538

Dear Chairman Faith:

In accordance with provisions of the federal Regional Haze Rule (RHR) under 40 Code of Federal Regulations, Part 51, Subpart P, §51.308(i)(2), the State of North Dakota is hereby offering the opportunity for consultation on the draft Regional Haze State Implementation Plan (RH SIP) revision.

The draft RH SIP revision has been uploaded to the North Dakota Department of Environmental Quality, Division of Air Quality's Regional Haze webpage:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx

A 60-day consultation period for North Dakota's draft RH SIP revision will be held from September 20, 2021 through November 19, 2021. Written comments can be mailed to the North Dakota Department of Environmental Quality, Division of Air Quality, 4201 Normandy Street, Bismarck, ND 58503-1324 or emailed to AirQuality@nd.gov. Comments sent via email should include "Regional Haze Consultation Comments" in the subject line.

Upon completion of the consultation period, North Dakota will include a description of how comments provided by the appropriate stakeholders were addressed. Only comments received from appropriate stakeholders will be added during this consultation period.

If you are unable to access the draft RH SIP revision online, require a hardcopy or prefer the information through other means, contact David Stroh at (701)328-5229 or destroh@nd.gov.

If you wish to schedule an in-person or video conference meeting to discuss the draft RH SIP revision, contact David Stroh.

If you have any general questions about this process, please contact David Stroh or myself at (701)328-5188.

Sincerely,

Jim Semerad
Director
Division of Air Quality

JS/DES:saj

September 15, 2021

Tribal Council
Sisseton Wahpeton Oyate
12554 BIA Highway 711
Agency Village, SD 57262

Tribal Council Members:

In accordance with provisions of the federal Regional Haze Rule (RHR) under 40 Code of Federal Regulations, Part 51, Subpart P, §51.308(i)(2), the State of North Dakota is hereby offering the opportunity for consultation on the draft Regional Haze State Implementation Plan (RH SIP) revision.

The draft RH SIP revision has been uploaded to the North Dakota Department of Environmental Quality, Division of Air Quality's Regional Haze webpage:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx

A 60-day consultation period for North Dakota's draft RH SIP revision will be held from September 20, 2021 through November 19, 2021. Written comments can be mailed to the North Dakota Department of Environmental Quality, Division of Air Quality, 4201 Normandy Street, Bismarck, ND 58503-1324 or emailed to AirQuality@nd.gov. Comments sent via email should include "Regional Haze Consultation Comments" in the subject line.

Upon completion of the consultation period, North Dakota will include a description of how comments provided by the appropriate stakeholders were addressed. Only comments received from appropriate stakeholders will be added during this consultation period.

If you are unable to access the draft RH SIP revision online, require a hardcopy or prefer the information through other means, contact David Stroh at (701)328-5229 or destroh@nd.gov.

If you wish to schedule an in-person or video conference meeting to discuss the draft RH SIP revision, contact David Stroh.

If you have any general questions about this process, please contact David Stroh or myself at (701)328-5188.

Sincerely,

Jim Semerad

Jim Semerad
Director
Division of Air Quality

JS/DES:saj

September 15, 2021

Tribal Chairman Jamie Azure
Turtle Mountain Tribe
4180 Highway 281
Belcourt, ND 58316

Dear Chairman Azure:

In accordance with provisions of the federal Regional Haze Rule (RHR) under 40 Code of Federal Regulations, Part 51, Subpart P, §51.308(i)(2), the State of North Dakota is hereby offering the opportunity for consultation on the draft Regional Haze State Implementation Plan (RH SIP) revision.

The draft RH SIP revision has been uploaded to the North Dakota Department of Environmental Quality, Division of Air Quality's Regional Haze webpage:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx

A 60-day consultation period for North Dakota's draft RH SIP revision will be held from September 20, 2021 through November 19, 2021. Written comments can be mailed to the North Dakota Department of Environmental Quality, Division of Air Quality, 4201 Normandy Street, Bismarck, ND 58503-1324 or emailed to AirQuality@nd.gov. Comments sent via email should include "Regional Haze Consultation Comments" in the subject line.

Upon completion of the consultation period, North Dakota will include a description of how comments provided by the appropriate stakeholders were addressed. Only comments received from appropriate stakeholders will be added during this consultation period.

If you are unable to access the draft RH SIP revision online, require a hardcopy or prefer the information through other means, contact David Stroh at (701)328-5229 or destroh@nd.gov.

If you wish to schedule an in-person or video conference meeting to discuss the draft RH SIP revision, contact David Stroh.

If you have any general questions about this process, please contact David Stroh or myself at (701)328-5188.

Sincerely,

Jim Semerad
Director
Division of Air Quality

JS/DES:saj

D.2 – FLM Consultation Feedback and Department Response

D.2.a – National Park Service Comments

Stroh, David E.

From: Pohlman, David C. <David_Pohlman@nps.gov>
Sent: Monday, November 22, 2021 8:11 AM
To: Stroh, David E.
Cc: Glatt, Dave D.; Thorton, Rhannon T.; Semerad, Jim L.; Peters, Melanie
Subject: Re: [EXTERNAL] RE: NPS Consultation on Draft North Dakota Regional Haze SIP

***** **CAUTION:** This email originated from an outside source. Do not click links or open attachments unless you know they are safe. *****

Thanks, David. I'm glad we got it figured out. Sorry for all the frantic emails on Friday!

David

David Pohlman
Air Quality Specialist
National Park Service
Interior Region 3: Great Lakes
Interior Region 4: Mississippi Basin
Interior Region 5: Missouri Basin

111 Kellogg Blvd. E., Suite 105
Saint Paul, MN 55101
Phone: ~~651-293-8448~~
Now working from home: 651-491-3497

From: Stroh, David E. <deStroh@nd.gov>
Sent: Monday, November 22, 2021 8:08 AM
To: Pohlman, David C. <David_Pohlman@nps.gov>
Cc: Glatt, Dave D. <dglatt@nd.gov>; Thorton, Rhannon T. <rThorton@nd.gov>; Semerad, Jim L. <jsemerad@nd.gov>; Peters, Melanie <Melanie_Peters@nps.gov>
Subject: [EXTERNAL] RE: NPS Consultation on Draft North Dakota Regional Haze SIP

This email has been received from outside of DOI - Use caution before clicking on links, opening attachments, or responding.

Morning David,

We have received the comments. I was also able to access the calculation spreadsheets (the zip files) from the Sharepoint link provided by Sara Wilson (folder name: "NPS-ND_RH_Calculations_And_References").

If we have any questions/comments as we work through these documents, we will reach out.

Thank you,

David

David Stroh

Environmental Engineer

701-328-5229 • destroh@nd.gov

4201 Normandy St., Bismarck, ND 58503-1324

NORTH Dakota Be Legendary | Environmental Quality

From: Pohlman, David C. <David_Pohlman@nps.gov>
Sent: Friday, November 19, 2021 5:18 PM
To: Stroh, David E. <deStroh@nd.gov>
Cc: Glatt, Dave D. <dglatt@nd.gov>; Thorton, Rhannon T. <rThorton@nd.gov>; Semerad, Jim L. <jsemerad@nd.gov>
Subject: Fw: NPS Consultation on Draft North Dakota Regional Haze SIP

David,

I tried sending out consultation comments to ND, but I got an "undeliverable" message from all the ND addressees. I'm sending it again without the .zip file which seems to be problematic. Any ideas on how to get that file to you? It contains all the calculations spreadsheets, etc.

Have a good weekend!

David Pohlman
Air Quality Specialist
National Park Service
Interior Region 3: Great Lakes
Interior Region 4: Mississippi Basin
Interior Region 5: Missouri Basin

111 Kellogg Blvd. E., Suite 105
Saint Paul, MN 55101
Phone: ~~651-293-8448~~
Now working from home: 651-491-3497

From: Pohlman, David C.
Sent: Friday, November 19, 2021 4:56 PM
To: Stroh, David E. <deStroh@nd.gov>
Cc: Peters, Melanie <Melanie_Peters@nps.gov>; Vimont, John <John_Vimont@nps.gov>; King, Kirsten L <kirsten_king@nps.gov>; Shepherd, Don <Don_Shepherd@nps.gov>; Miller, Debra C <Debra_Miller@nps.gov>; Stacy, Andrea <Andrea_Stacy@nps.gov>; Ross, Wendy H <Wendy_Ross@nps.gov>; McGee-Ballinger, Maureen <Maureen_McGee-Ballinger@nps.gov>; Sexton, Chad L. <Chad_Sexton@nps.gov>; McCann, Blake E <blake_mccann@nps.gov>; Ohms, Marc J <Marc_Ohms@nps.gov>; Childers, Eddie L. <Eddie_Childers@nps.gov>; Allen, Tim <tim_allen@fws.gov>; Wickman, Trent R -FS <trent.wickman@usda.gov>; jill.webster@usda.gov <jill.webster@usda.gov>; Boehm, Shannon - FS <shannon.boehm@usda.gov>; Sorkin, Jeff- FS <Jeffrey.Sorkin@usda.gov>; dobrahner.jaslyn@epa.gov <dobrahner.jaslyn@epa.gov>; dglatt@nd.gov <dglatt@nd.gov>; Semerad, Jim L. <jsemerad@nd.gov>; Thorton, Rhannon T. <rThorton@nd.gov>; bean.clayton@epa.gov <bean.clayton@epa.gov>; worstell.aaron@epa.gov <worstell.aaron@epa.gov>
Subject: NPS Consultation on Draft North Dakota Regional Haze SIP

Hello David,

The National Park Service (NPS) appreciates the opportunity to review the Federal Land Manager (FLM) review draft of the North Dakota Regional Haze State Implementation Plan (SIP) for the Second Implementation Period (2018-2028). On October 19, 2021, staff from the NPS Air Resources Division (ARD) and NPS Interior Regions 3, 4, and 5 hosted a regional haze consultation meeting with the North Dakota Department of Environmental Quality (NDDEQ) staff to discuss NPS input on the draft North Dakota Regional Haze SIP. Representatives from the U.S. Forest Service and Environmental Protection Agency (Region 8) also attended. An annotated set of slides shared during this meeting are attached along with detailed technical feedback and supporting calculation worksheets. This email and the attachments document NPS conclusions and recommendations presented during our formal regional haze consultation, as required by 42 U.S.C. §7491(d).

As you know, North Dakota contains one NPS managed Class I area, Theodore Roosevelt National Park. Of all states North Dakota has the biggest influence on haze in NPS Class I areas based on a cumulative analysis of surrogate visibility impacts (emissions/distance). Emissions from North Dakota point and area sources are significant across the region and specifically contribute to regional haze at Theodore Roosevelt National Park in North Dakota as well as Badlands and Wind Cave National Parks in South Dakota.

We recognize North Dakota for putting together a well laid out and detailed SIP, and for engaging with NPS early in the SIP development process. We appreciate your commitment to reducing pollutants in the region to help improve visibility in all Class I areas. Still, significant additional progress is necessary before the ultimate visibility goal of no human caused visibility impairment is realized. It is with this in mind that we provide SIP review feedback, summarized here.

North Dakota selected all of the NPS recommended facilities to analyze for haze causing emission reduction opportunities. The North Dakota draft SIP provides some of the best four-factor analyses that we have reviewed in this planning period. However, there are several overarching issues that generally inflated costs associated with controls. Please see the attached technical review document and supporting calculation worksheets for a detailed review of individual analyses.

As part of early engagement, NPS requested that North Dakota consider opportunities to reduce haze causing emissions from the oil and gas sector. NPS research indicates that oil and gas emissions contribute to visibility impairment at Theodore Roosevelt National Park. Emissions from oil and gas sources in the North Dakota portion of the Williston Basin are the highest in the Western Regional Air Partnership region, and are projected to increase rather than decrease. However, North Dakota determined individual engine controls are not reasonable during this planning period. Significant cumulative emissions coupled with a limited footprint from any single wellsite points to the need for statewide rules addressing the oil and gas source sector. Many states now implement state or region-wide requirements to limit NOx emissions from area source engines. We encourage North Dakota to consider similar rules to reduce haze causing emissions in this planning period.

We request that North Dakota remove the discussion of correlation between most visually impaired days at Theodore Roosevelt National Park and park visitation.

We recommend that North Dakota establish a cost-effectiveness threshold for reasonable progress in line with other states and/or based on North Dakota thresholds used for previous rounds of regional haze (adjusted for inflation). In doing so, the four-factor analyses would likely show that a number of cost-effective controls are available for the facilities evaluated.

In the draft SIP NDDEQ concludes that additional measures are not needed because:

- Trends in haze on most impaired days are going down.
- Progress on most impaired days is below adjusted uniform rate of progress (URP).
- They will not result in significant visibility improvements.

While overall visibility impairment trends are improving, in recent years (2016-2019) haze has increased on the most impaired days in NPS Class I areas most affected by North Dakota emissions. Continuous improvement will be needed to continue the downward trend in haze and meet the 2064 goals. The URP glideslope is a planning tool, not a standard. EPA has made it clear that being under the glideslope is not a reason to dismiss otherwise reasonable controls. The goal of the Clean Air Act and the Regional Haze Rule is natural conditions, and no Class I area in the state or downstream has reached that goal yet.

Visibility improvement in Class I areas depends on the cumulative effects of regional emission reductions. Although the EPA 2019 Regional Haze Guidance allows states to consider visibility when determining their long-term strategy, the guidance did not intend for visibility improvement to be used as a fifth factor to reject controls that would otherwise be determined reasonable. In order to achieve reasonable progress in this round of SIP development we request that North Dakota require all technically feasible and cost-effective controls identified through four-factor analysis.

Please know that we welcome the opportunity for further dialogue with you as North Dakota progresses to a final SIP revision. If you have any questions, do not hesitate to reach out to us. Also, feel free to let us know if you have any edits to this summary and especially if any corrections are needed.

Best,

David

Attachment List:
NPS-ND_RH_CalculationsAndReferences.zip
NPS-ND_RH-ConsultationSlides_2021.pdf
NPS_ND_RH-SIP-ConsultationFeedback.docx

David Pohlman
Air Quality Specialist
National Park Service
Interior Region 3: Great Lakes
Interior Region 4: Mississippi Basin
Interior Region 5: Missouri Basin

111 Kellogg Blvd. E., Suite 105
Saint Paul, MN 55101
Phone: ~~651-293-8448~~
Now working from home: 651-491-3497

National Park Service (NPS) Regional Haze SIP feedback for the North Dakota, Department of Environmental Quality

November 19, 2021

Contents

1 Executive Summary

The National Park Service (NPS) appreciates the opportunity to review the Federal Land Manager (FLM) review draft of the North Dakota Regional Haze State Implementation Plan (SIP) for the Second Implementation Period (2018-2028). On October 19, 2021, staff from the NPS Air Resources Division (ARD) and NPS Interior Regions 3, 4, and 5 hosted a regional haze consultation meeting with the North Dakota Department of Environmental Quality (NDDEQ) staff to discuss NPS input on the draft North Dakota Regional Haze SIP. We provide the following recommendations to strengthen the SIP, which were discussed during our consultation meeting and detailed in this document.

North Dakota is home to one NPS-managed Class I area, Theodore Roosevelt National Park. Of all states, North Dakota has the most significant influence on haze in NPS Class I areas based on a cumulative analysis of surrogate visibility impacts (emissions/distance). Emissions from North Dakota point and area sources contribute to regional haze at Theodore Roosevelt National Park in North Dakota as well as Badlands and Wind Cave National Parks in South Dakota.

In summary, we request that North Dakota:

1. Require cost-effective measures to reduce haze-forming pollutants identified through the four-factor analyses in SIP. Our facility-specific recommendations are discussed in subsequent sections.
2. Consider oil and gas emission reduction opportunities in this planning period.
3. Establish a cost-effectiveness threshold for reasonable progress that is in line with other states and/or based on NDDEQ thresholds used for previous rounds of regional haze (adjusted for inflation) (see Section 2.2).
4. Remove the discussion that correlates the most visually impaired days at Theodore Roosevelt National Park with park visitation data (see Section 2.1).

In the draft SIP NDDEQ concludes that additional emission reduction measures are not needed because:

- Trends in haze on most impaired days are going down.
- Progress on most impaired days is below the adjusted uniform rate of progress (URP).
- They will not result in significant visibility improvements.

While overall visibility impairment trends are improving, in recent years (2016-2019) haze has increased on the most impaired days in NPS Class I areas most affected by North Dakota emissions. Continuous improvement will be needed to continue the downward trend in haze and meet the 2064 goals. The URP glideslope is a planning tool, not a standard. EPA has made it clear that being under the glideslope is not a reason to dismiss otherwise reasonable controls. The goal of the Clean Air Act and the Regional Haze Rule is natural conditions, and no Class I area in the state or downstream has reached that goal (see Section 2.3).

Visibility improvement in Class I areas depends on the cumulative effects of regional emission reductions. Although the EPA 2019 Regional Haze Guidance allows states to consider visibility when determining their long-term strategy, the guidance did not intend for visibility improvement to be used as a fifth factor to reject otherwise reasonable controls. To achieve reasonable progress in this round of SIP development we request that North Dakota require technically feasible and cost-effective controls identified through the four-factor analyses (see Section 2.3).

NDDEQ selected all the NPS recommended facilities to analyze for haze causing emission reduction opportunities. Four-factor reasonable progress analyses for the following facilities are included in the North Dakota draft SIP:

- Coyote Station
- Antelope Valley Station
- Coal Creek Station
- Milton R Young Station
- Leland Olds Station
- R M Heskett Station
- Great Plains Synfuels Plant
- Tioga Gas Plant
- Little Knife Gas Plant
- Northern Border Pipeline Compressor Station No. 4

The North Dakota draft SIP provides some of the best, technically sound four-factor analyses that the NPS has reviewed in this planning period. However, there are several recurring issues with the four-factor analyses that generally the inflated cost of controls. These are discussed in Section 2.4 of this document. The potential to use Selective Catalytic Reduction (SCR) to reduce nitrogen oxide emission for units burning North Dakota lignite coal is evaluated and discussed in Section 2.5. Please see Section 3 and supporting calculation worksheets for a detailed review of individual four-factor analyses.

As part of early engagement, NPS requested that NDDEQ consider opportunities to reduce haze causing emissions from the upstream oil and gas source sector. As described in Section 4, NPS research indicates that oil and gas emissions contribute to visibility impairment at Theodore Roosevelt National Park. NOx emissions from oil and gas sources in the North Dakota portion of the Williston Basin are the highest in the Western Regional Air Partnership region. Modest decreases in NO_x emissions are projected for North Dakota oil and gas sources, while SO_2 emissions are projected to increase by 2028. However, NDDEQ determined individual engine controls are not reasonable during this planning period. Significant cumulative emissions coupled with a limited footprint from any single wellsite points to the need for statewide rules addressing the oil and gas source sector. Many states now implement state or region-wide requirements to limit NO_x emissions from engines. We encourage NDDEQ to consider similar rules to reduce haze causing emissions in this planning period.

2 Overarching feedback

2.1 Low visitation correlation with most impaired days

In section 1.3.2 of the SIP, NDDEQ noted that 75% of visitation to Theodore Roosevelt NP occurs during the months of June through September, but that these four months account for only 4% of the most impaired days. From this, the SIP concludes that "that focusing on the MID for TRNP will not meaningfully improve visibility or a visitor's experience in TRNP" (p. 25). We disagree with this conclusion for the following reasons. First, the Clean Air Act amendments of 1977 set a national goal of the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I federal areas which impairment results from man-made air pollution." In order to meet this goal, the Clean Air Act requires that the long-term strategy and reasonable progress goals must provide for improvement in visibility on the most impaired days while preventing deterioration of visibility on the clearest days and that reasonable progress determinations are to be based on the four statutory factors. In its 2019 guidance document (*Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 2019), EPA also addressed this issue by saying (p. 41):

> *We do not recommend the use of weighting of visitation, high or low, in protecting visibility in Class I areas. In addition, we believe that a state should not give less weight to protecting visibility in a given Class I area during times of the year with lower visitation.*

Second, while park visitation is higher in the summer months, that should not discount the importance of the visitor experience in other months of the year. The National Park Service's Organic Act (16 U.S.C. §1) requires the service to conserve resources "in a manner and by such means as will leave them unimpaired" for future generations. The Act does not allow the service to provide less protection for park resources based upon the timing or relative levels of visitation. In 2021, there were 115,884 visitors to Theodore Roosevelt NP in January through May.[1] Visitor survey data consistently indicate that clean air and clear views are important to park visitors. The opportunity to experience unimpaired vistas is just as relevant to a visitor in January as it is in July. Fluctuations in visitation levels are not germane to the goals of the Regional Haze Rule or to the management requirements of the National Park Service and we recommend that this discussion be deleted from the ND draft SIP.

[1] Data available at: https://irma.nps.gov/STATS/SSRSReports/Park%20Specific%20Reports/Recreation%20Visitors%20By%20Month%20(1979%20-%20Last%20Calendar%20Year)?Park=THRO

2.2 Cost effectiveness thresholds

In 2011, the North Dakota Department of Environmental Quality (NDDEQ) established cost-effectiveness thresholds for Best Available Retrofit Technology (BART):

- $4,100/ton for average cost-effectiveness and
- $7,300/ton for incremental costs effectiveness.

Applying the Chemical Engineering Plant Cost Index to adjust for inflations, these thresholds in 2019$ are:

- $4,200/ton for average cost-effectiveness and
- $7,500/ton for incremental costs effectiveness.

However, EPA has expressed caution regarding using BART costs for Reasonable Progress[2]:

> *Given the differences between the BART factors and RP factors and the nature of the applicability criteria that would trigger BART and RP analyses, we do not necessarily consider the cost-effectiveness and visibility benefit values from BART determinations to be directly comparable to RP analyses*

It is generally accepted that the cost-effectiveness threshold for Reasonable Progress will be higher as smaller emission units are considered. Other states have set cost-effectiveness thresholds of: $5,000/ton for EGUs in AR and TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

2.3 Visibility benefit & URP

The long-term strategy selected by the state does not include additional controls for any of the sources selected for four-factor analysis, despite the fact there are technically feasible, cost-effective control options for several of the emissions units considered. According to the SIP, the state believes that further controls are not needed because (1) the projected 2028 visibility is below the uniform rate of progress (URP) at the North Dakota Class I areas and (2) potential improvements to visibility from additional reductions would be insignificant. These conclusions are inconsistent with our understanding of the Regional Haze Rule requirements.

Under the CAA (§7491 (g)(1)), reasonable progress determinations *shall* consider the:

> *"…costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements;"*

[2] ENVIRONMENTAL PROTECTION AGENCY, 40 CFR Part 52, [EPA–R09–OAR–2013–0588; FRL–9912–97–OAR], Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, ACTION: Final rule. September 3, 2014

Reasonable Progress requirements of the rule (40 CFR § 51.308 (f)), states are required to include a long-term strategy that "must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress."

Specifically omitted from this list is the consideration of the visibility benefit of control measures. The rule requires that the state determine the URP needed to meet the goal of unimpaired visibility by 2064. However, EPA has clarified that the URP is not a "safe harbor." States should not dismiss otherwise technically feasible, cost-effective controls solely because visibility progress in state's Class I areas is better than the URP. The URP is a planning tool that allows states to evaluate their overall progress toward the goal, but it is not a standard that indicates by itself whether or not progress is reasonable. It may be that a state's Class I areas are not meeting the URP but the state is still making reasonable progress if it finds by applying four-factor analysis to its sources that there are no technically feasible, cost effective controls to implement. Conversely, it may be that a state's Class I areas are meeting the URP but are still not making reasonable progress if the state rejects technically feasible cost-effective controls because the Class I areas are below the glideslope. As EPA noted in its July 2021 clarification memo:

> *The 2017 RHR preamble and the August 2019 Guidance clearly state that it is not appropriate to use the URP in this way, i.e., as a "safe harbor." The URP is a planning metric used to gauge the amount of progress made thus far and the amount left to make. It is not based on consideration of the four statutory factors and, therefore, cannot answer the question of whether the amount of progress made in any particular implementation period is "reasonable progress." This concept was explained in the RHR preamble. Therefore, states must select a reasonable number sources and evaluate and determine emission reduction measures that are necessary to make reasonable progress by considering the four statutory factors.*

This memo is consistent with earlier guidance from EPA. As EPA noted in the preamble to the 2017 Regional Haze Rule (82 FR 3099):

> *The CAA requires that each SIP revision contain long-term strategies for making reasonable progress, and that in determining reasonable progress states must consider the four statutory factors. Treating the URP as a safe harbor would be inconsistent with the statutory requirement that states assess the potential to make further reasonable progress towards natural visibility goal in every implementation period.* ***Even if a state is currently on or below the URP, there may be sources contributing to visibility impairment for which it would be reasonable to apply additional control measures in light of the four factors****. Although it may conversely be the case that no such sources or control measures exist in a particular state with respect to a particular Class I area and implementation period, this should be determined based on a four-factor analysis for a reasonable set of in-state sources that are contributing the most to the visibility impairment that is still occurring at the*

*Class I area. **It would bypass the four statutory factors and undermine the fundamental structure and purpose of the reasonable progress analysis to treat the URP as a safe harbor, or as a rigid requirement** (emphasis added).*

We also note that while trends in visibility conditions show improvement on the most impaired days since 2000, data since 2016 show an increase in haze at Theodore Roosevelt, Badlands, and Wind Cave National Parks (Figure 1). This highlights the need for continuing progress in reducing haze-causing emissions during this planning period.

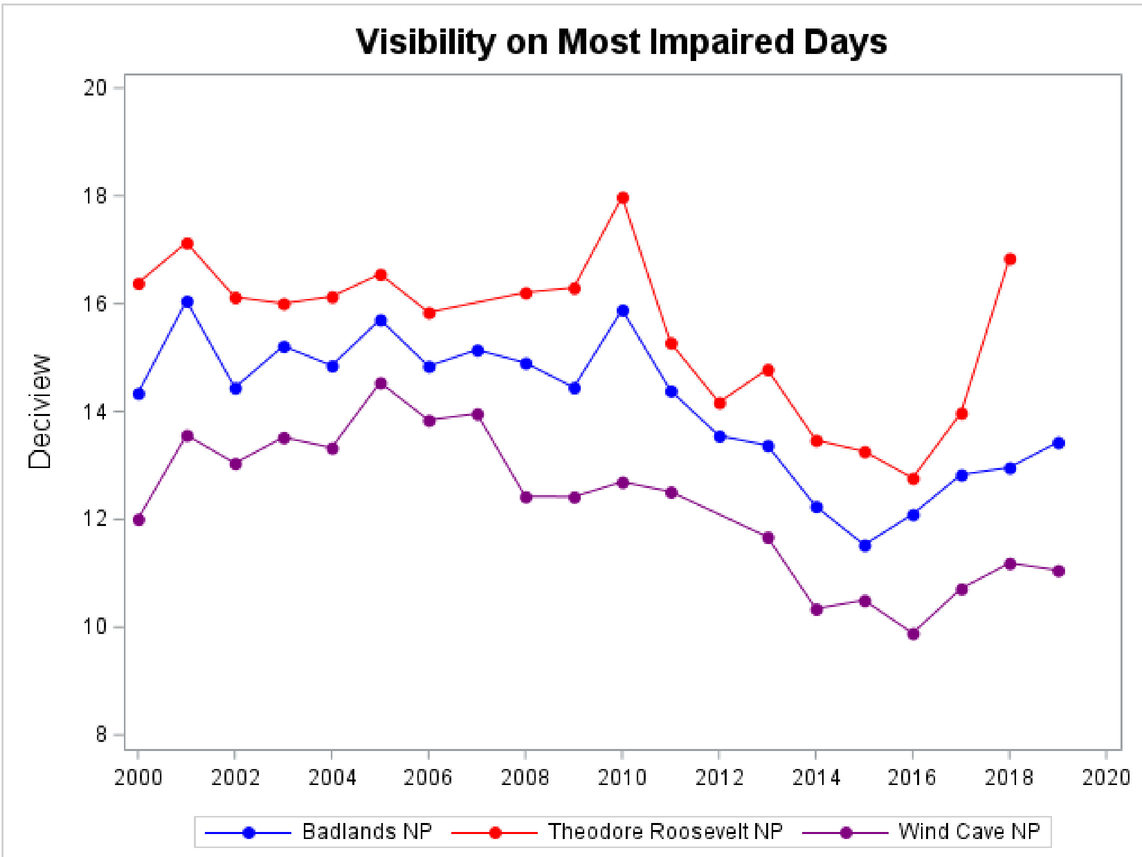


Figure 1. Visibility on most impaired days for Badlands, Theodore Roosevelt, and Wind Cave National Parks (2000-2020)

In its 2021 memo, EPA also addressed the use of visibility benefit when considering potential emissions controls. Similar to its conclusion regarding the use of the URP, EPA stated that it is not appropriate to reject cost-effective control measures simply because the impact on visibility is considered to be insignificant:

We have observed that some draft SIPs are using modeled visibility benefits to justify rejecting otherwise cost-effective control measures. It is important that, where applicable, each state considers the magnitude of modeled visibility impacts or benefits in the context of its own contribution to visibility impairment. That is, whether a particular visibility impact or change is "meaningful" should be assessed in the context of the individual state's

> *contribution to visibility impairment, rather than total impairment at a Class I area. As stated in the RHR preamble:*
>
> > *Regional haze is visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. At any given Class I area, hundreds or even thousands of individual sources may contribute to regional haze. Thus, it would not be appropriate for a state to reject a control measure (or measures) because its effect on the RPG is subjectively assessed as not "meaningful."*

EPA's 2019 guidance acknowledges that the Clean Air Act does not prohibit a state from considering visibility benefit when determining which control measures are needed to make reasonable progress. However, the RH guidance and the 2021 Clarification Memorandum identify appropriate and inappropriate methods for examining visibility impacts and benefit from individual sources. For example, section II.B.4.g of the guidance notes:

> *In particular, a state should not use the difference in projected 2028 visibility with and without the control measure (e.g., the effect on the 2028 RPG) as its only characterization of the visibility benefit of the measure.*

The guidance explains in a footnote that when using visibility benefits to inform decisions on emissions controls for individual sources, a state should not rely on an estimate of visibility benefits relative to a "dirty background"—that is, a condition where background visibility impairment is greater than natural conditions—because doing so would obscure the full benefits of control measures. However, this is what North Dakota has done. The state compared projected overall visibility conditions at Theodore Roosevelt NP on the most impaired days in 2028 under two scenarios—one with only on-the-books reductions (2028 OTB) and one with potential additional control measures included (2028PAC1)—and concluded that the modeled 0.08 DV difference would not meaningfully improve visibility (pp. 127-128). By choosing 2028 as the projected year for this comparison, the state has made a comparison of visibility conditions quantified in deciviews against a background where visibility conditions are greater than natural conditions (i.e., a "dirty" background).

In addition, the 2028PAC1 modeling run only included additional potential controls from two North Dakota sources. Our analysis shows that there are a number of additional technically feasible, cost-effective controls available for other North Dakota's sources. The result is that the comparison in projected visibility conditions understates the potential visibility improvements that would result at the park from additional controls.

We request that North Dakota require all control measures found to be technically feasible and cost-effective through analysis of the four factors specified in the Regional Haze Rule.

2.4 Reasonable Progress Costs of Compliance

The "costs of compliance" is the first of the four reasonable progress statutory factors contained in Section 169 of the Clean Air Act.

Overestimation of Costs

In reviewing four-factor analyses presented in the ND draft Reasonable Progress SIP, we identified several re-occurring errors in the cost analyses that generally result in overestimation of costs. As much as possible, we relied upon the most recent versions of EPA's Control Cost Manual (CCM) to identify these errors and inform our calculations. NPS cost analyses for individual ND facilities are described below and documented in the attached calculation spreadsheets.

- Several four-factor analyses applied a 20% Contingency Cost of Direct and indirect capital costs to all capital cost analyses. The CCM says:

  > *The contingency, C, accounts for unexpected costs associated with the fabrication and installation of the absorber and is calculated by multiplying the total direct and indirect costs by a contingency factor (CF). A default value of 10% is typically used for CF.*

- Several four-factor analyses applied 2% of Direct cost as Owners' Costs—this is not allowed by EPA.
- In some cases, four-factor analyses include Property Taxes = 1% of TCI. Insurance = 1% of TCI. Administration = 2% of TCI. The CCM says:

  > *property taxes and overhead are both assumed to be zero, and insurance costs are assumed to be negligible. Thus, administrative charges and capital recovery are the only components of indirect annual costs estimated in this analysis.*

- Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25% and equipment life of 20 years.
  - EPA's Control Cost Manual (CCM) recommends a scrubber and SCR equipment life of 30 years and use of the current prime interest rate (3.25%) unless a site-specific interest rate is justified. The CCM recommends 20 years for SNCR equipment life.

2.5 Selective Catalytic Reduction (SCR) on North Dakota Lignite

SCR is a process by which ammonia (NH_3) reacts with nitric oxide (NO) and nitrogen dioxide (NO_2), collectively NO_x, in the presence of a catalyst to reduce the NO_x to nitrogen (N_2) and water (H_2O). SCR technology has been applied to NO_x-bearing flue gases generated from power generating facilities burning various types of coal, including bituminous, subbituminous, and Texas lignite. The principal reactions resulting in NO_x reduction are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NO_2 + 8NH_3 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

Because these reactions proceed slowly at typical boiler exit gas temperatures of a coal-fired steam -electric generating unit, a catalyst is used to increase the reaction rate between NO_x and

NH_3. Depending on the specific constituents in the flue gas, a typical temperature range of 550°F to 780°F is necessary to achieve normal performance of the catalyst. For the typical coal-fired boiler, optimal performance will be in the range of approximately 650°F to 750°F.

SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation) or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition).

2.5.1 SCR Configurations

In general, there are three candidate SCR configurations that can be employed on coal-fired steam electric generating units. The SCR configuration designations generally describe the location of the SCR reaction vessel in relation to other post-combustion air quality control systems. Candidate SCR configurations include:

- High-dust configuration
- Low-dust configuration
- Tail-end configuration

High-Dust Configuration

In a high-dust configuration, the SCR reactor is located in the flue gas stream between the economizer outlet and the air heater inlet. This configuration locates the SCR within the inherently optimal temperature range environment for NO_x reduction (i.e., 650°F to 750°F); however, flue gas characteristics at the economizer outlet can also have detrimental effects on the SCR catalyst. As an example, the high-dust SCR configuration exposes the SCR catalyst to high levels of fly ash loading. High levels of fly ash can result in significant erosion of the catalyst, resulting in more frequent cleaning cycles and catalyst replacement. A second major concern with the high-dust configuration is the presence of high levels of sodium (both in the vapor-phase and as submicron aerosols) in the North Dakota lignite-derived flue gas. Sodium is a known SCR catalyst poison, and also affects the adhesive and cohesive characteristics of the fly ash, which in turn, would have an adverse effect on the SCR catalyst and reactor vessel.

Low-Dust Configuration

In the low-dust configuration, the SCR reactor vessel is located in the flue gas stream after the particulate collection device (i.e. ESP or FF). The potential advantage of a Low-Dust SCR configuration is that the mechanisms that result in particulate capture may also capture some of the vapor-phase alkali and the alkali-enriched submicron particles, reducing the risk of catalyst poisoning and/or deactivation.

Tail-End Configuration

In the tail-end configuration, the SCR reaction vessel is located in the flue gas stream after the particulate and FGD control systems. The potential advantage of a Tail-End SCR (TE-SCR) configuration is that the mechanisms that capture of SO_2 and particulate will also capture some of the vapor-phase alkali and the alkali-enriched submicron particles, reducing the risk of catalyst poisoning and/or deactivation.

2.5.2 SCR Technical Feasibility

In evaluating the "Cost of Compliance" (Clean Air Act Statutory Factor #1), potential control strategies must be evaluated for their technical feasibility. There are two components to the technical feasibility determination: **availability** and **applicability**.

SCR is available— it has been applied to numerous coal-fired boilers, including lignite-fired boilers[3]. The question is whether it is applicable. According to the BART Guidelines:

> *What do we mean by ''applicable'' technology?*
>
> *You need to exercise technical judgment in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been used on the same or a similar source type. Absent a showing of this type, you evaluate technical feasibility by examining the physical and chemical characteristics of the pollutant-bearing gas stream, and comparing them to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on a new or existing source with similar gas stream characteristics is generally a sufficient basis for concluding the technology is technically feasible barring a demonstration to the contrary as described below.*
>
> *What type of demonstration is required if I conclude that an option is not technically feasible?*
>
> *Where you conclude that a control option identified in Step 1 is technically infeasible, you should demonstrate that the option is either commercially unavailable, or that specific circumstances preclude its application to a particular emission unit. Generally, such a demonstration involves an evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology. Alternatively, a demonstration of technical infeasibility may involve a showing that there are unresolvable technical difficulties with applying the control to the source (e.g., size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability, and adverse side effects on the rest of the facility).*

The primary argument against the applicability of SCR to boilers fired with ND lignite is that the catalyst will experience rapid deactivation.

[3] Sandow unit #4 and Oak Grove in Texas

2.5.3 SCR Catalyst Deactivation

SCR catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is caused by either exposure of the catalyst to excessive temperatures (thermal deactivation) or masking of the catalyst due to entrainment of particulate from the flue gas stream (fouling). Chemical deactivation is caused by either an irreversible reaction of the catalyst with a contaminant in the gas stream (poisoning) or a reversible absorption of a contaminant on the surface of the catalyst (inhibition).

SCR catalyst poisoning can result from the presence of trace elements and strong alkaline substances in flue gas. including sodium (Na). potassium (K), and calcium (Ca). Alkaline metals can chemically attach to active catalyst pore sites and cause deactivation. Sodium and potassium are of prime concern especially in their water-soluble forms, which are more mobile and can penetrate into the catalyst pores. Earth metals, especially calcium, can react with SO_3 absorbed within the catalyst to form $CaSO_4$ and blind the catalyst.

ND lignite contains relatively high levels of organically associated alkali and alkaline-earth elements, including Na, Ca, K, and magnesium. Na levels in North Dakota lignite are typically 5 to 20 times higher than Na levels in bituminous and subbituminous coals, and Na compounds can represent between 5% and 11% of the ash generated from firing ND lignite.

EPA guidance recommends a demonstration of technical infeasibility *"involves an evaluation of the characteristics of the pollutant-bearing gas stream."* In the first planning period, NDDEQ relied upon testing of SCR catalyst described as follows:

> *To evaluate deactivation rates on a North Dakota lignite-fired boiler, [U of ND Energy & Environmental Research Center] EERC and several utilities and catalyst vendors conducted pilot scale testing at the Coyote Station in 2003-2004. The pilot scale test reactor SCR deployed at the Coyote Station became plugged and the catalyst pores deactivated after 2 months of operation (approximately 1,430 hours). This deactivation rate is significantly faster than the deactivation rate observed on bituminous and subbituminous coal-fired units, which can achieve catalyst life ranging between 10,000 and 30,000 operating hours. The EERC described the deactivation at the Coyote Station as extremely rapid and severe. NDDEQ prepared a comprehensive technical feasibility assessment of high dust SCR on lignite-fired boilers during the first planning period. The Department concluded, based on the unique characteristics of North Dakota lignite-derived flue gas, that the high-dust SCR configuration was not a technically feasible or commercially available* NO_x *control option for North Dakota lignite-fired boilers.*

This "demonstration" was conducted on a pilot-scale SCR located in a high-dust configuration on a cyclone boiler firing ND lignite; this narrow, 17-year-old, demonstration does not apply to SCR in either a low-dust or tail-end configuration or on other types of boilers. The burden to demonstrate that the gas stream characteristics would render SCR technically unfeasible rests upon the source owner. Because these are existing emission units, the source owners have had many years to test emissions downstream of the emission control systems. We are not aware that any such testing has been conducted or results made available. In the absence of such demonstrations, we conclude that tail-end SCR is technically-feasible on boilers firing ND lignite. Ultimately, the rate of catalyst deactivation is a factor to be considered in the economic analysis, not in the technical feasibility determination.

During the first regional haze program planning period in North Dakota, the ND Department of Environmental Quality (NDDEQ) determined that installation of SCR in any configuration was not a technically feasible control technology because it had not been demonstrated in practice on ND lignite. However, the earlier determination was based upon pilot testing on cyclone-fired boilers in a high-dust configuration. Also, some source owners (through their consultants) argued that SCR is not technically feasible because catalyst vendors concluded that they would not be able to provide a catalyst life guarantee for either low-dust or tail-end SCR without pilot-scale testing. However, the absence of a vendor guarantee does not mean that a technology is infeasible.

Now, NDDEQ is saying that:

> *Successful use of Tail-End SCR (TE-SCR) controls have since been demonstrated at existing bituminous- and subbituminous-fired units. Therefore, the current determination is deeming TE-SCR as being technically feasible on tangentially-fired and wall-fired boilers burning North Dakota lignite.*[4]

We note that NDDEQ continues to say that SCR is not technically-feasible in any configuration of cyclone boilers burning ND lignite.[5]

2.5.4 SCR Effectiveness

NDDEQ assumed that TE-SCR could achieve 0.05 lb/mmBtu. However, Tail-End SCR should be able to reduce NO_x emissions by up to 90% and achieve 0.04 lb/mmBtu. For example, CAMD data contains 11 coal-fired EGUs with SCR at 0.04 lb/mmBtu annual average.

[4] Tangentially-fired Units 1 and Unit 2 at Antelope Valley Station and Coal Creek Station, as well as the wall-fired Unit 1 at Leland Olds Station.

[5] Coyote Station, Leland Olds Station Unit 2, Milton R. Young Station Units 1 and 2.

Table 1. Coal-Fired EGUs with SCR at 0.04lb/mmBtu Annual Average

State	Facility Name	Unit ID	Avg. NO_x Rate (lb/MMBtu)	Unit Type
WI	Edgewater (4050)	5	0.04	Dry bottom wall-fired boiler
KY	Trimble County	2	0.04	Dry bottom wall-fired boiler
TX	J K Spruce	**2	0.04	Tangentially-fired
WY	Dry Fork Station	1	0.04	Dry bottom wall-fired boiler
KS	Jeffrey Energy Center	1	0.04	Tangentially-fired
KY	E W Brown	3	0.04	Tangentially-fired
IA	Walter Scott Jr. Energy Center	4	0.04	Dry bottom wall-fired boiler
IA	Lansing	4	0.04	Dry bottom turbo-fired boiler
AR	John W. Turk Jr. Power Plant	SN-01	0.04	Dry bottom wall-fired boiler
TX	W A Parish	WAP7	0.04	Tangentially-fired
TX	Sandy Creek Energy Station	S01	0.04	Dry bottom wall-fired boiler

Furthermore, EPA assumed in 2014 that SCR could achieve the 0.04 lb/mmBtu annual emission rate proposed by Basin Electric at its Laramie River Station in WY.

2.5.5 SCR Cost Elements

Successful operation of the tail-end configuration might also require a heat exchanger to reheat the flue gas. However, special catalysts are available that operate at lower or higher temperatures. According to SCR vendor Ceram:

> *Our honeycomb catalyst can be tailored to customer specifications by varying the vanadia content. Our products are suitable for temperatures between 150°C and 550°C /300°F and 1020°F.*

According to EPA's Control Cost Manual (CCM):

> *A tail-end system may have higher capital and operating costs than the other SCR systems because of the additional equipment and operational costs associated with flue gas reheating and heat recovery. However, these costs are in part offset by reductions in catalyst costs. Tail-end units require less catalyst because they can use catalysts with smaller pitch and higher surface area per unit volume. Tail-end SCR typically require only 2 layers of catalyst, although some use four half-layers of catalyst to allow for greater flexibility for catalyst replacement. In addition, because there is less fly ash, catalyst poisons, and SO_2 in the flue gas for tail-end units, the catalyst lifetime is*

significantly increased, and less expensive catalyst may be used. Some sources have reported catalyst lifetimes for tail-end SCRs to be over 100,000 hours. The tail-end SCRs may also have longer lifetimes due to the lower operating temperatures and lower levels of dust and SO_3.

Please see EPA Control Cost Manual Chapter 2, Selective Catalytic Reduction, June 2019; (§2.2.3 SCR System Configurations pg's 34-35) for more information on TE-SCR.

2.5.6 Conclusions & Recommendations

- NDDEQ has determined that Tail-End Selective Catalytic Reduction (TE-SCR) is technically-feasible on tangentially-fired and wall-fired boilers burning ND lignite.
- Catalyst deactivation is normal; the rate of deactivation is an economic factor rather than a technical-feasibility issue.
- No demonstration has been provided that TE-SCR is not feasible on cyclone boilers burning ND lignite. We conclude that TE-SCR is technically-feasible on these boilers.
- SCR can achieve NO_x rates as low as 0.04 lb/mmBtu.
- Capital and operating costs of TE-SCR likely warrant further evaluation.

3 Specific Review of Four-Factor Analyses

3.1 Coyote Station

3.1.1 Summary of NPS Recommendations and Requests for Coyote Station

NPS review of the four-factor analysis conducted for Coyote Station (Coyote) finds that there are technically feasible and cost-effective opportunities available to further control SO_2 and NO_x emissions from Unit 1. In fact, we find that the cost of control is more economical than estimated when analyses are adjusted in accordance with the EPA Cost Control Manual.

Although ND has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of: $5,000/ton for EGUs in AR and TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

The cost effectiveness of replacing the existing SO_2 scrubber at Coyote would be acceptable in the context of the previous ND BART thresholds as well as the thresholds used by the states listed above. Replacement of the existing dry scrubbers with modern new scrubbers could cost-effectively reduce facility SO_2 emissions by almost 11,600 tons/yr.

We find at least two cost effective opportunities for reducing NO_x emissions at Coyote. 1) The addition of SNCR + RRI very cost effective and could reduce NO_x emissions by almost 4,000 tons/yr. 2) The average cost effectiveness of adding SCR at Coyote would also be acceptable in the context of the previous ND BART thresholds as well as the thresholds used by the states cited. Addition of SCR could reduce facility NO_x emissions by almost 5,700 tons/yr.

We recommend that ND take every opportunity to reduce SO_2 and NO_x emissions from the Coyote Station in this planning period. By requiring implementation of identified controls ND will be reducing haze causing emissions and advancing incremental improvement of visibility at Theodore Roosevelt, Badlands, and Wind Cave National Parks as well as other Class I areas in the region.

3.1.2 Plant Characteristics

Coyote Station (Coyote) is a lignite coal-fired power station operated by Otter Tail Power near Beulah, North Dakota, 109 km east of Theodore Roosevelt National Park, a Class I area administered by the National Park Service (NPS).

Of 3,317 Electricity Generating Units (EGUs) in EPA's Clean Air Markets Database (CAMD) in 2020, Coyote ranked #5 for sulfur dioxide (SO_2) emissions (11,975 ton) and #4 for nitrogen oxides (NO_x at 5,883 tons). Coyote's carbon dioxide emissions of 2,909,521 tons rank #112 in the US. Coyote also ranked #42 for EGU mercury (Hg) emissions with 81 lb in 2017.

The facility is a single unit station with one 450 MW Babcock and Wilcox subcritical cyclone boiler (Coyote Unit 1). Coyote Unit 1 is designed to fire North Dakota lignite and is equipped with separated overfire air (SOFA) for NO_x control, and dry flue gas desulfurization (DFGD or dry FGD) and a fabric filter baghouse (FF) for SO_2 and particulate matter (PM) control. Coyote began Halogenated Powdered Activated Carbon Sorbent Injection Apr 16, 2015 to comply with the Mercury and Air Toxics Standards. Lignite is delivered to the Station from the Coyote Creek Mine, whose primary operations are approximately 3-4 miles from the Coyote Station.

3.1.3 First Planning Period Reasonable Progress Control Requirements for Coyote Station

Coyote Unit 1 commenced operation in 1981 and was not classified as a BART -eligible source or subject to the BART requirements. Nevertheless, during the initial planning period, the North Dakota Department of Environmental Quality (NDDEQ) evaluated emissions from the Coyote Station as a Reasonable Progress (RP) source. The RP analysis prepared by NDDEQ concluded that no additional controls would be required on Coyote Unit 1 during the initial planning period; however, NDDEQ and Otter Tail reached an agreement whereby Otter Tail committed to install SOFA equipment to reduce NO_x emissions. SOFA began Jun 15, 2016 and the effects can be seen on the chart below.

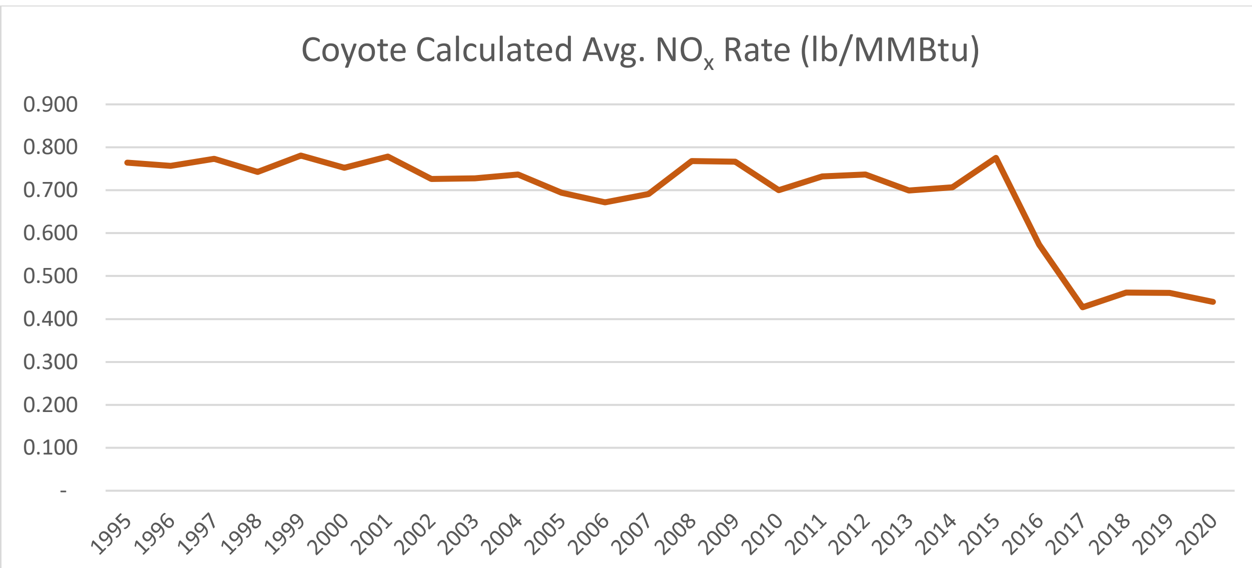


Figure 2. Calculated Avg. NO_x Rate for Coyote Station Unit 1 (1995-2020)

Coyote Unit 1 is equipped with 12 ten-foot cyclones, six on the front wall and six on the rear wall, two levels of three on each wall. The lignite coal requires a pre-dry system, which conveys the coal through individual crushers and into a cyclone separator for moisture separation. The dried coal is discharged from the bottom of the separator through a rotary seal, while the transport air (with a small quantity of fines) is discharged out the top and into ports above the cyclones. The coal discharged through the bottom rotary seal is blown into the cyclone through a pipe referred to as the "lift line" or known as primary air on most other similar installations. The temperature of the pre-dry air/coal temperature is regulated along with the lift line air by injecting cold (tempering) air into the hot primary air stream to regulate the outlet temperatures.

In 2016, The Babcock and Wilcox Company (B&W) installed fourteen separated overfire air (SOFA) ports (seven on the front and rear wall) and modified the cyclones with smaller re-entrant throats and a Vi - Vi split air damper (each having its own damper) to reduce NO_x

emissions. For the SOFA process, the injection of air into the boiler is staged into two zones, in which approximately 5% to 20% of the total combustion air is diverted from the burners and injected through ports located above the top burner level. Staging of the combustion air reduces NO_x formation by two mechanisms. First, staged combustion results in a cooler flame which will reduce the formation of thermal NO_x. Second the staged combustion results in less oxygen reacting with fuel molecules. The degree of staging is limited by operational problems since the staged combustion results in incomplete combustion conditions and a longer flame profile. The units normally operate with the damper closed or nearly closed to help recirculate the coal in the cyclone and allows for increased coal retention and improved combustion. Since the SOFA installation. Coyote Unit 1 has achieved average controlled NO_x emissions approximately 0.46 lb/MMBtu.

S&L for Coyote: Tuning of the cyclone boiler to optimize the combustion process and minimize the generation of NO_x was recently completed at Coyote Unit I. Tuning was completed by lowering the stoichiometry (i.e., lower the air-to-fuel ratio) in the cyclone barrel and tracking the cyclone combustion stability, while staying within the OEM specifications for best combustion engineering practice. Based on the testing results, Coyote Unit 1 was able to achieve average NO_x emissions of approximately 0.42 lb/MMBtu without obvious impacts to boiler performance and with minimal slagging. Based on the results of the combustion turning tests, combustion optimization is considered a technically feasible NO_x control option.

NPS: The 2016–2020 NO_x average was 0.448 lb/mmBtu. (EPA Guidance[6] recommends use of five years of recent emissions data.[7]) The tuning and combustion optimization efforts appear to have yielded a 34% reduction compared to NO_x emissions prior to the 2016 efforts. (We are not aware of any similar efforts to reduce SO_2 emissions at Coyote.)

[6] final_signed_7-8-21_regional_haze_clarifications_memo

[7] Information on a source's past performance using its existing measures may help to inform the expected future operation of that source. If either a source's implementation of its existing measures or the emission rate achieved using those measures has not been consistent in the past, it is not reasonable to assume that the source's emission rate will remain consistent and will not increase in the future. To this end, states should include data for a representative historical period demonstrating that the source has consistently implemented its existing measures and has achieved, using those measures, a reasonably consistent emission rate. For most sources, data from the most recent 5 years (if available) is sufficient to make this showing. Information pertinent to a source's implementation of its existing measures going forward is also critical to a state's demonstration. States should provide data and information on the source's projected emission rate (e.g., for 2028), including assumptions and inputs to those projections. States should justify those assumptions and inputs and explain why it is reasonable to expect that the source's emission rate will not increase in the future.

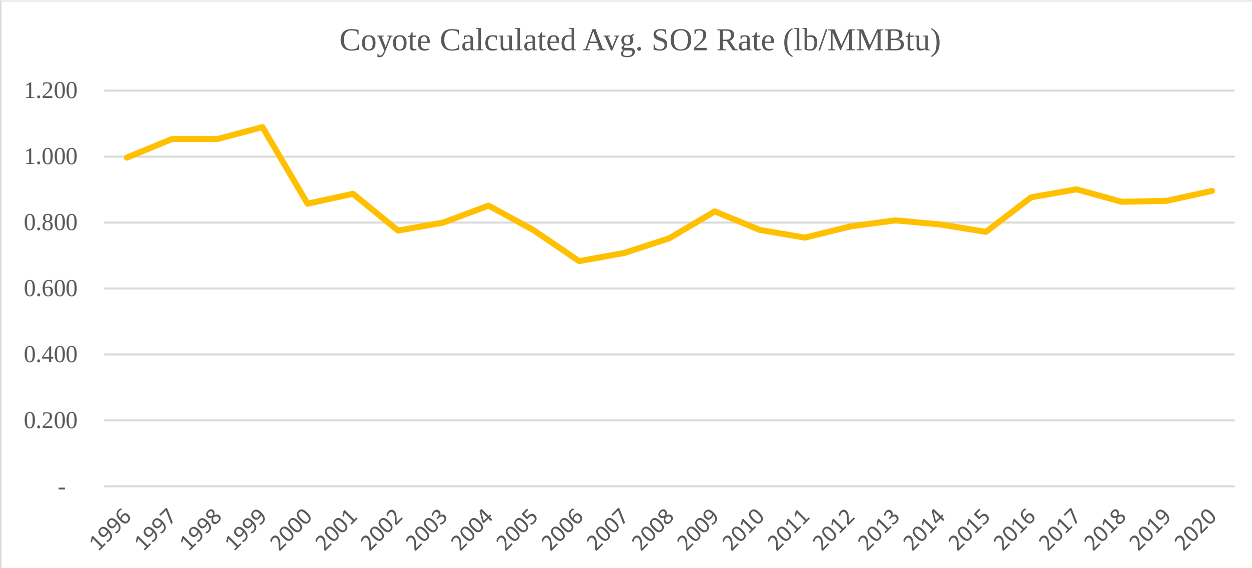


Figure 3. Calculated Avg. SO_2 Rate for Coyote Station Unit 1 (1996-2020)

In the initial planning period SIP, NDDEQ noted that additional SO_2 and NO_x controls for Coyote Unit 1 would be reevaluated during future planning periods to determine if additional emissions reductions would be required.

3.1.4 Second Planning Period Reasonable Progress Control Requirements for Coyote Station

NDDEQ: Otter Tail Power Company submitted their original four-factors analysis to the NDDEQ on January 30, 2019. A revised four factors analysis was submitted on May 10, 2019 in response to comments from the NDDEQ, which were submitted to Otter Tail Power Company on March 20, 2019. Another revised four factors analysis was submitted to the NDDEQ on January 6, 2020 to update the costs for the installation and operation of selected non-catalytic reduction (SNCR) and rich reagent injection (RRI). A final update to the four factors analysis was submitted to the NDDEQ on June 8, 2020 to update the analysis associated with some of the SO_2 controls evaluated.

SO_2 Analysis

SO_2 technology excerpts from the Sargent & Lundy (S&L) reports prepared for Coyote Station.

Existing FGD + Dry Sorbent Injection

Sorbent injection (dry or wet) upstream of the existing dry scrubber is a technically feasible and commercially available SO_2 control option for Coyote Unit 1. Taking into consideration the fact that Coyote is currently equipped with a calcium-based dry scrubbing system, hydrated lime dry sorbent injection would be the most practical, and potentially the most effective, sorbent injection control option. Sodium-based systems would require extensive testing to determine the potential impacts associated with introducing significant quantities of sodium into the existing system, and are not considered practical control options for Coyote Unit 1.

Based on engineering judgment, and assuming adequate residence time in the duct work upstream of the existing dry scrubber, hydrated lime injection could reduce SO_2 concentrations at the dry scrubber inlet by approximately 35%. Based on future design fuel characteristics, this would reduce SO_2 concentrations at the dry scrubber inlet from approximately 3.12 lb/MMBtu to approximately 2.03 lb/MMBtu. Applying the current scrubber SO_2 removal efficiency of 71% (dry scrubber plus fabric filter), would result in a controlled SO_2 emission rate of 0.58 lb/MMBtu. DSI upstream of the existing dry scrubbing system is considered a technically feasible SO_2 control technology; however, flow modeling and field testing at Coyote Unit 1 would be needed to ensure that adequate residence time is available for SO_2 control and to confirm the incremental reduction in SO_2 emissions achievable without creating unacceptable operational issues.

EXISTING DFGD OPERATIONAL IMPROVEMENTS AND EQUIPMENT UPGRADES

Operational and other design changes/upgrades to the existing dry scrubber may provide an opportunity for additional SO_2 removal and allow the unit to achieve lower controlled SO_2 emissions. S&L working with OTP personnel, identified a number of potentially feasible operational changes that may be available to increase SO_2 removal efficiency with the existing equipment. A discussion of each of these options is provided in the following sections.

Lime Quality

Based on a review of available lime analyses, and a review of operating data from the existing lime slaking system. Coyote Unit 1 currently procures a high-quality lime for use in the dry scrubbers. The typical CaO content of the lime used at Coyote is 90% or greater, and, when slaked, can achieve a 39.4 °C temperature rise in 3 minutes of adding water. For these reasons, changing the lime quality is not considered a technically-feasible operational change available to control SO_2 emissions from Coyote Unit 1 and will not be evaluated further.

Ca:S Stoichiometric Ratio

Based on information provided by the station, the DFGD system on Coyote Unit 1 currently operates the recycle system at approximately 24% solids. The Coyote Unit 1 recycle system is operating within the original design conditions and system capacity. The plant has tested higher recycle rates (up to 28-30% solids), but at these higher rates plant personnel reported significant problems with the atomizer wheels spilling over and pluggage of various strainers. Based on the adverse operational impacts observed during these tests, as well as the design limitations of the existing dry scrubber modules, increasing the recycle % solids is not considered a technically feasible SO_2 control option for Coyote Unit 1.

As an alternative to increasing the recycle rate, the Ca:S stoichiometric ratio in the system may be increased by increasing the quantity of fresh lime introduced to the system. Testing was completed in October 2018 on Coyote Unit 1 to determine the impact of increasing the amount of fresh lime slurry fed to the atomizer feed tanks while adjusting the amount of recycle slurry in order to maintain the design 24% solids to the absorber. During the test program, Coyote Unit 1 was able to achieve an average controlled SO_2 emission rate of 0.50 lb/MMBtu without significant adverse operational impacts and represents an average emission rate that Coyote would be expected to achieve on an on-going long-term basis under normal operating conditions.

Increasing the quantity of fresh lime introduced to the system will require the existing atomizer wheels to be upgraded from the eight-nozzle wheel to a twelve-nozzle wheel to mitigate for potential plugging and spill over issues caused by the percent solids limitation of the existing atomizer wheels, and to prevent the possibility of moisture carry-over that could occur with the increase in lime slurry flow. Although upgrades to the existing atomizer wheels and nozzles will be required, increasing the Ca:S stoichiometric ratio by adding additional fresh lime to the system is considered a technically feasible SO_2 control option for Coyote Unit 1, and will be included in the Four-Factor Analysis.

Approach to Saturation Temperature

The Coyote Unit 1 dry scrubbers currently operate at an outlet temperature of 190-210 °F, which is approximately 55-75 °F above the adiabatic saturation temperature and within original the OEM design steady-state operating parameter of 190 °F at the stack. More recent dry scrubbing systems have been designed to operate at 30 °F approach to adiabatic saturation. The station has attempted to lower the outlet temperatures to 165-170°F; however, this change caused significant corrosion of the absorber vessels and downstream equipment. Corrosion was likely due to the fact that the Coyote Unit 1 scrubbers were not able to completely dry the slurry droplets because the absorber vessels were designed with a residence time of approximately 1.0 second. More-recent dry scrubbers are designed with approximately 10 seconds of residence time. The low residence time at Coyote limits the scrubbers' ability to dry all slurry droplets when the system is operated too close to the approach to adiabatic saturation temperature. Due to the design limitations of the existing absorber vessels, reducing the outlet temperature is not considered a technically feasible SO_2 control option for Coyote Unit 1, and will not be evaluated further.

Atomizer Replacement

Based on S&L's assessment of the existing control system, previous testing completed by the station, and input from station operators, the existing DFGD system is limited in residence time, and the ability to increase the recycle ratio (solids content) to allow for more effective Ca:S contact in the scrubber vessels. The existing atomizers with eight-nozzle wheels would need to be upgraded to a twelve-nozzle wheel to mitigate for potential plugging and spill-over issues that could occur with the increased Ca:S stoichiometric ratio

Based on engineering judgment, new 12-nozzle atomizers would improve spray atomization to produce slurry droplets that are smaller in size than the droplets produced by the existing nozzle design. Improved materials of construction would also allow for higher solids content in the slurry without detrimental equipment pluggage or spill-over.

Replacing the existing nozzles with a more recent 12-nozzle wheel design would provide better atomization of the slurry spray and allow for more effective Ca:S contact in the absorber vessels. However, nozzle replacement would not, on its own. be expected to provide a significant increase in SO_2 control. Nozzle upgrades coupled with operational changes designed to increase the Ca;S stoichiometric ratio is a technically feasible option that would be expected to provide additional SO_2 control.

Slaker Replacement

Lime slurry, the reagent used for SO_2 removal in a dry scrubber, is produced by mixing pebble lime with heated water in a slaker; this process is referred to as "slaking". The slaker is operated at an optimum water-to-lime ratio (typically between 3:1 and 6:1) to produce lime slurry by metering the amount of water and the amount of lime added to the slaker. Slakers are typically designed to produce a lime slurry between 15-20% solids.

The lime slurry is added to recycle slurry in a mix tank and then sent to the atomizer where it is sprayed into the scrubber for SO_2 removal. Coyote Unit 1 still operates the original Dorr-Oliver detention slakers. The slakers operate at a 5:1 water-to-lime ratio and approximately 18% solids, which is in line with the design as well as industry practice. Therefore, replacing the slakers would not result in improved Ca:S contact in the absorber vessels or provide additional SO_2 removal. Replacing the lime slakers is not considered a technically feasible SO_2 control option for Coyote Unit 1, and will not be evaluated further.

FGD Operational Improvements + DSI

Technically feasible FGD operational improvements include increasing the Ca;S stoichiometric ratio of the FGD by introducing additional fresh lime to the absorber modules. Based on engineering judgement, layering FGD operational improvements with DSI could reduce SO_2 emissions from the baseline SO_2 emission rate of 0.85 lb/MMBtu to approximately 0.33 lb/MMBtu at Coyote Unit 1. However, as stated previously, flow modeling and field testing at Coyote Unit 1 would be needed to ensure that adequate residence time is available for SO_2 control and to confirm the incremental reduction in SO_2 emissions achievable without creating unacceptable operational issues.

Adding an Absorber Module

Another option for extending the residence time within the reactor modules and increasing Ca:S contact would be to add an additional absorber module. The existing system is designed with four absorber modules that share three fabric filter zones. The system is designed to operate with four modules at full load, three or four modules at 75% load and two modules at 50% load. At full load, the flue gas residence time in the reactor modules is approximately 1.0 second. More recent dry scrubbing systems have been designed with reaction vessel residence times of 10 seconds or more.

One potential option available to the Coyote Station to increase absorber module residence time would be to add an additional absorber module to the existing dry scrubbing system. The number of absorber modules used in a DFGD system is dependent on multiple operating parameters, including the flue gas flow rate and SO_2 concentrations. DFGD absorber modules are typically specified with minimum and maximum flue gas flow rates. If the absorber modules are oversized, flue gas velocities through the module can be too low, causing solids dropout inside the vessel. If the absorber modules are undersized, flue gas velocities can be too high, causing residence time to fall below recommended levels.

Dry scrubbing units that are operating at flue gas volumes significantly above the design flow rate can benefit from adding an extra module to the system. The module would be placed in parallel with the existing modules to achieve a similar pressure drop through each vessel and to ensure equal flue gas distribution to the vessels. Although adding an absorber module would likely allow additional residence time for the SO_2 removal reactions to occur, it would require extensive engineering and modifications to the existing system. More importantly, the Coyote Unit 1 absorber module design is no longer available from Combustion Engineering, and it would likely not be possible to procure a commercial offering from another technology vendor that would be compatible with the existing modules. Therefore, incorporating an additional absorber module into the existing system is not a commercially available or technically feasible SO_2 control strategy for Coyote, and will not be evaluated further.

Replacing Existing Absorbers with New Absorber Modules

Removed from Four-factor Analysis—see discussion below.

FGD Upgrades – Replace Existing Absorbers with Two New Absorbers

(Adjacent to Existing FF + Increased Lime Injection)

One of the technically feasible sulfur dioxide control technologies presented to the NDDEQ in the initial Four-Factor Analysis for Coyote Station Unit 1 involved retrofitting the existing dry flue gas desulfurization (DFGD) system with new absorber modules. This option was specifically limited to dismantling Coyote Station Unit 1's existing absorber modules and installing new reactor absorbers in the same location. The same location was used for the retrofit absorbers as the existing DFGD because, at the time of the initial Four-Factor Analysis, it was predicted that redirecting flue gas to a different location would likely result in significant solids dropout and other operational issues.

Since submittal of the Four-Factor Analysis, OTP became aware of a recent successful project by Babcock and Wilcox (B&W) that involved redirecting flue gas to a new SDA module located adjacent to an existing fabric filter. Therefore, OTP engaged B&W and Sargent & Lundy to perform a supplemental evaluation of this option for Coyote Station Unit 1.

B&W evaluated single module and two-module equipment arrangements for Coyote Station Unit 1. Given B&W's extensive project experience and Coyote Station's operating conditions, B&W's evaluation focused on the two-module design in order to confidently treat 100% of the Coyote Station Unit 1 flue gas. B&W's evaluation determined that Coyote Station's flue gas could in fact be re-directed through two new 62 ft. diameter modules located adjacent to the existing Coyote Station Unit 1 DFGD, and then following the new SDA modules, the flue gas could be routed back to the existing Reverse Air Fabric Filter (RAFF). The expected performance of this arrangement is an average controlled SO_2 emission rate of approximately 0.09 lb/MMBtu at Coyote Station Unit 1. Based on this additional evaluation by Sargent & Lundy and B&W, re-directing Coyote Station's Unit 1 flue gas to two new absorber modules adjacent to the existing fabric filter is considered a technically feasible option.

Install New Dry FGD System

Since the new two-SDA-module option is substantially lower in annualized costs and achieves the same emissions reductions as compared to the prior Four-Factor Analysis option for a new Dry FGD, the new Dry FGD option was removed from the cost effectiveness table.

Install New Wet FGD System

A large majority of the wet FGD systems designed to remove SO_2 from existing high-sulfur utility boilers have been designed as wet limestone scrubbers with spray towers and forced oxidation systems. Therefore, for this evaluation, it was assumed that the WFGD control system would be designed as a limestone spray tower scrubber with forced oxidation. Other potentially available wet scrubber designs are not included in this evaluation because the chemistry involved in all wet scrubbing systems are essentially identical, alternative designs would not provide any additional SO_2 control, and control system costs would be similar.

Wet Limestone Scrubbing

For this evaluation it was assumed that the existing Coyote Unit 1 dry scrubber reactor vessels would remain in place, and that the WFGD control system would be located downstream of the existing FFs and ID fans, most likely northeast of the unit's existing dry scrubber/FF. Dry scrubber reactor vessel internals would ultimately be removed to reduce pressure drop through the system. A single WFGD absorber tower would be sufficient for the Coyote Unit 1 flue gas flow. In addition to the absorber tower and reaction vessel, the WFGD control system would require a limestone handling and preparation system and by-product dewatering systems. Because of the saturated nature of the flue gas exiting the WFGD, a new stack with a liner capable of wet flue gas operation would be required. New booster ID fans would also be required to account for the additional pressure drop through the WFGD control system.

Based on engineering judgment and information from control system vendors, it is anticipated that a retrofit WFGD control system on a North Dakota lignite-fired unit would be designed to achieve an SO_2 removal efficiency of approximately 98%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system. On Coyote Unit 1, 98% removal would result in an average controlled SO_2 emission rate of approximately 0.06 lb/MMBtu and represents an average emission rate that Coyote would be expected to achieve on an on-going long-term basis under normal operating conditions.

NO_x Analysis

NO_x technology excerpts from the Sargent & Lundy (S&L) reports prepared for Coyote Station.

TECHNICAL FEASIBILITY OF AVAILABLE NO_X CONTROL OPTIONS

Potentially available NO_x control options were evaluated for technical feasibility (i.e., availability and applicability to Coyote Unit 1) based on a review of physical, chemical, and engineering principals, and an assessment of commercial availability. Options deemed to be technically infeasible, or options that have no practical application to Coyote Unit I, were eliminated from further review. S&L evaluated the effectiveness of the control options determined to be technically feasible, and established an emission performance level (i.e., controlled emission rate) for each.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH_3) or urea ($CO(NH_2)_2$) in an oxidizing environment. The ammonia or urea reacts with NO_x in the flue gas to produce N_2 and water as shown below.

$$(NH_2)_2CO + 2N0 + N_2O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$
$$2NH_3 + 2N0 + N_2O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reagent injection can greatly affect NO_x removal efficiencies and the quantity of NH_3 or urea that will pass through the SNCR unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective in the range of l,600°F - 2,100°F. At temperatures below the desired operating range, the NO_x reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to $N0_2$, resulting in low NO_2 reduction efficiencies.

SNCR can be applied on cyclone boilers due to having reasonable temperature windows and residence time; however, the potential NO_x reduction is boiler-specific. SNCR has been used as a retrofit NO_x control system of on pulverized coal, fluidized bed boilers, and cyclone boilers. Furthermore, SNCR can be implemented on boilers equipped with low-NO_x burners, overfire air. or SOFA systems. Based on the boiler residence time, temperature profile, and stoichiometry. as well as input from SNCR OEMs, it is estimated that an SNCR system could achieve an average controlled NO_x emission rate of approximately 0.28 lb/MMBtu (approximately 39% below the baseline emission rate of 0.46 lb/MMBtu) at full load while limiting ammonia slip to 10 ppmvd.

NPS: SNCR was added to a similar-sized (477 MW) cyclone boiler burning ND lignite at the M.R. Young Station in late 2010. As a result, NO_x emissions reduced by 53% (from 0.70 lb/mmBtu to 0.33 lb/mmBtu).

Rich Reagent Injection

Similar to SNCR, the concept of rich reagent injection (RRI) is to use a nitrogen-containing additive (e.g., urea) injected into a reducing environment to promote NO_x removal. RRI is a commercial technology for cyclone boilers only. Due to the changes of the lower furnace stoichiometry, RRI is often not a technically feasible option at low loads. Once the stoichiometric ratio increases to >1.0, the potential exists for NO_x generation due to the reaction of NH3 with oxygen, especially if the injection location and rate is not optimized. Based on these limitations, RRI is considered most effective at full load.

The RRI process is a commercially available process. Based on engineering judgment, RRI is expected to reduce NO_x emissions by approximately 20-40% at Coyote Unit 1 when operating at full load with minimal ammonia slip. However, due to the cyclone combustion temperature window, this technology only provides effective NO_x reduction at or near full load. At low loads, RRI does not provide effective control; however, RRI can be combined with SNCR to provide NO_x control across the full range of normal operating loads. RRI is a technically feasible NO_x

reduction option for North Dakota lignite-fired cyclone boilers. However, due to its limited operating conditions and ineffective NO_x reduction at low loads. RRI alone is not considered an available NO_x control option, and will only be evaluated in conjunction with SNCR.

NPS: Burns & McDonnell estimated that addition of RRI to the 477 MW cyclone Unit #2 at the M.R. Young Station could reduce NO_x emissions by 22% below the current emissions (0.33 lb/mmBtu) from the SNCR system down to 0.26 lb/mmBtu.

SNCR + RRI

While RRI alone will provide beneficial NO_x reduction at full load only, coupling RRI with SNCR can provide a balanced approach to NO_x reduction through all load ranges. Since RRI and SNCR injectors are located at different elevations of the furnace and in different temperature windows, there are not concerns of spatial impacts. The combined system would utilize a relatively high urea injection rate, staged at multiple locations throughout the boiler. The main advantage of this combined system is that the SNCR can provide better NO_x reduction at low load and at a lower NSR than RRI alone: thus, the combined system is expected to provide effective NO_x control across all normal operating load ranges. Coupling RRI and SNCR is considered a technically feasible and commercially available NO_x control technology option on Coyote Unit 1. Based on input from SNCR OEMs and engineering judgment, the control option is expected to achieve an average outlet NO_x rate of approximately 0.20 lb/MMBtu with an ammonia slip of 10 ppmvd.

NPS: Compared to the estimates for SNCR+RRI at MRYS#2, this may be slightly optimistic.

Gas Reburn

Gas reburn is a retrofit technique that has been used to control NO_x emissions from coal- and oil-fired boilers. Gas reburn involves combustion in three distinct zones within the boiler: (I) a primary combustion zone, where the primary fuel is fired using conventional burners: (2) a reburn zone, where secondary fuel, typically natural gas. is introduced into the boiler: and (3) an OFA burnout zone.

Gas reburn can have a positive impact on NO_x emissions: however, in order to make a meaningful prediction of the N0x removal capabilities at Coyote Unit 1, extensive testing would be required because gas reburn performance is significantly dependent upon boiler operating characteristics. More importantly, the lack of natural gas available at the Coyote Station precludes the ability to test and implement this control option on Coyote Unit 1. For these reasons, gas reburn is not considered an available or technically feasible NO_x control technology at Coyote Unit 1.

NPS: Although this technology is available, it is probably not economically feasible.

Selective Catalytic Reduction

SCR is a process by which ammonia reacts with nitric oxide (NO) and nitrogen dioxide (NO_2), collectively NO_x, in the presence of a catalyst to reduce the NO_x to nitrogen (N_2) and water. SCR technology has been applied to NO_x-bearing flue gases generated from power generating facilities burning various types of coal, including bituminous, subbituminous. and Texas lignite. The principal reactions resulting in NO_x reduction are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_20$$
$$4NO_2 + 8NH_3 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

Because these reactions proceed slowly at typical boiler exit gas temperatures of a coal-fired steam electric generating unit, a catalyst is used to increase the reaction rate between NO_x and ammonia. Depending on the specific constituents in the flue gas, a typical temperature range of 550°F to 780°F is necessary to achieve normal performance of the catalyst. For the typical coal-fired boiler, optimal performance will be in the range of approximately 650°F to 750°F.

NPS: Special catalysts are available that operate at lower or higher temperatures. Ceram:

> *Our honeycomb catalyst can be tailored to customer specifications by varying the vanadium content. Our products are suitable for temperatures between 150°C and 550°C / 300°F and 1020°F.*

In general, there are three candidate SCR configurations that can be employed on coal-fired steam electric generating units. The SCR configuration designations generally describe the location of the SCR reaction vessel in relation to other post-combustion air quality control systems. Candidate SCR configurations include:

- High-dust configuration
- Low-dust configuration
- Tail-end configuration

Because there are unresolved issues associated with catalyst poisoning, catalyst blinding and plugging, and catalyst erosion: and engineering solutions have not been determined or demonstrated and the high dust configuration has not moved beyond pilot scale testing, high dust SCR is not an available technically feasible NO_x control technology for Coyote Unit 1.

Low-Dust Configuration

In the low-dust configuration, the SCR reactor vessel is located in the flue gas stream after the particulate collection device (i.e., ESP or FF). Because Coyote Unit 1 is equipped with existing dry FGD/FF controls, low-dust SCR has no practical application on the unit, and low-dust SCR is not considered a technically feasible NO_x control option for Coyote Unit 1.

Tail-End Configuration

In the tail-end configuration, the SCR reaction vessel is located in the flue gas stream after the particulate and FGD control systems. The potential advantage of a tail-end SCR configuration at Coyote Unit 1 is that the flue gas will have passed through the dry FGD/FF system prior to the SCR catalyst. As such, there is the possibility that the mass transfer mechanism that results in the capture of SO_2 will also capture some of the vapor-phase sodium and the sodium-enriched submicron particles, reducing the risk of catalyst poisoning and/or deactivation.

NPS: We recommend that Basin should test the gas stream exiting the baghouse to properly evaluate this potential issue.

S&L for Coyote: During the first planning period, NDDEQ initially concluded, based on preliminary information provided by SCR catalyst vendors, that the tail-end SCR configuration would be a technically feasible option for units firing North Dakota lignite that are subject to BART requirements. However, as part of the Milton R. Young Station (MRYS) NO_x BACT determination process, detailed information describing the expected ash characteristics and flue gas characteristics was provided to two SCR catalyst vendors (CERAM Environmental, Inc. (CERAM) and Haldor Topsoe, Inc.). Based on their review of the data, both vendors concluded that they would not be able to provide a catalyst life guarantee for either low-dust or tail-end SCR without pilot-scale testing.

NPS: The applicability of the MRYS BACT determination to Coyote may not be appropriate. MRYS uses different SO_2 control equipment (electrostatic precipitators and wet scrubbers rather than dry scrubbers with a baghouse). Pilot-scale testing is routinely performed before any SCR project proceeds. The absence of a vendor guarantee does not mean that a technology is infeasible.

S&L for Coyote: Successful operation of the tail-end configuration would also require a capital and operating cost-intensive gas-to gas heat exchanger to reheat the flue gas from approximately 200°F downstream of the existing FF to approximately 550°F to support the SCR NO_x reactions. After the flue gas passes through the SCR (at approximately 550°F). it would pass through the hot side of the gas-to-gas heat exchanger to cool the flue gas to 150°F prior to the exhaust stack. Although this stack gas temperature would be lower than the current stack temperature (190-210°F), it is still higher than the adiabatic saturation temperature of the flue gas (i.e., approximately 135°F). As such, it is likely that the existing stack could be reused without any major modifications.

Both vendors also made statements bringing into question the technical feasibility of either low-dust or tail-end SCR. For example. CERAM stated that the high levels of sodium oxide (NaO) in the ash for North Dakota lignite are not commonly found in subbituminous and bituminous coals which are fired in boilers equipped with SCR systems, and that it was unaware of any SCR application experience in the industry with the level and form of sodium in the North Dakota lignite-derived MRYS ash.

NPS: Please provide these vendor statements. Did they apply to a tail-end configuration or only to a low-dust configuration? Is there a more recent vendor statement that can be shared?

S&L for Coyote: Based in part on this information provided by SCR design engineering firms and SCR catalyst vendors, NDDEQ concluded that the use of SCR technology, including low-dust and tail-end SCR. on the lignite-fired MRYS boilers would be technically infeasible.

NPS: This is no longer entirely true. The boilers at Milton R. Young (MRYS) are cyclone boilers. NDDEQ has determined that tail-end SCR is technically-feasible on the tangentially-fired boilers at Antelope Valley Station.

S&L for Coyote: Based on a review of SCR installations on coal-fired boilers, and a review of reported advances in SCR catalysts since the first planning period, deactivation rates due to soluble alkali compounds in the flue gas (including soluble sodium and potassium compounds) remain a concern for all North Dakota lignite-fired boilers. Tail-end SCR has not been demonstrated or installed on a North Dakota lignite-fired boiler, and there are still significant technical concerns associated with the availability of existing SCR catalysts on a North Dakota lignite-fired unit. Catalyst in a tail-end SCR will still be vulnerable to alkali poisoning, pore pluggage, and premature catalyst deactivation, and it is not known whether the comparatively high levels of soluble sodium and potassium in North Dakota lignite will be effectively removed by the upstream dry FGD/FF. Furthermore, the potential exists for fine particulate remaining in the flue gas to get into the catalyst pores reducing catalyst activity. Pilot-scale studies needed to better understand catalyst deactivation mechanisms associated with high soluble alkali compound concentrations in the flue gas have not been completed.

In order to understand the effect of North Dakota lignite-derived flue gas on the tail-end SCR catalyst, identify potential design solutions, and evaluate the technical feasibility and effectiveness of tail-end SCR at Coyote Unit 1 with any degree of certainty, extended pilot scale testing of the control configuration would be needed. Additionally, because there are unresolved issues associated with catalyst poisoning, it's unlikely that OTP could obtain a viable commercial offering for tail-end SCR on Coyote Unit 1. Therefore, tail-end SCR is not an available technically feasible NO_x control technology.

NPS: A technical feasibility determination should not be based upon speculation, especially when questions can be addressed by real-world testing. Basin bears the burden of proof to show that the gas stream exiting the fabric filter would render the SCR technically infeasible and to determine the catalyst deactivation rate. Questions about catalyst deactivation could have been addressed by Basin with pilot testing on the existing system of emission controls. Because Basin did not exercise this option, tail-end SCR is presumed technically feasible.

SCR is certainly available—the question is whether it is applicable. According to the BART Guidelines:

> *What do we mean by ''applicable'' technology?*
>
> *You need to exercise technical judgment in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been used on the same or a similar source type. Absent a showing of this type, you evaluate technical feasibility by examining the physical and chemical characteristics of the pollutant-bearing gas stream, and comparing them to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on a new or existing source with similar gas stream characteristics is generally a sufficient basis for concluding the technology is technically feasible barring a demonstration to the contrary as described below.*

> *What type of demonstration is required if I conclude that an option is not technically feasible?*
>
> *Where you conclude that a control option identified in Step 1 is technically infeasible, you should demonstrate that the option is either commercially unavailable, or that specific circumstances preclude its application to a particular emission unit. Generally, such a demonstration involves an evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology. Alternatively, a demonstration of technical infeasibility may involve a showing that there are unresolvable technical difficulties with applying the control to the source (e.g., size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability, and adverse side effects on the rest of the facility).*

<u>*SCR Summary*</u>

S&L: During the first planning period NDDEQ determined that high-dust SCR and tail-end SCR are not available, and thus, not a technically feasible NO_x control option for North Dakota lignite-fired boilers. The administrative record developed during the first planning period, including the BART determinations and MRYS BACT analysis, supports the conclusion that high-dust SCR and tail-end SCR are not an available NO_x control option for Coyote Unit 1. An evaluation of SCR installations and reported advances in SCR catalysts since the first planning period, coupled with the fact that high-dust SCR and tail-end SCR have not been demonstrated on a North Dakota lignite-fired boiler, and the likelihood that OTP could not obtain a viable commercial offering for tail-end SCR without extended pilot-scale testing, continues to support the conclusion that high-dust SCR and tail-end SCR are not available NO_x control technologies.

NPS: NDDEQ has determined that tail-end SCR is technically feasible on the lignite-fueled tangentially-fired boilers at Antelope Valley Station. Basin bears the burden of proof to show that tail-end SCR is not technically feasible at Coyote Unit 1. Lack of a vendor guarantee does not mean that an application of SCR is not viable or automatically eliminate consideration of SCR.

MARCH 20,2019 LETTER FROM TERRY L. O'CLAIR, P.E., DIRECTOR, DIVISION OF AIR QUALITY TO MR. MARK THOMA, MANAGER, ENVIRONMENTAL SERVICES, OTTER TAIL POWER COOPERATIVE, RE: FOUR FACTORS ANALYSIS - COYOTE STATION

> *"The Department included tail-end selective catalytic reduction (SCR) as a technically feasible option in the first Regional Haze planning period. However, as you noted in your analysis, The Department ultimately determined that high dust, low dust and tail-end SCR are not technically feasible for cyclone boilers combusting North Dakota lignite (see United States of America and the State of North Dakota versus Minnkota Power Cooperative and Square Butte Power Cooperative). Table lists tail-end SCR as a technically infeasible option. Since tail-end SCR is not a technically feasible*

option, we suggest that it be removed from the four-factor analysis in Tables 5-11, 6-3 and 6-4."

MAY 10. 2019 LETTER TO MR. JIM SEMERAD, DIRECTOR. DIVISION OF AIR QUALITY, NORTH DAKOTA DEPARTMENT OF ENVIRONMENTAL QUALITY FROM MARK THOMA, MANAGER, ENVIRONMENTAL SERVICES, OTTERTAIL POWER COOPERATIVE

OTP Response: "The Four-Factor Analysis has been revised to remove tail-end SCR from Tables 5-11, 6-3, and 6-4. Portions of the text were also updated to be consistent with this change."

– Cost of Compliance (Statutory Factor 1)

S&L for Coyote: Capital and O&M cost estimates were developed by S&L for each of the technically feasible SO_2 and NO_x control options. The Coyote Unit 1 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Unit 1 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems. Preliminary equipment sizing developed for the major pieces of equipment (based on Coyote Unit 1-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the Coyote Unit 1 retrofit technologies as "concept screening" cost estimates generally based on parametric models, judgment, or analogy.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor.

Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing dry scrubber and FF control systems.

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next-more-stringent level of control will also be calculated to evaluate the cost effectiveness of the more stringent control.

NPS: The Coyote four-factor analysis used spreadsheets based upon internal studies at similar facilities instead of the EPA CCM workbooks. Cost estimates in the analysis were not based upon site-specific vendor quotes or detailed engineering evaluations. The cost analysis spreadsheets contained several cost items (sales tax, owner's costs, property taxes) not included in the CCM workbooks, and applied a 20% contingency factor instead of the CCM's default 10% factor. The four-factor analysis applied a 20% contingency cost of direct and indirect capital costs to all capital cost analyses.

- The CCM says:
    - *The contingency, C, accounts for unexpected costs associated with the fabrication and installation of the absorber and is calculated by multiplying the total direct and indirect costs by a contingency factor (CF). A default value of 10% is typically used for CF.*
- Coyote four-factor analysis cost analyses applied 2% of Direct cost as Owners' Costs—this is not allowed by EPA.
- Coyote four-factor analysis cost analyses included Property Taxes = 1% of TCI. Insurance = 1% of TCI. Administration = 2% of TCI. The CCM says:
    - property taxes and overhead are both assumed to be zero, and insurance costs are assumed to be negligible. Thus, administrative charges and capital recovery are the only components of indirect annual costs estimated in this analysis.

S&L for Coyote: Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25% and equipment life of 20 years.

NPS: EPA's CCM recommends a scrubber and SCR equipment life of 30 years and use of the current prime interest rate (3.25%) unless a site-specific interest rate is justified. The CCM recommends 20 years as an equipment life for SNCR.

S&L for Coyote: In an email to the North Dakota Department of Health dated December 18, 2018, EPA recommended use of a 5.25% interest rate. Otter Tail stated it does not necessarily agree that this is an appropriate percentage to use and reserves the right to update and modify this percentage at a later date. Notably, on September 26, 2018 the North Dakota Public Service Commission approved a rate of return for Otter Tail of 7.64%. This ROR represents a total weighted average cost of capital. An interest rate of 5.25% is more representative of the long-term cost of debt, which is only one component of capital structure. All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing dry scrubber and FF control systems.

NPS: We used the 5.25% interest rate for Coyote in our calculations due to its PUC filings.

– Economic Evaluation - SO_2 Controls

NPS: Even with the factors that inflated costs, noted above, the average and incremental cost effectiveness of replacing the old scrubber at Coyote would be acceptable in the context of the previous ND BART thresholds as well as the thresholds used by the states cited. Table 2 below (NDDEQ's Table 9) shows that all of the options evaluated, except for the WFGD, are reasonably cost-effective.

Table 2.(NDDEQ draft SIP, Table 9) SO_2 Cost of Compliance and Incremental Cost of Compliance for Coyote Unit 1

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
DFGD/FF (Baseline)	0.85				
DSI + Existing FGD	0.58	4,118	12,371,000	3,004	
FGD Improvements	0.50	5,338	2,085,000	391	-8,431
DSI + FGD Improvements	0.33	7,930	14,456,000	1,823	4,772
Absorber Replacement	0.09	11,590	21,122,000	1,822	1,821
WFGD	0.06	12,048	49,094,000	4,075	61,139

We revised S&L's cost estimates for the absorber replacement option to eliminate owner's costs and property taxes, reduce the contingency cost, and revise the capital recovery cost to reflect a 30-year scrubber life.

Table 3. NPS Revised SO_2 Cost of Compliance and Incremental Cost of Compliance for Coyote Unit 1

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
DSI + FGD Improvements	0.33	7,930	14,456,000	1,823	4,772
Absorber Replacement	0.09	11,590	17,338,329	1,496	788

Replacement of the existing dry scrubber could reduce SO_2 emissions by almost 11,600 tons/year versus baseline emissions.

– Time Necessary for Compliance (Statutory Factor 2)

NDDEQ: A summary of anticipated timelines for installation of controls is provided in Table 10.

Table 4. (NDDEQ draft SIP, Table 10) Time Required for SO_2 Controls

Control Technology	Total time after SIP approval (months)
DSI + Existing FGD	18
FGD Improvements	0
DSI + FGD Improvements	18
Absorber Replacement	32

– Energy and Non-Air Quality Environmental Impacts (Statutory Factor 3)

Energy

NDDEQ: Small changes to onsite energy consumption are likely to be experienced with the implementation of any SO_2 control options. The impacts are not significant enough to eliminate and SO_2 controls as viable control options.

Non-Air Quality Environmental Impacts

NDDEQ: Similar to the energy impacts for SO_2 controls, any non-air quality environmental impacts are not significant enough to eliminate additional SO_2 controls as a viable option.

– Remaining Useful Life (Statutory Factor 4)

NDDEQ: Based on the information provided to the Department, Coyote is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

Economic Evaluation - NO_x Controls

NDDEQ: The cost of compliance and incremental cost for the reasonable progress controls are listed in Table 6.

Table 5. (NDDEQ draft SIP, Table 6) NO_x Cost of Compliance and Incremental Cost of Compliance for Coyote Unit 1

Control Technology	**Performance Rate (lb/MMBtu)**	**Annual Emission Reduction (tpy)**	**Annualized Total Cost ($)**	**Cost of Compliance ($/ton)**	**Incremental Cost of Compliance ($/ton)**
SOFA (Baseline)	0.46				
SOFA Optimization	0.42	610	0	0	
SNCR + Optimization	0.28	2,745	4,753,933	1,732	
SNCR + RRI + Optimization	0.20	3,965	12,690,135	3,200	6,505

A detailed breakdown of the costs listed in NDDEQ draft SIP, Table 6 (Table 5 above) can be found in Coyote's submitted four factors analysis. The Department has reviewed these costs and believes them to be accurate.

As displayed in NDDEQ Table 6 (Table 5 above) and stated in Section 3.1.1, there is no cost associated with optimization of the combustion process. The 0.04 lb NO_x per MMBtu improvement over the baseline performance would be required as the first step for any of the remaining technologies evaluated.

If SNCR is installed in conjunction with combustion optimization, a performance rate improvement of 0.18 lb NO_x per MMBtu could be achieved. This equates to a potential reduction of approximately 2,750 tons NO_x per year from the baseline emissions. Fiscally, SNCR installation requires an estimated annualized cost of $4.75 million and NO_x removal cost of roughly $1,700 per ton.

The addition of RRI to SNCR and combustion optimization results in an expected performance improvement of 0.26 lb NO_x per MMBtu from the baseline performance rate. This equates to a potential reduction of approximately 3,970 tons NO_x per year from the baseline emissions. Fiscally, SNCR + RRI installation requires an estimated annualized cost of $12.7 million and NO_x removal cost of $3,200 per ton. To determine the appropriate reasonable progress control selection between SNCR and SNCR + RRI, the Department determined the stand-alone cost of installing RRI after SNCR is installed. This stand-alone cost is referred to as the incremental cost of compliance. Incremental cost of compliance is a key factor to consider when selecting reasonable progress controls since it details the cost effectiveness of RRI installation. A cost breakdown indicates approximately $8 million of the annualized cost is attributable to the installation of RRI, and results in the potential for an additional 1,220 tons of NO_x to be removed. This results in an incremental cost of compliance of roughly $6,500 per ton.

NPS: We added estimates for SCR based upon the CCM workbook. Our estimate that SCR on Coyote Unit 1 can achieve 0.05 lb/mmBtu is consistent with demonstrated SCR emission rates and does not exceed 90% efficiency.

Table 6. NPS Revised NO_x Cost of Compliance and Incremental Cost of Compliance for Coyote Unit 1

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
SOFA (Baseline)	0.46				
SOFA Optimization	0.42	610	0	0	
SNCR + Optimization	0.28	2,745	4,753,933	1,732	
SNCR + RRI + Optimization	0.20	3,965	12,690,135	3,200	6,505
SCR	0.05	5,684	13,778,780	2,424	633

Addition of RRI to Optimized SNCR could reduce NO_x emissions by almost 4,000 tons/year versus baseline emissions. Addition of SCR could reduce NO_x emissions by almost 5,700 tons/year versus baseline emissions.

– Time Necessary for Compliance (Statutory Factor 2)

A summary of the anticipated timelines for the installation of controls is provided in NDDEQ Table 7 (Table 7 below).

Table 7.(NDDEQ draft SIP, Table 7) Time Required for NO_x Controls

Control Technology	Total time after SIP approval (months)
SOFA Optimization	0
SNCR + Optimization	22
SNCR + RRI + Optimization	22

– Energy and Non-Air Quality Environmental Impacts (Statutory Factor 3)

ENERGY

Small changes to onsite energy consumption are likely to be experienced with the implementation of any add-on NO_x controls.[5] The impact not significant enough to eliminate add-on NO_x controls as a control option.

NON-AIR QUALITY ENVIRONMENTAL IMPACTS

SNCR use ammonia as a reagent. Ammonia slip emissions will result in the flue gas stream on the exhaust side of the control equipment due to the operation of the SNCR (~10 ppm). The ammonia slip emissions from the operation of SNCR would likely combine with the dry FGD solids. The ammoniated dry FGD solids would require that further safety precautions are taken for Coyote staff who perform maintenance on the ash handling system or staff who dispose of waste.

Similar to the energy impacts for add-on NO_x controls, the non-air quality environmental impacts are not significant enough to eliminate add-on NO_x controls as a control option.

– Remaining Useful Life (Statutory Factor 4)

Based on the information provided to the Department, Coyote is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

3.1.5 Conclusions & Recommendations

- Other states have set cost-effectiveness thresholds of: $5,000/ton for EGUs in AR and TX, $7,000/ton in NM, and $10,000/ton in CO and OR.
- The cost effectiveness of replacing the old scrubber at Coyote would be acceptable in the context of the previous ND BART thresholds as well as the thresholds used by the states cited. Replacement of the existing dry scrubbers with modern new scrubbers could cost-effectively reduce facility SO_2 emissions by almost 11,600 tons/yr.
- The annual average cost effectiveness of adding SNCR + RRI at Coyote would be acceptable in the context of the previous ND BART thresholds as well as the thresholds used by the states cited. Addition of SNCR + RRI could reduce facility NO_x emissions by almost 4,000 tons/yr.

- The average cost effectiveness of adding SCR at Coyote would be acceptable in the context of the previous ND BART thresholds as well as the thresholds used by the states cited. Addition of SCR could reduce facility NO_x emissions by almost 5,700 tons/yr.

3.2 Antelope Valley Station

3.2.1 Summary of NPS Recommendations and Requests for Antelope Valley

NPS review of the four-factor analysis conducted for Antelope Valley Station (AVS) finds that there are technically feasible and cost-effective opportunities available to further control SO2 and NO_x emissions from Units 1 and 2. In fact, we find that the cost of control is more economical than estimated when analyses are adjusted in accordance with the EPA Cost Control Manual.

Although ND has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of: $5,000/ton for EGUs in AR and TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

The incremental cost effectiveness of replacing the existing SO_2 scrubbers at AVS would be acceptable in the context of the previous ND BART thresholds as well as the thresholds used by the states cited. Replacement of the existing dry scrubbers with modern new scrubbers could cost-effectively reduce facility SO_2 emissions by over 10,000 tons/yr.

We find SNCR and SCR opportunities for reducing NO_x emissions at AVS. 1) Addition of SNCR would be cost effective in the context of the previous ND BART thresholds as well as the thresholds used by other states in this round of RH SIP planning. SNCR at AVS Units 1 and 2 and could reduce facility NO_x emissions by 700 tons/yr. 2) The average cost effectiveness of adding SCR at Coyote would meet the cost thresholds used by CO and OR. Addition of SCR could reduce facility NO_x emissions by over 2,300 tons/yr.

We recommend that ND take every opportunity to reduce SO_2 and NO_x emissions from the Antelope Valley Station in this planning period. By requiring implementation of identified controls ND will be reducing haze causing emissions and advancing incremental improvement of visibility at Theodore Roosevelt, Badlands, and Wind Cave National Parks as well as other Class I areas in the region.

3.2.2 Plant Characteristics

AVS is a 954 MW power station owned and operated by Basin Electric Power Cooperative (Basin) near Beulah, North Dakota. Theodore Roosevelt National Park, an NPS Class I area, is 109 km west of this facility.

Of 1,167 facilities in EPA's Clean Air Markets Database (CAMD) in 2020, AVS ranked #15 for SO_2 emissions (11,316 tons) and #64 for NO_x) emissions (3,496 tons). AVS' carbon dioxide emissions of 6,876,033 tons rank #49 in the US. AVS also ranked #7 for EGU mercury (Hg) emissions with 183 lb in 2017.

AVS has two generating units (Units 1 and 2) each rated at 477 megawatts (MW). AVS Unit 1 went on-line in 1984 and Unit 2 in 1986. AVS Units 1 and 2 are Combustion Engineering (CE) subcritical pulverized coal (PC), tangential-fired units firing North Dakota lignite. Unit 1 and Unit 2 each have a heat input capacity of 6,275 MMBtu per hour. AVS receives a majority of its lignite fuel from the fine coal rejected by the adjacent Great Plains Synfuels Plant (GPSP) coal screening process, with the balance of fuel requirements being delivered directly to AVS from the Freedom Mine, which is located adjacent to the AVS/GPSP Complex.

Each unit has the same control equipment. NO_x emissions are controlled by a separated over-fire air (SOFA), Low-NO_x Concentric Firing System (LNCFS), and Omnivise Combustion Optimizer. SO_2 and PM emissions are controlled by a dry lime flue gas desulfurization (DFGD) system, and fabric filter baghouse (FF) control system. . Mercury emissions are controlled by a sorbent injection system to comply with the Mercury and Air Toxics Standards.[8] The Table 8 below shows a breakdown of 2020 SO_2 and NO_x emissions and how they rank versus the 3,317 EGUs in CAMD.

Table 8. Antelope Valley Station 2020 SO_2 and NO_x emissions and rank out of 3,317 EGUs in CAMD

Unit ID	Gross Load (MW-h)	SO_2 (tons)	SO_2 (tons) Rank	Avg. SO_2 Rate (lb/MMBtu)	Avg. SO_2 Rate (lb/MMBtu) Rank	Avg. NO_x Rate (lb/MMBtu)	Avg. NO_x Rate (lb/MMBtu) Rank	NO_x (tons)	NO_x (tons) Rank
B1	2,989,552	5,420	34	0.367	109	0.1148	671	1,702	120
B2	3,084,092	5,896	31	0.351	118	0.1074	721	1,794	111

3.2.3 First Planning Period Reasonable Progress Control Requirements for AVS Units 1 and 2

AVS Units 1 and 2 were not subject to the Regional Haze BART requirements of 40 CFR 51.208(e). Nevertheless, during the initial planning period NDDEQ evaluated emissions reductions from AVS as a Reasonable Progress[9] (RP) source. Based on an evaluation of control technology costs and the resulting incremental improvement in visibility, NDDEQ found that no additional NO_x controls were warranted during the initial planning period.

On September 21, 2011, EPA published a proposed rule to partially approve and partially disapprove specific aspects of the North Dakota Regional Haze SIP.[10] Among other things, EPA proposed to disapprove the state's reasonable progress determination for AVS Units 1 and 2. EPA proposed the promulgation of a Federal Implementation Plan (FIP) which included a

[8] January 2021 Hg emissions were: Unit 1= 2.92 lb/Trillion Btu (TBtu), Unit 2 = 2.52 lb/TBtu.
[9] The Regional Haze Rule (RHR) requires states to demonstrate the progress made to date and determine any additional progress needed to achieve the visibility improvement goals established for this planning period. States are required to set Reasonable Progress goals which 1) must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and 2) ensure no degradation in visibility for the least impaired days over the same period.
[10] 76 Fed. Reg. 58570, September 21, 2011 (the "Proposed FIP").

reasonable progress determination and NO_x emission limits for AVS Units 1 and 2. EPA proposed low-NO_x burners (LNB) plus SOFA and an emission limit of 0.17 lb/MMBtu (30-day rolling average) for reasonable progress NO_x control on AVS Units 1 and 2.[11]

EPA issued its final rule on April 6, 2012.[12] With respect to NO_x control on AVS Units 1 and 2, EPA finalized its proposed determination that LNB+SOFA and a NO_x emission rate of 0.17 lb/MMBtu (30-day rolling average) was required for reasonable progress. North Dakota challenged EPA's disapproval of its reasonable progress determination for AVS Units 1 and 2, and EPA's subsequent promulgation of the FIP. The District Court found that EPA's determination on this matter was entitled to judicial deference, and could not conclude that EPA acted in a manner that was arbitrary or capricious; therefore, the state's petition for review was denied and EPA's reasonable progress determination for AVS Units 1 and 2 was upheld.

The FIP required Basin to install the NO_x control technologies on AVS Units 1 and 2 by July 31, 2018. In accordance with the FIP requirements, Basin installed a low-NO_x concentric firing system (LNCFS) on AVS Units 1 and 2 in 2014 and 2016, respectively, coinciding with the scheduled tri-annual maintenance outages.

The NDDEQ has submitted a SIP revision for AVS, which would replace the FIP. On March 12, 2021 EPA proposed to approve the SIP revision submitted by the NDDEQ 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 AVS.

2020 fuels data from the Energy Information Administration shows the average sulfur content of the lignite burned at AVS would result in uncontrolled SO_2 emissions of 2.08 lb/mmBtu.[13] CAMD data for AVS in 2020 showed that controlled SO_2 emissions averaged 0.367 lb/mmBtu. The average annual SO_2 removal efficiency was 82%–83%. The charts below show SO_2 and NO_x emissions for the AVS units.

[11] Id. at pg. 58632. EPA: We have eliminated higher performing options—SNCR + LNB, SCR, and SCR + LNB—because their cost-effectiveness values are significantly higher and/or the emission reductions are not that much higher than LNB. Considering the statutory factors, we find that it is not reasonable to insist on these higher control levels in this first planning period. However, we expect the State to consider such controls in the next planning period.

[12] 77 Fed. Reg. 20894.

13 Average sulfur content was 0.91% with an average heat content of 13.154mmBtu/ton.

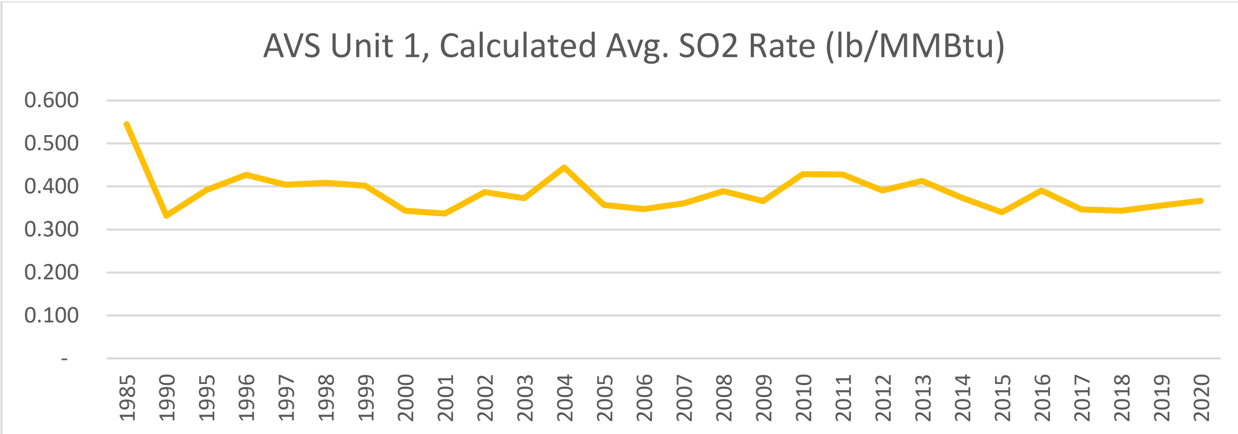


Figure 4. AVS Unit 1, Calculated Avg. SO_2 Rate (1985–2020)

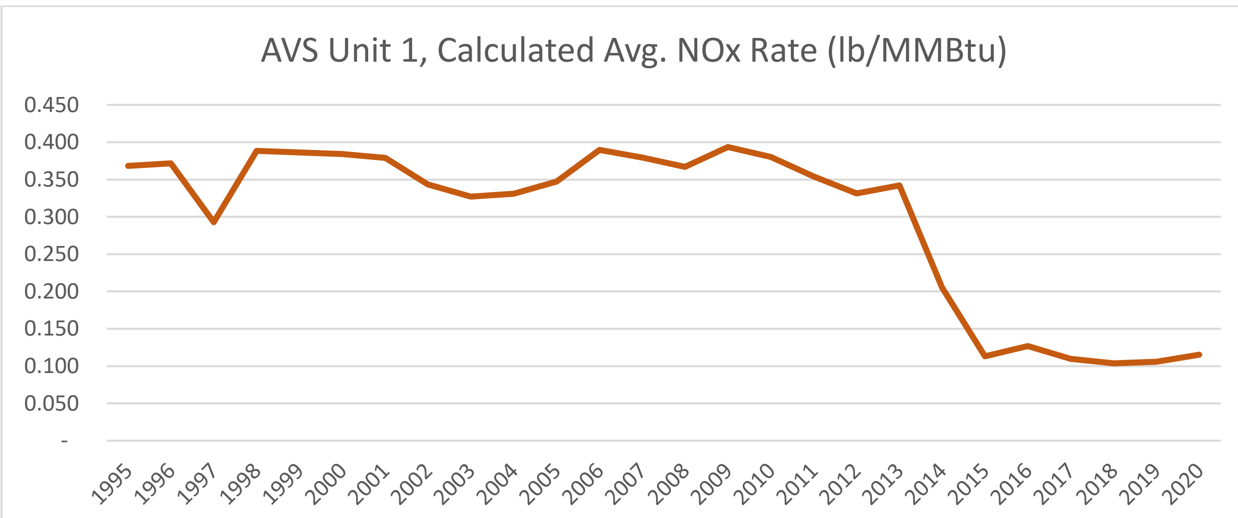


Figure 5. AVS Unit 1, Calculated Avg. NO_x Rate (1995–2020)

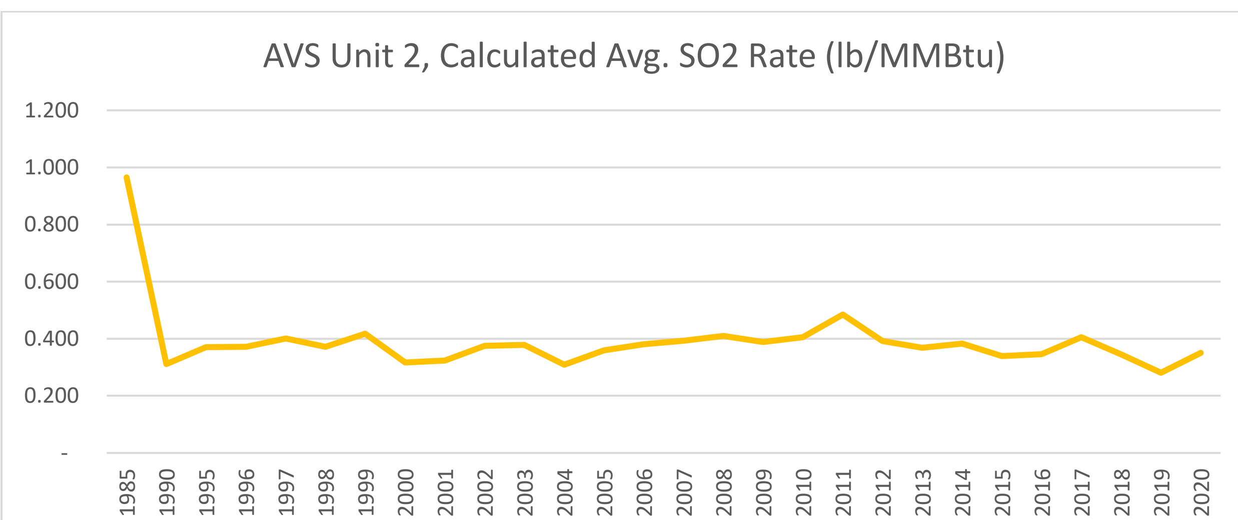


Figure 6. AVS Unit 2, Calculated Avg. SO_2 Rate (1985–2020)

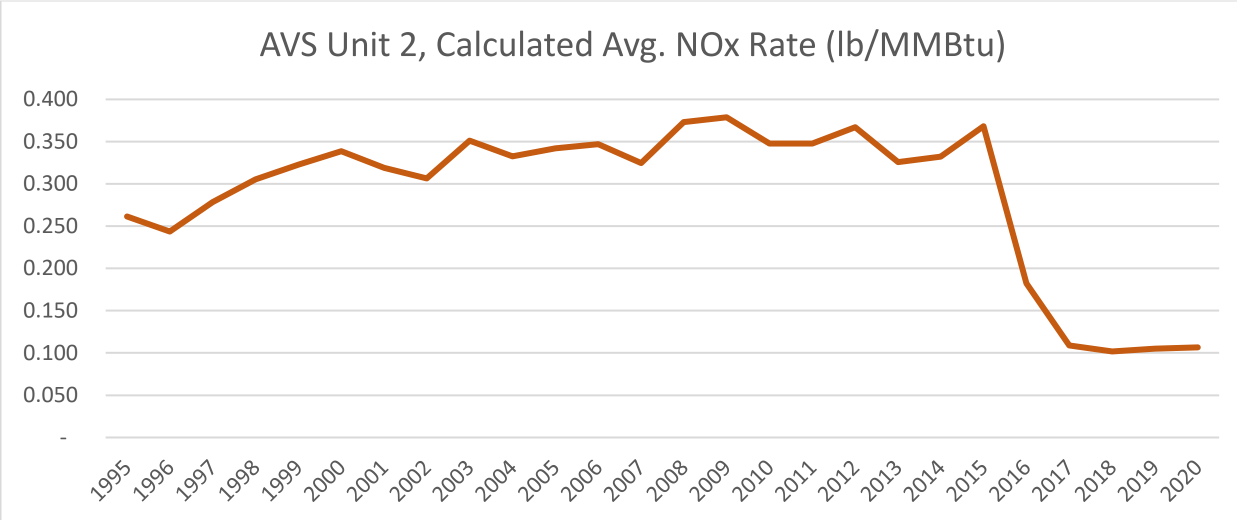


Figure 7. AVS Unit 2, Calculated Avg. NO_x Rate (1995–2020)

3.2.4 Second Planning Period Reasonable Progress Control Requirements for AVS Units 1 and 2

NDDEQ: NDDEQ sent a letter to Basin on May 2, 2018 requesting a four factors analysis[14] (4FA) for AVS. The letter required that the four factors analysis be submitted to the NDDEQ on or before January 31, 2019.

In January 2019, Sargent & Lundy LLC (S&L) prepared a 4FA for the AVS on behalf of Basin.[15] The analysis included an assessment of potentially available SO_2 and NO_x emission reduction technologies for AVS Unit 1 and 2.

NDDEQ provided comments to Basin regarding Basin's 4FA on June 20, 2019: "The design sulfur emission rate should be reevaluated and appropriate revision to the analysis made." Basin submitted a response to the NDDEQ's comments on July 12, 2019:

> *Although S&L used an uncontrolled SO_2 rate of 3.39 lb/MBtu as the design basis for the Four-Factor Analysis, that value was only used for the Projected Future Maximum Case. Uncontrolled SO_2 rates of 2.90 lb SO_2/MBtu for Units 1 and 2 (see Table 4-4 of the Four Factor Analysis) were used for the Actual Average Case…We agree that the existing DFGD alone may provide a removal efficiency of approximately 82-83%,*

14 42 U.S. Code § 7491.Visibility protection for Federal class I areas
(g) Definitions For the purpose of this section—
(1) in determining reasonable progress there shall be taken into consideration the costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements;
15 Basin's original four-factor analysis was submitted to the Department on January 31, 2019.

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

NPS: Following are excerpts from the January 2019 S&L report—we note where we have differences.

SO_2 Emissions Controls

– Technical Feasibility of Available SO_2 Control Options

FUEL SWITCHING

AVS is a mine mouth generation facility. AVS was designed and developed to burn North Dakota lignite coal received from the adjacent Freedom Mine for the purpose of generating electricity. Previous regulatory and court decisions have concluded that requiring a mine mouth facility to evaluate low sulfur coal would require the facility to redefine its fundamental purpose and design; therefore, fuel switching can be rejected as an available control option. Because the use of North Dakota lignite from the adjacent Freedom Mine is an inherent aspect of AVS operation, fuel switching will not be evaluated.

EXISTING FGD OPERATIONAL IMPROVEMENTS AND EQUIPMENT UPGRADES

Operational and other design changes/upgrades to the existing dry scrubber may provide an opportunity for additional SO_2 removal and allow the units to achieve lower controlled SO_2 emissions. S&L, working with Basin Electric personnel on behalf of AVS, identified a number of potentially feasible operational changes that may be available to increase SO_2 removal efficiency with the existing equipment. A detailed discussion of each of these options is provided in the following sections.

Station Work Practices

AVS Units 1 and 2 have a 3-hour SO_2 plantwide applicability limit (PAL) of 3,845 lb/hr in their Title V Air Permit that allows the station to adjust operation of each unit's FGD system as long as they achieve the overall plantwide limit. Historically, when one unit was in extended major outage the station would adjust operation (i.e., decrease SO_2 removal) on the other Unit to be in compliance with the PAL. AVS schedules major maintenance outages on a tri-annual (three-year) basis. As such, the opportunity for additional reductions is available one out of every 3 years on each unit. S&L reviewed the operating practices of the two units over the period June 2015–June 2018 to determine the increase in SO_2 emissions for the unit that was not in outage. The excess emission on Units 1 and 2 were 472 tons and 396 tons, respectively on an annual basis. Using the annual baseline SO_2 emissions and annual average heat input, eliminating these emissions would reduce the outlet SO_2 emission rate from 0.37 lb/MMBtu to a controlled emission rate of 0.35 lb/MMBtu on each Unit. However, it should be noted that under the current outage schedule, the emission reductions would only be achieved every 3rd year for a single unit since outages occur on a tri-annual basis. Based on this analysis, a change to the current station work practice is considered a technically feasible SO_2 control option for AVS Units 1 and 2.

Lime Quality

Based on a review of lime analyses and a review of operating data from the existing lime slaking system, AVS currently procures a high-quality lime for use in the dry scrubbers. The typical CaO content of the lime used at AVS is 90% or greater, and the slaking process achieves a 40°C temperature rise within three minutes of adding water. For these reasons, changing the lime quality is not considered a technically feasible operational change available to control SO_2 emissions from AVS, and will not be evaluated further.

Ca:S Stoichiometric Ratio

Other operational changes that may be available to increase the Ca:S stoichiometry in the existing dry scrubber include: (1) increasing the byproduct recycle ash rate; and/or (2) increasing the quantity of fresh hydrated lime introduced to the system. Due to the cost savings that may be realized with the first option, some facilities with existing DFGD controls have opted to increase solids recycle rates to as high as 40-50% solids to achieve an incremental increase in SO_2 reduction, if capacity was available in the byproducts handling system. If capacity is not available, increasing fresh lime addition to the system may also be a viable option to increase the Ca:S stoichiometric ratio.

Within each AVS DFGD, there are two parallel slurry preparation trains that prepare and supply the lime slurry feed to each of the five scrubber modules. The slurry preparation trains consist of recycle ash silos, ash mix tanks, slurry feed tanks and associated slurry and atomizer feed pumps, piping and controls and instrumentation. Solids from a dry scrubber consist of fly ash, reaction byproduct, and residual unreacted hydrated lime. On AVS Units 1 and 2, solids collected in the fabric filter hoppers are conveyed to either a dry storage silo for disposal or to a recycle ash silo where it is used as reactant slurry. The recycle system is designed to utilize a portion of the unreacted lime in the solids rather than disposing of all of the solids. Recycle solids are combined with the fresh lime addition to provide the makeup lime needed for SO_2 reduction. Increasing the recycle rate can increase the amount of available Ca added to the system (i.e., stoichiometric ratio) without increasing the quantity of fresh lime added to the system.

The DFGD systems on the AVS Units currently operate the recycle system at approximately 45% solids. The AVS recycle system is operating within the original design conditions and system capacity which is in line with industry practice. The plant has tested higher recycle rates, but at these higher rates plant personnel reported significant problems with recycle slurry pumping and pluggage of the recycle tanks and negative impacts to the fabric filter due to the increase in ash loading. Based on the adverse operational impacts observed during these tests, increasing the recycle percent solids is not considered a technically feasible SO_2 control option for the AVS Units, and will not be evaluated further.

As an alternative to increasing the recycle rate, the Ca:S stoichiometric ratio in the system may be increased by increasing the quantity of fresh lime introduced to the system. Basin Electric contracted with B&W, the original equipment manufacturer (OEM) of the AVS DFGD system, to determine if additional SO_2 removal could be achieved by increasing the amount of fresh lime added to the system while maintaining approximate 40-45% solids slurry to the atomizer. B&W ran their proprietary software which estimates the AVS DFGD performance. The results of the model indicated that AVS could potentially achieve 93% SO_2 removal of normal DFGD operation at 1% sulfur coal by increasing the fresh lime to the DFGD. Due to the uncertainties with the model, additional analysis is required to fully understand plant operational and performance impacts associated with an increased Ca:S stoichiometric ratio. There would be percent solids capacity limitation with the existing recycle slurry system and risks of increased scaling and build-up within tanks and piping with the increased lime solids. As such, this system will require modifications including new mix tanks, pumps and piping to minimize slurry preparation train outages. When a slurry preparation train fails, it requires the standby slurry preparation train to come on-line that could result in an increase in short term emissions until the slurry preparation train is placed into service. The 93% removal represents an average percent control that each AVS unit would be expected to achieve on an on-going long-term basis under normal operating conditions with the equipment upgrades installed. The emission rate should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Approach to Saturation Temperature

The AVS dry scrubbers currently operate with at an outlet temperature near 165-170°F, which is approximately 30°F above the adiabatic saturation temperature and within the OEM design. This is in line with new spray dryer absorbers which are typically designed to operate at 30°F approach to saturation. Therefore, the current approach to saturation temperature achieved on the AVS scrubbers are aligned with standard industry practices. Lowering the outlet temperature further has significant potential to cause detrimental corrosion of the vessel or downstream equipment and other significant operating issues. Therefore, further reducing the absorber module outlet temperature is not considered a technically feasible SO_2 control option for AVS, and will not be evaluated further.

Atomizer Replacement

AVS Units 1 and 2 dry scrubbers were provided by B&W's predecessor Joy Niro, and were designed with five absorber modules each with a single rotary atomizer with a 12-nozzle wheel to achieve a fine slurry spray. The design of the atomizer and speed at which the wheel rotates are controlling factors for the size and form of the droplets in the spray. Each atomizer wheel in AVS Unit 1 absorber module is powered by a 700 hp motor and Unit 2 absorber modules are designed with a 800 hp motor. In addition, the design of the atomizers is highly dependent on the spray pattern needed to mix with the hot flue gas in the scrubber module for optimum absorption of SO_2 while also preventing wetting of the absorber walls. Based on S&L's analysis and input from the station, there has not been any significant moisture carry-over into the baghouse or wetting of the absorber walls that would indicate that the atomizers are not achieving an optimum droplet size or spray pattern. In addition, both AVS dry scrubbers are operating at a consistent 30°F approach to saturation temperature, in-line with industry practice, concluding that the droplets are drying efficiently. Therefore, replacing the atomizer motor or atomizer wheel is not considered a technically feasible SO_2 control option for the AVS scrubbers, and will not be evaluated further.

Slaker Replacement

Lime slurry, the reagent used for SO_2 removal in a dry scrubber, is produced by mixing pebble lime with heated water in a slaker; this process is referred to as "slaking". The slaker is operated at an optimum water-to-lime ratio (typically between 3:1 and 6:1) to produce lime slurry by metering the amount of water and the amount of lime added to the slaker. Slakers are typically designed to produce a lime slurry between 15-20% solids. The lime slurry is added to the recycle slurry in a mix tank and then sent to the atomizer where it is sprayed into the scrubber for SO_2 removal.

In 2011, additional slaking capacity was installed at a cost pf approximately $15 million, in the form of two Vert-Mill lime slakers, lime storage and conveying systems in preparation of higher sulfur fuel deliveries. The slakers operate at a 5:1 water to lime ratio and approximately 18% solids which is in line with the design as well as industry practice. Therefore, replacing the already upgraded slaking systems is not considered a technically feasible SO_2 control option for the AVS scrubbers, and will not be evaluated further.

Adding an Absorber Module

Another option for extending the residence time within the reactor modules and increasing Ca:S contact would be to add an additional reactor module to each AVS unit. The existing system is designed with five absorber modules per unit. The system was originally designed to operate with four modules carrying full load gas flow with a standby spare available for routine maintenance. Subsequently, operation was changed so that all five modules are operated for full load gas flow. This change increased flue gas residence time in the reaction vessels from 5.0 seconds (at full load) to 6.5 seconds. More recent dry scrubbing systems have been designed with reaction vessel residence times of 10 seconds or more.

One potential option available to AVS to further increase reaction vessel residence time would be to add an additional absorber module to the existing dry scrubbing system on each unit. The number of absorber modules used in a DFGD system is dependent on multiple operating parameters, including the flue gas flow rate and SO_2 concentrations. DFGD modules are typically specified with minimum and maximum flue gas flow rates. If the absorber modules are oversized, flue gas velocities through the module can be too low, causing solids dropout inside the vessel. If the absorber modules are undersized, flue gas velocities can be too high, causing residence time to fall below recommended levels.

Dry scrubbing units that are operating at flue gas volumes significantly above the design flow rate can benefit from adding an extra module to the system. The module would be placed in parallel with the existing modules to achieve a similar pressure drop through each vessel and to ensure equal flue gas distribution to the modules. In 2006, Basin Electric hired B&W's Allen-Sherman Hoff to develop a computer model of the existing five scrubber modules to determine the impact of adding a 6^{th} absorber module to each of the AVS units in response to potentially higher-sulfur fuels in the future. The modeling showed the five existing absorbers have adequate residence time for the expected higher sulfur in the coal and operate at an approach to saturation of 30°F which is consistent with industry practice. Installation of a sixth absorber would not provide any significant improvement towards removing additional sulfur. The primary benefit of a sixth SDA chamber would be to provide redundancy. While this would be beneficial towards maintaining unit loads without having to restrict generating capacity for chamber maintenance items, inspections and chamber cleaning, it would not provide any additional improvement to reducing SO_2. Therefore, incorporating an additional absorber module into the existing system is not a technically feasible SO_2 control strategy for AVS, and will not be evaluated further.

Replacing Existing Absorbers with New Absorber Modules

Replacing the existing modules with new absorber modules would require significant engineering and facility modifications. Based on a preliminary review of the control system layout, the only practical location for this option would be to construct the new vessels in the same location as the existing modules. Locating the DFGD modules adjacent to the existing dry scrubber would require flue gas to be redirected from the air heater outlet to the new absorbers and back to the existing fabric filter, which would likely result in significant solids dropout and other operational issues. Therefore, locating the new absorber modules adjacent to the existing absorber modules is not considered a technically feasible option.

DFGD control systems use a hydrated lime slurry to remove SO_2 from the combustion gases. Various operating parameters will affect the efficiency of the DFGD process including the residence time and how close the system operates to saturation. These are the same operating parameters that affect the efficiency of the existing AVS Units 1 and 2 dry scrubbers. The AVS Units 1 and 2 dry scrubbers already operate at an approach to saturation temperature of 30°F which is consistent with industry practice as well as have adequate residence time. Therefore, replacing the existing absorber modules with new absorber modules would not provide any additional benefit and will not be evaluated further.

EXISTING FGD + DRY DSI

DSI upstream of the existing dry scrubber is a technically feasible and commercially available SO_2 control option for AVS Units 1 and 2. Taking into consideration the fact that AVS is currently equipped with a calcium-based dry scrubbing system, hydrated lime dry DSI would be the most practical, and potentially the most effective, DSI control option. Sodium-based systems would require extensive testing to determine the potential impacts associated with introducing significant quantities of sodium into the existing system, and are not considered practical control options for AVS Units 1 and 2. However, although DSI is a technically feasible control option, it should be noted that DSI upstream of the existing DFGD control system at AVS would not provide any additional SO_2 removal than what could already be achieved by increasing the fresh lime or calcium content through the existing upgraded lime slaking system as discussed in Section 4.3.2.2 Ca:S Stoichiometric Ratio. The existing upgraded lime slaking system at AVS has sufficient capacity to provide the increase in calcium content. Therefore, DSI will not be evaluated further.

RETROFIT NEW DRY FGD SYSTEM

Replacing the existing dry scrubber/FF with new control systems would require significant engineering and modifications to the facility. Based on a preliminary review of the facility layout, the new control systems could be located south of Unit 1 and north of the Unit 2 existing dry scrubber/FF. The new DFGD/FF and all auxiliary equipment could be constructed while the units remain on-line. The control systems could be tied-in to the existing systems during a scheduled major outage.

Spray Dryer Absorber / Fabric Filter

Replacing the existing dry scrubber/FF with a new SDA/FF control systems is a technically feasible and commercially available control option on the AVS Units. SDA/FF control systems are generally limited to an SO_2 removal of approximately 95%. This removal represents what the control system vendor would be willing to guarantee upon initial operation of the control system.

Circulating Dry Scrubber / Fabric Filter

A second type of dry scrubbing system is the circulating dry scrubber (CDS). Similar to other DFGD systems, the CDS system would be located after the air preheater, and byproducts from the system collected in an integrated fabric filter. Unlike the SDA systems, CDS systems use a circulating fluidized bed of hydrated lime reagent to remove SO_2 rather than an atomized lime slurry; however, similar chemical reaction kinetics are used in the SO_2 removal process.

As with the SDA/FF option, replacing the existing DFGD with a new CDS/FF control system would require significant engineering and modifications to the existing facility. For this evaluation it was assumed that the CDS/FF control systems could be located adjacent to the existing dry scrubber/FF, and that the control systems could be tied-in to the existing system during a scheduled major outage.

Replacing the existing dry scrubber and FF with a new CDS/FF control system is a technically feasible and commercially available control option for the AVS units. Based on engineering judgment, it is anticipated that the retrofit CDS/FF control option would achieve controlled SO_2 emission rates higher than those achieved with a SDA/FF due to the increased Ca:S in the fluidized bed absorber vessel. Based on recent CDS retrofit projects, and taking into consideration expected future design coal characteristics, it is anticipated that the retrofit CDS/FF control system could achieve SO_2 removal efficiencies of approximately 97%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system and on an ongoing long-term basis under normal operating conditions.

Retrofit New Wet FGD System

Another option available to AVS would be to replace the existing dry scrubbing system with a new wet FGD control system located downstream of the existing FF.

Wet Limestone Scrubbing

For this evaluation, it was assumed that the existing AVS dry scrubber reactor vessel would remain in place, and that the WFGD control system would be located downstream of the existing FFs and ID fans most likely south of Unit 1 and north of the Unit 2 existing dry scrubber/FF. Dry scrubber reactor vessel internals would ultimately be removed to reduce pressure drop through the system. A single absorber tower for each Unit would be sufficient for the flue gas flow. In addition to the absorber tower and reaction vessel, the WFGD control system would require a limestone handling and preparation system and by-product dewatering systems. Because of the saturated nature of the flue gas exiting the WFGD and the velocity requirements with wet stack operation, a new stack with a liner capable of wet flue gas operation would be required. New booster ID fans would also be required to account for the additional pressure drop through the WFGD control system.

Wet FGD technology is an established SO_2 control technology. Wet scrubbing systems have been installed on units that fire medium to high sulfur coals, and would be a technically feasible SO_2 control option for AVS Units 1 and 2. Based on engineering judgment and information from control system vendors, it is anticipated that a retrofit WFGD control system on a North Dakota lignite-fired unit would be designed to achieve and SO_2 removal efficiency of approximately 98%. This removal efficiency represents what the control system vendor would be willing to guarantee upon initial operation of the system and on an on-going long-term basis under normal operating conditions.

– Cost of Compliance (Statutory Factor 1)

S&L for AVS: Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25% and equipment life of 20 years.

NPS: EPA's Control Cost Manual (CCM) recommends use of the current prime interest rate of 3.25% and equipment life of 30years.

S&L for AVS: Capital and O&M cost estimates were developed for each of the technically feasible SO_2 control options. The AVS Units 1 and 2 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Units 1 and 2 control system upgrades. All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing dry scrubber and fabric filter control systems.

NPS: S&L used spreadsheets based upon internal studies at similar facilities to estimate costs, these cost estimates were not based upon site-specific vendor quotes or detailed engineering evaluations. The S&L spreadsheet contained several cost items (sales tax, owner's costs, property taxes) not included in the CCM workbooks, and applied a 20% contingency factor instead of the CCM's default 10% factor. We applied the CCM workbook for wet and dry scrubbers as described below.

We applied the CCM "Wet and Dry Scrubbers for Acid Gas Control" workbook to the existing SDA scrubbers based upon 2020 EIA fuels data and the most-recent five years of CAMD data. We estimated that the current SDA scrubbers have a direct annual cost of \$12– \$13 million which would end if the scrubbers are replaced. The costs of the new replacement 98% efficient wet FGD and new 97% efficient CDS were also estimated using the CCM workbook; results are tabulated below.

*Table 9. NPS Revised NDDEQ Table 9: AVS **Unit 1** SO_2 Cost of Compliance and Incremental Cost of Compliance*

Control Technology	Performance Rate (lb SO_2/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
DFGD/FF (Baseline)	0.36				
Station Work Practice	0.35	174	135,000	775	
Ca:S Stoichiometry	0.2	2,788	1,938,773	695	690
DFGD (CDS/FF)	0.06	4,986	14,066,450	2,821	5,518
WFGD	0.04	5,316	15,811,967	2,974	5,278

*Table 10. NPS Revised NDDEQ Table 9: AVS **Unit 2** SO_2 Cost of Compliance and Incremental Cost of Compliance*

Control Technology	Performance Rate (lb SO_2/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
DFGD/FF (Baseline)	0.36				
Station Work Practice	0.35	174	135,000	775	
Ca:S Stoichiometry	0.2	2,788	1,938,773	695	690
DFGD (CDS/FF)	0.06	4,699	14,407,153	3,066	6,526
WFGD	0.04	5,038	16,167,853	3,209	5,188

Replacement of the existing dry scrubbers with modern new scrubbers could cost-effectively reduce facility SO_2 emissions by over 10,000 tons/yr.

– Time Necessary for Compliance (Statutory Factor 2)

NDDEQ: A summary of the anticipated timelines for the installation of the technically feasible control technologies is provided in Table 10.

Table 11. (NDDEQ draft SIP Table 10) Time Required for SO_2 Controls

Control Technology	Total time after SIP approval (months)
Station Work Practice	3
Ca:S Stoichiometry	51
DFGD (CDS/FF)	56
WFGD	60

The anticipated timelines for the installation of each of the control technologies indicates all options could be installed prior to the end of the second planning period.

– Energy and Non-Air Quality Environmental Impacts (Statutory Factor 3)

Energy

NDDEQ: The replacement of the existing drying scrubbing system with a CDS/FF or WFGD would increase the pressure drop through the control systems, which will increase the auxiliary power requirements. This would adversely affect the net plant heat rate. This impact is significant but not significant enough to eliminate either CDS/FF or WFGD as a control option.

NPS: This is an economic issue addressed under statutory factor 1, cost of compliance.

Non-Air Quality Environmental Impacts

NDDEQ: The installation and operation of a WFGD control option would generate a liquid calcium sulfate by-product that would need to be dewatered prior to disposal. In addition, WFGD control systems generate wastewater streams that typically contain a saturated solution of calcium sulfate, calcium sulfite, sodium chloride, trace amounts of fly ash, and unreacted limestone. The wastewater stream would need to be treated prior to discharge. WFGD systems also require significantly more water than dry systems. The non-air quality environmental impacts for WFGD are significant but not significant enough to eliminate WFGD as a control option.

NPS: The impacts raised are standard to the operation of WFGD.

– Remaining Useful Life (Statutory Factor 4)

NDDEQ: Based on the information provided to the Department, AVS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

NO_x Emission Controls

SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia or urea ($CO(NH_2)_2$) at high flue gas temperatures (approximately 1,600ºF – 2,100ºF) in an oxidizing environment. The ammonia or urea reacts with NO_x in the flue gas to produce N_2 and water as shown below.

$$(NH_2)_2CO + 2NO + \frac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$
$$2NH_3 + 2NO + \frac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

NDDEQ: Installation of SNCR post combustion add-on control equipment has a limited impact on removing NO_x emissions from the flue gas. The limited removal is due to low NO_x concentrations in the flue gas stream affecting the reaction kinetics. Sources that are well suited for SNCR typically have an uncontrolled NO_x concentration above 200 ppm. AVS is generally around 60 ppm uncontrolled NO_x, making AVS not well suited for SNCR application. SNCR is anticipated to provide an approximately 18% reduction in NO_x emissions from the baseline scenario, lowering the expected performance rate from

0.11 to 0.09 lb NO_x per MMBtu. SNCR has a limited impact on reducing NO_x, however, installation of

SNCR on Unit 1 and Unit 2 at AVS is technically feasible and will be evaluated further.

SELECTIVE CATALYTIC REDUCTION (SCR)

S&L for AVS: SCR is a process by which ammonia (NH_3) reacts with nitric oxide (NO) and nitrogen dioxide (NO_2), collectively NO_x, in the presence of a catalyst to reduce the NO_x to nitrogen (N_2) and water (H_2O). SCR technology has been applied to NO_x-bearing flue gases generated from power generating facilities burning various types of coal, including bituminous, subbituminous, and Texas lignite. The principal reactions resulting in NO_x reduction are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_20$$
$$4NO_2 + 8NH_3 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

Because these reactions proceed slowly at typical boiler exit gas temperatures of a coal-fired steam -electric generating unit, a catalyst is used to increase the reaction rate between NO_x and NH_3. Depending on the specific constituents in the flue gas, a typical temperature range of 550°F to 780°F is necessary to achieve normal performance of the catalyst. For the typical coal-fired boiler, optimal performance will be in the range of approximately 650°F to 750°F.

In the tail-end configuration, the SCR reaction vessel is located in the flue gas stream after the particulate and FGD control systems. The potential advantage of a tail-end SCR configuration at Coyote Unit 1 is that the flue gas will have passed through the dry FGD/FF system prior to the SCR catalyst. As such, there is the possibility that the mass transfer mechanism that results in the capture of SO_2 will also capture some of the vapor-phase sodium and the sodium-enriched submicron particles, reducing the risk of catalyst poisoning and/or deactivation.

Successful operation of the tail-end configuration would also require a capital and operating cost-intensive gas-to-gas heat exchanger to reheat the flue gas from approximately 170 °F downstream of the existing fabric filter to approximately 550°F to support the SCR NO_x reactions. After the flue gas passes through the SCR (at approximately 550°F), it would pass through the hot side of the gas-to-gas heat exchanger to cool the flue gas to 150°F prior to the exhaust stack. Although this stack gas temperature would be lower than the current stack temperature (165-170°F), it is still higher than the adiabatic saturation temperature of the flue gas (i.e., approximately 135°F). As such, it is likely that the existing stack could be reused with minor modifications.

NDDEQ: During the first regional haze program planning period in North Dakota, the Department determined that installation of SCR, in any configuration, is not a technically feasible control technology since it has not been demonstrated in practice on North Dakota lignite coal. However, the earlier determination focused on cyclone-fired boilers. Successful use of TE-SCR controls have since been demonstrated at existing bituminous- and subbituminous-fired units. Therefore, the current determination is deeming TE-SCR as being technically feasible. TE-SCR is anticipated to provide an approximately 55% reduction in NO_x emissions from the baseline scenario, lowering the expected performance rate from 0.11 to 0.05 lb NO_x per MMBtu. TE-SCR is assumed technically feasible for installation on Unit 1 and Unit 2 at AVS and will be evaluated further.

NPS: Tail-End SCR should be able to reduce NO_x emissions by at least 60% and achieve 0.04 lb/mmBtu at AVS. For example, EPA assumed in 2014 that SCR could achieve the 0.04 lb/mmBtu annual emissions proposed by Basin at its Laramie River Station in WY. 2020 CAMD data contains 11 coal-fired EGUs with SCR at 0.04 lb/mmBtu annual average.

– Cost of Compliance (Statutory Factor 1)

S&L for AVS : Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25% and equipment life of 20 years.

NPS: The CCM recommends use of the current prime interest rate of 3.25% over a 30-year life.

S&L for AVS: The AVS Units 1 and 2 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Units 1 and 2 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on AVS-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the AVS Units 1 and 2 retrofit technologies as “concept screening” cost estimates generally based on parametric models, judgment, or analogy.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, Contractor G&A expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing control systems.

NPS: Instead of using CCM cost models the four-factor analysis used an outdated methodology that includes owners costs as well as property taxes and an unjustified contingency cost. Inclusion of owners costs is not allowed by EPA and ND does not assess property taxes. We analyzed costs according to the CCM and provide results in Tables 12 and 13 below.

Table 12. NPS Revised, NDDEQ draft SIP Table 6: NO_x Cost of Compliance and Incremental Cost of Compliance for AVS Unit1

Control Technology	**Performance Rate (lb/MMBtu)**	**Annual Emission Reduction (tpy)**	**Annualized Total Cost ($)**	**Cost of Compliance ($/ton)**	**Incremental Cost of Compliance ($/ton)**
SOFA/LNCFS (Baseline)	0.11				
SNCR	0.09	350	2,333,250	6,673	
TE-SCR	0.04	1,200	9,866,596	8,225	8,864

Table 13. NPS Revised NDDEQ Table 6: NO_x Cost of Compliance and Incremental Cost of Compliance for AVS Unit2

Control Technology	**Performance Rate (lb/MMBtu)**	**Annual Emission Reduction (tpy)**	**Annualized Total Cost ($)**	**Cost of Compliance ($/ton)**	**Incremental Cost of Compliance ($/ton)**
SOFA/LNCFS (Baseline)	0.11				
SNCR	0.09	345	2,394,353	6,939	
TE-SCR	0.04	1,151	10,303,449	8,955	9,818

Addition of SNCR could reduce facility NO_x emissions by 700 ton/yr while addition of SCR could reduce facility NO_x emissions by over 2,300 tons/yr.

– Time Necessary for Compliance (Statutory Factor 2)

NDDEQ: A summary of the anticipated timelines for the installation of SNCR and TE-SCR is provided in Table 7.

Table 14. (NDDEQ draft SIP Table 7) Time Required for NO_x Controls

Control Technology	Total time after SIP approval (months)
SNCR	22
TE-SCR	52

The anticipated timelines for the installation of SNCR and TE-SCR indicate either option could be installed prior to the end of the second planning period.

– Energy and Non-Air Quality Environmental Impacts (Statutory Factor 3)

ENERGY

NDDEQ: The installation and operation of a TE-SCR would increase the pressure drop through the control systems, which would increase the auxiliary power requirements. This would adversely affect the net plant heat rate. This impact is significant but not significant enough to eliminate TE-SCR as a control option.

NON-AIR QUALITY ENVIRONMENTAL IMPACTS

NDDEQ: The installation and operation of the TE-SCR could result in an increase in sulfur emissions due to the potential oxidation of SO_2 to SO_3 and the subsequent reaction with moisture in the stack to form H_2SO_4.

NPS: This is not likely to be a problem with low-sulfur fuels.

NDDEQ: Both TE-SCR and SNCR use ammonia as a reagent. Ammonia slip emissions will result in the flue gas stream on the exhaust side of the control equipment due to the operation of TE-SCR (~2 ppm) and SNCR (~10 ppm). The ammonia slip emissions from the operation of SNCR would likely combine with the dry FGD solids. The ammoniated dry FGD solids would require that further safety precautions are taken for AVS staff who perform maintenance on the ash handling system or staff who dispose of waste. Ammonia slip emissions from the operation of the TE-SCR would be emitted to the atmosphere. Subsequently, the ammonia could combine with SOX and NO_x to form sulfates and nitrates, which will affect visibility.

The non-air quality environmental impacts for TE-SCR and SNCR are significant but not significant enough to eliminate either of them as a control option.

NPS: None of these impacts are unusual.

– Remaining Useful Life (Statutory Factor 4)

Based on the information provided to the Department, AVS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

3.2.5 Conclusions & Recommendations

- Other states have set cost-effectiveness thresholds of: $5,000/ton for EGUs in AR and TX, $7,000/ton in NM, and $10,000/ton in CO and OR.
- The incremental cost effectiveness of replacing the old scrubbers at AVS would be acceptable in the context of the previous ND BART thresholds as well as the thresholds used by the states cited. Replacement of the existing dry scrubbers with modern new scrubbers could cost-effectively reduce facility SO_2 emissions by over 10,000 tons/yr.
- The annual average cost effectiveness of adding SNCR at AVS would be acceptable in the context of the thresholds used by CO, NM, and OR. Addition of SNCR could reduce facility NO_x emissions by 700 tons/yr.
- The annual average cost effectiveness of adding SCR at AVS would be acceptable in the context of the thresholds used by CO and OR. Addition of SCR could reduce facility NO_x emissions by over 2,300 tons/yr.

3.3 Coal Creek

3.3.1 Summary of NPS Recommendations and Requests for Coal Creek Station

NPS review of the four-factor analysis conducted for Coal Creek Station (CCS) finds that there are technically feasible and cost-effective opportunities available to further control SO_2 and NO_x emissions from Units 1 and 2. In fact, we find that the cost of control is more economical than estimated when analyses are adjusted in accordance with the EPA Cost Control Manual.

Although ND has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of: $5,000/ton for EGUs in AR and TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

The cost effectiveness of minimizing flue gas bypass to reduce SO_2 emissions at CCS would be acceptable in the context of the previous ND BART thresholds as well as the thresholds used by other states in this planning period. This control could cost-effectively reduce facility SO_2 emissions by almost 1,400 tons/yr.

We find SNCR and SCR opportunities for reducing NO_x emissions at CCS. 1) Addition of SNCR would be cost effective in the context of the previous ND BART thresholds as well as the thresholds used by other states in this round of RH SIP planning. SNCR at CCS Units 1 and 2 and could reduce facility NO_x emissions by almost 1,200 tons/yr. 2) The incremental cost effectiveness of adding SCR at CCS would be acceptable in the context of the previous threshold used by ND. Addition of SCR could reduce facility NO_x emissions by over 4,200 tons/yr.

CCS may also be able to reduce its substantial mercury emissions (ranked #1 in the country) by choosing to implement SCR ahead of the ESP or wet scrubbers. We encourage NDDEQ to evaluate this potential and weigh the co-benefits of mercury emission reduction when considering NO_x controls for CCS. This can be considered in reasonable progress analyses as part of statutory factor 3 (energy and non-air quality environmental impacts).

We recommend that ND take every opportunity to reduce SO_2 and NO_x emissions from the Coal Creek Station in this planning period. By requiring implementation of identified controls ND will be reducing haze causing emissions and advancing incremental improvement of visibility at Theodore Roosevelt, Badlands, and Wind Cave National Parks as well as other Class I areas in the region.

3.3.2 Coal Creek Station Plant Characteristics

Coal Creek Station (CCS) is a 1,210 MW mine-mouth lignite coal-fired power station owned and operated by Great River Energy (GRE) near Underwood, North Dakota. Theodore Roosevelt National Park, a Class I area administered by the National Park Service (NPS), is 159 km west of this facility.

Of 1,167 facilities in EPA's Clean Air Markets Database (CAMD) in 2020, CCS ranked #42 for sulfur dioxide (SO_2) emissions (5,301 tons) and #22 for nitrogen oxides (NO_x at 6,263 tons). CCS' carbon dioxide emissions of 9,543,317 tons rank #19 in the US. CCS also ranked #1 for EGU mercury (Hg) emissions with 314 lb in 2017.

Unit 1 and Unit 2 are identical subcritical 605 MW Combustion Engineering boilers firing pulverized lignite coal tangentially. Unit 1 began commercial operation in 1979 and Unit 2 began commercial operation in 1980. 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 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 NO_x 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 the second quarter of 2020. Each unit is equipped with wet flue gas desulfurization (FGD) for SO_2 control and an electrostatic precipitator (ESP) for particulate control. Each unit employs halide injection and activated carbon injection for the control of mercury.[16] Table 15 below shows a breakdown of 2020 SO_2 and NO_x emissions and how they rank versus the 3,317 EGUs in CAMD.

Table 15. CCS 2020 SO_2 and NO_x emissions and rank versus the 3,317 EGUs in CAMD

Unit ID	SO_2 (tons)	SO_2 (tons) Rank	Avg. SO_2 Rate (lb/MMBtu)	Avg. SO_2 Rate (lb/MMBtu) Rank	NO_x (tons)	NO_x (tons) Rank	Avg. NO_x Rate (lb/MMBtu)	Avg. NO_x Rate (lb/MMBtu) Rank
1	2,499	85	0.122	257	3,277	29	0.1630	396
2	2,801	75	0.120	260	2,986	40	0.1272	581

[16] January 2021 Hg emissions were: Unit 1= 3.79 lb/Trillion Btu (TBtu), Unit 2 = 3.82 lb/TBtu.

3.3.3 First Planning Period Regional Haze Control Requirements for CCS Units 1 and 2

CCS units 1 and 2 were subject to Best Available Retrofit Technology (BART) requirements. 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, Region 8 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 NO_x emissions. In June 2012, North Dakota received a revised NO_x 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 NO_x BART analysis for CCS.

"Supplement No. 2" provided updated and corrected information to the NO_x 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 NDDEQ's (the Department's) NO_x BART determination, including the Department's submitted "Supplement No. 2". EPA received comments 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.

CCS Units 1 and 2 are identical tangentially-fired pulverized coal boilers combusting North Dakota lignite coal. The existing NO_x 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.

Supporting factors for NDDEQ's BART determination 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. The charts below show SO_2 and NO_x emissions for the CCS units.

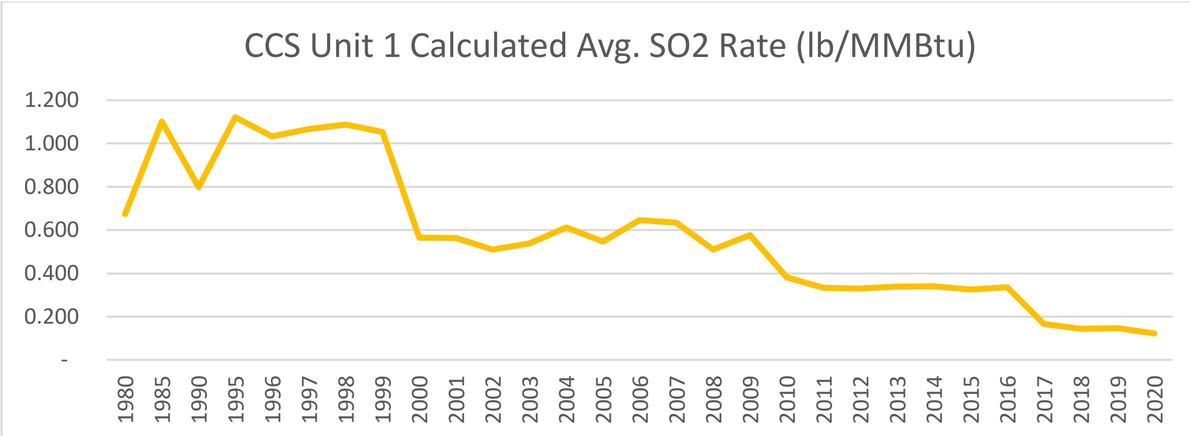


Figure 8. CCS Unit 1, Calculated Avg. SO_2 Rate (1980–2020)

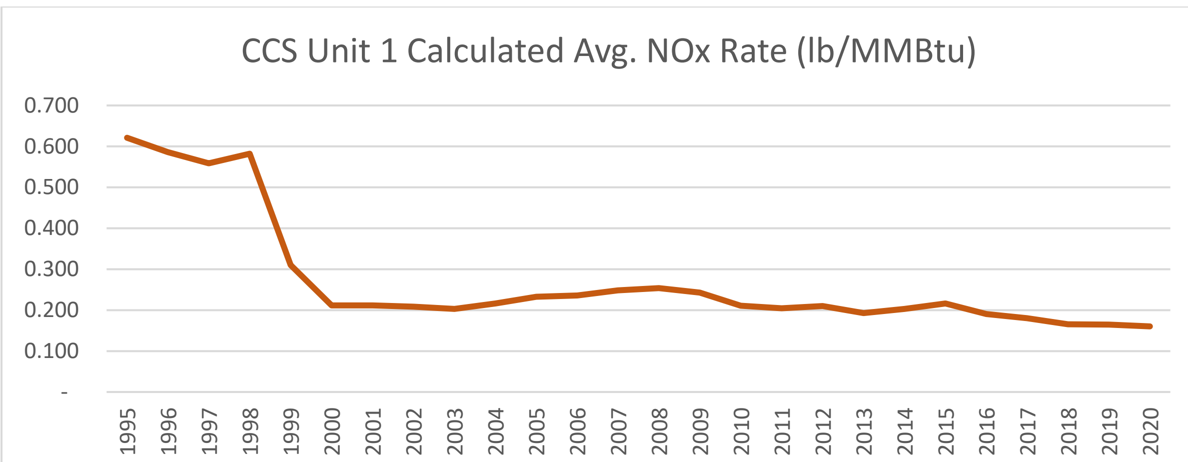


Figure 9. CCS Unit 1, Calculated Avg. NO_x Rate (1995–2020)

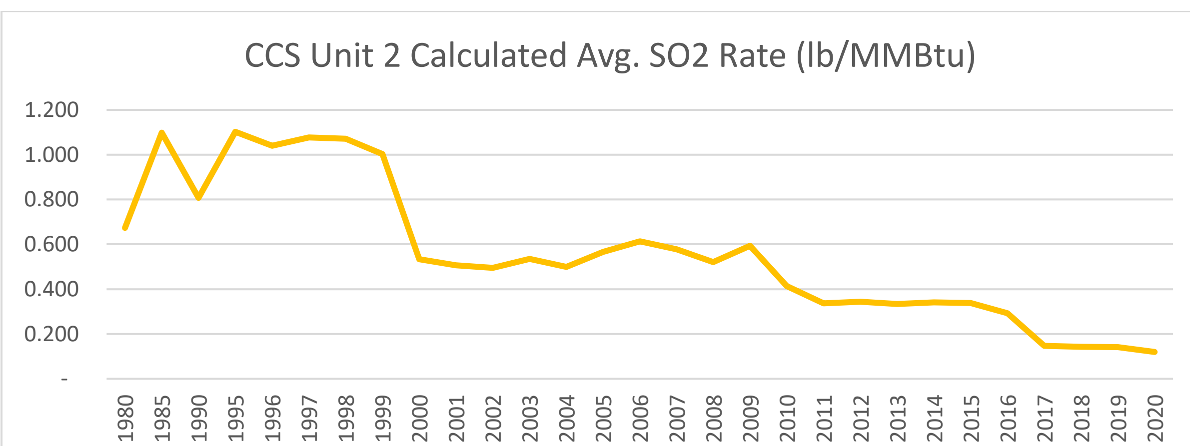


Figure 10. CCS Unit 2, Calculated Avg. SO_2 Rate (1980–2020)

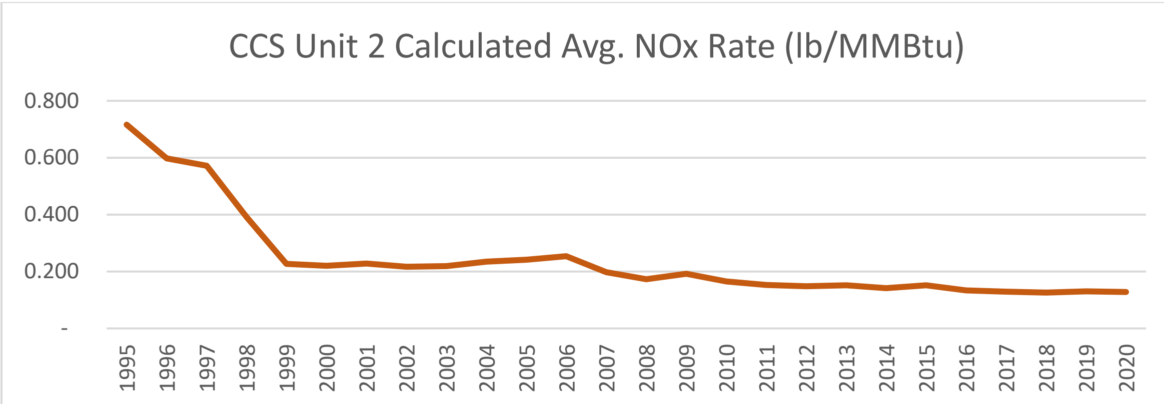


Figure 11. CCS Unit 2, Calculated Avg. NO_x Rate (1996–2020)

3.3.4 Second Planning Period BART/Reasonable Progress Requirements for CCS Units 1 and 2

NDDEQ: The Department sent a letter to GRE on May 2, 2018 requesting a four factors analysis for CCS. The letter required that GRE's four factors analysis be submitted to the Department on or before January 31, 2019. The Department emailed GRE on December 18, 2018 to inform GRE that they should focus on completing an updated BART analysis for the first round of Regional Haze planning. On September 12, 2019, GRE submitted an updated BART analysis associated with the first round of Regional Haze planning.

SO_2 Emissions History

NDDEQ: June 2017 through December 2018 was used to determine the SO_2 baseline emissions rate from CCS. This time period was chosen since it serves as the best representation of expected emissions and performance rate of the WFGD operations. The average emissions rate of 0.14 lb SO_2 per MMBtu is representative of future expected operations. This value is used as the starting point when determining the cost of compliance for the add-on controls.

NPS: According to Barr Engineering's December 2019 report:

> *Subsequently, in 2017, GRE designed and implemented a novel stack flue gas reheat system, which increases the exhaust temperature in order to allow each unit to operate with a dry stack and with improved capture of the flue gas to the existing wet gas scrubber (i.e., reduced use of the scrubber bypass).*

We reviewed SO_2 emissions data January 2018 through September 2021 and agree with NDDEQ that 0.14 lb/mmBtu is an appropriate baseline.

SO_2 Emissions Controls

Barr for CCS: As described in GRE's CCS BART report, several wet scrubber modifications were assessed. These included the addition of a fifth scrubber module and expansion of the existing absorber towers to scrub all the flue gas. With the implementation of DryFining™, the flue gas volume was reduced such that the existing scrubber modules could handle 100% of the flue gas, notwithstanding that the current stacks are designed as dry stacks. Therefore, the fifth absorber module and/or expanded absorber towers are no longer needed. Further, conducting a four-factor evaluation to replace the existing wet scrubber system with a new design for a possible incremental level of improved SO_2 performance will inherently result in unreasonable costs on absolute cost and average cost effectiveness bases.

NDDEQ: The reasonable progress controls that were identified for analysis for CCS Unit 1 and Unit 2 are listed in Table 4, along with their approximate annual control efficiency. All controls were deemed technically feasible.

Table 16. (NDDEQ draft SIP Table 4) CCS Units 1 and 2, SO_2 Controls Identified for Analysis

Control Technology	Approximate Annual Control Efficiency
Dry Sorbent Injection	50-70%
Spray Dry Absorption	70-90%
Natural Gas Reheat System	96%
New Wet Stack	96%

CCS currently utilizes a minor bypass in limited situations to maintain dry stack conditions. A natural gas reheat system or new wet stacks would theoretically remove the need for this bypass, maximizing the proportion of flue gas to the wet scrubber. Both methods were analyzed as potential options and result in the same control efficiency. The existing WFGD system currently achieves an annual average removal efficiency of approximately 94% to 95%. Dry sorbent injection and spray dry absorption would not provide improvement over CCS's existing SO_2 emissions control system and were not evaluated further.

– Cost of Compliance (Statutory Factor 1)

NPS: We reviewed Barr's cost estimates and note that the Capital Recovery Cost was based upon a 5.25% interest rate and 20-year life which resulted in a Capital Recovery Factor = 0.08368. Instead, the Control Cost Manual (CCM) recommends use of the current prime interest rate (3.25%) over 30 years which yields a CRF = 0.0527.

NEW WET STACK

NDDEQ: One control option that was analyzed was the replacement of the current stacks on Unit 1 and Unit 2. CCS Unit 1 and Unit 2 are both dry stacks, despite using a wet scrubber. Converting the existing stacks to a wet stack design is not possible and instead new wet stacks would need to be constructed and the current stacks would be abandoned and demolished. For the evaluation of a new wet stack, Hamon Custodis, Inc. provided an initial high-level concept to effectively replace the two existing stacks with a rough budget price. CCS has added to this price a high-level and conservatively low set of cost estimates to convert the Custodis cost to an appropriate diameter and to include foundations, duct work, and continuous emissions monitoring systems (CEMS). A new wet stack would result in an approximate 1,377 ton per year reduction of SO_2.

Natural Gas Reheat System

CCS Units 1 and 2 currently utilize a novel flue gas reheat system that can maintain a dry stack under most operating situations, while maximizing the proportion of flue gas to the wet scrubber. During low load and cold weather operation, the existing reheat system does not provide enough thermal energy to reheat the stack gas to a dry state. The existing reheat system adds approximately 11 MMBtu/hr, and CCS estimates that approximately 31.5 MMBtu/hr of additional energy would be required to maintain a dry stack under all operating conditions. WBI Energy provided a cost estimate for a new gas line, with the cost split between both units. Barr Engineering provided an estimate for the natural gas-fired duct burner system, with additional consideration for site-specific installation factors. The installation of a new natural gas reheat system would result in an approximate 1,377 ton per year reduction of SO_2.

NPS: We calculated capital costs using the CCM recommended 3.25% interest rate and 30-year life. The cost-effectiveness of the options evaluated is well within accepted values.

Table 17. NPS Revised NDDEQ Table 5: SO_2 Cost of Compliance and Incremental Cost of Compliance for CCS Units 1 and 2

Control Technology	Performance Rate (lb SO_2/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
WFGD (Baseline)	0.14			
New Wet Stack	0.08	1,377	2,841,363	2,063
Natural Gas Reheat System	0.08	1,377	3,000,849	2,179

– Time Necessary for Compliance (Statutory Factor 2)

NDDEQ: Both the new wet stack and natural gas reheat system would require at least two to three years to engineer, permit, and install the equipment. Therefore, time necessary for compliance is not a limiting factor when determining additional reasonable controls. The anticipated timeline would allow for either option to be installed prior to the end of the second round of regional haze.

– Energy and Non-Air Quality Environmental Impacts (Statutory Factor 3)

NDDEQ: The replacement wet stack would result in the demolition and disposal of a significant amount of materials with associated use of demolition equipment and portable engines to accommodate these activities.

The natural gas-fired reheat system would result in additional non-SO_2 pollutant emissions from the combustion of natural gas onsite. Potential NO_x emissions are estimated to be between 14 and 27 tons per year.

The energy and non-air quality environmental impacts from the new wet stack or the natural gas reheat system are significant but not significant enough to remove the control technology from consideration.

NPS: Energy impacts are included in the cost analyses. There are no unusual environmental impacts.

– Remaining Useful Life (Statutory Factor 4)

NDDEQ: For the purposes of this analysis, a 20-year life was used for CCS to calculate emission reductions, amortized costs, and cost effectiveness. Therefore, remaining useful life does not need to be considered for the purposes of round 2 planning.

NPS: In the absence of a federally-enforceable constraint, we assumed a 30-year life.

3.3.5 NO_x BART analysis for Coal Creek Station Unit 1 and Unit 2

EXISTING NO_X CONTROLS

NDDEQ: The NO_x controls currently installed at CCS Units 1 and 2 consist of LNC3 (combination of closed coupled overfired air, separated overfired air, and low NO_x burners) is installed on Units 1 and 2. This technology is considered as part of the baseline emission calculation.

DryFining™ technology has been installed and operating on Units 1 and 2 since 2010. DryFining™ is an innovative technology developed by Great River Energy that reduces moisture and refines lignite coal. The technology increases the efficiency and performance of the fuel while reducing emissions. This technology is considered part of the baseline emissions. Units 1 and 2 have experienced approximately 0.02 lb NO_x/MMBtu of reductions since completion of DryFining™.

LNC3+ (LNC3 with expanded overfired air registers in conjunction with DryFining™) was installed on Unit 2 in 2007. Expanded overfired air was completed in 2007 with DryFining™ coming online in 2010. Collectively, LNC3+ became fully operational on Unit 2 in 2010. Unit 1 had expanded overfired air registers installed in the second quarter of 2020. Unit 1's LNC3+ is expected to operate with a similar NO_x profile as the LNC3+ on Unit 2.

HISTORICAL AND FUTURE ANTICIPATED EMISSIONS

CCS installed LNC3+ on Unit 2 in 2010 and on Unit 1 in 2020 in advance of being required through an approved regional haze SIP amendment. Reducing NO_x emissions through combustion upgrades (e.g., LNC3+) in advance of installing add-on post combustion controls (e.g., SNCR or SCR) is always recommended as the first step. Fundamentally, it is better to produce less NO_x during the combustion process than it is to add-on post combustion pollution controls to remove NO_x after formation. This reduces the equipment size and the associated operational and maintenance costs of the add-on controls. CCS has already taken the step to install LNC3+ on both Units.

NO_x BART Determination for Unit 1 and Unit 2

The following determination was derived using combined average historical data for both units and using the data to make a single BART determination, which applies to both units. A single NO_x BART determination is made because Unit 1 and Unit 2 are identical boilers and have historically operated consistently.

– Step 1 – Identify All Available Retrofit Control Technologies

The BART controls that were evaluated for CCS are listed in Table 18 below (NDDEQ draft SIP table 6). Each control technology is listed along with its associated performance rate and total expected emissions on a yearly basis. Expected emissions were calculated using the performance rate, the potential heat input, and the annual capacity factor.

Table 18. (NDDEQ draft SIP Table 6) NO_x BART Control Options

Control Technology	**Control Technology Abbreviation**	**Emission Rate (lb/MMBtu)**	**Emissions (tons/year)**
low NOx burners with closed coupled overfired air	LNC3 [A]	0.18	4,143 [B]
LNC3 with expanded overfired air registers in conjunction with DryFining™	LNC3+	0.13	2,980
selective non-catalytic reduction	SNCR	0.10	2,293
selective catalytic reduction	SCR	0.08-0.06	1,830-1,380

[A] The emission rate for LNC3 includes the DryFining™ operation
[B] 0.18 lb NO_x/MMBtu x 52.72×10^6 MMBtu/yr x 0.87 / 2000 = 4,140 tons NO_x/year

NPS: Unit 1 had expanded overfired air registers installed in the second quarter of 2020. We evaluated 21 months of CAMD NO_x emissions data (January 2020–September 2021) and determined that the average emission rate was 0.146 lb/mmBtu (Figure 12).

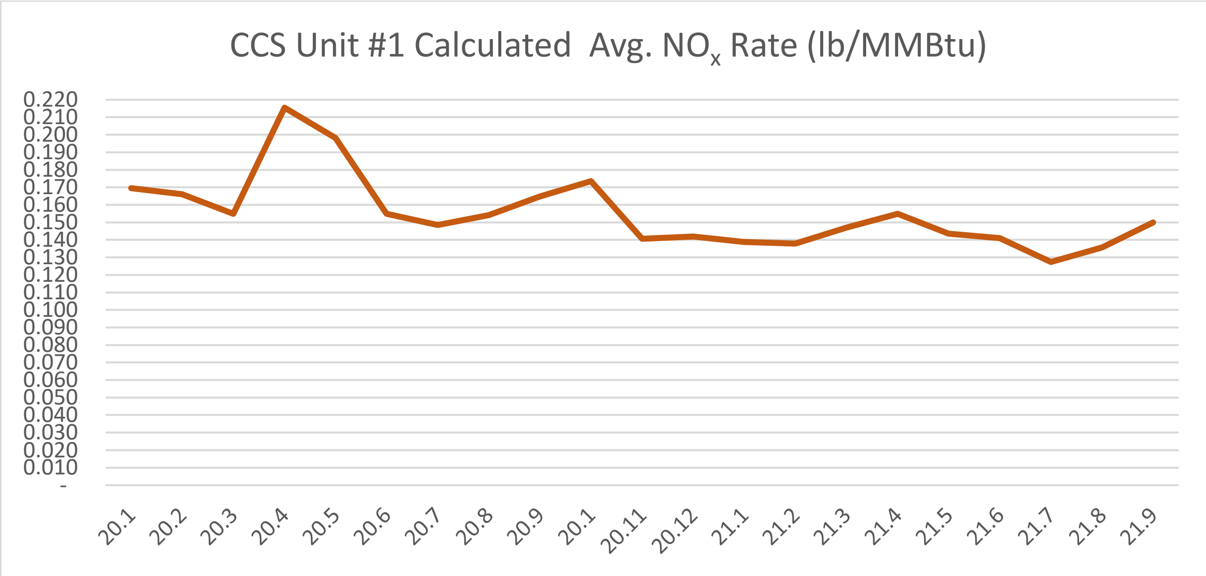


Figure 12. CCS Unit #1 Calculated Monthly Avg. NO_x Rate (January 2020–September 2021)

Per EPA guidance, we used the last five years of NO_x emissions data for Unit 2 to determine an average emission rate of 0.129 lb/mmBtu. We use these values to estimate the cost-effectiveness of adding post-combustion NO_x controls.

– Step 2 – Evaluate Technically Feasible Control Technologies

NDDEQ: LNC3+ is technically feasible and is currently installed and operational on Unit 1 and Unit 2. LNC3+ was installed on Unit 2 in 2010 and was installed on Unit 1 in 2020.

SNCR is a type of post combustion add-on control equipment. SNCR is technically feasible for both units at CCS and was reviewed as a potential additional control option after LNC3+ installation.

SCR is a type of post combustion add-on control equipment. The technical feasibility of SCR is uncertain at CCS. SCR was reviewed as a potential additional control option after LNC3+ installation. SCR was evaluated based on two potential arrangements, including a "high- dust" and "low-dust" system. High-dust systems are located upstream of the particulate controls (electrostatic precipitator) and low-dust systems are located downstream of the particulate controls.

High-dust SCR systems have significant potential for catalyst surface plugging due to the high sodium concentrations in the lignite coal used at CCS. Additionally, without the completion of pilot testing, the SCR catalyst supplier was unable to ensure reliable performance and catalyst life given the significant uncertainty with potential plugging and catalyst deactivation.[4] For these reasons, a high-dust SCR system is determined to be technically infeasible. This is consistent with the Department's 2009 determination that high-dust SCR is not technically feasible for Units combusting North Dakota lignite coal.[5]

Low-dust SCR systems (including tail-end SCR) are located downstream of the electrostatic precipitator where most of the sodium-bearing fly ash particles are expected to be removed, potentially mitigating the issue of SCR catalyst plugging.[6] The catalyst vendor, IBDEM Ceram, and the SNCR/SCR vendor, Fuel Tech, both expressed overall concerns with North Dakota lignite coal impacts on the SCR catalyst plugging and fouling. Both independently recommended pilot scale testing be completed to obtain actual performance data and determine catalyst impacts. Without consideration of the recommended pilot testing, a low-dust system potentially removes the concern with technical feasibility in relation to catalyst plugging. Therefore, a low-dust SCR system is determined to be technically feasible and is carried forward for further evaluation.

– Step 3 – Evaluate Control Effectiveness

NDDEQ: The efficiency of the BART controls, anticipated performance rates, and the projected emission reductions for each control option are listed in Table 7. The projected emissions reductions listed in Table 7 would occur at each unit (e.g. SNCR would reduce NO_x emissions by 1,850 tons per year from both Unit 1 and Unit 2, totaling 3,700 tons per year, beyond the baseline emissions).

Table 19. (NDDEQ draft SIP Table 7) Control Effectiveness and Emissions Reductions for CCS Units 1 and 2

Control Technology	Emission Rate (lb/MMBtu)	Control Efficiency	Emission Reduction (tons/year)
Baseline, LNC3[1]	0.18	--	--
LNC3+	0.13	28%	1,163
SNCR	0.10	45%	1,850
SCR	0.08-0.06	56%-67%	2,310-2,770

[1] *The emission rate for LNC3 includes the DryFining™ operation*

Within the Updated BART Analysis, a range of performance rates for SCR were evaluated, which is why the information in Table 7 includes a range of options for SCR. The performance rates evaluated are consistent with currently available information for units operating SCRs. These anticipated performance rates ranged from 0.04 to 0.08 lb NO_x per MMBtu. The performance rate of 0.04 lb NO_x per MMBtu is not listed in Table 7 due to significant uncertainty that this rate could be achieved in practice and sustained for an extended timeframe. Therefore, the Department will not evaluate SCR at a performance rate of 0.04 lb NO_x per MMBtu for the purposes of this BART determination. Information presented throughout the remainder of this BART determination is specific to SCR at a performance rate of 0.06 and 0.08 lb NO_x per MMBtu.

NPS: For Selective Non-Catalytic Reduction (SNCR), we applied the relationship $y = 22.554x + 16.725$ from Figure 1.1c in the Control Cost Manual to estimate efficiency of 19% - 20%.

NPS: We estimate that Selective Catalytic Reduction (SCR) could achieve up to 69% - 73%% NO_x reduction down to 0.04 lb/mmBtu. (We note that Black & Veatch used this value in its September 4, 2019 Attachment A, Report "Best Available Retrofit Technology for NO_x Emissions from Coal Creek Unit 2 - 2019 Update.") EPA assumed in 2014 that SCR could achieve the 0.04 lb/mmBtu annual emissions proposed by Basin at its Laramie River Station in WY. 2020 CAMD data contains 11 coal-fired EGUs with SCR at 0.04 lb/mmBtu annual average.

– Step 4 – Evaluate Impacts

Cost of Compliance (Statutory Factor 1)

NDDEQ: The cost of compliance and incremental cost for the BART controls are listed in Table 8 for a single unit. The incremental costs displayed in Table 8 were determined from LNC3+ to SNCR and from LNC3+ to SCR. The incremental cost between SNCR and SCR is not shown in Table 8 due to the high annualized cost difference in conjunction with a limited improvement in emissions reduction.

Table 20. (NDDEQ draft SIP Table 8) Cost of Compliance and Incremental Cost of Compliance for CCS Units 1 and 2

Control Technology	Performance Level (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
Baseline, LNC3	0.18	--	--	--	--
LNC3+	0.13	1,162	793,418	683	--
LNC3+ w/ SNCR	0.10	1,850	6,194,244	3,348	7,850
LNC3+ w/ SCR	0.08	2,309	16,122,491	6,983	13,368
LNC3+ w/ SCR	0.06	2,767	17,391,169	6,284	10,339

A detailed breakdown of the costs listed in Table 8 can be found in the Updated BART Analysis. The Department has reviewed these costs and believes them to be accurate.

NPS: We adjusted the CCS four-factor analysis cost analyses for SNCR and SCR as follows:

- We used the CCM Method 1 to estimate catalyst cost because it is "transparent" and relies upon defined values for catalyst volume, cost, life, and interest rate. CCS four-factor analyses used the CCM Method 2 which does not reveal the inputs.
- We estimated costs in 2019$ and used a lower CEPCI value. The CCS four-factor analyses used 2018$ and an unjustified high CEPCI.
- We used the current prime interest rate (3.25%) as recommended by the CCM instead of 5.25%.

NDDEQ: As displayed in Table 8, the cost of compliance for the installation of LNC3+ at CCS is $700 per ton of NO_x reduced. This represents a 0.05 lb NO_x per MMBtu improvement over the baseline performance rate and results in an annual reduction of over 1,100 tons of NO_x per unit.

If SNCR is installed along with LNC3+, a performance rate improvement of 0.03 lb NO_x per MMBtu could be achieved. This equates to an additional reduction of approximately 700 tons of NO_x per year for each unit. To provide the most conservative cost of compliance (i.e., the lowest dollar per ton of pollutant reduction) for SNCR, Table 8 does not include additional costs associated with the treating of ammoniated fly-ash or the additional cost incurred due to the loss of a saleable by- product, which would result in an increase in fly-ash disposal. There is also uncertainty in the amount of saleable by-product that would be lost and the limited commercial application of the treating process; both of which are required to better understand the impacts a treating system would have at CCS. Without this information, the ultimate cost of SNCR is unknown. Without taking these costs into consideration, the cost of compliance to concurrently install LNC3+ with SNCR is $3,300 per ton of NO_x reduced.

To determine the appropriate BART controls when comparing between the installation of only LNC3+ and the installation of LNC3+ with SNCR, the Department calculated the stand-alone cost of installing SNCR after LNC3+ is installed. This stand-alone cost is referred to as the incremental cost of compliance or the incremental cost effectiveness in the BART guidelines. Incremental cost is a key factor to consider when selecting BART controls since it details the cost effectiveness specific to the SNCR. The incremental cost of compliance was determined to be $7,800 per ton of NO_x reduced. Therefore, even though the cost of compliance for LNC3+ with SNCR listed in Table 8 appears reasonable at $3,300 per ton, it is more accurate to represent the cost of LNC3+ at $700 per ton and the cost of SNCR after the installation of LNC3+ at $7,800 per ton. The Department believes $7,800 is an unreasonably high cost, especially in consideration of the potential increased costs through the installation of a fly-ash treating system, lost fly-ash sales, and the technological uncertainty with the treating system viability at CCS. Between LNC3+ and LNC3+ with SNCR, LNC3+ is the most appropriate BART control from the perspective of cost feasibility.

All costs associated with the SCRs are provided for the high-dust arrangement. High-dust systems are generally considered more economical than low-dust systems since less equipment is required during operation. Exhaust gas re-heat and cooling systems are among the additional costs required with low-dust SCR systems. The cost of compliance will increase significantly with the additional equipment needed for a low-dust SCR system. Without taking these added costs into consideration, the cost to install LNC3+ concurrently with SCR is (at a minimum) $6,300 per ton of NO_x reduced. Using the same logic applied in the SNCR discussion in the above paragraph, the incremental cost to install SCR after LNC3+ is $10,300 per ton. Additionally, for consistency with the BART guidelines, the Department calculated the incremental cost between SNCR and SCR. This resulted in an incremental cost of $12,200 per ton. The Department believes all these costs are unreasonably high, especially in consideration of the technological uncertainty with SCR and the added costs associated with the exhaust reheat and cooling systems.

NPS: the results of our application of the CCM workbooks are shown in Table 21 below.

Table 21. NPS Revised Table 8: CCS Unit 1 Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Level (lb/MMBtu)	Annual Emission Reduction (tpy)[1]	Annualized Total Cost ($)[2]	Cost of Compliance ($/ton)[2]	Incremental Cost of Compliance ($/ton)[3]
Baseline, LNC3	0.18	--	--	--	--
LNC3+	0.15	1,032	793,418	768	--
LNC3+ w/ SNCR	0.12	631	3,141,707	4,982	
LNC3+ w/ SCR	0.04	2,344	12,988,582	5,542	5,748

[1] relative to LNC3+
[2] in addition to LNC3+
[3] relative to LNC3+ w/ SNCR

We agree with NDDEQ that optimizing the combustion controls is the appropriate first step in reducing emissions, so we based our estimates on adding post-combustion controls to the existing LNC3+ controls. Because CAMD data has shown that LNC3+ on Unit 1 is achieving 0.15 lb/mmBtu (instead of the 0.13 lb/mmBtu assumed by NDDEQ), we adjusted its "Annual Emission Reduction" accordingly.

Addition of SNCR could reduce NO_x by an additional 631 tons/year at an additional cost of $3.1 million /yr. The cost-effectiveness of this strategy is less than $5,000/ton and is well below the NDDEQ round one threshold adjusted for inflation ($7,300/ton incremental cost-effectiveness).

Addition of SCR could reduce NO_x by an additional 2,344 tons/year (versus LNC3+) at an additional cost of $13million/yr. The cost-effectiveness of this strategy is less than $6,000/ton and is well below the NDDEQ round one threshold adjusted for inflation. Likewise, the incremental cost-effectiveness relative to the SNCR strategy is below $6,000/ton, also well below the NDDEQ round one threshold adjusted for inflation.

Table 22. NPS Revised NDDEQ Table 8: CCS Unit 2 Cost of Compliance and Incremental Cost of Compliance

Control Technology	Performance Level (lb/MMBtu)	Annual Emission Reduction (tpy)[1]	Annualized Total Cost ($)[2]	Cost of Compliance ($/ton)[2]	Incremental Cost of Compliance ($/ton)[3]
Baseline, LNC3	0.18	--	--	--	--
LNC3+	0.13	1,162	793,418	683	--
LNC3+ w/ SNCR	0.13	535	2,981,040	5,573	
LNC3+ w/ SCR	0.04	1,927	12,867,354	6,679	7,104

[1] relative to LNC3+
[2] in addition to LNC3+
[3] relative to LNC3+ w/ SNCR

CAMD data has shown that LNC3+ on Unit 2 is achieving the 0.13 lb/mmBtu assumed by NDDEQ. Addition of SNCR could reduce NO_x by an additional 535 tons/year at an additional cost of $3 million /yr; the cost-effectiveness of this strategy is less than $5,600/ton and is well below the NDDEQ round one threshold adjusted for inflation.

Addition of SCR could reduce NO_x by an additional 1,927 tons/year (versus LNC3+) at an additional cost of $13 million/yr; the cost-effectiveness of this strategy is less than $6,700/ton and is well below the NDDEQ round one threshold adjusted for inflation established by NDDEQ. Likewise, the incremental cost-effectiveness relative to the SNCR strategy is below $7,100/ton, also below the NDDEQ round one threshold adjusted for inflation.

Energy and Non-Air Quality Environmental Impacts (Statutory Factor 3)

NDDEQ: LNC3+ is determined to have negligible energy and/or non-air quality environmental impacts. LNC3+ technology reduces the formation of NO_x during the combustion process and does not affect items such as: auxiliary power consumption, water usage, potential fly ash sales, and/or ammonia slip, which are all potential impacts associated with SNCR and/or SCR.

The largest potential non-air quality environmental impact with SNCR is the potential for producing ammoniated fly-ash, which could inhibit or severely limit CCS from selling fly-ash for beneficial use (e.g., concrete additive). This ammoniated fly-ash has the largest impact on non-air quality environmental impacts since ammoniated fly-ash not being sold for beneficial use could end up significantly increasing the amount of fly-ash disposed of in landfills. The production of ammoniated fly-ash also reduces any economic benefit CCS receives from selling this by-product. SNCR also requires a significant increase in water consumption for the injection skid. Additionally, ammonia slip from the SNCR will likely result in nitrogen being carried through the scrubber water that is routed to the evaporation ponds, causing potential issues with pond maintenance.

Low-dust SCR has the same potential non-air quality environmental impacts as SNCR regarding increased water consumption and ammonia slip.

NPS: The impacts of SCR on water consumption and ammonia slip are far less than for SNCR.

NDDEQ: There is also increased power and fuel consumption required with SCR related equipment and from the gas reheat and cooling systems.

NPS: These factors are accounted for in the economic analysis, statutory factor 1.

NDDEQ: The non-air quality environmental impacts for SNCR and SCR are significant, but not significant enough to eliminate them as a control option.

Remaining Useful Life (Statutory Factor 4)

NDDEQ: Coal Creek Station is expected to operate beyond the life of the control equipment, therefore, remaining useful life was not considered.

3.3.6 Conclusions & Recommendations

- Other states have set cost-effectiveness thresholds of: \$5,000/ton for EGUs in AR and TX, \$7,000/ton in NM, and \$10,000/ton in CO and OR.
- The cost effectiveness of minimizing flue gas bypass at CCS would be acceptable in the context of the previous ND BART thresholds as well as the thresholds used by the states cited and could cost-effectively reduce facility SO_2 emissions by almost 1,400 tons/yr.
- The incremental cost effectiveness of adding SNCR at CCS would be acceptable in the context of the previous threshold used by ND. Addition of SNCR could reduce facility NO_x emissions by almost 1,200 tons/yr.
- The incremental cost effectiveness of adding SCR at CCS would be acceptable in the context of the previous threshold used by ND. Addition of SCR could reduce facility NO_x emissions by over 4,200 tons/yr.

3.4 Milton R Young

3.4.1 Summary of NPS Recommendations and Requests for Milton R. Young Station

The NPS review of the four-factor analysis conducted for Milton R. Young Station (MRYS) finds that there are technically feasible and cost-effective opportunities available to further control SO_2 and NO_x emissions from Units 1 and 2. In fact, we find that the cost of control is more economical than the SIP estimate when analyses are adjusted in accordance with the EPA Cost Control Manual.

Although ND has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of: $5,000/ton for EGUs in AR and TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

The cost effectiveness of modifying the existing SO_2 scrubbers at MRYS would be acceptable in the context of the previous ND BART thresholds as well as the thresholds used by states in this round of regional haze planning. This strategy could reduce SO_2 emissions by over 1,600 tons/year compared to existing controls.

We find two opportunities for reducing NO_x emissions at MYRS. 1) The annual average and incremental cost-effectiveness of adding Rich Reagent Injection (RRI) to reduce NO_x emissions at MRYS Unit 2 would be acceptable in the context of the thresholds used by CO, NM, and OR. This strategy could reduce NO_x emissions by over 3,500 tons/year compared to existing controls. 2) The annual average cost effectiveness of adding SCR at MRYS Units 1 and 2 would be acceptable in the context of the previous ND BART thresholds as well as the thresholds used by other states in this round of regional haze planning. This strategy could reduce NO_x emissions by over 10,700 tons/year compared to existing controls.

We recommend that ND take every opportunity to reduce SO_2 and NO_x emissions from the Milton R. Young Station in this planning period. By requiring implementation of identified controls ND will be reducing haze causing emissions and advancing incremental improvement of visibility at Theodore Roosevelt, Badlands, and Wind Cave National Parks as well as other Class I areas in the region.

3.4.2 Milton R. Young Plant Characteristics

Milton R. Young Station (MRYS) is a 734 MW lignite coal-fired power station near Center, North Dakota. Theodore Roosevelt National Park, a Class I area administered by the National Park Service (NPS), is 161 km west of this facility.

Of 1,167 facilities in EPA's Clean Air Markets Database (CAMD) in 2020, MRYS ranked #74 for sulfur dioxide (SO_2) emissions (2,677 tons) and #9 for nitrogen oxides (NO_x at 8,562 tons). MRYS' carbon dioxide emissions of 5,579,430 tons rank #63 in the US. MRYS also ranked #5 for EGU mercury (Hg) emissions with 198 lb in 2017.

MRYS has two subcritical Babcock & Wilcox cyclone boiler generating units firing North Dakota lignite supplied from BNI Coal, Ltd's adjacent Center Mine. Unit 1 (257 MW) is owned by Minnkota Power Cooperative and commenced commercial operation in 1970. The boiler is fired by seven ten-foot diameter cyclone furnaces, arranged "three over four" across the front wall of the lower boiler.

Unit 2 (477 MW) is owned by Square Butte Electric Cooperative and commenced operation in 1977. The boiler is fired by twelve ten-foot diameter cyclone furnaces, arranged "three over three" across the front and rear walls of the lower boiler.

Both units have tubular air heaters installed between the boiler and the flue gas ductwork leading to an ESP. The boilers at MRYS include a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel.

On April 24, 2006 the Department of Justice and the EPA announced a settlement of a case alleging violations of the New Source Review (NSR) provisions of the Clean Air Act requiring Minnkota Power Cooperative and Square Butte Ele. On April 24, 2006 the Department of Justice and the EPA announced a settlement of a case alleging violations of the New Source Review (NSR) provisions of the Clean Air Act requiring Minnkota Power Cooperative and Square Butte Electric Cooperative (both member-owned rural utilities) to reduce 23,561 tons/year of SO_2 by 2012, 9,458 tons/year of NO_x by 2010, and to comply with declining plant-wide caps for SO_2. (The proposed Consent Decree requirements were incorporated into enforceable permits.) The agreement resolved Clean Air Act violations that occurred at MRYS. As a result, both units are now equipped with selective non-catalytic reduction (SNCR) for NO_x control. Each unit is equipped with wet flue gas desulfurization (FGD) for SO_2 control and an electrostatic precipitator (ESP) for particulate control. Each unit employs halide injection and activated carbon injection for the control of mercury.[17] Table 23 below shows a breakdown of 2020 SO_2 and NO_x emissions and how they rank versus the 3,317 EGUs in CAMD.

Table 23. MRYS 2020 SO_2 and NO_x emissions and how they rank versus the 3,317 EGUs in CAMD

Unit ID	SO_2 (tons)	SO_2 (tons) Rank	Avg. SO_2 Rate (lb/MMBtu)	Avg. SO_2 Rate (lb/MMBtu) Rank	NO_x (tons)	NO_x (tons) Rank	Avg. NO_x Rate (lb/MMBtu)	Avg. NO_x Rate (lb/MMBtu) Rank
B1	504	296	0.053	433	3,166	32	0.334	80
B2	2,173	101	0.134	236	5,396	6	0.334	81

3.4.3 First Planning Period Regional Haze Control Requirements for MRYS 1 and 2

Best Available Retrofit Technology (BART) controls selected in the first round of the Regional Haze program were Advanced Separated Over Fire Air (ASOFA) for NO_x control. (The SNCR was added as a result of the federal enforcement action.) In United States v. Minnkota Power

[17] January 2021 Hg emissions were: Unit 1= 3.22 lb/Trillion Btu (TBtu), Unit 2 = 3.61 lb/TBtu.

Cooperative, Inc. the court concluded that the State's best available control technology (BACT) analysis for NO_x control on Minnkota Power's Milton R. Young Station (MRYS) Units 1 and 2 was not unreasonable, a conclusion that was contrary to EPA's position at the time of the Proposed FIP. Subsequently, EPA noted that the technical feasibility determination under the BACT and BART analyses was substantially the same. The BART Guidelines permit a state to rely upon a BACT determination for purposes of selecting BART unless new technologies have become available or best control levels for recent retrofits have become more stringent. The charts below show SO_2 and NO_x emissions for the MRYS units.

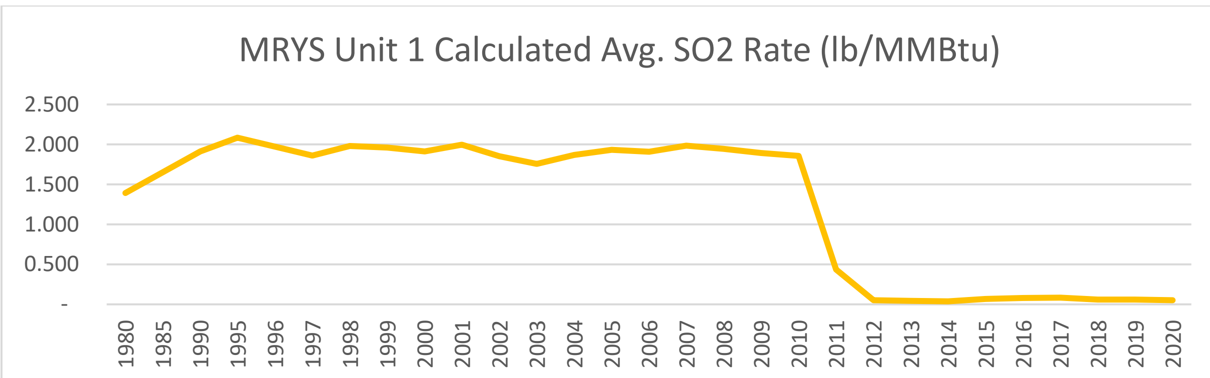


Figure 13. MRYS Unit 1, Calculated Avg. SO_2 Rate (1980–2020)

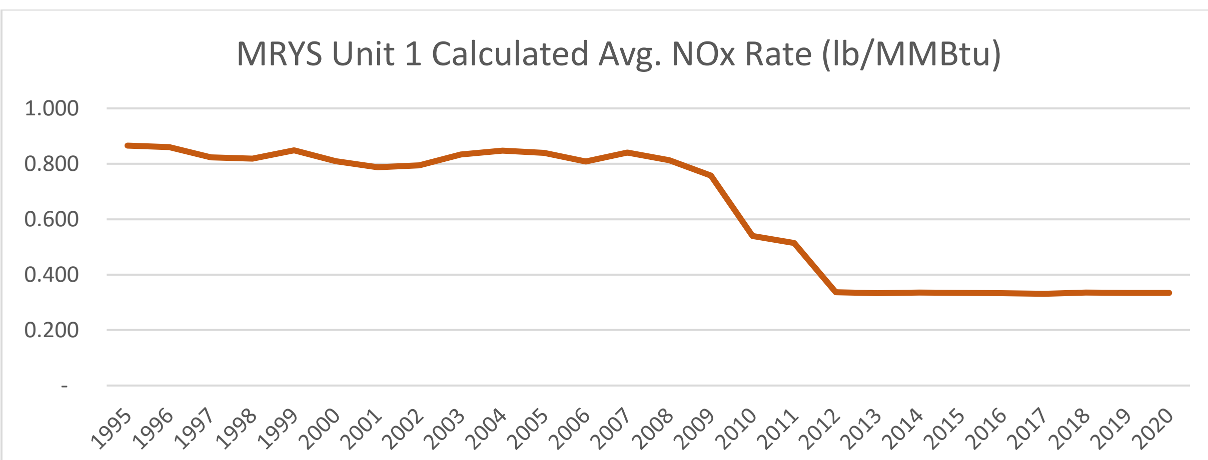


Figure 14. MRYS Unit 1, Calculated Avg. NO_x Rate (1995–2020)

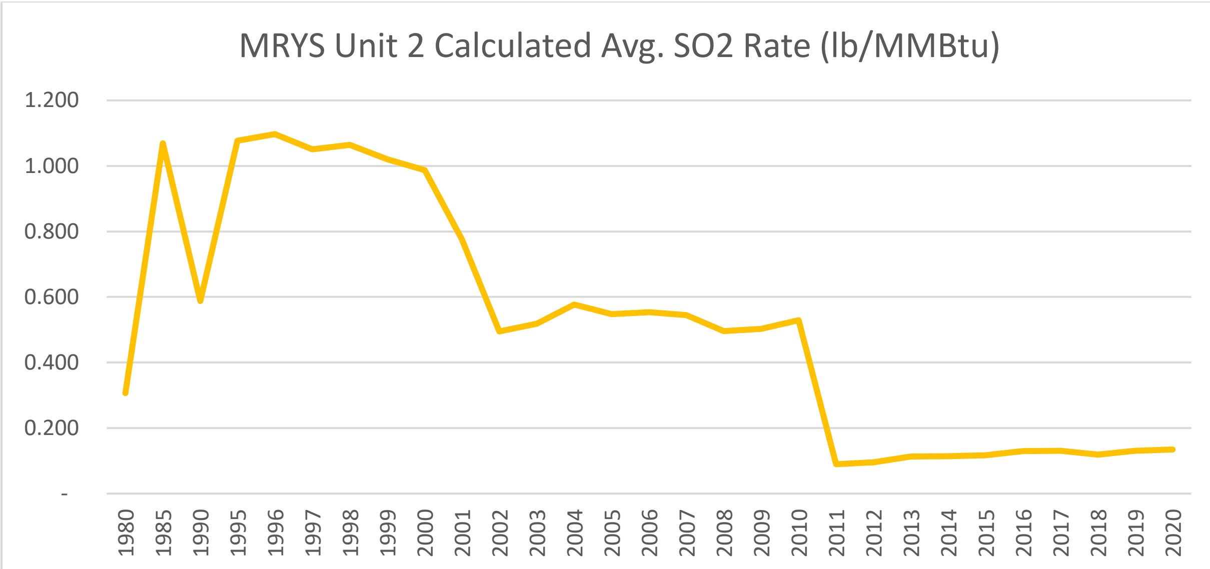


Figure 15. MRYS Unit 2, Calculated Avg. SO_2 Rate (1980–2020)

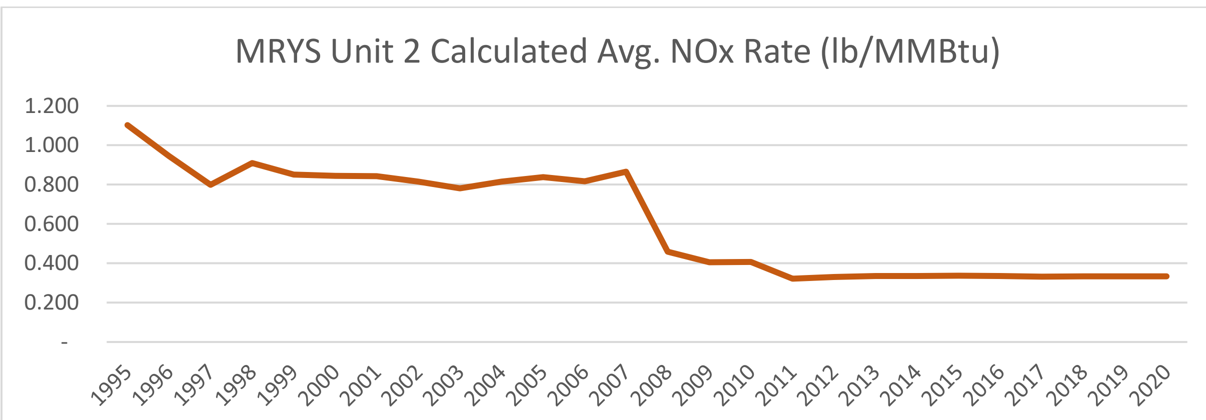


Figure 16. MRYS Unit 2, Calculated Avg. NO_x Rate (1995–2020)

3.4.4 Second Planning Period Reasonable Progress Control Requirements for AVS Units 1 and 2

NDDEQ: MRYS Unit 1 has a Q/d of 24 and MRYS Unit 2 has a Q/d of 43. Therefore, the Department sent a letter to Minnkota Power Cooperative, Inc. (Minnkota) on May 2, 2018 requesting a four-factor analysis for MRYS. The letter required that Minnkota's four-factor analysis be submitted to the Department on or before January 31, 2019. Minnkota's original four-factor analysis was submitted to the Department on January 31, 2019. The Department provided comments to Minnkota regarding their four-factor analysis on March 18, 2019.

Burns & McDonnell Engineering Co. (B&M) submitted a response to the Department's comments on behalf of Minnkota, along with a revised four-factor analysis, on May 29, 2019. The analysis included an assessment of potentially available SO_2 and NO_x emission reduction technologies that could be applied to MRYS Units 1 and 2. Following are excerpts from the May 2019 B&M report—we note where we have differences.

SO_2 Emissions Controls

B&M for MRYS: The scrubber inlet SO_2 conditions for each unit at MRYS are measured using continuous emissions monitors (CEMS). These inlet conditions during the baseline period for Unit 1 (2.327 lb/MMBtu) and Unit 2 (2.487 lb/MMBtu) will be used as the basis for future sulfur content at the inlet of each scrubber.[18]

WET FLUE GAS DESULFURIZATION

B&M for MRYS: For the purposes of this analysis, new wet FGD performance was evaluated at 98% SO_2 removal. Due to the relative ages of Unit 1 and Unit 2 scrubbers, a new wet scrubber was considered only for Unit 2, as the Unit 1 wet scrubber was placed in service relatively recently, in 2011. Based on the ability of a new wet FGD system to achieve 98% percent SO_2 removal efficiency and considering the commercial availability and applicability, a new wet FGD system was found to be a technically feasible regional haze control technology[19] alternative for MRYS Unit 2 SO_2 emission control.

MODIFICATION OF EXISTING WET FGDS.

B&M for MRYS: This report also evaluates the modification of the existing wet FGD process currently operating on Unit 1 and Unit 2 as a possible regional haze control technology alternative. The original equipment manufacturer (OEM) of the Unit 1 scrubber was engaged to evaluate modifications required to increase the removal efficiency of the existing wet FGD processes. The same OEM has previously studied upgrading the Unit 2 scrubber to achieve higher removal efficiency, and was engaged to update and confirm the results of that study. Upgrades evaluated include increasing the liquid-to-gas ratio, installation of new types of spray nozzles, running additional pumps, and adjusting the operating conditions of the scrubber. The OEM study evaluated the scrubbers based on the highest sulfur coal (3.16 lb SO_2/MMBtu) identified by core samples collected and analyzed by the mine that supplies MRYS. The high sulfur fuel is utilized in this evaluation to ensure the updated scrubber is capable of the necessary long-term fuel flexibility associated with a mine mouth plant. The removal rates referenced in the confidential vendor proposal (submitted separately under confidentiality) are coal to chimney short term (test period) removal rates reflective of vendor determined performance. This regional haze control technology evaluation has applied selected removal rates across the scrubber.

The selected rates applied across the scrubber is considered a reasonable balance of the difference between: the baseline scrubber inlet SO_2 and the studied sulfur content of the coal, consideration of the need for margin between a guarantee and long term continuously achievable performance, and long term (annual performance) basis of this evaluation. Optimizing Unit 1 is

18 The baseline emission rates were developed by evaluating the three most recent years (2016-2018) for Unit 1 and for Unit 2. This baseline was established in consultation with the NDDEQ. The baseline period, for each unit, contains two non-major outage years and one major outage year.

[19] Regional Haze Control Technology

assumed to increase removal across the scrubber to 97.4% by increasing stoichiometry (Ca/S) to 1.025.[20] Upgrading Unit 2 is assumed to increase removal across the scrubber to 97.6% utilizing the recommended nozzle changes, additional spray header, and increasing the stoichiometry to 1.020.[21] MRYS did not increase the stoichiometry in Unit 2 to the same level as Unit 1 because MRYS experience on Unit 2 is that operating at higher pH (associated with higher stoichiometry) will cause increased scaling and plugging of the suction screens to the spray recycle pumps that will reduce the liquid to gas ratios, and hence lower SO_2 removal.

NPS: The chart below shows increasing SO_2 emission rates at Unit 2.

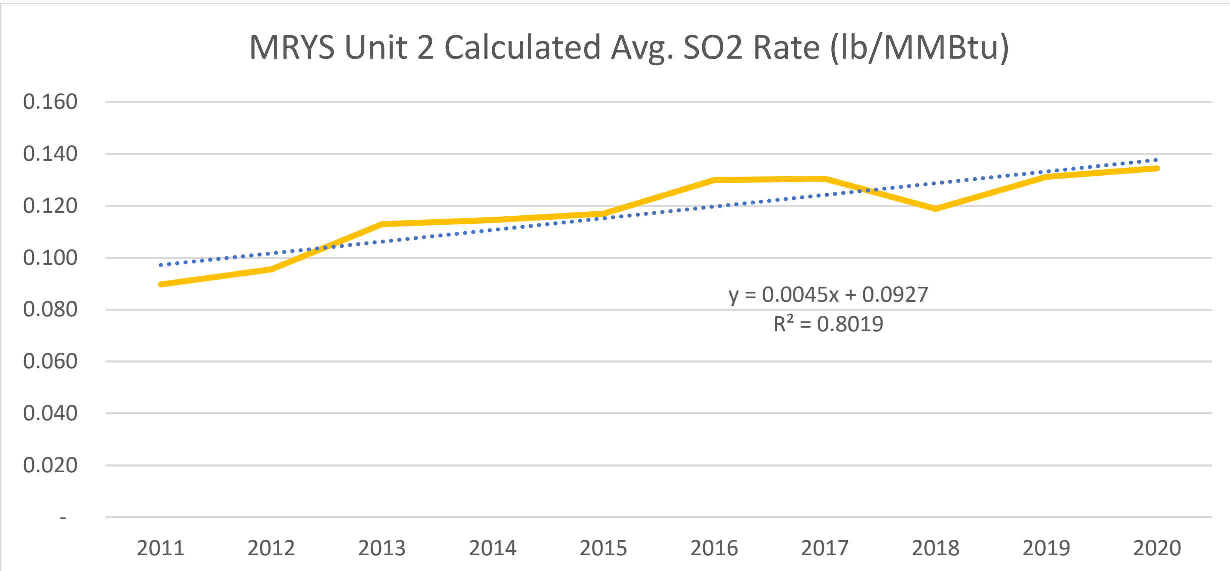


Figure 17. MRYS Unit 2, Increasing SO_2 emission rate (2011–2020)

Semi-Dry Flue Gas Desulfurization

B&M for MRYS: No SDA process has clearly demonstrated the ability to achieve SO_2 removal levels similar to wet FGD systems in the U.S. The application of high SO_2 removal SDA system for high sulfur coal have been limited in the industry due to multiple factors. For purposes of completeness an SDA system is assumed to be able to achieve 93% removal in this application.

The CDS system can increase the lime injection rate independent of the water injection and higher removal rates can be achieved. The CDS system removal is assumed to be equivalent to the retrofit wet FGD system achieving 95-97% removal.

ReACT Dry Scrubbing Process

B&M for MRYS: ReACT (Regenerative Activated Coke Technology) is a multipollutant control system that utilizes activated coke to remove SO_2, NO_x and mercury. The process is divided into three main processes: 1) adsorption, 2) regeneration, and 3) recovery. In the first

[20] NPS: We estimate that the Unit 1 FGD is currently achieving 97.1% efficiency.
[21] NPS: We estimate that the Unit 2 FGD is currently achieving 94.8% efficiency.

step, ammonia is injected into the flue gas and the flue gas is passed through an adsorber filled with a moving bed of activated coke pellets where the SO_2 and mercury are adsorbed and the NO_x is reduced to N_2. In the second step, the activated coke pellets are transferred to a second vessel to be regenerated for recycle/reuse through thermal desorption. The captured mercury is concentrated in the lower portion of the regenerator vessel. The resulting gas from the regeneration step is a concentrated stream of SO_2 that must be further treated in a separate acid recovery plant to produce a sellable sulfuric acid byproduct. Sulfuric acid is a worldwide commodity that, with access, can be sold year-round. This ReACT process is installed and operating on multiple low sulfur coal fired units achieving 2'99% SO_2 removal. Burns & McDonnell contacted the supplier of the ReACT process and discussed the application of the technology to an application like MRYS. It was determined that MRYS is 'not a good application' for the technology, however, the technology could be applied and would work. Factors in this application at MRYS that would impact performance and cost of ReACT include that the inlet temperature is too high, higher oxidation of the activated coke can be expected, and the sulfuric acid production rates would be very high. This technology is still considered a viable alternative and previous ReACT pilot tests on high sulfur coals have shown ReACT can achieve 92-98% SO_2 removal rates.

– Cost of Compliance (Statutory Factor 1)

B&M for MRYS: The following sections evaluate the top two ranked control options for Unit 2, replacing the existing wet FGD system with a new wet FGD system, and upgrading the Unit 2 scrubber. A new wet FGD was not considered for Unit 1, as the existing wet FGD began operations in 2011 as part of the previous BART/BACT analysis and is within the previously evaluated useful life. The top ranked control option for Unit 1, modify the existing wet FGD, is evaluated.

NEW WET FGD CAPITAL COST ESTIMATE

B&M for MRYS: Cost estimates for the new wet FGD SO_2 control technologies were completed utilizing the 'IPM Model - Updates to Cost and Performance for APC Technologies Wet FGD Cost Development Methodology' available from the U.S. Environmental Protection Agency and supplemented with engineering estimates based upon Burns & McDonnell's in-house experience. The IPM Model Update is a formula-based report that was specifically developed to estimate the cost of wet FGD technologies for utility power plants. The report was prepared for the EPA in January 2017. The report is available for download from the U.S. EPA website[7].

NPS: Subsequent to the B&M analysis, EPA revised the Control Cost Manual (CCM) to estimate costs of acid gas controls—the EGU estimates are based upon the IPM models referenced by B&M and developed by Sargent & Lundy. Our application of the CCM to replacement of the wet scrubbers resulted in cost-effectiveness values that are prohibitive.

WET FGD MODIFICATION CAPITAL COST ESTIMATE

B&M for MRYS: Cost estimates for retrofitting the existing wet FGD systems were based on the equipment modification and associated pricing provided by the OEM (provided separately under confidentiality) and supplemented with engineering estimates for installation based upon Burns & McDonnell's in-house experience.

This evaluation assumes all of the existing BOP systems are capable of supporting the new system with no further upgrades. Further, it is assumed there is no change in operating staff and only a proportional change in the variable operating cost. These conservative assumptions minimize the overall project cost resulting in a conservatively low dollars per ton control cost.

The capital cost estimate for the Unit 1 wet FGD system modification includes the OEM recommendation to replace three out of the four recirculation pump motors to increase the liquid to gas ratio in the scrubber. During this investigation, the existing electrical system and foundation associated with the pump was reviewed and is believed to be sufficient to support this upgrade with no further modifications.

The capital cost estimate for the Unit 2 wet FGD system modification includes the OEM recommendation to replace all of the absorber spray nozzles with dual flow nozzles. The OEM did not recommend upgrading the pumps on Unit 2 due to velocity limitations in the riser pipe and headers and did not recommend upgrading the riser headers and spray headers to accommodate more flow as these upgrades could compromise or complicate the conditions of the existing towers.

NPS: We reviewed B&M's cost estimates and note that the Capital Recovery Cost was based upon a 5.5% interest rate and 20-year life which resulted in a Capital Recovery Factor = 0.08368. The CCM recommends use of the current prime interest rate (3.25%) over 30 years which yields a CRF = 0.0527. Our revised costs are shown in Tables 24 and 25 below.

Table 24. NPS Revised B&M Table 3-8: MRYS Unit 1 SO_2 Control System Annualized Total Cost

SO_2 Control Alternative	**Percent Removal**	**Emission Rate lb/10^6 Btu**	**Annual Emission (tpy) [1]**	**Annual Emission Reduction (tpy) [1]**	**Installed Capital Cost ($)[2]**	**Capital Recovery Cost ($)[2]**	**Annual O&M Cost ($)**	**Annualized Total Cost ($) [3]**	**Actual Unit Control Cost ($/ton) [4]**
Modified Wet FGD	97.40%	0.061	632	145	800,000	42,160	300,000	342,160	2,360
Baseline	96.80%	0.075	777	Baseline					

[1] Based on baseline heat input of 20,726,417 MMBtu/yr
[2] All Costs in 2019 dollars.
[3] For ATC calculation, Capital Recovery Factor = 0.0527 and first year O&M Cost.
[4] Overall control cost is ATC divided by actual annual emissions reduction of each alternative.

Table 25. NPS Revised B&M Table 3-9: MRYS Unit 2 SO_2 Control System Annualized Total Cost

SO_2 Control Alternative	Percent Removal	Emission Rate lb/10^6 Btu	Annual Emission (tpy) [1]	Annual Emission Reduction (tpy) [1]	Installed Capital Cost ($) [2]	Capital Recovery Cost ($) [2]	Annual O&M Cost ($)	Annualized Total Cost ($) [3]	Actual Unit Control Cost ($/ton) [4]
Modified Wet FGD	97.70%	0.057	979	1,185	1,700,000	9,590	700,000	789,590	666
Baseline	94.90%	0.126	2,164	Baseline					

[1] Based on baseline heat input of 34,354,956 MMBtu/yr
[2] All Costs in 2019 dollars.
[3] For ATC calculation, Capital Recovery Factor = 0.0527 and first year O&M Cost.
[4] Overall control cost is ATC divided by actual annual emissions reduction of each alternative.

NPS: The cost-effectiveness of modifying the existing scrubbers is well within accepted values.

– Time Necessary for Compliance (Statutory Factor 2)

NDDEQ: The process to bid, design, purchase, and install retrofits to an existing WFGD system can take two to three years. The time necessary for compliance is not a limiting factor when determining additional reasonable controls for MRYS Unit 1 SO_2 emissions since the WFDG could be modified prior to the end of the second planning period.

– Energy and Non-Air Quality Environmental Impacts (Statutory Factor 3)

ENERGY

NPS: Energy impacts are addressed under statutory factor 1, cost of compliance.

NON-AIR QUALITY ENVIRONMENTAL IMPACTS

B&M for MRYS: Non-air quality environmental impacts of replacing the existing wet FGD with a new wet FGD or retrofitting the existing FGD systems are expected to be very similar to the impacts of the existing system. These may include hazardous waste generation, solid and aqueous waste streams. The primary change anticipated due to the use of a new wet FGD or modifying the existing FGD systems will be an incremental increase in the solids disposal rate as additional removal of SO_2 will result in increased byproduct.

NPS: The impacts raised are standard to the operation of this control technology.

– Remaining Useful Life (Statutory Factor 4)

NDDEQ: Based on the information provided to the Department, MRYS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

NO_x Emission Controls

SELECTIVE CATALYTIC REDUCTION

B&M: There are variations in the SCR process for coal-fired boilers that mostly involve locations in the flue gas path where the catalyst is placed in order to promote the desired NO_x emission reduction effect. This technology was reviewed in the previous BART and BACT analysis (2008-2010) and it was concluded by NDDEQ that SCR systems (of all types) are technically infeasible at MRYS. No new information or experience has occurred since 2010 to change the conclusion of this analysis and this technology remains technically infeasible.

NPS: NDDEQ has recently determined that Tail-End SCR (TE-SCR) is technically feasible on ND lignite-fired boilers that are tangentially- or wall-fired, but infeasible for cyclone boilers like those at MRYS. We are not aware of any test data on the tail-end emissions at MRYS that support NDDEQ's determination. We recommend that TE-SCR should be fully evaluated at MRYS.

Rich Reagent Injection & Selective Non-Catalytic Reduction

B&M for MRYS: Rich Reagent Injection (RRI) has been demonstrated and placed in continuous operation on multiple cyclone boilers. RRI is specifically intended for NO_x emissions control on cyclone boilers. RRI adds dilute urea reagent to the hot boiler gases near the cyclones, which must be devoid of free oxygen in order to avoid oxidation of the urea and formation of additional NO_x. This system is combined with SNCR to further reduce NO_x emissions within the boiler. The ASOFA system would be operated in conjunction with the RRI and SNCR systems. RRI is considered technically feasible under limited conditions for application on the Unit 1 and Unit 2 cyclone boilers at MRYS.

Optimized Selective Non-Catalytic Reduction

B&M for MRYS: Taking into consideration the past operating experience of the existing system and vendor experience since the original installation, there is potential to reduce the emission rate further with enhancements to the existing system. These enhancements could include changing the nozzles on existing lances, replacing the existing lances, and adding lances in new locations. Additionally, allowing for higher ammonia slip rates than originally designed (i.e., 10 ppm vs. 5 ppm) will allow for higher levels of urea injection, which has the potential to further reduce NO_x emission rates. The ASOFA system would be operated in conjunction with the optimized SNCR system. Optimized SNCR is considered technically feasible for application on the Unit 1 and Unit 2 cyclone boilers at MRYS.

– Cost of Compliance (Statutory Factor 1)

B&M for MRYS: Cost estimates for the RRI + SNCR control technology were developed based on proposals from an RRI + SNCR vendor, and installation estimates were based upon Burns & McDonnell's in-house experience for additional water treatment, compressed air, balance of plant (BOP) piping, access, and installation. The RRI + SNCR vendor utilized computerized fluid dynamics (CFD) modeling results completed by another vendor as well as conducted on-site data measurement of boiler temperature and species of NO_x, CO and O_2. The measured data was mapped and used to perform additional CFD modeling to determine the equipment and optimum injection locations. The data collected by these vendors and the proposal of the RRI + SNCR technology vendor provide good assurance that the application of these technologies, and their associated costs, are well understood for the boilers at MRYS.

NPS: We reviewed B&M’s cost estimates and note that the Capital Recovery Cost was based upon a 5.5% interest rate and 20-year life which resulted in a Capital Recovery Factor = 0.08368. The CCM recommends use of the current prime interest rate (3.25%) over 20 years for SNCR which yields a CRF = 0.0688; for SCR the CCM recommends a 30-year life which yields a CRF = 0.0527.

We applied the current CCM SNCR workbook to estimate the costs of the existing systems and subtracted those O&M costs from the costs of new SCR systems which were estimated by application of the corresponding CCM workbook. Our results are shown in the Tables 26 and 27 below.

Table 26. NPS Revision 1 to B&M Table 2-8: Annualized Total Cost of MRYS Unit 1 NO_x Control Technologies (2019$)

NO_x Control Alternative	**Emission Rate (lb/mmBtu)**	**Annual Emission Reduction (tpy)**	**Installed Capital Cost**	**Capital Recovery Cost ($)**	**Annual O&M Cost ($)**	**Annualized Total Cost ($)**	**Actual Unit Control Cost ($/ton)**	**Incremental Unit Control Cost ($/ton)**
SCR	0.05	3,961	103,534,350	5,456,260	-2,107,972	3,356,906	1,857	-730
Applied RRI+SNCR/ASOFA	0.28	539	8,164,160	561,694	5,292,000	5,853,694	10,860	7,456
Applied Optimized SNCR/ASOFA	0.33	21	2,301,440	158,339	1,833,000	1,991,339	94,826	
Existing SNCR/ASOFA	0.332	Baseline						

SCR O&M costs are less than for the existing SNCR system due to lower reagent costs. At less than $2,000/ton, replacing the existing SNCR with SCR on MRYS Unit 1 could be very cost-effective.

Applied RRI + SNCR/ASOFA has a greater annual cost than SCR and reduces fewer emissions; this option should be discarded if SCR is considered. The analysis then becomes:

Table 27. NPS Revision 2 to B&M Table 2-8: Annualized Total Cost of MRYS Unit 1 NO_x Control Technologies (2019$)

NO_x Control Alternative	**Emission Rate (lb/mmBtu)**	**Annual Emission Reduction (tpy)**	**Installed Capital Cost**	**Capital Recovery Cost ($)**	**Annual O&M Cost ($)**	**Annualized Total Cost ($)**	**Actual Unit Control Cost ($/ton)**	**Incremental Unit Control Cost ($/ton)**
SCR	0.05	3,961	103,534,350	5,456,260	-2,107,972	3,356,906	1,857	347
Applied Optimized SNCR/ASOFA	0.33	21	2,301,440	158,339	1,833,000	1,991,339	94,826	
Existing SNCR/ASOFA	0.332	Baseline						

The incremental cost-effectiveness of replacing the existing SNCR with SCR on MRYS Unit 1 is also very reasonable.

Table 28. NPS Revision to B&M Table 2-9: Annualized Total Cost of MRYS Unit 2 NO_x Control Technologies (2019$)

N0x Control Alternative	Emission Rate (lb/mmBtu)	Annual Emission Reductio n (tpy)	Installed Capital Cost	Capital Recovery Cost ($)	Annual O&M Cost ($)	Annualize d Total Cost ($)	Actual Unit Contro l Cost ($/ton)	Incrementa l Unit Control Cost ($/ton)
SCR	0.04	6,738	170,493,97 8	8,985,03 3	-624,003	8,373,549	1,658	207
Applied RRI+SNCR/ASOF A	0.26	1271	14,005,800	963,599	6,278,00 0	7,241,599	5,698	5,350
Applied Optimized SNCR/ASOFA	0.32	240	3,323,200	228,636	1,497,00 0	1,725,636	7,190	
Existing SNCR/ASOFA	0.334	Baseline						

SCR O&M costs are less than for the existing SNCR system due to lower reagent costs. At less than $2,000/ton, replacing the existing SNCR with SCR on MRYS Unit 2 could be very cost-effective.

Applied RRI + SNCR/ASOFA and SNCR Optimization are also viable options.

– Time Necessary for Compliance (Statutory Factor 2)

NDDEQ: The time necessary for compliance is not a limiting factor when determining additional reasonable controls for MRYS Unit 2 NO_x emissions since SNCR optimization and/or RRI could be installed prior to the end of the second planning period.

– Energy and Non-Air Quality Environmental Impacts (Statutory Factor 3)

ENERGY

NDDEQ: The primary energy impact of utilizing RRI with SNCR or optimizing existing SNCR system is reduced boiler efficiency due to evaporation of large amounts of dilute urea. This results in excess coal needing to be burned to evaporate the expected amount of dilute urea in the boiler. An incremental increase in energy will also result from providing more compressed air for reagent atomization.

Auxiliary power requirements result in a 66 kW increase in an optimized SNCR, and a 132 kW increase with RRI and SNCR These energy impacts are only incrementally higher than the existing system, and do not remove either option from consideration.

NPS: Energy impacts are addressed under statutory factor 1, cost of compliance.

Non-Air Quality Environmental Impacts

NDDEQ: Non-air quality impacts of the control technologies are very similar to the impacts of the existing SNCR system. There may be an increase in ammonia slip, but a majority will be captured in the WFGD system. There will also be additional reverse osmosis/condensate waste due to the increase in demand from the systems and the need to dilute concentrated urea. This would result in millions of gallons of additional water treatment wastewaters being discharged from the MRYS facility on an annual basis. These impacts are considered acceptable and do not remove either option from consideration.

NPS: The impacts raised are standard to the operation of this control technology.

– Remaining Useful Life (Statutory Factor 4)

NDDEQ: Based on the information provided to the Department, MRYS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

3.4.5 Conclusions & Recommendations

- Other states have set cost-effectiveness thresholds of: $5,000/ton for EGUs in AR and TX, $7,000/ton in NM, and $10,000/ton in CO and OR.
- The cost effectiveness of modifying the existing scrubbers at MRYS would be acceptable in the context of the previous ND BART thresholds as well as the thresholds used by the states cited. This strategy could reduce SO_2 emissions by over 1,600 tons/year compared to existing controls.
- The annual average and incremental cost-effectiveness of adding RRI at MRYS Unit 2 would be acceptable in the context of the thresholds used by CO, NM, and OR. This strategy could reduce NO_x emissions by over 3,500 tons/year compared to existing controls.
- The annual average cost effectiveness of adding SCR at MRYS would be acceptable in the context of the previous ND BART thresholds as well as the thresholds used by the states cited. This strategy could reduce NO_x emissions by over 10,700 tons/year compared to existing controls.

3.5 Leland Olds Station

3.5.1 Summary of NPS Recommendations and Requests for Leland Olds Station

The NPS review of the four-factor analysis conducted for Leland Olds Station (LOS) finds that there are technically feasible and cost-effective opportunities available to further control NO_x emissions from Unit 2. In fact, we find that the cost of control is more economical than the SIP estimate when analyses are adjusted in accordance with the EPA Cost Control Manual.

In addition, our review of recent emissions data from LOS revealed two areas of concern. First, emissions data from the EPA Air Markets Program indicate that January 2021 mercury emissions were 5.02 lb/TBtu at LOS Unit 2. This is extremely concerning given the Mercury and Air Toxics Standard for existing boilers firing low rank virgin coal is 4.0 lb/TBtu. Secondly, the

SO_2 emission rate from LOS Unit 1, while low compared to historic rates, has been steadily increasing since 2014. We request that NDDEQ investigate these matters and take action to reduce mercury emissions from LOS Unit 2 and optimize SO_2 control efficiency for LOS Unit 1.

Although ND has not established a cost threshold for this round of regional haze planning, we can advise that other states have set cost-effectiveness thresholds of: $5,000/ton for EGUs in AR and TX, $7,000/ton in NM, and $10,000/ton in CO and OR.

The annual average cost-effectiveness of adding SCR to reduce NO_x emissions at LOS Unit 1 would exceed the thresholds used by all states we have seen. However, there are two opportunities to cost-effectively reduce NO_x emissions from Unit 2. 1) The annual average cost effectiveness of adding Rich Reagent Injection (RRI) to SNCR at LOS Unit 2 would be acceptable in the context of the previous ND BART thresholds as well as thresholds used by AR, TX, CO, NM, and OR. This strategy could reduce NO_x emissions by almost 1,200 tons/year. 2) The annual average cost effectiveness of adding SCR at LOS Unit 2 would also be acceptable in the context of the previous ND BART thresholds as well as thresholds used by AR, TX, CO, NM, and OR. This strategy could reduce NO_x emissions by over 3,500 tons/year compared to existing controls.

We recommend that ND take every opportunity to reduce NO_x emissions from the Leland Olds Station in this planning period. By requiring implementation of identified controls ND will be reducing haze causing emissions and advancing incremental improvement of visibility at Theodore Roosevelt, Badlands, and Wind Cave National Parks as well as other Class I areas in the region.

3.5.2 Leland Olds Plant Characteristics

Leland Olds Station (LOS) is a 656 MW lignite coal-fired power station owned and operated by Basin Electric Power Cooperative (Basin) near Stanton, North Dakota. Theodore Roosevelt National Park, a Class I area administered by the National Park Service (NPS), is 149 km west of this facility.

Of 1,167 facilities in EPA's Clean Air Markets Database (CAMD) in 2020, LOS ranked #105 for sulfur dioxide (SO_2) emissions (1,720 tons) and #48 for nitrogen oxides (NO_x at 4,420 tons). LOS' carbon dioxide emissions of 3,784.483 tons rank #111 in the US. LOS also ranked #41 for EGU mercury (Hg) emissions with 82 lb in 2017.

LOS has two generating units (Units 1 and 2) that burn lignite from the Freedom Mine operated by Dakota Coal. LOS Unit 1 is a 216 MW Babcock and Wilcox (B&W) opposed wall-fired unit that went online in 1966. LOS Unit 1 is equipped with an Emerson combustion optimizer, Low-NO_x burners (LNB), advanced separated overfire air (SOFA) and selective non-catalytic reduction (SNCR) for NO_x control, wet limestone flue gas desulfurization (WFGD) system for SO_2 control, and electrostatic precipitators (ESP) for particulate matter (PM) control. LOS Unit 2 is a 440 B&W cyclone- fired unit that went online in 1975. LOS Unit 2 is equipped with an Emerson combustion optimizer, SOFA, and SNCR for NO_x control, WFGD for SO_2 control, and ESP for PM control. Mercury is controlled by Powdered Activated

Carbon Sorbent Injection.[22] The Table 29 below shows a breakdown of 2020 SO_2 and NO_x emissions and how they rank versus the 3,317 EGUs in CAMD.

Table 29. LOS 2020 SO_2 and NO_x emissions and rank versus the 3,317 EGUs in CAMD

Unit ID	SO_2 (tons)	SO_2 (tons) Rank	Avg. SO_2 Rate (lb/MMBtu)	Avg. SO_2 Rate (lb/MMBtu) Rank	NO_x (tons)	NO_x (tons) Rank	Avg. NO_x Rate (lb/MMBtu)	Avg. NO_x Rate (lb/MMBtu) Rank
1	484	301	0.103	296	660	306	0.137	514
2	1,236	167	0.098	307	3,760	20	0.285	120

3.5.3 First Planning Period Regional Haze Control Requirements for LOS 1 and 2

Basin Electric's LOS Units 1 and 2 were evaluated by the NDDEQ as subject-to-BART (Best Available Retrofit Technology) sources. NDDEQ concluded that BART for both LOS units included new WFGD for SO_2 control and SOFA with SNCR for NO_x control. NDDEQ determined that selective catalytic reduction (SCR) was not an available, and thus not a technically-feasible, option.

On September 21, 2011, EPA proposed to partially approve and partially disapprove specific aspects the Regional Haze SIP. EPA proposed to disapprove the State's determination of BART for LOS Unit 2and approve the State's BART determination for SO_2 control at LOS (i.e., new WFGD) and the NO_x BART determination for LOS Unit 1 (i.e., SOFA+SNCR). EPA also proposed the promulgation of a Federal Implementation Plan (FIP) which included a NO_x BART determination and emission limits for LOS Unit 2. EPA proposed advanced SOFA (ASOFA) plus SCR and an emission rate of 0.07 lb/MMBtu (30-day rolling average) as BART for NO_x control on LOS Unit 2.

EPA issued its Final Rule on April 6, 2012 and reversed its position regarding the technical feasibility of SCR on LOS Unit 2 and decided to approve the State's BART determination for NO_x control on LOS Unit 2.

EPA's decision to accept the BART determinations for LOS Unit 2 was based primarily on the decision in United States v. Minnkota Power Cooperative, Inc. which concluded that the State's best available control technology (BACT) analysis for NO_x control on Minnkota Power's Milton R. Young Station (MRYS) Units 1 and 2 was not unreasonable, a conclusion that was contrary to EPA's position at the time of the Proposed FIP. EPA noted that the technical feasibility determination under the BACT and BART analyses was substantially the same, and that the BART Guidelines permit a state to rely upon a BACT determination for purposes of selecting BART unless new technologies have become available or best control levels for recent retrofits

[22] The Mercury and Air Toxics Standard for existing boilers firing low rank virgin coal is 4.0 lb/TBtu. January 2021 Hg emissions were: Unit 1= 1.01 lb/Trillion Btu (TBtu), Unit 2 = **5.02** lb/TBtu.

have become more stringent. EPA concluded that it would be inappropriate to proceed with its proposed disapproval of SNCR as BART and approved the State's determination that ASOFA+SNCR and an emission rate of 0.35 lb/MMBtu (30-day rolling average) was BART for NO_x control on LOS Unit 2.

The BART selected by NDDEQ for LOS Unit 1 and Unit 2 was WFGD for SO_2 control and SOFA and SNCR for NO_x control with a compliance date of April 4, 2017. A 0.15 lb SO_2/MMBtu or 95% SO_2 removal on a 30-day rolling average limit was placed on each LOS Unit, which corresponds with the Presumptive BART SO_2 control level proposed by EPA for a WFGD. A NO_x limit of 0.19 lb/MMBtu and 0.35 lb/MMBtu on a 30-day rolling average was placed on LOS Units 1 and 2, respectively.

The WFGD systems for Units 1 and 2 were placed in early operation in 2012 (LOS Unit 2) and 2013 (LOS Unit 1), due to the increasing sulfur content of the fuel supply. The layered NO_x control systems were placed in service in stages over several years with the systems fully in service and optimized in 2016 for both units. Changes in emissions resulting from these actions are shown in the charts below.

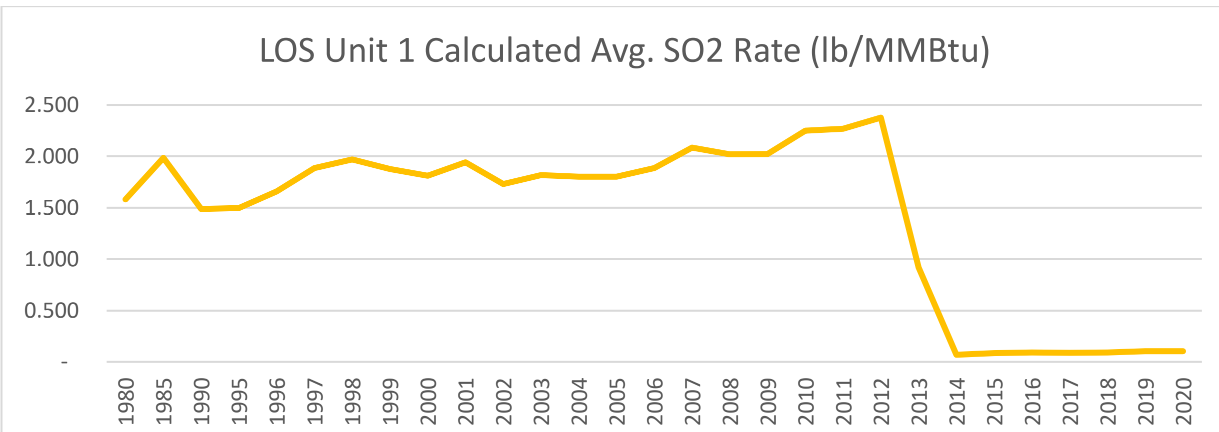


Figure 18. LOS Unit 1, Calculated Avg. SO_2 Rate (1980–2020)

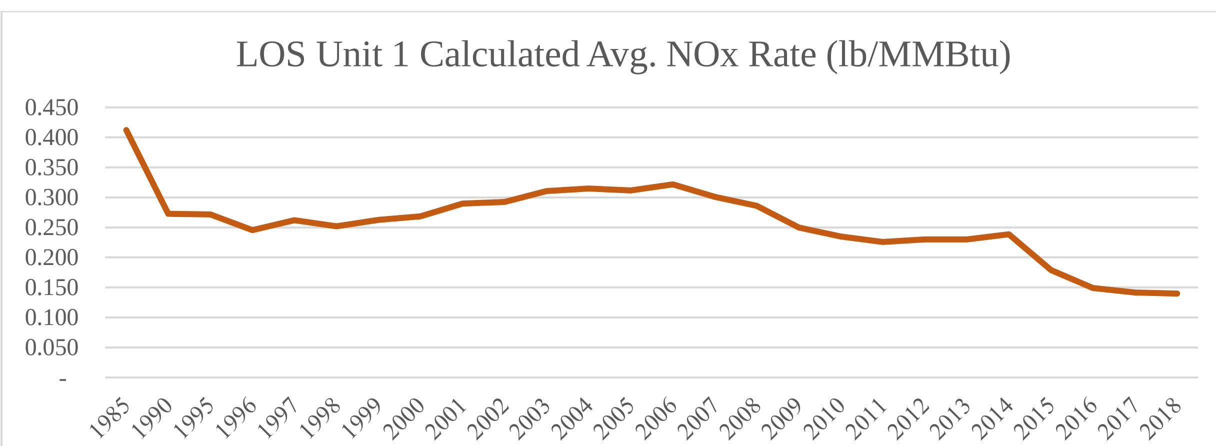


Figure 19. LOS Unit 1, Calculated Avg. NO_x Rate (1985–2018)

3.5.4 Second Planning Period Reasonable Progress Control Requirements for LOS 1 and 2

NDDEQ: The NDDEQ sent a letter to Basin on May 2, 2018 requesting a four-factor analysis (4FA) for LOS. The letter required that Basin's 4FA be submitted to the NDDEQ by January 31, 2019.

In January 2019, Sargent & Lundy LLC (S&L) prepared a 4FA for the LOS on behalf of Basin. The analysis included an assessment of potentially available SO_2 and NO_x emission reduction technologies that could be applied to LOS Units 1 and 2.

Basin's original 4FA was submitted to the NDDEQ on January 31, 2019. The NDDEQ provided comments to Basin regarding Basin's 4FA on April 15 and April 22, 2019. Basin submitted a response to the NDDEQ's comments on July 26, 2019. On November 20, 2019, Basin submitted an update to the steam cost that was used to develop the operating costs for the technically feasible NO_x reduction technologies. Based on the information reviewed, future operations and emissions profiles are expected to remain consistent with current conditions.

NPS: 2020 fuels data from the Energy Information Administration shows the average sulfur content of the lignite burned at LOS would result in uncontrolled SO_2 emissions of 2.08 lb/mmBtu.[23] CAMD data for LOS in 2020 showed that controlled SO_2 emissions averaged 0.103 lb/mmBtu at Unit 1 and 0.098 lb/mmBtu at Unit 2. However, Unit 1 emission rates have been increasing recently.

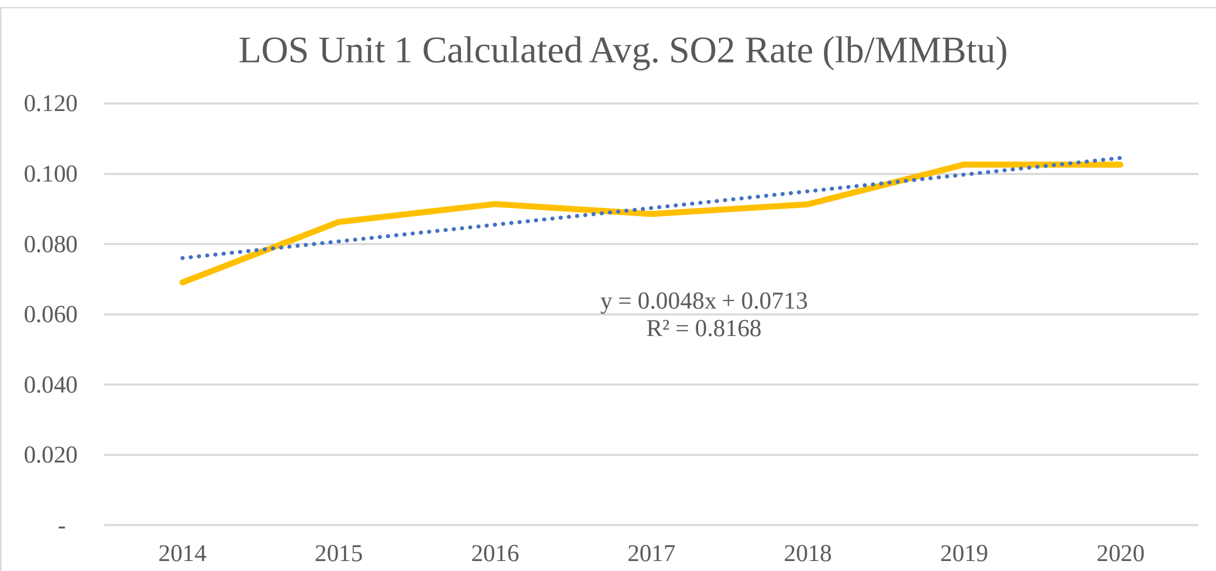


Figure 20. LOS Unit 1 SO_2 emission rates have been increasing recently (2014–2020)

[23] Average sulfur content was 0.97% with an average heat content of 13.25 mmBtu/ton.

Following are excerpts from the January 2019 S&L report—we note where we have differences.

SO_2 Emissions Controls

Identify Available SO_2 Control Options

As part of the first planning period for Regional Haze, the NDDEQ concluded that WFGD for SO_2 control was BART for LOS Units 1 and 2. For the Round II Determination's 4FA presented in this report, the NDDEQ requested Basin Electric evaluate improvements or upgrades to the existing WFGD systems that could be made to reduce SO_2 emissions further.

Technical Feasibility of Available SO_2 Control Options

Operational Improvements and Equipment Upgrades on Existing WFGD

Limestone Quality

The LOS WFGD byproduct is currently disposed, as such using a lower quality limestone is acceptable. The facility on average receives 90% or greater $CaCO_3$ content, which is on the high end of quality for generating WFGD byproduct for disposal. Procuring a higher $CaCO_3$ content limestone would not provide any valuable improvement in WFGD performance. Thus, changing the limestone quality is not a technically feasible SO_2 control option for LOS, and will not be evaluated further.

Ca:S Stoichiometric Ratio

S&L reviewed limestone addition data provided by LOS for Units 1 and 2. At LOS Unit 1, limestone feed rate is maintained relatively close to the maximum design stoichiometry based on the inlet SO_2 concentration. Increasing the fresh limestone addition rate to operate closer to the maximum design stoichiometry could provide nominal additional SO_2 removal. Further increases to limestone consumption beyond the design rate are not recommended, due to potential harmful effects of changes of slurry pH, which can lead to scaling concerns and oxidation-reduction potential (ORP) issues. LOS has already had issues with pH control and limestone addition beyond the design rate may drive the pH too high. As such, an increase in Ca:S stoichiometry to the design is considered to be a technically feasible SO_2 control option for LOS Unit 1. This adjustment to station work practices would require a slight increase in limestone addition to achieve an 11% reduction from the baseline SO_2 hourly rate (in lb/hr).

A similar analysis was conducted on Unit 2 limestone addition rates. Similarly, there is minor improvement to achieve maximum design stoichiometry at full load based on the inlet sulfur. It is not recommended to increase the rates above design, due to the aforementioned effects of operating outside of design pH range. However, increasing stoichiometry would have to be done in conjunction with increasing the L/G ratio. The L/G, which is a measurement of the volume of liquid slurry recycled in comparison to the volumetric flow rate of gas passing through the absorber, also typically has an effect on removal efficiency. Since the limestone injection rate and the L/G ratio rely upon each other for the system to operate as designed, it is difficult to predict performance improvement with increased limestone alone. As such, for LOS Unit 2, increased limestone stoichiometry will be reviewed in conjunction with increasing the L/G ratio as discussed in the next section.

Liquid-to-Gas Ratio

S&L estimated recycle slurry flow rates based on pump operating data provided by LOS for Units 1 and 2. Based on the data provided, the Unit 1 pumps operate with three of the four spray levels always in service. Current industry practice for WFGD systems are such that the system is designed with a spare recycle pump and spray level in order to maintain SO_2 removal while performing maintenance activities on the recycle pumps. Furthermore, the recycle flow rate data suggest that all Unit 1 operating pumps are working at their maximum capacity at all times. This was confirmed by LOS operating personnel that explained that the recycle pumps are manually operated and not adjusted for operating load or SO_2 loading. This suggests there is no potential for increased L/G ratio without major modifications to the spray headers. For these reasons, changes to L/G ratio are not considered to be a technically feasible SO_2 reduction option for LOS Unit 1 and will not be evaluated further.

As mentioned in the previous section, Unit 2 is not operating at its maximum design L/G ratio. The design of the Unit 2 WFGD is based on four of five recycle pumps operating at maximum flow at full load, to satisfy the design operating profile; however, the facility has only been operating three at a time, due to lower inlet sulfur loading than design (3.9 lb/MMBtu) and is still maintaining SO_2 emissions below the permitted limit. Fuel forecasts suggest that the inlet sulfur loading could increase to 3.73 lb/MMBtu on a short-term basis, within the next 5-10 years, from the baseline SO_2 fuel composition of 3.05 lb/MMBtu for Unit 2. As the facility starts to burn higher sulfur coal in comparison to the recent historical quality, the site personnel can manually place the fourth pump in service.

However, based on review of data provided by LOS, the flow rate of the pumps that are in operation is less than design, which is mainly due to the rigorous required maintenance to keep them at full efficiency and design flow rate. If the pumps are increased to maximum design capacity and the limestone is increased to the appropriate ratio (as referenced in the previous section), the Unit 2 WFGD would be expected to achieve a nominal reduction in SO_2 emissions at full load. For these reasons, operating changes resulting in an increase in Ca:S stoichiometry in conjunction with an increase in L/G is considered to be a technically feasible SO_2 control option for LOS Unit 2 and will be evaluated further. It is expected that the adjustment to station work practices may achieve a 15% reduction from the baseline SO_2 hourly rate (in lb/hr).

Additional Spray Level

Another method to increase L/G ratio in a WFGD system is to increase the amount of spray levels. As mentioned previously, Units 1 and 2 are designed with a spare spray level to account for a certain level of redundancy for maintenance purposes. If increased L/G ratio cannot be obtained by increasing the throughput of slurry through the existing spray headers, an additional recycle pump and spray header may be added. An additional spray level would increase the L/G ratio by 33% on Unit 1 and 20% on Unit 2.

The original equipment manufacturer (OEM) provided correction curves that suggest an additional 1% removal efficiency could be achieved with all pumps and spray levels in service at both LOS units. As such, it is expected that installing an additional spray level would improve LOS Unit 1 and 2 performance. However, S&L reviewed the absorber drawings for each unit and concludes there is no room for an additional slurry spray level. Due to the location of the mist eliminators which are directly above the highest spray level and the inlet flue gas duct located directly below the first spray level, there is no room to install another spray level unless the top of the absorber is extended to make room for another spray level. All of the internals in this section would need to be restructured including the outlet cone ductwork to the chimney. For these reasons, an additional spray header is not considered to be a technically feasible SO_2 control option for LOS Unit 1or 2 and will not be evaluated further.

Optimized Spray Level Coverage

S&L consulted the WFGD OEM to determine if there have been any developments in spray header design since the LOS WFGD's were installed. The OEM concluded that the LOS WFGD systems were originally designed with state-of-the-art spray coverage and up/down nozzle patterns, which is consistent with the most modern WFGD systems. As such no additional improvements could be made to the spray nozzle design to improve the WFGD efficiency. For these reasons, optimizing the spray nozzle design is not considered to be a technically feasible SO_2 control option for LOS Unit 1or 2, and will not be evaluated further.

pH Buffer Additive

The use of DBA in conjunction with increasing fresh limestone injection rates is expected to provide the WFGD with an additional 1% SO_2 removal efficiency. This performance could be obtained for the expected fuel sulfur content up to 3.73 lb/MMBtu. The facility is currently equipped with two common limestone ball mills, one operating and one spare, and a forwarding system with four slurry pumps. Based on the maximum future fuel sulfur content, the ball mills and slurry forwarding systems have sufficient capacity to provide the additional limestone required for Units 1 and 2 while still maintaining complete redundancy. Additional equipment for the DBA addition system would require a small tank and pump to add to the slurry holding tank. As such, DBA and increased limestone makeup is determined to be a technically feasible option for providing additional SO_2 removal efficiency on LOS Units 1 and 2.

– Cost of Compliance (Statutory Factor 1)

S&L for LOS: Capital costs were annualized using a capital recovery factor based on an annual interest rate of 5.25% and equipment life of 20 years.

NPS: The CCM recommends use of the current prime interest rate of 3.25% and 30-year life.

S&L for LOS: Capital and O&M cost estimates were developed for each of the technically feasible SO_2 control options. The LOS Units 1 and 2 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Units 1 and 2 control system upgrades. Rather, equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on Units 1 and 2-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the LOS Units 1 and 2 retrofit technologies as "concept screening" cost estimates generally based on parametric models, judgment, or analogy.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimates (e.g., mobilization and demobilization, consumables, contractor general and administrative (G&A) expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes.

NPS: The LOS four-factor analysis applies a 20% Contingency Cost of Direct and Indirect capital costs to all capital cost analyses. The CCM says:

> *The contingency, C, accounts for unexpected costs associated with the fabrication and installation of the absorber and is calculated by multiplying the total direct and indirect costs by a contingency factor (CF). A default value of 10% is typically used for CF.*

The four-factor analyses also applied 2% of Direct cost as owner's costs—this is not allowed by EPA.

S&L for LOS: Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing WFGD systems.

NPS: The cost analysis spreadsheet contained property taxes not assessed by ND.

NDDEQ presented LOS four-factor analysis results in Tables 30 and 31 below.

Table 30. (NDDEQ draft SIP Table 16) SO_2 Cost of Compliance and Incremental Cost of Compliance (Unit 1)

Control Technology	Performance Rate (lb SO_2/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
WFGD (Baseline)	0.09				
Ca:S Stoichiometry	0.08	59	752,000	12,698	
pH Buffer Additive	0.06	237	4,441,865	18,742	20,730

Table 31. (NDDEQ draft SIP Table 17) SO_2 Cost of Compliance and Incremental Cost of Compliance (Unit 2)

Control Technology	Performance Rate (lb SO_2/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
WFGD (Baseline)	0.09				
Ca:S Stoichiometry and L/G Ratio	0.08	128	1,439,000	11,264	
pH Buffer Additive	0.05	464	7,740,386	16,682	18,754

– Time Necessary for Compliance (Statutory Factor 2)

Control Technology	Total time after SIP approval (months)
Ca:S Stoichiometry	3
pH Buffer Additive	12

– Energy and Non-Air Quality Environmental Impacts (Statutory Factor 3)

ENERGY

NDDEQ: Adjustment of the Ca:S stoichiometric ratio would require an increased operation of the recycle pump, which will increase the auxiliary power requirements. This would adversely affect the net plant heat rate. This impact is significant but not significant enough to eliminate adjustment of the Ca:S stoichiometric ratio as a control option.

NPS: This should be included in the cost analysis under statutory factor 1, cost of compliance.

NON-AIR QUALITY ENVIRONMENTAL IMPACTS

NDDEQ: There are no known significant non-air quality environmental impacts associated with any of the technically feasible SO_2 control technologies.

– Remaining Useful Life (Statutory Factor 4)

NDDEQ: Based on the information provided to the NDDEQ, LOS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

NO_x Emission Controls

SELECTIVE CATALYTIC REDUCTION (SCR)

NDDEQ: Successful use of TE-SCR controls has since been demonstrated at existing bituminous- and subbituminous-fired units. Even though this has not been demonstrated on

North Dakota lignite-fired boilers, the current determination is deeming TE-SCR as being technically feasible for Unit 1 at LOS, which is an opposed wall-fired boiler. TE-SCR is anticipated to provide an approximately 69% reduction in NO_x emissions from the baseline scenario on Unit 1. This would lower the expected performance rate from 0.16 to 0.05 lb NO_x per MMBtu for Unit 1. TE-SCR is assumed to be technically feasible for installation on Unit 1 at LOS and will be evaluated further. The earlier determination focused on North Dakota lignite-fired cyclone boilers. Therefore, SCR is not considered technically feasible for Unit 2 at LOS.

NPS: Tail-End SCR should be able to reduce NO_x emissions by at least 77% on Unit 1 and 87% on Unit 2 to achieve 0.04 lb/mmBtu. For example, EPA assumed in 2014 that SCR could achieve the 0.04 lb/mmBtu annual emissions proposed by Basin at its Laramie River Station in WY. 2020 CAMD data contains 11 coal-fired EGUs with SCR at 0.04 lb/mmBtu annual average.

Optimized Selective Non-Catalytic Reduction

S&L for LOS: SNCR involves the direct injection of ammonia or urea ($(NH_2)_2CO$) at high flue gas temperatures (approximately 1,600ºF – 2,100ºF) in an oxidizing environment. The ammonia or urea reacts with NO_x in the flue gas to produce N_2 and water as shown below.

$$(NH_2)_2CO + 2NO + ½O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$
$$2NH_3 + 2NO + ½O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reagent injection can greatly affect NO_x removal efficiencies and the quantity of ammonia or urea that will pass through the SNCR unreacted (referred to as ammonia slip). In general, SNCR reactions are effective in the range of 1,600ºF – 2,100ºF. At temperatures below the desired operating range, the NO_x reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NO_x resulting in low NO_x reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. Retractable multi-nozzle lances (MNLs) are sometimes used to improve SNCR performance, especially if the furnace exit flue gas temperatures are too high. The retractable lances allow injection into the appropriate temperature zone more so than wall injectors, depending on the unit load and temperatures. The MNLs also help improve performance by refining the spray pattern for quicker vaporization of the conveying water. MNLs are often used in conjunction with wall injection to provide optimized coverage while reducing reagent cost.

For LOS Unit 1, SNCR boiler computational fluid dynamics (CFD) modeling was completed to understand the best performance expected prior to implementation and tuning of the system. Based on the SOFA, LNB, and combustion optimization systems, SNCR was predicted to achieve 20% removal with an outlet NO_x rate just over 0.17 lb/MMBtu. Based on flow and NO_x CEMS data, average performance of the SNCR is currently slightly below 0.17 lb/MMBtu. As such, the current SNCR system is considered fully optimized based on the expected CFD modeling; any additional urea injection may result in negative impacts with ammonia slip emissions. Also, MNLs were initially modeled in addition to the wall injectors and were found to improve removal efficiency by another 6%; however, the optimal locations of the MNLs were determined to have physical interferences which would have limited the possibility of installation and thus were not installed. As such, MNLs are considered technically infeasible as part of this evaluation. For these reasons, SNCR optimization is not considered to be a technically feasible NO_x control option for LOS Unit 1 and will not be evaluated further.

NPS: We estimate that SNCR on LOS Unit 1 is achieving 30% control.

S&L for LOS: As discussed previously, the SNCR on LOS Unit 2 was implemented after SOFA tuning, combustion optimization, and four vent ports were relocated. As such, the pre-SNCR baseline emission rate is much lower than the 0.67 lb/MMBtu uncontrolled baseline reported in the First Implementation Phase. S&L and Basin Electric consulted SNCR OEMs to determine the expected SNCR performance for a cyclone boiler similar to LOS Unit 2, considering the pre-SNCR baseline. The OEM, who performed a significant amount of modeling when the SNCR system was being designed on Unit 2, suggested that the SNCR system could be further optimized. Improvement of the stoichiometry would be required, by relocating all cyclone vent ports. Additionally, due to revised temperatures within the boiler from the new SOFA, vent port relocations, and combustion optimizers, the current urea injection lances are recommended to be relocated for better utilization of the reagent.

NPS: We estimate that SNCR on LOS Unit 2 is achieving 4% control.

S&L for LOS: By optimizing LOS Unit 2's SNCR system based on additional vent port relocation and SNCR injection lance relocation, the unit may be able to achieve an additional 10% reduction from the annual baseline NO_x rate or approximately 0.27 lb/MMBtu at the boiler outlet at full load. This is consistent with greater than 25% reduction from an estimated pre-SNCR NO_x rate. In this case for LOS Unit 2, the limiting factor for optimized SNCR operation is full load. Overall, it is expected that optimization of the Unit 2 SNCR system at all loads is a technically feasible option to reduce NO_x emissions and will be evaluated further.

Rich Reagent Injection

Similar to SNCR, the concept of RRI is to use a nitrogen-containing additive (urea) injected into a reducing environment to promote peak NO_x reduction efficiency. RRI is a commercial technology for cyclone boilers only, thus is not an applicable option for LOS Unit 1. In contrast to SNCR, RRI typically is applied with only one injection level in the lower furnace near the cyclone barrels (temperature window of 2000°F-2600°F). The technology requires a sub-stoichiometric oxygen concentration near the barrels at <0.95. This allows for a higher injection rate of reagent without oxidizing to NO_x due to the sub-stoichiometry. Injection at this location also creates lower level of excess NH_3 emissions (ammonia slip), while injecting at an NSR of 2.0-3.0.

The RRI process is a commercially available process and has been predicted to typically reduce NO_x emissions by 20-40% at full load with no ammonia slip, but is highly dependent on the stoichiometry. However, this technology provides the most beneficial reduction at full load, due to the cyclone temperature window and stoichiometry. At mid- and low-loads, the predicted reduction is less than the current SNCR baseline operation at these loads. Therefore, low load operation is considered the limiting factor of RRI alone and the effectiveness of RRI is marginalized at mid-loads. SNCR would still be needed to achieve a similar reduction at low load. As such, RRI on its own is not a technically feasible NO_x reduction technology due to its limited operating conditions throughout all load ranges and will not be considered further.

Optimized SNCR + RRI

While RRI alone will provide beneficial NO_x reduction at full load only, coupling RRI with SNCR will provide a balanced approach to NO_x reduction through all load ranges. RRI and SNCR injectors are located at different elevations of the furnace and in different temperature windows. The system utilizes a high urea injection rate, staged at multiple locations throughout the boiler. The main advantage of this combined system is that the SNCR can provide better NO_x reduction at mid- and low-loads and at a lower NSR than RRI alone. Therefore, this combined system is expected to be able to provide a lower emission rate through all load ranges.

Boiler CFD modeling of the SNCR and RRI systems was previously conducted with different assumptions of SOFA and vent port relocation performance. However, S&L consulted the CFD modeling company to provide insight into what performance could be achieved with the revised pre-SNCR baseline NO_x emission rate. This information was also provided to an SNCR+RRI system OEM who suggested that an additional 43% reduction from the annual baseline could be guaranteed at full load, which would provide an outlet emission rate of 0.17 lb/MMBtu. This is consistent with greater than 50% reduction from an estimated pre-SNCR NO_x rate.

Alternatively to the optimized SNCR case, low load operation is the limiting factor for SNCR+RRI performance. RRI becomes ineffective at low load and the OEM suggested that almost no NO_x reduction would occur at this load due to RRI. Initial modeling suggested that increasing the urea NSR to 3.0 at low load could achieve an additional 2% reduction, but there is a concern about ammonia slip rates with this operating profile.

The SNCR + RRI combination would require all new penetrations for the RRI system as well as the relocation of the existing SNCR system. The RRI system will require a larger urea storage tank, additional water treatment equipment for solutionizing, additional pump forwarding capacity, new piping to lower boiler elevations, additional boiler penetrations, injectors, and all balance of plant related equipment. At the lower elevation for the RRI ports, the most optimal injection location happens to occur at the same elevation of the windbox. Therefore, specialized retractable and cooled injection lances with windbox modifications would be required. This design creates engineering and operational challenges that are normally avoided by injecting reagent in more accessible areas of the boiler.

Overall, the implementation of an RRI system along with optimization of the existing SNCR system is a technically feasible NO_x control option on Unit 2. Based on input from previous CFD modeling and SNCR OEMs, it is expected that LOS Unit 2 could achieve an outlet NO_x rate of 0.22 lb/MMBtu with an ammonia slip of 10 ppmvd with vent port relocation, optimized SNCR, and RRI.

Gas Reburn

Gas reburn is a retrofit technique that has been used to control NO_x emissions from coal- and oil-fired boilers. Gas reburn involves combustion in three distinct zones within the boiler: (1) a primary combustion zone, where the primary fuel is fired using conventional burners; (2) a reburn zone, where secondary fuel, typically natural gas, is introduced into the boiler; and (3) an overfire air burnout zone. Lack of natural gas available on site precludes the ability to test and implement this control option on LOS Units 1 and 2, which use fuel oil as the startup fuel. As such, gas reburn is not considered a technically feasible NO_x control technology at LOS Units 1 and 2.

– Cost of Compliance (Statutory Factor 1)

S&L for LOS: The economic analysis performed as part of the four-factor analysis examines the cost-effectiveness of each technically feasible control technology, on a dollar per ton of pollutant removed basis. Capital costs and lost revenues were annualized using a capital recovery factor based on an annual interest rate of 5.25% and equipment life of 20 years.

NPS: The CCM recommends use of the current prime interest rate (3.25%) and equipment lives of 20 years for SNCR and 30 years for SCR.

S&L for LOS: Capital and O&M cost estimates were developed for each of the technically feasible NO_x control options. The LOS Units 1 and 2 cost estimates are conceptual in nature; thus, S&L did not procure equipment quotes specifically for the Units 1 and 2 control system upgrades. Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects.

NPS: The four-factor analysis for LOS applied a 20% Contingency Cost of Direct and indirect capital costs to all capital cost analyses. The CCM says:

> *The contingency, C, accounts for unexpected costs associated with the fabrication and installation of the absorber and is calculated by multiplying the total direct and indirect costs by a contingency factor (CF). A default value of 10% is typically used for CF.*

The four-factor analysis additionally applied 2% of direct cost as owner's costs which are not allowed by EPA.

S&L for LOS: Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing SNCR systems.

NPS: The LOS four-factor analysis included Property Taxes = 1% of TCI; Insurance = 1% of TCI; and Administration = 2% of TCI. The CCM says:

> *Property taxes and overhead are both assumed to be zero, and insurance costs are assumed to be negligible. Thus, administrative charges and capital recovery are the only components of indirect annual costs estimated in this analysis.*

NDDEQ: The cost of compliance and incremental cost for the reasonable progress controls are listed in Table 10 (Unit 1) and Table 11 (Unit 2).

Table 32. (NDDEQ draft SIP Table 10) NO_x Cost of Compliance and Incremental Cost of Compliance (LOS Unit 1)

Control Technology	**Performance Rate (lb/MMBtu)**	**Annual Emission Reduction (tpy)**	**Annualized Total Cost ($)**	**Cost of Compliance ($/ton)**
LNB/SNCR/SOFA (Baseline)	0.16			
TE-SCR	0.05	796	33,663,928	42,316

Table 33. (NDDEQ draft SIP Table 11*) NO_x* Cost of Compliance and Incremental Cost of Compliance (LOS Unit 2)

Control Technology	**Performance Rate (lb/MMBtu)**	**Annual Emission Reduction (tpy)**	**Annualized Total Cost ($)**	**Cost of Compliance ($/ton)**	**Incremental Cost of Compliance ($/ton)**
SNCR/SOFA (Baseline)	0.29				
Optimized SNCR	0.27	258	924,151	3,582	
Optimized SNCR + RRI	0.22	931	5,402,503	5,801	6,650

A detailed breakdown of the costs listed in Table 10 and Table 11 can be found in Basin's submitted four-factor analysis. The Department has reviewed these costs and believes them to be accurate.

NPS: We based our estimates for the incremental costs and benefits of SCR for Unit 1 (versus the existing SNCR) on SNCR and SCR cost models developed by S&L and incorporated into the CCM by EPA. Our Table 34 (Revised NDDEQ Table 10) is presented below and our calculations have been provided.

Table 34. NPS Revised NDDEQ draft SIP Table 10: NO_x Cost of Compliance and Incremental Cost of Compliance (LOS Unit 1)

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
LNB/SNCR/SOFA (Baseline)	0.16			
TE-SCR	0.04	393	4,487,987	11,420

We based our estimates for the incremental costs and benefits of SCR for Unit 2 (versus the existing SNCR) on SNCR and SCR cost models developed by S&L and incorporated into the CCM by EPA. For SNCR Optimization + RRI on Unit 2, we corrected S&L's errors. Our Table 35 (revised NDDEQ Table 11) is presented below and our calculations have been provided.

Table 35. NPS Revised NDDEQ draft SIP Table 11: NO_x Cost of Compliance and Incremental Cost of Compliance (LOS Unit 2)

Control Technology	Performance Rate (lb/MMBtu)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)	Incremental Cost of Compliance ($/ton)
SNCR/SOFA (Baseline)	0.29				
Optimized SNCR	0.27	423	924,151	2,185	
Optimized SNCR+RRI	0.22	1,183	5,065,379	4,282	5,449
SCR	0.04	3,514	8,159,276	2,322	1,327

– Time Necessary for Compliance (Statutory Factor 2)

A summary of the anticipated timeline for the installation of TE-SCR on Unit 1 is provided in Table 36 (NDDEQ Table 12).

*Table 36. (*NDDEQ draft SIP *Table 12) Time Required for NO_x Controls (LOS Unit 1)*

Control Technology	Total time after SIP approval (months)
TE-SCR	52

A summary of the anticipated timelines for the optimization of SNCR and the optimization of SNCR plus RRI for Unit 2 is provided in Table 37 (NDDEQ Table 13).

Table 37. (NDDEQ draft SIP Table 12) Time Required for NO_x Controls (LOS Unit 2)

Control Technology	Total time after SIP approval (months)
Optimized SNCR	12
Optimized SNCR + RRI	16

– Energy and Non-Air Quality Environmental Impacts (Statutory Factor 3)

ENERGY

NDDEQ: The installation and operation of a TE-SCR on Unit 1 would increase the pressure drop through the control systems, which would increase the auxiliary power requirements. This would adversely affect the net plant heat rate. This impact is significant but not significant enough to eliminate TE-SCR as a control option.

NPS: We estimate the energy cost at 5% of the Total Annual Cost of SCR. This is an economic issue addressed under statutory factor 1, cost of compliance.

NDDEQ: Optimization of the SNCR and optimization of the SNCR plus RRI on Unit 2 will adversely affect the net plant heat rate due to the amount of water that will be injected with urea, which will negatively impact boiler efficiency. This impact is significant but not significant enough to eliminate optimization of the SNCR or optimization of the SNCR plus RRI as control options.

NPS: We estimate the energy cost at 1% of the Total Annual Cost of SNCR + RRI. This is an economic issue addressed under statutory factor 1, cost of compliance.

NON-AIR QUALITY ENVIRONMENTAL IMPACTS

NDDEQ: The installation and operation of the TE-SCR on Unit 1 could result in an increase in sulfur emissions due to the potential oxidation of SO_2 to SO3 and the subsequent reaction with moisture in the stack to form H2SO4.

NPS: This is not an issue with the low-sulfur lignite burned at LOS.

NDDEQ: TE-SCR uses ammonia as a reagent. Ammonia slip emissions will result in the flue gas stream on the exhaust side of the control equipment due to the operation of TE-SCR (~2 ppm). Ammonia slip emissions from the operation of the TE-SCR would be emitted to the atmosphere. The non-air quality environmental impacts for TE-SCR are significant but not significant enough to eliminate either of them as a control option.

NPS: 2ppm ammonia slip is the typical limit for SCR.

– Remaining Useful Life (Statutory Factor 4)

NDDEQ: Based on the information provided to the Department, LOS is expected to operate beyond the life of the control equipment. Therefore, remaining useful life was not considered.

3.5.5 Conclusions & Recommendations

- NPS recommends that NDDEQ address the:
  - Increasing SO_2 emission rates from LOS Unit 1.
  - High mercury emission rates from LOS Unit 2.
- The annual average cost-effectiveness of adding SCR at LOS Unit 1 would exceed the thresholds used by all states we have seen.
- The annual average cost effectiveness of adding RRI to SNCR at LOS Unit 2 would be acceptable in the context of the previous ND BART thresholds as well as thresholds used by AR, TX, CO, NM, and OR. This strategy could reduce NO_x emissions by almost 1,200 tons/year.
- The annual average cost effectiveness of adding SCR at LOS Unit 2 would be acceptable in the context of the previous ND BART thresholds as well as thresholds used by AR, TX, CO, NM, and OR. This strategy could reduce NO_x emissions by over 3,500 tons/year compared to existing controls.

3.6 R M Heskett

It is our understanding that RM Heskett plant will cease burning coal in 2022 and install an 88 MW natural gas-fired simple-cycle combustion turbine. The permitted sum of future annual SO_2 (12 tpy) and NO_x (315 tpy) divided by the distance (185 km) to Theodore Roosevelt NP is 1.8. Because these emission reductions are certain, we agree that no four-factor analysis is needed for this facility.

3.7 Great Plains Synfuels Plant

The Dakota Gasification Company operates the Great Plains Synfuels Plant (GPSP), which is located six miles northwest of Beulah, North Dakota. The facility produces synthetic natural gas, fertilizers, and other byproducts resulting from the gasification of lignite coal. Emissions units at the facility include three Riley boilers rated at 763 MMBtu/hour apiece and two superheaters rated at 169 MMBtu/hour each that share a common stack. The facility also includes a package boiler and several flares. This one-of-a-kind facility began operation in 1984.

The boilers burn a variety of gasification products, including waste gas, stink gas, tar oil, naphtha/phenol (N/P) blend, lock gas, medium BTU purge gas, and synthetic natural gas. The boilers are equipped with low NO_x burners (LNB) and a pseudo-overfire air system for NO_x control, and there is a wet flue gas desulfurization system that removes 97% of the SO_2 from the main stack. According to the four-factor analysis, baseline emissions for the emissions units included in the analysis are 3,404 tons of SO_2/year and 2,590 tons of NO_x/year.

The four-factor analysis considered post-combustion controls to reduce NO_x emissions from the Riley boilers and superheaters. The three Riley boilers were considered as a single unit since they share a common stack, and the two superheaters were similarly considered as a single unit. According to the analysis, the concentrations of alkaline elements are not tracked in the fuels used in the boilers, but it is expected that high levels of these contaminants would make either low-dust or high-dust selective catalytic reduction (SCR) infeasible due to the potential for catalyst poisoning. The analysis dismissed these options without providing any data on contaminant concentrations in the flue gas. The flue gas should be tested to determine conclusively whether these options are infeasible. However, the four-factor analysis did evaluate tail-end SCR as a possible option; this would allow the boiler flue gas to pass through the wet flue gas desulfurization system before reaching the SCR.

The four-factor analysis for a possible tail-end SCR system overestimated some of the costs. The EPA Control Cost Manual 7th Edition, Section 1, Chapter 2, states that *"if firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates"* for use in cost estimation. Unless there is a justification for the use of the 5.5% rate, the bank prime rate should be used. In addition, the analysis assumed a 20-year lifetime. The Control Cost Manual recommends a 30-year lifetime for SCR systems on coal-fired boilers, and 20 to 30 years for other sources. Regarding the application of tail-end SCR systems, Section 4, Chapter 2 of the manual says: "The tail-end SCRs may also have longer lifetimes due to the lower operating temperatures and lower levels of dust and SO_3." Unless there is a justification for assuming a lower useful life for the SCR system, the assumed lifetime should be closer to 30 years. The assumption of 80% NO_x removal efficiency is low, given that many SCR systems achieve removal efficiencies > 90%. The analysis should explain why a lower value of 80% was used in for this facility. The analysis also includes owner's costs. The EPA's Control Cost Manual chapter on SCR states that owner's costs are not part of the cost methodology.

The cost analysis for the tail-end SCR system does not explain in detail how some of the costs were estimated, such as the equipment costs and labor costs for installation. The four-factor analysis prepared by Sargent & Lundy says that costs for equipment, labor, and other direct costs were derived by scaling costs estimates prepared for other projects. The cost table provided in Appendix C of the four-factor analysis says that equipment and materials costs, as well as installation labor costs, were "based on Sargent & Lundy's conceptual cost estimating system" but does not provide further details. Without this information, we are unable to fully evaluate the total system cost estimate and provide feedback. We recommend that Sargent & Lundy provide details on how these costs were derived, or revise the estimates using the cost estimate methods in the 7th edition of the Control Cost Manual and the associated Excel-based cost estimation worksheet provided by EPA.

3.8 Tioga Gas Plant

The Hess Tioga Gas Plant (TGP) is located approximately 91 km from Theodore Roosevelt National Park. The significant emission sources at the plant that were addressed in the four-factor analysis include:

- A sulfur recovery unit tail gas incinerator which is the primary SO_2 emission source at the facility during normal operations.
- Seven two-stroke lean burn (2SLB) natural gas-fired reciprocating internal combustion engines (RICE), which are the primary NO_x emission sources at the facility:

- Five engines rated at 1,920 HP. These five engines, C1A, C1B, C1C, C1E, and C1G, have not been significantly modified since installation/construction in the 1950's).
- Two engines rated at 2,350 HP. These two engines, C1D and C1F, required modification in 2004, which entailed adding turbocharging systems. The turbocharging system significantly reduced NO_x emissions from these engines compared to the other five engines. As such, these engines were not considered in the analysis.

3.8.1 SO_2 Controls for the Tioga Sulfur Recovery Unit Tail Gas Incinerator

The cost analyses for the Tioga Gas Plant SRU considered three control options:

- *Flue Gas Desulfurization (FGD)*. This control was discussed in the cost analysis but was not brought forward in the cost analysis. NDDEQ's rationale for excluding this control option from the cost analyses was that tail gas treatment and acid gas disposal options are more effective and have less disadvantages associated with implementation.
- *Tail Gas Treatment*: This option was brought forward in the cost analysis.
- *Acid Gas Disposal Injection Well*: This option was considered in the cost analyses.

As discussed below, each of these options may be cost-effective and we recommend that one is selected to significantly to reduce SO_2 emissions from the Tioga Gas Plant in this round of regional haze planning.

Flue Gas Desulfurization (FGD)

Although it was found to be technically feasible, NDDEQ did not evaluate the costs of tail gas FGD. We recommend that a cost analysis should be completed for all technically feasible options to determine cost effectiveness relative to other technologies, as cost-effectiveness is frequently a primary determining factor in most control technology decisions. We note that the costs of wet FGD were evaluated in the four-factor analysis for a similar gas sweeting plant in Wyoming and it appears to be cost-effective. We recommend that NDDEQ include a cost analysis for a FGD retrofit.

Tail Gas Treatment

Both Hess TGP and NDDEQ provided cost estimates for additional tail gas treatment units to reduce SO_2 emissions. According to Appendix A, NDDEQ's estimate was based on LO-CAT technology and resulted in a cost-effectiveness of $11,321/ton of SO_2 removed. However, NDDEQ does not provide the detailed calculations for their cost estimates in the SIP. According to Appendix B, the analysis provided by Hess was based on Shell Claus Off-gas Treatment (SCOT) technology and resulted in a cost-effectiveness of $11,815/ton of SO_2 removed.

The Hess TGP analysis used a 10% interest rate and 10-year equipment life. The NPS re-evaluated the cost of this control to correct identified analysis issues and estimated a cost-effectiveness of $4,978/ton (see attached spreadsheet). We could not evaluate NDDEQ's costs calculations because this information was not provided in the SIP. NPS revisions to the cost analysis suggest that a tail gas treatment unit appears to be very cost effective.

ACID GAS DISPOSAL INJECTION WELL

Both NDDEQ and Hess TGP estimated the costs of an acid gas injection (AGI) well, which would eliminate virtually all routine SO_2 emissions from the facility. According to NDDEQ estimates AGI is very cost effective at $3,248/ton for the acid gas injection well and $4,443/ton for the injection well along with redundant compressor and plumbing costs. Hess TGP estimated the cost of an acid gas injection well to be $3,821/ton. Each of these estimates is well below the cost-effectiveness thresholds selected by other states in this round of regional haze planning. Regardless, we re-evaluated Hess TGP's estimates using the current bank prime rate, a 25-year equipment life and an SO_2 reduction of 702 tons/year, which is the average of annual SO_2 emissions in the last four years, as reported in the SIP. Our revisions indicate that AGI may be even more cost-effective at $2,636/ton SO_2 removed.

We recommend that NDDEQ require cost effective options to reduce SO_2 emissions in the SIP.

3.8.2 NO_x Controls for the Tioga Facility Reciprocating Internal Combustion Engines

The operating hours and emissions for each of the engines are listed in Tables 38, 39, and 40 below. Given the magnitude of emissions produced from the Clark engines (91% of the facility total NO_x), we agree that they should be the focus the NO_x control evaluation under the reasonable progress determination. We also agree that engines C1D and C1F can be excluded from the control technology analysis based on current emissions and existing controls. The rows highlighted in grey are the annual periods selected to represent the maximum and minimum operation years for the engines considered in our re-evaluation of the NO_x emission control costs.

Table 38. Clark Engine Operation (hours)

Year	C1A	C1B	C1C	C1E	C1G	C1D	C1F
2015	6,520	7,749	5,818	7,437	7,885	8,314	8,568
2016	3,720	6,417	6,965	6,600	5,217	7,045	7,962
2017	528	3,506	4,258	2,070	6,240	8,165	6,708
2018	3,228	4,438	4,648	0	5,325	5,133	3,668
Average	**3,499**	**5,528**	**5,422**	**5,369**	**6,167**	**7,164**	**6,727**

Table 39. Annual NO_x Emissions from Clark Engines (tons)

Year	C1A	C1B	C1C	C1E	C1G	C1D[A]	C1F[A]
2015	238	293	209	353	207	30	35
2016	171	215	255	257	150	25	30
2017	18	99	127	81	155	26	29
2018	107	148	139	0	186	19	16
Average	**134**	**189**	**183**	**231**	**175**	**25**	**27**

[A] C1D and C1F were modified in 2004

Table 40. Non-modified Clark Engine NO_x Emissions (lb/hr)

Year	C1A	C1B	C1C	C1E	C1G
2015	73	76	72	95	53
2016	92	67	73	78	57
2017	66	56	60	78	50
2018	66	67	60	0	70
Average	**75**	**66**	**66**	**84**	**57**

ND evaluated the costs of Low Emissions Combustion (LEC) retrofits for five of the seven RICE. Citing the difficulty in operating SCR on old 2SLB engines and the fact that LEC would achieve similar emission reductions, SCR was not evaluated for the engines. While there are examples of SCR applied to RICE, we agree that in this case, LEC may produce similar results and therefore limited our review to LEC controls. NDDEQ estimated the cost effectiveness of LEC to be $8,784/ton of NO_x removed. This is within the range of cost effectiveness thresholds selected by other states in this round of haze planning, and the NDDEQ estimates of LEC retrofits seem high relative to other information. For example, EPA developed cost estimates for LEC retrofits on engines to support their analysis of control options under the Cross State Air Pollution Rule (CSAPR)[24] and the Ozone Transport Commission developed a report on emission control techniques for the oil and gas industry[25].

Based on this information, costs to retrofit the Tioga RICE (C1A-C1C, C1E and C1G) may range from $500-$1,400/ton under most operating scenarios (up to $6,899/ton in the lowest emission year). Results are summarized in Table 41 below. We recommend that LEC is likely cost-effective for the RICE at the Hess Tioga Gas plant. Given the proximity of this source to Theodore Roosevelt NP as well as the oil and gas source sector impacts within the region, we recommend that NDDEQ require this cost-effective option within this round of regional haze planning.

[24] Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS Docket ID No. EPA-HQ-OAR-2014-0289; Assessment of Non-EGU NO_x Emission Controls, Cost of Controls, and Time for Compliance.

[25] Ozone Transport Commission, Technical Information Oil and Gas Sector Significant Stationary Sources of NO_x Emissions, October 17, 2012.

Table 41. Clark Engine NO_x Emissions Control Costs Base on EPA Cost Information Prepared for the CSAPR and OTC Estimates for NO_x Emission Control Techniques for the Oil and Gas Industry

Engine	***Year***	***Operating Hours (hr/yr)***	***Annual NO_x Emissions (tpy)***	***Target NO_x Emission Rate (g/hp-hr)***	***Emission Reduction (tpy)***	***Cost Effectiveness Range; EPA CSAPR & OTC Low & High End Costs ($/ton in 2019$)***
C1A	2015	6,520	238	1.0	224	EPA CSAPR: $502/ton OTC Study Info: $498/ton to $1,248/ton
	2017	528	18	1.0	16	EPA CSAPR: $6854/ton OTC Study Info: $6796/ton to $17,046/ton
C1B	2015	7,749	293	1.0	277	EPA CSAPR: $406/ton OTC Study Info: $403/ton to $1,010/ton
	2017	3,506	99	1.0	92	EPA CSAPR: $1,223/ton OTC Study Info: $1,213/ton to $3,042/ton
C1C	2015	5,818	209	1.0	197	EPA CSAPR: $571/ton OTC Study Info: $566/ton to $1,419/ton
	2017	4,258	127	1.0	118	EPA CSAPR: $954/ton OTC Study Info: $946/ton to $2,373/ton
C1E	2015	7,437	353	1.0	338	EPA CSAPR: $333/ton OTC Study Info: $330/ton to $829/ton
	2017	2,070	81	1.0	77	EPA CSAPR: $1,469/ton OTC Study Info: $1,457/ton to $3,654/ton
C1G	2015	7,885	207	1.0	191	EPA CSAPR: $590/ton OTC Study Info: $585/ton to $1,467/ton
	2017	6,240	155	1.0	142	EPA CSAPR: $791/ton OTC Study Info: $785/ton to $1,968/ton

3.9 Little Knife Gas Plant

Little Knife Gas Plant (LKGP) is located 39 km from Theodore Roosevelt NP. The major emissions source onsite is the 2-stage 2-bed Cold Bed Absorption (CBA) sulfur recovery unit (SRU) tail gas incinerator, accounting for at least 85% of the total facility emissions since 2016. The SRU units recover approximately 94% of the sulfur from the acid gas and convert it to elemental sulfur. The remainder of the acid gas is converted from H_2S to SO_2 by the tail gas incinerator.

The control options evaluated by Petro Hunt include (1) acid gas injection, which essentially eliminates all SO_2 emissions and is relatively cost effective and (2) catalyst replacement in the reactors, which the company estimates will remove 39.42 tons/year. However, NDDEQ determined that "Catalyst replacement due to degradation and/or fouling happens on a regular basis and is not considered for reasonable progress controls."

The company estimated the cost-effectiveness of AGI to be $13,665.53, but it appears they inappropriately amortized the costs and miscalculated the annual cost effectiveness in $/ton. NDDEQ corrected these errors and estimated a cost effectiveness of $1,598/ton of SO_2 removed.

The NPS also recalculated the cost-effectiveness of AGI using the company's estimates of total capital investment to drill the injection well and the annual operating and maintenance costs provided by Petro Hunt. We calculated three scenarios. In the first scenario, we used assumptions that NDDEQ implemented for other sources, including a 5.5% interest rate and a 20-year equipment life. Using these assumptions, we derived a cost-effectiveness estimate that is very close to NDDEQ's at $1,620/ton (without the redundant piping and compressor). We also evaluated the costs of AGI using the current bank prime rate of 3.25% and a 25-year equipment life (the CCM recommends that in the absence of documentation justifying a source-specific interest rate, the bank prime rate should be used). With these revisions, AGI is even more cost-effective at $1,415/ton. Finally, we note that it appears Petro Hunt assumed an electricity cost of 87.94 cents per kilowatt-hour[26]. This is exceptionally high relative to the default values used in the CCM as well as costs reported by the Energy Information Administration (EIA). The attached EIA document reports that industrial customers in North Dakota paid an average of 7.94 cents per kilowatt-hour for electricity in 2019. When the electricity cost is adjusted to reflect EIA estimates, the estimated cost effectiveness drops to $1,034/ton. (We did not estimate the costs of a redundant compressor and plumbing, however, this only makes a $450 difference in the cost effectiveness.)

If AGI is installed, all routine SO_2 emissions from the current SRU process will be eliminated. The cost-effectiveness estimate provided by NDDEQ of $1,600/ton for the AGI well and $2,050/ton for the AGI well with redundant compressor and piping systems are well below the cost effectiveness thresholds selected by other states. Most states are proposing cost effectiveness thresholds in the $4,000-$10,000/ton range. Our revisions to the cost estimates indicate that it may be even more cost-effective than NDDEQ's estimates. Given the proximity of this source to Theodore Roosevelt NP, we recommend that NDDEQ require this cost-effective option to further reduce SO_2 emissions through the draft SIP.

3.10 Northern Border Pipeline Compressor Station No. 4

NDDEQ requested a four-factor analysis from this facility based on its proximity to Theodore Roosevelt NP and recent emissions information. Northern Border Pipeline's (NBPL) Compressor Station No. 4 (CS4) is located 18 km from the Class I park and consists of a 20,000-horsepower simple cycle natural gas-fired Cooper-Rolls Model Coberra 2648S Avon Turbine. The turbine at this facility is currently uncontrolled and has not been upgraded since installation. Therefore, we agree with NDDEQ's conclusion that this facility should complete a four-factor analysis for potential NO_x emission controls. As discussed below, we recommend that SCR is

[26] Petro Hunt assumed the electricity costs of operating a 2,400-volt, 500 HP motor, drawing 107 amps that would use 400 KWH would cost $351.74 / day and $128,385.00 / year. This works out to 87.93 cents per kilowatt hour.

cost-effective for this facility and request that NDDEQ include this control measure for CS4 in the regional haze SIP.

Based on NDDEQ's analysis, data from 2012–2018 was used to when determining representative operations for the facility because this seven-year period captured two high utilization years, two low utilization years, and three moderate utilization years. (See Table 42 below.)

Table 42. NBPL Compressor Station No. 4 Yearly Operational Data

Year	Operating Time (hrs)	Yearly Duty (MMBtu/yr)	Utilization
2012	8,494	1,262,480	97%
2013	8,346	1,328,516	95%
2014	4,116	594,188	47%
2015	3,713	499,517	42%
2016	7,161	1,052,922	82%
2017	6,822	1,048,291	78%
2018	6,909	983,570	79%
Average	**6,509**	**967,069**	**74%**

According to the North Dakota SIP "[t]he representative emissions rate (lb/MMBtu) was calculated from an average of 11 tests over the 7 years. These tests are considered representative of typical operations and anticipated future operations. Load during testing ranged from 58% to 95%, with an average of 81%. Emissions rates varied from 0.21 to 0.33 lb/MMBtu, with an average of 0.27 lb/MMBtu.3 The value of 0.27 lb/MMBtu is used as the starting point when determining the cost of compliance for add-on controls evaluated in 3.2." (See Table 43 below.)

Table 43. NBPL Compressor Station No. 4 Yearly Emissions Data

Year	Representative Emissions Rate (lb/MMBtu)[A]	Emissions Rate (lb/hr)	Calculated NO_X Emissions (tpy)
2012	0.27	40.3	171
2013	0.27	43.1	180
2014	0.27	39.1	80
2015	0.27	36.5	68
2016	0.27	39.8	143
2017	0.27	41.6	142
2018	0.27	38.6	133
Average	**0.27**	**39.9**	**131**

A. Average tested emission rate from testing completed from 2012-2018.

NDDEQ and NBPL analyzed the cost of one add-on control, which was SCR. The applicant considered water injection as a control option, but this was eliminated from consideration by NDDEQ. We agree with this determination given the modest NO_x control performance of water injection relative to SCR. Combustion controls were not considered because the "turbine manufacturer does not offer a burner retrofit option for lean premixed combustion." NDDEQ's cost effectiveness estimate of $13,040/ton of NO_x removed was based on an assumed 80% control-efficiency and a seven-year average of emissions. NBPL's cost-effectiveness estimate was slightly higher at $13,280/ton.

We re-evaluated the SCR cost-effectiveness calculations for CS4 that considered a range of operating/emission scenarios. The scenarios presented in our written feedback are as follows:

1. An analysis using the average emissions (2012-2018) utilized by NDDEQ, representing 74% utilization, 90% NO_x control efficiency, a 3.25% interest rate and 25-year equipment life.
2. An analysis using the average emissions (2012-2018) utilized by NDDEQ, representing 74% utilization, 80% NO_x control efficiency, a 3.25% interest rate and 25-year equipment life.
3. An analysis using maximum actual emissions (2013) and 90% NO_x control efficiency, a 3.25% interest rate and 25-year equipment life.
4. An analysis using maximum actual emissions (2013) and 80% NO_x control efficiency, a 3.25% interest rate and 25-year equipment life.
5. An analysis using potential-to-emit (PTE) at 8760 hours and max uncontrolled emission rate of 66.8 lb/hr (from the Title 5 permit) and 90% control (per the July 2021 EPA Clarification Memorandum—see explanation below).
6. An analysis using PTE at 8760 hours and max uncontrolled emission rate of 66.8 lb/hr (from the Title 5 permit) and 80% control (per the July 2021 EPA Clarification Memorandum—see explanation below).

As noted in our November 10, 2021 PowerPoint presentation, we also calculated several other operational scenarios. However, our conclusions provided in this written feedback rely on the results from the six scenarios listed above for several reasons.

First, when considering the seven years of operational data provided in the North Dakota SIP, in five of the seven years, CS4 operated at approximately 80% capacity or greater. It is anticipated that the facility will continue operation at this level in *most* years. The minimum operation scenario may not be representative of the facility's emissions on average, nor does it capture the potential maximum impact of the facility in Theodore Roosevelt NP. Second, the SIP notes that based on testing data, emission rates ranged from 0.21 up to 0.33 lb/MMBtu, which is at (or slightly above) the source's permitted limit of 66.8 lb/hr, indicating that at times, the facility operates up to it potential-to-emit.

In Section 4.5 of their July 2021 Clarification Memorandum, EPA addresses how utilization assumptions should be handled in a four-factor cost analysis:

> *“However, in some cases states may have projected significantly lower total emissions* ***due to unenforceable utilization or production assumptions*** *and those projections are dispositive of the four-factor analysis. For example, a state that rejected new controls solely based* ***on cost effectiveness values that were higher due to low utilization assumptions****. In this circumstance, an emission limit that requires compliance with only an emission rate may not be able to reasonably ensure that the source’s future emissions will be consistent with the assumptions relied upon for the reasonable progress determination.”*

We recommend that this issue is particularly important for “load-following” sources such as compressor stations, which can have significant year-to-year variation in utilization, as demonstrated in the seven years of operational data for NBPL’s CS4. For this reason, we recommend that operational assumptions used in cost analyses should reflect averages over a recent period as well as maximum *actual* operations, as this does not skew the cost-effectiveness estimates based unenforceable low-utilization assumptions. The PTE scenario reflects an upper bound of emissions given that the facility *may* operate up to this limit. When estimates indicate that the control technology may be cost-effective for each of these scenarios (average actual emissions, maximum actual emissions, and PTE), it is likely that the technology is economically feasible.

Our cost analysis results for each of these scenarios are presented in Table 44 below.

Table 44. NPS SCR Cost-Effectiveness Estimates for Six Operational Scenarios

Control Scenario	NPS Estimated Cost Effectiveness ($/ton)
7-year Average Emissions (2012-2018) 131 TPY—Approx. 74% Avg. Capacity 90% Control Efficiency	$3,688
7-year Average Emissions (2012-2018) 131 TPY—Approx. 74% Avg. Capacity 80% Control Efficiency	$4,120
Max Actual Emissions/Operating Year (2013) 180 TPY—95% Capacity 90% Control Efficiency	$2,800
Max Actual Emissions/Operating Year (2013) 180 TPY—95% Capacity 80% Control Efficiency	$3,126
PTE Emissions 293 TPY—100% Capacity 90% Control Efficiency	$1,844
PTE Emissions 293 TPY—100% Capacity 80% Control Efficiency	$2,056

Our revisions to the cost estimates indicate that SCR is cost-effective under a range of operating scenarios. Given the proximity of this source to Theodore Roosevelt NP, we recommend that NDDEQ require this cost-effective option to reduce NO_x emissions in the draft SIP.

4 Oil & Gas Area Source Recommendations

4.1 NPS Conclusions/Response

We recommend that North Dakota should address NO_x emissions from both point and upstream oil and gas area sources in this round of regional haze planning. Our recommendations on the three oil and gas point sources selected for four-factor analysis are provided in the preceding sections. This section addresses our recommendations for upstream oil and gas area sources, including the need for basin-wide stationary engine NO_x requirements. We recommend that such measures are and will continue to be necessary to address oil and gas emission impacts in Theodore Roosevelt NP.

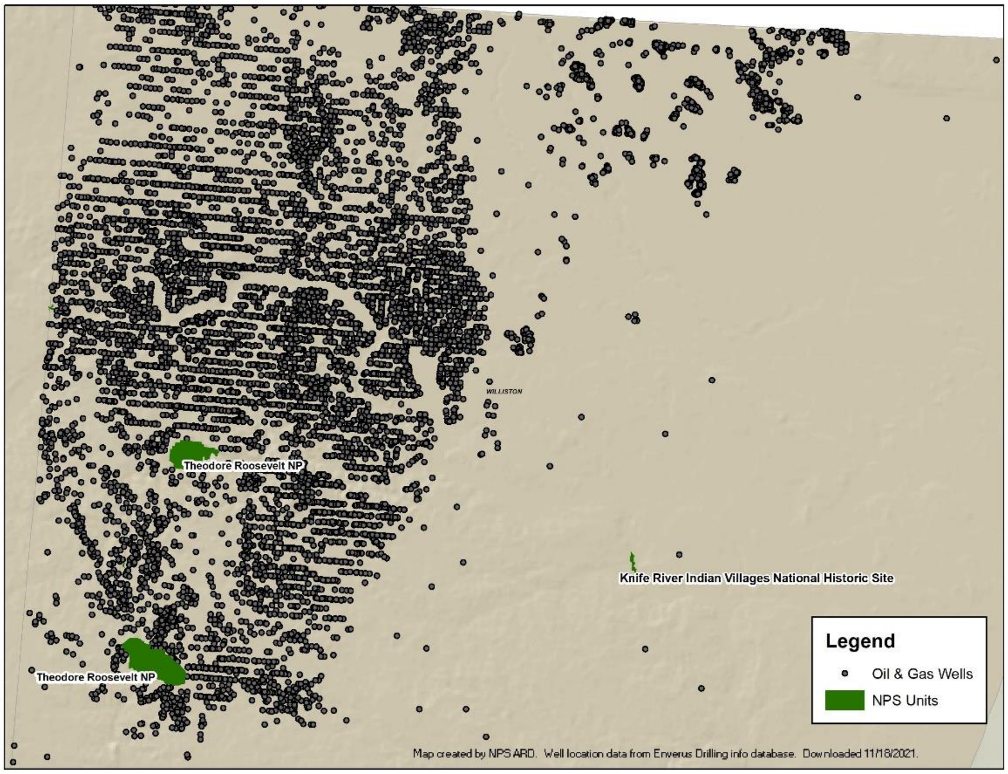
Emissions from oil and gas sources in the Williston Basin are significant. Based on the final future year oil and gas inventories developed by the Western Regional Air Partnership (WRAP) Oil and Gas workgroup, the Williston Basin has the highest NO_x emissions of any oil and gas basin within the WRAP region.[27] Using NDDEQ's 2028 projections in Table 15 of the SIP (which are slightly lower than the WRAP projections for oil and gas), future year 2028 NO_x emissions from point and area oil and gas sources are nearly double the anticipated 2028 NO_x emissions from North Dakota EGUs. In short, in the future 2028 NO_x emissions from the oil and gas industry will outpace emissions from EGUs, and to some degree, may be offsetting the benefit of reductions from the EGU source sector.

As of November 18, 2021, there were 22,166 active, drilled or permitted wells within the North Dakota portion of the Williston Basin.[28] As shown in Figure 21 below, the oil and gas development within the region surrounds Theodore Roosevelt NP.

[27] Final WRAP oil and gas inventories include the "Continuation of Historical Trends" projection as well as the Future Year Lower Scenario and Future Year Higher Scenario Spreadsheets. Final reports and spreadsheets for each future year inventory are available on the WRAP website at: https://www.wrapair2.org/ogwg.aspx. Estimates/comparisons drawn do not include the Texas side of the Permian Basin. Emissions from the Texas and New Mexico side of the Permian Basin combined likely rival those in the Williston Basin. Nonetheless, NOx emissions from upstream oil and gas sources near Theodore Roosevelt NP are substantial.

[28] Source: Enverus DrillingInfo database query, 11/18/2021. See https://www.enverus.com/about-enverus/.

Figure 21: Active ND Oil and Gas Well Surface Locations Near Theodore Roosevelt NP.



We agree that NO_x emissions are the primary concern from oil and gas operations. However, we disagree with NDDEQ's conclusion regarding oil and gas SO_2 emissions: "*SO2 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*."

According to the North Dakota SIP, oil and gas area and point sources currently account for 15,205 tons/year of SO_2 based on 2016-2018 emissions information. This is not trivial and we recommend that NDDEQ require the SO_2 emission reduction measures for the oil and gas point sources addressed in Sections 3.8 and 3.9 of this comment document.

With regard to oil and gas area source NO_x emissions, NDDEQ determined that:

> *"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*."*

As discussed below, we recommend that NDDEQ require NO_x reduction opportunities in this round of regional haze planning.

4.2 Engine Rules—NO_x Reduction Opportunity

The significant cumulative emissions from the upstream oil and gas source sector combined with the limited emissions footprint from any single wellsite points to the need for source category rules such as statewide engine rules. As noted by NDDEQ in the draft SIP, *"collectively, emissions from wellsite engines in North Dakota are the largest source of NOx emission from upstream oil and gas development."* Many states now implement state or region-wide requirements to limit NO_x emissions from area source engines. We encourage ND to consider similar rules and provide several examples here. Below is a summary of the best examples of statewide NO_x limits for NG-fired <u>lean-burn</u> engines:

- 0.5 g/hp-hr
  - TX requires this limit for all engines > 50 HP in their ozone nonattainment areas and a 33-county region.
  - PA requires this limit for all new and existing (permitted between 2013-2018) lean-burn engines > 500 HP
- 0.3 g/hp-hr
  - PA requires this limit for all new lean-burn engines > 2,370 HP
  - NM has permitted large (5,000 HP) engines at this limit
- 0.15 g/hp-hr (approximate conversion – limit is expressed as 11 ppmvd where 1 g/bhp-hr = approximately 73 ppmv for lean burn engines)
  - CA's South Coast Air Quality Management District and San Joaquin Valley Air Pollution Control District require this for all engines > 50 HP. These were phased-in requirements. It is assumed that post combustion control is necessary to achieve these limits. Furthermore, the SCAQMD prioritizes engine replacement with electric motors.
  - This limit is higher for engines used for gas compression in the SJVAPCD (65 ppmv or 0.89 g/hp-hr).

The options for retrofit or add-on controls that have the most significant emission reduction potential for engines include SCR and Low Emissions Combustion (LEC). The CSAPR TSD Assessment on Non-EGU NO_x Emission Controls[29] provides a good discussion of these control technologies and associated costs for lean-burn RICE. For example, with regard to SCR installation on lean-burn engines, the EPA developed linear regression equations for capital and annual costs based on engine HP (2001–2003$). The EPA relied on information in a 2012 OTC document (Technical Information Oil and Gas Sector Significant Stationary Sources of NO_x

[29]EPA, Final Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS Docket ID No. EPA-HQ-OAR-2015-0500; Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance Final TSD U.S. Environmental Protection Agency Office of Air and Radiation, August 2016.

Emissions) and a 2003 cost analysis completed by the CA South Coast Air Quality Management District in support of Rule 4702 when developing these linear regressions. NO_x reductions of approximately 90% or greater are achievable. EPA developed similar regression equations to estimate the costs of LEC retrofits.

Below is a summary of the best examples of statewide NO_x limits for NG-fired rich-burn engines:

- 0.20 g/hp-hr with the application of NSCR (a.k.a. 3-way catalyst)
  - PA requires this limit for all rich-burn engines > 500 HP. PA also has a 0.25 g/hp-hr limit for all existing and new rich burn engines > 100 HP and ≤ 500 HP
- 0.16 g/hp-hr
  - This limit is applicable in CA's South Coast Air Quality Management District and San Joaquin Valley Air Pollution Control District (see note below)

Please note, the CA and TX limits described above apply to rich and lean-burn engines alike (for rich burn engines, the 11 ppmvd limit in CA is approximately 0.16 g/hp-hr). It is anticipated that these limits will be achieved with NSCR. Colorado currently requires installation on NSCR on all rich-burn engines and recently approved a proposal that established NO_x limits for rich-burn engines of 0.8 g/hp-hr on existing engines (in service on or before November 14, 2020) and 0.5 g/hp-hr for new engines (in service, modified, or relocated after November 14, 2020).

We recommend that North Dakota consider engine rules similar to those implemented in Pennsylvania, Texas or California to reduce NO_x emissions from engines associated with upstream oil and gas operations.

4.3 NPS Oil and Gas Special Study

Data from an intensive study at Theodore Roosevelt National Park in 2013 and 2014 demonstrated that emissions from oil and gas activities are impacting ambient concentrations of nitrogen oxides, black carbon and VOCs in the region (Prenni et al., Atmospheric Chemistry and Physics, 16, 1401–1416, 2016). Wintertime haze episodes were observed during this same study at the North Unit of Theodore Roosevelt National Park. (Evanoski-Cole et al., Atmospheric Environment, 156, 77-87, 2017). Haze episodes were associated with periods of stagnation and were dominated by emissions from the Bakken region. Formation of ammonium nitrate, the dominant haze component, was most sensitive to nitric acid concentrations during early spring, suggesting capacity for further ammonium nitrate formation if nitrogen oxide emissions increase.

Bakken oil and gas activities have also led to an increase in regional fine soil and elemental carbon concentrations, as well as coarse mass from 2002 to 2015 (Gebhart et al., Journal of the Air & Waste Management Association, 68, 477–493, 2018).

Although oil and gas activities have led to increases in particulate matter, the impact has been at least partially offset by a concurrent reduction in emissions from coal-fired electric generating stations.

This information suggests that oil and gas emission are currently impacting air quality and anthropogenic haze levels in Theodore Roosevelt NP. Based on future year emission inventory projections, it is likely the impacts from oil and gas emissions will continue throughout the planning period. Again, we recommend that NDDEQ address this source sector and require NO_x emission reduction measures for the engine source category.

Our National Parks

North Dakota Regional Haze Consultation *– 11/10/2021*
NPS, Air Resources Division & Interior Regions 3, 4, & 5
North Dakota Department of Environmental Quality

11/10/2021 - NPS Formal Consultation Call with the North Dakota Department of Environmental Quality on Regional Haze SIP Development. Attendees:

- National Park Service
    - Wendy Ross, Theodore Roosevelt NP, ND
    - Maureen McGee-Ballinger, Theodore Roosevelt NP, ND
    - David Pohlman, Interior Region 3, 4, & 5 – St. Paul, MN
    - Kirsten King, Air Resources Division (ARD) – Denver, CO
    - Debbie Miller, ARD – Denver, CO
    - Melanie Peters, ARD – Denver, CO
    - Don Shepherd, ARD – Denver, CO
    - Andrea Stacy, ARD – Denver, CO
- North Dakota DEQ
    - David Stroh
    - David Glatt (NDDEQ Director),
    - Jim Semerad (Air Quality Director),
    - Rhannon Thorton (RH SIP team)
- Fish & Wildlife Service
    - absent
- U. S. Forest Service
    - Shannon Boehm
    - Jeff Sorkin
    - Jill Webster
    - Trent Wickman
- Environmental Protection Agency (EPA) Region 8
    - Clayton Bean
    - Jaslyn Dobrahner

NPS photos from left to right: Acadia NP, Denali NP, Yellowstone NP, Grand Canyon NP

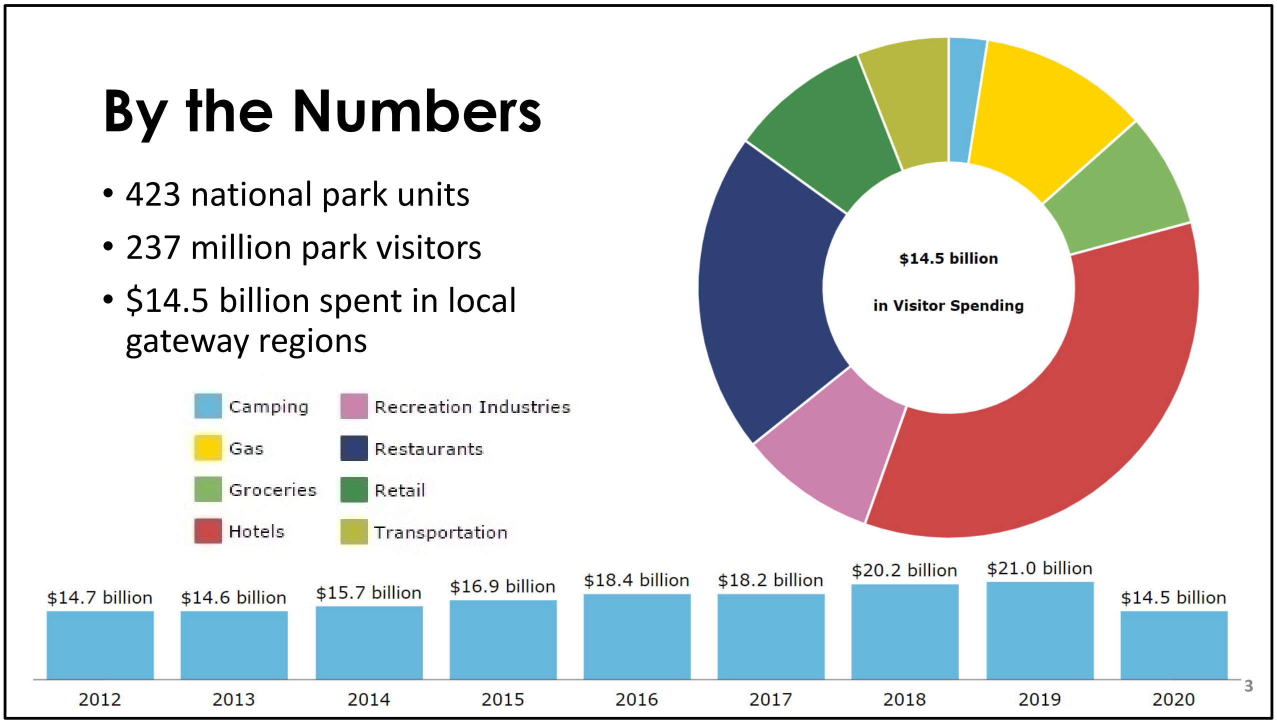
Agenda

- Welcome & Introductions
- NPS Regional Haze Background
- North Dakota Context
  - NPS Class I Areas affected
  - Emissions
- NPS SIP Feedback for North Dakota
  - Source Selection
  - Four-Factor Analysis Feedback
  - Long Term Strategy
- Next-Steps

2

We welcome discussion at any time during this presentation. Please feel free to ask questions or add information along the way.

NPS Photo of a bison, Badlands NP



Nationally, in 2020 NPS visitation and spending numbers were down due to the pandemic. It is pretty amazing that even in 2020 there were 237 million park visitors who generated $14.5 billion for the economy – perhaps emphasizing more than ever the economic value of National Parks to our country.

For comparison in 2019:

328 million park visitors spent an estimated $21 billion in local gateway regions while visiting National Park Service lands across the country.

These expenditures supported a total of
- 341 thousand jobs,
- $14.1 billion in labor income,
- $24.3 billion in value added, and
- $41.7 billion in economic output in the national economy.

https://www.nps.gov/subjects/socialscience/vse.htm

By the Numbers

- **48** Class I areas
- In **24** states
- **90%** of visitors surveyed say that scenic views are ***extremely*** to ***very*** important
- **100%** of visitors surveyed rate clean air in the **top 5** attributes to protect in national parks

List of Class I areas: https://www.nps.gov/subjects/air/npsclass1.htm

States with at least one Class I area:
AK, AZ, CA, CO, FL, HI, ID, KY, ME, MI, MN, MT, NC, ND, NM, OR, SD, TN, TX, UT, VA, VI, WA, WY

Statistics citation:
Kulesza C and Others. 2013. National Park Service visitor values & perceptions of clean air, scenic views, & dark night skies; 1988–2011. Natural Resource Report. NPS/NRSS/ARD/NRR—2013/622. National Park Service. Fort Collins, Colorado

NPS photo of Great Smoky Mountains NP, NC & TN

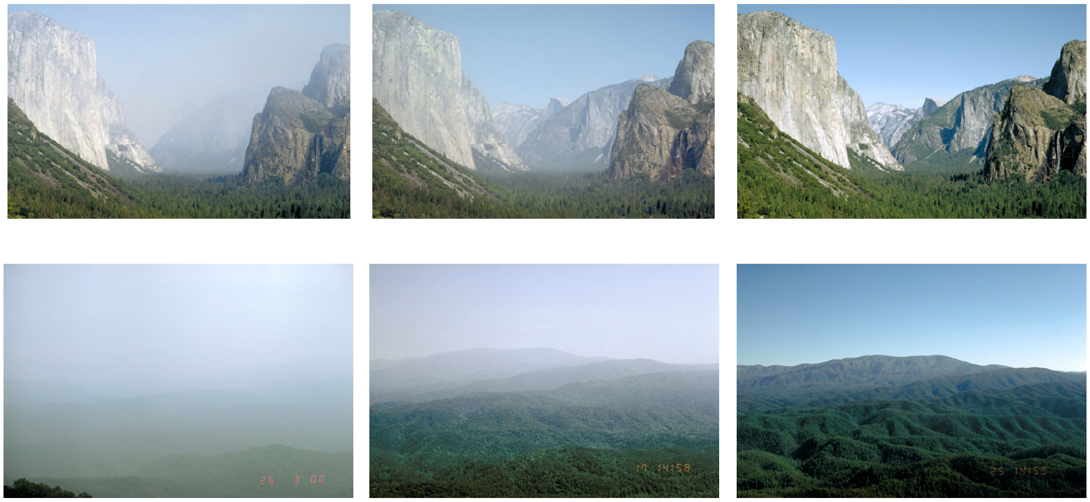
The NPS has an affirmative legal responsibility to protect clean air in national parks.

- 1916 NPS Organic Act: created the agency with the mandate to conserve the scenery, natural and cultural resources, and other values of parks in a way that will leave them unimpaired for the enjoyment of future generations. This statutory responsibility to leave National Park Service units "unimpaired" requires us to protect all National Park Service units from the harmful effects of air pollution.
- 1970 Clean Air Act: authorized the development of comprehensive federal and state regulations to limit emissions from both stationary (industrial) sources and mobile sources. The Act also requires the Environmental Protection Agency to set air quality standards.
- 1977 Clean Air Act Amendments: these amendments to the Clean Air Act provide a framework for federal land managers such as the National Park Service to have a special role in decisions related to new sources of air pollution, and other pollution control programs to protect visibility, or how well you can see distant views. The Act established a national goal to prevent future and remedy existing visibility impairment in national parks larger than 6,000 acres and national wilderness areas larger than 5,000 acres that were in existence when the amendments were enacted (Class I areas).
- 1990 Clean Air Act Amendments: created regulatory programs to address acid rain and expanded the visibility protection and toxic air pollution programs. The acid rain regulations began a series of regional emissions reductions from electric generating facilities and industrial sources that have substantially reduced air pollutant emissions.

NPS photo of Washington DC: https://npgallery.nps.gov/AirWebCams/wash

Visibility goal:

Restore natural conditions by 2064



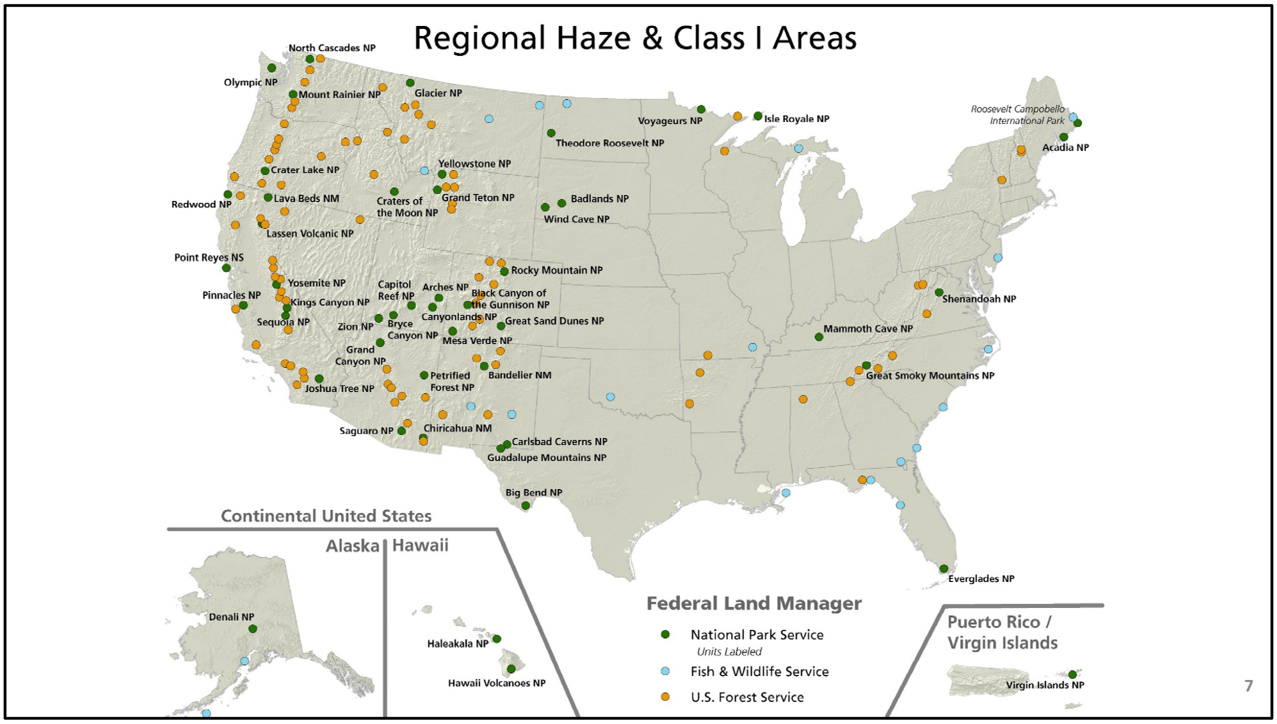
6

Yosemite NP, California and Great Smoky Mountains NP, Tennessee and North Carolina

Left to right images illustrate hazy to clear conditions.

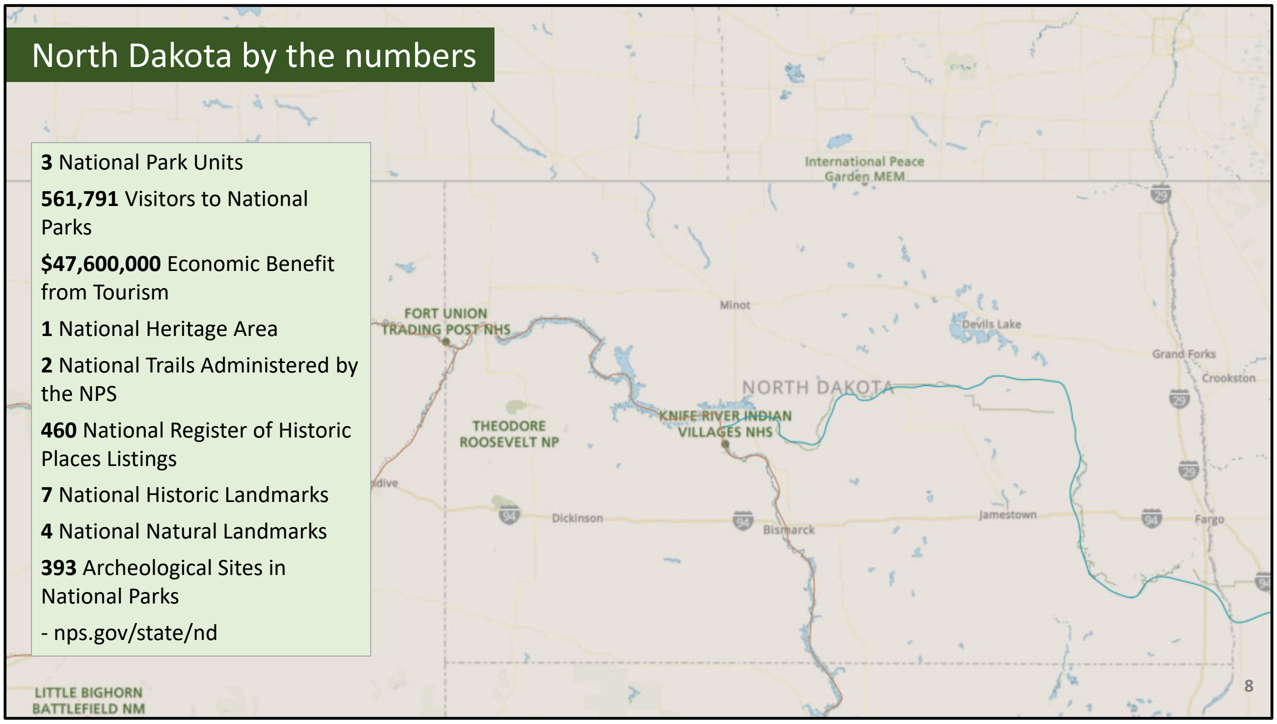
Haze obscures the color and detail in distant features.

NPS photos



As you know, the NPS is one of three Federal Land Managers (FLMs) with responsibility for the 156 Class I areas nationwide. The NPS manages 48 Class I areas. North Dakota is home to one NPS managed Class I area: Theodore Roosevelt NP. In addition, emissions from the state affect visibility at nearby Wind Cave and Badlands National Parks in South Dakota, and Voyageurs National Park, in Minnesota.

NPS map of Class I areas, 2020



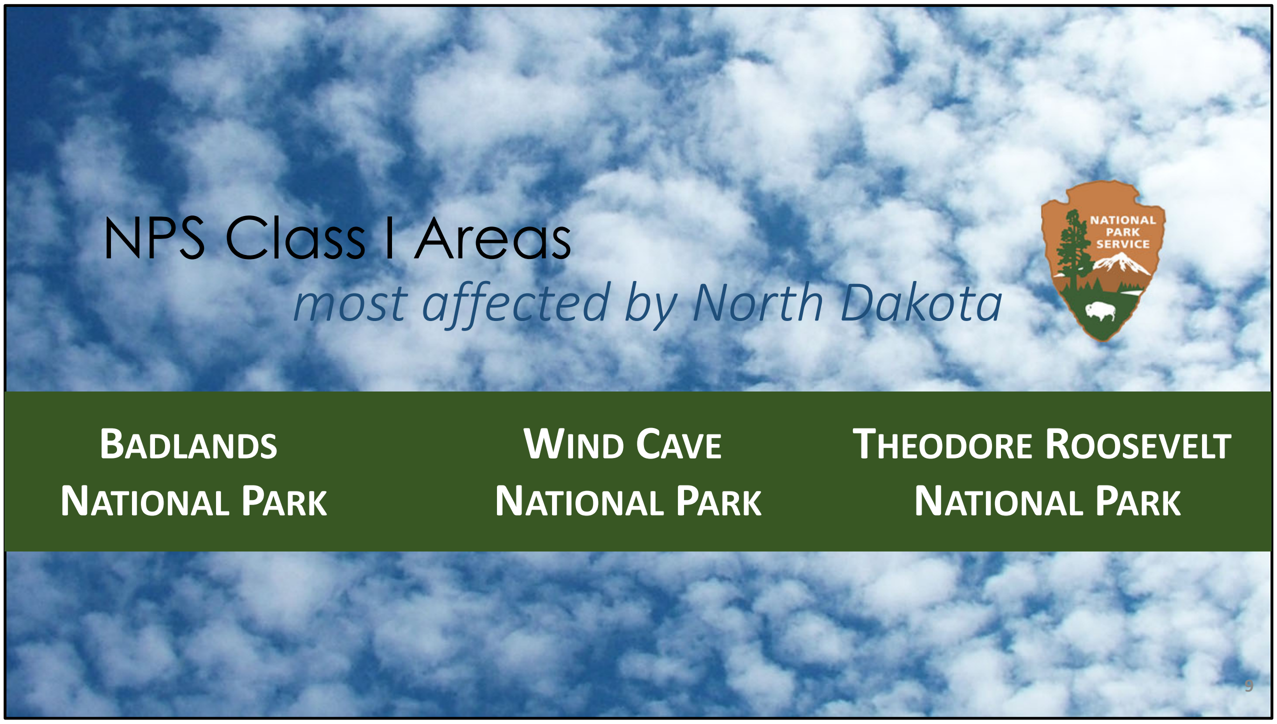
Parks managed by the National Park Service in North Dakota:

1. Fort Union Trading Post National Historic Site; ND and MT
2. Knife River Indian Villages National Historic Site
3. Theodore Roosevelt National Park

Lewis & Clark National Historic Trail; Sixteen States:
IA,ID,IL,IN,KS,KY,MO,MT,NE,ND,OH,OR,PA,SD,WA,WV

North Country National Scenic Trail; Seven States-New York to North Dakota
MI,MN,ND,NY,OH,PA,VT,WI

NPS information and map, 2021; https://www.nps.gov/state/nd/index.htm


NPS Class I Areas
most affected by North Dakota
NATIONAL PARK SERVICE
BADLANDS NATIONAL PARK
WIND CAVE NATIONAL PARK
THEODORE ROOSEVELT NATIONAL PARK
9

The rugged beauty of the Badlands draws visitors from around the world. These striking geologic deposits contain one of the world's richest fossil beds. Ancient horses and rhinos once roamed here. The park's 244,000 acres protect an expanse of mixed-grass prairie where bison, bighorn sheep, prairie dogs, and black-footed ferrets live.

Badlands National Park is home to many resilient creatures, including some of the most endangered species in North America. To survive the bitter winters and searing summers of the Great Plains, you need a good plan -- and the wildlife of the park have arrived at many ingenious solutions to the problems of exposure, heat, cold, and drought. Iconic animals as the American Bison, Black-footed Ferret and Rocky Mountain Bighorn Sheep are just a few of these species.

The largest mixed grass prairie in the Region is within Badlands NP.

A prairie is a large, open expanse of grasslands. A mixed-grass prairie is a grassland where grasses of many different heights grow. Mixed-grass prairies are the transition between eastern tall-grass prairies, where more rainfall means that taller grasses can grow, and western short-grass prairies, where the dry environment favors shorter grasses. In mixed-grass prairies, such as the grasslands surrounding Badlands National Park, grasses can range in height from ankle-high to waist-high.

Because they are in this transition zone, mixed-grass prairies have a greater number of plant species than any other type of prairie. There are over 400 plant species in Badlands National Park. Although trees, shrubs, and forbs grow in the Badlands, grasses dominate the landscape. The most common grass in the park is Western Wheatgrass, which grows one to three feet tall and is the state grass of South Dakota!

One interesting fact to note is the existence of the Badlands Wilderness Area composed of the Conata and Sage Creek Units. This vast 64,000 acre area is home to bison, prairie dogs, bighorn sheep and the most endangered land mammal in North America. Furthermore, it was critical to the designation of the Park as a class one airshed. The Park is also in the process of being designated as an International dark sky site. Badlands NP is truly a world class park!

NPS photos of the rugged Badlands Landscape, Rocky Mountain Bighorn lambs, and a Sego Lily.

Wind Cave NP is one of only 48 Clean Air Act designated Class I areas managed by the NPS.

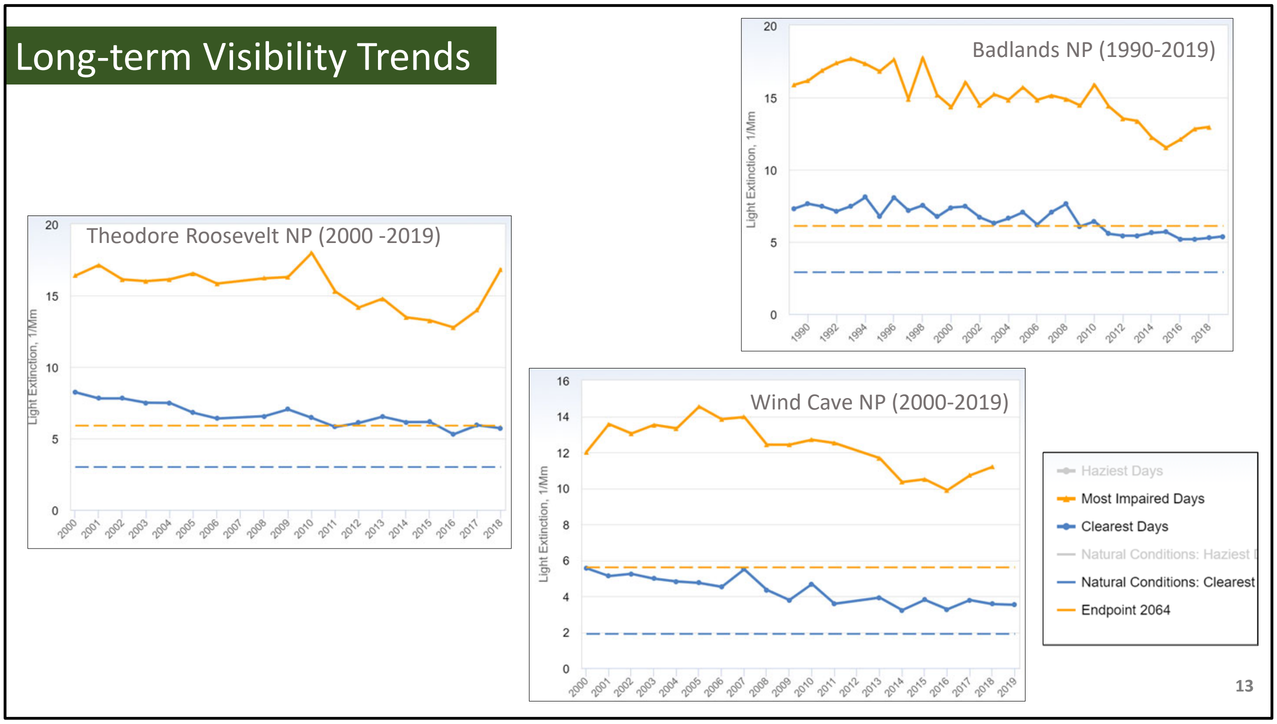
- The park was established in 1903 and is the 7th oldest national park in the NPS.
- The mapped portions of Wind Cave itself include over 157 miles of passages, making it one of the longest caves on the world. Exploration is still ongoing.
- The park is sacred to the Lakota people, who trace their origin and that of the buffalo as emerging from Wind Cave. Many other Native American Tribes also have cultural affiliations with the park.
- The surface area of the park is 34,000 acres in size and consists of a mixed grass prairie and ponderosa pine forest. Wildlife includes a genetically distinct bison herd, elk, prairie dogs, and the endangered black-footed ferret.
- There are over 30 miles of hiking trails at Wind Cave, allowing visitors to experience and view the prairie grasslands and its wildlife. The eastern views are very scenic, including the iconic Buffalo Gap and, on a clear day from the top of Rankin Ridge, you can see the Badlands.
- The park receives around 650,000 recreational visitors per year. 89% of visitors indicate they view wildlife and surface features during their visit and scenic vistas are the most highly rated value for a park visitor. Air quality is vital to maintaining this opportunity.
- Wind Cave has over 30 years of air quality monitoring, dating back to 1979. Currently we operate a NADP, CASTnet, IMPROVE, Purple Air, ozone, and particulate matters stations.
- Air quality is considered a vital resource in all management and planning documents. The park completed its Resource Stewardship Strategy in 2021, which states both long term and short-term goals regarding air quality.
- Short term goals include improving our understanding of resource sensitivity, outreach and education about the importance of air quality, and collaboration with partners and other management agencies to protect our airshed.
- The Park is in the process of receiving the designation of an International Dark Sky Park.
- Long-Term stewardship goals are to maintain the data record through continued in-park monitoring, to work with others to reduce pollutant deposition to below ecosystem critical loads, and to eliminate human-caused visibility impairment by the year 2064.

Moon Rise Over Boland Ridge, Wind Cave National Park. NPS Photo/Callie Tominsky

Theodore Roosevelt National Park comprises 70,447 acres of land in three separate units. The park was established in 1947 as Theodore Roosevelt National Memorial Park, to honor the memory of Theodore Roosevelt. The North Unit was added in 1948. In 1978 Congress redesignated the area as Theodore Roosevelt National Park and also established the 29,920-acre Theodore Roosevelt Wilderness within the park's North Unit and South Unit. This national park preserves a landscape—the North Dakota Badlands (also referred to as the Little Missouri River Badlands)—that had a profound effect on Theodore Roosevelt. He sought repose, solitude, and mental rejuvenation, and found all three during his time living at the Elkhorn Ranch, which is now the most historically significant portion of the park.

The North Dakota Badlands landscape is one of striking contrasts. The gently rolling mixed grass prairies of the Northern Great Plains suddenly give way to fantastically broken terrain. The landscape was created when soft soils and sedimentary rocks were broken down by the erosive forces of weather and the Little Missouri River and its tributaries. This rugged landscape of sheer cliffs, grassy plateaus, and colored bluffs of red, gray, tan, and golden hues seems inhospitable at first glance. Yet it is home to a variety of plants and an abundance of Northern Great Plains wildlife, including iconic animals of the West such as bison, elk, and bighorn sheep. All together, the three separate units of the park stretch across more than 45 miles of this landscape. And while the three units are geographically separate, they are all linked by the free-flowing Little Missouri River, the park's most important surface water resource.

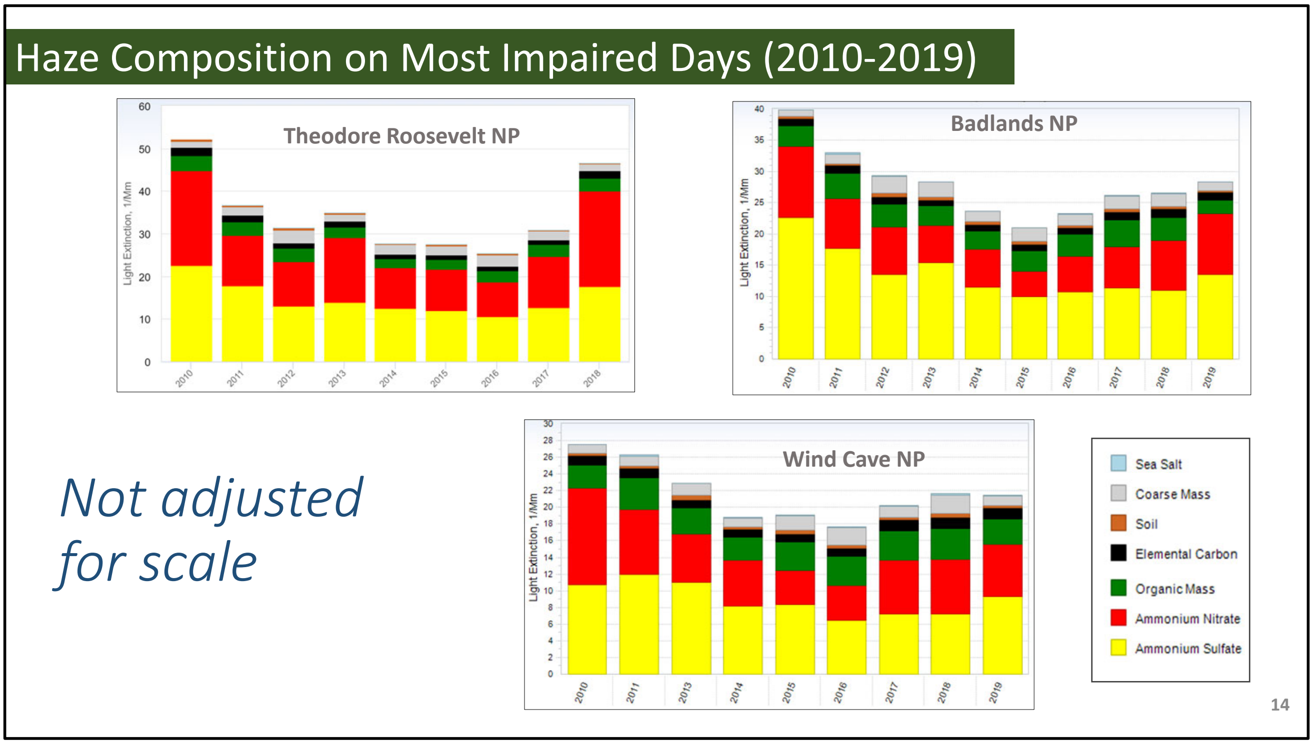
NPS Photo of River Bend Overlook, Theodore Roosevelt NP, by Dave Bruner.



There is a long history of visibility monitoring in our regional Class I areas.

- Theodore Roosevelt National Park has been monitoring visibility since 2000, the monitor for Badlands National Park began operation in 1990 while the monitor at Wind Cave National Park dates back to 2000. NPS staff support the operation of the IMPROVE monitoring network nationally and for many individual monitoring sites. This is how we keep track of the visibility conditions in our Class I areas and monitor progress.
- Graphs shown here highlight the annual average light extinction on most impaired days and on clearest days compared to the target condition (endpoint) for most impaired days and estimated natural conditions on clearest days. These charts show long term improvement and recent increases in haze on most impaired days.

Long term visibility trend graphs generated from:
http://views.cira.colostate.edu/fed/Express/AqrvTools.aspx



These annual extinction bar graphs show total haze composition over the past 10 years at Theodore Roosevelt, Badlands, and Wind Cave National Parks. These Class I areas have not seen dramatic improvements in light extinction on most impaired days over the past 10 years. In fact, the past few years in all three parks have seen increasing levels of haze. This may not be a statistically significant trend yet, but it is certainly something that we are keeping an eye on. Ammonium sulfate and ammonium nitrate are mostly responsible for recent increases in haze.

Most-impaired days annual light extinction composition stacked bar graphs from:
http://vista.cira.colostate.edu/Improve/aqrv-summaries/

North Dakota by the numbers

Haze Causing Emissions

North Dakota

- Has the **biggest influence** on haze in NPS Class I areas **of any state**.
  - Based on a cumulative Q/d analysis using recent emissions inventory data.
- Among all states, North Dakota EGU emissions are:
  - **Top 10** for SO_2 (34,383 tpy) and
  - **Top 5** for NO_x (29,897 tpy)
- Emissions from **oil and gas** sources in the ND portion of the Williston Basin are the highest in the WRAP region.

2017 NEI and 2019 CAMD inventory data were used to assess the $NO_x + SO_2$ (Q) divided by distance (d) visibility impact surrogate for all point sources to each NPS managed Class I area in the country. The top 80% contributing to each Class I area were initially recommended by NPS for evaluation as part of reasonable progress. As part of a prioritization exercise, we summed the Q/d metric for each facility with respect to NPS Class I areas and tallied by state. Based on this, North Dakota ranks number one with respect to cumulative Q/d.

EGU emissions rankings are from the CAMD database and oil and gas emissions data are from the WRAP oil and gas workgroup products.

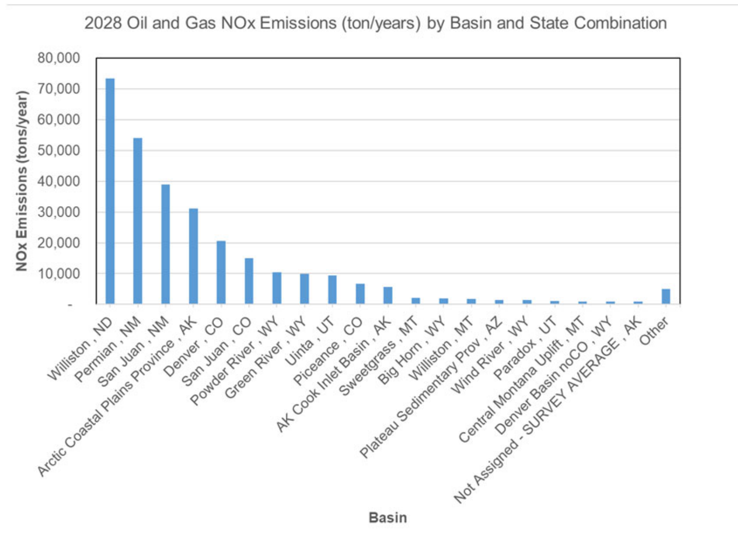
NPS Photo of Elk, Theodore Roosevelt NP

North Dakota by the numbers

Haze Causing Emissions

- The oil and gas source sector is a significant source of both NO_x and SO_2 emissions in North Dakota.
- Oil and gas emissions are impacting visibility in Theodore Roosevelt NP.
- Future year 2028 NO_x emissions from point and area oil and gas sources are nearly double future year EGU NO_x emissions.
- While EGU SO_2 emissions are projected to decrease, SO_2 emissions from oil and gas area sources are projected to increase.

WRAP Oil and Gas Workgroup Future Year Emissions—Low Scenario



16

Future year oil and gas NO_x emissions graph from the WRAP oil and gas workgroup low development scenario emission inventory.

WESTAR_OGWG_Future_Emissions_Inventory_Low_Scenario_webdist_121619_nolink.xlsx
Available at: https://www.wrapair2.org/ogwg.aspx

North Dakota Draft SIP Feedback

Source Selection

North Dakota selected all nine NPS-recommended sources for four-factor analysis plus Northern Border

1. Coyote
2. Antelope Valley
3. Coal Creek
4. Milton R Young
5. Leland Olds
6. R M Heskett
7. Great Plains Synfuels Plant
8. Tioga Gas Plant
9. Little Knife Gas Plant
10. Northern Border

❖ *Oil & Gas Area Sources*

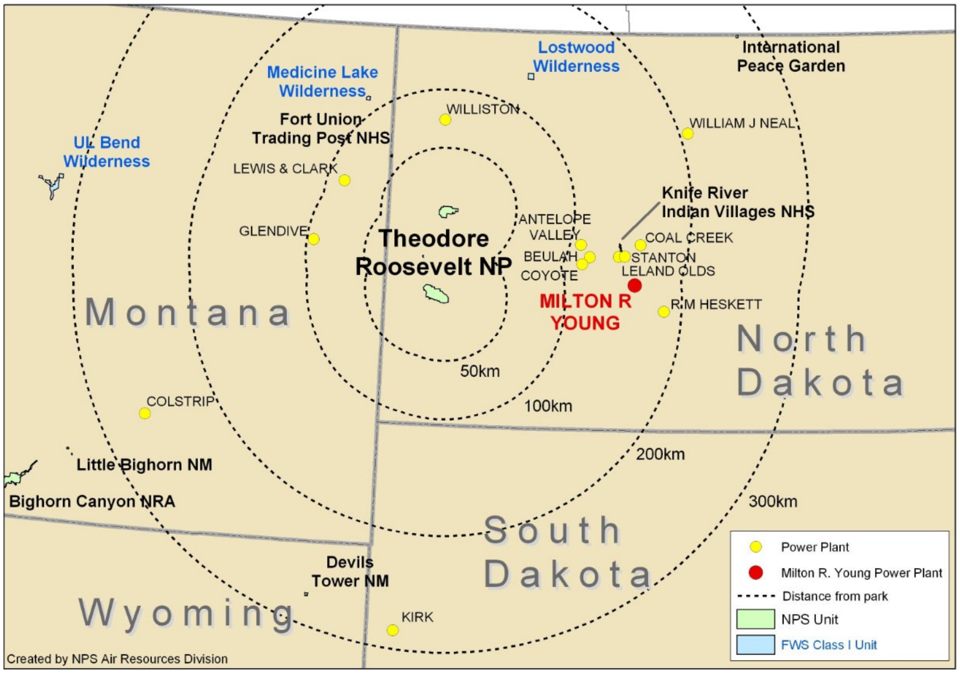
We appreciate that ND selected all of the NPS recommended point sources.

We also recommended that ND consider opportunities to address haze causing emissions Oil and Gas area sources when we met as part of early engagement.

We have reviewed each of the four factor analyses and will spend the next portion of this presentation providing our feedback and recommendations on these and asking questions where they remain.

*Note, we have slightly re-arranged this list from the order in the draft SIP to group the source sectors. Highlighting indicates the division of review among NPS staff who will be presenting today.

NPS Photo of Blanket flower, Wind Cave NP



Electric Generating Units Near Theodore Roosevelt NP

18

NPS Map – Note, this map was created for a previous review focused on Milton R Young. For this purpose, we present the map to highlight the proximity of EGUs to Theodore Roosevelt NP and not to single that facility out specifically.

Cost of Control

- Overarching EGU Feedback

- The 4FAs provided are the best we have seen. However, they suffer from some common errors:
  - Contingency Cost multiplier of 20% is too high—CCM recommends 10%
  - Inclusion of Owners Costs
  - Interest Rates is too high without justification—CCM recommends current prime (3.25%)
  - Remaining Useful Life is too short—CCM recommends 20 years for SNCR and 30-years for scrubbers and SCR unless limited by a federally-enforceable condition.
  - Inclusion of Property Taxes

North Dakota Draft SIP Feedback

Technical Feasibility

- SCR on North Dakota lignite

- SCR is available.
- SCR is applicable because it is in use on coal-fired EGUs, including lignite-fired EGUs (in Texas)
- The critical issue is SCR deactivation due to catalyst poisoning. Catalyst deactivation is an economic issue.
- We agree with ND that TE-SCR is technically-feasible on tangentially-fired and wall-fired boilers burning ND lignite. Has SCR been tested in a tail-end configuration on a ND lignite-fired cyclone boiler?

North Dakota Draft SIP Feedback

Coyote Station

- Electric Generating Unit

- Of 3,317 EGUs in CAMD in 2020, Coyote ranked #5 for SO_2 and #4 for NO_x.
- All of the SO_2 control options, including replacement of the existing scrubbers, are reasonable on an average $/ton basis. The incremental cost of a new WFGD may be prohibitive.
- Replacement of the existing dry scrubber could reduce SO_2 emissions by almost 11,600 tpy versus baseline emissions.
- All of the NO_x control options evaluated are reasonable.
- Addition of RRI to Optimized SNCR could reduce NO_x emissions by almost 4,000 tpy versus baseline emissions.
- Addition of SCR could reduce NO_x emissions by almost 5,700 tpy versus baseline emissions.

North Dakota Draft SIP Feedback

Antelope Valley Station

- Electric Generating Unit

- Of 1,167 facilities in CAMD in 2020, AVS ranked #15 for SO_2 and #64 for NO_x.
- All of the SO_2 control options, including replacement of the existing scrubbers, are reasonable.
- Replacement of the existing dry scrubbers with modern new scrubbers could cost-effectively reduce facility SO_2 emissions by over 10,000 ton/yr.
- Addition of SNCR would cost less than $7,000/ton.
- Addition of SCR would have an average cost lest than $9,000/ton with incremental cost (versus SNCR) of less than $10,000/ton.
- Addition of SNCR could reduce facility NO_x emissions by 700 ton/yr while addition of SCR could reduce facility NO_x emissions by over 2,300 ton/yr.

22

North Dakota Draft SIP Feedback

Coal Creek Station

- Electric Generating Unit

- *Note – Still Under Review

North Dakota Draft SIP Feedback

Milton R. Young Station

- Electric Generating Unit

- Of 1,179 facilities in CAMD in 2019, MRYS ranked #93 for SO_2 and #12 for NO_x
- We evaluated addition of TE-SCR to Units 1 & 2 and found it cost-effective and reduces plant NO_x emissions by over 6,800 tpy.
- The scrubber on Unit 1 is 96.5% efficient. The scrubber modifications evaluated appear to be cost-effective.
- The scrubber on Unit 2 is 93.3% efficient and recent emission rates have been increasing. Improved scrubber efficiency should be evaluated.
- *Note – *Still Under Review*

North Dakota Draft SIP Feedback

Leland Olds Station (1 of 2)

- Electric Generating Unit

- Of 1,167 facilities in CAMD in 2020, LOS ranked #105 for SO_2 and #48 for NO_x.
- January 2021 Hg emissions were: Unit 1= 1.01 lb/Trillion Btu (TBtu), Unit 2 = 5.02 lb/TBtu.
- Unit 1 SO_2 emission rates have been increasing.
- All of the NO_x control options evaluated are reasonable.
- The existing SNCR on Unit 2 is only about 4% effective. Adding RRI to SNCR could reduce NO_x emissions by almost 1,200 tpy
- We evaluated addition of TE-SCR to Unit 2 and found it cost-effective. This strategy could reduce NO_x emissions by over 3,500 tpy compared to existing controls.

North Dakota Draft SIP Feedback

Leland Olds Station (2 of 2)

- Electric Generating Unit

- We evaluated addition of TE-SCR to Unit 2 and found it cost-effective
- The annual average cost effectiveness of adding RRI to SNCR at LOS Unit 2 would be acceptable in the context of the thresholds used by AR, TX, CO, NM, and OR. This strategy could reduce NO_x emissions by almost 1,200 tpy.
- The annual average cost effectiveness of adding SCR at LOS Unit 2 would be acceptable in the context of the thresholds used by AR, TX, CO, NM, and OR. This strategy could reduce NO_x emissions by over 3,500 tpy compared to existing controls.

North Dakota Draft SIP Feedback

R. M. Heskett

- Electric Generating Unit

- It is our understanding that the plant will cease burning coal in 2022 and install an 88 MW natural gas-fired simple-cycle combustion turbine.
- The permitted sum of future annual SO_2 (12 tpy) and NO_x (315 tpy) divided by the distance 185 km) to THRO is 1.8.
- We agree that no 4FA is needed.

North Dakota Draft SIP Feedback

Great Plains Synfuels Plant

- Coal Gasification & Fertilizer Facility

- Emissions units include three 763 MMBtu/hr Riley boilers and two 169 MMBtu/hr superheaters with common stack
  - Boilers burn waste gas, stink gas, tar oil, naphtha/phenol (N/P) blend, lock gas, medium BTU purge gas, and SNG
- Baseline emissions of 3,003 tons SO_2/year and 2,454 tons NO_x/year; q/d=61
- Analysis of tail-end SCR suggests potential for catalyst poisoning
  - Are concentrations of alkalis/other contaminants known?
- SCR analysis uses 5.5% interest rate (vs. bank prime) and 20-year life
- Analysis lacks details on major costs such as equipment and labor
- SIP suggests facility may discontinue gasification process

28

North Dakota Draft SIP Feedback

Hess Tioga Gas Plant (1 of 2)

- Natural Gas Processing Facility

- The Hess Tioga Gas Plant is located approx. 91 km from Theodore Roosevelt NP.
- ND evaluated the costs of LEC for 5 of the 7 RICE. (SCR was not evaluated for the RICEs).
  - ND estimated the cost effectiveness of LEC to be $8,784
  - ND estimates seem high relative to other information (i.e., EPA cost estimates to support analysis of control options under the CSAPR and Ozone Transport Commission Information on control techniques for the oil and gas industry).
  - Based on this information, costs to retrofit the Tioga RICE may range from $500-$1,400/ton (up to $6,899/ton in the lowest emission year).
- For the sulfur recovery unit tail gas incinerator, ND evaluated the costs of tail gas treatment (SCOT process) and Acid Gas Injection (AGI).

29

Hess Tioga Gas Plant (2 of 2)

- Natural Gas Processing Facility

- Although it was found to be technically feasible, ND did not evaluate the costs of tail gas FGD.
  - A cost analysis should be completed for all technically feasible options to determine cost effectiveness relative to other technologies
- According to ND estimates AGI is very cost effective at $3,248/ton and $4,443/ton.
  - We recommend ND implement cost effective options to reduce SO_2 emissions
- ND and the company estimated tail gas treatment cost effectiveness at approximately $11,000/ton
  - The Hess analysis used a 10% interest rate and 10-yr equipment life
  - The NPS re-evaluated the cost of this control to correct identified analysis issues and estimated a cost-effectiveness of $4,978/ton, which is very cost effective.

Petro-Hunt Little Knife Gas Plant (1 of 2)

- Natural Gas Processing Facility

- Little Knife Gas Plant (LKGP) is located 39 km from Theodore Roosevelt National Park, the closest Class I area.
- The major emissions source onsite is sulfur recovery unit (SRU) tail gas incinerator. NO_x emissions from the source are minimal.
- Acid gas injection (AGI) was the only technically feasible option considered and would eliminate all SO_2 emissions from the source.
- Both LKGP and ND evaluated the costs of drilling an AGI well. ND's cost effectiveness estimates were considerably lower than LKGP's; likely due to errors in LKGP cost analysis.
- NPS re-analyzed LKGP's estimates and derived cost effectiveness estimates that are comparable with North Dakota's.

North Dakota Draft SIP Feedback

Petro-Hunt Little Knife Gas Plant (2 of 2)

- Natural Gas Processing Facility

- North Dakota's estimates for AGI are very cost-effective
- We recommend North Dakota implement these cost-effective controls

Control Technology	Emissions (tons/year)	Annual Emission Reduction (tpy)	Annualized Total Cost ($)	Cost of Compliance ($/ton)
Existing SRU (baseline)	307			
Acid Gas Injection	0	307	490,009	1,598
Acid Gas Injection[A]	0	307	628,523	2,050

North Dakota Draft SIP Feedback

Northern Border Pipeline Company

- Compressor Station No. 4

- NBPL is located 18 km from Theodore Roosevelt National Park
- The 20,000 HP turbine is not equiped with recent NO_x controls.
- The 4FA found SCR and Water injection to be the only feasible controls for the turbine.
- ND estimated a cost effectiveness of $13,040/ton. NBPL estimated a cost-effectiveness of $14,435/ton. Can you please clarify the differences between the ND and NBPL cost analyses?
- NBPL assumed a 10-year equipment life, 7% interest and 80% control efficiency.

33

Northern Border Pipeline Company

- Compressor Station No. 4

- We re-evaluated the costs of SCR using the bank prime rate and a longer equipment life under various operational and capacity scenarios.
- Although the costs vary among scenarios, generally, we found SCR to be cost effective even with reduced capacity.

Control Scenario	NPS Estimated Cost Effectiveness
Max Throughput Year—2012 at 97% Capacity 90% control efficiency 0.325 lb/MMBtu uncontrolled emission rate	$2,051
Max Throughput Year—2012 at 97% Capacity 80% control efficiency 0.325 lb/MMBtu uncontrolled emission rate	$2,288
Max Throughput Year—2012 at 97% Capacity 90% control efficiency 0.27 lb/MMBtu uncontrolled emission rate	$3,136
Max Throughput Year—2012 at 97% Capacity 80% control efficiency 0.27 lb/MMBtu uncontrolled emission rate	$3,505
Min Throughput Year—2015 at 42% Capacity 90% control efficiency 0.325 lb/MMBtu uncontrolled emission rate	$4,189
Min Throughput Year—2015 at 42% Capacity 80% control efficiency 0.325 lb/MMBtu uncontrolled emission rate	$4,683

North Dakota Draft SIP Feedback

Oil & Gas Area Source

- SIP Conclusions for Oil and Gas Area Sources:

- Collectively, emissions from wellsite engines in North Dakota are the largest source of NO_x emission from upstream oil and gas development.
- However, ND determined individual engine controls are not reasonable during this planning period given:
  - The limited emissions footprint from any single wellsite and;
  - Relatively small contribution to visibility impairment from this sector.

Oil & Gas Area Source

- NPS Response to SIP Conclusions for Oil and Gas Area Sources:

- Significant cumulative emissions coupled with a limited footprint from any single wellsite points to the need for statewide rules that target the oil and gas source sector.
- Many states now implement state or region-wide requirements to limit NOx emissions from area source engines. We encourage ND to consider similar rules.
- NPS study points to visibility impairment from the oil and gas source sector.

North Dakota Draft SIP Feedback

Oil & Gas Area Source

-Examples of Engine Rules from Other States:

Pennsylvania Requirements Existing* Engines

Engine Type	Rated bhp	NOx Limit
Lean-burn	≤100	2.0 g/bhp-hr
	>100 to ≤500	1.0 g/bhp-hr
	>500	0.50 g/bhp-hr
	>1,000	0.50 g/bhp-hr
Rich-burn	>100 to ≤500	0.25 g/bhp-h
	>500	0.20 g/bhp-h
	>1,000	0.20 g/bhp-h

*Applies to any source permitted under GP-5 on or after Feb 2, 2013 but prior to Aug 8, 2018

- Texas requires engines to meet a 0.5 g/hp-hr limit for all engines > 50 HP in their ozone nonattainment areas and a 33-county region.
- CA's South Coast Air Quality Management District and San Joaquin Valley Air Pollution Control District require all engines > 50 HP to meet a 0.15 g/hp-hr NOx limit (approximate conversion – limit is express as 11 ppmvd where 1 g/bhp-hr = 73 ppmv for lean burn engines)

North Dakota Draft SIP Feedback

Oil & Gas Area Source

- Theodore Roosevelt Special Study (1 of 3)

- Data from an intensive study at Theodore Roosevelt NP in 2013 and 2014 demonstrated that emissions from oil and gas activities are impacting ambient concentrations of nitrogen oxides, black carbon, and VOCs in the region

(Prenni et al., Atmospheric Chemistry and Physics, 16, 1401–1416, 2016)

NPS photo, Theodore Roosevelt NP

Oil & Gas Area Source

- Theodore Roosevelt Special Study (2 of 3)

- Wintertime haze episodes were observed during this same study at the North Unit of Theodore Roosevelt NP.

  (Evanoski-Cole et al., Atmospheric Environment, 156, 77-87, 2017)
  - Haze episodes were associated with periods of stagnation and were dominated by emissions from the Bakken region.
  - Formation of ammonium nitrate, the dominant component, was most sensitive to nitric acid concentrations during early spring, suggesting capacity for further ammonium nitrate formation if nitrogen oxide emissions increase.

NPS Photo, Theodore Roosevelt NP

North Dakota Draft SIP Feedback

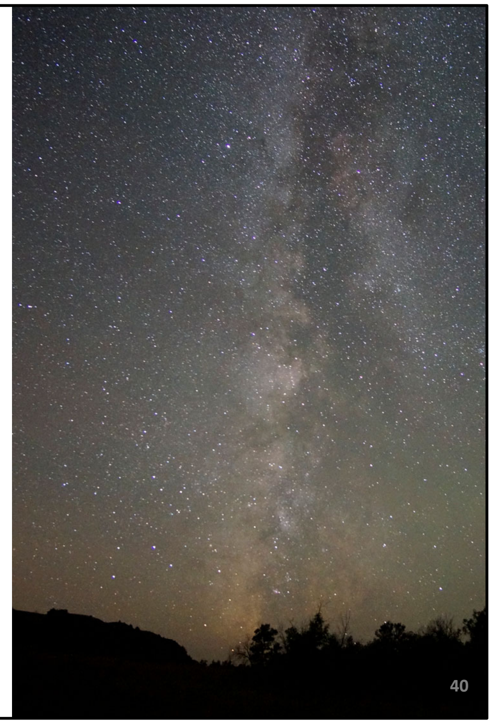
Oil & Gas Area Source

- Theodore Roosevelt Special Study (3 of 3)

- Bakken oil and gas activities have also led to an increase in regional fine soil and elemental carbon concentrations, as well as coarse mass from 2002 to 2015

  (Gebhart et al., Journal of the Air & Waste Management Association, 68, 477–493, 2018)

  - Although oil and gas activities have led to increases in particulate matter, the impact has been at least partially offset by a concurrent reduction in emissions from coal-fired electric generating stations.



40

NPS Photo, Theodore Roosevelt NP

North Dakota Draft SIP Feedback

Long Term Strategy

- Correlation of Visitation and Most Impaired Days

- SIP states that focusing on the most impaired days for Theodore Roosevelt NP will not "meaningfully improve visibility or a visitor's experience" because these days occur primarily during months with lower visitation.
  - Clean Air Act set national goal of "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I federal areas which impairment results from man-made air pollution".
  - RHR requires that the long-term strategy and RPG must provide for improvement in visibility for the most impaired days
  - NPS is required to conserve resources "in a manner and by such means as will leave them unimpaired" for future generations (16 U.S.C. §1)
  - Protecting visibility is no less important on days with lower visitation

North Dakota Draft SIP Feedback

Long Term Strategy

- Cost Effectiveness Thresholds (1 of 2)

- ND has not shared a cost effectiveness threshold for this planning period.
- In the first planning period, NDDEQ set BART cost-effectiveness thresholds at $4,100/ton average and $7,300/ton incremental based upon 2011$.
- We adjusted those thresholds to $4,200/ton average and $7,500/ton incremental based upon based upon the 2019 CEPCI.
- We are seeing several states with higher thresholds for average cost-effectiveness:
  - AZ @ $4,000 - $6,500/ton
  - TX @ $5,000/ton
  - AR @ $5,000/ton for EGUs
  - WA @ 6,250/ton for NOX on industrial boilers
  - NM @ $7,000/ton
  - CO & OR @ 10,000/ton

North Dakota Draft SIP Feedback

Long Term Strategy

- Cost Effectiveness Thresholds (2 of 2)

- EPA has expressed caution regarding using BART costs for Reasonable Progress:

  Given the differences between the BART factors and RP factors and the nature of the applicability criteria that would trigger BART and RP analyses, we do not necessarily consider the cost-effectiveness and visibility benefit values from BART determinations to be directly comparable to RP analyses

- It is generally accepted that the cost-effectiveness threshold for Reasonable Progress will be higher as smaller emission units are considered.

43

ENVIRONMENTAL PROTECTION AGENCY, 40 CFR Part 52, [EPA–R09–OAR–2013–0588; FRL–9912–97– OAR], Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, ACTION: Final rule. September 3, 2014

North Dakota Draft SIP Feedback

Long Term Strategy

- Visibility benefit and URP

SIP suggests that additional measures not needed because trends in haze on most impaired days are going down

- Overall trends beginning in 2000 are down, but haze increased on most impaired days 2016-2018; continuous improvement will be needed to meet the 2064 goals
- SIP 2064 projection uses adjusted endpoint; this endpoint may change in the future

44

Note, we intend to elaborate on these concepts in our follow up documentation.

In addition to the points above, it is not appropriate to look at visibility benefits of emission reductions in comparison with 2028 “dirty” background. Many small incremental improvements will be needed in this and subsequent planning periods in order to reach the goal of no human caused impairment by 2064. This “clean” condition is the one against which potential improvements are more appropriately considered.

NPS Photo, Wind Cave NP

North Dakota Draft SIP Feedback

Long Term Strategy

- Visibility benefit and URP

SIP indicates THRO progress on most impaired days is below adjusted uniform rate of progress

- The glideslope is a planning tool.
- RHR expects states to make continuous progress based upon the four-factor analysis. EPA has made it clear that being under the glideslope is not a reason to dismiss otherwise reasonable controls.
- The goal of the RHR is natural conditions, and no Class I area in the state or downstream has reached that goal yet.

45

Note, we intend to elaborate on these concepts in our follow up documentation.

In addition to the points above, it is not appropriate to look at visibility benefits of emission reductions in comparison with 2028 "dirty" background. Many small incremental improvements will be needed in this and subsequent planning periods in order to reach the goal of no human caused impairment by 2064. This "clean" condition is the one against which potential improvements are more appropriately considered.

North Dakota Draft SIP Feedback

Long Term Strategy

- Visibility benefit and URP

- Perceptibility, or visibility benefit, is not a requirement for reasonable progress. EPA's 2019 guidance (§II.B.4.g) explicitly states that modeled benefits must be compared to a clean background (e.g., 2064) rather than a dirty background (e.g., 2028) in order to appropriately gauge the potential visibility benefit to overall progress.
- The cumulative benefit of emission reductions over time will be necessary to achieve the Clean Air Act and Regional Haze Rule goal to "prevent future and remedy existing visibility impairment" in Class I areas.

Next Steps

- Thank you for meeting with us!
- Please share:
  - Anticipated SIP schedule
  - How you will respond to NPS comments
- Please let us know:
  - When public comment period opens
  - If/when a public hearing will be held
- The NPS will:
  - Email call summary & detailed comments
    - By **November 19, 2021**
  - Share our comments with EPA Region 8

47

The NPS will submit an email summary of our November 8, 2021 consultation call along with final review comments by November 19, 2021.

We ask that the state notify us when the draft SIP will be open for public review and comment, and alert us to any public hearing dates.

Please reach out to us with any questions.

For any formal notifications of public documents, please include the above list of NPS staff.

The NPS values clean air and clear views and recognizes these as essential to our visitor experience and the very purpose of our Class I areas. We recognize opportunities for significant progress to be made in this planning period as we strive toward the goal of unimpaired visibility. We welcome future opportunities to engage with North Dakota and work together on efforts to reduce haze causing pollution and address regional haze in our national parks.

NPS photo, Theodore Roosevelt NP

D.2.b – U.S. Forrest Service Comments

United States Department of Agriculture
Forest Service
Region One

Northern Region
26 Fort Missoula Road
Missoula, MT 59804

File Code: 2580
Date: November 16, 2021

L. David Glatt, P.E.
Director, North Dakota Department of Environmental Quality
4201 Normandy Street
Bismarck, ND 58503-1324

Dear Mr. Glatt:

On September 20th, 2021, the State of North Dakota submitted a draft Regional Haze State Implementation Plan describing your proposal to continue improving air quality by reducing regional haze impacts at mandatory Class I areas across the region. We appreciate the opportunity to work closely with your State through the initial evaluation, development, and subsequent review of this plan. Cooperative efforts such as these ensure that, together, we will continue to make progress toward the Clean Air Act's goal of natural visibility conditions at our Class I areas.

This letter acknowledges that the U.S. Department of Agriculture, U.S. Forest Service, has received and conducted a substantive review of your proposed Regional Haze State Implementation Plan. This review satisfies your requirements under the federal regulations 40 C.F.R. § 51.308(i)(2). Please note, however, that only the U.S. Environmental Protection Agency (EPA) can make a final determination about the document's completeness, and therefore, only the EPA has the authority to approve the document.

We have attached comments to this letter based on our review. We look forward to your response required by 40 C.F.R. § 51.308(i)(3). For further information, please contact Jill Webster at jill.webster@usda or (406) 361-5380.

Again, we appreciate the opportunity to work closely with the State of North Dakota. The Forest Service compliments you on your hard work and dedication to significant improvement in our nation's air quality values and visibility.

Sincerely,

LEANNE M. MARTEN
Regional Forester

Enclosure

cc: David Stroh, Jim Semerad, Bennie South, Shannon Boehm, Craig Glazier, Jill Webster

<u>North Dakota DRAFT Regional Haze State Implementation Plan (SIP)</u>

<u>Technical Comments</u>

The USFS recognizes and applauds the significant emission reductions made in North Dakota since the early 2000's. Further, we appreciate the strong working relationship among our respective staff and the routine communications during the development of this draft Regional Haze plan.

Overall, the USFS finds that the draft SIP is well organized and comprehensive. We specifically appreciate the thorough and technically sound 'four factor analyses' included in the draft SIP.

The USFS requests that the North Dakota Department of Environmental Quality consider the following before final adoption of the SIP.

Relevance of the Visibility Impact of Individual Sources

Although EPA's 2019 Regional Haze Guidance allows for the consideration of visibility in determining whether emissions control measures are necessary for making reasonable progress, the guidance also states that "because regional haze results from a multitude of sources over a broad geographic area, a measure may be necessary for reasonable progress even if that measure in isolation does not result in perceptible visibility improvement". Widespread emissions controls, particularly for SO_2 and NO_x, are essential for making reasonable progress at Class I areas both near to, and more distant from, emissions sources. Further, small visibility improvements, even those that may be imperceptible by themselves, are essential for making progress towards the National Goal of restoring natural conditions at Class I areas by 2064. EPA further emphasized this requirement of the rule in its memo dated July 8th, 2021.

It appears that North Dakota is *not* considering cost effective controls at several facilities based solely on the argument that source contributions do not significantly impact overall visibility improvements and are therefore, not reasonable. Cost effective controls should be considered regardless of the source's individual, or combined, impact to visibility.

Visibility Impacts During Peak/Off Peak Visitation

While the most anthropogenically impaired days a Class I area, could indeed correspond to periods of the least visitation (as illustrated with Figure 13 in the draft SIP), this does not mean that there is no impairment during periods of high visitation. Any period of visibility impairment should be considered.

Cost Effective Controls Identified, But Not Considered

Again, we applaud North Dakota's comprehensive evaluation of its 'four factor sources'. North Dakota does not define a cost-effective value, in dollars per ton of emission reductions. However, it does identify controls for several sources, at a cost per ton, that has been deemed cost effective by other states and EPA. We ask that the State reconsider requiring some of these emissions reducing controls, particularly those at the lower end of the cost range. Specifically, reconsider controls identified for sulfur and nitrogen oxides at Coyote, and those improving existing sulfur controls at Antelope Valley units 1 and 2. It is worth noting that similar plants in the State currently perform at less than 0.15 pounds of SO_2 per million BTU. In addition, the State previously determined that enhanced NO_x controls at Coal Creek could feasibly achieve 0.15 pounds of NO_x per million BTU; we see no reason why these controls should not be included in this SIP.

Contribution of North Dakota Emissions to Neighboring State Class I Areas

The draft SIP, sec 2.1.4, states that 'South Dakota did not identify any sources or areas of concern regarding visibility impacts from North Dakota.' However, per the draft South Dakota SIP, several North Dakota facilities appear to be ranked as 'contributing sources' to visibility at several South Dakota Class I areas. Please consult with the South Dakota Department of Agriculture and Natural Resources regarding these sources and their impact on South Dakota Class I areas. (See Tables 3-1 to 3-3, Tables 3-8 to 3-11, page 84, Figure 3-16, and Tables 3-12 to 3-15 in the South Dakota draft Regional Haze SIP)

Prescribed Fire Emissions

Fire plays an important role in shaping the vegetation and landscape in North Dakota and surrounding states. Recurring fire has been a part of the landscape for thousands of years. Aggressive fire suppression, coupled with an array of other disturbances has changed the historic composition and structure of the forests. Periodic prescribed burning and other vegetation management can recreate the ecological role of fire in a controlled manner. Fire and fuels management supports a variety of desired conditions and objectives across the forests and grasslands (e.g., community protection, hazardous fuels reduction, native ecosystems restoration, historic fire regimes restoration, wildlife openings, and open woodland creation, etc.). The USFS along with our partners, including the North Dakota Forest Service (NDFS), plan to increase the use of prescribed fire to accomplish these goals.

The 2017 Regional Haze Rule includes a provision to allow states to adjust the glidepath to account for prescribed fire. The draft SIP states that prescribed fire emissions were taken from the 2014v2 National Emissions Inventory (NEI) and were carried forward into the 2028 future year emissions. Recent data on prescribed fire activity, especially within the USFS, show that the number of acres burned have increased since the development of the 2014v2 emissions inventory and are projected to increase through the planning period. Therefore, keeping prescribed fire emissions steady to 2028 undercounts these emissions. Nevertheless, the USFS is requesting that North Dakota adjust the glidepaths for prescribed fire projections as a clear acknowledgement of the shared state and federal goals of restoring fire adapted ecosystems. The Future Fire Scenario (FFS2) modeling provided by the Western Regional Air Partnership provides an updated and more accurate assessment of prescribed burning in North Dakota and surrounding states.

Stroh, David E.

From: Webster, Jill - FS <jill.webster@usda.gov>
Sent: Tuesday, October 12, 2021 1:04 PM
To: Stroh, David E.
Subject: FFS2 RH endpoint adjustments
Attachments: FFS2-RH-ND.xlsx; Description-FFS2-ND.docx

Follow Up Flag: Follow up
Flag Status: Completed

Hi David,

I'm making my way through the North Dakota Regional Haze SIP. Congrats on reaching this milestone!

We, the Forest Service, have been reaching out to states regarding the FFS2 modeling that was completed by Ramboll. As you may be aware, this modeling incorporated more accurate Rx burning estimates for Regional Haze planning. However, the modeling was completed later and the data was uploaded to the TSS in April, which I understand, was a bit late in the planning process. Bret Anderson and Scott Copeland have been working with those projections in order to glean out the increased Rx projection and the corresponding endpoint adjustment. This is meant to provide states with an easy way to adjust their 2064 endpoints, even at this late stage in the process, to reflect a more accurate assessment of Rx in the future.

I'm attaching the data for you to consider using in ND's SIP. Since ND is adjusting it's 2064 endpoint to reflect Rx burning, you may consider using these estimates.

Please let me know if you have any questions and would like to discuss!

Talk Soon,
Jill

Jill Webster
Air Quality Program Manager

Forest Service
Northern Rockies Region

p: 406-329-3672
c: 406-361-5380
Jill.Webster@usda.gov

26 Fort Missoula Road
Missoula, MT 59804
www.fs.fed.us

Caring for the land and serving people

This electronic message contains information generated by the USDA solely for the intended recipients. Any unauthorized interception of this message or the use or disclosure of the information it contains may violate the law and subject the violator to civil or criminal penalties. If you believe you have received this message in error, please notify the sender and delete the email immediately.

Future fire sensitivities added wildfire emissions (FFS1) or wildland prescribed fire emissions (FFS2) as two potential future variations in fire activity that are not specific to any single future year. The fire sensitivities are added to the 2028OTBa2 reference case scenario to replace historic fire emissions originally used in the 2028OTBa2 scenario while keeping constant all other U.S. anthropogenic, international, natural, and non-US fire emissions. The only differences between the 2028OTBa2 and the fire sensitivities are due to the FFS1 and FFS2 assumptions. Emissions development of the future fire sensitivities is described in the Air Sciences, Inc. report Fire Emissions Inventories for Regional Haze Planning: Methods and Results (April 2020). Modeling methods are defined in WRAP Future Fire Sensitivity Simulations (August 2021).

Theoretically, since the only differences between 2028OTBa2 and the FFS2 are the assumptions due to the increased acres treated in FFS2, one should be able to isolate the change in extinction on the most impaired days (MID) by calculating the incremental difference FFS2 and 2028OTBa2 by subtracting the 2028OTBa2 results from the FFS2 results.

Procedures

1. Get "Default" Rx fire adjustment from Product #5, WRAP TSS, Model Express Tools ("Adjustment Options for End of URP Glidepath")

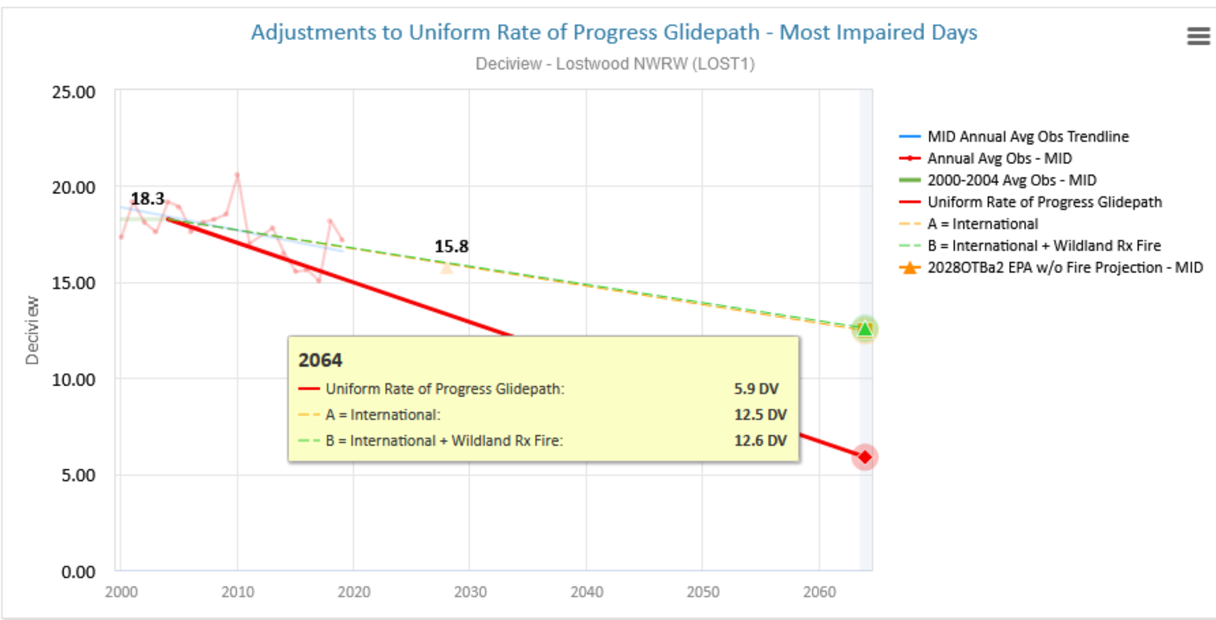


Figure 1- Example WRAP TSS Product #5, Model Express Tools

2. Subtract "End Point A – International" from "End Point B – International + Wildland Rx Fire"
    a. Example: LOST1: B = 12.6 DV, A = 12.5 DV. Rx fire component of adjustment = B – A or 12.6 – 12.5, which yields 0.1 DV different or "default endpoint adjustment for Wildland Rx fire.
3. Convert Wildland Rx Fire DV to extinction units (Mm^{-1})
    a. Obtain 2064 unadjusted end point in DV from Product #5, WRAP TSS (see figure 1 above, URP Glidepath)
        i. Example: LOST1: end of the URP in 2064 = 5.9 DV
    b. Add Wildland Rx Fire DV from Step 2 to Unadjusted 2064 end point from Step 1 and Subtract 2064 URP end point (unadjusted) to calculate Wildland Rx Fire contribution in extinction units by following formula: $10*EXP((2064_{DV}+RxFire_{DV})/10)-10*EXP(2064_{DV}/10)$.
        i. Example: GRCA2: 10*EXP((5.9 + 0.1)/10) – 10*EXP(5.9/10) = 0.18 Mm^{-1}

4. To calculate incremental contribution from WRAP Future Fire Scenario 2 (Increased Wildland Rx Fire ("FFS2")), obtain extinction results for 2028 OTBa2 scenario AND 2028 FFS2 scenario from WRAP TSS, Model Express tools, Product #18 ("Future Fire Sensitivities Visibility Projections – Most Impaired Days")
    a.
        i. 2028 OTBa2 results: stacked bar chart, column 2 = 39.37 Mm^{-1} (Figure 2, "A")
        ii. 2028 FFS2 results: stacked bar chart, column 4 = 39.82 Mm^{-1} (Figure 2, "B")
    b. Add Rayleigh scatter back to each value from steps 4.a.i and 4.a.ii
        i. Example: LOST1: Rayleigh =11, so add Rayleigh back to 2028 OTBa2 and 2028 FFS2
            1. 2028 OTBa2 = 39.37; Rayleigh = 11; Total Bext = 50.37 Mm^{-1}
            2. 2028 FFS2 = 39.82; Rayleigh =11; Total Bext = 50.82 Mm^{-1}
    c. Subtract total extinction, 2028 OTBa2 from total extinction, 2028 FFS2
        i. Example: LOST1: 50.82 Mm^{-1} (2028_{FFS2} Bext) – 50.37 Mm^{-1} (Bext 2028_{OTBa2}) = 0.45 Mm^{-1} ($Bext_{\Delta 2028FFS2}$)
    d. Difference from 4.c.i will yield the incremental increase of 2028_{FFS2} above 2028_{OTBa2} in extinction units (Mm^{-1}).
    e. Convert the 2064 URP unadjusted endpoint into extinction units (Mm^{-1})
        i. Example: LOST1: $Bext_{2064URP}$ = 10*EXP($DV_{2064URP}$/10), or 10*EXP(5.9/10)
    f. To calculate the "alternative glideslope adjustment" (which reflects the land management policy change of increasing acres treated with prescribed fire = Total ΔWildland Rx Fire which is the sum of 2028OTBa2 and FFS2 prescribed fire impacts in Mm^{-1}), add the incremental change in extinction units from 2028_{FFS2} (step 4.c.i) to the original projection from 2028_{OTBa2} in extinction units (step 3.b) and convert to deciview units by the following equation: 10*LN((($Bext_{\Delta 2028FFS2}$ (Mm-1) + $Bext_{2028OTBa2}$) + $Bext_{2064URP}$)/10) – $DV_{2064URP}$

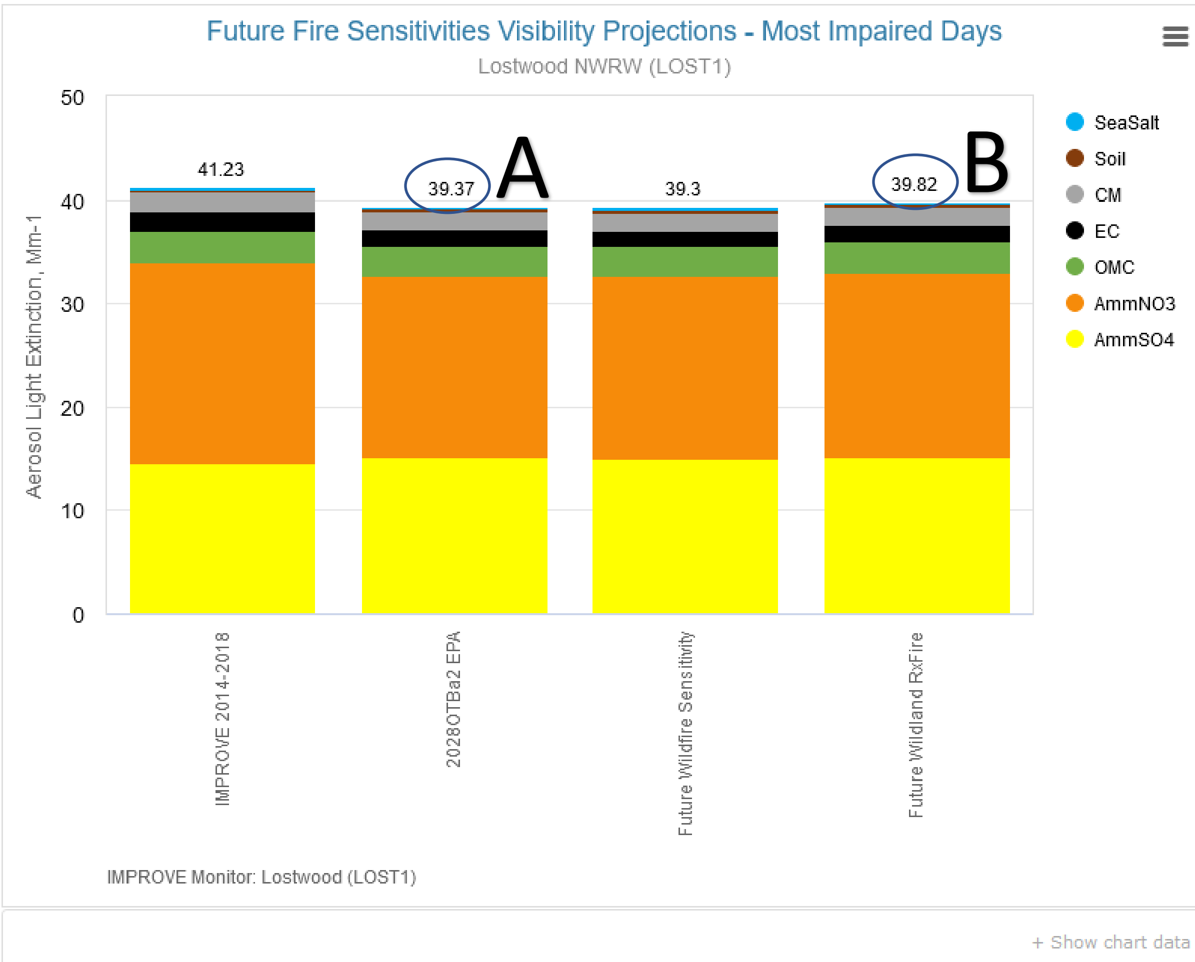


Figure 2 - Future Fire Sensitivities Total Extinction - Most Impaired Days

Class I Area	2064 Unadjusted	Rx Fire	Rx Fire (Mm-1)
THRO1	5.9	0.1	0.18
LOST1	5.9	0.1	0.18

Class I Area	2064 Unadjusted (DV)	2064 unadjusted Mm-1	Rayleigh	2028 OTBa2 (Mm-1)	Total 2028OTBa2 (Mm-1)	FFS2 (Mm-1)	Total FFS2 (Mm-1)	FFS2 - 2028 OTBa2 (Mm-1)	Allternative Glide slope (DV)
THRO1	5.9	18.03988415	11	29.63	40.63	29.85	40.85	0.22	0.220015484
LOST1	5.9	18.03988415	11	39.37	50.37	39.82	50.82	0.45	0.343964942

D.2.c – Department Response to FLM Feedback

Response to Feedback Received from the Federal Land Managers During the Consultation Process

Under the Clean Air Act (CAA) Section 169A(d) and 40 Code of Federal Regulations (CFR) §51.308(i)(3), the State is required to consult with the appropriate Federal land managers during the development of the implementation plan. This document contains NDDEQ's responses to feedback received from the National Park Service (NPS) on November 19, 2021, and from the U.S. Forest Service (USFS) on November 17, 2021. The entirety of the feedback received from the Federal land managers is included in in Appendix D.2.a and D.2.b of the RH SIP revision.

National Park Service (NPS)

The NPS provided the Department (NDDEQ) with over 100 pages of comments separated into the following four sections: Executive Summary, Overarching feedback, Specific Review of Four-Factor Analyses, and Oil & Gas Area Source Recommendations.

As stated in the Executive Summary provided by NPS: "*The North Dakota draft SIP provides some of the best, technically sound four-factor analyses that the NPS has reviewed in this planning period. However, there are several recurring issues with the four-factor analyses that generally the inflated cost of controls.*"

Establishment of a Cost Threshold

NDDEQ conducted four-factor analyses on each source selected through the screening analysis. NDDEQ has required everything that is appropriate and necessary to demonstrate reasonable progress during this planning period with this RH SIP revision.

NPS uses the term "cost-effectiveness". NDDEQ notes that "cost effectiveness" is a subjective term and is not used in the CAA Section 169A nor in 40 CFR §51.308. If the term "cost-effectiveness" is used, it must be understood that what was "cost-effective" previously may no longer be "cost-effective" today given current circumstances. A "cost-effectiveness" determination is made by the State under the CAA. In doing so, NDDEQ must follow "reasoned decision making" where "not only must an agency's decreed result be within the scope of its lawful authority, but the process by which it reaches that result must be logical and rational".[1] NDDEQ followed this process by considering all the available data and results prior to reaching the state's determinations set forth in the proposed RH SIP revision. As a result, North Dakota does not believe it is appropriate or necessary to establish a "cost-threshold in line with other states or based on NDDEQ thresholds from previous rounds" for this planning period of the regional haze program. The projected impact resulting from additional control must be considered prior to requiring any control measures which fall below a set cost threshold.

North Dakota Class I areas are currently below the adjusted uniform rate of progress needed to achieve the 2064 visibility end goals and North Dakota Class I areas are projected to remain below the adjusted uniform rate of progress in 2028. Being under the adjusted uniform rate of progress demonstrates that

[1] See Michigan v. Environmental Protection Agency, 576 U.S. 743, 750 (2015).

North Dakota is on track to accomplish the goals of the regional haze program. This was not used as a safe harbor, as four-factor analyses were completed by NDDEQ, but was factored into the decision-making. NDDEQ will continue to track Class I area visibility and will reevaluate what appropriate costs of controls may be in future regional haze planning periods.

In addition, NPS raised the Chemical Engineering Plant Cost Index (CEPCI) values in their feedback. CEPCI, the gold standard for adjusting plant costs and used in EPA's cost control spreadsheets, was up 28.5% since the cost analyses were performed and submitted to NDDEQ.[2] This means all the costs presented in the control measures evaluations are likely underestimated by almost 30% when compared to today's dollar. The 2018 CEPCI value was 603, while the final value for October 2021 was 761. See the following table for an accurate expectation of how underpredicted the costs presented in the four-factor analyses are.

Year	**CEPCI**	**Year to Year Increase**
2018	603.1	--
2019	607.5	0.7%
2020	596.2	-1.9%
2021 Oct	761.4	26.5%
2021 Nov	773.1	28.5%

North Dakota's correlation of low visitation with MID

The information provided in Section 1.3.2 of the RH SIP revision was not used to determine whether controls should be required. This information was provided to help show a more complete story of regional haze and to highlight a significant area of concern regarding the regional haze programs most impaired days metric for North Dakota Class I areas. The information provided in the RH SIP revision Section 1.3.2 helps highlight what is generally known by the public throughout the state of North Dakota, that the most significant air quality problems and corresponding visibility impairment results from out of state wildfires, and these fires coincide with times park visitation is the highest. While beyond the scope of this RH SIP, reducing the wildfire impacts would provide the single greatest benefit to visibility improvement while simultaneously reducing the health-based impacts from wildfire smoke. This is important background information of which all parties should be aware.

Visibility Benefits, URP, and IMPROVE Data Trends

Overview

As mentioned by NPS, NDDEQ's long-term strategy does not include additional controls for any of the sources selected for four-factor analysis and NDDEQ agrees that there are technically feasible control options available for several units. However, as outlined in "Establishment of a Cost Threshold" of this response to comment document, the additional technically feasible control options on the four-factor sources are not "cost-effective." And, as explained in the proposed RH SIP revision, North Dakota

[2] Available at: https://www.toweringskills.com/financial-analysis/cost-indices/ (last visited April 7, 2022)

determination is that it is not “reasonable” to require these control options based on the following considerations:

- the lack of visibility impairment currently caused by anthropogenic sources located in North Dakota (Section 3.1 of the proposed RH SIP revision)
- the lack of modeled visibility improvement when additional control scenarios were evaluated based on NDDEQ’s four-factor analyses (Section 6.1.1 of the proposed RH SIP revision)
- North Dakota Class I areas are currently below the adjusted uniform rate of progress (URP) needed to achieve the 2064 visibility end goals and North Dakota Class I areas are projected to remain below the adjusted URP in 2028 (Section 3.2.7 and 6.1.1 of the proposed RH SIP revision)
- the excellent air quality currently maintained by North Dakota when significant wildfires are not occurring outside the state and impacting North Dakota’s air (Air Quality in North Dakota Section and Section 3.3. of the proposed RH SIP revision)

This information supports North Dakota’s determination not to recommend additional controls for round 2 of regional haze. Should any of these considerations change in the future, NDDEQ will reevaluate this decision. The regional haze program set an end goal target date of 2064 and broke the program into decadal planning periods with the understanding that improvements would not be made all at once. Each round should be evaluated separately with the end goal in mind, making improvements at a reasonable pace while not overburdening essential industries. North Dakota made substantial improvements in round 1 (Section 1.3 of the proposed RH SIP) and is on track to meet the 2064 end goals of the program.

Visibility Benefits and URP

NDDEQ agrees with NPS statements regarding the URP and that simply being under the URP is not a “safe harbor” or reason for a recommendation of no controls. However, NDDEQ did not rely on being under the URP as a “safe harbor” or as the basis for North Dakota’s determinations. Many factors, as explained throughout North Dakota’s proposed RH SIP revision and this response to comment were used to conclude no additional controls for regional haze are warranted in this planning period.

The demonstration that North Dakota Class I areas remain below the URP and are projected to remain below the URP through 2028 shows that North Dakota has and is expected to continue to show reasonable progress toward improving visibility through 2028 and is on track to accomplish the 2064 end goal of the program. North Dakota’s projected level of visibility improvement on the most impaired days meets a core requirement of the regional haze program requirements. 40 CFR 51.308(f)(3)(i) states in part *“The long-term strategy and the reasonable progress goals must provide for an improvement in visibility for the most impaired days since the baseline period and ensure no degradation in visibility for the clearest days since the baseline period.”* The information provided by NDDEQ indicates North Dakota Class I areas are expected to meet these core requirements of the rule, see Section 3.1 and Section 6.1 of the proposed RH SIP revision. North Dakota considered the rate of progress made to improve visibility and the lack of cost reasonable controls as key factors to reject additional controls, beyond what is currently proposed, for round 2 of the regional haze program.

IMPROVE Data Trends

NPS states that overall visibility impairment trends in the area are improving but recent years (2016-2019) have experienced increases on the most impaired days. NDDEQ notes that 2019 was an incomplete data year for Theodore Roosevelt National Park.[3] NPS suggests continuous emissions reductions are needed to meet the 2064 goals and the uniform rate of progress glideslope is a planning tool and not a standard. This paragraph concludes that no state has met the 2064 end goal yet. NDDEQ notes two items. 1) the referenced data is volatile from year to year, which is why five-year averaging periods are used. A simple review of most Class I areas across the western U.S. shows this volatility and overreacting to one year of data is a misuse of the information. 2) 2020 visibility impairment data for the most impaired days in Theodore Roosevelt indicates one of the lowest amounts of annual most impaired days visibility impairment on record, only behind 2016, 2015, and 2014, respectively. It is also noted that 2014, the height of development in the Williston Basin oil field, has the 3rd lowest annual most impaired days visibility impairment on record for Theodore Roosevelt National Park.

Response to Selective Catalytic Reduction (SCR) Determinations

Of note prior to addressing specifics in the following sections, SCR is generally control technology which can be used to reduce NO_X emissions from fossil fuel combustion. NO_X emissions contribute to and result in ammonium nitrate light extinction. Ammonium nitrate light extinction from North Dakota coal fired electrical generating utilities are projected to account for 0.4% and 1% of the 2028 total light extinction on the most impaired days at Theodore Roosevelt National Park and Lostwood Wilderness Area, respectively. In other words, eliminating 100% of NO_X emissions from North Dakota electrical generating utilities would result in a maximum projected improvement in visibility of 1% on these days. SCR cannot achieve a 100% percent reduction, meaning this 1% improvement is unobtainable even if installed on every North Dakota electrical generating utility.

Technical feasibility of SCR on all boiler types

NDDEQ agrees that technically feasible control options need to be both available and applicable. NPS correctly states that SCR is available, but this statement is misleading for North Dakota sources. SCR has never been demonstrated in practice on North Dakota lignite fired boilers. SCR has never been through the licensing and commercial demonstration in North Dakota; and has experienced no commercial sales for North Dakota lignite fired boilers. The regional haze best available retrofit technology (BART) guidelines[4] states "*A control technique is considered available, within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as "available" for purposes of BART review*". SCR has been demonstrated in practice, but never on units firing North Dakota lignite. Further the BART guidelines also state "*Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered as available; we do not expect the source owner to purchase or construct a process or control device that has not*

[3] 2019 was incomplete, in part, due to the federal government shutdown.

[4] Appendix Y to Part 51 - Guidelines for BART Determinations Under the Regional Haze Rule

already been demonstrated in practice." In summary, this is the case for North Dakota. Therefore, questions on SCR availability and applicability for North Dakota lignite have not been resolved.

Tangentially- and Wall-Fired Boilers

NDDEQ conservatively carried TE-SCR on tangentially-fired and wall-fired boilers burning North Dakota lignite forward for cost evaluation, even though uncertainty remains regarding the real-world feasibility on North Dakota lignite boilers.

Cyclone-Fired Boilers

NDDEQ agrees that no demonstration has been provided showing TE-SCR technical feasibility on cyclone boilers burning North Dakota lignite. Therefore, this technology was removed from consideration for cyclone units.

Catalyst Deactivation

NDDEQ agrees that catalyst deactivation is normal, and the rate of deactivation is an economic factor rather than a technical-feasibility issue. Catalyst deactivation was not used as rational for not recommending SCR controls.

NDDEQ appreciates NPS's recognition of the unique characteristics of North Dakota lignite flue gas and acknowledgement of the SCR pilot testing performed in the early 2000s. As NPS stated, *"North Dakota lignite contains relatively high levels of organically associated alkali and alkaline-earth elements, including Na, Ca, K, and magnesium. Na levels in North Dakota lignite are typically 5 to 20 times higher than Na levels in bituminous and subbituminous coals, and Na compounds can represent between 5% and 11% of the ash generated from firing ND lignite."* Since that pilot testing was performed, cyclone boiler fly ash sampling at the scrubber outlet has shown that submicron particles of sodium and potassium are still present. These particles have the potential to interact with and penetrate low dust or tail end SCR.[5]

SCR NOx Rates

NDDEQ generally agrees that SCR can achieve NOx rates as low as 0.04 lb/MMBtu at non-lignite facilities. However, this has not been demonstrated and is likely untrue for North Dakota lignite sources. Significant pilot testing, optimization and tuning, and time would be needed to determine a sustainable NOx rate for North Dakota sources. Further, NDDEQ notes that none of the 11 listed EGUs in the NPS comments are in North Dakota and none of them burn North Dakota lignite coal. Many, if not all, NPS noted facilities appear to combust bituminous or subbituminous coal and none of the referenced units were cyclone fired boilers. As such, NDDEQ believes it is not accurate to compare dissimilar units and assuming the same outcome is achievable.

TE-SCR for cyclone boilers combusting North Dakota lignite is still considered technically infeasible. Coyote Station did, however, initially include and carry TE-SCR forward for cost evaluation with a

[5] Benson, Schulte, Patwardhan, Jones. (2021) "The Formation and Fate of Aerosols in Combustion Systems for SCR NOx Control Strategies". A&WMA's 114th Annual Conference, paper# 983723.

predicted achievable NOx emissions rate of 0.09 lb/MMBtu.[6] TE-SCR was ultimately removed for consideration from this facility due to the technology being unproven.[7]

Since TE-SCR is an unproven technology on North Dakota lignite boilers, a NOx emissions rate of 0.04 lb/MMBtu would never be proposed by NDDEQ. For non-cyclone units, NDDEQ already addressed the selection of appropriate NOx rates for analysis in Appendix A, supported by the control measures evaluations included in Appendix B.

SCR Capital and Operating Costs

NDDEQ does not agree that the capital and operating costs of TE-SCR warrant further evaluation. Rather, ND determined that the exorbitant cost of TE-SCR quickly eliminates it as an economically feasible control option for round 2 of regional haze. Since the technology is dismissed due to extreme costs, the technical feasibility uncertainty is inherently less of less concern. If anything, coupling the very high cost with the uncertainty leads to a clear decision to not recommend TE-SCR, or SCR in any configuration.

Further, NPS incorrectly provided "updated or corrected" costs based on a high-dust configuration SCR (the EPA cost control manual spreadsheets utilize SCR in the high-dust configuration).

NDDEQ compiled the cost estimates from all four-factor sources which evaluated the costs of TE-SCR to highlight the significance of these costs, see table below. The average capital cost for TE-SCR systems is projected to be over $200,000,000 ($200 million) with annualized costs ranging between $15,000,000 and $41,000,000 ($15–41 million).

Cost Comparison of SCR for North Dakota Lignite Fired Sources

Facility	Boiler Type	Baseline NOx Emissions Rate (lb/MMBtu)	Technology	NOx Emissions Rate (lb/MMBtu)	Total Capital Invest ment (MM$)	Annualized Cost (MM$)	Cost per Emissions Reduced ($/ton) - Projected
Coal Creek Station, Unit 1 and 2	Tangentially -Fired	0.18 [A]	TE-SCR [B]	0.06	191.7	16.7	6,280
				0.08	180.0	15.4	6,980
Antelope Valley Station, Unit 1 and 2	Tangentially -Fired	0.11	TE-SCR	0.05	221.4	36.3	34,750
Leland Old	Opposed Wall-Fired	0.16	TE-SCR	0.05	227.7	33.7	42,320

[6] Appendix B.1.b., page 5-36 through 5-39. PDF pages 70–73.
[7] TE-SCR was also not considered feasible for the other Cyclone boilers in North Dakota. Which include Coyote, Leland Olds Station Unit 2, Milton R. Young Station Units 1 and 2.

Facility	Boiler Type	Baseline NOx Emissions Rate (lb/MMBtu)	Technology	NOx Emissions Rate (lb/MMBtu)	Total Capital Invest ment (MM$)	Annualized Cost (MM$)	Cost per Emissions Reduced ($/ton) - Projected
Station, Unit 2							
Coyote Station	Cyclone-Fired	0.46	TE-SCR [C]	0.09	254.1	41.3	7,300

[A] The current emissions rate is ~0.13 lb/MMBtu. Using this value changes the $/ton to $10,340 and $13,370 for target rates of 0.06 and 0.08 lb/MMBtu, respectively.
[B] Costs are for a high-dust SCR system. High-dust SCR is not technically feasible but is significantly less expensive. Therefore, the total capital Investment, the annualized costs, and the $/ton of a TE-SCR would be significantly greater. Couple this with the lower baseline rate discussed in Footnote A, and the costs will become even greater.
[C] This technology is not technically feasible. Regardless, the costs demonstrate the lack of economic feasibility eliminating any need to discuss technical feasibility uncertainty.

Response to Reasonable Progress Cost of Compliance and Inflated Costs of North Dakota's Four Factor Analyses

NPS noted four considerations it believes result in an overestimation of control costs. Each of these items shall be addressed, but it is noted that the response provided in "Establishment of a Cost Threshold" takes precedence over these items. The four cost items NPS raised as issues are:

- Contingency cost of direct and indirect capital costs to all capital projects (20% vs 10%)
- Direct costs as owners' costs (2%)
- Property taxes, insurance, and administrative charges (1%, 1%, 2%)
- Interest rate and equipment life (5.25% vs 3.25% and 20-years vs 30-years)

NPS carried each of these four cost item bullets forward to "correct" the "inflated costs" presented by NDDEQ. As explained in the following sections, the NDDEQ believes NPS utilized inappropriate cost "corrections" and NDDEQ used appropriate cost information in its four factor analyses.

Contingency

NDDEQ used a consistent contingency factor of 20% for similar sources during this review and believes it to be accurate value to utilize at this stage of control cost estimation. Using a consistent contingency factor amongst the sources holds everyone to a level playing field when control costs are initially evaluated. Contrary to EPA's cost control manual 'default' contingency recommendation of 10%, there is no such thing as a standard contingency factor. Contingency factors change depending on the level of cost projected and become smaller (more accurate) as more detailed cost estimates are completed.

Owner's Cost

NPS provide no support for the statement that owners costs are not allowed by EPA. Owner's costs (e.g., staff time) are real and should be considered. Further, this is only 2% of the direct capital cost and does not materially change any conclusions reached.

Property Taxes, Overhead, and Insurance

NPS misrepresents the cost control manual stance on property taxes, overhead, and insurance. NDDEQ has included the figure below from EPA's Cost Control Manual, Chapter 2, Section 2.4.2, Figure 2.3 (page 13)[8]. As shown in the following figure, each of these items NPS takes issue with is listed as a cost associated with the total annual cost, specifically, the indirect costs.

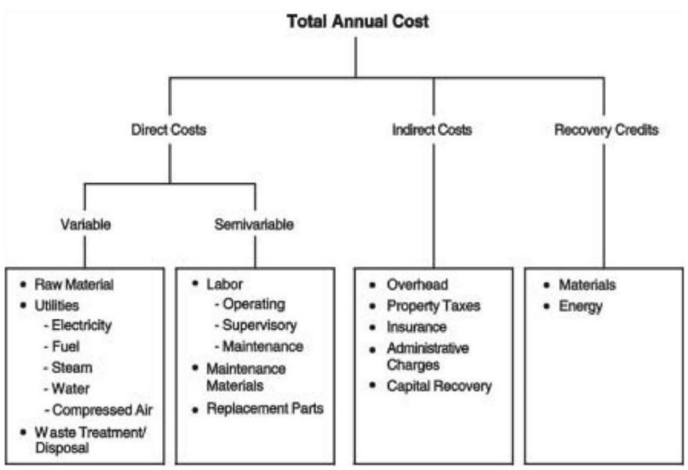


Figure 2.3: Elements of Total Annual Cost

Interest rate and equipment life

Based on consideration of the NPS' feedback, the NDDEQ continues to believe the decision to use an interest rate of 5.25% and a 20-year equipment life for the second planning period is appropriate. The interest rate was the bank prime rate at the time these analyses were prepared, and 20-years is a reasonable equipment life.

The interest rate in the four factor analyses was consistent with the bank prime rate at the time the evaluations were performed. At that time, the rate of 5.25% was confirmed by EPA Region 8.[9] Additionally, using a consistent interest rate amongst the sources holds everyone to a level playing field when control costs are initially evaluated. NPS provides no reference to a statute or regulation to justify why NDDEQ should use lower interest rates for the controls evaluated. Further, lowering the interest rate has no impact on the overall decision as the impact of the controls reviewed toward improving

[8] Available at; https://www.epa.gov/sites/default/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[9] NDDEQ proposed RH SIP revision, Appendix E, page E.2-130 and E.2-131.

visibility is the first question that must be answered. Even if the interest rate is lowered, it does not materially change any determinations made by NDDEQ.

For consistency of cost estimations between sources and technologies, NDDEQ believe it is reasonable to use an equipment life (or more properly, a loan amortization period) of 20 years. Using consistent equipment life amongst the sources holds everyone to a level playing field when control costs are initially evaluated.

Response to request for upstream oil and gas regulations

Thank you for the comment regarding North Dakota Oil and Gas upstream operations. In lieu of addressing each comment section individually, NDDEQ addresses all three sections comments with the following response.

NDDEQ has addressed wellsite NO_X emissions from NDDEQ regulated sources in the RH SIP revision in Section 5.2.11. NDDEQ notes that federal engines rules under NSPS JJJJ, NSPS IIII, and MACT ZZZZ already exist and contain NO_X emission standards. NDDEQ is the delegated authority for NSPS JJJJ, NSPS IIII, and MACT ZZZZ (for major sources) while EPA Region 8 maintains authority for MACT ZZZZ for area sources. NO_X engine emissions concerns from sources under EPA Region 8 authority should be directed toward EPA Region 8 given that federal agency has regulatory authority over approximately 20% of the oil and gas operations in North Dakota on Tribal land. NDDEQ sent letters to each of the Tribal partners in the state requesting feedback on the proposed RH SIP revision but, to date, has not received any comments in response.

On Nov. 2, 2021, EPA has proposed additional federal rules for the oil and gas sector. These rules include updates to the existing New Source Performance Standards (NSPS) OOOO (2012) and NSPS OOOOa (2016) standards, a new NSPS OOOOb standard for post-2021 sources, and emissions guidelines for existing designated facilities under a NSPS OOOOc standard (pre-2012 sources). The NSPS OOOOc standard may require NDDEQ to develop a CAA Section 111(d) plan which, at a minimum, meets EPA emissions guidelines under NSPS OOOOc.

U.S. Forest Service (USFS)

The USFS provided the NDDEQ with two pages of comments separated into the five topics. These topics included: relevance of visibility impact of individual sources, visibility impacts during peak/off peak visitation, cost effective controls identified but not considered, contribution of North Dakota emissions to neighboring state class I areas, and prescribed fire emissions.

The USFS comments stated: *"The USFS recognizes and applauds the significant emission reductions made in North Dakota since the early 2000's. Further, we appreciate the strong working relationship among our respective staff and the routine communications during the development of this draft Regional Haze plan.*

Overall, the USFS finds that the draft SIP is well organized and comprehensive. We specifically appreciate the thorough and technically sound 'four factor analyses' included in the draft SIP." NDDEQ thanks USFS for this feedback and appreciates the working relationship between staff.

Response to Relevance of the Visibility Impact of Individual Sources

NDDEQ does not believe USFS accurately portrayed NDDEQ's summary conclusions presented in the North Dakota's RH SIP revision. NDDEQ did consider the installation of additional controls, as is covered in detail throughout the RH SIP revision. The executive summary in the RH SIP revision sets forth various considerations made by North Dakota prior to coming to the conclusions presented. Further, Section 2 to provide a more robust description of the State's RH SIP revision development process.

"Cost-effective" controls are further addressed in the NPS response above "Establishment of a Cost Threshold".

Response to Visibility Impacts During Peak/Off Peak visitation

NDDEQ has considered all aspects of visibility impairment, as presented throughout the RH SIP revision. Visitation and visibility impacts are further addressed in the NPS response above "North Dakota's correlation of low visitation with MID".

Response to Cost Effective Controls Identified, But Not Considered

See NPS response above under "Establishment of a Cost Threshold" for NDDEQ's position on this matter. Consistent with USFS recommendation, but in contrast to their statement, NDDEQ has proposed NO_X limits at Coal Creek of 0.15 lb/MMBtu on a 30-day rolling average. See Appendix F of the RH SIP revision.

Response to Contribution of North Dakota Emissions to Neighboring State Class I Areas

NDDEQ has consulted with, reached out too, and provided many opportunities for South Dakota Department of Agriculture and Natural Resources to identify sources or areas of concern regarding visibility impacts coming from North Dakota.

NDDEQ notes that the Wind Canyon National Park in South Dakota is projected to exceed the visibility end goals by 2028 and Badlands National Park is only 2.2 deciviews away from achieving this target. This likely played a significant role in South Dakota's decision to not reach out to NDDEQ and request additional controls for regional haze during this planning period.

Response to Prescribed Fire Emissions Comments

NDDEQ agrees with the information provided by USFS and as addressed many times in the RH SIP revision, believes fires are of the upmost importance. This is true regarding both prescribed and extreme wildfire events. NDDEQ supports USFS statement that *"Fire and fuels management supports a variety of desired conditions and objectives across the forests and grasslands (e.g., community protection, hazardous fuels reduction, native ecosystems restoration, historic fire regimes restoration, wildlife openings, and open woodland creation, etc.). The USFS along with our partners, including the North Dakota Forest Service (NDFS), plan to increase the use of prescribed fire to accomplish these goals."* NDDEQ recommends, as identified in the Grand Canyon Visibility Transport Commission report, that USFS and partners also increase efforts to reduce the excessive fuel loads through utilization of mechanical treatments where appropriate.

D.3 – Public Record

D.3.a – Public Hearing Notice

Stroh, David E.

From: Stroh, David E.
Sent: Tuesday, April 19, 2022 8:56 AM
To: Worstell, Aaron; Dobrahner, Jaslyn; Bean, Clayton
Cc: Thorton, Rhannon T.; Semerad, Jim L.; Jackson, Scott; Morales, Monica; Gregory, Kate
Subject: North Dakota Proposed Regional Haze SIP Revision Notice
Attachments: 20220418_EPAR8.pdf; Notice_of_Intent.pdf

Attached is a signed electronic notice and notice of intent to issue for the North Dakota Department of Environmental Quality (NDDEQ) proposed regional haze state implementation plan (RH SIP) revision for public comment. This plan is being made available to provide you with an opportunity to comment on NDDEQ's proposed RH SIP revision.

The location of the material available for review is included in the attached notice and can be found at:
https://www.deq.nd.gov/AQ/planning/RegHaze.aspx
(note: webpage and material will be updated prior to April 27th)

Comments can be sent through the mail or electronically to: AirQuality@nd.gov
If electronic comments are provided, please include "Regional Haze Public Comments" in the subject line.

Please review the attached and reach out with any comments or questions.

Regards,
David

David Stroh
Environmental Engineer

701-328-5229 • destroh@nd.gov
4201 Normandy St., Bismarck, ND 58503-1324

North Dakota | Environmental Quality
Be Legendary

Notice of Intent
To Amend the State Implementation Plan
For Air Pollution Control
Relating to the Regional Haze Rule

North Dakota
Department of Environmental Quality

will hold an in-person public hearing to address proposed changes to the State Implementation Plan (SIP) for the Control of Air Pollution for the State of North Dakota which addresses Regional Haze (RH) in the Federal Class I areas.

Normandy Building
4201 Normandy Street (Room 223)
Bismarck, ND
May 31, 2022
9:00 a.m. CDT

For those unable to attend in-person, a virtual listening option has been made available on the Department's Regional Haze webpage: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision and supporting documentation may be accessed at the above link. A copy of the proposed RH SIP revision may also be obtained by writing to the North Dakota Department of Environmental Quality, Division of Air Quality, 4201 Normandy Street, Bismarck, North Dakota 58503 or calling (701)328-5188. Written comments may be submitted to the above address on or before June 1, 2022. The RH SIP revision addresses the requirements to show reasonable progress to reduce regional haze (visibility impairment) in Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA). The RH SIP revision includes a Permit to Construct for Coal Creek Station which establishes a limit of nitrogen oxides intended to improve visibility conditions in TRNP and LWA.

The National Park Service is the Federal Land Manager for TRNP and provided comments on the draft RH SIP revision. The U.S. Fish and Wildlife Service is the Federal Land Manager for LWA and did not provide comment on the draft RH SIP revision. The Department also received comments from the U.S. Forest Service on the draft RH SIP revision. The comments received can be found in Appendix D.2 of the RH SIP revision. These comments may be accessed at the website listed above or by contacting the Department. The Department has provided a written response to these comments in Appendix D.2.

If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department of Environmental Quality at the above address at least seven days prior to the hearing.

Dated this 18th day of April 2022

James L. Semerad
Director
Division of Air Quality

NORTH **Dakota** | Environmental Quality

Be Legendary.™

April 18, 2022

Sent via Email to EDukart@bepc.com

Re: Regional Haze State Implementation Plan Revision for Public Comment

Erin Fox-Dukart:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office	Division of Air Quality	Division of Municipal Facilities	Division of Waste Management	Division of Water Quality	Division of Chemistry
701-328-5150	701-328-5188	701-328-5211	701-328-5166	701-328-5210	701-328-6140 2635 East Main Ave Bismarck ND 58501

April 18, 2022

Sent via Email to bca@badlandsconservationalliance.org

Re: Regional Haze State Implementation Plan Revision for Public Comment

Elizabeth Loos:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Sent via Email to JCharles@GREnergy.com and BGress@GREnergy.com

Re: Regional Haze State Implementation Plan Revision for Public Comment

Jennifer Charles and Ben Gress:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH Dakota | Environmental Quality

Be Legendary.™

April 18, 2022

Sent via Email to DWhitley@bepc.com

Re: Regional Haze State Implementation Plan Revision for Public Comment

Dan Whitley:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office	Division of Air Quality	Division of Municipal Facilities	Division of Waste Management	Division of Water Quality	Division of Chemistry
701-328-5150	701-328-5188	701-328-5211	701-328-5166	701-328-5210	701-328-6140 2635 East Main Ave Bismarck ND 58501

April 18, 2022

Sent via Email to Worstell.Aaron@epa.gov, Dobrahner.Jaslyn@epa.gov and Bean.Clayton@epa.gov

Re: Regional Haze State Implementation Plan Revision for Public Comment

Aaron Worstell, Jaslyn Dobrahner and Clayton Bean:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office 701-328-5150
Division of Air Quality 701-328-5188
Division of Municipal Facilities 701-328-5211
Division of Waste Management 701-328-5166
Division of Water Quality 701-328-5210
Division of Chemistry 701-328-6140 2635 East Main Ave Bismarck ND 58501

NORTH
Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Sent via Email to Tim_Allen@fws.gov

Re: Regional Haze State Implementation Plan Revision for Public Comment

Tim Allen:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH
Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Sent via Email to GArcher@GREnergy.com

Re: Regional Haze State Implementation Plan Revision for Public Comment

Greg Archer:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH
Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Sent via Email to JasonBohrer@lignite.com and JonathanFortner@lignite.com

Re: Regional Haze State Implementation Plan Revision for Public Comment

Jason Bohrer and Jonathan Fortner:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office 701-328-5150 | Division of Air Quality 701-328-5188 | Division of Municipal Facilities 701-328-5211 | Division of Waste Management 701-328-5166 | Division of Water Quality 701-328-5210 | Division of Chemistry 701-328-6140 2635 East Main Ave Bismarck ND 58501

NORTH **Dakota** | Environmental Quality

Be Legendary.™

April 18, 2022

Sent via Email to Jay.Skabo@mdu.com, Mark.Dihle@mdu.com and Abbie.Krebsbach@mdu.com

Re: Regional Haze State Implementation Plan Revision for Public Comment

Jay Skabo, Mark Dihle and Abbie Krebsbach:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Sent via Email to CBleth@minnkota.com, JMadison@minnkota.com, SMikula@minnkota.com and Shopfauf@minnkota.com

Re: Regional Haze State Implementation Plan Revision for Public Comment

Craig Bleth, Jon Madison, Shannon Mikula and Scott Hopfauf:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office 701-328-5150 | Division of Air Quality 701-328-5188 | Division of Municipal Facilities 701-328-5211 | Division of Waste Management 701-328-5166 | Division of Water Quality 701-328-5210 | Division of Chemistry 701-328-6140 2635 East Main Ave Bismarck ND 58501

April 18, 2022

Sent via Email to Hassan.Bouchareb@state.mn.us and Margaret.McCourtney@state.mn.us

Re: Regional Haze State Implementation Plan Revision for Public Comment

Hassan Bouchareb and Margaret McCourtney:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Sent via Email to repayne@mt.gov and bmcguire@mt.gov

Re: Regional Haze State Implementation Plan Revision for Public Comment

Rhonda Payne and Brandon McGuire:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH Dakota | Environmental Quality

Be Legendary.™

April 18, 2022

Sent via Email to Rick_Duncan@transcanada.com

Re: Regional Haze State Implementation Plan Revision for Public Comment

Rick Duncan:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH Dakota | Environmental Quality

Be Legendary.™

April 18, 2022

Sent via Email to Mike.Barnes@northwestern.com

Re: Regional Haze State Implementation Plan Revision for Public Comment

Mike Barnes:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH
Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Sent via Email to SKodish@npca.org

Re: Regional Haze State Implementation Plan Revision for Public Comment

Stephanie Kodish:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office 701-328-5150 · Division of Air Quality 701-328-5188 · Division of Municipal Facilities 701-328-5211 · Division of Waste Management 701-328-5166 · Division of Water Quality 701-328-5210 · Division of Chemistry 701-328-6140, 2635 East Main Ave, Bismarck ND 58501

April 18, 2022

Sent via Email to Kirsten_King@nps.gov, David_Pohlman@nps.gov, Melanie_Peters@nps.gov, Don_Shepherd@nps.gov, Debra_Miller@nps.gov and Andrea_Stacy@nps.gov

Re: Regional Haze State Implementation Plan Revision for Public Comment

Kirsten King, David Pohlman, Melanie Peters, Don Shepherd, Debbie Miller, and Andrea Stacy:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH **Dakota** | Environmental Quality

Be Legendary.™

April 18, 2022

Sent via Email to mthoma@otpco.com

Re: Regional Haze State Implementation Plan Revision for Public Comment

Mark Thoma:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH
Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Sent via Email to DEnderud@petrohunt.com and GKohler@petrohunt.com

Re: Regional Haze State Implementation Plan Revision for Public Comment

Derek Enderud and Gary Kohler:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Sent via Email to Laurie.Williams@sierraclub.org

Re: Regional Haze State Implementation Plan Revision for Public Comment

Laurie Williams:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH **Dakota** | Environmental Quality

Be Legendary.™

April 18, 2022

Sent via Email to Anthony.Lueck@state.sd.us and Rick.Boddicker@state.sd.us

Re: Regional Haze State Implementation Plan Revision for Public Comment

Anthony Lueck and Rick Boddicker:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office 701-328-5150 | Division of Air Quality 701-328-5188 | Division of Municipal Facilities 701-328-5211 | Division of Waste Management 701-328-5166 | Division of Water Quality 701-328-5210 | Division of Chemistry 701-328-6140, 2635 East Main Ave, Bismarck ND 58501

NORTH
Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Sent via Email to TStClair@hess.com

Re: Regional Haze State Implementation Plan Revision for Public Comment

Tony St. Clair:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH
Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Sent via Email to Jill.Webster@usda.gov

Re: Regional Haze State Implementation Plan Revision for Public Comment

Jill Webster:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH Dakota | Environmental Quality

Be Legendary.™

April 18, 2022

Sent via Email to nathan.davis@nd.gov

Re: Regional Haze State Implementation Plan Revision for Public Comment

Mr. Davis:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office	Division of Air Quality	Division of Municipal Facilities	Division of Waste Management	Division of Water Quality	Division of Chemistry
701-328-5150	701-328-5188	701-328-5211	701-328-5166	701-328-5210	701-328-6140 2635 East Main Ave Bismarck ND 58501

NORTH
Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Sent via Email to EdmundBaker@mhanation.com

Re: Regional Haze State Implementation Plan Revision for Public Comment

Edmund Baker:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

April 18, 2022

Tribal Chairman Mark Fox
Mandan, Hidatsa & Arikara Nation
MHA TERO - Environmental Division
404 Frontage Road
New Town, ND 58763

Re: Regional Haze State Implementation Plan Revision for Public Comment

Chairman Fox:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH
Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Tribal Chairman Douglas Yankton, Sr.
Spirit Lake Tribe
P.O. Box 359
Fort Totten, ND 58335

Re: Regional Haze State Implementation Plan Revision for Public Comment

Chairman Yankton:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

NORTH
Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Tribal Chairman Mike Faith
Standing Rock Sioux Tribe
1 Standing Rock Ave
Fort Yates, ND 58538

Re: Regional Haze State Implementation Plan Revision for Public Comment

Chairman Faith:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office	Division of Air Quality	Division of Municipal Facilities	Division of Waste Management	Division of Water Quality	Division of Chemistry
701-328-5150	701-328-5188	701-328-5211	701-328-5166	701-328-5210	701-328-6140 2635 East Main Ave Bismarck ND 58501

NORTH Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Tribal Council
Sisseton Wahpeton Oyate
12554 BIA Highway 711
Agency Village, SD 57262

Re: Regional Haze State Implementation Plan Revision for Public Comment

Tribal Council Members:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office 701-328-5150
Division of Air Quality 701-328-5188
Division of Municipal Facilities 701-328-5211
Division of Waste Management 701-328-5166
Division of Water Quality 701-328-5210
Division of Chemistry 701-328-6140 2635 East Main Ave Bismarck ND 58501

NORTH
Dakota | Environmental Quality
Be Legendary.™

April 18, 2022

Tribal Chairman Jamie Azure
Turtle Mountain Tribe
4180 Highway 281
Belcourt, ND 58316

Re: Regional Haze State Implementation Plan Revision for Public Comment

Chairman Azure:

The North Dakota Department of Environmental Quality, Division of Air Quality (Department) has developed a State Implementation Plan (SIP) Revision to address the Regional Haze (RH) requirements of 40 CFR 51.308. The proposed RH SIP revision may be viewed at the Department's office, 4201 Normandy Street, Bismarck, North Dakota or at the Department's website at: https://www.deq.nd.gov/AQ/planning/RegHaze.aspx. A copy of the proposed RH SIP revision may be requested by writing the Department at the above address or by calling (701)328-5188. Also included is a notice announcing a public hearing that will be held to accept oral testimony regarding the proposed RH SIP revision. The hearing is scheduled for May 31, 2022. The Department welcomes any comments you or your staff may have regarding the RH SIP revision. All comments received by June 1, 2022, will be included as part of the public record. Written comments must be sent to the address listed above or submitted via email to AirQuality@nd.gov. Comments submitted via email should include "Regional Haze Public Comments" in the subject line.

You are invited to attend and present testimony at the hearing. If you plan to attend the hearing and will need special facilities or assistance relating to a disability, please contact the Department at the above telephone number or address at least seven days prior to the hearing.

If you have any questions, please contact David Stroh of my staff at (701)328-5229.

Sincerely,

James L. Semerad
Director
Division of Air Quality

JLS/DS:saj
Enc:

4201 Normandy Street | Bismarck ND 58503-1324 | Fax 701-328-5200 | deq.nd.gov

Director's Office 701-328-5150
Division of Air Quality 701-328-5188
Division of Municipal Facilities 701-328-5211
Division of Waste Management 701-328-5166
Division of Water Quality 701-328-5210
Division of Chemistry 701-328-6140 2635 East Main Ave Bismarck ND 58501

D.3.b – Press Release

NORTH Dakota | Environmental Quality
Be Legendary.™

NEWS | **FOR IMMEDIATE RELEASE** | April 19, 2022

Department of Environmental Quality schedules public hearing to address air pollution control plan

BISMARCK, N.D. – The North Dakota Department of Environmental Quality has scheduled a public hearing to address proposed changes to the North Dakota State Implementation Plan for air pollution control on May 31 at 9:00 a.m. at 4201 Normandy Street in Bismarck. The hearing will address Environmental Quality's plan revision for addressing haze (visibility impairment) in Theodore Roosevelt National Park and the Lostwood National Wildlife Refuge Wilderness Area. See further details at https://www.deq.nd.gov/AQ/planning/RegHaze.aspx.

Environmental Quality will accept in-person oral testimony from the public during the hearing. The public may also listen online at https://www.deq.nd.gov/AQ/planning/RegHaze.aspx.

Environmental Quality will accept written comments regarding the changes by June 1, 2022. Please address written comments to James L. Semerad, Division of Air Quality, North Dakota Department of Environmental Quality, 4201 Normandy Street, Bismarck, ND 58503, or email them to airquality@nd.gov with Public Comment for Air Pollution Control SIP in the subject line.

Environmental Quality will consider every request for reasonable accommodation to provide an accessible meeting facility or other accommodation for people with disabilities, language interpretation for people with limited English proficiency, and translations of written material necessary to access programs and information. To request accommodations, contact Jennifer Skjod, Public Information Officer at 701-328-5226 or jskjod@nd.gov. TTY users may use Relay North Dakota at 711 or 1-800-366-6888.

For more information contact:

David Stroh
Division of Air Quality
4201 Normandy Street | Bismarck, ND 58503-1324 |
PHONE: 701-328-5229 | EMAIL: destroh@nd.gov
www.deq.nd.gov

# # #

D.3.c – Affidavit of Publication
(RESERVED)

D.3.d – Invoice of Publication

(RESERVED)

D.3.e – Registration List of Attendees
(RESERVED)

D.3.f – Hearing Transcript

(RESERVED)

D.3.g – Certificate of Hearing

(RESERVED)

D.4 – Environmental Protection Agency Comments

Stroh, David E.

From: Daly, Carl <Daly.Carl@epa.gov>
Sent: Thursday, January 13, 2022 4:31 PM
To: Semerad, Jim L.
Cc: Morales, Monica (she/her); Worstell, Aaron; Jackson, Scott; Stroh, David E.
Subject: EPA Comment Letter on ND's Draft 2nd Round Regional Haze SIP
Attachments: EPA Comments on draft ND RH Round 2 SIP.docx

Follow Up Flag: Follow up
Flag Status: Flagged

Jim

Attached is a letter that provides EPA's comments and recommendations on North Dakota's draft SIP for the regional haze second implementation period (2018 to 2028). We have based our comments and recommendations on the positions provided for in the Regional Haze Rule, the 2019 regional haze guidance, and the July 2021 clarifications memo OAR issued.

It may be helpful for your staff to discuss these comments on a call with Region 8 and OAQPS staff. Please let us know if you are interested in such a call.

We appreciate the opportunity to comment on the draft SIP. We recognize the significant efforts made by the North Dakota Division of Air Quality in developing the draft SIP and the Division's commitment to improving air quality and visibility impacts in North Dakota.

Regards

Carl Daly
Acting Director, Air and Radiation Division, EPA Region 8
303-312-6416

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone 800-227-8917
www.epa.gov/region8

Ref: 8ARD

Jim Semerad
Director, Division of Air Quality
North Dakota Department of Environmental Quality
4201 Normandy Street, 2nd Floor
Bismarck, North Dakota 58503-1324
jsemerad@nd.gov

Dear Mr. Semerad:

Thank you for submitting the draft North Dakota State Implementation Plan for Regional Haze (RH SIP) revision for our review, which we received by email on September 15, 2021. Based on our initial review of the draft RH SIP revision, we are providing the enclosed comments. Please note that this is only an initial review and that we will reach a final conclusion regarding the adequacy of the RH SIP revision only when we act through notice and comment rulemaking.

We appreciate the opportunity to comment on the draft RH SIP revision. If you have any questions, please feel free to contact me or your staff may contact Aaron Worstell at (303) 312-6073 or at worstell.aaron@epa.gov.

Sincerely,

X

Carl Daly
Acting Director
Air and Radiation Division

Enclosure

Enclosure

EPA Comments on the North Dakota State Implementation Plan for Regional Haze (RH SIP) – Draft for Federal Land Manager Review

1. Overall comment on the regional haze "reasonable progress" requirement. The Regional Haze Rule establishes a framework of periodic SIP revisions to implement Congress' requirement that states' SIPs include long-term strategies for making reasonable progress towards the national visibility goal. To this end, 40 CFR 51.308(f) requires that each periodic SIP revision contain a strategy for making reasonable progress for the applicable period. The increment of progress that is "reasonable progress" for a given implementation period is determined through the four factors. 40 CFR 51.308(f)(2)(i). EPA has explained that reasonable progress cannot be determined prior to or independently from the analysis of control measures for sources. See 82 FR 3078, 3091/3 (Jan. 10, 2017); *Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period* (July 8, 2021; hereinafter "Clarifications Memo") at 6.[1] North Dakota must therefore determine what is necessary to make reasonable progress in the second implementation period by using the four factors to analyze control measures for sources. We acknowledge the progress made in the first implementation period, and that ongoing emission trends and anticipated changes in emissions may inform a state's regional haze planning process. However, these circumstances alone do not satisfy a state's obligation to include the measures that are necessary to make reasonable progress in its SIP.

2. Overall comment on enforceable measures in SIPs. Section 110(a) of the Clean Air Act (42 USC section 7410(a)) outlines the requirement that SIPs contain enforceable emissions limitations and other control measures, means, or techniques relied on and include a program for the enforcement of the measures. Therefore, any emission limits or control measures ultimately relied on by North Dakota to make reasonable progress must be in the SIP and accompanied by provisions to ensure that the emission limits or other control measures are enforceable. EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (August 20, 2019; hereinafter "Guidance") at 42. Also, see 40 CFR 51.308(f)(2). See related comment number 20 below.

3. Section 2.4, *North Dakota sources identified by downwind states that are reasonably anticipated to impact CIAs*. North Dakota should clarify whether this section, along with the Weighted Emissions Potential (WEP) and Area of Influence (AOI) products in Appendix C.3, are intended to represent North Dakota's determination of which Class I areas in other states may be affected by emissions from North Dakota, as is necessary under 40 CFR 51.308(f)(2). In this section, or elsewhere in the SIP, North Dakota should explicitly identify which Class I areas in other states may be affected by emissions from North Dakota, as well as the basis for making that determination. In addition, the determination should be based on the visibility impairment contributed to by all types of anthropogenic sources (such as major and minor stationary sources, mobile sources, and area sources) in the state, not merely large point sources. See Guidance at 8.

[1] "Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period," *available at* https://www.epa.gov/visibility/clarifications-regarding-regional-haze-State-implementation-plans-second-implementation.

4. Section 2.4, *North Dakota sources identified by downwind states that are reasonably anticipated to impact CIAs*. Statements in this section appear to conflict with the state's evaluation of the WEP/AOI analysis in Appendix C.3. Specifically, this section states that the impacts from North Dakota sources to Class I areas in other states are "insignificant," while the WEP/AOI results in Appendix C.3, and the state's evaluation of those results, indicate otherwise. For example, as shown Appendix C.3, emissions emanating from North Dakota, and in particular emissions from the EGU and oil and gas sectors, have among the highest potential to impair visibility at Medicine Lake Wilderness Area in Montana.[2] In fact, in Section 5.1 and Appendix C.3, North Dakota cites these impacts as justifying the state's consideration of additional controls for sources in the EGU and oil gas sectors under four factor analyses. Given the relatively large potential of sources in North Dakota to impair visibility, we recommend that the state reassess whether its emissions affect visibility impairment in Class I areas in other states.

5. Section 2.4, *North Dakota sources identified by downwind states that are reasonably anticipated to impact CIAs*. In addition to the WEP/AOI analysis, we recommend that North Dakota consider WRAP's source apportionment analysis (2028OTBa2, low-level) when determining which Class I areas in other states may be affected by emissions from sources in North Dakota under 40 CFR 51.308(f)(2). EPA notes that the WRAP's source apportionment analysis indicates that North Dakota sources, such as those from the EGU and oil and gas sectors, are among the largest contributors to U.S. anthropogenic impairment due to ammonium nitrate and ammonium sulfate in 2028. For example, at Badlands National Park, the contribution to ammonium sulfate light extinction from the EGU sector in North Dakota is the largest for any state-sector in the WRAP region. Similarly, at Badlands National Park, the contribution to ammonium nitrate light extinction from the oil and gas sector in North Dakota is the largest for any state-sector in the WRAP region.[3] Moreover, for all anthropogenic source categories combined, North Dakota contributes more to ammonium nitrate and ammonium sulfate light extinction at Badlands National Park than any other state in the WRAP region. Given these relatively large contributions from sources in North Dakota, we recommend that the state reassess whether its emissions affect visibility impairment in Class I areas in other states.

6. Section 3.1, *Visibility Summary*. Based on source apportionment modeling, North Dakota presents the state's percentage contribution to *total* visibility impairment from ammonium nitrate and ammonium sulfate to Class I areas within the State (as light extinction). Among other things, as presented the total visibility impairment includes that from international emissions, natural emissions, and Rayleigh background. The national goal of the visibility protection program is to prevent any future and remedy any existing *anthropogenic* visibility impairment in Class I areas. Clean Air Act section 169A(a). The state should focus on its own contributions to visibility impairment and must address the requirement to include emission limits and other measures for in-state sources that are necessary to make reasonable progress towards the national visibility goal. We acknowledge that North Dakota cannot directly control emissions from international anthropogenic sources. Nonetheless, the state can focus on its own contributions to visibility impairment and must address the requirement to include emission limits and other measures for in-state sources that are necessary to make reasonable progress towards the national visibility goal. Therefore, North Dakota should present the state's percentage contribution to total anthropogenic

[2] Appendix C.3, Figures 13 through 15.
[3] Based on WRAP state-sector source apportionment results available in the Technical Support System at https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx

and/or U.S. anthropogenic impairment. Comparing the contribution from North Dakota sources to the contribution from all sources (including natural and Rayleigh), rather than that from anthropogenic sources, has the effect of understating the percent contribution by North Dakota to sources of visibility impairment that can be controlled.

7. Section 4.2.1.1.1, *SO_2 Emissions from North Dakota Coal Fired EGUs* and Section 4.2.1.1.2 *NO_X Emissions from North Dakota Coal Fired EGUs*. Tables 22 and 24, for SO_2 and NO_X, respectively, provide a comparison between the representative annual baseline emission rate (lb/MMBtu) and the most stringent existing or proposed emission limit for selected EGUs. These comparisons should prove useful in relation to our comments below regarding 1) whether existing measures are necessary to make reasonable progress and need to be included in the long-term strategy, and 2) emission limit tightening. For EGUs with only a 3-hour rolling average emission limit for SO_2 (which is generally much higher than the indicated annual performance rate), we recommend that the state consider adding a 30-day rolling average emission limit that is either reflective of any new controls ultimately selected through the SIP development process, or at a minimum, that are commensurate with the performance of existing controls. In addition, we recommend, that to the extent possible, North Dakota provide a similar table for selected non-EGU sources.

8. Section, 5.1.2 *Determination of Subject Facilities*. In the Q/d analysis used to select sources for four factor analysis, North Dakota uses average annual emissions from 2012 through 2016. To meet the requirements of 40 CFR 51.308(f)(2)(iii) of the regional haze rule, "emissions information must include, but need not be limited to, information on emissions in a year at least as recent as the most recent year for which the state has submitted emission inventory information to EPA as part of the triennial National Emissions Inventory process." Guidance at 17 and 18. Accordingly, we recommend that the state assess whether using more recent emissions data (2017 or newer data) would alter which sources are selected for four factor analysis.

   Additionally, North Dakota states that it used a Q/d of 10 when determining which sources would be selected for a four-factor analysis. However, North Dakota does not explain why that threshold was selected, how the threshold was selected, or how the threshold will ensure that a reasonable set of sources are selected for four factor analyses. EPA suggests that North Dakota include additional explanation as to how their source-selection will result in fulfillment of its reasonable progress requirements.

9. Section 5.2, *§51.308(f)(2)(i) - Four Factors Analyses for Point Sources*. In several places, North Dakota states that the Class I areas in North Dakota are under the projected 2028 adjusted glidepath. We recommend that North Dakota refrain from relying on the fact that the Class I areas remain below the adjusted glidepath projected to 2028 to determine whether additional controls are necessary for reasonable progress in the second planning period. We have stated repeatedly that the uniform rate of progress or glidepath is not a "safe harbor" and that Class I areas' position vis-à-vis the glidepath cannot be a basis for justifying a particular set of controls or decision to not require controls. Instead, the uniform rate of progress is a planning metric used to gauge the amount of progress made thus far and the amount left to make. Because the uniform rate of progress is not based on the four statutory factors, it cannot be used to determine whether the amount of progress made in any particular implementation period is reasonable. See Guidance at 50 and Clarifications Memo at 15. While we recognize the progress North Dakota has made to date, we recommend that North Dakota determine reasonable progress through application of the four statutory factors to sources and to seek meaningful reductions in visibility impairing

pollutants in the second planning period to build on the progress North Dakota has already achieved and continue progress towards natural visibility conditions for the two Class I areas within North Dakota and out-of-state Class I areas affected by emissions from North Dakota.

10. Section 5.2, *§51.308(f)(2)(i) - Four Factors Analyses for Point Sources*. Pursuant to 40 CFR 51.308(f)(2)(i), North Dakota must include in its submission an evaluation of the four-factors when determining emission reduction measures to be included in its long-term strategy. However, North Dakota only included the conclusions of the four factor analyses in the SIP submission and not the four-factor analyses themselves, which were in an appendix. While the state may choose to summarize the analyses in the SIP submission, we recommend that the summary provide enough detail to show how each of the four individual factors were considered for each source in order to ensure reasonable determinations were made.

    After a reasonable analysis of the four factors, if North Dakota determines, for a particular source, that no additional (i.e., new) measures are necessary to make reasonable progress, the state must determine whether the source's existing measures are necessary to make reasonable progress. See section 4 (pages 8 – 12) of the Clarifications Memo for information on determining when a source's existing measures are necessary to make reasonable progress. Generally, a source's existing measures are needed to prevent future emission increases and are thus needed to make reasonable progress. If North Dakota concludes that the existing controls at a selected source are necessary to make reasonable progress, North Dakota must adopt emissions limits based on those controls as part of its long-term strategy for the second planning period and include those limits in its SIP (to the extent they do not already exist in the SIP). Alternatively, if North Dakota can demonstrate that the source will continue to implement its existing measures and will not increase its emission rate and provide appropriate documentation to support its demonstration, it may be reasonable for the state to conclude that the existing controls are not necessary to make reasonable progress. In such case, the emission limits may not need to be adopted into the long-term strategy. As the SIP is currently drafted, it is unclear what measures the state considers to be necessary for reasonable progress and thus a part of the long-term strategy and which measures the state is merely discussing in its SIP narrative as part of its consideration of ongoing air pollution control programs. Therefore, we recommend that North Dakota make clear its determination for each source and explain whether it is including either existing or new emission limits for each source in the long-term strategy and SIP (or whether emission limits already exist in the SIP). See Guidance at 43; Clarifications Memo at 8-9.

11. Section 5.2, *§51.308(f)(2)(i) - Four Factors Analyses for Point Sources*. Throughout, we recommend that for each of the selected sources the state consider whether a source can achieve or is already achieving a lower emission rate using its existing measures. If a source is operating or is capable of operating at a lower emission rate than assumed either (1) as the basis for not conducting a full four-factor analysis or (2) as the baseline for four-factor analysis, that lower rate should be analyzed as a potential control measure. See Clarifications Memo at 5, 7. For example, at Antelope Valley Station Units 1 and 2, where the existing NO_X emission limit is 0.17 lb/MMBtu (30-day rolling average) at each unit, and where each unit has been operating consistently below 0.13 lb/MMBtu (monthly) for many years, we recommend that the state consider an emission limit commensurate with the actual operation and emissions of the source with existing measures. (The example is only in the instance where North Dakota ultimately elects not to require new or upgraded controls at Antelope Valley Station.) This is sometimes referred to as "emission limit tightening."

12. Section 5.2, *§51.308(f)(2)(i) - Four Factors Analyses for Point Sources*. North Dakota rejects additional controls for selected sources, at least in part, on the basis that the state deems the modeled visibility improvements to "not be considered significant." EPA has explained that states choosing to consider visibility benefits as an optional additional factor should not use visibility to summarily dismiss cost-effective potential controls, and that a state that has identified cost-effective controls but rejects most or all of them based on visibility benefits is likely to be improperly using visibility as an additional factor. Clarifications Memo at 13. In this case, it appears that North Dakota is rejecting all additional controls at its selected sources, regardless of whether they are cost effective, because the Class I areas are below their uniform rates of progress and the potential emission reductions do not have a meaningful impact on visibility. These are generally inappropriate bases on which to make reasonable progress determinations for sources. Please see pages 12 and 13 of the Clarifications Memo for generally permissible ways to consider visibility in a four-factor analysis and control determination. We recommend that the state reconsider its four-factor analysis accordingly.

    Relatedly, we note that whether a particular visibility impact is "meaningful" should be assessed in the context of an individual state's contribution to impairment, as opposed to total impairment at a Class I area. Clarifications Memo at 14. As many of the largest individual visibility impairing sources have either already been controlled (under the RHR or other CAA or state programs) or have retired, the remaining individual sources are often smaller and better controlled, with each source making relatively smaller contributions to a class I area as a proportion of total impairment. This does not mean, however, that such sources need not be controlled. To the contrary, the evaluation and control of such smaller sources may be necessary to achieve the national goal of the prevention of any future, and the remedying of any existing, anthropogenic impairment of visibility in class I areas. Also, North Dakota states that the visibility improvements "are smaller than what is perceptible by an unaided human eye." Visibility improvements need not be perceptible in order to justify additional controls. Guidance at 38 and Clarifications Memo at 14.

    Furthermore, we caution North Dakota that it should not reject cost-effective controls and otherwise reasonable controls merely because some portion of visibility-impairing pollutants come from international sources. The national goal of the visibility protection program is to prevent any future and remedy any existing anthropogenic visibility impairment in Class I areas. Clean Air Act section 169A(a). We acknowledge that North Dakota cannot directly control emissions from international anthropogenic sources. Nonetheless, the state can focus on its own contributions to visibility impairment and must address the requirement to include emission limits and other measures for in-state sources that are necessary to make reasonable progress towards the national visibility goal.

13. Section 5.2, *§51.308(f)(2)(i) - Four Factors Analyses for Point Sources* and Appendix A. Throughout, we recommend that the costs of compliance be calculated consistent with the methods set forth in EPA's Control Cost Manual. We recommend that if North Dakota deviates from these methods that North Dakota explain, document, and provide a technical basis on how its alternative approach is appropriate. Guidance at 31.

14. Section 5.2, *§51.308(f)(2)(i) - Four Factors Analyses for Point Sources* and Appendix A. Throughout, where a firm-specific interest rate is available, we recommend that it be used to assess

costs. We also recommend that the basis for any firm-specific interest rate be well-documented and justified. For example, where applicable (e.g., for a regulated electric utility), North Dakota may choose to justify the rate based on the cost of capital, including from both equity and debt, approved for a particular company by the North Dakota Public Service Commission. If a firm-specific interest rate is not available, then the bank prime rate (currently 3.25%[4]) can be an appropriate estimate of the interest rate. These recommendations are consistent with EPA's Control Cost Manual at Chapter 2, page 15.

15. Section 5.2, *§51.308(f)(2)(i) - Four Factors Analyses for Point Sources* and Appendix A. Throughout, we recommend that the equipment life used to calculate costs for each control technology option, unless constrained by an enforceable retirement date for the source, be consistent with that found in the respective chapter of EPA's Control Cost Manual. Any deviations from EPA's Control Cost Manual need to be documented with an appropriate rationale provided as the basis for the deviation. Notably, the state's four factor analyses often use an equipment life of 20 years for selective catalytic reduction (NO_X) and wet and dry scrubbers, while the Control Cost Manual recommends an equipment life of 30 years. See Guidance at 33-34.

16. Section 5.2.1, *Otter Tail Power Company – Coyote Station*. Through the four factor analysis, North Dakota identifies cost-effective controls at Coyote Station for inclusion in the 2028 potential additional control modeling scenarios (PAC1 and PAC2). North Dakota noted that these control options are "in line with the control technologies and emissions rates of similar EGUs which were subject to the BART requirements." For the single unit at the facility, the cost-effective SO_2 controls include 1) replacing the existing SO_2 absorber module that would reduce SO_2 by 11,600 tons per year at a cost of $1,800 per ton of SO_2 reduced (PAC1 model scenario), and 2) flue gas desulfurization (FGD) efficiency improvements that would reduce SO_2 by 5,300 tons per year at a cost-effectiveness of $400 per ton of SO_2 reduced (PAC2 modeling scenario). For NO_X, the cost-effective control options include selective noncatalytic reduction (SNCR) that would reduce NOx by 3,000 tons per year at a cost-effectiveness of $1,700 per ton of NO_X reduced (PAC 1 model scenario). North Dakota then rejects these cost-effective controls because 1) the "modeling has indicated no expected significant change in visibility" (for either PAC1 or PAC2), and 2) the Class I areas in North Dakota are projected to achieve the URP. However, as noted in previous comments, North Dakota is likely to be improperly using the non-statutory factor of visibility as an additional factor to negate the four factor requirements. In addition, as noted in other comments, being below the glidepath is not an appropriate basis for rejecting cost-effective controls. Accordingly, using the four statutory factors, North Dakota should reassess its determination that these cost-effective controls are not warranted for Coyote Station.

17. Section 5.2.2, *Basin Electric Power Cooperative – Antelope Valley Station*. Through the four factor analysis, North Dakota identifies cost-effective controls at Antelope Valley Station for inclusion in the 2028 potential additional control modeling scenarios (PAC1 only). North Dakota noted that these control options are "in line with the control technologies and emissions rates of similar EGUs which were subject to the BART requirements." For each of the two identical units, the cost-effective SO_2 controls include increasing the stoichiometric ratio (Ca:S) on the existing flue gas desulfurization unit that would reduce SO_2 by 2,900 tons per year at a cost of $700 per ton of SO_2 reduced (PAC1 model scenario). North Dakota then rejects these cost-effective controls because 1) the "modeling has indicated no expected significant change in visibility" (for PAC 1),

[4] https://www.federalreserve.gov/releases/h15/

and 2) the Class I areas in North Dakota are projected to achieve the URP. However, as noted in other comments here, North Dakota is likely to be improperly using the non-statutory factor of visibility as an additional factor to negate the four statutory factors. The use of additional factors may be appropriate to aid in the evaluation but not for the purpose of negating the underlying requirements in the four statutory factors. In addition, as noted in other comments, being below the glidepath is not an appropriate basis for rejecting cost-effective controls. Accordingly, using the four statutory factors, North Dakota should reassess its determination that these cost-effective controls are not warranted for Antelope Valley Station.

18. Section 5.2.11, *North Dakota Upstream Oil and Gas Development (Area Sources)*. North Dakota elects not to evaluate SO_2 emission controls for upstream oil and gas sources because "NO_X emissions are the primary concern." However, the state's emissions analysis of upstream oil and gas sources in Section 4.3.1 shows large current (RepBase2) SO_2 emissions of 9,391 tons per year increasing to 15,203 tons per year in 2028 (2028OTB) (per Table 27). Accordingly, we recommend that North Dakota reassess its decision to not evaluate SO_2 controls for upstream oil and gas sources, or in the alternative, provide a technical basis for excluding SO_2 emissions analysis of upstream oil and gas sources given the large SO_2 emissions from these sources and explain why not implementing additional controls on this sector fulfills the state's regional haze requirements.

19. Section 5.2.11.1, *Wellsite Engines*, page 102. North Dakota concludes that individual engine controls are not reasonable because of "the limited emissions footprint from any single wellsite and relatively small contribution to visibility impairment from this sector." However, source apportionment analysis, as presented in Appendix C.2, indicates that the NO_X emissions from the oil and gas sector are the largest contributor to U.S. anthropogenic ammonium nitrate impairment at certain Class I areas in 2028. For example, at Lostwood Wilderness Area and Theodore National Park, the contribution to ammonium nitrate light extinction from the oil and gas sector in North Dakota is by far the largest for any state-sector in the WRAP region. Moreover, wellsite emissions account for 50% of the upstream oil and gas emissions which in turn account for the bulk of the emissions from the oil and gas sector.[5] Given the source apportionment analysis demonstrating large impacts from oil and gas NO_X emissions, North Dakota should reassess its statement in the SIP regarding individual engine controls and evaluate whether wellsite engines can be controlled as a sector (through a statewide rule), using the four statutory factors, or, conversely, explain how not controlling their oil and gas sources nonetheless fulfills their reasonable progress requirements.

20. Section 5.3.3, *§51.308(f)(2)(iv)(C) - Source Retirement and Replacement Schedules*. To the extent North Dakota is relying on anticipated fuel switching, existing retirements, or anticipated source retirements as part of its long-term strategy for making reasonable progress, those retirements and fuel switches must be enforceable and in the SIP. See Clarifications Memo at 10; Comment 2 above regarding enforceability requirements in a SIP under CAA Section 110(a).

21. Section 6, *§51.308(f)(3) – Modeling of Long-Term Strategy to Set Reasonable Progress Goals*. North Dakota appears to have set the reasonable progress goals (RPGs) for Lostwood Wilderness

[5] Additional Reasonable Control Strategies for Oil and Gas Emission Sources in the WESTAR-WRAP region, Memorandum, Table 1, Ramboll, March 23, 2020.

Area and Theodore Roosevelt National Park based on on-the-books control measures anticipated by 2028. However, the RPGs should be based on North Dakota's LTS, the LTSs of other states that may affect a Class I area, as well as other CAA requirements, which can be implemented by the end of the planning period. Guidance at 46-48; Clarifications Memo at 6. Even if North Dakota ultimately elects not to require additional control measures, the reported RPGs fail to reflect additional control measures in other states.

22. Section 6.1.1, *Modeling of Additional Potential Controls* and elsewhere. North Dakota argues that the costs of additional controls are not justified by the modeled visibility improvements, which the state characterizes as not being meaningful. For example, North Dakota asserts that the modeled visibility improvement of 0.1 dv at Lostwood Wilderness Area is insufficient to justify a combined capital cost of approximately $150 million and a combined annualized cost of approximately $30 million.[6] See our comment above regarding how states can properly consider visibility benefits as an optional additional factor in a four factor analysis.

23. Section 6.1.1, *Modeling of Additional Potential Controls and elsewhere*. In Section 6.1.1 the state discusses modeling results for two potential additional control scenarios (PAC1 and PAC2) to evaluate "how sensitive is the model to the magnitude of reductions evaluated and will this meaningfully impact future visibility." Figure 46 shows the effects of the PAC1 and PAC2 emissions reductions on the modeled RPG in 2028 and compares the RPGs to the URP in 2028. This approach correctly shows the modeled visibility progress relative to polluted conditions in 2028; however, this is not the approach that EPA Guidance recommends for evaluating visibility benefits when making control strategy decisions. Because the 2028 conditions still include substantial anthropogenic impairment, the 2028 model RPGs underestimate the visibility benefits of the PAC1 and PAC2 scenarios compared to natural visibility conditions. On page 16 of the Guidance, EPA states:

    > A state should not evaluate the visibility impact of a source by only using a delta deciview value for which the current visibility condition, or the projected 2028 condition, is the "background" in the delta deciview calculation. The "background" value should be the light extinction due to natural sources only. EPA recommends the use of the natural condition values included in the December 2018 Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program as the background value.

    Thus, when evaluating visibility changes in deciviews, an additional calculation is required to evaluate the visibility benefits of PAC1 and PAC2 relative to natural visibility conditions using this equation:

    > Visibility improvement = 10ln(PAC extinction + natural extinction)/10) - 10ln(natural extinction)/10)

    Where "PAC extinction" represents the change in light extinction in each of the PAC1 and PAC2 control scenarios, "natural extinction" represents the natural light extinction in inverse megameters at each Class I area, and "10" represents default Rayleigh scattering light extinction. A state may

[6] The costs noted are associated with potential additional controls at three facilities – Coyote Station, Antelope Valley Station, and Coal Creek Station – which would result in combined annual SO_2 and NO_X reductions of approximately 22,000 tons per year as reflected in Tables 18, 21, 23 of the draft SIP.

use the average of the daily visibility benefits on the 20 percent most anthropogenically impaired days as its visibility benefit metric. However, alternative metrics may be more appropriate when examining visibility impacts from individual sources. Modeled demonstrations that provide a single year of meteorological regimes at a given Class I area may not capture days over the broader multi-year period where a source may be contributing to visibility impairment. Depending on wind direction and other meteorological factors, emissions from a single source may not always or frequently impact a particular Class I area. But there may be individual day visibility impacts that may be important to consider. Therefore, for individual sources (such as Coyote and Antelope Valley), the maximum daily visibility impact on all days may be a more meaningful metric. A state may instead, or also, consider the maximum daily visibility benefit within the most impaired days or the values of visibility benefits on other days. Guidance at 15 and 35.

In summary, while the procedures used in the WRAP modeling for the RPG estimates in 2028 are consistent with EPA Guidance for comparing RPGs to the URP in 2028, additional analysis of day specific visibility benefits relative to natural visibility conditions is needed if the modeled visibility results are to be used to inform decisions about control strategies for specific facilities.

24. Equity and Environmental Justice. We encourage North Dakota to consider whether the SIP revision will result in equity and environmental justice impacts or impacts on any potentially affected communities. We also encourage North Dakota to describe any outreach to environmental justice communities that the state conducted, the opportunities North Dakota has provided for communities to give feedback on its proposed strategy, and the consideration North Dakota gave environmental justice in its technical analyses. See Clarifications Memo at 16.

25. Appendix A, *Department Four-Factor Summaries*. Throughout, for each of the selected sources, and for each emission unit evaluated, we recommend the appendix document and identify existing emission limits and where those limits are located (e.g., in the SIP, in a federal and/or state permit, in a consent decree). In addition, we recommend that it discuss how they compare to the baseline emissions used in the four-factor analyses. Some of this information is already contained in Tables 22 and 24 of Sections 4.2.1.1.1 and 4.2.1.1.2.

26. Appendix F.1, *NO_X BART analysis for Coal Creek Station Unit 1 and Unit 2*. In Table 6 and throughout, specify the averaging period for the lb/MMBtu emission rates.

27. Appendix F.1, *NO_X BART analysis for Coal Creek Station Unit 1 and Unit 2*. For clarity, in Tables 6 and 7 and throughout, use “LNC3+ w/SNCR” or “LNC3+ w/SCR” where SNCR or SCR are evaluated in combination with LNC3+. This is consistent with how the control options are described in Table 8 and elsewhere.

28. Appendix F.1, *NO_X BART analysis for Coal Creek Station Unit 1 and Unit 2*. In Table 8, include the incremental cost-effectiveness of LNC3+ with SCR over LNC3+ with SNCR. It is given as $12,200/ton at the bottom of page F.1-8.

29. Appendix F.1, *NO_X BART analysis for Coal Creek Station Unit 1 and Unit 2*. When discussing remaining useful life, specify the equipment life used for each control technology evaluated relative to the remaining useful life of the source.

30. Appendix F.1, *NO_X BART analysis for Coal Creek Station Unit 1 and Unit 2*. When evaluating visibility impacts, we recommend that visibility impacts be presented and evaluated on a per unit basis in parallel to the per unit costs of compliance in section 3.4.1.

31. Appendix F.1, *NO_X BART analysis for Coal Creek Station Unit 1 and Unit 2*. When evaluating visibility impacts, we recommend that North Dakota base its BART determination on the year with the highest visibility improvement rather than the average of the three modeled years (2000-2002).

32. Appendix F.1, *NO_X BART analysis for Coal Creek Station Unit 1 and Unit 2*, page F.1-14 and F.1-15. In addition to incremental cost-effectiveness, discuss whether the state finds the average cost-effectiveness for each control option reasonable. Specifically, describe whether the average cost-effectiveness of each of the control options is considered reasonable relative to any cost thresholds previously used by the state (when adjusted for inflation).

33. Appendix F.1, *NO_X BART analysis for Coal Creek Station Unit 1 and Unit 2*, page F.1-15. Consistent with the BART Guidelines, specify the incremental cost-effectiveness of LNC3+ with SCR relative to the next most stringent control option, LNC3+ with SNCR.

D.4.a – Department Response to EPA Comments

(RESERVED)

D.5 – Public Comments

(RESERVED)

D.5.a – Department Response to Public Comments
(RESERVED)