Attachment 3

Attachment 3 to Initial Comments of the Clean Energy Organizations

June 1, 2022

Submitted via Electronic Mail

Mr. L. David Glatt, P.E.
Director
North Dakota Department of Environmental Quality
918 East Divide Ave
Bismarck, ND 58501-1947

Mr. Jim Semerad
Director, Division of Air Quality
North Dakota Department of Environmental Quality
918 East Divide Ave
Bismarck, ND 58501-1947

RE: Comments of National Parks Conservation Association and Sierra Club on the Draft North Dakota State Implementation Plan for Regional Haze for the Second Planning Period.

National Parks Conservation Association ("NPCA") and Sierra Club, and Badlands Conservation Alliance ("Conservation Organizations") submit the attached comments on North Dakota Department of Environmental Quality's ("DEQ's") Draft State Implementation Plan ("SIP") for Regional Haze for the Second Planning Period. We also attach and incorporate by reference the following technical comments regarding North Dakota's second planning period SIP: (1) A Review of North Dakota Regional Haze State Implementation Plan, prepared by Joe Kordzi, dated May 2022 (attached as Ex. 1) ["2022 Kordzi Report"]; (2) *A Review of the Record Concerning the Technical Feasibility of Selective Catalytic Reduction on North Dakota Lignite Electric Generating Units*, prepared by Joe Kordzi and Ron Sahu, dated October 2020 (attached as Ex. 2) ["SCR Technical Feasibility Report"]; (3) *NOx and SO_2 Reasonable Progress Analysis for the Otter Tail Coyote Station*, prepared by Joe Kordzi, dated November 2020 (attached as Ex. 3) ["Coyote

Reasonable Progress Report"]; (4) *North Dakota BART and Reasonable Progress Analysis*, prepared by Joe Kordzi, dated November 2020 (attached as Ex. 4) ["2020 Kordzi Report"]; (5) Oil and Gas Sector Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories, prepared by Vicki Stamper and Megan Williams, dated March 6, 2020 (attached as Ex. 5) ["Stamper Report"]; and (6) Assessment of Cost Effectiveness Analyses for Controls Evaluated Four – Factor Analyses for Oil and Gas Facilities for the New Mexico Environment Department's Regional Haze Plan for the Second Implementation Period, prepared by Vicki Stamper and Megan Williams, dated July 2, 2020 (attached as Ex. 6).

National Parks Conservation Association ("NPCA") is a national organization whose mission is to protect and enhance America's National Parks for present and future generations. NPCA performs its work through advocacy and education, with its main office in Washington, D.C. and 24 regional and field offices. NPCA has over 1.5 million members and supporters nationwide, with more than 2570 in North Dakota. NPCA is active nationwide in advocating for strong air quality requirements to protect our parks, including submission of petitions and comments relating to visibility issues, regional haze State Implementation Plans, climate change and mercury impacts on parks, and emissions from power plants, oil and gas operations and other sources of pollution affecting National Parks and communities. NPCA's members live near, work at, and recreate in all the national parks, including those directly affected by emissions from North Dakota's sources.

Sierra Club is a national nonprofit organization with 67 chapters and more than 832,000 members dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. The Sierra Club has long participated in Regional Haze rulemaking and litigation across the country in order to advocate for public health and our nation's national parks.

Badlands Conservation Alliance is a non-profit organization based in western North Dakota dedicated to the wise stewardship of public lands, including the approximately 70,000 acres of Theodore Roosevelt National Park. Many of our members are from the small communities and rural landscapes surrounding the park, and value them for a host of ecological, heritage and personal reasons, frequently through multiple generations.

As explained in detail below, we have serious concerns regarding DEQ's Draft Regional Haze SIP for the second planning period. In addition to the errors identified in the attached 2022 Kordzi Report, DEQ must correct the following flaws:

1. DEQ has not adequately documented key data that underlies its SIP proposal, and failed to independently evaluate the availability of cost-effective controls for North Dakota sources.

2. DEQ impermissibly exempts EGUs and non-EGUs from further control analysis based on the state's purported compliance with the Uniform Rate of Progress.

3. DEQ impermissibly exempts EGUs from technically feasible, cost-effective controls based on the purportedly insignificant modeled visibility benefits associated with individual source controls.

4. DEQ erroneously and impermissibly relies on unenforceable emission reductions to avoid further control analyses for North Dakota sources.

5. DEQ improperly relies on on-the-books Clean Air Act programs to sidestep cost effective controls.

6. DEQ arbitrarily concludes that selective catalytic reduction technology is technically infeasible for lignite-burning electric generating units, and fails to mention or evaluate extensive, updated technological data in the record demonstrating that SCR is feasible across lignite EGUs.

7. DEQ arbitrarily and impermissibly fails to identify cost-effectiveness thresholds for reasonable progress controls.

8. DEQ's control evaluation for the state's EGU sector—the Coyote, Coal Creek, Milton Young, Antelope Valley, and Leyland Olds power plants, in particular—relies on numerous unsupported or erroneous cost assumptions, and fails to satisfy the Regional Haze Rule's requirement that the state include the "robust" technical demonstration showing that no additional controls are reasonable.

9. The Proposed SIP fails to properly evaluate the statutory reasonable progress factors for the non-EGU sources (Little Knife Gas Plant, Hess Tioga Gas Plant, Northern Border Pipeline Compressor Station No. 4, Great Plains Synfuels Plant) and instead refuses to impose any additional controls based on erroneous and unsupported cost assumptions, unenforceable equipment life assumptions, erroneous emission baseline figures, undocumented interest rates, too low plant efficiencies, and inappropriate inclusion of sales tax.

10. DEQ fails to – and must – conduct Four-Factor Analyses and require emission limitations on the oil and gas sector sources.

11. DEQ's treatment of the Regional Haze Rule's consultation requirement in Section 51.308(f)(2)(ii) is entirely perfunctory and does not satisfy the rule's requirements.

12. DEQ fails to evaluate the impacts of the proposed SIP on environmental justice and historically disadvantaged tribal communities.

As it currently stands, DEQ's Regional Haze SIP does not meet the legal requirements of the Clean Air Act or federal regulations, and therefore cannot be approved by EPA. We urge DEQ to revise the plan to address the fundamental flaws identified in these comments, the attached Kordzi Report and other above referenced reports which we incorporate in full in these comments.

I. INTRODUCTION AND BACKGROUND

To improve air quality in our most treasured landscapes, Congress passed the visibility protection provisions of the Clean Air Act in 1977, establishing "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in the mandatory class I Federal areas which impairment results from manmade air pollution."[1] "Manmade air pollution" is defined as "air pollution which results directly or indirectly from human activities."[2] To protect Class I areas' "intrinsic beauty and historical and archeological treasures," Congress instructed EPA to implement regulations that require states to design and implement programs to curb haze-causing emissions within their jurisdictions.[3] Each state must submit for EPA review a state implementation plan ("SIP") designed to make reasonable progress toward achieving natural visibility conditions.[4]

Each regional haze SIP must provide "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal."[5] Two of the most critical features of the regional haze program—both of which are at issue here—are the requirements, *first*, for the installation of Best Available Retrofit Technology ("BART") limits on emissions from the largest and oldest sources of haze pollution, like North Dakota's Coal Creek Station, which still does not have a fully approved BART determination, and *second*, a long-term strategy, including enforceable emissions limitations, for all other sources to ensure reasonable progress toward the national visibility goal.[6] Although many states addressed the Clean Air Act's BART requirements in their

---

[1] 42 U.S.C. § 7491(a)(1).
[2] *Id.* § 7491(g)(3).
[3] H.R. Rep. No. 294, 95th Cong. 1st Sess., at 203-04 (1977).
[4] *Id.* § 7491(b)(2).
[5] 42 U.S.C. § 7491(b)(2).
[6] *Id.* § 7491(b)(2)(B); 40 C.F.R. § 51.308(d)(1)(i)(B).

initial regional haze plans, EPA's 2017 revisions to the RHR make clear that BART was not a once-and-done requirement. Indeed, states "will need" to reassess "BART-eligible sources that installed only moderately effective controls (or no controls at all)" for any additional technically-achievable controls in the second planning period.[7] The haze requirements in the Clean Air Act present an unparalleled opportunity to protect and restore regional air quality by curbing visibility-impairing emissions from a variety of polluting sources.

North Dakota is home to two Class I areas—the Theodore Roosevelt National Park, which consists of three distinct units and the Lostwood Wildlife Refuge Wilderness Area. North Dakota's sources have significant, adverse impacts to air quality in several Class I areas across the region, including iconic places like Wind Cave and Badlands National Parks in South Dakota, Voyageurs National Park in Minnesota, and Medicine Lake and UL Bend Wilderness Areas in Montana. [8]

Congress directed states and the Environmental Protection Agency to protect and improve air quality in these national parks and wilderness areas to preserve our natural heritage for generations. Implementing the Regional Haze Rule, however, promises benefits beyond improving visibility. These same national parks and wilderness areas generate millions of dollars in tourism revenue, provide habitat for a range of species, and provide year-round recreational opportunities for residents. Moreover, pollutants that cause visibility impairment also harm public health. For example, oxides of nitrogen ("NOx") are a precursor to ground-level ozone which is associated with respiratory disease and asthma attacks. NOx also reacts with ammonia, moisture and other compounds to form particulates that can cause and/or worsen respiratory diseases, aggravate heart disease, and lead to premature death. Similarly, sulfur dioxide ("SO_2") increases asthma symptoms, leads to increased hospital visits, and can also form particulates. NOx and SO_2 emissions also harm terrestrial and aquatic plants and animals through acid rain as well as through deposition of nitrates (which in turn cause ecosystem changes including eutrophication of mountain lakes).

Unfortunately, the Clean Air Act's goal of achieving natural visibility in all Class I areas remains unfulfilled because the states, including North Dakota, have failed to require cost-effective, industry-standard emission controls at many of the largest and oldest sources of haze-causing pollution, as discussed below.

---

[7] 82 Fed. Reg. 3078, 3,083 (Jan. 10, 2017); *see also id.* at 3,096 ("states must evaluate and reassess all elements required by 40 CFR 51.308(d)").
[8] Draft SIP, App'x D at pdf page 147, 254.

II. LEGAL FRAMEWORK

A. The Regional Haze Rule

The Clean Air Act establishes "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." 42 U.S.C. § 7491(a)(1). To that end, EPA issued the Regional Haze Rule, which requires the states (or EPA where a state fails to act) to make incremental, "reasonable progress" toward eliminating human-caused visibility impairment at each Class I area by 2064. 40 C.F.R. § 51.308(d)(1), (d)(3). Together, the Clean Air Act and EPA's Regional Haze Rule require states to periodically develop and implement state implementation plans ("SIPs"), each of which must contain a long-term strategy, which includes *enforceable* "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward the national goal." 42 U.S.C. § 7491(b)(2); *see also* 42 U.S.C. § 7410(a)(2); 40 C.F.R. § 51.308.

In developing its long-term strategy, a state must consider all anthropogenic sources of visibility impairment and evaluate different emission reduction strategies, including and beyond those prescribed by the BART provisions.[9] A state should consider "major and minor stationary sources, mobile sources and area sources."[10] At a minimum, a state must consider the following factors in developing its long-term strategy:

> (A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
> (B) Measures to mitigate the impacts of construction activities;
> (C) Emissions limitations and schedules for compliance to achieve the reasonable progress goal;
> (D) Source retirement and replacement schedules;
> (E) Smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the State for these purposes;
> (F) Enforceability of emission limitations and control measures; and
> (G) The anticipated net effect on visibility due to projected changes in point, area, and mobile emissions over the period addressed by the long-term strategy.[11]

---

[9] 40 C.F.R. § 51.308(f).
[10] *Id.* § 51.308(f)(2)(i).
[11] *Id.* § 51.308(f)(2)(iv).

Additionally, a state must document the technical basis for its long-term strategy, including a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy for making reasonable progress.[12]

In evaluating the emission reductions necessary to make "reasonable progress" toward natural visibility, the state must consider four factors: (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of any potentially affected sources. 42 U.S.C. § 7491(g)(1); 40 C.F.R. § 51.308(d)(1)(i)(A), (d)(3). Notably, the statute does *not* list visibility improvement as a fifth factor in the reasonable progress analysis, and in implementing those statutory factors, EPA has made clear that it is *not* appropriate to reject a cost-effective control measures based on purportedly insufficient visibility benefits. In determining whether each state's haze plan satisfies the statutory mandate to make reasonable progress, EPA reviews whether the state follows the requirements to consult with other states and reasonably considers the four statutory factors for reasonable progress. 40 C.F.R. § 51.308(d)(1)(iii).

B. EPA's 2017 Revisions to the Regional Haze Rule

On January 10, 2017, the EPA revised the Regional Haze Rule to strengthen and clarify the reasonable progress and consultation requirements of the rule. *See generally* 82 Fed. Reg. 3078. In particular, the rule revisions make clear that states are to *first* conduct the required four-factor analysis for its sources, considering the four statutory factors, and *then* use the results from its four-factor analyses and determinations to develop the reasonable progress goals.[13] Thus, the rule "codif[ies]" EPA's "long-standing interpretation" of the SIP "planning sequence" States are required to follow:

> (1) [C]alculate baseline, current and natural visibility conditions, progress to date and the [Uniform Rate of Progress] URP;
>
> (2) [D]evelop a long-term strategy for addressing regional haze by evaluating the four factors to determine what emission limits and other measures are necessary to make reasonable progress;
>
> (3) [C]onduct regional-scale modeling of projected future emissions under the long-term strategies to establish RPGs and then compare those goals to the URP line; and

[12] 40 C.F.R. § 51.308(f)(2)(i).
[13] 82 Fed. Reg. 3078, 3090-91 (Jan. 10, 2017).

> (4) [A]dopt a monitoring strategy and other measures to track future progress and ensure compliance.[14]

Thus, the Regional Haze Rule makes clear that a state must conduct four-factor analysis and cannot rely on uniform rate of progress as an excuse for failing to perform the core functions of the law:

> The CAA requires states to determine what emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors. The CAA does not provide that states may then reject some control measures already determined to be reasonable if, in the aggregate, the controls are projected to result in too much or too little progress. Rather, the rate of progress that will be achieved by the emission reductions resulting from all reasonable control measures is, by definition, a reasonable rate of progress. … [I]f a state has reasonably selected a set of sources for analysis and has reasonably considered the four factors in determining what additional control measures are necessary to make reasonable progress, then the state's analytical obligations are complete if the resulting RPG for the most impaired days is below the URP line. *The URP is not a safe harbor*, however, and states may not subsequently reject control measures that they have already determined are reasonable.[15]

Moreover, for each Class I area within its borders, a state must determine the uniform rate of progress ("URP"), which is the amount of progress that, if kept constant each year, would ensure that natural visibility conditions are achieved in 2064. 40 C.F.R. § 51.308(d)(1)(i)(B). If a state establishes reasonable progress goals that provide for a slower rate of improvement in visibility than the uniform rate of progress, the state must provide a technically "robust" demonstration, based on a careful consideration of the statutory reasonable progress factors, that "there are no additional emission reduction measures for anthropogenic sources or groups of sources" that are reasonably be anticipated to contribute to visibility impairment in affected Class I areas.[16]

Although many states addressed the Clean Air Act's BART requirements in their initial regional haze plans, EPA's 2017 revisions to the Regional Haze Rule make clear that BART was not a once-and-done requirement. Indeed, states "will need" to reassess "BART-eligible sources that installed only moderately effective

[14] *Id.* at 3091.
[15] *Id. at* 3093 (emphasis added).
[16] *Id.* § 51.308 (f)(2)(ii)(A).

controls (or no controls at all)" for any additional technically-achievable controls in the second planning period.[17]

To the extent that a state declines to evaluate additional pollution controls for any source based on that source's planned retirement or decline in utilization, it must incorporate those operating parameters or assumptions as enforceable limitations in the second planning period SIP.[18] The Clean Air Act requires that "[e]ach state implementation plan . . . *shall*" include "enforceable limitations and other control measures" as necessary to "meet the applicable requirements" of the Act. 42 U.S.C. § 7410(a)(2)(A). The Regional Haze Rule similarly requires each state to include "enforceable emission limitations" as necessary to ensure reasonable progress toward the national visibility goal.[19] Moreover, where a source plans to permanently cease operations or projects that future operating parameters (*e.g.*, limited hours of operation or capacity utilization) will differ from past practice, and if this projection has a deciding whether additional pollution controls are necessary to ensure reasonable progress, then the state "must" make those parameters or assumptions into enforceable limitations.[20]

Finally, the state's SIP revisions must meet certain procedural and consultation requirements.[21] The state must consult with the Federal Land Managers ("FLMs") and look to the FLMs' expertise of the lands and knowledge of the way pollution harms them to guide the state to ensure SIPs do what they must to help restore natural skies.[22] The rule also requires that in "developing any implementation plan (or plan revision) or progress report, the State must include a description of how it addressed any comments provided by the Federal Land Managers."[23]

C. EPA's July 8, 2021 Regional Haze Clarification Memorandum

On July 8, 2021, EPA issued additional guidance clarifying certain aspects of the revised Regional Haze Rule and providing further information to states and EPA regional offices regarding their planning obligations for the Second Planning Period.[24] EPA's July 2021 "Clarification Memo" confirms that certain aspects of

---

[17] 82 Fed. Reg. at 3,083; *see also id.* at 3,096 ("states must evaluate and reassess all elements required by 40 CFR 51.308(d)").
[18] 40 C.F.R. pt.51, App'x. Y § IV(D)(4)(d)(2) (if a).
[19] *See generally* 40 C.F.R. § 51.308(d)(3).
[20] *See* 40 C.F.R. pt. 51, App. Y § IV(D)(4)(d)(2).
[21] For example, in addition to the RHR requirements, states must also follow the SIP processing requirements in 40 C.F.R. §§ 51.104, 51.102.
[22] 40 C.F.R. § 51.308(i).
[23] *Id.* § 51.308(i)(3).
[24] July 8, 2021 Memo from Peter Tsirogotis to Regional Air Directors, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period at 3 ("July 2021

DEQ's proposed Regional Haze SIP are fundamentally flawed and cannot be approved. Particularly relevant here, EPA made clear that States must secure additional emission reductions that build on progress already achieved, there is an expectation that reductions are additive to ongoing and upcoming reductions under other CAA programs.[25] In evaluating sources for emission reductions, EPA emphasized that:

> Source selection is a critical step in states' analytical processes. All subsequent determinations of what constitutes reasonable progress flow from states' initial decisions regarding the universe of pollutants and sources they will consider for the second planning period. States cannot reasonably determine that they are making reasonable progress if they have not adequately considered the contributors to visibility impairment. Thus, while states have discretion to reasonably select sources, this analysis should be designed and conducted to ensure that source selection results in a set of pollutants and sources the evaluation of which has the potential to meaningfully reduce their contributions to visibility impairment.[26]

Thus, it is generally not reasonable to exclude from further evaluation large sources or entire sectors of visibility-impairing pollution. Moreover, the memo reiterates that the fact that a Class I area is meeting the Uniform Rate of Progress is "not a safe harbor" and does not excuse the state from its obligation to consider the statutory reasonable progress factors in evaluating reasonable control options.[27]

For sources that have previously installed controls, states should still evaluate the "full range of potentially reasonable options for reducing emissions," including options that may "achieve greater control efficiencies, and, therefore, lower emission rates, using their existing measures."[28] Moreover, "[i]f a state determines that an in-place emission control at a source is a measure that is necessary to make reasonable progress and there is not already an enforceable emission limit corresponding to that control in the SIP, the state is required to adopt emission limits based on those controls as part of its long-term strategy in the SIP via the regional haze second planning period plan submission."[29] This means that so-called "on-the-way" measures, including anticipated shutdowns or reductions in a source's emissions or utilization, that are relied upon to forgo a four-factor analysis or to shorten the remaining useful life of a source "*must* be included

Memo"), https://www.epa.gov/visibility/clarifications-regarding-regional-haze-state-implementation-plans-second-implementation.

[25] *Id*. at 2.

[26] *Id*. at 3.

[27] *Id*. at 2.

[28] *Id*. at 7.

[29] *Id*. at 8.

in the SIP" as enforceable emission reduction measures.[30] In addition, the Memo makes clear that a state should generally not reject cost-effective and otherwise reasonable controls merely because there have been emission reductions since the first planning period owing to other ongoing air pollution control programs or merely because visibility is otherwise projected to improve at Class I areas. Finally, the Memo confirms EPA's recommendation that states take into consideration environmental justice concerns and impacts in issuing any SIP revision for the second planning period.

In sum, EPA's July 2021 Memo makes clear that the states' regional haze plans for the second planning period must include meaningful emission reductions to make reasonable progress towards the national goal of restoring visibility in Class I areas. The Clarification Memo confirms that DEQ's efforts to avoid emission reductions—by asserting, for example, that reductions are not necessary because visibility has improved, because reductions are anticipated reductions at some later date or due to implementation of another program, or because a source has some level of control— is at odds with the state's haze obligations under the Clean Air Act and the Regional Haze Rule itself.

III. DEQ'S PROPOSED SIP FAILS TO MEET THE BASIC REQUIREMENTS OF THE REGIONAL HAZE RULE.

Section 51.308(f)(2)(i) of the Regional Haze Rule requires a SIP to include a description of the criteria the state has used to determine the sources or groups of sources it evaluated for potential controls. In its Draft SIP, DEQ indicates that it identified sources for which it would request four-factor control analyses based on the Q/d metric—*i.e.*, emissions divided by distance to Class I area.[31] Based on 2012-2016 emissions, DEQ established a screening threshold Q/d value of 10 resulting in the screening out of most oil and gas sector emissions as well as sources with lower emissions or located at farther distances from Class I areas.[32]

Although DEQ required four-factor reasonable progress analyses for each of the facilities exceeding the 10 Q/d threshold, the agency then summarily declined to impose any controls, concluding:

> North Dakota is currently projected to meet its 2028 visibility goals and is projected to remain on track to meet the 2064 visibility goals (below the adjusted glidepath). Continuing to remain below an

[30] *Id*. at 8-9 (emphasis added).
[31] North Dakota Department of Environmental Quality (" DEQ"), Draft North Dakota State Implementation Plan for regional Haze, A Plan Revision for the Regional Haze Program Requirements of Section 308 of 40 CFR Part 51, Subpart P – Protection of Visibility at 95 ("Draft SIP").
[32] *Id*.

> adjusted glidepath and showing improvement on the most impaired days for each planning period will accomplish the 2064 end goals. North Dakota has determined that the additional controls evaluated will not have a meaningful impact on the 2028 visibility projections. Therefore, the Department determined that it is not reasonable to require additional controls during this planning period.[33]

Moreover, by accepting the four-factor analyses for industry submissions, the DEQ effectively takes the position that no additional controls are warranted. For example, EGU owners submitted four factor analyses asserting that selective catalytic reduction ("SCR") is technically infeasible for any EGU that burns North Dakota lignite, a finding the state adopted as its own.

As explained below, and in the attached 2022 Kordzi Report, which we incorporate by reference, that explanation and the agency's conclusion about the feasibility of SCR technology are arbitrary and capricious, and inconsistent with the Clean Air Act and the Regional Haze Rule, for numerous reasons.

A. DEQ Failed to Conduct Any Independent Emission Control Analyses for Any Sources.

The most significant omission in the proposed SIP is DEQ's failure to independently evaluate and analyze emission reduction measures for any source that may necessary to make reasonable progress based on a four-factor analysis. The RHR requires, in part, that a state's long-term strategy meet the following requirements:

> *The State* must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment. The State should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. *The State* must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in

[33] *Id*. at 11.

> determining whether the measure is necessary to make reasonable progress.

40 C.F.R. §51.308(f)(2)(i).

Here, DEQ developed a list of sources for which the agency requested information relating to a four-factor analysis, and the agency's Draft SIP includes those individual analyses (without change) as attachments. It is clear that the agency itself did not independently evaluate, analyze or verify current emission control efficacies, cost analyses or assumptions, or the technological feasibility of additional emission reductions measures from any source.[34]. As the Regional Haze Rule makes clear, the *state* has a duty to conduct a "robust" analysis of potential reasonable progress controls, and must "document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects."[35]

In fact, the entirety of DEQ's four-factor analysis for each source appears in a few short paragraphs essentially summarizing the individual source's analyses, without any critical or independent evaluation. As discussed more fully below and in the attached technical report of Joe Kordzi, the technical and emissions inventory data that DEQ did include in the SIP for sources contains several significant errors and unsupported assumptions, and appears to be designed to reach the respective utilities' preferred results—a determination that any additional controls are unnecessary.

This lack of basic documentation not only precludes DEQ or any independent reviewer from verifying the respective utility modeling or control cost analyses, but it is contrary to the Clean Air Act and the Regional Haze Rule itself. [36] DEQ has a legal obligation to submit a SIP that complies with the Clean Air Act—which includes, among other things, requiring enforceable emission limitations necessary to ensure reasonable progress.[37] And as explained below, and in the attached Kordzi Reports, there are, in fact, cost-effective and reasonable post-combustion controls or upgrades for the facilities the state selected for a four factor analysis.

---

[34] 2022 Kordzi Report at 7-8; 12-17.
[35] 40 C.F.R. § 51.308(f)(2)(iii).
[36] *See id*.
[37] 42 U.S.C. §§ 7410(a)(2)(A); 7491(b)(2).

B. DEQ impermissibly exempts sources from further control analysis based on the state's purported compliance with the Uniform Rate of Progress.

As noted, DEQ attempts to justify its decision to defer further emission reductions for every major source in the state by pointing out that the Class I areas affected by North Dakota's EGUs and non EGUs appear to be trending below these area's glide path or URP.[38] EPA has made clear, however, that meeting or exceeding the glide path or URP does *no*t obviate the need for states to conduct a robust analysis and making a technical demonstration that additional controls or emission reductions are not reasonable. "[A]n evaluation of the four statutory factors is required . . . regardless of the Class I area's position on the glidepath . . . . the URP does not establish a 'safe harbor' for the state in setting its progress goals."[39] Rather, states must "determine what emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors" and must not reject "control measures determined to be reasonable" based on the degree of progress.[40] Indeed, in its July 8, 2021 Memo, EPA reiterated that the uniform rate of progress is "not a safe harbor," and that it is not appropriate to reject cost-effective emission reductions on the basis that visibility in a particular Class I area is on the glide path. Instead, states are required to "evaluate and determine emission reduction measures that are necessary to make reasonable progress *by considering the four statutory factors*."[41] Here, DEQ's decision to defer reasonable and cost-effective controls to another planning period, simply because the affected Class I areas are on the glidepath, is contrary to the Clean Air Act and the Regional Haze Rule.

Third, DEQ's "glide path" rationale is misplaced because the agency failed to evaluate the Clean Air Act's reasonable progress factors in determining whether emission reductions are may be necessary to ensure reasonable progress towards

---

[38] Draft SIP at 11.
[39] 81 Fed. Reg. 66,331, 66,631 (Sept. 27, 2016); *see also* 81 Fed. Reg. 296, 326 (Jan. 5, 2016) (determining, as part of the reasonable progress federal implementation plan for Texas, "the uniform rate of progress is not a 'safe harbor' under the Regional Haze Rule."); EPA, Responses to Comments at 120, Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan: Best Available Retrofit Technology and Interstate Transport Provisions, EPA Docket No. EPA-R06-OAR-2016-6011 (June 2020) ("EPA has repeatedly and consistently taken the position that meeting a specific reasonable progress goal is not, itself, a "safe harbor," and does not relieve the state of the obligation to consider additional measures for reasonable progress. If it is reasonable to make more progress than the URP, a state must do so, as EPA explained in the 1999 Regional Haze Rule) (citing 64 Fed. Reg. at 35732); *see also* 81 Fed. Reg. at 66,370 ("EPA's longstanding interpretation of the Regional Haze Rule is that 'the URP does not establish a 'safe harbor' for the state in setting its progress goals.") (quoting 79 Fed. Reg. 74818, 74834)).
[40] 82 Fed. Reg. at 3093; see also 81 Fed. Reg. at 66,631.
[41] July 2021 Memo at 15-16 (emphasis added).

natural visibility in *each* Class I area that North Dakota sources affect, including Class I areas in North Dakota as well as out-of-state Class I areas.[42] In so doing, North Dakota must provide a "robust demonstration," including documenting the criteria used to determine which sources or groups or sources were evaluated and how the four factors were taken into consideration. Given North Dakota's sources' impacts to iconic places like Wind Cave and Badlands National Parks in South Dakota, Voyageurs National Park in Minnesota, and Medicine Lake and UL Bend Wilderness Areas in Montana, [43] DEQ must provide the "robust demonstration," based on a consideration of the four statutory reasonable progress factors, that no further emission reductions are cost effective and reasonable for the power plants that affect visibility in Class I areas outside the state. And again, as discussed further below, the attached Kordzi Report evaluated each of North Dakota's power plants and the non-EGUs evaluated by DEQ, and concludes that there are cost-effective control measures available, or at a minimum, that those facilities should have their emissions limits tightened to ensure current levels do not rise.

Finally, DEQ's improper reliance on the URP to defer any control determinations is compounded by its erroneous adoption of the projected deciview improvement at nearby Class I areas, included in EPA's 2028 modeling update, as the state's reasonable progress goal.[44] "Reasonable progress goals," however, are a function of the reasonable progress achievable through the adoption of emission controls and reductions, based on a consideration of the four statutory factors: (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of any potentially affected sources.[45] As EPA's July 8, 2021 Memo makes clear, reasonable progress goals "are *the modeled result of the measures in states' long-term strategies*, as well as other measures required under the CAA (that have compliance dates on or before the end of 2028). Thus, RPGs cannot be determined before states have conducted their four-factor analyses and determined the control measures that are necessary to make reasonable progress."[46] Here, DEQ failed to conduct any analysis or require any emission reductions as part of its SIP, and therefore its selection of EPA's projected deciview improvements from *other* Clean Air Act measures not included in the state's SIP, is arbitrary and capricious and contrary to the Regional Haze Rule.

---

[42] *See* 40 C.F.R. § 51.308(f)(2) ("Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State *and for each mandatory Class I Federal area located outside the State that may be affected by emissions from the State*.") (emphasis added); *id*. § 51.308(f) (3)(ii)(A)-(B).
[43] Draft SIP, App'x D at pdf page 147, 254.
[44] Draft SIP at 37-38.
[45] 42 U.S.C. § 7491(g)(1); 40 C.F.R. § 51.308(d)(1)(i)(A), (d)(3).
[46] July 2021 Memo at 6.

C. DEQ Cannot Rely on the Purported Lack of Visibility Benefits to Avoid Cost-Effective Controls.

Based on two air quality modeling scenarios, DEQ concludes that additional controls for North Dakota sources will not have a perceptible visibility benefit in the relevant Class I areas and therefore no controls are warranted to ensure reasonable progress.[47] To reach that conclusion, DEQ evaluated visibility modeling for two control scenarios for just Antelope Valley and Coyote Station. Under the first scenario, DEQ asserted that controls at each of those facilities would result in 22,000 tons of combined NOx and SO_2 reductions at a capital cost of approximately $150 million and an annualized cost of approximately $30 million, with a projected improvement to baseline 2028 visibility of 0.1 deciview benefit at Lostwood Wilderness Area and 0.08 deciviews at Theodore Roosevelt National Park. The second scenario included over 7,000 tons of combined NOx and SO_2 reductions at a capital cost of approximately $0.5 million and an annualized cost of approximately $2 million, with a projected visibility benefit of 0.04 deciview improvement at Lostwood and 0.03 deciviews at Theodore Roosevelt. Apparently according to DEQ, these benefits were not worth the cost.

DEQ's approach is inconsistent with Clean Air Act. Indeed, the consideration of visibility perceptibility (or the lack thereof) has never been allowed under the Regional Haze Rule's reasonable progress provisions. While visibility is the goal of the regional haze program, *id*. at 7491(a)(1), the four-factor reasonable progress evaluation does not itself incorporate visibility, and states may not give it the same weight as the four statutory factors. Indeed, in finalizing the 2017 revisions to the Regional Haze Rule, EPA made clear that "the existence of an impact above a perceptibility threshold is not a statutory or regulatory factor to be used when determining whether a source or sources contribute to visibility impairment or when determining measures needed for reasonable progress."[48]

As a fundamental matter, regional haze is "visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area." 40 CFR 51.301. At any given Class I area, hundreds or even thousands of individual sources may contribute to regional haze. Thus, it is *not* appropriate to reject a control measure for a single emission unit, a single source, or even a group of sources on the basis of the associated visibility benefits being imperceptible to the human eye. Nor may states use the lack of visibility improvement as a factor that overrides controls that are cost-effective and reasonable under a four-factor analysis. In other words, at the control analysis stage, states should consider *only* the four statutory factors to determine whether

---

[47] *Id*. at 10.

[48] Responses to Comments on Protection of Visibility: Amendments to Requirements for State Plans; Proposed Rule (81 FR 26942, May 4, 2016), Docket Number EPA-HQ-OAR-2015-0531 U.S. Environmental Protection Agency, December 2016. Page 268.

control measures are necessary to achieve reasonable progress. The Regional Haze Rule and EPA's 2019 Guidance make clear that states cannot weigh the supposed lack of sufficient visibility benefit of controls against the four statutory factors to identify appropriate control measures. Rather, for each source or source category that is selected for further analysis during the screening process, states would require whatever control measures are determined to be reasonable after considering the four statutory factors alone. And as explained in the attached technical reports, additional controls or emission control upgrades are cost-effective, technically feasible, and reasonable for several sources.

D. DEQ Erroneously Relied on Unenforceable and Unverifiable Emission Reductions.

Along with its unlawful reliance on the URP to excuse any further emission reductions, DEQ repeatedly points to "anticipated" or "planned" emission reductions or source retirements to avoid a meaningful analysis of potential cost-effective controls.[49] This blanket reliance on remaining useful life to excuse further analysis is flawed in at least four ways. First, to the extent that DEQ declines to evaluate additional pollution controls for any source based on that source's planned decline in utilization or anticipated emission reductions, North Dakota must incorporate those operating parameters or emissions assumptions as enforceable limitations in the second planning period SIP.[50] The Clean Air Act requires that "[e]ach state implementation plan . . . *shall*" include "enforceable limitations and other control measures" as necessary to "meet the applicable requirements" of the Act. 42 U.S.C. § 7410(a)(2)(A). The Regional Haze Rule similarly requires each state to include "enforceable emission limitations" as necessary to ensure reasonable progress toward the national visibility goal.[51] Underscoring this requirement of enforceability, RPGs adopted by a state with a Class I area must be based only on emission controls measures that have been adopted and are enforceable.[52] Thus, to the extent that DEQ declines to impose cost-effective emissions limitations for sources that are expected to reduce operation or emissions, the state must, at a minimum, make those future emissions reductions federally enforceable through the second planning period SIP.

Second, even where a facility, like Coal Creek Station, has installed only moderately effective controls, like low-NOx post-combustion controls, DEQ is obligated to consider whether there are cost-effective control measures that could be

---

[49] *See, e.g.*, Draft SIP at 64-66 (discussing emission reductions at Coal Creek and Coyote); *see also* Draft SIP at 102 (discussing anticipated reduction of NOx emissions at Coal Creek).
[50] 40 C.F.R. pt.51, App'x. Y § IV(D)(4)(d)(2) (if a).
[51] *See generally* 40 C.F.R. § 51.308(d)(3).
[52] 40 C.F.R. § 51.308(f)(3).

implemented.[53] As EPA explained in its revisions to the Regional Haze Rule, we anticipate that a number of BART-eligible sources that installed only moderately effective controls (or no controls at all) will need to be reassessed.[54] EPA's July 2021 Memo is also instructive. There, the agency made clear that in evaluating reasonable progress for all sources, states should consider the "full range of potentially reasonable options for reducing emissions . . . may be able to achieve greater control efficiencies, and, therefore, lower emission rates, using their existing measures."[55] As discussed below, for several North Dakota sources, including Coal Creek, there are some types of control measures that are likely to be cost-effective *in addition* to current controls.

E. DEQ Improperly Defers Making any Four-Factor Determinations Based on Purported Emission Reductions from Existing Clean Air Act Programs.

In addition to its reliance on "anticipated" and unenforceable emission reductions, DEQ relies heavily on the continued implementation of various air quality rules and programs to ensure reasonable progress.[56] DEQ's reliance on existing air quality programs is misplaced. First, as discussed below and in the attached technical reports of Joe Kordzi and Ron Sahu, there are cost-effective pollution control measures that are readily achievable for several of North Dakota's EGUs and non EGUs. In fact, several EGUs are capable of achieving on a continuous basis better emission rates than they are currently displaying. Second, reasonable progress requires that states consider the four statutory factors and adopt and include in their SIPs enforceable emission limitations to achieve reasonable progress toward the elimination of all anthropogenic pollution in Class I areas. This means that states must secure meaningful emission reductions that build on progress already achieved, there is an expectation that reductions are

---

[53] *See, e.g.*, 40 C.F.R. § 51.308(f)(2)(i) (The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment."); *see also* 82 Fed. Reg. at 3088 ("Consistent with CAA section 169A(g)(1) and our action on the Texas SIP, a state's reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by . . . failing to include cost-effective controls at sources with significant visibility impacts, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a FIP."). Even if a source has a limited remaining useful life, EPA's Guidance contemplates that states consider cost-effective operational upgrades. Regional Haze Rule Guidance § II.B.3(f) ("If a control measure involves only operational changes, there typically will be only small capital costs, if any, and the useful life of the source or control equipment will not materially affect the annualized cost of the measure.").

[54] 82 Fed. Reg. at 3,083.

[55] July 2021 Memo at 7.

[56] *See, e.g.*, Draft SIP at 113-17

additive to ongoing and upcoming reductions under other CAA programs. Indeed, as EPA's July 2021 Memo makes clear,

> a state should generally not reject cost-effective and otherwise reasonable controls merely because there have been emission reductions since the first planning period owing to other ongoing air pollution control programs or merely because visibility is otherwise projected to improve at Class I areas. More broadly, we do not think a state should rely on these two additional factors to summarily assert that the state has already made sufficient progress and, therefore, no sources need to be selected or no new controls are needed regardless of the outcome of four-factor analyses.[57]

IV. DEQ MUST REEVALUATE CONTROLS FOR EGU SOURCES OF HAZE CAUSING POLLUTION.

Aside from DEQ's improper reliance on the so-called glidepath or the purported lack of sufficient visibility benefits to avoid additional pollution controls, the attached Kordzi Report makes clear that there are cost-effective and reasonable control upgrades for many of the state's largest sources of haze-causing pollution, including Coyote, Antelope Valley, Coal Creek Station, Milton R. Young, and Leland Olds, in addition to several non-EGU sources. Ultimately, DEQ's reasonable progress analyses must be based on accurate information that is consistent with the Act and EPA's implementing regulations.

A. Selective Catalytic Reduction is Technically Feasible for North Dakota Lignite EGU's.

By accepting the four-factor analyses, of North Dakota's EGUs without modification or verification, DEQ effectively adopts the position that selective catalytic reduction ("SCR") in any configuration is technically infeasible for any EGU that burns North Dakota lignite. That outdated position, however, is not supported by the record. Indeed, as the attached technical report of Joe Kordzi and Ron Sahu demonstrate, recent technological developments make clear that SCR technology is, in fact, technically feasible for North Dakota lignite fired EGUs. As a result, DEQ must evaluate SCR as a control option for each of those lignite facilities as part of North Dakota's Regional Haze SIP.[58] Although EPA approved DEQ's

---

[57] July 2021 Memo at 13.

[58] 40 C.F.R. § 51.308(f)(2)(iii); *see also* 40 C.F.R. pt.51, App'x. Y § IV(D)Step 2 (describing the process of determining technical feasibility). Because "the reasonable progress factors share obvious similarities with the BART factors," those factors are relevant to determining appropriate control measures for reasonable progress. 82 Fed. Reg. at 3,091.

finding, more than a decade ago, that SCR was not technically feasible for lignite facilities, EPA also made clear that North Dakota would be required to both revisit the range of technically feasible controls, including SCR, and the cost-effectiveness of those controls in its second round of regional haze SIP.[59] EPA's 2016 revisions to the Regional Haze Rule confirm that states "will need" to reassess "BART-eligible sources that installed only moderately effective controls (or no controls at all)" for any additional technically-achievable controls in the second planning period.[60] Moreover, any reasonable progress analysis—including any conclusion that SCR is not technically feasible—must be supported by a robust technical demonstration.[61] DEQ may not simply rely on its decade-old factual findings, or the conclusory assertions of the lignite power plant operators that SCR technology is infeasible.

B. DEQ Arbitrarily Fails to Identify Cost-Effectiveness Thresholds for Reasonable Progress Controls.

Under the Regional Haze rule,

> The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy.[62]

DEQ has attached several individual source four-factor analyses to the SIP. In each case, the agency concludes, without any analysis or explanation and without establishing any cost threshold for controls, that the costs of individual source controls is too expensive.

The agency's failure to evaluate or establish reasonable cost thresholds is arbitrary and contrary to the Regional Haze Rule, for several reasons. First, the cost evaluation—which is a statutory requirement—requires more than simply estimating control costs for an individual source or arbitrarily determining that the costs exceed the benefits. It requires the state to document why each of the four-factors, including the costs of controls, would or would not be considered reasonable. In its 2019 Guidance, EPA recommends that such determinations be made on the

---

[59] *See, e.g.*, 77 Fed. Reg. 20,894, 20,937/2 (Apr. 6, 2012).
[60] 82 Fed. Reg. 3,078, 3,083/1 (Jan. 10, 2017); *see also id.* at 3,096 ("states must evaluate and reassess all
elements required by 40 CFR 51.308(d)").
[61] 40 C.F.R. §§ 51.308 (d)(3)(iii); (f)(3)(ii)(A); *see also* 82 Fed. Reg. at 3,126 ("The State must provide a robust demonstration, including documenting the criteria used to determine which sources or groups or sources were evaluated and how the four factors required by paragraph (f)(2)(i) were taken into consideration in selecting the measures for inclusion in its long-term strategy.").
[62] 40 C.F.R. § 51.308 (f)(2)(i) (emphasis added).

basis of a cost per ton of pollutant reduced. Here, DEQ has not explained what level of cost (if any) would be considered acceptable and why this is reasonable for North Dakota sources.

Second, DEQ's approach is arbitrarily inconsistent with its own precedent. In the BART context, DEQ established a $4,100/ton for average cost-effectiveness and a $7,300/ton for incremental costs-effectiveness threshold. As explained below, and in the attached technical reports, there are several control options for North Dakota sources that fall within that range.

To be clear, we do not suggest that DEQ simply adopt the same BART cost thresholds because the first round BART and reasonable progress determinations were focused on the largest sources with controls that were very cost-effective or resulted in large cumulative reductions in emissions. As a result of these controls and the uneconomical nature of many under-controlled coal-fired EGUs, many of these types of sources are now at least partially controlled or retired. The cheapest sources of emissions reductions have, in many but not all cases, been addressed.

For the second planning period, it is generally accepted that the cost-effectiveness threshold for Reasonable Progress will be higher as smaller emission units are considered. Indeed, to achieve the Clean Air Act's goals, smaller sources and somewhat less cost-effective controls must be required. These controls may result in less cumulative emissions reduction, but are nevertheless necessary in order to make continued progress toward the national goal of a return to natural visibility. To deny this reality by using first round cost-effectiveness thresholds would render regional haze progress static, as the same or similar controls would be continuously rejected. EPA recognizes this with regard to visibility impacts in its Clarifications Memo:[63]

> Evaluation of control measures for relatively smaller sources (with commensurate smaller visibility benefits from each individual source) will be needed to continue making reasonable progress towards the national goal. This is true for the second planning period, 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. To this end, EPA is reiterating that visibility thresholds used for BART and other analyses in the first planning period (e.g., 0.5 deciviews) *are, in most cases, not appropriate thresholds for selecting sources or evaluating the impact of controls for reasonable progress in the second planning period*.

[63] 2021 Clarifications Memo at 14.

Thus, DEQ should adopt cost-effectiveness thresholds that recognize this reality. For example, states have established the following thresholds for the second-round regional haze plans, including: Arizona ($4,000 to $6,500/ton)[64], New Mexico ($7,000 per ton)[65], Oregon ($10,000/ton)[66], Washington ($6,300/ton for Kraft pulp and paper power boilers)[67], and Colorado ($10,000/ton).[68] Although DEQ has some discretion in adopting a threshold, the state must adopt some objective metric by which it compares the cost-effectiveness of different control options. Without such a threshold, DEQ's control determinations are inherently arbitrary and it is impossible to compare potential control opportunities for different sources. We urge DEQ to identify a cost-effectiveness threshold for reasonable progress in line with other states and to require the cost-effective, technically feasible controls identified through four factor analyses.

C. The Four-Factor Analyses for North Dakota EGUs Include Several Common Errors and Unsupported Assumptions.

As noted, in 2020, DEQ requested four-factor analyses from several North Dakota sources, including each of the state's coal- or lignite-burning EGUs. In November 2020, in an attempt to inform DEQ's review of those individual four-factor analyses, the Conservation Organizations submitted several reports evaluating those four factor analyses. Those 2020 reports are attached to these comments.[69] Unfortunately, DEQ's Draft SIP fails to address, or even mention, those technical reviews. Moreover, with a few minor exceptions, DEQ refused to update any of the North Dakota EGU analyses, despite the documentation of numerous errors, inappropriate assumptions, and undocumented claims. As a result, the Conservation Organizations' earlier reports are still relevant and incorporated by reference.

---

[64] *See, e.g.,* Arizona Department of Environmental Quality, 2021 Regional Haze Four-Factor Initial Control Determination, Tucson Electric Power Springerville Generating Station, at 15, https://www.azdeq.gov/2021-regional-haze-sip-planning

[65] *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf

[66] *See, e.g.,* September 9, 2020 Letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2, https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf

[67] *See, e.g.,* Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, https://fortress.wa.gov/ecy/ezshare/AQ/RegionalHaze/docs/RespondFLM20210111.pdf

[68] *See* Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, November 17 to 19, 2021 Public Hearing, Prehearing Statement, at 7, https://drive.google.com/drive/u/1/folders/1TK41unOYnMKp5uuakhZiDK0-fuziE58v

[69] *See* Ex. 2, SCR Technical Feasibility Report; Ex. 3, Coyote Reasonable Progress Report; Ex. 4, 2020 Kordzi Report.

As explained in the attached 2022 Kordzi Report, and the earlier 2020 cost-effectiveness reports attached to these comments, the four-factor analyses submitted by North Dakota's coal EGUs often overstate the costs of pollution controls, while underestimating the emissions reductions achievable by additional controls or increasing the efficiency of existing pollution controls. This results in skewed four-factor analyses. It is imperative for DEQ to correct the deficiencies in these sources' four-factor analyses, and to conduct an independent four-factor analysis for each source that fully complies with the Clean Air Act and the Regional Haze Rule. The attached cost-effectiveness report highlights the flaws in the analyses including those submitted by Coyote Station, Coal Creek Station, Antelope Valley Station, Milton R. Young, and Leyland Olds Station, and identifies the measures DEQ should take to correct the sources' flawed analyses.[70]

1. Coyote Station Merits Reasonable Progress Controls for NOx and SO2.

Coyote Station is a single unit, 450 MW, lignite fired EGU located near Beulah, North Dakota, and operated by Otter Tail Power. It is located approximately 109 km from the Theodore Roosevelt National Park. Coyote came online in 1981, and burns lignite from the nearby Coyote Creek Mine. It is equipped with Separated Overfire Air ("SOFA") for NOx control, and an older, underperforming spray dryer absorber with fabric filter baghouse for SO2 and particulate matter control. Because it has underperforming controls, Coyote is one of the largest overall emitters of haze-causing SO_2 and NOx in the country. In 2020, Coyote was the 5th largest EGU emitted of SO_2 in the country, at 11,975 tons, and the 4th largest for NOx at 5,883 tons.[71] In 2020, Coyote also emitted 2,909,521 tons of CO2, putting it at the 112th largest EGU source of carbon emissions in the nation.

In its analysis, Otter Tail assumed no additional emission reductions from its existing SO_2 and NOx controls—which achieve a 0.85 lb/mmbtu and a 0.46 lb/mmbtu rate, respectively[72]—are needed. As detailed in the attached technical reports, however, the Coyote Station four factor analyses significantly inflated the cost-effectiveness of potential NOx and SO_2 control upgrades, and relied on a number of incorrect cost-inflating assumptions, which DEQ essentially accepted, including:

- Use of an undocumented 5.25% interest rate.[73]
- Assumption of a 20-year equipment life.

[70] *See, e.g.*, 2022 Kordzi Report at 14-17.
[71] https://ampd.epa.gov/ampd/
[72] See Draft SIP, App'x B at pdf page 34 (Otter Tail Four Factor Analysis at 4-1).
[73] Note that the Bank Prime Interest rate is 3.50%, which is what Otter Tail should have used. https://www.federalreserve.gov/releases/h15/.

- Inclusion of owner's costs.
- Miscalculation of SO_2 and NOx tons removed by underestimating the removal efficiency of both replacement and upgraded SO2 and NOx controls.
- Inappropriate level of contingency.
- Lack of documentation for cost items.

Despite these errors, Otter Tail's own cost-effectiveness calculation for replacing its SO_2 control system with either a dry or wet flue gas desulfurization system would be $3,485/ton or $4,065/ton, for expected annual reductions of 11,619 and 12,078 tons, respectively. Upgrading its current SO_2 controls would be $1,818/ton, for 7,952 tons reduced annually.[74]Each of those costs is well within the range that EPA and other states have deemed reasonable. In fact, several states have adopted much higher thresholds for cost-effectiveness in their second-round regional haze plans, including Arizona ($4,000 to $6,500/ton), New Mexico ($7,000 per ton), Oregon ($10,000/ton), Washington ($6,300/ton for Kraft pulp and paper power boilers), and Colorado ($10,000/ton).[75]

In any case, when Otter Tail's errors are corrected, a range of potential SO_2 controls including an SDA system replacement or upgrade are cost-effective, and would result in significant improvements emissions reductions. As discussed in the attached Kordzi Reports, when Otter Tail's inflated cost-effectiveness assumptions are corrected, upgrades to the Coyote SDA system are even more cost-effective. Replacing Coyote's current SO2 controls with a dry FGD system would be $2,357/ton; and upgrading the current system would be just $1,436/ton for a removal of 12,344.3 tons of SO_2 annually.[76] DEQ must corrects its cost effectiveness calculation for Coyote, and at a minimum, it should require the plant to upgrade its existing SO_2 controls.

Otter Tail's cost analyses for NOx controls are likewise inflated. As an initial matter, and contrary to DEQ's apparent conclusions, recent technological developments make clear that SCR technology is, in fact, technically feasible for North Dakota lignite fired EGUs, including Coyote. As demonstrated in the attached report of Joe Kordzi, SCR technology at Coyote would be extremely cost-effective, at $2,329/ton reduced, and result in 11,752 tons reduced annually.[77] DEQ should find that SCR is cost effective for Coyote.

---

[74] See Draft SIP, App'x B at pdf page 181 (Final Otter Tail Four Factor Analysis at 6-4).
[75] *See* Section II.A.1 above.
[76] *See* Ex. 3 at 9-10 (Coyote Reasonable Progress Report).
[77] *Id*. at 18, 27-28.

2. Reasonable Progress Measures Must be Required for Coal Creek.

Coal Creek Station is a two-unit electrical generating station. Both units are 600 MW tangentially-fired boilers that burn lignite coal. Both units are fitted with wet scrubber and NOx combustion controls. Coal Creek is subject to BART, but the facility still does not have a NOx BART determination. Although Great River Energy had announced that it was retiring the facility, the owner is now in discussions to sell the plant to another owner and therefore DEQ must again assess Coal Creek for NOx BART.[78]

According to EPA's Clean Air Markets Database, in 2020, Coal Creek was the 42nd largest emitter of SO_2 (5,301 tons) and the 22nd largest emitter of NOx (6,263 tons) in the country. The facility is the 19th largest emitter of carbon dioxide (9,543,317 tons) in the United States; Coal Creek also ranked as the largest EGU emitter of mercury in 2017 with 314 pounds. The existing NOx control equipment for both Unit 1 and Unit 2 is LNC3+. LNC3+ is a combination of closed coupled overfired air, separated overfired air, and low NOx burners (LNC3) in conjunction with DryFiningTM and expanded overfire air registers (the "+" in LNC3+). Each unit is equipped with wet flue gas desulfurization.

As explained in the attached 2022 Kordzi Report and the FLM review of the four-factor analysis conducted for Coal Creek, there are technically feasible and cost-effective opportunities available and should be required as reasonable progress controls for SO_2 and NOx emissions from Units 1 and 2.

a. SCR or SNCR controls at Coal Creek are cost effective.

First, as reflected in the attached technical report, the addition of SCR at Coal Creek Units 1 and 2 would reduce facility-wide NOx emissions by over 4,100 tons/yr.[79] As the Kordzi Report indicates, after correcting several unsupported cost assumptions in Great River Energy's control analysis, including an inflated interest rate, catalyst replacement costs, the assumed efficiency of controls, and errors in the assumed equipment life for each technology, SCR would be very cost effective, at $6,407/ton, resulting in at least 2,051 tons of NOx reduced annually at each unit—again for a total of more than 4,100 tons per year.[80] These costs are well within the range of cost-effectiveness thresholds that states have adopted in their second-round regional haze plans, including Arizona ($4,000 to $6,500/ton), New Mexico ($7,000 per ton), Oregon ($10,000/ton), Washington ($6,300/ton for Kraft pulp and paper power boilers), and Colorado ($10,000/ton). We note that Coal Creek may also be able to reduce its substantial mercury emissions—ranked #1 in the country in

[78] Draft SIP at 19.
[79] 2022 Kordzi Report at 41; *see also* Draft SIP, App'x D at D.2.a-60 (Comments of NPS).
[80] 2022 Kordzi Report at 40-42.

2017—by choosing to implement SCR ahead of the ESP or wet scrubbers.[81] DEQ should reevaluate potential SCR controls, including the co-benefits of mercury emission reduction.[82]

Second, and alternatively, the addition of SNCR at Coal Creek Units 1 and 2 would also be very cost effective, at only $1,123/ton, although it would reduce facility-wide NOx emissions by approximately 2,250 tons/yr.[83] As reflected in the attached Kordzi Report, the cost-effectiveness of SNCR at Coal Creek Unit 1 or Unit 2 is significantly less than the owner's four factor analysis suggests because that four factor analysis greatly overstates the costs of controls and the interest rate, and underestimates the achievable emissions reductions. The Kordzi Report also demonstrates that SNCR would be cost-effective at several different removal efficiencies.[84]

Finally, at a minimum, DEQ must require Coal Creek to operate its existing LNC3 controls and achieve an emission rate commensurate with the continuous operation of LNC3+. The record indicates that Coal Creek may have installed LNC3+ controls in order to avoid more stringent BART controls, but it is not clear that the facility is operating those controls efficiently. Again, as reflected in the attached Kordzi Report, Coal Creek LNC3+ is capable of achieving a NOx emission rate of 0.13 lb/mmbtu, which should reduce NOx emissions over the baseline by approximately 2,000 tons per year. SCR or SNCR should be required to ensure reasonable progress unless DEQ's haze plan includes an enforceable retirement date for the facility in which case the state should require the continuous operation of the facility's existing controls.

b. SO2 controls at Coal Creek are likewise cost effective.

As reflected in the attached Kordzi Report, when Coal Creek's inflated cost assumptions are corrected, the facility could cost-effectively reduce SO2 emissions by nearly 3,000 tons per year.[85] Indeed, Coal Creek could significantly, and cost-effectively reduce SO2 emissions by either installing new wet stacks or new natural gas reheating systems. By replacing the facility's wet stacks, Coal Creek could reduce SO2 emissions by approximately 3,000 tons annually at a cost-effectiveness of $1,861-2,093 per ton.[86] Replacing the reheating system would achieve similar SO_2 reductions, at a slightly higher cost. Either option, however, would be significantly

[81] *See* Draft SIP, App'x D at D.2.a-60.
[82] We also note that while DEQ asserts that the non-air quality environmental impacts for SNCR and SCR are significant, the agency acknowledges that they are not significant enough to eliminate them as a control option. *See, e.g.*, Draft SIP, App'x D at D.2.a-74.
[83] 2022 Kordzi Report at 43; *see also* Draft SIP, App'x D at D.2.a-60 (Comments of NPS).
[84] 2022 Kordzi Report at 44.
[85] *Id.* at 49.
[86] *Id.*

more cost-effective than suggested by Coal Creek's four factor analysis, which includes inflated interest costs, undocumented and reduced removal efficiencies, and an unsupported estimate of equipment life.[87] Once those errors are corrected, it is clear that SO2 controls at Coal Creek should be required to ensure reasonable progress.

The cost effectiveness of minimizing flue gas bypass to reduce SO2 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 SO2 emissions by almost 1,400 tons/yr.

3. SO2 and NOx Emission Reductions are Cost Effective at Milton R. Young.

Milton R. Young Station is a 734 MW lignite coal-fired power station near Center, North Dakota. Theodore Roosevelt National Park is approximately 161 km west of this facility. According to EPA's Clean Air Markets Database,[88] in 2020, Young was the 74th largest emitted of SO_2 at 2,677 tons, and the 9th largest for NOx at 8,562 tons, nationwide. Young emitted 5,579,430 tons of CO2 in 2020, ranking 63rd in the nation, In 2017, Young was the 5th largest emitted of mercury in the country with 198 pounds. Young has two subcritical cyclone boiler generating units that burn lignite. Each unit is equipped with SNCR for NOx and wet FGD for SO_2 control and an electrostatic precipitator for particulate matter control.

As reflected in the attached Kordzi Report, and confirmed in the technical comments submitted by the National Park Service,[89] there are technically feasible and cost-effective options for reducing SO2 and NOx emissions from Milton R. Young Station. As an initial matter, the 2020 Kordzi Report, attached as Exhibit 3, found that the 2019 Burns & McDonald four-factor analysis for Young included numerous errors in cost documentation of control efficiencies, incorrect equipment life, interest rate, and contingency assumptions, and ultimately overstated, significantly, the cost of adding Rich Reagent Injection ("RRI") plus SNCR for the facility. It does not appear that DEQ has addressed any of those issues identified and therefore, those comments remain pertinent.

In any case, there are likely cost effective opportunities for reducing NOx emissions at Young, including the addition of SCR to Units 1 and 2 which would be technically feasible and reduce emissions by at least 7,400 tons per year at a cost-effectiveness of $2,394/ton for Unit 2 and $2,556/ton at Unit 1.[90] Those costs are

[87] *Id.*
[88] https://ampd.epa.gov/ampd/
[89] Draft SIP, App'x D at 74.
[90] 2022 Kordzi Report at 58-59. The National Park Service estimates that SCR reduce NOx emissions by over 10,700 tons/year compared to Young's existing controls.

well within the range of cost-effectiveness thresholds that the FLMs have recommended,[91] or that states have adopted in their second-round regional haze plans, including Arizona ($4,000 to $6,500/ton), New Mexico ($7,000 per ton), Oregon ($10,000/ton), Washington ($6,300/ton for Kraft pulp and paper power boilers), and Colorado ($10,000/ton).[92]

There are also cost-effective measures that would reduce SO_2 that impairs visibility at Theodore Roosevelt, Badlands, and Wind Cave National Parks as well as other Class I areas in the region.[93] As an initial matter, Burns & MacDonald's four-factor analysis for Young improperly based its SO_2 control analysis on a hypothetical future fuel use.[94] Specifically, Burns & MacDonald based its scrubber control cost analyses on the highest sulfur content lignite it expected to receive from its mine, which the report suggests is 3.16 lbs/mmBtu.[95] But there is no documentation in the record to support this figure, which deviates from the typical historical sulfur contents for the facility. This assumption makes the cost-effectiveness of additional SO_2 controls appear less favorable. As discussed, to the extent that North Dakota declines to require additional pollution reductions from Young based on operating parameters that differ from recent year emissions, the state must incorporate those operating parameters or assumptions as enforceable limitations in the second planning period SIP. The Clean Air Act requires that "[e]ach state implementation plan . . . *shall*" include "enforceable limitations and other control measures" as necessary to "meet the applicable requirements" of the Act. 42 U.S.C. § 7410(a)(2)(A).[96]

---

[91] *See, e.g.*, Draft SIP, App'x D at D.2.a-74 to 75.
[92] *See,* September 9, 2020 letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2, https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf; *See* Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, November 17 to 19, 2021 Public Hearing, Prehearing Statement, at 7, https://drive.google.com/drive/u/1/folders/1TK41unOYnMKp5uuakhZiDK0-fuziE58v.
[93] Draft SIP, App'x D at D.2.a-75 (NPS Comments).
[94] *See* Ex. 3 at 35 (2020 Kordzi Report, evaluating Burns and McDonnell, Regional Haze Control Study, Minnkota Power Cooperative, Inc., Milton R. Young Station Unit 1 and Unit 2, Project No. 107926, Revision 1, 5/28/2019).
[95] *Id.*
[96] 40 C.F.R. §§ 51.308(i); (d)(3) ("The long-term strategy must include enforceable emissions limitations, compliance schedules . . ."); (f)(2) (the long-term strategy must include "enforceable emissions limitations"); *see also* Memorandum from Peter Tsirigotis, Director at EPA Office of Air Quality Planning and Standards, to EPA Air Division Directors Regions, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," EPA-457/B-19-003, at 22 (Aug. 2019), https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf. ["2019 Guidance"] ("in selecting sources for control measure analysis," the state may choose "not selecting sources that have an enforceable commitment to be retired or replaced by 2028"); *id.* at 34 (To the extent a retirement or reduction in operation "is being relied upon for a reasonable progress determination, the measure would need to be included in the SIP and/or be federally enforceable.") (citing 40 C.F.R. § 51.308(f)(2)); 2019 Guidance at 43 ("[i]f a state determines that an in-place emission control at a source is a measure that is necessary to make reasonable progress and there is not already an enforceable emission limit corresponding to that

In short, DEQ must either include Burns & MacDonald's assumed sulfur content for Young as an enforceable limitation in the SIP, or the agency must correct the analysis and reevaluate FGD upgrades as a reasonable progress measure. As the attached Kordzi Report demonstrates, once that error is corrected along with additional calculation errors, upgrading the scrubbers at Young would be very cost effective. For Unit 2, a scrubber upgrade would yield 1,185 tons SO2 per year removed at a cost-effectiveness of $632/ton.[97] This is far below the range of reasonable progress control cost thresholds that the FLMs and other states have deemed reasonable, and DEQ must take the opportunity to reduce SO2 emissions that harm Class I areas throughout the region.

4. *SO2 and NOx reductions must be required for reasonable progress at Antelope Valley.*

Antelope Valley is a 954 MW power station owned and operated by Basin Electric Power Cooperative near Beulah, North Dakota, approximately 109 km away from Theodore Roosevelt National Park. In 2020, Antelope Valley was the 15th largest emitted of SO_2 in the country, at 11,316 tons, and 64th for NOx emissions, at 3,496 tons.[98] The facility's 2020 carbon dioxide emissions of 6,876,033 tons rank 49th in the U.S. Antelope Valley has two generating units, each rated at 477 megawatts that burn North Dakota lignite. Each unit has the same control equipment: NOx emissions are controlled by a separated over-fire air, low-NOx Concentric Firing System, 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.

As reflected in the attached 2022 Kordzi Report, the 2020 Kordzi report, and confirmed in the technical comments submitted by the National Park Service, there are technically feasible and cost-effective options for reducing SO_2 and NOx emissions from Antelope Valley. First, as discussed in the attached Kordzi Reports, the cost effectiveness of installing new scrubbers is within the range of costs that the FLMs and other states have deemed reasonable. Antelope Valley could install new dry FGD technology for approximately $2,821-3,066/ton at each unit, resulting in more than 10,000 tons per year reduction.[99] At a minimum, Antelope Valley should be required to upgrade its scrubbers, which would be very cost effective. Indeed, the facility could reduce annual SO_2 emissions by more than 5,000 tons per year at a cost-effectiveness of $690/ton simply by upgrading the scrubbers, and

---

control in the SIP, the state is required to adopt emission limits based on those controls as part of its long-term strategy in the SIP via the regional haze second planning period plan submission.").

[97] 2022 Kordzi Report at 52.

[98] https://ampd.epa.gov/ampd/

[99] Draft SIP, App'x D at D.2.a-54.

meeting a continuous 0.20 lb/mmbtu emission limit, which is technically feasible as reflected by the plant's historic emissions.[100]

Second, the record indicates that SCR could be cost effective, and that SNCR is very cost effective. According to the FLMs, SCR could reduce facility NOx emissions by over 2,300 tons/yr.[101] Even if DEQ concludes that SCR is not cost effective, the attached technical reports make clear that the addition of SNCR at Antelope Valley Units 1 and 2 would reduce facility-wide NOx emissions by approximately 1000 tons/year at a cost-effectiveness of $2,113/ton, which squarely within the range of costs other states have established for reasonable progress measures.[102]

5. DEQ should require NOx controls at Leland Olds Unit 2.

Leland Olds Station is a 656 MW lignite coal-fired power station owned and operated by Basin Electric Power Cooperative near Stanton, North Dakota, approximately 149 km from Theodore Roosevelt National Park. In 2020, Leland was the 105th largest emitter of SO_2 emissions in the country, at 1,720 tons, and the 48th largest for NOx, at 4,420 tons.[103] In 2020, Leland also emitted 3,784.483 tons of CO_2, the 111th largest EGU source in the nation. Leland has two generating units that burn lignite. Unit 1 is a 216 MW EGU that went online in 1966, and is equipped with low-NOx burners, separated overfire air, and selective non-catalytic reduction for NOx control, wet limestone flue gas desulfurization for SO_2 control, and electrostatic precipitators for particulate matter (PM). Unit 2 is a 440 MW, lignite-burning unit that went online in 1975, and is equipped with SOFA, and SNCR for NOx control, WFGD for SO_2 control, and ESP for PM control.

As reflected in the 2020 technical report prepared by Joe Kordzi,[104] and the FLM's technical analysis, there are a number of unsupported assumptions and errors in the four-factor analysis for Leland, which arbitrarily and unreasonably inflate the costs of potential controls for the facility.[105] Even setting aside the lack of documentation for its cost assumptions, Leland's four factor analysis, like the other EGU analyses includes inflated interest rate assumptions and shorter equipment life, and impermissibly includes owner's costs. For NOx controls, the Leland analyses includes highly inflated ammonia costs, unexplained catalyst costs, and a likely high auxiliary power cost.[106]

[100] 2022 Kordzi Report at 30; *see also* Ex. 3 at 8-12 (2020 Kordzi Reasonable Progress Report); Draft SIP, App'x D at D.2.a-54.
[101] Draft SIP, App'x D at D.2.a-58.
[102] 2022 Kordzi Report at 41; *see also* Draft SIP, App'x D at D.2.a-60 (Comments of NPS).
[103] https://ampd.epa.gov/ampd/
[104] Ex. 4 at 16-27 (2020 Kordzi Report).
[105] Draft SIP, App'x D at D.2.a-87 to 88.
[106] Ex. 3 at 27 (2020 Kordzi Report).

When those unsupported cost assumptions are corrected, there are technically feasible and cost-effective opportunities available to reduce NOx emissions from Unit 2. Specifically, DEQ should require the installation of Rich Reagent Injection plus SNCR, which would result in reductions in NOx of approximately 931 tons per year at a cost of $5,801.[107] That cost is within the range of cost thresholds that the FLM and other states have established as presumptively reasonable. DEQ should require Leland to submit an updated analysis addressing the unsupported and erroneous assumptions identified in the 2020 Kordzi Report.[108]

V. DEQ FAILED TO REQUIRE APPROPRITE FOUR-FACTOR ANALYSES FOR NORTH DAKOTA NON-EGUS IDENTIFIED FOR REASONABLE PROGRESS EVALUTAIONS.

As shown in the below table there are four non-EGUs of concern to commenters that impact North Dakota's Class I areas, these are discussed in this section.[109]

Table 1: Non-EGUs of Concern to Commenters

Facility Name	County	Description	Cumulative Q/d	Q (tons)	Closest CIA	Q/d	d (km)
Little Knife Gas Plant	Billings	Crude Petroleum and Natural Gas Extraction	11.8	409	Theodore Roosevelt NP	11.8	34.65
Hess Tioga Gas Plant	Williams	Natural Gas Liquid Extraction	63.5	1,399	Lostwood	34.7	40.33

[107] Draft SIP, App'x D at D.2.a-101.
[108] Ex. 3 at 14-28 (2020 Kordzi Report).
[109] NPCA calculated Q using the 2017 NEI for non-EGUs and for power plants NPCA used 2019 AMDP (EPA Air Markets Data Program). This information is from the NPCA interactive map that provides users access to point and non-point source emissions data based on NPCA's assessment of publicly available information curated to identify sources and industrial sectors of concern to visibility in Class I area national parks and wilderness areas. The sources identified likely merit review by states to determine whether and what emission reduction options are feasible to achieve reasonable progress towards the restoration of natural visibility at Class I areas, and otherwise benefit progress toward clean air in all of our communities. The map lets one visualize the locations and details of emission sources, the level of emissions of different pollutants, and the Class I areas potentially affected by each source. The interactive map also provides information on emissions from oil and gas infrastructure such as wells, drilling rigs, compressor stations, pipelines, and refineries at the county level. Additional layers are available to visualize the 8-hour Ozone (2015) nonattainment areas as well as vulnerable populations by county density, including people of color and people living below the poverty line., https://npca.maps.arcgis.com/apps/MapSeries/index.html?appid=73a82ae150df4d5a8160a2275591e45d.

					Wilderness		
Northern Border Pipeline Compressor Station No. 4	McKenzie	Pipeline Transportation of Natural Gas	10.7	177	Theodore Roosevelt NP	10.7	16.51
Great Plains Synfuels Plant	Mercer	Natural Gas Distribution	486.5	8,231	Theodore Roosevelt NP	75.4	109.17

A. DEQ's Little Knife Gas Plant Four-Factor Analysis is Inconsistent with the Clean Air Act and Regional Haze Rule Requirements.

The Draft SIP explained that Petro-Hunt, L.L.C. (Petro-Hunt) – Little Knife Gas Plant (LKGP) is comprised of numerous fuel gas combustion units, process equipment, tankage, flares, and a sulfur recovery process controlled by an incinerator. The major emissions source onsite is the 2-stage 2-bed Cold Bed Absorption (CBA) sulfur recovery unit (SRU) tail gas incinerator. The LKGP is located approximately 18 miles southwest of Killdeer, North Dakota in Billings County.[110] The closest Class I area is Theodore Roosevelt National Park, at 34.65 km.

As explained in the Kordzi Report, NOx emissions are very small and are not evaluated further.[111] SO_2 emissions have averaged 307 tons from 2016 – 2018.[112] More recent data provided by DEQ via a public records request verifies this figure.[113] DEQ summarizes its four-factor analysis in section 5, which references a longer analysis in Appendix A.[114]

1. DEQ Must Evaluate Upgrades to the SRU.

In evaluating upgrades sources must consider upgrades installed by similar facilities, which neither the source nor DEQ has done. As explained in the Kordzi Report, DEQ stated on page A.7-2 that during 2016–2018, the Sulfur Recovery Unit (SRU) recovered approximately 94% of the sulfur entering the unit, which is significantly lower than efficiencies of other sulfur recovery units.[115] For example, a recent Four-Factor Analysis performed at the U.S. Steel Clairton Facility in Pennsylvania indicated that its Shell Claus Off-gas Treating (SCOT) plant has a

---

110 Draft SIP at A.7-1.
111 2022 Kordzi Report at 59.
112 *Id.*
113 *Id.*
114 *Id.*
115 *Id.*

99.8% efficiency.[116] This high level of efficiency is not unusual, as the vendor indicates.[117] Consequently, DEQ must investigate upgrades for Little Knife's SRU system or consider an add-on SCOT or similar system.

2. DEQ Must Correct the Inflated Cost-Effectiveness Well Figures.

The duty to ensure reasonable progress requirements are met for purposes of submitting a SIP to EPA rests with the state, not the source. Therefore, it is the state's responsibility to independently review, evaluate and verify a draft Four-Factor Analysis submitted by a source and submit a SIP that complies with the Act.[118] A state must not "rubber stamp" a source's analysis. Despite the requirement for the State to conduct an independent analysis, DEQ did not review the cost-effectiveness well figures. The Regional Haze Rule makes clear, the *state* has a duty to conduct a "robust" analysis of potential reasonable progress controls, and must "document the technical basis, including modeling, monitoring, *cost*, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects."[119] If a source prepares a flawed, incomplete or undocumented Four-Factor Analysis, the state must either require the source to make the necessary corrections or make the corrections itself and ensure that the Four-Factor Analyses is accurately and completely documented *before* the start of the public notice and comment period. This lack of basic documentation not only precludes the state and any independent reviewer from verifying the respective utility modeling or control cost analyses, but it is contrary to the Act and the RHR. Using inaccurate information in this instance had the effect of inflating the cost-effectiveness calculations. These errors mean that the public cannot meaningfully comment on the proposed SIP.

---

[116] Trinity Consultant, Regional Haze Four-Factor Analysis, U. S. Steel – Mon Valley Works Clairton Plant, (Oct. 29, 2020), attached as Ex. 7.
[117] *See, e.g.*, Royal Dutch Shell plc, Claus Off-Gas Treating (SCOT) Process) https://www.shell.com/business-customers/catalysts-technologies/licensed-technologies/emissions-standards/tail-gas-treatment-unit/scot-process.html.
[118] 40 C.F.R. § 51.308(f)(2)(i)("*The State* must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment. *see also* 42 U.S.C. § 7491(g)(1); *see also* 40 C.F.R. §§ 51.308(d)(3), (f)(2)(i); *see also* 42 U.S.C. §§ 7410(a)(2)(A); 7491(b)(2) (SIP must include among other things, requiring enforceable emission limitations necessary to ensure reasonable progress).
[119] 40 C.F.R. § 51.308(f)(2)(iii).

As explained in the Kordzi Report, DEQ failed to correct the source's errors replicating Four-Factor Analysis mistakes, which included improper use of the overnight method.[120]

Furthermore, despite the requirement to document the technical basis for its decisions, as the Kordzi Report explained, DEQ did not indicate how it rolled Petro-Hunt's cost figures into its cost-effectiveness calculation. In particular, DEQ does not disclose how it calculated the total annualized cost and what interest rate and equipment life it assumed.[121] The Kordzi Report described that it appeared that DEQ appeared to use a procedure to add its $4,229,584 capital cost to its estimated $15,000/year maintenance cost and its estimated $128,385 annual electrical cost to result in a figure of $4,372,969. It then divided this figure by seven years to produce a figure of $624,710. Since DEQ's figure is close to this, it is reasonable to assume it accepted this procedure, which is incorrect and does not comply with the Control Cost Manual's requirement that cost-effectiveness be performed using the overnight method.[122]

The Kordzi Report used Petro-Hunt's figures and properly calculated the cost-effectiveness using the overnight method, which resulted in the below:[123]

Table 2. Revised Little Knife SO_2 Cost-Effectiveness

Injection well capital cost	**$4,229,584**
Equipment Life (years)	30
Interest Rate (%)	3.50
Capital Recovery Factor	0.0544
Annualized Capital Cost	**$229,968**
Annual compressor maintenance	$15,000
Annual electrical cost	$128,385
Total Annual Operating Cost	**$143,385**
Total Annual Cost	**$373,353**
SO_2 Removed (tpy)	307
Cost-effectiveness ($/ton)	**$1,216**

[120] Kordzi Report at 60; *see also Oklahoma v. U.S. E.P.A.*, 723 F.3d 1201, 1212 (10th Cir. 2013) (holding EPA has a reasonable basis for rejecting cost estimates where the agency explained the estimates "contain[ed] ... fundamental methodological flaws, such as including escalation and Allowance for Funds Used During Construction (AFUDC)…" and that "[t]he cost of scrubbers would not be substantially higher than those reported for other similar projects if OG & E had used the costing method and basis, i.e., overnight costs in current dollars, prescribed by the Control Cost Manual…") (internal citations omitted).
[121] 2022 Kordzi Report at 60.
[122] *Id.* at 60.
[123] *See* "Little Knife cost-effectiveness.xlsx."

The Kordzi Report explained that in the above table, an interest rate of 3.5% (corresponding to the current Bank Prime Rate) and an equipment life of 30 years was assumed. There is ample support that typical injection wells can operate for at least 30 years.[124] Thus, an injection well disposal option, which would remove all of the Little Knife's SO_2 emissions, is even more cost-effective than calculated by DEQ and should be required.

B. DEQ's Hess Tioga Gas Plant's Four-Factor Analysis is Inconsistent with the Clean Air Act and Regional Haze Rule Requirements.

The Draft SIP explained that Hess Tioga Gas Plant, LLC (Hess) – Hess Tioga Gas Plant (TGP) is comprised of numerous boilers, heaters, compressor engines, turbines, storage tanks, process equipment, flares, and a sulfur recovery process controlled by an incinerator. Most of the emissions are sourced from the compressor engines and the amine gas sweetening unit (the SRU tail gas incinerator). Tioga is located just to the east of Tioga, North Dakota in Williams County.[125] The closest Class I area is the Lostwood Wilderness Area at 40.33 km.

The Kordzi Report explained that the Clark compressor engines account for about 91% of the NOx emissions and so reasonably were the only NOx sources evaluated.[126] Most of the SO_2 emissions come from the tail gas incinerator portion of the sulfur recovery unit, with a small amount emitted by flares.[127] DEQ summarized its four-factor analysis in section 5, which referenced a longer analysis in Appendix A.[128]

1. DEQ Underestimated and Must Correct SO_2 Emissions.

As presented in the Kordzi Report, DEQ's Draft SIP represented emissions from 2015 through 2018, as seen in the below table.

---

[124] *See*, http://www.novusint.com/Portals/0/Resources/789fef6a-b434-428b-b463-2cdb40ddd400.pdf, ("[t]he proposed operating lifetime of the wells is 50 years."); *see also*, https://www.twdb.texas.gov/publications/reports/contracted_reports/doc/1004831106_injectionwells.pdf ("the duration of injection is on different time scales; concentrate disposal may last for decades (50 years or longer) while enhanced recovery of hydrocarbons may range from a few years up to 30 years" … "For older wells, constructed many (thirty or more) years ago, there may not be adequate well construction and performance records available.").

[125] Draft SIP at A.8-8.

[126] 2022 Kordzi Report at 61.

[127] *Id.*

[128] *Id.*

Table 3: DEQ's Representation of the Tioga Gas Plant SO_2 Emissions

Year	Tail Gas Incineration	Acid Gas Flaring	Inlet Gas Flaring	Total
2015	614	178	114	906
2016	481	308	77	866
2017	719	29	2	749
2018	994	20	26	1,040
Average	**702**	**134**	**55**	**890**

More recent data provided by DEQ via a public records request indicates the following annual SO_2 emissions for the tail gas incinerator:

Table 4: Recent Tioga Gas Plant SO_2 Emissions[129]

Year	Tail Gas Incineration
2018	994
2019	1,195
2020	1,195
Average	**1,128**

This newer data indicates a clear increase in the tail gas incineration SO_2 emissions, and as explained in the Kordzi Report is a better indicator of the SO_2 baseline.[130] Therefore, it was unreasonable for DEQ to use 2015 through 2018 historical emissions data and suggest that they are representative of a historical period when more recent emissions shows otherwise. DEQ must use the more recent emission data to assess the cost-effectiveness of controls at Tioga.

2. DEQ Must Require that Tioga Document all Cost Figures.

For example, the Kordzi Report explained that in Appendix A3 of its initial December 20, 2018 report (pdf page 1,353), Tioga calculated the cost-effectiveness of installing a SCOT tail gas treatment for its SRU as being $11,815.[131] Despite the legal requirements outlined above to document the cost figures, DEQ failed to require that the Tioga do so. DEQ must require that Tioga document the cost of installing a SCOT tail gas treatment and all cost figures.

[129] *Id*. at 62.
[130] *Id*.
[131] *Id*.

3. *DEQ Incorrectly Relies on the Consumer Price Index to Escalate Costs.*

DEQ failed to correct Tioga's error in using the Consumer Price Index (CPI) to escalate its "assumed" 2009 capital costs to 2018.[132] Referencing EPA's Control Cost Manual, the Kordzi Report explained that the CPI is not a suitable index with which to escalate cost items for regional haze determinations.[133]

4. *DEQ Must Require that Tioga Obtain a New Cost Estimate for the SCOT Plant.*

The Kordzi Report explained that DEQ should require that Tioga obtain a cost estimate for its SCOT plant as it is not appropriate to escalate costs from 2009 using index, as the 2009 time period is far outside the time window suitable for escalation, which is usually regarded as five years.[134]

5. *DEQ Must Correct Tioga's Inflated Cost-Effectiveness SCOT Tail Gas Treatment Figures.*

DEQ also failed to corrected Tioga's use of four other erroneous figures for the SCOT tail gas treatment for its SRU:

- Use of a 10% interest rate, which was too high,
- Use of a 10-year equipment life, which was too low,
- SO2 baseline that was too law, and
- SCOT plant efficiency that was too low.[135]

The Kordzi Report explained that regarding the equipment life, neither DEQ nor Tioga represent any reason why a SCOT plant should not be assessed as having an equipment life equal to common pollution control equipment installed on EGUs, including scrubber, SCR and SNCR systems, which as discussed elsewhere in the 2022 Kordzi Report is assessed using a 30-year life.[136] Tioga did not consent to enter into an enforceable commitment for a 10-year or 20-year life. Therefore, lacking documentation to the contrary and in the interest of establishing a fair apples-to-apples comparison with other controls assessed, a 30-year equipment life was

---

[132] 2022 Kordzi Report at 62-63.
[133] *Id.* (citing Control Cost Manual Section 1 Chapter 2, Cost Estimation: Concepts and Methodology, (Nov. 2017), at 18 ("The CPI is not recommended because the price change of interest is among consumer goods and services which have little relevance to capital project spending or industrial intermediate goods such as raw materials such as reagents.")).
[134] 2022 Kordzi Report at 63, citation omitted.
[135] *Id.* at 63.
[136] As the Kordzi Report noted, when Tioga abandoned its SCOT cost-effectiveness calculation in its March 2019 report update in favor of a LO-CAT process, it arbitrarily assumed a 20-year equipment life.

assumed in the Kordzi Report analysis. The Kordzi Report corrected all of these issues and escalated the costs to 2020 dollars, which resulted in the following revisions:[137]

Table 5: Revised Tioga SCOT Tail Gas Treatment Cost-Effectiveness

Cost Item	Factor	Tioga Cost	Revised Cost	Comments
DIRECT COSTS				
SCOT Capital Cost (2009)		$15,000,000		
Tioga SCOT Capital Cost (2018)	A	$16,750,000		
Revised SCOT Capital Cost (2020)			$17,135,467[138]	Tioga improperly used CPI to escalate. Revised cost escalated 2009 to 2020 using CEPCI.
Instrumentation	0.10A	$1,675,000	$1,713,547	
Sales Tax	0.05A	$837,500	$0	ND exempts sales tax on pollution controls.
Freight	0.05A	$837,500	$856,773	
Purchased Equipment Costs (PEC)		$19,262,500	$19,705,787	Tioga Total Incorrect; should be $20,100,000 (not carried forward).
Direct Installation Costs				
Foundations and supports	0.08B	$1,541,000	$1,576,463	
Handling and erection	0.14B	$2,696,750	$2,758,810	
Electrical	0.04B	$770,500	$788,231	
Piping	0.02B	$385,250	$394,116	
Insulation for ductwork	0.01B	$192,625	$197,058	
Painting	0.01B	$192,625	$197,058	
Total Direct Cost (DC)		$25,041,250	$25,617,523	
INDIRECT COSTS (Installation)				
Engineering	0.10B	$1,926,250	$1,970,579	
Construction & field expenses	0.05B	$963,125	$985,289	
Contractor fees	0.10B	$1,926,250	$1,970,579	
Start-up	0.02B	$385,250	$394,116	
Performance test	0.01B	$192,625	$197,058	
Contingencies	0.03B	$577,875	$591,174	
Total Capital Investment (TCI)		$31,012,625	$31,726,316	

[137] *See* file, "Tioga cost-effectiveness.xlsx."
[138] As the Kordzi Report explained, the 2009 CEPCI is 521.9 and the 2020 CEPCI is 596.2. Therefore, the escalated cost is $15M x (596.2/521.9) = $17,135,467.

DIRECT ANNUAL COSTS		$51,030	$51,030	
INDIRECT ANNUAL COSTS				
Overhead		$30,618	$30,618	
Administrative	2% of TCI	$620,253	$634,526	
Property Taxes	1% of TCI	$310,126	$317,263	
Insurance	1% of TCI	$310,126	$317,263	
Equipment life (years)		10	30	Tioga's equipment life is too low.
Interest Rate (%)		10.00	3.50	Tioga's interest rate is undocumented.
Capital Recovery Factor		0.1627	0.0544	
Annualized Capital Costs		$5,047,162	$1,725,002	
TOTAL ANNUAL COST		$6,369,315	$3,075,703	
Uncontrolled Emissions (tons/yr)		599	1,128	DEQ uses a figure of 702. Low compared to more recent data.
Control efficiency (%)		90	99	Tioga's SCOT efficiency is too low, based on vendor information.
SO_2 removed (tons/yr)		539.1	1,116.7	
Cost-Effectiveness ($/ton)		**$11,815**	**$2,754**	

As the Kordzi Report explained, as can be seen from the revised cost-effectiveness calculation, DEC relied on a control cost-effectiveness figure for the Tioga SCOT tail gas treatment that was greatly inflated.[139] The Kordzi Report's revised cost-effectiveness figure of $2,754 per ton is accurate and reflects the reasonable progress control option the state should select.

6. *DEQ Must Correct Tioga's Inflated Cost-Effectiveness LO-CAT Figures*

The Kordzi Report explained that, in its March 15, 2019 report, Tioga abandoned – without explanation – the SCOT Tail Gas Treatment Cost-Effectiveness calculation it performed in its December 20, 2018 report and instead pivoted to a LO-CAT process that converts H_2S in the acid gas to solid elemental sulfur using an aqueous solution of iron as catalyst.[140] As it failed in SCOT cost-effectiveness calculation, DEQ failed to correct Tioga's LO-CAT cost-effectiveness

[139] 2022 Kordzi Report at 65, and the cost of controls is reasonable.
[140] *Id*. at 65.

calculations.[141] The one change that DEQ made was that it assumed a 20-year equipment life. On page A.8-14, DEQ recalculated the cost-effectiveness as \$11,321/ton, based on a revised SO_2 baseline (discussed above) and as well as undisclosed modifications to Tioga's costs.[142] The Kordzi Report corrected all of these issues and escalated the costs to 2020 dollars, which resulted in the following revisions:[143]

Table 6: Revised Tioga LO-CAT Tail Gas Treatment Cost-Effectiveness[144]

Cost Item	**Factor**	**Tioga Cost**	**Revised Cost**	**Comments**
DIRECT COSTS				
LO-CAT Capital Cost (2020)	A	\$21,000,000	\$20,609,383	Revised escalated 2019 to 2020 using CEPCI
Freight	0.05A	\$1,050,000	\$1,030,469	
Purchased Equipment Costs (PEC)		\$22,050,000	\$21,639,852	
Direct Installation Costs				
Foundations and supports	0.08B	\$1,764,000	\$1,731,188	
Handling and erection	0.14B	\$3,087,000	\$3,029,579	
Electrical	0.04B	\$882,000	\$865,594	
Piping	0.02B	\$441,000	\$432,797	
Insulation for ductwork	0.01B	\$220,500	\$216,399	
Painting	0.01B	\$220,500	\$216,399	
Total Direct Cost (DC)		\$28,665,000	\$28,131,807	
INDIRECT COSTS (Installation)				
Engineering	0.10B	\$2,205,000	\$2,163,985	
Construction and field expenses	0.05B	\$1,102,500	\$1,081,993	
Performance test	0.01B	\$220,500	\$216,399	
Total Capital Investment (TCI)		\$32,193,000	\$31,594,184	
DIRECT ANNUAL COSTS		\$3,217,475	\$3,217,475	
INDIRECT ANNUAL COSTS				
Administrative	2% of TCI	\$643,860	\$631,884	
Property Taxes	1% of TCI	\$321,930	\$315,942	
Insurance	1% of TCI	\$321,930	\$315,942	

141 2022 Kordzi Report at 65.
142 *Id.*
143 *See* file, "Tioga cost-effectiveness.xlsx."
144 2022 Kordzi Report at 65-66.

Equipment life (years)		20	30	Tioga's equipment life is too low
Interest Rate (%)		5.50	3.50	Tioga's interest rate is undocumented
Capital Recovery Factor		0.0837	0.0544	
Annualized Capital Costs		$2,693,889	$1,717,818	
TOTAL ANNUAL COST		$7,199,084	$6,199,060	
Uncontrolled Emissions (tons/yr)		605	1,128	DEQ uses a figure of 702, which is low compared to more recent data
Control efficiency (%)		90	99	Tioga's LO-CAT efficiency is too low, based on vendor information
SO_2 removed (tons/yr)		544.5	1116.7	
Cost-Effectiveness ($/ton)		**$13,221**	**$5,551**	

The Kordzi Report's revised cost-effectiveness figure of $5,551 reflects the correct cost and the state should select LO-CAT tail gas treatment control for this source.

7. *DEQ's Tioga's Injection Well Cost-Effectiveness Figure is Greatly Inflated*

The Kordzi Report also explained that in its March 15, 2019 report, Tioga added an injection well option as a tail gas treatment for its SRU, which it had not included in its December 20, 2018 report,[145] these calculations suffered same issues described above in its SCOT and LO-CAT analyses, and yet despite its responsibility to independently review the submittal, DEQ again failed to correct the errors.[146] Instead, as the Kordzi Report noted, on page A.8-14, DEQ recalculated the cost-effectiveness of the injection well as being $3,248/ton, based on a revised SO_2 baseline (discussed above) and undisclosed modifications to Tioga's costs. Despite the legal requirements to explain and "show its work" to the public on how it calculated the costs, DEQ failed to do so. The Kordzi Report corrected all of these issues and escalated the costs to 2020 dollar, which resulted in the following revisions:[147]

Table 7: Revised Tioga Injection Well Tail Gas Treatment Cost-Effectiveness

Cost Item	Factor	Tioga Cost	Revised Cost	Comments
DIRECT COSTS				

[145] 2022 Kordzi Report at 66.
[146] *Id*. at 66-67.
[147] *Id*. at 67-69, *see* file, "Tioga cost-effectiveness.xlsx." DEQ also adds a redundant compressor and plumbing costs, which were not deemed necessary in Tioga's cost-estimate and therefore were not carried forward in the revision.

Compressor Engine Capital Cost (2018)	A	$3,500,000	$3,434,897	Revised escalated 2019 to 2020 using CEPCI
Acid Gas Dehy	A	$1,750,000	$1,717,449	Revised escalated 2019 to 2020 using CEPCI
Instrumentation	0.10A	$525,000	$515,235	
Sales Tax	0.05A	$262,500	$0	ND exempts sales tax on pollution controls for gas plants
Freight	0.05A	$262,500	$257,617	
Purchased Equipment Costs (PEC)		$6,300,000	$5,925,198	
Direct Installation Costs				
Foundations and supports	0.08B	$504,000	$474,016	
Handling and erection	0.14B	$882,000	$829,528	
Electrical	0.04B	$252,000	$237,008	
Piping	0.02B	$126,000	$118,504	
Insulation for ductwork	0.01B	$63,000	$59,252	
Painting	0.01B	$63,000	$59,252	
Total Direct Cost (DC) Compressor/Dehy		$8,190,000	$7,702,757	
INDIRECT COSTS (Installation)				
Engineering	0.10B	$630,000	$592,520	
Construction and field expenses	0.05B	$315,000	$296,260	
Contractor fees	0.10B	$630,000	$592,520	
Start-up	0.02B	$126,000	$118,504	
Performance test	0.01B	$63,000	$59,252	
Contingencies	0.03B	$189,000	$177,756	
Total Indirect Cost (IC) Compressor/Dehy	0.31B	$1,953,000	$1,836,811	
DIRECT & INDIRECT COSTS (Installation)				
Pipeline Installation		$2,500,000	$2,453,498	Revised escalated 2019 to 2020 using CEPCI
Install Disposal Well		$5,000,000	$4,906,996	Revised escalated 2019 to 2020 using CEPCI
Land Acquisition		$20,000	$20,000	
Permitting		$125,000	$125,000	
Total DC & IC Cost (pipeline & disposal well)		$7,645,000	$7,505,494	
Total Capital Investment (TCI)		$17,788,000	$17,045,062	
DIRECT ANNUAL COSTS		$800,000	$800,000	
Equipment life (years)		20	30	Tioga's equipment life is too low

Interest Rate (%)		5.50	3.50	Tioga's interest rate is undocumented
Capital Recovery Factor		0.0837	0.0544	
Annualized Capital Costs		$1,488,488	$926,763	
TOTAL ANNUAL COST		$2,288,488	$1,726,763	
Uncontrolled Emissions (tons/yr)		605	1,128	DEQ uses a figure of 702, which is low compared to more recent data
Control efficiency (%)		99	100	Assume all emissions controlled by well
SO_2 removed (tons/yr)		599.0	1128.0	
Cost-Effectiveness ($/ton)		**$3,821**	**$1,531**	

As can be seen from the revised cost-effectiveness calculation in the above table, the Tioga and DEQ (which assumed Tioga's calculations with some undisclosed modifications) injection well tail gas treatment control cost-effectiveness figures are greatly inflated, and the revised figure of $1,531 is accurate DEQ should select the control to satisfy reasonable progress requirements at the source.

C. DEQ' Clark Compressor Engines NOx Four-Factor Analysis at the Tioga Plant is Inconsistent with the Clean Air Act and Regional Haze Rule Requirements.

The Kordzi Report presents six issues with the Four-Factor Analysis conducted for the Clark engines. DEQ must correct the Draft SIP for all these issues.

1. DEQ Relies on a NOx Baseline That is Not Representative of Future Operations.

The Kordzi Report explained that DEQ calculated that the average NOx emissions for the Clark engines, from both a straight average from 2015-2018 and on a pound of NOx per hour basis are both approximately 182 tons/yr.[148] It then used this as the NOx baseline for each engine when it assessed NOx controls. Kordzi Report explained that DEQ's approach was not representative of future operations as demonstrated in the below analysis.[149]

The historical NOx emissions from the Clark engines are as follows:

Table 8: Historical NOx Emissions of the Tioga Clark Compressor Engines[150]

---

[148] 2022 Kordzi Report at 69.
[149] *Id.* at 69-70.
[150] *Id.* at 70.

Year	C-1A	C-1B	C-1C	C-1E	C-1G	C-1D	C-1F
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
2019	227	73	208	0	100	23	14
2020	103	116	150	0	100	16	4
Average 2016-2020	125	130	176	68	138	22	19
Average 2016-2020 excluding max and min	**203**	**193**	**235**	113	**197**	31	30

DEQ and Tioga reasonably concluded that engines C1D and C1F (shaded in the above table) should not be included in the four-factor analysis, since both engines have been retrofitted with turbochargers, which have significantly reduced their NOx emissions.[151] Also, based on information provided by DEQ via a public records request, it appears that beginning in 2018, emissions from engine C1E have no longer been reported. DEQ failed to disclose in its Draft SIP, and it must indicate whether this engine retired or is still in service and if the latter, it must be included in Tioga's four-factor analysis.[152]

While DEQ assumed a NOx baseline of 182 tons/yr, each of these engines exceeded 200 tons/year one or more times since 2015. It was unreasonable of DEQ to use a baseline of 182 that did not represent all years of operations, including future operations. Therefore, as the Kordzi Report concluded, a more representative NOx baseline would be to assess each engine separately, and use a five-year average that excludes the maximum and minimum values.[153] This approach would reasonably account for the years when the engines operate outside of their average NOx emissions and is what DEQ must do in revising its SIP.

2. DEQ Must Properly Review SCR for the Clark Compressor Engines

DEQ's dismissal of SCR for the Clark compressor engines was misplaced. First, as the Kordzi Report pointed out, DEQ erroneously concluded that "[s]ince LEC could achieve the emissions same rate as SCR with less impacts elsewhere,

[151] 2022 Kordzi Report at 70.
[152] *Id.* at 70.
[153] *Id.* at 70.

SCR will not be evaluated further."[154] While Tioga assessed SCR, its analysis was flawed in the following three respects:

- **DEQ failed to require that Tioga investigate the use of multiple engines sharing SCR systems**.[155] Tioga assessed SCR on an engine-by-engine basis. DEQ must require that Tioga investigate the use of multiple engines sharing. The Kordzi Report explained that it as it is likely that if some of the engines are located close to each other, there will be opportunities for them to share a single SCR system (minimally reagent storage), thereby reducing costs.[156] In addition, it may be possible for the turbines, although relatively small NOx sources, to also be plumbed into the SCR systems, which would not only reduce NOx further but potentially help keep the catalyst temperature in the optimal range.[157]

- **DEQ must require that Tioga update its SCR cost analysis**.[158] The Kordzi Report notes that it appears Tioga used cost estimating data from a 2000 NESCAUM report, which itself used data from 1994.[159] Data of this vintage is outside of the acceptable 5-year window.

- **It is expected that an efficiency of 95% or greater could be expected.[160]** DEQ must require that Tioga either demonstrate that its assumed 85% SCR NOx control is the maximum that could be expected, or assume a higher control level.

3. DEQ Must Obtain and Review Tioga's Information with Confidential Business Information Claims.

All assertions, parameters, assumed control efficiencies, cost items, assumed future operating capacities, etc. in a control cost analysis must be documented so that DEQ's independent analyst, with a reasonable amount of expertise, can duplicate the control cost figures. This documentation should include vendor quotes, actual costs from a similar facility, generally accepted estimate, etc. In particular, upgrades require specific knowledge of the configuration in order to determine what upgrades can be considered. In rare instances, it is recognized that this level of documentation may include the use of Confidential Business Information (CBI). The

---

[154] 2022 Kordzi Report at 70, citing Draft SIP at A.8-12.
[155] 2022 Kordzi Report at 70.
[156] *Id.*
[157] *Id.*
[158] *Id.*
[159] *Id.*
[160] *Id.*

states, North Dakota and EPA have procedures in place to adequately treat and protect CBI, so this should not present a problem.

As the Kordzi Report pointed out, Siemens provided a cost estimate for a LEC upgrade to the Clark engines. Tioga asserted to DEQ that the information it obtained from Siemens – the scope of work and cost estimate – is Siemens proprietary information – and was not provided to DEQ.[161] As the Kordzi Report explained,

> DEQ must actually review this material and indicate whether it finds that the estimate is acceptable and whether Tioga's use of it conforms to the Control Cost Manual requirements. This is especially important in this case, considering the greatly inflated cost-effectiveness calculations, as described below.[162]

This is an issue. DEQ cannot advance a SIP to EPA without first obtaining and reviewing the underlying information. DEQ must request and obtain the information with the CBI claims and review it to determine whether it is consistent with the Control Cost Manual, regulations and Act requirements.

4. DEQ Must Require that Tioga Eliminate Questionable Compressor Engine Costs.

The Kordzi Report explained that compressor engine retrofits are broadly understood to include one of the following activities:

(1) Redesign of the cylinder head and pistons to improve mixing (on smaller engines),
(2) Precombustion chamber,
(3) Turbocharger,
(4) High energy ignition system
(5) Aftercooler, and
(6) Air to fuel ratio controller.[163]

DEQ's Draft SIP failed to question and request documentation from Tioga for the following cost items in its LEC retrofit, which as noted in the Kordzi Report, are exorbitant engines maintenance-related items and not required for an LEC retrofit.[164]

---

[161] 2022 Kordzi Report at 71.
[162] *Id*. at 71.
[163] *Id*. at 71, citing, EPA, 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, (Nov. 2015), at 5-3.
[164] 2022 Kordzi Report at 71.

Table 9: Maintenance-Related Costs That Must Not be Included[165]

Tioga Description of Activity	Tioga Cost Estimate	Kordzi Report Analysis
Replace the cooling system to eliminate boil-off and replace the water pump system	$345,000	If the cooling systems for these engines are already boiling over, then they have existing problems and the cost of these problems must not be included in an LEC retrofit.
"Zero-hour" engine overhaul	$2,500,000 per engine cost	Typically, the term "zero-hour engine overhaul" is understood to be a complete engine rebuild to factory new specifications. Engines do not require a full rebuild in order to be retrofit with LEC upgrades.

Finally, the Kordzi Report pointed out that Tioga specified a $2.0 - $2.5M cost that it described as a "one-time 'balance of plant' engineering and hardware to support multiple engine retrofits. Cost is the same regardless of 1 or all 5 engines,"[166] which it explained appeared to be a charge to design and support the installation of all the LEC components. However, despite Tioga noting that this "cost is the same regardless of 1 or all 5 engines," Tioga included it in each engine's LEC cost-effectiveness calculation.[167] Tioga's methodology was flawed, and DEQ failed to make the necessary correction. As the Kordzi Report concluded, obviously, if all five engines are retrofitted, then this cost should be split between the engines.[168] DEQ must make the necessary corrections in the SIP for these the cost-effectiveness calculations.

5. DEQ Must Revise the LEC Efficiency, Which It Underestimated

As the Kordzi Report explained, in the revised cost-effectiveness calculations, an LEC efficiency of 90% was reasonably assumed.[169] This was based on numerous publications, which indicate that LEC can reasonably be expected to achieve a rate of 0.5 g/BHP-hr.[170]

---

[165] 2022 Kordzi Report at 71.
[166] *Id.* at 71.
[167] *Id.*
[168] *Id.*
[169] *Id.* at 71-72.
[170] *Id.* at 72 (citing https://www.cooperservices.com/engines-and-compressors/upgrades/0-5-gbhp-hr-nox-solution%E2%80%8B/ ("Cooper is very proud to offer a complete upgrade solution for 0.5 g/bhp-hr NOx emission that is available for all Clark, Cooper-Bessemer, and Ingersoll Rand slow speed engine models. This solution is fully backed by Cooper's ownership of guarantee.")).

6. *DEQ Must Revise the Tioga's Cost-Effectiveness Figures, Which Are Greatly Inflated*

The Kordzi Report explained that Tioga claimed that installing LEC on each of the five compressor engines will entail extremely high costs. This included $4,000,000 per engine to retrofit them with a high-pressure fuel injection system, another $2,500,000 per engine to perform "zero-hour overhauls," and another $2,250,000 per engine for an apportioned balance of plant cost.[171] This resulted in cost-effectiveness calculations of $6,890/ton to $16,567/ton.

DEQ made limited – unexplained and undocumented – changes, which resulted in $8,784 per engine.[172] Tioga's and DEQ's figures greatly exceed typical LEC capital costs and cost-effectiveness figures, as the following brief sampling of available information indicates.

- From a capital cost perspective, a recent Interstate Natural Gas Association of America (INGAA) Report provides information on particular Clark engine LEC retrofit capital costs.[173] LEC retrofit costs range from $300–$600/hp, for upgrades to the scavenging, intercooler (already turbocharged), and fuel systems. Translating these figures to the Tioga 1,950 hp engines results in capital costs of $585,000 to $1,170,000 (presumably in 2017 dollars). Although not entirely translatable to the Tioga engines, these figures suggest that the Tioga costs are very high in comparison. Another reference for Clark engines indicates that LEC controls would cost approximately $140/hp.[174]

- Furthermore, as discussed in the 2020 BART and RP Report, a recent March 2020 oil and gas four-factor report[175] cited to an EPA Technical Support Document for Non-EGU NOx emissions for the CSAPR rule.[176] Here, EPA presented an equation for estimating the capital cost of LEC

---

[171] 2022 Kordzi Report at 72.

[172] The 2022 Kordzi Report noted that the Tioga cost-effectiveness figures all resulted in total annualized costs of $1,205,122 but with different NOx baselines. DEQ assumes Tioga's costs (with slight undisclosed modifications) but uses one NOx baseline to represent all the engines.

[173] 2022 Kordzi Report at 72, citing INGAA, Report No. 2016-6, Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOx Control for Natural Gas Transmission and Storage Compressor Drivers (December 2017), available at: https://www.ingaa.org/File.aspx?id=33789.

[174] 2022 Kordzi Report at 72, citing November 2019 Regional Haze Four-Factor Analysis for Enterprise Chaco Gas Plant cost data for Clark engines at just under $140/hp.

[175] Ex. 5, Vicki Stamper & Megan Williams, Oil and Gas Sector Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines Natural Gas-Fired Turbines Diesel-Fired Engines Natural Gas-Fired Heaters and Boilers Flaring and Incineration, (March 6, 2020), at 32.

[176] 2022 Kordzi Report at 72, citing EPA, CSAPR TSD for Non-EGU NOx Emissions Controls, (2016), Appendix A, at 5-5.

on natural gas lean-burn engines, based on cost calculations for engines of varying size and annual capacity factor from the California Air Resources Board (CARB) 2001 Guidance:

$$\text{Capital cost} = \$16{,}019\ e^{0.0016 \times (hp)}$$

This equation was derived from CARB's cost analysis of LEC on a wide range of varying engine sizes. Applying the above equation results in a capital cost of $362,772 for retrofitting LEC per engine.[177] The March 2020 oil and gas four-factor report presents many examples of LEC retrofits cost much less and resulting in much lower cost-effectiveness figures than Tioga presents.[178] DEQ must consider the information in the March 2020 report, which the commenters incorporate by reference in these comments.

- A 2015 EPA publication lists the cost of LEC for lean burn compressor engines as $649/ton.[179]

- Even more recently, the NPCA commissioned a comprehensive report on reasonable progress four-factor control analysis for the oil and gas industry.[180] This study cites many examples of LEC for engines similar to those used by Tioga, resulting in much lower cost-effectiveness figures.[181] DEQ must consider the information in this July 2020 report, which the commenters incorporate by reference in these comments.

Thus, there is a great deal of evidence of similar LEC retrofits with much lower capital costs and resulting cost-effectiveness figures. There is no reason offered by Tioga or DEQ to conclude that the Tioga engines are so different from these examples that retrofitting them with LEC would be expected to result in much greater capital costs. Therefore, DEQ must require a more in-depth accounting of Tioga's costs. This must include a justification that the questionable cost items, mentioned in the 2020 BART and RP Report and discussed below, are actually needed.[182]

---

[177] 2022 Kordzi Report at 73, explaining $\$16{,}019\ e^{0.0016 \times (1{,}950)} = \$362{,}772$.
[178] *Id*. at 73.
[179] *Id*. at 73, citing U.S. Environmental Protection Agency Office of Air and Radiation,, 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, (Nov. 2015), at 13, https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[180] 2022 Kordzi Report at 73, citing Vicki Stamper & Megan Williams, Assessment of Cost Effectiveness Analyses for Controls Evaluated Four – Factor Analyses for Oil and Gas Facilities for the New Mexico Environment Department's Regional Haze Plan for the Second Implementation Period, (July 2, 2020).
[181] 2022 Kordzi Report at 73.
[182] *Id*. at 73.

Below are selected revised cost-effectiveness calculations that address the issues described above, which clearly show the costs are reasonable to retrofit the engines at $2,834 per ton.[183]

Table 10: Revised Tioga LEC Retrofit for Engine C-1A Cost-Effectiveness

Cost Item	Factor	Tioga Cost	Revised Cost	Comments
DIRECT COSTS				
High Pressure Fuel Injection (2018)		$4,000,000	$3,954,236	Revised escalated 2018 to 2020 using CEPCI
Zero-hour overhaul		$2,500,000	$0	Full engine rebuild likely not necessary for LEC
Replace cooling system		$345,000	$0	Maintenance item, not LEC
Total Direct Cost, DC		$6,845,000	$3,954,236	
INDIRECT COSTS (Installation)				
Balance of Plant Engineering + Hardware		$2,250,000	$450,000	Apportioned to each engine by dividing by 5
Total Indirect Costs		$2,250,000	$450,000	
Total Capital Investment (TCI)		$9,095,000	$4,404,236	
DIRECT ANNUAL COSTS		$102,060	$102,060	
INDIRECT ANNUAL COSTS				
Overhead		$61,236	$61,236	
Administrative	2% of TCI	$181,900	$88,085	
Property Taxes	1% of TCI	$90,950	$44,042	
Insurance	1% of TCI	$90,950	$44,042	
Equipment life (years)		25	30	Tioga's equipment life is too low
Interest Rate (%)		5.50	3.50	Tioga's interest rate is undocumente d
Capital Recovery Factor		0.0745	0.0544	
Annualized Capital Costs		$678,026	$239,464	

[183] Kordzi Report at 73-75.

TOTAL ANNUAL COST		$1,205,122	$517,694	
Uncontrolled Emissions (tons/yr)		91	203	Tioga's NOx baseline is too low. DEQ uses a figure of 181, which is also low compared to more recent data
Control efficiency (%)		80.2	90.0	Tioga's LEC efficiency is too low, based on vendor information
NOx removed (tons/yr)		73.0	182.7	
Cost-Effectiveness ($/ton)		**$16,513**	**$2,834**	

D. DEQ's Northern Border Pipeline Compressor Station Four-Factor Analysis is Inconsistent with the Clean Air Act and Regional Haze Rule Requirements.

The Draft SIP explained that Northern Border Pipeline Company (NBPC) – Compressor Station No. 4 (CS4) is a compressor station with the majority of emissions being sourced from a 20,000-horsepower simple cycle natural gas-fired combustion turbine (Unit CE1), which drives a natural gas compressor. The turbine is a Cooper-Rolls Model Coberra 2648S Avon. CS4 is located approximately nine miles west of Watford City, North Dakota in McKenzie County.[184] NBPC's Q/d is 10.7 and the closest Class I area is Theodore Roosevelt National Park.

As the Kordzi Report explains, the issues with the Four-Factor Analysis for the NBPC fall into the following categories, none of which DEQ corrected:

- NOx baseline is too low
- Failed to consider all NOx control technologies, despite considering them for the same compressor station in Montana
- DEQ failed to correct NPPC's highly flawed SCR retrofit cost-effectiveness calculations
- Lacked basic documentation of cost items and interest rate
- NBPC's assumed SCR efficiency is too low
- NBPC's initial and revised SCR cost-effectiveness calculations were both flawed[185]

[184] Draft SIP at A.9-1.
[185] 2022 Kordzi Report at 76.

1. DEQ's NOx Baseline is Low and Not Representative of Future Emissions.

DEQ calculated the NOx baseline based on emission testing conducted between 2012 through 2018. While actual NOx emission data is available, which were provided via a public information request, DEQ failed to use that data in its SIP.[186] The data DEQ provided appears in the below table.

Table 11. Historical NOx Emissions for the NBPC CE1Turbine

Year	NOx Emissions (tons)
2016	171.1
2017	170.4
2018	159.8
2019	141.4
2020	1.0
2021	5.4
2016-2019 Average	160.7

Initially, the public record request submitted to DEQ did not include data beyond 2019 for this source. A second inquiry to DEQ resulted in the 2020-2021 data. However, because the CE1Turbine did not operate much in 2020-2021, data from these years was not considered representative of future operations. DEQ's derived NOx baseline of 131 tons was below that for each year from 2016-2019. Therefore, a reasonable NOx baseline results from averaging the actual emissions data from 2016-2019, resulting in a figure of 160.7 tons per year.[187]

2. DEQ Failed to Consider All NOx Control Technologies for the NBPC's CE1 Turbine.

As explained in the Kordzi Report, contrary to assertions by the source, which were concurred on by DEQ, in a forecast of the market for the Rolls-Royce Industrial Avon turbine, Forecast International states that regarding the CooperRolls Model Coberra 2648S Avon, Dry Low Emissions (DLE) combustion technology is available as an option for new Avon units, as well as a retrofit for

[186] 2022 Kordzi Report at 76.
[187] *Id*. at 76.

existing packages.[188] The Kordzi Report further noted that, DLE is the terminology used for second generation combustor NOx controls that have replaced the use of water/steam injection as a means of NOx controls.[189] In fact, NBPC's Compressor Station No. 3 in Montana, where the source conducted a Four-Factor Analysis, employs a similar model of the Cooper Rolls Coberra turbine that employs this technology.[190] Consequently, NBPC and DEQ reached the erroneous conclusion that the turbine manufacturer does not offer a burner retrofit option and accordingly must revisit and investigate this NOx control option.

3. *NBPC's Initial and Revised SCR Cost-Effective Calculations Were Both Highly Flawed.*

As discussed in detail in the Kordzi Report, there are numerous deficiencies in NBPC's SCR cost-effectiveness calculations.[191] The root of several of the source's errors stem from its reliance on outdated information.[192] These include the following:

- Use of an undocumented capital cost figure of $720,000
- Use of cost data from a 1999 report, which is outside the five-year window
- No documentation for direct costs
- No documentation for indirect costs
- Erroneous assertion that "[c]osts from PA DEP analysis are higher" than what the source assumed, when as detailed in the Kordzi report, they are not[193]
- Inflated interest rate of 7%
- Unenforceable equipment life of 10-years[194]

---

[188] 2022 Kordzi Report at 76-77, citing, Industrial & Marine Turbine Forecast - Gas & Steam Turbines, Rolls-Royce Industrial Avon, Forecast International 2009, (April 2009), at 4), https://kipdf.com/download/rolls-royce-industrial-avon_5aed17137f8b9a10078b45ac.html (The article makes a number of references to the availability of this technology for this specific turbine and other similar models.)

[189] 2022 Kordzi Report at 77.

[190] *Id.* at 77, citing Northern Pipeline Company, Clean Air Act, Four-Factor Analysis For Compressor Station No. 3, Cooper Rolls Coberra 6562 DLE Compressor Turbine, Roosevelt County, Montana, (June 11, 2019), https://deq.mt.gov/files/Air/AirQuality/Documents/Planning/PDF/MT%20Four%20Factors%20Analysis_NBPL%20Compressor%20Station%20No%203_090619%20redline.pdf?ver=2020-02-04-131921-270.

[191] 2022 Kordzi Report at 77-78.

[192] The 2022 Kordzi Report points out that the source relied on a 1999 DOE report and a 2013 Pennsylvania Department of Environmental Protection analysis associated with NOx controls for a general permitting program, both of which are outside the five-year window, *id.* at 77.

[193] 2022 Kordzi Report at 77.

[194] *Id.* at 77-78.

- Assumed a too low SCR efficiency of 80% gas-fired turbine, SCR efficiencies of at least 90% are widely advertised by vendors[195]

The Kordzi Report revised the cost-effectiveness for the turbine, which resulted in the following:[196]

Table 12: Revised NBPC CE1 Turbine SCR Retrofit Cost-Effectiveness

Cost Item	**NBPC**	**Revised**	**Comments**
Purchased Equipment Cost (PEC)	$783,000	$752,292	Escalated from 2018 to 2020 and sales tax of $21,750 deleted
Total Installation Cost (TIC)	$690,000	$690,000	
Total Direct Costs	$1,473,000	$1,442,292	
Total Indirect Costs	$176,320	$176,320	
Total Capital Investment (TCI)	$1,649,320	$1,618,612	
Total Direct Annual Costs	$217,375	$217,375	
Equipment life (years)	10	30	NBPC's equipment life is too low
Interest Rate (%)	7.00	3.50	NBPC's interest rate is undocumented
Capital Recovery Factor	0.1424	0.0544	
Overhead	$19,125	$19,125	
Administrative Charges	$32,986	$32,986	
Property Taxes	$16,493	$16,493	
Insurance	$16,493	$16,493	
Capital Recovery	$234,863	$88,006	
Total Indirect Annual Costs	$319,960	$173,103	
Total Annual Costs	$537,335	$390,478	
Uncontrolled NOx rate (lbs/hr)	14.32		Not used in the revised calculation. Actual annual NOx emissions used instead
Controlled NOx rate (lbs/hr)	2.86		
Total operating hours	6,500		
Uncontrolled Emissions (tons/yr)	46.5	161	NBPC's NOx baseline is too low. DEQ uses a figure of 131, which is also low compared to more recent data

[195] 2022 Kordzi Report at 78, citing, EPA, Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, (June 2019), (numerous references to 90% SCR control); *see also*, https://sviindustrial.com/selective-catalytic-reduction-systems/, https://www.environex.com/insights/advanced-class-gas-turbine-scr-and-co-catalyst-system-operating-challenges.

[196] Kordzi Report at 78-79.

Control efficiency (%)	80.0	90.0	NBPC's SCR efficiency is too low
NOx removed (tons/yr)	37.2	144.6	
Cost-Effectiveness ($/ton)	**$14,435**	**$2,700**	

As the Kordzi Report explained, and as seen in the above table, accepting NBPC's undocumented costs and making the revisions described above shows that NBPC's SCR cost-effectiveness for the CE1 Turbine was greatly inflated and moreover, at $2,700 per ton DEQ must require SCR at this source.

NBPC made feeble attempts to correct a few of these errors, several of which were identified in a letter from DEQ. However, as explained in the Kordzi Report, the source's revisions were not justified and were based on the outdated 1999 information. As discussed previously in these comments, the Regional Haze Rule requires that cost-effectiveness figures be specific to the source and be documented. Furthermore, figures must be current and within the past five years. The "revised" information NBPC provided is unacceptable. DEQ must require that NBPC perform a proper SCR cost-effectiveness calculation for its CE1 Turbine that include either a vendor quote or other valid documented costs.

E. DEQ's Dakota Great Plains Synfuels Plant Four-Factor Analysis is Inconsistent with the Clean Air Act and Regional Haze Rule Requirements.

The Draft SIP explained that Dakota Gasification Company (DGC) – Great Plains Synfuels Plant (GPSP) is owned and operated by Bain Electric Power Cooperative (Basin). DGC produces synthetic natural gas, fertilizers, and other byproducts resulting from the gasification of lignite coal.[197] GPSP also captures carbon dioxide, which is transported via pipeline to oil fields in Saskatchewan Canada. The sources evaluated of NOx and SO_2 emissions include:

- Three Riley boilers each rated at 763 MMBtu per hour,
- Two superheaters each rated at 169 MMBtu per hour, and
- The main flare and the start-up flare.

The DGC GPSP is located approximately six miles northwest of the town of Beulah, North Dakota in Mercer County. The GPSP receives lignite coal from the Coteau Properties Freedom Mine located approximately two miles north of the GPSP. The closest Class I area is Theodore Roosevelt National Park, with a Q/d of 75.4.

[197] Draft SIP at A.10-1.

1. DEQ Failed to Resolve Numerous Issues in the Four-Factor Analyses.

Despite identifying numerous issues with the DGC Four-Factor Analyses, the following issues remain unresolved.[198] As discussed previously, these are based on specific legal requirements and DEQ must ensure that its SIP contains documentation and the correct information for the following before submittal to EPA:

- Lack of documentation of cost items,
- Assumption of a 20-year control life in all cost-effectiveness calculations,
- Lack of information on how baseline emissions were apportioned/calculated,
- Lack of documentation for Riley boiler scrubber efficiency,
- Incorrect information regarding SCR feasibility and performance,
- Lack of documentation concerning superheater combustion tuning claims,
- Undocumented interest rate,
- Use of owner's costs, and
- Use of too high of a contingency in cost-effectiveness calculations.

2. DEQ Must Ensure that DGC Account for the Significant Bypass Emissions in the Four-Factor Analysis.

The Kordzi Report explained that emissions from the three individual Riley boilers and the superheaters are not directly monitored. Rather, the CEMS are located in the stacks, which serves the five sources.[199] The main stack exhausts *routine* emissions from all three of the Riley boilers and the two superheaters, and the bypass stack exhausts *routine* emissions from the package boiler and *non-routine* emissions from the Riley boilers and the superheaters.[200] Moreover, emissions from the non-routine emissions are significant, indeed in 2017 they were nearly the same as routine (2,152 non-routine, 2,272).[201] These non-routine (malfunction) emissions must be accounted for in the Four-Factor Analysis.

3. DEQ Must Require that the Riley Boilers' Wet Scrubber Be Assessed for Upgrades.

The Kordzi Report explained that the Riley boilers' wet scrubber system may not be operating at the 97-98% efficiency claimed due to the frequent bypasses.[202] It may be that scrubber system was designed to operate at that efficiency but based on the amount of exhaust gas that is routed to the bypass scrubber, either the scrubber

---

[198] 2022 Kordzi Report at 80-81.
[199] *Id*. at 81.
[200] *Id*.
[201] *Id*.
[202] *Id*.

system does not operate at that efficiency and/or the bypass exhaust comes from the superheaters, which DGC must explain.[203] Therefore, DEQ must require that DGC:

- Present data that can support the actual scrubber system efficiency,
- Explain what is causing the frequent scrubber bypasses,
- Perform a Four-Factor Analysis of how it can eliminate these bypasses, and
- Explore whether it can upgrade or optimize the scrubber system.[204]

Even if the scrubber system were experiencing these bypasses, it is not adequate for DGC to simply claim a high scrubber efficiency.[205] Consistent with the legal requirements, DGC must provide documentation to justify its claim.[206]

4. DEQ Must Require that the Superheaters be Properly Assessed.

The Kordzi Report noted that emissions to the main stack and the bypass stack come from the Riley boilers and/or the superheaters.[207] Because of the significant amount of emissions, DEQ must require that DGC explain under what conditions exhaust from the superheaters is routed to the bypass stack, which then must be taken into consideration in the Four-Factor Analyses.[208] Also, the superheaters can and do burn synthetic natural gas and tar oil in combination or up to 100% of either fuel. DEQ must require that these units be assessed for post combustion controls.[209]

Furthermore, the superheater exhaust is used to reheat the exhaust from the scrubber system in order to keep it above the condensation temperature inside the main stack. However, DGC fails to explain why some of the superheater exhaust is routed to the bypass stack and whether this exhaust could be routed through the wet scrubber and controlled, DEQ must require that DGC provide an explanation for this control option.[210]

5. DEQ Must Ensure That the Riley Boilers Are Properly Assessed for SNCR.

As highlighted and discussed in detailed in the Kordzi Report, DGC's historical information regarding the technical feasibility of SNCR for the Riley

[203] 2022 Kordzi Report at 81.
[204] *Id*. at 81.
[205] *Id*. at 82.
[206] *Id*.
[207] *Id*.
[208] *Id*.
[209] *Id*.
[210] *Id*.

boilers in 1997 is not persuasive.[211] Particularly in light of a large number of coal-fired EGUs, some that burn high sulfur eastern coals, that have successfully employed SNCR systems for years.[212] Moreover, "[a] number of companies offer proven solutions to remove and prevent the formation ammonium bisulfate from air pre-heaters and superheaters."[213] Additionally, one vendor uses as a case study the successful remedying of superheater fouling and slagging for the San Miguel facility in Texas.[214] This facility likely burns the highest sulfur coal in the U. S., with an uncontrolled SO_2 rate of approximately 10 lbs/MMBtu.[215] Thus, as the Kordzi Report concluded, even the most extreme fouling due to the burning of high sulfur coal has been successfully addressed.

Therefore, DEQ must ensure that the Riley Boilers are properly assessed for SNCR.[216]

6. DEQ Must Require that DGC Assess SCR for the Riley Boilers.

DEQ failed to assess SCR for the Riley Boilers based on the faulty premise that they burn lignite – they do not burn lignite directly.[217] As the Kordzi Report lists, the Riley Boilers burn the following fuels:

- Waste gas,
- Fuel gas,
- Tar oil,
- Naphtha,
- Phenol,
- CO_2,
- Liquefaction off-gas, and
- Substitute natural gas.

Lignite is not on the list.[218] Therefore, the underlying reason DEQ provided for excluding the control is moot and DEQ must include SCR in the Four-Factor Analysis for the Riley Boilers.[219] Moreover, even if the facility burned lignite,

[211] 2022 Kordzi Report at 82.
[212] *Id.*
[213] *Id.* (citing, https://clyde-industries.com/products-and-solutions/air-heater-sootblower; *see also*, https://www.power-eng.com/emissions/air-pollution-control-equipment-services/eliminating-air-heater-plugging-and-corrosion-caused-by-scr-sncr-systems-for-nox-control-on-coal-fired-boilers/).
[214] 2022 Kordzi Report at 83 (citing, https://clyde-industries.com/case-studies).
[215] 2022 Kordzi Report 83 (citing, 81 Fed. Red. 318 (Jan. 5, 2016) (explaining that after a 94% SO_2 removal from its scrubber, the San Miguel outlet was still 0.60 lbs/MMBtu, which equates to an inlet SO_2 rate of 10.0 lbs/MMBtu (0.60 lbs/MMBtu/0.06 lbs/MMBtu = 10 lbs/MMBtu)).
[216] 2022 Kordzi Report at 83.
[217] *Id.*
[218] *Id.*
[219] *Id.*

assuming the excuses for neglecting to evaluate SCR for this facility are similar as those DEQ provided for disregarding the control at EGUs, the reasons for disregarding the control is invalid and as such must be evaluated here.

7. *DEQ Failed to Require That DGC Correct Its Highly Flawed and Inflated SCR Cost-Effectiveness Calculation.*

The Kordzi Report reviewed, discussed and provided a corrected cost-effective calculation for DGC's SCR figure, which was highly flawed and DEQ failed to correct. Kordzi's Report explained it made numerous corrections, which included the following:

- Removal of the cost of the DSI system,[220]
- Removal of sales tax,[221]
- Too short of an equipment life (20 years),[222]
- Undocumented interest rate (5.5%),[223]
- Inclusion of owner's costs (disallowed by the Control Cost Manual),[224]
- Too high contingency (20%),[225] and
- Too low of an SCR efficiency (80%).[226]

The corrections resulted in the following cost-effectiveness calculation.

Table 13: Revised DGC Riley Boilers SCR Retrofit Cost-Effectiveness[227]

Cost Item	**DGC**	**Revised**	**Comments**
Capital Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$60,114,000	$59,426,242	S&L's undocumented figure which includes a DSI system, escalated to 2020
Estimated Capital Cost of DSI system		-$13,057,627	Remove estimated capital cost of DSI (escalated from 2016 to 2020)
Sales tax	$3,006,000	$0	Remove sales tax of $3,006,000

[220] 2022 Kordzi Report at 84-85.
[221] *Id*. at 85.
[222] *Id*.
[223] *Id*.
[224] *Id*.
[225] *Id*.
[226] *Id*.
[227] *Id*. at 85-87.

Freight	$3,006,000	$2,345,497	Revised based on ratio of DSI capital cost
Total PEC	$66,126,000	$48,714,112	
Total Direct Installation Costs	$47,449,000	$37,023,112	S&L's undocumented figure; revised based on ratio of DSI capital cost
Total Direct Costs (TDC)	$113,575,000	$85,737,223	
Indirect Costs			
Contractors general and administration (10% of TDC)	$11,358,000	$8,573,722	
Contractor's profit (5% of TDC)	$5,679,000	$4,286,861	
Engineering procurement $project services (8% of TDC)	$9,086,000	$6,858,978	
Construction management/field engineering (4% of TDC)	$4,543,000	$3,429,489	
S-U/commissioning (1.5% of TDC)	$1,704,000	$1,286,058	
Spare parts (0.5% of TDC)	$568,000	$428,686	
Owner's costs (2% of TDC)	$2,272,000	$0	Disallowed by Control Cost Manual
Total Indirect Costs (TIC)	$35,210,000	$24,863,795	
Contingency (20% of TDC + TIC)	$29,757,000	$11,060,102	Revised to more reasonable 10% of TDC + TIC)
Total Capital Investment (TCI)	$178,542,000	$121,661,120	
Equipment life (years)	20	30	DGC 's equipment life is too low
Interest Rate (%)	5.50	3.50	DGC's interest rate is undocumented
Capital Recovery Factor	0.0837	0.0544	
Annualized Capital Costs	$14,940,275	$6,614,877	
Outage Costs			
Annualized lost revenue due to retrofit	$3,515,000	$0	DGC assumes it will lose $1,000,000 per day for 42 days due to the SCR installation, with no documentation
Operating Costs			
Variable Operating Costs			
Ammonia reagent cost	$197,000	$197,000	
Hydrated lime cost	$1,066,000	$0	Delete reagent for unnecessary DSI system
Catalyst replacement and disposal cost	$2,166,000	$2,166,000	

SNG cost	$990,000	$990,000	Assumed to power reheater
Lost fertilizer revenue	$36,010,000	$0	No lost sales with elimination of DSI
Additional solid waste cost	$786,000	$0	No additional waste with elimination of DSI
Electrical power cost	$881,000	$687,419	Revised based on ratio of DSI capital cost
Total Variable O&M Cost	$42,096,000	$4,040,419	
Fixed O&M Costs			
Operating labor	$398,000	$310,548	Revised based on ratio of DSI capital cost
Supervisor labor	$60,000	$46,816	Revised based on ratio of DSI capital cost
Maintenance materials (1.5% of TDC)	$1,704,000	$1,286,058	
Total Fixed O&M Cost	$2,162,000	$1,643,423	
Indirect Operating Cost			
Property Taxes (1% of TCI)	$1,785,420	$1,216,611	
Insurance (1% of TCI)	$1,785,420	$1,216,611	
Administration (2% of TCI)	$3,570,840	$2,433,222	
Total Indirect Operating Cost	$7,141,680	$4,866,445	
Total Annual Operating Cost	$51,399,680	$10,550,287	
Total Annual Cost	$69,854,955	$17,165,164	
NOx baseline (tons)	2,260	2,260	
SCR efficiency (%)	80.0	90.0	DGC's SCR efficiency is low
NOx removed (tons)	1,808.0	2,034.0	
Cost-effectiveness	**38,637**	**8,439**	

As seen in the above table, DGC's cost-effectiveness for the installation of an SCR system to serve the Riley boilers is greatly inflated. DEQ must require that DGC revise its SCR cost-effectiveness calculation and document all assumptions and costs. The Kordzi Report explains that lacking alternative information it retained out of necessity DGC's undocumented cost items, which included unnecessary charges for the capital and operating costs of a reheat system typically needed in a tail-end SCR system. Also, as discussed above, this calculation greatly depends on the actual NOx baseline of the Riley boilers, which was undocumented. Thus, the cost-effective figure is reasonable at $8,439 per ton, and within the range of what other states have found reasonable (e.g., Oregon $10,000/ton[228] and Colorado $10,000/ton[229]). Once DGC revises its cost-effectiveness calculation to remove the erroneous and unnecessary charges, the figure will be less.

VI. DEQ FAILED TO – *AND MUST* – CONDUCT FOUR-FACTOR ANALYSES AND REQUIRE EMISSION LIMITATIONS ON OIL AND GAS AREA SOURCES.

The Draft SIP failed to include Four-Factor Analyses and emission limitations for area (nonpoint) sources. In North Dakota, the NOx emissions impact the nearby Class I areas as well as the nearby environmental justice communities.[230] The RHR requires that states must evaluate major and minor stationary sources or groups of sources, mobile sources, and area sources.[231] DEQ cannot evade its responsibility to conduct Four-Factor Analyses for emissions for sources in the oil and gas sector within its jurisdiction.[232]

DEQ's Draft SIP shows that NOx emissions from the oil and gas industry account for 72% of the nonpoint NOx emissions and it acknowledges that much of the development occurs in the western third of the state, which is the same geographic area as both of the state's Class I areas.[233] Yet, despite this significant contribution of NOx emissions from wellsite engines, wellsite heaters and boilers, and from flaring activities (and many other emitting units and fugitive sources), DEQ's Draft SIP indicated "these will not be evaluated during this planned period."[234]

DEQ made numerous erroneous claims to evade its legal responsibility to control oil and gas emissions. First, DEQ suggested it lacked regulatory authority over mobile sources, and therefore these sources were not considered in its Draft SIP.[235] DEQ is mistaken, it has two options to control the mobile source engines.

---

[228] *See,* September 9, 2020 letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2, https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf.
[229] *See* Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, November 17 to 19, 2021 Public Hearing, Prehearing Statement, at 7, https://drive.google.com/drive/u/1/folders/1TK41unOYnMKp5uuakhZiDK0-fuziE58v.
[230] For example, the environmental justice communities located nearby the Fort Berthold Reservation.
[231] 40 C.F.R. § 51.308(f)(2)(i).
[232] *See e.g.*, Draft SIP at 37; *see also* discussion elsewhere in the SIP where DEQ offers discussion of emissions from Canadian oil and gas emissions.
[233] Draft SIP at 110.
[234] Draft SIP at 109, 110.
[235] Draft SIP at 110.

- **Adopt California Standards**. Adopt standards that are identical to California standards where EPA has issued a waiver of preemptions. 42 U.S.C. § 7543(e).

- **Regulate Use and Operation**. Regulate the use and operation of non-road engines, such as regulations on hours of usage, daily mass emission limits, or sulfur limits on fuel.

The state SIP could include restrictions on the hours, days of operation, and/or how many drill rigs operate in a field. Other states include similar restrictions in their SIPs. DEQ must consider and include such enforceable limitations in its SIP.

Second, DEQ explained that the state has "roughly 15,000 active operating wells…[with]…projected emissions of 29,000 tons of NOx."[236] The State should have stopped there. Instead, it continued with its analysis, and noted that "[a]veraged across the total wellsite's in North Dakota, this is less than 2 tons of NOx per well."[237] DEQ's Draft SIP then concluded that "the limited emissions footprint from any single wellsite and relatively small contribution to visibility impairment from this sector"[238] … allowed it to take a pass during this planning period. It appears DEQ does not understand what "area source" means. The RHR does not contemplate the state using fuzzy math to subdivide emissions from all the wellsite area sources into thousands of small "single" sources to evade the Four-Factor Analysis requirements. This is the wrong approach.

DEQ has a legal duty to perform the Four-Factor Analyses and include emission limitations in this planning period for the thousands of wellsites – along with the other oil and gas area source categories – that emit thousands of tons of NOx emissions every year in western North Dakota. Indeed, the regional haze Rule provides for regulation of groupings of sources, and area sources in particular, not just major and minor sources alone.

DEQ cannot rely on its misplaced claims to avoid addressing the oil and gas sector in its Draft SIP; the oil and gas sector is a significant contributor to regional haze pollution in North Dakota and in the region and thus the haze SIP is the instrument where reductions must be required and secured in the current planning period. A plan to "kick the can down the road" is simply not acceptable and DEQ must give sufficient consideration of and include enforceable emission reduction measures for area sources, including oil and gas area sources that contribute to impairment both in-state and out-of-state.

---

[236] Draft SIP at 110. (emphasis added)
[237] Draft SIP at 110.
[238] Draft SIP at 111.

Additionally, as discussed in National Park Service consultation comments,[239] DEQ cannot rely on EPA's oil and gas regulations because they only address controls on new sources, and this RH SIP must address emissions from *existing* oil and gas sources.

DEQ must revise its Draft SIP to require statewide NOx requirements for engines, flaring, and other oil and gas sector area sources. As documented in the technical report containing comprehensive Four-Factor Analyses for the oil and gas sector,[240] there are numerous opportunities for technically feasible and cost-effective control of oil and gas area sources, which are summarized below.

[239] Letter from Herbert C. Frost, Ph.D., Regional Director, National Park Service, Interior Region 3, 4, 5, to James L. Semerad, Director of Air Quality, North Dakota Department of Environmental Quality, Division of Air Quality Attachment, Consultation Comments from National Park Service (NPS) Regional Haze SIP feedback for the North Dakota, Department of Environmental Quality (NDDEQ), at 12-13, (June 1, 2022).

[240] Stamper, V. and M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, at ES-2 (March 6, 2020).

Summary of Cost Effective Control Options for Air Emissions Sources of the Oil and Gas Sector

SOURCE CATEGORY	NOx POLLUTION CONTROL	NOx COST EFFECTIVENESS ($/TON)	PERCENT NOx REMOVAL, AND EMISSION RATES	OTHER POLLUTION CONTROLS
Natural Gas (NG)-Fired RICE Compressors	Replace with Electric Compressors	$1,228–$2,766/ton (2011 $)	100% Removal of NOx and All Other Pollutants	Power Compressors with Renewable Energy
NG-Fired RICE Rich Burn >50 hp	Nonselective Catalytic Reduction (NSCR) and Air Fuel Ratio Controller (AFRC)	$44–$3,383/ton (2009$)	94–98% 11–67 ppmv 0.16–1.0 g/hp-hr	VOC Controls integrated into NSCR.
NG-Fired RICE Lean Burn >50 hp	Low Emission Combustion (LEC)	$47–$941/ton (2001$)	87–93% 75–150 ppmv 1.0–2.0 g/hp-hr	Oxidation Catalyst for VOC Emissions
	Selective Catalytic Combustion (SCR)	$628–$13,567/ton (1999$–2001$)	90–99% 11–73 ppmv 0.15–1.0 g/hp-hr	
NG-Fired Combustion Turbines	SCR (alone or with Dry Low NOx Combustion)	$566–$13,238/ton (1999–2000$)	80–95+% 3-15 ppmv	Oxidation Catalyst for VOC Emissions
	Dry Low NOx Combustion	$208–$2,140/ton (1999$–2000$)	80–95% 9-25 ppmv	
Diesel-Fired RICE	Use Electric Engines and Tier 4 Gen Sets -------------------- OR Replace Older Engines w/ Tier 4	$564–$9,921/ton (2010$)	94% 0.5 g/hp-hr -------------------- 49%–96% 0.3-3.5 g/hp-hr	Catalytic Diesel Particulate Filter For PM (81%-97.5% control) Use of Ultra-Low Sulfur Diesel Fuel
	Replace w/ NG RICE	Implemented by several companies	85–94%	
	Retrofit with SCR	$3,759–$6,781/ton	90%	
Heaters/Boilers >20 MMBtu/hr	Ultra-Low NOx Burners (ULNB)	$545–$3,270/ton (2018$)	93% 6 ppmv	Other Options: Lower heater-treater temperatures Install insulation on separators
	SCR	$1,025–$6,149/ton (2018$)	97% 2.5 ppmv	
Heaters/Boilers >5 and ≤20 MMBtu/hr	ULNB	$727–$5,232/ton (2018$)	93% 6 ppmv	
Heaters/Boilers ≤5 MMBtu/hr	Replacement of Heater with New Unit with ULNB	$4,055-$10,809/ton (2005$)	82–89% 9-20 ppmv	

Note: The range of cost effectiveness for each control reflects a range of capacities of emission units and also reflects a wide range of operating hours per year. Refer to the report for more details.

VII. DEQ'S CONSULTATION PROCESS WAS FUNDAMENTALLY INADEQUATE.

Congress required that EPA's regulations must require each applicable implementation plan for a State in which any mandatory Class I Federal area is located to contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal.[241] The Act further requires states to determine the measures necessary to make reasonable progress by considering the four factors,[242] while Congress set the national goal as preventing future and remedying existing anthropogenic visibility impairment in all Class I areas.[243] Thus, "Congress was clear that both downwind states (*i.e.* , "a State in which any [mandatory Class I Federal] area . . . is located) and upwind states (*i.e.* , "a State the emissions from which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area") must revise their SIPs to include measures that will make reasonable progress at all affected Class I areas."[244]

In order to achieve this objective, states are obligated to consult with each other to ensure measures to achieve reasonable progress for each state's visibility impairing emissions contributes to the goal of restoring natural visibility across all Class I areas. "This consultation obligation is a key element of the regional haze program. Congress, the states, the courts and the EPA have long recognized that regional haze is a regional problem that requires regional solutions. *Vermont v. Thomas*, 850 F.2d 99, 101 (2d Cir. 1988)."[245] Congress intended this provision of the Clean Air Act to "equalize the positions of the States with respect to interstate pollution," (S. Rep. No. 95-127, at 41 (1977)) and EPA's interpretation of this requirement accomplishes this goal by ensuring that downwind states can seek recourse from EPA if an upwind state is not doing enough to address visibility transport.[246]

In developing a long-term strategy for regional haze, EPA's regulation 40 C.F.R. § 51.308(f)(2) requires that a state take three distinct steps: consultation; demonstration; and consideration. Specifically, the regulation requires:

> (ii) The State *must consult* with those States that have emissions that are reasonably anticipated to contribute to visibility impairment in the mandatory Class I Federal area to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress.

---

[241] 42 U.S.C. § 7491(b)(2).
[242] *Id*. § 7491(g)(1).
[243] *Id*. § 7491(a)(1).
[244] 82 Fed. Reg. 3078, 3094 (Jan. 10, 2017).
[245] *Id*. at 3085.
[246] *Id*.

> (A) The State *must demonstrate* that it has included in its implementation plan all measures agreed to during state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement.
> (B) The State *must consider* the emission reduction measures identified by other States for their sources as being necessary to make reasonable progress in the mandatory Class I Federal area.[247]

The RHR also requires that the

> [P]lan revision … must provide procedures for continuing consultation between the State … on the implementation of the visibility protection program required by this subpart, including development and review of implementation plan revisions and progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas.[248]

In its 2017 amendments to the RHR EPA explained that "states *must* exchange their four-factor analyses and the associated technical information that was developed in the course of devising their long-term strategies. This information includes modeling, monitoring and emissions data and cost and feasibility studies."[249] In the event of a recalcitrant state, "[t]o the extent that one state does not provide another state with these analyses and information, or to the extent that the analyses or information are materially deficient, the latter state should document this fact so that the EPA can assess whether the former state has failed to meaningfully comply with the consultation requirements."[250]

A. DEQ Must Adapt Its SIP to Meaningfully Address and Incorporate Comments from the Federal Land Manager.

The Clean Air Act and the Regional Haze Rule require states to consult with the Federal Land Manager ("FLM")—either the National Park Service or the U.S. Forest Service—that oversees the Class I national parks or wilderness areas impacted by a state's sources.[251] Specifically, the state "must provide the Federal Land Manager with an opportunity for consultation, in person at a point early enough in the State's policy analyses of its long-term strategy emission reduction

---

[247] 40 C.F.R. § 51.308(f)(2) (emphasis added); *see also*, 64 Fed. Reg. 35,765, 35,735 (July 1, 1999) (In conducting the four-factor analysis, EPA explained that "…the State must consult with other States which are anticipated to contribute to visibility impairment in the Class I area under consideration … any such State must consult with other States before submitting its long-term strategy to EPA.").
[248] 40 C.F.R. § 51.308(f)(4).
[249] 82 Fed. Reg. at 3088 (emphasis added).
[250] *Id.*
[251] 42 U.S.C. § 7491(d); 40 C.F.R. § 51.308(i)(2).

obligation so that information and recommendations provided by the Federal Land Manager can *meaningfully inform* the State's decisions on the long-term strategy."[252] The "consultation must be early enough for state officials to meaningfully consider the views expressed by the FLMs."[253] The rule further requires states to provide for "continuing consultation" between the state and the Federal Land Manager, and to meaningfully address the FLM's comments in the proposed SIP.[254] Thus, the FLM consultation process is not a mere box checking exercise; instead, it is a mandatory, iterative process, requiring the state to meaningfully consider and incorporate into the SIP the concerns of the agencies responsible for managing the Class I resources impacted by pollution from the state.

As noted, the FLMs' comments on the Draft SIP were, in many respects, similar to the concerns raised above and in the attached technical reports of Joe Kordzi and Ron Sahu. In particular, the National Park Service raised concerns about DEQ's refusal to establish reasonable cost thresholds for second planning period controls,[255] DEQ's use of the glidepath and the purported lack of visibility benefits to avoid otherwise cost-effective controls,[256] the lack of documentation for DEQ's determination that SCR technology was technically infeasible for lignite EGUs,[257] and numerous flawed and inflated cost estimates for oil and gas and EGU controls.[258]

In response to those FLM concerns, DEQ refused to make *any* substantive adjustments to its long-term strategy or control analyses. Indeed, in the Draft SIP, DEQ concludes that additional emission reductions measures are not needed because of downward haze trends, current progress below the uniform rate of progress to meet haze goals, and the minimal benefit of potential controls at North Dakota sources. As discussed above, however, both the FLMs and EPA have repeatedly admonished states against using the URP or modeled visibility benefit as a bases for rejecting otherwise cost-effective controls. And as the National Parks Service comments make clear, there are technically available controls at several North Dakota EGU and non-EGU sources that are well within the range of costs that other states and EPA have indicated are cost effective for the second planning period.

DEQ's response to the FLMs—essentially ignoring their analysis and recommendations—is arbitrary and unreasonable. DEQ may not simply reject all additional controls, regardless of whether they are cost effective, because the Class I

---

[252] 40 C.F.R. § 51.308(i)(2) (emphasis added).
[253] EPA, Responses to Comments at 445, Protection of Visibility: Amendments to Requirements for State Plans; Proposed Rule (81 FR 26942, May 4, 2016), Docket No. EPA-HQ-OAR-2015-0531 (Dec. 2016) [hereinafter, "Regional Haze Rule Revision Response to Comment"].
[254] 40 C.F.R. § 51.308(i)(2); Regional Haze Rule Revision Response to Comment at 445.
[255] Draft SIP, App'x D at D.2.a-10.
[256] *Id*. at D.2.a-10 to 12.
[257] *Id*. at D.2.a-14 to 19.
[258] See generally id. at D.2.a-21 to 117.

areas are below their uniform rates of progress and the purported lack of perceptibility of potential source-specific controls. These are generally inappropriate bases on which to make reasonable progress determinations for sources. Moreover, as NPS notes in its follow-up comments on the Draft SIP, the CAMx modeling upon which DEQ relies to conclude that controls will have minimal visibility benefits likely underestimates visibility impacts at affected Class I areas.[259] In sum, DEQ must reevaluate limiting oil and gas emissions, as well as EGU emissions, or explain how the agency's refusal to require any substantive emission reductions comports with the Regional Haze Rule and its guidance, and will ensure reasonable progress.

B. DEQ Has Not Satisfied its Interstate Consultation Obligation.

North Dakota's interstate consultation is incomplete and does not satisfy multiple portions of 40 C.F.R. § 51.308(f)(2). On page 11 of the Draft SIP, DEQ summarizes its interstate consultation efforts:

> source apportionment modeling indicated that neighboring state [Class I areas] are not significantly impacted by emissions from North Dakota. Additionally, the modeling indicated that neighboring state sources were not significantly impacting visibility in North Dakota CIAs. Documentation is included in Section 3 and Appendix C. North Dakota requested feedback from the states of Minnesota, Montana, and South Dakota on these determinations in June 2021. North Dakota has not received responses from neighboring states regarding this determination.

Separately, DEQ notes that North Dakota sources are responsible for up to 8% of nitrate and 6% of the sulfate light extinction in Montana's Medicine Lake Wilderness area, and also contributes to light extinction in Wind Cave and Badlands National Parks in South Dakota and Voyageurs National Park in Minnesota.[260] There is no documentation in the draft SIP, however, indicating that North Dakota consulted with those downwind states.

On this record, DEQ's interstate consultation is incomplete and cannot be approved. DEQ must include in its SIP documentation of its consultations with Minnesota, Montana, and South Dakota (including North Dakota's potential emission reductions to protect visibility in those downwind states), and explain whether emission reductions are necessary to protect visibility in any Class I area. EPA confirms this position in its 2017 Regional Haze Rule Revision:

---

[259] *See* Ex. 8 at 6-7, May 25, 2022 Comments of National Parks Serv. on North Dakota's proposed Regional Haze State Implementation Plan.
[260] Draft SIP at 148-49.

> [S]tates must exchange their four-factor analyses and the associated technical information that was developed in the course of devising their long-term strategies. This information includes modeling, monitoring and emissions data and cost and feasibility studies. To the extent that one state does not provide another other state with these analyses and information, or to the extent that the analyses or information are materially deficient, the latter state should document this fact so that the EPA can assess whether the former state has failed to meaningfully comply with the consultation requirements.[261]

Here, it does not appear that DEQ requested four-factor analyses from any other state; nor did North Dakota provide any four-factor analysis to other states, even though North Dakota sources impact visibility in several Class I areas. Indeed, there is no indication in the Draft SIP that DEQ performed any real assessment of the likelihood of additional reasonable progress controls for Minnesota, Montana, or South Dakota sources. Instead, DEQ's treatment of the Regional Haze Rule's consultation requirement in Section 51.308(f)(2)(ii) appears to be entirely perfunctory and clearly does not satisfy the intention of this requirement.

VIII. DEQ SHOULD ANALYZE THE ENVIRONMENTAL JUSTICE IMPACTS OF THE PROPOSED SIP.

We urge DEQ to take impacts to Environmental Justice communities into consideration as it evaluates all sources that impact regional haze. Indeed, many sources that harm the air in our treasured Class I areas are also located in or close to environmental justice areas. According to the EPA's EJScreen tool, and as reflected in the attached comments on EPA's approval of the first regional haze state implementation plan and withdrawal of EPA's federal implementation plan,[262] which we incorporate by reference, North Dakota's oil and gas sources are located in close proximity to block groups with high levels of unemployment rates and low income.

There are numerous bases for DEQ to take Environmental Justice impacts into consideration in developing its Regional Haze SIP. First, in evaluating reasonable progress under the Clean Air Act, the state must consider all "non-air quality environmental impacts of compliance." Although the Regional Haze Rule does not define "non-air quality environmental impacts," the BART Guidelines, which should inform a state's reasonable progress analysis, explain that the term should be interpreted broadly. Moreover, under the Clean Air Act, states are

[261] 82 Fed. Reg. at 3088.
[262] Ex. 8, NPCA et al., Comments on the Proposed Approval of North Dakota Regional Haze State Implementation Plan for Regional Haze and Withdrawal of the Federal Implementation Plan, 86 Fed. Reg. 14,055 (Mar. 12, 2021).

permitted to include in SIP measures that are authorized by state law but go beyond the minimum requirements of federal law.[263] Environmental justice impacts are the types of "non-air quality environmental" impacts that DEQ should consider and doing so is consistent with the Clean Air Act.

Second, consideration of Environmental Justice impacts is also consistent with EPA's recent guidance in implementing the Regional Haze Rule. Indeed, on July 8, 2021, EPA issued guidance explicitly "encourag[ing] states to consider whether there may be equity and environmental justice impacts when developing their regional haze strategies for the second planning period," including by taking such concerns into account in their source selection and four-factor analyses.[264] EPA's guidance makes clear that states may consider beneficial Environmental Justice impacts under the "non-air quality environmental impacts" reasonable progress factor.[265] EPA has also endorsed the consideration of guidance intended for use in environmental impact assessments under the National Environmental Policy Act, which includes guidance for evaluating Environmental Justice, as part of its Regional Haze planning process.[266]

Finally, consideration of the beneficial environmental impacts of additional Regional Haze emission reductions would be consistent with, and would further, the nation's environmental justice policy goals. Under Executive Order 12,898, Federal agencies must ensure they are achieving environmental justice goals as a part of their mission. To further that, President Biden's Executive Order 13,990 directs agencies to review and correct federal regulations and agency actions over the last four years that conflict with the national objectives to advance and prioritize environmental justice, and to conserve and protect our national treasures and monuments consistent with federal law. Executive Order 14,008 builds on, and reaffirms, the Biden Administration's commitment to environmental justice, and

---

[263] *See Union Elec. Co v. EPA*, 427 U.S. 246, 265 (1976) ("States may submit implementation plans more stringent than federal law requires and . . . the Administrator must approve such plans if they meet the minimum requirements of s 110(a)(2)."); *Ariz. Pub. Serv. Co. v. EPA*, 562 F.3d 1116, 1126 (10th Cir. 2009) (quoting *Union Elec. Co.*, 427 U.S. at 265) ("In sum, the key criterion in determining the adequacy of any plan is attainment and maintenance of the national air standards . . . 'States may submit implementation plans more stringent than federal law requires and [ ] the [EPA] must approve such plans if they meet the minimum [Clean Air Act] requirements of § 110(a)(2).'"); *BCCA Appeal Group v. EPA*, 355 F.3d 817, 826 n. 6 (5th Cir. 2003) ("Because the states can adopt more stringent air pollution control measures than federal law requires, the EPA is empowered to disapprove state plans only when they fall below the level of stringency required by federal law.").

[264] 2021 Clarification Memo at 16.

[265] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, EPA-457/B-19-003 (Aug. 2019).

[266] *Id.* at 33. A collection of EPA policies and guidance related to the National Environmental Policy Act (NEPA) is available at https://www.epa.gov/nepa/national-environmental-policy-act-policies-and-guidance. One of these policies concerns Environmental Justice. *See*, https://www.epa.gov/nepa/environmental-justice-guidance-national-environmental-policy-act-reviews.

directs EPA to strengthen the enforcement of the Clean Air Act. Given the plain intent of President Biden's Executive Order that EPA consider environmental justice concerns in implementing the Clean Air Act, the state should consider the environmental justice impacts of its Second Planning Period SIP both for sources located in disproportionately impacted communities, and further downwind.

Although DEQ is not bound to adhere to those recent Executive Orders, it certainly has authority to take those factors into consideration. And even if DEQ refuses to evaluate those impacts, EPA will be required to consider Environmental Justice impacts in reviewing North Dakota's SIP submittal. Thus, as a matter of both good public policy and efficiency, DEQ should analyze the environmental justice impacts of its second planning period haze SIP. For those sources located in or near a low-income or minority community that suffers disproportionate environmental harms, DEQ's four-factor analysis for that source should take into consideration how each considered measure would either increase or reduce the environmental justice impacts to the community. Such considerations will not only lead to sound policy decisions but are also pragmatic as pointed out above, where sectors and sources implicated under the regional haze program are of concern to disproportionately impacted communities in North Dakota. Thus, considering the intersection of these issues and advancing regulations accordingly will help deliver necessary environmental improvements across Clean Air Act programs and issue areas, reduce uncertainty for the regulated community, increase the state's regulatory efficiency, result in more rational decision making.

IX. CONCLUSION

We urge DEQ to reevaluate its proposed SIP in consideration of the above comments and attached reports as well as the comments of EPA and NPS and in light of EPA's July 8, 2021 Memo, which confirms that the proposed SIP is fundamentally flawed. Due to the deficiencies outlined above and in the attached reports, the state must revise and reissue a valid haze SIP for public notice and comment. Please do not hesitate to contact us with any questions or to discuss the matters raised in these comments.

Sincerely,

Joshua Smith
Sierra Club
2101 Webster St., Ste. 1300
Oakland, CA 94612
415-977-5560
joshua.smith@sierraclub.org

Stephanie Kodish
National Parks Conservation Association

706 Walnut Street, Suite 200
Knoxville, TN 37902
(856) 329-2424 ext. 28
skodish@npca.org

Sara L. Laumann
Laumann Legal, LLC.
3800 Buchtel Blvd. S. #100236
Denver, CO 80210
sara@laumannlegal.com
Counsel for National Parks Conservation
Association

Cc:

Mr. David E. Stroh
Environmental Engineer
North Dakota Department of Environmental Quality
918 East Divide Ave
Bismarck, ND 58501-1947
deStroh@nd.gov

Attachment 3

NOx and SO_2 Reasonable Progress Analysis for the Otter Tail Coyote Station

Prepared for

National Parks Conservation Association

Prepared by Joe Kordzi (Consultant)

November 2020

Table of Contents

List of Tables

List of Figures

Attachment 3

1 Executive Summary

This report describes (1) the methodology I used to construct a cost-effectiveness calculation for a Tail-End SCR (TESCR) installation at the Otter Tail Coyote Station and (2) a review of the company's May 8, 2019 sulfur dioxide (SO_2) reasonable progress analysis. I believe this report can be used to inform reasonable progress decision making by both North Dakota and EPA under the Regional Haze Program. As the units are similar, I used a previously prepared TESCR cost-effectiveness analysis prepared by Dr. Phyllis Fox as a surrogate for calculating the TESCR cost-effectiveness at Coyote. Regarding NOx, my analysis indicates that a TESCR installation at Coyote has a cost-effectiveness of approximately $2,329/ton. In comparison to past best available retrofit (BART) and reasonable progress cost-effectiveness figures, the cost-effectiveness of TESCR at Coyote Station is very reasonable.

My review of Otter Tail's SO_2 reasonable progress analysis indicates that Otter Tail's contractor, Sargent & Lundy (S&L) made errors in various aspects of its SO_2 cost analyses and employed unwarranted inputs. I corrected these errors and unwarranted inputs and revised S&L's cost-effectiveness figures to more reasonable values. My results indicate that all three upgrades to the existing underperforming spray dryer absorber (SDA) scrubber system that were considered: replacement of the SDA absorber modules, and replacement of the existing SDA system with a new CDS system, or a wet flue gas desulfurization (FGD) system are cost-effective. The following is a comparison of S&L's cost-effectiveness figures to my own:

SO_2 Technology	S&L Cost-effectiveness ($/ton)	Revised Cost-effectiveness ($/ton)
SDA Absorber Replacement	$2,592	$1,073
Replacement CDS System	$3,485	$1,761
Replacement Wet FGD System	$4,065	$1,671

2 Introduction

I have been retained by the National Parks Conservation Association (NPCA) to prepare a TESCR cost analysis for the Coyote Station and to review its SO_2 reasonable progress analysis. This work is intended to support a Reasonable Progress, four-factor analysis for control of Nitrogen Oxides (NO_x) and SO_2 for the second round of State Implementation Plans (SIPs) for Regional Haze.

The Coyote Station is a single unit, 450 MW, lignite fired Electricity Generating Unit (EGU) located near Beulah, N.D. It came online in 1981 and is operated by Otter Tail Power Company. It burns lignite from the nearby Coyote Creek Mine in a Babcock and Wilcox cyclone boiler. It is equipped with Separated Overfire Air (SOFA) for NOx control, and an older underperforming spray dryer absorber with fabric filter baghouse for SO_2 and particulate matter control.

3 SO_2 Reasonable Progress Review

In this section, I review certain aspects of Otter Tail's May 8, 2019 SO_2 reasonable progress analysis.[1] This includes (1) comments concerning S&L's lack of documentation and errors in basic inputs to its calculations, (2) comments concerning S&L's cost-effectiveness analyses for upgrading Coyote's existing SDA scrubbing system, (3) comments and calculations concerning a replacement SDA system, and

3.1 S&L Does Not Provide Appropriate Documentation for its Cost Analyses.

On page 6-1 of its reasonable progress analysis, S&L states that equipment costs 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 characterizes the cost estimates for the Coyote Unit 1 retrofit technologies as "concept screening" cost estimates generally based on parametric models, judgment, or analogy. It further adds that these cost estimates were developed by scaling cost estimates prepared by S&L for other similar projects. Neither S&L nor Otter Tail provide any documentation for these figures. Consequently, none of the dozens of individual cost items presented in S&L's cost analyses can be independently verified, making much of S&L's cost estimates a black box.

While I present specific objections to many aspects of S&L's cost estimating in other comments, I note generally that in EPA's evaluation of similar S&L and other contractor cost estimates, EPA frequently noted significant differences between these estimates and its own which were prepared according to the methodology laid out in the Control Cost Manual. In many instances, these contractor estimates, which were also devoid of any real, verifiable documentation, resulted in much higher cost-effectiveness ($/ton) values than EPA's own calculations. It is understood that some of this documentation may be proprietary. However, both North Dakota and EPA have procedures in place to treat CBI information. Consequently, Otter Tail and S&L should provide this basic documentation.

3.2 S&L Incorporates an Undocumented Future Lignite Sulfur Percentage into its Cost Analyses

On page 5-11, S&L speculates that the Coyote Station may receive higher sulfur lignite in the future and proceeds to incorporate it into its cost analysis for new absorbers. No documentation is provided to support these future operating parameters. By incorporating undocumented higher-sulfur lignite into its cost analyses, S&L skews it to a less cost-effective result. For instance, on page 5-11, S&L estimates that the present scrubber system is capable of a 70% removal efficiency, using an inlet of 2.83 lbs/MMBtu and an outlet of 0.85 lbs/MMBtu. It assumes that after replacing the SDA modules with new ones, it can raise this removal efficiency

[1] Otter Tail Power Company, Coyote Station Unit 1, North Dakota Regional Haze Second Planning Period Four-Factor Analysis, SL-014745 Final Rev 1, May 8, 2019 Project No. 12715-011, Sargent & Lundy.

to 91%, resulting in an outlet of 0.29 lbs/MMBtu.[2] Had S&L assumed the current 2.83 lbs/MMBtu lignite sulfur content, this 91% removal efficiency would have resulted in an outlet of 0.26 lbs/MMBtu. Assuming a higher-sulfur lignite than is currently being burned results in higher capital and operational costs. The cost-effectiveness calculation ($/ton of SO_2 removed) at least partially offsets this due to the increased SO_2 removal, but I cannot perform this calculation because S&L's capital and operational costs do not contain the necessary level of detail.

The BART Guidelines recognized this problem when it stated the following:[3]

> The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period. When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.

This approach was upheld by the Tenth Circuit Court when OG&E attempted to skew the cost-effectiveness of its scrubber calculations on the basis of a stated desire to purchase future coal with a higher sulfur content.[4] Although this is not a BART cost analyses, there is no technical reason to deviate from this approach, except in one area: because these units have been operating substantially under 100% capacity, Otter Tail should assume SO_2 and NOx baselines based on 100% capacity or it should commit to an enforceable restriction to a less capacity. In all its cost analyses, S&L should either assume the current lignite sulfur content or provide documentation that the future lignite sulfur will change and make the above comparison so it can be evaluated.

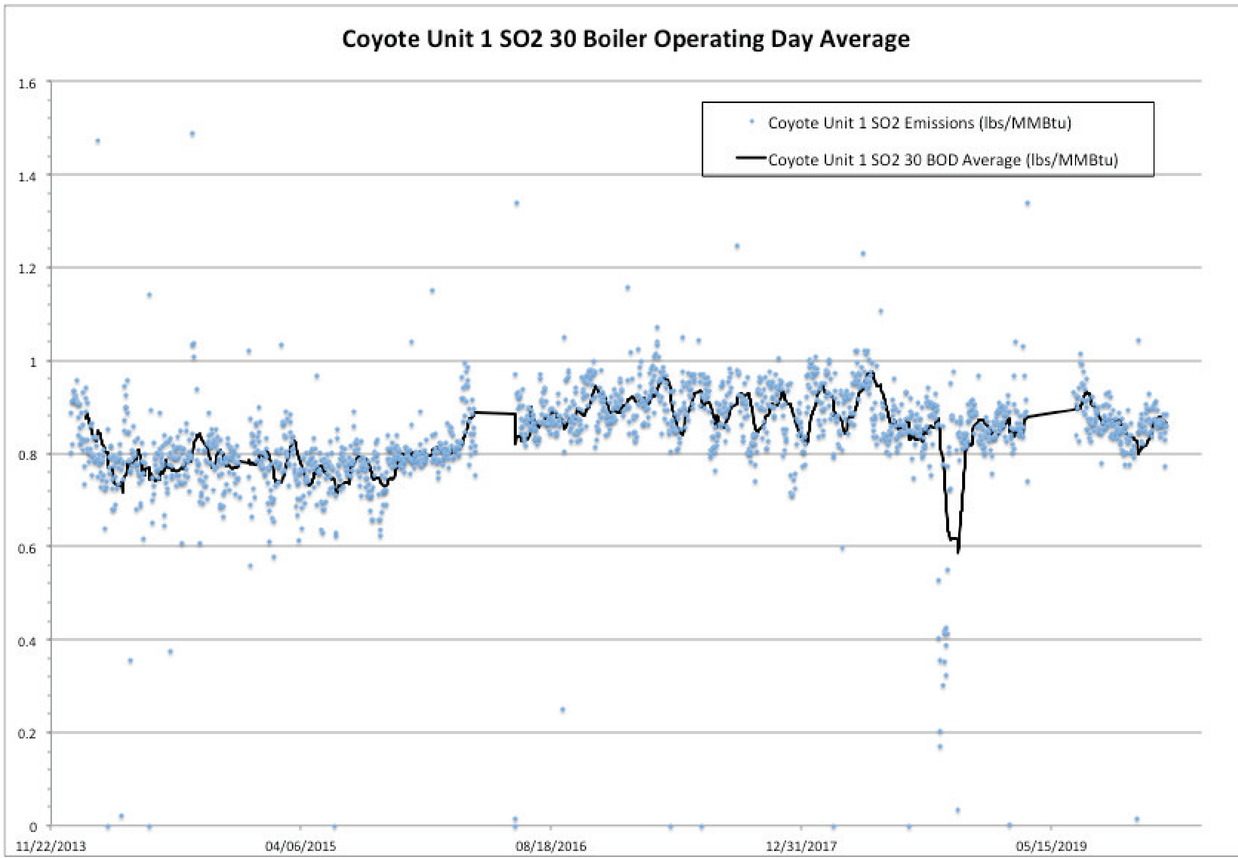
3.3 S&L Does Not Adequately Analyze Improving the Ca:S Stoichiometric Ratio

On page 5-5, S&L begins its consideration of methods to improve the Ca:S stoichiometric ration of the Coyote scrubber system. S&L states that testing was completed in October 2018 on Coyote Unit 1 to determine the impact of increasing the amount of fresh lime. S&L reports that 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." However, S&L then moderates that expectation when it states the emission rate should not be construed to represent proposed permit limits and that permit limits must be evaluated on a control system specific basis and that an additional 10-15% margin would likely be needed to account for operating margin. First, Otter Tail should provide complete

[2] Actually, a 91% removal efficiency applied to a 3.12 lbs/MMBtu sulfur coal would result in an outlet of 0.28 lbs/MMBtu (0.09 X 3.12 = 0.28).
[3] 70 FR 39167.
[4] *Oklahoma v. U.S. E.P.A.*, 723 F.3d 1201, 1215 (10th Cir. 2013).

information on this test, so that it can be properly evaluated. It appears from an examination of Coyote's 24 hour SO_2 emissions that even lower emissions were actually achieved, as the following figure demonstrates:

Figure 1. Coyote Unit 1 30 BOD SO_2 Emissions



As can be seen from examining the 24 hour emissions in Figure 4, the daily SO_2 emissions during this test (the dip in the right portion of the graph) much lower than 0.50 lbs/MMBtu were achieved.[5]

Second, the very fact that this test demonstrated that Coyote was able to meet 0.50 lb/MMBtu without adverse impacts and represents a long term emission rate, demonstrates its suitability (assuming that rate is not actually lower) as a permit limit with no need for any margin. After submission and evaluation of this test, S&L should re-assess the actual scrubber system efficiency and if found to be better than the 50% reported, rerun its cost analysis for this option.

[5] Note that dots in the figure represent individual 24 hour SO_2 emission rates and indicate that SO_2 emissions well below 0.50 lbs/MMBtu were achieved. The solid line represents a 30 BOD average and due to the short duration of the test is not representative of the SO_2 emission rate that could be achieved long term.

3.4 There are a Number of Inappropriate Items in S&L's Control Cost Estimates.

3.4.1 Otter Tail Should Provide Documentation of its Assumed Interest Rate.

On page 6-1, S&L states that an interest rate of 5.25% was assumed in the control cost calculations. However, no documentation was provided to support this rate. As I indicate above in my TESCR cost analysis, the Control Cost Manual states that "if firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates given the potential difficulties in eliciting accurate private nominal interest rates since these rates may be regarded as confidential business information or difficult to verify."[6] As of the date of this report, the current Bank Prime Interest Rate is 3.25%.[7] Consequently, Otter Tail should provide verification of its interest rate, or the Bank Prime Interest Rate should be used in all control cost calculations. Using a lower interest rate will directly lower the total annualized costs and reduce (lower $/ton) the cost-effectiveness of all controls.

3.4.2 S&L Underestimated Pollution Control Equipment Life.

On page 6-1, S&L states it is assuming an equipment life of 20 years, as that is the life North Dakota assumed in its previous regional haze SIP. Regarding this, the Control Cost Manual states: "The life of the control is defined in this Manual as the equipment life. This is the expected design or operational life of the control equipment. This is not an estimate of the economic life, for there are many parameters and plant-specific considerations that can yield widely differing estimates for a particular type of control equipment."[8] EPA has consistently assumed a 30 year equipment life for scrubber retrofits, scrubber upgrades, SCRs, and SNCR installations. Much of this is summarized and cited to in EPA's response to comments document for its Texas and Oklahoma Regional Haze SIP final disapproval and FIP.[9] Unless Otter Tail is willing to enter into an enforceable consent decree or similar instrument guaranteeing a shorter equipment life, and which is incorporated into the North Dakota SIP, all of the SO_2 and NOx cost estimates should be done on the basis of a 30 year life.

S&L's use of a 20 year equipment life artificially inflates its cost-effectiveness figures (higher $/ton). For example, in Appendix B, page 2/7 of S&L's SO_2 cost effectiveness calculations for DSI + Existing FGD, S&L assumes a 20 year equipment life. This, along with S&L's undocumented 5.25% interest rate, results in a Capital Recovery Factor (CRF) of 0.0820, an annualized capital cost of $1,948,000, and a cost-effectiveness of $2,994/ton. Using the correct

---

6 Ibid., page 15.
7 https://www.federalreserve.gov/releases/h15/.
8 See Control Cost Manual, Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, November 2017, page 22.
9 See Response to Comments for the Federal Register Notice for the Texas and Oklahoma Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze; and Federal Implementation Plan for Regional Haze, Docket No. EPA-R06-OAR-2014-0754, 12/9/2015, available here: https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0087. See pages 240-245, 268, and 274. Also see the Texas BART FIP proposal, which conducted extensive cost determinations for scrubber upgrades, at 82 FR 930 and 938. Also see Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, June 2019, pdf page 80: "For the purposes of this cost example, the equipment lifetime of an SCR system is assumed to be 30 years for power plants."

30 year equipment life (and retaining the undocumented 5.25% interest rate) results in a CRF of 0.0669 which reduces the annualized capital cost to $1,589,879, the total annualized cost to $12,012,879, and the cost-effectiveness to $2,908. Thus, Otter Tail should revise its cost analyses to use a 30 year equipment Life.

3.4.3 S&L Must Strike Owner's Costs from All of its Cost Analyses.

S&L inappropriately includes owner's costs in its cost analyses. As the Control Cost Manual indicates, "owner's costs and AFUDC costs are capital cost items that are not included in the EPA Control Cost Manual methodology, and thus are not included in the total capital investment (TCI) estimates in this section."[10] S&L should therefore strike owner's costs from all the cost analyses.

3.4.4 S&L Assumes an Inappropriate Level of Contingency in its Cost Analyses.

Regarding contingency costs, the Control Cost Manual states: "For mature control technologies, which reflect the control technologies covered in the other chapters of this Manual, the contingency can range from 5 to 15% of the TCI."[11] With the possible exception of tail-end SCR, all of the SO_2 and NOx controls contemplated in S&L's report are in fact mature control technologies, having been installed on numerous coal-fired EGUs. Consequently, the contingency percentages should be in the low end of this range, probably at 10%, but as the Control Cost Manual states, no more than 15%. Thus, S&L should make the appropriate changes to its cost analyses.

3.4.5 S&L Miscalculates SO_2 Tons Removed

On page 5-18, S&L states that it expects a replacement CDS scrubber system to be 97% efficient. In Appendix B page 1/7, S&L lists the SO_2 baseline as 12,994 tons, with the tons removed for the CDS scrubber system as 11,619. However, 11,619/12,994 = 89.42%, not 97%. Similar errors result from making the same calculation on other SO_2 controls. These errors are summarized on Table ES-1, page ES-2, where S&L lists these reduced removal efficiencies. It does not appear, however, that S&L indicates how it goes from a 97% removal efficiency for CDS, for example, to its assumed 89% removal efficiency. It may be that S&L is reducing the removal efficiencies by the "additional 10-15% margin [that] would likely be needed to account for operating margin," which is unwarranted. In any case, S&L should be performing its control and cost-effectiveness calculations on the basis of the full removal efficiencies applied to the SO_2 baseline.

3.5 S&L Provides no Documentation to Support a DSI Removal Efficiency of 35%

---

[10] Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, June 2019, pdf page 65: "owner's costs and AFUDC costs are capital cost items that are not included in the EPA Control Cost Manual methodology, and thus are not included in the total capital investment (TCI) estimates in this section."

[11] See Control Cost Manual, Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, November 2017, page 22.

On page 5-14, S&L assumes a DSI removal efficiency of 35%, based on engineering judgment. This is a very low efficiency, in comparison to real world experience.[12] S&L should provide documentation to support its assumed removal efficiency, or assume a higher removal efficiency that is in line with real world experience.

3.6 Comments Concerning Upgrades to Coyote's Existing SDA System

3.6.1 S&L Underestimates Replacement SDA Module Efficiency

On page 5-11, S&L states that replacement SDA modules may improve the overall scrubber system efficiency to 91%, assuming 80% for the SDA modules and 11% for the fabric filters. It is well known that retrofit SDA scrubber systems can perform at 95% or greater removal efficiency.[13] In fact, S&L's own SDA cost model indicates this.[14] S&L does not explain its assumption for a reduced efficiency, but perhaps this lies in other portions of the SDA scrubber system, such as the existing fabric filter which is retained. S&L should either assume a 95% control efficiency in its cost analysis or provide documentation why two higher capacity replacement modules (considering my other comments on module size) plus the existing fabric filters cannot achieve this level of performance.

Curiously, despite its statement that upgrading the existing SDA system with replacement modules can increase the efficiency to 91%, S&L only assumes an efficiency of 65.9% when performing its cost-effectiveness calculations for this option in Appendix B. As I note above, this is within the current SO_2 scrubber system performance. S&L should either explain this apparent error or correct it.

3.6.2 S&L's Should Provide Further Documentation Concerning the Addition of Another Absorber

On page 5-1, S&L states:

> 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

[12] For instance, see: https://www.babcock.com/products/sorbent-injection-systems for a general overview of DSI removal efficiency. Also see https://www.sorbacal.com/sites/default/files/downloadcenter/so2_control_using_dry_sorbent_injection_technology_with_hydrated_lime.pdf, pdf page 15 which compares the removal efficiency of Sorbacal to conventional hydrated lime. R. K. Srivastava & W. Jozewicz (2001) Flue Gas Desulfurization: The State of the Art, Journal of the Air & Waste Management Association, 51:12, 1676-1688, DOI: 10.1080/10473289.2001.10464387, page 1,681: "Approximately 50–60% SO_2 capture may be expected with the DSI using lime."

[13] Power Engineering, Circulating Fluidized Bed Scrubber vs. Spray Dryer Absorber, Issue 9 and Volume 119. Available here: https://www.power-eng.com/2015/09/14/circulating-fluidized-bed-scrubber-vs-spray-dryer-absorber/. Typical B&W/GEA Niro SDA system installations operate at 90 to 95 percent SO_2 removal efficiency, with some plants running as high as 98 percent: https://www.babcock.com/products/spray-dryer-absorbers-sda

[14] IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final, January 2017. Available here: https://www.epa.gov/airmarkets/ipm-v6-emission-control-technologies-attachment-5-2-sda-fgd-cost-development-methodology.

> 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.

First, there is no technical reason why an added absorber module must come from the same manufacturer or even be of the same design. Absorber modules are largely made to order, based on the specifications of the facility. Second, S&L states that due to the design of the absorbers there is inadequate residence time (1 second as opposed to 10 seconds in modern absorbers). If there is adequate space for a replacement module, there may be adequate space for a *larger* absorber module of a modern design that would provide more residence time resulting from Coyote's original design. In fact, in comparison to the four module design used by Coyote, vendors are offering single SDA absorber modules capable of scrubbing 400 MW units.[15] Consequently, S&L should reassess this option.

3.6.3 S&L Provides no Documentation to Support a 12 Month Outage to Replace Absorber Modules

On page 5-12, S&L speculates that an outage of approximately 12 months would be necessary to install new absorber modules. This appears to be overly conservative and drives up the cost of the installation due to the increased labor time and because Coyote would have to purchase for additional surplus electricity from the grid. It appears that S&L is assuming a linear sequence of steps: that the existing modules will be dismantled, that their existing foundations and tie-ins will be modified, the new modules will moved into position and then tied-in. In contrast, on page 5-18, S&L assumes that an entirely newly constructed CDS scrubber system can be constructed adjacent to the existing scrubber system and then tied-in to the existing system during a regularly scheduled major outage. Consequently, S&L should either assume that the replacement modules can similarly be installed during a regularly scheduled major outage, or provide documentation to the contrary.

3.6.4 S&L Should Include Cost Analyses that Consider Alternatives to Hydrated Lime

S&L should investigate the potential for using other lime-based sorbents in place of hydrated lime in its SDA and DSI cost analyses. Several companies now offer these alternatives, which advertise improved efficiency and decreased product usage, and are drop-in replacements to traditional hydrated lime.[16] Consequently, S&L should investigate their use for potential integration into its SO_2 cost-effectiveness calculations.

3.6.5 Revised S&L SDA Absorber Module Replacement Cost-Effectiveness Calculation

---

[15] B&W markets SDA single module systems for units up to 400 MW: https://www.babcock.com/en/products/-/media/f07754e2609b461f9a6127f4ff0977a9.ashx

[16] For instance, see https://www.sorbacal.com/en, or http://novaconenergysystems.com/high-value-calcium-and-sodium-sorbent.

As I discuss above, there are a number of errors and unwarranted assumptions in S&L's SDA replacement module cost-effectiveness calculations. In this section, I correct those errors by making the following adjustments: (1) reducing the contingency from 20% to 15%, (2) removing owner's costs, (3) reducing the assumed interest rate from 5.25% to 3.25%, (4) eliminating the unwarranted outage costs, and (5) increasing the assumed efficiency from 65.9% to 91%. I did, however, retain S&L's undocumented capital and operational costs.[17]

Table 1. Revised Coyote SDA Absorber Module Replacement Control Cost-effectiveness Calculation

	S&L Replacement SDA Module Cost	**Revised S&L Replacement SDA Module Cost**
Total Direct Costs	$81,312,000	$81,312,000
Owner's Costs	$1,626,000	**$0**
Total Indirect Costs	$25,207,000	$23,581,000
Contingency (% total direct and indirect costs)	20%	**15%**
Contingency Amount	$21,304,000	$15,733,950
Total Capital Investment (TCI)	$127,823,000	$120,626,950
Equipment Life (years)	20	**30**
Interest Rate(%)	5.25	**3.25**
CRF	0.0820	**0.0527**
Annualized Capital Cost	$10,475,000	$6,354,835
Annualized Outage Costs	$5,390,000	**$0**
Annual Operating Cost	$6,332,000	$6,332,000
Total Annual Cost	$22,197,000	$12,686,835
Assumed Removal efficiency (%)	65.9	**91**
SO_2 Baseline (tons)	12,994	12,994
SO_2 Removed (tpy)	8,563	11,825
Cost-effectiveness ($/ton)	$2,592	**$1,073**

As can be seen from the above comparison, even keeping S&L's undocumented direct and indirect costs (with the exception of the disallowed owner's costs), removing the unwarranted outage charge, correcting the SO_2 removal efficiency, and substituting in more appropriate cost parameters for equipment life, contingency, and interest rate, results in significant improvement in cost-effectiveness. I conclude that S&L's SDA replacement module cost analysis is higher than it should be and this improvement to the existing underperforming SDA scrubber system is a cost-effective SO_2 control solution for the Coyote station.

3.7 Comments Concerning a Replacement SDA Scrubbing System

3.7.1 S&L's Replacement Dry Scrubber Cost is High

[17] North Dakota should require that Otter Tail provide documentation of all costs.

As discussed in an earlier comment, S&L does not provide any documentation of its individual cost items for any of its cost analyses. Therefore, in order to assess its CDS scrubber replacement cost analysis, I am limited to two approaches: First, I will apply S&L's own assumptions and operating parameters to the SDA costing procedure S&L supplies to EPA for use in its IPM model as a general check of its Coyote CDS scrubber cost estimate.[18] I note that EPA has used this same approach in costing SDA scrubbers in previous regional haze actions. In that SDA costing procedure, S&L states, "Recent industry experience has shown that a CDS FGD system has a similar installed cost to a comparable SDA FGD system and has been the technology of choice in the last four years."[19] Therefore, I believe S&L's SDA costing procedure is a good surrogate for costing a CDS scrubber system. In the first case, I used all of S&L's CDS cost estimate inputs where possible, despite earlier stated concerns with many of them. I also subtracted Coyote's existing annual lime cost from the operating costs. In the second case, I modified my cost estimate with more appropriate inputs, including reducing the interest rate from 5.25% to 3.25%, and increasing the equipment life from 20 to 30 years.

Below are the inputs and output from the first case,[20] using where possible all S&L's inputs to its CDS cost analysis.[21] The first case results in a cost-effectiveness of $2,102/ton. My cost-effectiveness is expressed in 2016 dollars, so escalating it to 2019 dollars results in a value of $2,357/ton,[22] which is considerably more cost-effective than S&L's result of $3,485/ton.[23] In the second case, using more appropriate inputs, I calculate a cost-effectiveness of $1,571/ton, which escalated to 2019 dollars is $1,761/ton. I conclude that S&L's CDS cost analysis is higher than it should be and that a higher performing CDS scrubber system replacement to the existing underperforming SDA scrubber system is a cost-effective SO_2 control solution for the Coyote station.

---

[18] IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final, January 2017. Available here: https://www.epa.gov/airmarkets/ipm-v6-emission-control-technologies-attachment-5-2-sda-fgd-cost-development-methodology.

[19] Ibid., page 4.

[20] See the file, Coyote SDA Cost Estimate.xlsx for more details and notes concerning how I replicated some of the inputs to S&L's Coyote CDS cost estimate.

[21] See Appendix B.

[22] The CEPCI for 2019 is 607.5 and that for 2016 is 541.7, which results in an escalation factor of 1.12.

[23] Even S&L's value of $3,485/ton is cost effective in comparison to values approved for BART and reasonable progress in the first planning period.

Attachment 3

Figure 2. SDA Surrogate for CDS Cost-effectiveness Using S&L Inputs

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	**427**	**<--- User Input (Greater than 50 MW)**
Retrofit Factor	B		**1**	**<--- User Input (an "average" retrofit has a factor =1.0)**
Gross Heat Rate	C	(Btu/kWh)	**8,171**	**<--- User Input**
SO2 Rate	D	(lb/MMBtu)	**3.12**	**<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)**
Type of Coal	E		**LIG**	**<--- User Input (PRB, BIT, or LIG)**
Coal Factor	F		1.07	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.81706	C/10000
Heat Input	H	(Btu/Hr)	3,488,846,200	A*C*1000
Operating SO_2 Removal	J	(%)	**89.42**	**<--- User Input (Used to adjust actual operating costs)**
Lime Rate	K	(Ton/Hr)	8	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(Ton/Hr)	18	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)
Include Aux Power in VOM	M	(%)	1.16	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	(1000 gph)	21	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/Ton)	**128**	**<--- User Input**
Waste Disposal Cost	Q	($/Ton)	**32.46**	**<--- User Input**
Aux Power Cost	R	($/kWh)	**0.023**	**<--- User Input**
Makeup Water Cost	S	($/1000[gal])	**1**	**<--- User Input**
Operating Labor Rate	T	($/hr)	**0**	**<--- User Input (Labor cost including all benefits)**
Elevation adjustment if > 500		(feet)	**1,950**	**<--- User Input (no entry needed if less than 500 feet)**
Interest Rate		(%)	**5.25**	**<---- User Input**
Equipment Lifetime		(years)	**20**	**<---- User Input**
Gross Load		(MW-hours)	**2,515,751**	**<---- User Input**
SO2 Emission Baseline		(tons/year)	**12,994**	**<---- User Input**
Atmospheric pressure	W	(psia)	13.72	(2116*((59-(0.0035*E23)+459.7)/518.6)^5.256)/144

Capital Cost Calculation		Explanation of Calculation
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit difficulty
BMR($)	44,816,000	Base module absorber island cost
BMRA($)	48,016,597	BMB plus adjustment (if any) due to elevation > 500 feet
BMF($)	31,159,000	Base module reagent preparation and waste recycle/handling cost
BMB($)	65,133,000	Base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.)
BMBA($)	69,784,564	BMB plus adjustment (if any) due to elevation > 500 feet
BM($)	**148,960,000**	Total Base module cost including retrofit factor
BM($/kW)	349	Base module cost per kW
Total Project Cost		
A1	14,896,000	Engineering and Construction Mnagement costs
A2	14,896,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3	14,896,000	Contractor profit and fees.
CECC ($)	**193,648,000**	Capital, engineering and construction cost subtotal
CECC($/kW)	**454**	Capital, engineering and construction cost subtotal per kW
TPC ($)	**193,648,000**	Total Project Cost (encluding AFUDC and owner's costs)
TPC ($/kW)	**454**	Total Project Cost per kW (encluding AFUDC and owner's costs)
Fixed O&M Cost		
FOMO ($/kW-yr)	0.00	Fixed O&M additional operating labor costs. Based on eight additional operators.
FOMM ($/kW-yr)	5.23	Fixed O&M costs for waste disposal
FOMA ($/kW-yr)	0.06	Fixed O&M additional administrative labor costs
FOM ($/kW-yr)	**5.30**	Total Fixed O&M costs
Variable O&M Cost		
VOMR ($/MWh)	2.38	Variable O&M costs for lime reagent
VOMW ($/MWh)	1.31	Variable O&M costs for waste disposal
VOMP ($/MWh)	0.27	Variable O&M costs for additional auxiliary power required including additional fan power (Refer
VOMM ($/MWh)	0.05	Variable O&M costs for makeup water
VOM ($/MWh)	**4.01**	Total Variable O&M Costs
Annualization		
Capital, engineering and construction cost	$193,648,000	Excludes owner's costs and AFUDC
Capital Recovery factor	0.081952	
Annualized capital costs	$15,869,896	
Variable operating costs	$10,090,347	VOM*(Gross Load)
Subtract existing SDA lime	**-$3,057,000**	
Fixed operating costs	$1,520,818	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)
Total annualized costs	**$24,424,061**	
SO2 emissions reduction (tons)	11,619	J/(100%)*(SO2 emission baseline)
$/ton	**2,102**	

Attachment 3

Figure 3. SDA Surrogate for CDS Cost-effectiveness Using Revised Inputs

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	**427**	**<--- User Input (Greater than 50 MW)**
Retrofit Factor	B		**1**	**<--- User Input (an "average" retrofit has a factor =1.0)**
Gross Heat Rate	C	(Btu/kWh)	**11,053**	**<--- User Input**
SO2 Rate	D	(lb/MMBtu)	**2.42**	**<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)**
Type of Coal	E		**LIG**	**<--- User Input (PRB, BIT, or LIG)**
Coal Factor	F		1.07	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		1.1053	C/10000
Heat Input	H	(Btu/Hr)	4,719,631,000	A*C*1000
Operating SO_2 Removal	J	(%)	**97.00**	**<--- User Input (Used to adjust actual operating costs)**
Lime Rate	K	(Ton/Hr)	9	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(Ton/Hr)	19	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)
Include Aux Power in VOM	M	(%)	1.56	(0.000547*D^2+0.00649*D+1.3)*F*G
Makeup Water Rate	N	(1000 gph)	29	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/Ton)	**128**	**<--- User Input**
Waste Disposal Cost	Q	($/Ton)	**32.46**	**<--- User Input**
Aux Power Cost	R	($/kWh)	**0.023**	**<--- User Input**
Makeup Water Cost	S	($/1000[gal])	**1**	**<--- User Input**
Operating Labor Rate	T	($/hr)	**0**	**<--- User Input (Labor cost including all benefits)**
Elevation adjustment if > 500		(feet)	**1,950**	**<--- User Input (no entry needed if less than 500 feet)**
Interest Rate		(%)	**3.25**	**<---- User Input**
Equipment Lifetime		(years)	**30**	**<---- User Input**
Gross Load		(MW-hours)	**2,515,751**	**<---- User Input**
SO2 Emission Baseline		(tons/year)	**12,994**	**<---- User Input**
Atmospheric pressure	W	(psia)	13.72	(2116*((59-(0.0035*E23)+459.7)/518.6)^5.256)/144

Capital Cost Calculation		**Explanation of Calculation**
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit difficulty
BMR($)	53,587,000	Base module absorber island cost
BMRA($)	57,413,991	BMB plus adjustment (if any) due to elevation > 500 feet
BMF($)	31,460,000	Base module reagent preparation and waste recycle/handling cost
BMB($)	73,501,000	Base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.)
BMBA($)	78,750,177	BMB plus adjustment (if any) due to elevation > 500 feet
BM($)	**167,624,000**	Total Base module cost including retrofit factor
BM($/kW)	393	Base module cost per kW
Total Project Cost		
A1	16,762,000	Engineering and Construction Mnagement costs
A2	16,762,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3	16,762,000	Contractor profit and fees.
CECC ($)	**217,910,000**	Capital, engineering and construction cost subtotal
CECC($/kW)	**510**	Capital, engineering and construction cost subtotal per kW
TPC ($)	**217,910,000**	Total Project Cost (encluding AFUDC and owner's costs)
TPC ($/kW)	**510**	Total Project Cost per kW (encluding AFUDC and owner's costs)
Fixed O&M Cost		
FOMO ($/kW-yr)	0.00	Fixed O&M additional operating labor costs. Based on eight additional operators.
FOMM ($/kW-yr)	5.89	Fixed O&M costs for waste disposal
FOMA ($/kW-yr)	0.07	Fixed O&M additional administrative labor costs
FOM ($/kW-yr)	**5.96**	Total Fixed O&M costs
Variable O&M Cost		
VOMR ($/MWh)	2.63	Variable O&M costs for lime reagent
VOMW ($/MWh)	1.47	Variable O&M costs for waste disposal
VOMP ($/MWh)	0.36	Variable O&M costs for additional auxiliary power required including additional fan power (Refer
VOMM ($/MWh)	0.07	Variable O&M costs for makeup water
VOM ($/MWh)	**4.52**	Total Variable O&M Costs
Annualization		
Capital, engineering and construction cost	$217,910,000	Excludes owner's costs and AFUDC
Capital Recovery factor	0.0527	
Annualized capital costs	$11,479,873	
Variable operating costs	$11,380,730	VOM*(Gross Load)
Subtract existing SDA lime cost	**-$3,057,000**	
Total annualized costs	**$19,803,603**	
SO2 emissions reduction (tons)	12,604	J/(100%)*(SO2 emission baseline)
$/ton	**1,571**	

3.8 Comments Concerning a Replacement Wet Scrubber System

3.8.1 S&L's Limestone Cost is High

In Appendix B, S&L assumes a limestone cost of $70 per ton in its wet scrubber cost analysis. It is important that this cost be well documented as to its unit cost and the amount required, as it is a significant part of the wet scrubber retrofit cost. This cost should not be considered proprietary, since it is not a quote for designs, does not involve proprietary technology, nor would it divulge some competitive advantage. Also, the vendor who supplies this commodity also provides it to a wide range of clients. Therefore, Otter Tail should certainly provide documentation for it.

For example, S&L's own wet scrubber costing procedure that it provides to EPA for use in the IPM modeling platform assumes a default limestone cost of $30.[24] In addition, one supplier of limestone used at the Basin Electric Antelope Valley facility, Montana Limestone, appears to sell industrial grade limestone at $15.20/ton FOB.[25]

3.8.2 S&L's Wet FGD Labor is Excessive

In Appendix B, S&L assumes that 4 additional operators per shift are necessary for the wet scrubber retrofit. Assuming three eight hour shifts per day, that equates to 12 additional operators. This is excessive, considering that the existing SDA scrubber system already has operators. S&L doesn't state how many operators are used to run the existing SDA scrubber system, but S&L's own SDA costing procedure it supplies to EPA for use in its IPM assumes 8 total operators are necessary for a SDA scrubber system and that 12 operators are necessary for a wet scrubber system less than or equal to 500 MW.[26] Consequently, S&L should have assumed an additional 4 total operators were necessary for a wet scrubber retrofit.

3.8.3 S&L's Replacement Wet Scrubber Cost is High

Similar to my approach in checking S&L's dry scrubber cost analysis, I will first apply S&L's own assumptions and operating parameters to the wet FGD costing procedure S&L supplies to EPA for use in its IPM model as a general check for its Coyote wet scrubber cost estimate.[27] I note that EPA has used this same approach in costing wet scrubbers in previous regional haze actions. In the first case, I used S&L's wet FGD cost estimate inputs where possible, despite my

[24] See IPM Model – Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology, Final, January 2017. Available here: https://www.epa.gov/airmarkets/ipm-v6-emission-control-technologies-attachment-5-1-wet-fgd-cost-development-methodology

[25] https://www.basinelectric.com/sites/CMS/files/files/pdf/Commerce/MLC-2020-Commercial-Price-List.pdf.

[26] IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final, January 2017. Available here: https://www.epa.gov/airmarkets/ipm-v6-emission-control-technologies-attachment-5-2-sda-fgd-cost-development-methodology. See IPM Model – Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology, Final, January 2017. Available here: https://www.epa.gov/airmarkets/ipm-v6-emission-control-technologies-attachment-5-1-wet-fgd-cost-development-methodology

[27] See IPM Model – Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology, Final, January 2017. Available here: https://www.epa.gov/airmarkets/ipm-v6-emission-control-technologies-attachment-5-1-wet-fgd-cost-development-methodology

earlier stated concerns with many of them. I also subtracted Coyote's existing annual lime cost from the operating costs. In the second case, I modified my cost estimate with more appropriate inputs, including reducing the limestone cost to $30, modifying S&L's wet FGD cost estimate for four additional operators, reducing the interest rate from 5.25% to 3.25%, and increasing the equipment life from 20 to 30 years. Below are the inputs and output from the first case,[28] using where possible all S&L's inputs to it's tail-end SCR baseline cost analysis.[29] The first case results in a cost-effectiveness of $2,173/ton. Escalating this to 2019 dollars results in a value of $2,437/ton which is considerably more cost-effective than S&L's result of $4,065/ton.[30] Following that in the second case, and using more appropriate inputs, I calculate a cost-effectiveness of $1,490/ton. Escalating this to 2019 dollars results in a value of $1,671/ton. I conclude that S&L's wet scrubber cost analysis is higher than it should be and that a higher performing wet scrubber system replacement to the existing underperforming SDA scrubber system is a cost-effective SO_2 control solution for the Coyote station.

[28] See the file, Coyote Wet FGD Cost Estimate.xlsx for more details and notes concerning how I replicated some of the inputs to S&L's Coyote wet FGD cost estimate.
[29] See Appendix B.
[30] Even S&L's value of $4,065/ton is cost effective in comparison to some values approved for BART and reasonable progress in the first planning period.

Attachment 3

Figure 4. Wet FGD Cost-effectiveness Using S&L Inputs

Variable	Designation	Units	Value	Calculation
Wastewater Treatment			Phys Chem-Biological	**<--- User Input (Phys Chem Biological, or None)**
Unit Size (Gross)	A	(MW)	**427**	**<--- User Input (Greater than 50 MW)**
Retrofit Factor	B		**1**	**<--- User Input (An "average" retrofit has a factor =1.0)**
Gross Heat Rate	C	(Btu/kWh)	**8,171**	**<--- User Input**
SO2 Rate	D	(lb/MMBtu)	**3.12**	
Type of Coal	E		**LIG**	**<--- User Input (PRB, BIT, or LIG)**
Coal Factor	F		1.07	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.8171	C/10000
Heat Input	H	(Btu/Hr)	3,489,017,000	A*C*1000
Operating SO_2 Removal	J	(%)	**92.95**	**<--- User Input (Used to adjust actual operating costs)**
Design Limestone Rate	K	(Ton/Hr)	10	(17.52*A*D*G/2000 (Based on 98% SO2 removal)
Design Waste Rate	L	(Ton/Hr)	17	1.811*K (Based on 98% SO2 removal)
Include Aux Power in VOM	M	(%)	1.59	(1.05e^(0.155*D+1.3))*F*G
Makeup Water Rate	N	(1000 gph)	30	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/Ton)	**70**	**<--- User Input**
Waste Disposal Cost	Q	($/Ton)	**32.46**	**<--- User Input**
Aux Power Cost	R	($/kWh)	**0.023**	**<--- User Input**
Makeup Water Cost	S	($/1000[gal])	**1**	**<--- User Input**
Operating Labor Rate	T	($/hr)	**62**	**<--- User Input (Labor cost including all benefits)**
Elevation adjustment if > 500 Feet		(feet)	**1,950**	**<--- User Input (no entry needed if less than 500 feet)**
Interest Rate		(%)	**5.25**	**<---- User Input**
Equipment Lifetime		(years)	**20**	**<---- User Input**
Gross Load		(MW-hours)	**2,515,751**	**<---- User Input**
SO2 Emission Baseline		(tons/year)	**12,994**	**<---- User Input**
Atmospheric pressure	W	(psia)	13.72	(2116*((59-(0.0035*E23)+459.7)/518.6)^5.256)/144

Capital Cost Calculation		**Explanation of Calculation**
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit difficulty
BMR($)	41,558,000	Base absorber island cost
BMRA($)	44,525,923	Adjustment to base absorber island costs, if elevation is greater than 500 feet. See page 3 of the S&L
BMF($)	20,449,000	Base reagent preparation and waste recycle/handling cost
BMW($)	12,348,000	Base reagent preparation cost
BMB($)	77,524,000	Base balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.)
BMBA($)	83,060,485	Adjustment to base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.), if elevation is greater than 500 feet. See page 3 of the S&L documentation.
BMWW($)	9,642,299	Base wastewater treatment facility to comply with ELG. Based on ~ 0.4 gpm/MW
BM($)	**167,058,000**	Total Base module cost including retrofit factor
BM($/kW)	391	Base cost per kW
Total Project Cost		
A1	16,706,000	Engineering and Construction Mnagement costs
A2	16,706,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3	16,706,000	Contractor profit and fees.
CECC ($)	**217,176,000**	Capital, engineering and construction cost subtotal
CECC($/kW)	**509**	Capital, engineering and construction cost subtotal per kW
Add in Disallowed Owner's Cost	**4,132,000**	
TPC ($)	**221,308,000**	Total Project Cost (excluding AFUDC ~~and owner's costs~~)
TPC ($/kW)	**518**	Total Project Cost per kW (excluding AFUDC and ~~owner's costs~~)
Fixed O&M Cost		
FOMO ($/kW-yr)	3.62	Fixed O&M additional operating labor costs. IF MW > 500, then 16 operators, else 12 operators
FOMM ($/kW-yr)	5.87	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW-yr)	0.18	Fixed O&M additional administrative labor costs
FOMWW ($/kW-yr)		Fixed O&M costs for wastewater treatment facility
FOM ($/kW-yr)	**9.67**	Total Fixed O&M costs
Variable O&M Cost		
VOMR ($/MWh)	1.48	Variable O&M costs for limestone reagent
VOMW ($/MWh)	1.25	Variable O&M costs for waste disposal
VOMP ($/MWh)	0.37	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh)	0.07	Variable O&M costs for makeup water
VOMWW ($/MWh)	0.17	Variable O&M costs for makeup water
VOM ($/MWh)	**3.33**	Total Variable O&M Costs
Annualization		
Capital, engineering and construction cost	$221,308,000	
Capital Recovery factor	0.0820	
Annualized capital costs	$18,136,696	
Variable operating costs	$8,385,087	VOM*(Gross Load)
Subtract existing SDA lime cost	**-$3,057,000**	
Fixed operating costs	$2,777,626	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)
Total annualized costs	**$26,242,409**	
SO2 emissions reduction (tons)	12,078	J/(100%)*(SO2 emission baseline)
$/ton	**2,173**	

Attachment 3

Figure 5. Wet FGD Cost-effectiveness Using Revised Inputs

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Phys Chem-Biological		**<--- User Input (Phys Chem Biological, or None)**
Unit Size (Gross)	A	(MW)	**427**	**<--- User Input (Greater than 50 MW)**
Retrofit Factor	B		**1**	**<--- User Input (An "average" retrofit has a factor =1.0)**
Gross Heat Rate	C	(Btu/kWh)	**11,053**	**<--- User Input**
SO2 Rate	D	(lb/MMBtu)	**2.42**	
Type of Coal	E		**LIG**	**<--- User Input (PRB, BIT, or LIG)**
Coal Factor	F		1.07	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		1.1053	C/10000
Heat Input	H	(Btu/Hr)	4,719,631,000	A*C*1000
Operating SO_2 Removal	J	(%)	**98.00**	**<--- User Input (Used to adjust actual operating costs)**
Design Limestone Rate	K	(Ton/Hr)	10	(17.52*A*D*G/2000 (Based on 98% SO2 removal)
Design Waste Rate	L	(Ton/Hr)	18	1.811*K (Based on 98% SO2 removal)
Include Aux Power in VOM	M	(%)	1.93	(1.05e^(0.155*D+1.3))*F*G
Makeup Water Rate	N	(1000 gph)	40	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/Ton)	**30**	**<--- User Input**
Waste Disposal Cost	Q	($/Ton)	**32.46**	**<--- User Input**
Aux Power Cost	R	($/kWh)	**0.023**	**<--- User Input**
Makeup Water Cost	S	($/1000[gal])	**1**	**<--- User Input**
Operating Labor Rate	T	($/hr)	**62**	**<--- User Input (Labor cost including all benefits)**
Elevation adjustment if > 500 Feet		(feet)	**1,950**	**<--- User Input (no entry needed if less than 500 feet)**
Interest Rate		(%)	**3.25**	**<---- User Input**
Equipment Lifetime		(years)	**30**	**<---- User Input**
Gross Load		(MW-hours)	**2,515,751**	**<---- User Input**
SO2 Emission Baseline		(tons/year)	**12,994**	**<---- User Input**
Atmospheric pressure	W	(psia)	13.72	(2116*((59-(0.0035*E23)+459.7)/518.6)^5.256)/144

Capital Cost Calculation		Explanation of Calculation
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit difficulty
BMR($)	49,565,000	Base absorber island cost
BMRA($)	53,104,754	Adjustment to base absorber island costs, if elevation is greater than 500 feet. See page 3 of the S&L
BMF($)	20,746,000	Base reagent preparation and waste recycle/handling cost
BMW($)	12,618,000	Base reagent preparation cost
BMB($)	87,481,000	Base balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.)
BMBA($)	93,728,578	Adjustment to base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.), if elevation is greater than 500 feet. See page 3 of the S&L documentation.
BMWW($)	9,642,299	Base wastewater treatment facility to comply with ELG. Based on ~ 0.4 gpm/MW
BM($)	**186,300,000**	Total Base module cost including retrofit factor
BM($/kW)	436	Base cost per kW
Total Project Cost		
A1	18,630,000	Engineering and Construction Mnagement costs
A2	18,630,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3	18,630,000	Contractor profit and fees.
CECC ($)	**242,190,000**	Capital, engineering and construction cost subtotal
CECC($/kW)	**567**	Capital, engineering and construction cost subtotal per kW
TPC ($)	**242,190,000**	Total Project Cost (excluding AFUDC and owner's costs)
TPC ($/kW)	**567**	Total Project Cost per kW (excluding AFUDC and owner's costs)
Fixed O&M Cost		
FOMO ($/kW-yr)	1.21	Fixed O&M additional operating labor costs. ~~If MW > 500, then 16 operators, else 12 operators~~
FOMM ($/kW-yr)	6.54	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW-yr)	0.11	Fixed O&M additional administrative labor costs
FOMWW ($/kW-yr)		Fixed O&M costs for wastewater treatment facility
FOM ($/kW-yr)	**7.87**	Total Fixed O&M costs
Variable O&M Cost		
VOMR ($/MWh)	0.70	Variable O&M costs for limestone reagent
VOMW ($/MWh)	1.38	Variable O&M costs for waste disposal
VOMP ($/MWh)	0.44	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh)	0.09	Variable O&M costs for makeup water
VOMWW ($/MWh)	0.17	Variable O&M costs for makeup water
VOM ($/MWh)	**2.79**	Total Variable O&M Costs
Annualization		
Capital, engineering and construction cost	$242,190,000	
Capital Recovery factor	0.0527	
Annualized capital costs	$12,758,985	
Variable operating costs	$7,010,880	VOM*(Gross Load)
Subtract existing SDA lime cost	**-$3,057,000**	
Fixed operating costs	$2,259,388	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)
Total annualized costs	**$18,972,253**	
SO2 emissions reduction (tons)	12,734	J/(100%)*(SO2 emission baseline)
$/ton	**1,490**	

4 TESCR Cost-effectiveness Development

4.1 Brief History of the Technical Feasibility Determination of SCR for Certain North Dakota EGUs

During the first round of regional haze SIPs in September of 2011, EPA proposed to correct deficiencies in North Dakota's SIP with a Federal Implementation Plan (FIP), concluding NOx BART for Leland Olds Unit 2, and Milton R. Young Units 1 and 2 should correspond to limits resulting from the installation of SCR. EPA's BART proposal was consistent with the agency's long-held position in a Clean Air Act New Source Review enforcement action that the best available control technology for NOx control at Milton R. Young was SCR. To resolve that enforcement case,[31] EPA, North Dakota, and Minnkota, the owner of Unit 1 and operator of both units, entered a Consent Decree on April 24, 2006, requiring in part that North Dakota perform a NOx BACT determination for both units of Milton R. Young.

Minnkota had steadfastly maintained that, based on the unique aspects of Milton R. Young's cyclone-fired boilers and due to the high alkali constituents, primarily sodium, in the lignite Minnkota burns, SCR in any configuration was infeasible. North Dakota changed its position regarding feasibility several times, but ultimately agreed with Minnkota in its November 2010 BACT determination that SCR for Milton R. Young was infeasible. EPA challenged that BACT determination. Applying a deferential standard of review, however, the United States District Court for the District of North Dakota agreed with North Dakota Department of Environmental Quality's assessment that, based on the unique boiler and lignite characteristics at Milton R. Young, SCR in any configuration was technically infeasible, and denied the United States' motion for dispute resolution concerning North Dakota's NOx BACT determination on December 21, 2011.[32] EPA subsequently adopted the position that the BACT and BART determination processes were so similar that it must accept the Court's position that SCR was technically infeasible at Milton R. Young for BART as well.

In its final partial approval of North Dakota's SIP, EPA concluded, based on "current evidence," that the state's determination regarding the feasibility of tail end SCR for North Dakota's lignite burning EGUs was not unreasonable.[33] Although EPA extended that determination to Coyote, the agency also noted that it may have reached different conclusions had EPA been conducting the analysis or if additional information had been available. . Therefore, on April 6, 2012, EPA approved North Dakota's SIP determinations for Leland Olds Unit 2 and Milton R. Young Units 1 and 2 that NOx BART should be based on NOx limits resulting from SNCR. Although EPA subsequently reconsidered this decision, it ultimately upheld it.

Thus, the Court's determination that North Dakota had demonstrated that SCR in any configuration at Milton R. Young was technically infeasible became a turning point for all future North Dakota lignite EGU NOx BACT, BART, and Reasonable Progress determinations. However, EPA specifically noted that it expected the state to revisit both the range of technically feasible controls and cost-effectiveness of those controls in the second round of regional haze

[31] United States v. Minnkota Power Cooperative, Inc., No. 1:06-cv-00034-DLH-CSM (D. N.D.).
[32] *Id.*, Order Denying Mot. for Stay and Mot. for Dispute Resolution, ECF Doc. 35.
[33] 77 Fed. Reg. at 20,899/2, 20,936/2,

SIPs.[34] In light of this, and to help in the review of the record concerning the technical feasibility of SCR at North Dakota lignite EGUs, myself and Dr. Ranajit Sahu have prepared a separate document demonstrating that SCR is in fact generally technically feasible for North Dakota lignite fired EGUs.[35]

4.2 Approach

I am not aware of any detailed SCR cost analysis that is in the public record for Coyote Station. North Dakota did calculate the total annualized cost and the cost-effectiveness of SCR for Coyote in the first planning period.[36] Below are those figures.

Table 2. North Dakota SIP Coyote SCR Cost-Effectiveness

Source	Control Technology	Total Annualized Cost ($)	Control Efficiency (%)	Emissions Reduction (tpy)	Cost Effectiveness ($/ton)
Coyote	SCR w/reheat	45.3-65.1 million	80	10,446	4,337-6,232
	ASOFA + SCR w/reheat	46.6-66.4 million	90	11,752	3,965-5,650

At the time of its analysis, Coyote had no NOx control, and so North Dakota considered two scenarios – (1) one with only SCR and (2) SCR plus Advanced Separated Overfire Air (ASOFA), a combustion NOx control.

I could not find any details concerning these figures except North Dakota's statement that they were, "[b]ased on BART cost estimate for Leland Olds Unit 2 and Minnkota 1 & 2 shared cost estimate."[37] I assume that North Dakota's reference to "Minnkota 1 & 2" refers to Milton R. Young Units 1 and 2. North Dakota does not disclose how it based its cost analysis of Coyote on these surrogate units, but I assume it was done by ratioing the costs to the unit sizes. Milton R. Young Unit 1 is 257 MW in size, and the Leland Olds Unit 2 and the Milton R. Young Unit 2 are of similar sizes (440 and 477 MW, respectively). All three units have cyclone furnaces and burn North Dakota lignite. Considering the level of detail required in a regional haze cost-effectiveness analysis,[38] I conclude that this basic approach is sound but is highly dependent on the quality of the cost analyses of the surrogate units.

---

[34] See, *e.g.*, 77 Fed. Reg. at 20,937/2.
[35] See ND Lignite SCR Report by Kordzi and Sahu (October 20, 2020).
[36] See Table 9.8 of the North Dakota State Implementation Plan for Regional Haze, A Plan for Implementing the Regional Haze Program Requirements of Section 308 of 40 CFR Part 51, Subpart P - Protection of Visibility, North Dakota Department of Health, Adopted: February 24, 2010 (North Dakota SIP) Available here: https://drive.google.com/drive/folders/1TNL9-c_SzVM5aQDVdeIuKzNZwwROVyNO.
[37] Ibid, page 185.
[38] Note that EPA's Control Cost Manual states that BACT and BART cost analyses should be performed to a study-level accuracy of +/- 30%. See EPA's Control Cost Manual, Section 1, Chapter 2, November 2017, page 6. All chapters of the Control Cost Manual are available here: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

Because the Milton R. Young Unit 2 and the Leland Olds Unit 2 are the most similar in size, these cost analyses can be regarded as potential surrogates. I note that North Dakota presented more detailed cost analyses than it did for Coyote for these two units in its SIP. However, in its September 21, 2011, FIP proposal (76 Fed. Reg. 58570), EPA found considerable errors in these analyses. These errors were mainly due to failures by the facility contractors to follow the Control Cost Manual, the use of undocumented costs, and the use of unnecessary or inflated costs. These issues are detailed in EPA's own SCR cost analyses for these units.[39] Of the two cost analyses, the one performed by Dr. Fox is accompanied by a full report and a working spreadsheet. However, the only information I could locate regarding the ERG cost analysis was a spreadsheet with little explanations of costing methodology.[40] Therefore, I will rely on Dr. Fox's cost analysis for the Leland Olds Unit 2 as my surrogate.

My approach consists of the following steps:

- Examine and update the operational cost inputs where possible.
- Escalate the capital costs to present.
- Update the capital recovery factor.
- Examine available information on Coyote to determine what further updates to the Leland Olds cost analysis can be made.
- Adapt the Leland Olds cost analysis to Coyote.
- Calculate the cost-effectiveness of TESCR for Coyote.

4.3 Overview of the Fox Cost Analysis for Leland Olds Unit 2

In her March 2011 report, Dr. Fox calculates the cost-effectiveness of a TESCR installation at Leland Olds Unit 2. She used a May 27, 2009, Sargent & Lundy (S&L) cost analysis as a starting point.[41] Dr. Fox calculated both a TESCR installation with ASOFA and a standalone tail-end SCR. Since, as stated above, Coyote now has ASOFA installed, I use the standalone TESCR cost analysis from Dr. Fox's report. Below I discuss the significant considerations in the application of Dr. Fox's cost analysis to the Coyote Station.

---

[39] See the Technical Support Document for EPA's Proposed Action on North Dakota's Regional Haze and Transport State Implementation Plans and EPA's Proposed Promulgation of Federal Implementation Plans, September 2011 (EPA's TSD); Appendix C, EPA Cost Analysis Supporting Documentation for Leland Olds Station Unit 2; Revised BART Cost Effectiveness Analysis for Tail-End Selective Catalytic Reduction at the Basin Electric Power Cooperative Leland Olds Station Unit 2, Final Report, Prepared for U.S. Environmental Protection Agency Region 8, by Phyllis Fox, Ph.D., PE (Consultant).
Also see EPA's TSD; Appendix D, EPA Cost Analysis Supporting Documentation for Milton R. Young Station Units 1 and 2; Revised ERG MRYS SCR Cost Estimate Summary. EPA's TSD and associated documents are available here: https://www.regulations.gov/document?D=EPA-R08-OAR-2010-0406-0076.

[40] Ibid., TSD, Appendix D.

[41] See pdf page 105 of the Appendix C.1 of the North Dakota SIP, available here: https://www.regulations.gov/document?D=EPA-R08-OAR-2010-0406-0005

4.4 The Leland Olds Analysis Assumed Gas Reheat

Dr. Fox noted that when costing TESCR for Leland Olds Unit 2, S&L assumed the exhaust gas reheat would be supplied by natural gas fired duct burners. Dr. Fox noted several problems with S&L's treatment of this:

- Use of a steam coil for reheat has "important advantages over natural gas including lower cost, no increase in flue gas flow rate from gas combustion byproducts, no moisture condensation on the catalyst, and no risk of re-vaporization of catalyst poisons in the flame of a duct burner. Most tail end SCRs in Europe use steam for reheating."[42]
- Vendors in the Milton R. Young case uniformly recommended the use of a steam coil in place of natural gas fired duct burners.[43]
- S&L did not evaluate the use of a steam coil, instead opting for a natural gas fired reheater, which would have been resulted in much more expensive annual operating costs.
- S&L assumed a higher rate of natural gas would be used, and also inflated the cost of natural gas.

In its May 27, 2009, SCR cost analysis, S&L does not state whether sufficient natural gas capacity existed at the Leland Olds site in order to supply a gas fired reheater. However, elsewhere in the Leland Olds BART determination, Burns & McDonald states its August 11, 2009, update regarding gas reburn NOx control (another NOx control technique separate from SCR), "conventional gas reburn alternatives would have high expected capital costs for a natural gas supply pipeline and on-going natural gas costs."[44] Consequently, although it does not so state, I assume that S&L was aware of this and included the capital cost of running a natural gas pipeline in its the capital costs for TESCR. Because it does not appear that Dr. Fox altered S&L's SCR capital cost, I further assume this cost was carried forward in her analysis.

The S&L May 8, 2019, Coyote Four Factor Analysis, states that Coyote does not have natural gas at its facility.[45] This presents a concern in using the Leland Olds TESCR cost analysis as a surrogate, since it assumes natural gas reheat. Although the Leland Olds TESCR estimate likely assumed the capital cost of installing a natural gas pipeline, that cost could be different for the Coyote Station. Regardless, the Control Cost Manual notes "Capital costs for these reheating options are similar, however steam supply piping, supports, and valves may increase the steam coil reheating capital costs. In a case study for a tail-end SCR on a 600 MW burning bituminous coal, one source cites SCR capital costs of $205 million for an SCR with steam coil reheating and $205 million for an SCR with a natural gas burner (2008$)."[46] The Control Cost Manual further notes, as does Dr. Fox above, that steam coil reheating typically results in much lower annual operating costs.[47] Thus, the assumed natural gas reheat costs in the Leland Olds TESCR

[42] Dr. Fox's original footnote: see the 1/8/10 EPA Comments, Enclosure I, p. 25.
[43] Dr. Fox's original footnote: see e.g., Hartenstein Report, April 20 I0, pp. 34-35,40-43.
[44] See pdf page 71 of the Appendix C.1 of the North Dakota SIP.
[45] Coyote Station Unit 1, North Dakota Regional Haze Second Planning Period, Four-Factor Analysis, Sl-014745 Final Rev 1, May 8, 2019 Project No. 12715-011. See page 5-28.
[46] EPA Control Cost Manual. Section 4, Chapter 2 Selective Catalytic Reduction, June 2019. See page 2-68.
[47] Ibid., see page 2-32.

analysis are likely high in comparison to steam coil reheating and should represent a conservatively high approximation for Coyote.

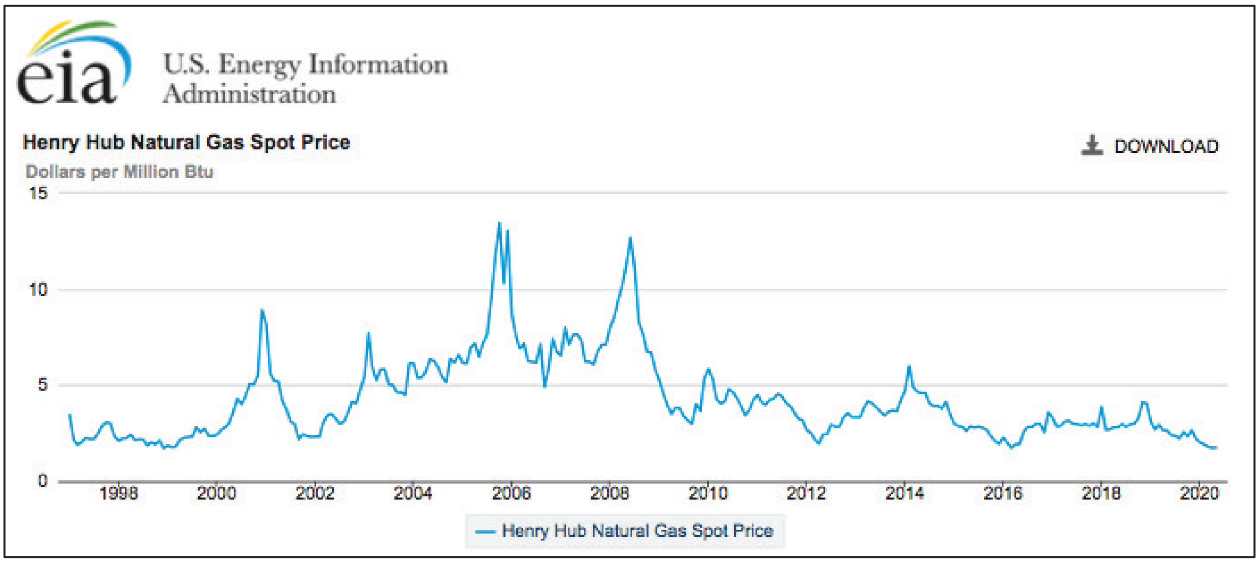
4.5 Examination and Adjustment of Operation and Maintenance Costs

In this section, I will examine key Operation and Maintenance (O&M) cost items to determine if they should be updated. These include ammonia, natural gas and catalyst replacement.

4.5.1 Natural Gas Costs

Dr. Fox criticized S&L for inflating the cost of natural gas for use in the reheaters. She noted that S&L assumed a cost ranging on $8/MMBtu to $12/MMBtu was, based on the Henry Hub spot price market, more reasonably estimated at $5.5/MMBtu, which included a transportation cost of $1/MMBtu. As the following chart from the Energy Information Agency indicates, her adjustment was correct:[48]

Figure 6. Henry Hub Monthly Natural Gas Spot Price.



Regarding future predictions, the EIA states, "The June STEO expects higher natural gas prices by the end of 2020, forecasting Henry Hub to average $2.95/MMBtu in December."[49] Adding in the same $1/MMBtu transportation cost results in a currently reasonable natural gas price of approximately $4/MMBtu, in contrast to the $5.50/MMBtu used in Dr. Fox's cost analysis. Consequently, I will adjust the price of natural gas to $4/MMBtu.

[48] See https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm.

[49] https://www.eia.gov/naturalgas/weekly/.

4.5.2 Ammonia Costs

As with natural gas, Dr. Fox adjusted S&L's ammonia cost downward. S&L had assumed a range of $450/ton to $700/ton[50] and Dr. Fox used $475/ton, based on other BART analyses conducted in 2010. Below I compare the average price of ammonia reported by the USGS:[51]

Table 3. Historical Ammonia Pricing

Year	Price ($/ton)
2008	590
2009	251
2010	396
2011	531
2012	579
2013	541
2014	530
2015	481
2016	267
2017	247
2018	281
2019	232[52]

* The 2019 figure is estimated by the USGS, based on current information available at the time of publication.

The above ammonia pricing is Freight on Board (FOB) at the Gulf Coast, meaning it doesn't include shipping. However, it can be used to construct an escalation index, similar to the use of the Chemical Engineering Plant Cost Index (CEPCI) used in escalating capital costs. Dr. Fox's cost analysis was done on the basis of 2010 dollars. Therefore, using the 2010 and 2019 figures, the escalation adjustment is 232/396 = 0.586. As S&L noted in its May 27, 2009, report, the price of ammonia is closely tied to that of natural gas, since natural gas is the feedstock. Consequently, because natural gas prices have declined since 2010, so have ammonia prices. Therefore, I adjust Dr. Fox's ammonia price of $475/ton as follows: $475/ton x 0.586 = $278/ton.

[50] See Appendix C.1 of the North Dakota SIP, pdf page 110. S&L noted in its May 27, 2009 report that "Ammonia prices are directly related to the price of natural gas. Approximately 33 mmBtu of natural gas are needed to produce one ton of ammonia, and natural gas accounts for approximately 80% of the ammonia production cost. Anhydrous ammonia costs are currently in the range of approximately $450/ton, but have historically been as high as $700/ton."
[51] See the USGS National Minerals Information Center, Nitrogen Statistics and Information, Mineral Commodities Summaries. Available here: https://www.usgs.gov/centers/nmic/nitrogen-statistics-and-information.
[52] The figure listed in the USGS report is $230/ton, which the USGS footnotes as an estimated value. Communication with the USGS clarifies that the final figure is $232/ton. See the file "Apodaca-Kordzi email 7-6-20 on NH3 pricing.pdf."

4.5.3 Catalyst Replacement Costs

Catalyst experiences erosion and deactivation over time and must be replaced. Catalyst life is in fact the central issue in the ongoing debate concerning the technical feasibility of SCR at North Dakota lignite EGUs. Thus, it is an O&M cost item. In its May 27, 2009, SCR cost analysis, S&L, assumed a catalyst cost of $7,500/m^3. Dr. Fox noted that this cost was high in comparison to vendor communications she was aware of. However, because of confidentiality concerns, she was not able to cite to better figures. Similarly, I must operate under the same constraints, leaving me no choice but to escalate that figure. The CEPCI for 2010 and 2019 are 550.8 and 2019 607.5, respectively. Consequently, the escalated catalyst cost is then: 607.5/550.8 x $7,500/m^3 = $8,272/m^3. This agrees reasonably well with the cost EPA has noted for catalyst pricing in 2016 dollars of $227/ft^3, or $8,021/m^3.[53]

In addition to a high catalyst cost, Dr. Fox noted many other problems with S&L's catalyst replacement cost assumptions, including (l) a very short catalyst lifetime of 6 months to 1 year; (2) frequent catalyst replacement of every six months to one year; (3) larger than necessary catalyst volume; (4) assumed 2 to 4 weeks to replace the catalyst; (5) a special outage for catalyst replacement, in which the unit is taken off line just to replace catalyst; and (6) ignoring the time value of money. Dr. Fox made a number of corrections to these cost assumptions and I see no reason not to apply them to Coyote.[54]

4.6 Adjustment of Capital Costs

Dr. Fox cited to a number of published figures demonstrating that S&L's undocumented capital cost of $350/kW for SCR was high. Because of the proprietary nature of pollution control capital costs, she had no other option but to accept that figure, which was in 2009 dollars. She escalated it to 2010 dollars in her analysis using the Chemical Engineering Plant Cost Index (CEPCI). I will similarly escalate S&L's figure to 2019 dollars. The CEPCI for 2010 and 2019 are 550.8 and 607.5, respectively. The revised escalated catalyst cost is then: 607.5/550.8 x $350/kW = $386/kW. I will use this cost for Coyote.

4.7 Adjustment of the Capital Recovery Factor

Both S&L and Dr. Fox used a Capital Recovery Factor (CRF) of 0.08718, which is unexplained in both the May 27, 2009, S&L report and Dr. Fox's report. The formula for calculating the CRF is:[55]

$$CRF = i(1+i)^n / ((1+i)^n - 1)$$

Where "i" is the interest rate and "n" is the equipment life in years. The Control Cost Manual states that "if firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates given the potential difficulties in eliciting accurate

---

[53] See https://www.epa.gov/sites/production/files/2019-06/scrcostmanualspreadsheet_june-2019vf.xlsm.

[54] *See also* ND Lignite SCR Report by Kordzi and Sahu (October 20, 2020).

[55] See EPA's Control Cost Manual, Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, November 2017. See page 22.

private nominal interest rates since these rates may be regarded as confidential business information or difficult to verify."[56] As of the date of this report, the current Bank Prime Interest Rate is 3.25%.[57] The Control Cost Manual states "broadly speaking, a representative value of the equipment life for SCR at power plants can be considered as 30 years."[58] The revised capital recovery factor is then: $0.0325(1.0325)^{30} / ((1.0325)^{30} - 1) = 0.0527$.

4.8 Calculation of the Coyote Annual Capacity Factor

The annual capacity factor for a power plant is simply the ratio of the actual annual electrical output in MW-h to the full output the plant is capable of generating in MW-h. If the pollution control equipment being costed is not planned to be operated continuously (not applicable in this case), then the capacity factor is further multiplied by the fraction of the run time of the pollution control equipment.[59]

Because the baseline period should reflect current operating conditions, or future conditions that have been secured by an enforceable mechanism, it is appropriate to consider Coyote's installation of Separated Overfire Air (SOFA), which significantly lowered Coyote's NOx emissions, and which EPA notes began on June 15, 2016.[60] Below are the annual emissions of Coyote Station:[61]

Table 4. Annual Emissions of Coyote Station

Year	Operating Time	Gross Load (MW-h)	SO_2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	Heat Input (MMBtu)
2010	8,037.5	3,254,130	13,691.2	0.702	12,323.2	35,201,254
2011	8,123.7	3,242,461	13,423.6	0.731	13,018.8	35,579,248
2012	6,393.5	2,439,038	10,639.4	0.727	9,943.6	27,008,173
2013	7,174.9	2,810,032	12,579.2	0.693	10,914.4	31,206,229
2014	7,641.3	2,914,829	12,777.1	0.700	11,374.5	32,197,996
2015	8,307.8	2,058,997	8,786.0	0.774	8,819.9	22,757,213
2016	6,746.3	2,586,763	11,872.9	0.580	7,771.8	27,102,662
2017	7,594.9	2,778,245	13,443.9	0.424	6,377.7	29,849,117
2018	7,954.2	3,244,441	14,913.5	0.456	7,974.9	34,550,493
2019	6,049.9	2,182,244	10,059.7	0.455	5,359.0	23,245,878

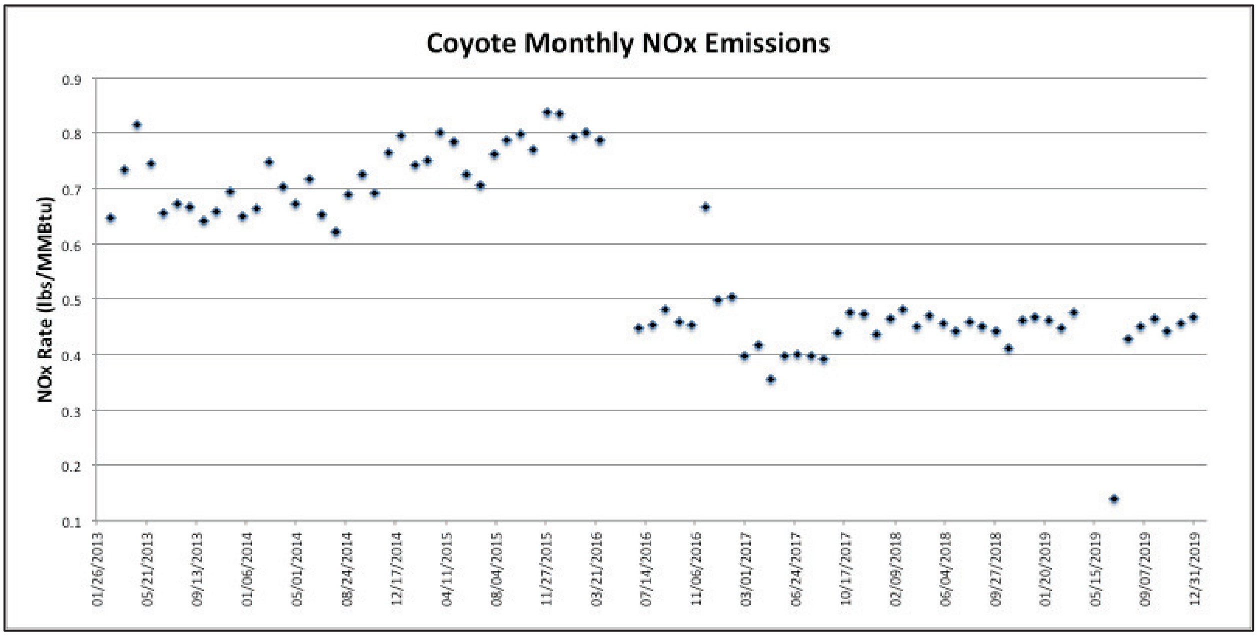
[56] Ibid., page 15.
[57] https://www.federalreserve.gov/releases/h15/.
[58] EPA Control Cost Manual. Section 4, Chapter 2 Selective Catalytic Reduction, June 2019. See page 2-78.
[59] Otter Tail states the nameplate rating for Coyote is 427 MW (https://www.minnkota.com/coyote-station.html), but the nameplate value reported to EIA Form 860 and assumed by EPA in its regional haze analyses (e.g., 76 FR 58570) is 450 MW. This is very close to the actual gross capacity, which can be calculated based on Coyote's maximum historical monthly gross load of 327,168 MW-h in January, 2010: (327,168 monthly MW-h)(12 months)/8760 h) = 448 MW. Thus, I use 450 MW.
[60] See the file, "Coyote Emissions.xlsx," which lists the annual and monthly emissions of Coyote Station, obtained from EPA's Air Markets Program Data website, available here: https://ampd.epa.gov/ampd/.
[61] Ibid.

For the purpose of calculating the capacity factor, I therefore assign the baseline period to 2017 - 2019, since those are the only whole years following the installation of SOFA. Therefore, the average gross load for the baseline period is: (2,778,245 + 3,244,441 + 2,182,244)/3 = 2,734,977 MW-h. The capacity factor is then: 2,734,977 MW-h/[(450 MW)(8760 h)] = 0.694.

4.9 Calculation of the Coyote SCR NOx Reduction

The cost analysis methodology used by S&L for Leland Olds and adopted by Dr. Fox calculates the amount of NOx removed based on the difference between the NOx rate baseline and the SCR NOx outlet. Dr. Fox adopted S&L's NOx rate baseline of 0.48 lbs/MMBtu for Leland Olds. This should be re-examined for Coyote. Below are the monthly NOx emissions from Coyote:[62]

Figure 7. Coyote Monthly NOx emissions



As discussed above, this analysis considers the time after June 15, 2016, when Coyote's SOFA was installed. Each data point depicted in Figure 2 represents one month's NOx average. I note that in its May 8, 2019 Coyote four-factor analysis, Otter Tail indicates the Coyote NOx baseline emission rate is 0.46 lbs/MMBtu.[63] It therefore appears to me this is a reasonable NOx baseline and I will use it in my Coyote analysis. Therefore, using the same SCR outlet of 0.05 lbs/MMBtu adopted by Dr. Fox in her Leland Olds cost analysis, a SCR control efficiency of 89.1% is calculated: 100% x (1-(0.05/0.46)) = 89.1%. The annual tonnage of NOx removed is then 6,393.[64]

---

[62] See the worksheet, "Coyote Monthly" in the workbook, "Coyote-LOS Emissions.xlsx."
[63] Coyote Station Unit 1, North Dakota Regional Haze Second Planning Period, Four-Factor Analysis, SL-014745 Final Rev 1, May 8, 2019 Project No. 12715-011. See page 4-2.
[64] This calculation also depends on the unit's annual capacity factor. As this calculation is somewhat long, please see the file, "Coyote-LOS Cost Effectiveness.xlsx," Worksheet "Coyote SCR."

4.10 Adjustment of the Catalyst Future Worth

The Control Cost Manual presents two different methods of calculating the catalyst replacement cost:[65]

> [The first] methodology is based on estimating the total volume of catalyst, the total number of catalyst layers, the number of layers replaced annually, and the future worth of the catalyst. This cost methodology assumes a guaranteed catalyst life of 24,000 hours or approximately 3 years for close to full time operation. The second methodology is an empirical equation that is part of the S&L cost methodology employed for power plants in the IPM.

In the above, the guaranteed catalyst life of 24,000 hours is an example. The Control Cost Manual further explains that if the SCR includes a spare catalyst layer, then only one catalyst layer is replaced at the end of the catalyst operating life. Because the catalyst is replaced every few years, the annual catalyst cost for all reactors is a function of the future worth of the catalyst. The cost analysis used by Dr. Fox uses the first methodology. The Control Cost Manual explains that the future worth factor is calculated by the following equation:[66]

$$FWF \square\ i(1/((1+ i)^{Y} -1)$$

where i is the interest rate (fraction). Y = the term in years, given by the following equation, which is rounded to the nearest integer:

$$Y = h_{catalyst}/h_{year}$$

where $h_{catalyst}$ = operating life of the catalyst in hours, and h_{year} = the number of hours per year the SCR is operated, which considers the capacity factor.

For Leland Olds, Dr. Fox calculated a future worth factor of 0.31, based on a 7% interest rate, a 24,000 hour catalyst life, and her capacity factor of 0.865. Because the interest rate has changed and Coyote's capacity factor is different, I must recalculate the future worth factor. Y is then 24,000 hours/(8760 hours x 0.694) = 3.95, which when rounded to the nearest integer equals 4. The revised future worth factor is then: $0.0325/(((1 + 0.0325)^{4})-1) = 0.24$. I will use this figure for the future worth factor for Coyote.

4.11 Miscellaneous Adjustments

The S&L cost analysis methodology adopted by Dr. Fox includes the boiler's heat input rate, which for Leland Olds equates to 5,130 MMBtu/hr. The May 8, 2019, Coyote four-factor analysis, reports this value as 4,900 MMBtu/hr. [67]

---

[65] EPA Control Cost Manual. Section 4, Chapter 2 Selective Catalytic Reduction, June 2019. See page 2-75.
[66] Ibid., see page 2-76.
[67] Coyote Station Unit 1, North Dakota Regional Haze Second Planning Period, Four-Factor Analysis, SL-014745 Final Rev 1, May 8, 2019 Project No. 12715-011. See page 2-1.

Dr. Fox used a power cost for Leland Olds of $38/MWh. In its May 8, 2019, Coyote four-factor analysis, Otter Tail indicates that the Coyote power cost is $23/MWh, which I adopt in my analysis.[68]

4.12 Summary of Changes in Leland Olds TESCR Cost Analysis

As discussed above, I have examined all the inputs to Dr. Fox's March 2011 TESCR cost analysis for Coyote Station and have updated those inputs that have changed over time. These include the gross capacity; the O&M costs for ammonia, natural gas, and catalyst; the capital SCR cost; the annual capacity factor, the interest rate; the capital recovery factor; and the catalyst future worth factor.

Typically, the cost-effectiveness of pollution controls has worsened (higher $/ton) over time. This is because the capital and operating costs have typically both increased over time. In comparison to Dr. Fox's cost analysis, a number of my revised inputs act to worsen the cost-effectiveness calculation. These include:

- An increase in the catalyst cost from $7,500/m^3 to $8,272/m$^{3.}$
- An increase in the SCR capital cost from $350/kW to $386/kW.
- A slight increase in the plant capacity from 440 MW to 450 MW.
- A slight decrease in the inlet NOx emission rate from 0.48 lbs/MMBtu to 0.46 lbs/MMBtu.

However, a number of other inputs act to improve of the cost-effectiveness calculation. These include:

- A drop in the power costs from $38/MWh to $23/MWh.
- A drop in the cost of natural gas from $5.50/MMBtu to $4.00/MMBtu.
- A drop in the cost of ammonia from $475/ton to $278/ton.
- A drop in the interest rate that is proper to use in a cost analysis from 7% to 3.25%, which impacts the capital recovery factor and hence the annualization of costs.

The net result is that the net effect of the adjustments I have made to the Leland Olds TESCR inputs act to decrease both the annualized capital and O&M costs.

4.13 Results

My adaptation of Dr. Fox's TESCR cost-effectiveness analysis for Leland Olds Unit 2 to Coyote Station results in a cost-effectiveness value of $2,329/ton. Below are the inputs and outputs to that calculation:[69]

[68] Ibid. See Appendix C, NOx Control Cost-Effectiveness Estimates, pdf page 96.
[69] See the file, "Coyote-LOS Cost Effectiveness.xlsx," Worksheet "Coyote SCR."

Attachment 3

Figure 8. Coyote TESCR Cost-Effectiveness

(Revised Inputs are ***Bold and Italicized***)	Units	Cost
INPUT DATA		
Design Coal		Lignite
SCR Configuration		Tail End
Capacity	MW	***450***
Heat Input	MMBtu/hr	4,900
Inlet NOx Emissions	lb/MMBtu	***0.46***
Outlet N0x Emissions	lb/MMBtu	0.05
Control Efficiency	%	89.1
NOx Removed	lb/hr	2,009
NOx Removed	tons/yr	6,107
Ammonia Required	lb/hr	791
Ammonia Cost	$/ton	***278***
Pressure Drop across catalyst	in w.c.	4
Pressure Drop	in w.c.	18
Power Consumption	kW	6,956
Power Cost	$/MWh	**23**
Temperature Rise Across Steam to Flue Gas Reheater	F	50
Natural Gas Requirement	MMBtu/hr	66
Natural Gas Cost	$/MMBtu	***4.0***
Unit Capital Cost SCR (Leland Olds Unit 2)	$/kW	350
CEPCI 2010		***550.8***
CEPCI 2019		***607.5***
Unit Capital Cost SCR	$/kW	***386***
Unit Catalyst Cost	$/$m^3$	***8,272***
Initial Catalyst Volume	m^3	440
Coal Cost	$/MBtu	1.00
Catalyst Cost	$	3,640,000
Annual Capacity Factor	%	***69.4***
Cost of Outage	$/week	0
Outage Duration	weeks	0
Catalyst Replacement	hrs or months	24,000
Number of Catalyst Layers		3
Interest Rate (Prime Bank Rate)		***0.0325***
Equipment Life	years	***30***
"Y" term in Future Worth Factor	integer	***4***
Future Worth Factor		***0.24***
Capital Recovery Factor		***0.0527***
Levelized Annual O&M Factor		1
TOTAL CAPITAL COST		
SCR + ASOFA Capital Cost	$	
SCR Capital Cost	$	185,130,000
SO3 Mitigation Capital Cost[a]	$	0
Total Installed Capital Cost	$	**185,130,000**
Annual Capital Cost	$/yr	**9,752,966**
FIXED O&M COST		
Operating Labor Cost	$/yr	$0
Maintenance Materials Cost	$/yr	$555,000
Maintenance Labor Cost	$/yr	$370,000
Administrative and Support Labor	$/yr	$0
Total Fixed O&M Cost	$/yr	**$925,000**
VARIABLE O&M COST		
Ammonia Cost	$/yr	669,000
Catalyst Cost	$/yr	289,000
Power Cost	$/yr	973,000
Gas Penalty	$/yr	1,615,000
Outage Penalty	$/yr	0
Sorbent Injection	$/yr	0
Total Variable O&M Cost	$/yr	**3,546,000**
Total Annual O&M Costs	$/yr	**4,471,000**
Cost Effectiveness	**$/ton**	**2,329**

4.14 Potential Criticisms of this Analysis

In this section, I review some potential criticisms of my approach to calculating the cost-effectiveness of TESCR at Coyote Station. This includes a review of the sensitivity of certain input parameters that have been carried over from Dr. Fox's Leland Olds cost analysis and my use of cost escalation.

4.15 Sensitivity of Certain Input Parameters

As I indicated earlier, I am not aware of any detailed TESCR cost analysis that is in the public record for Coyote Station. In addition, some of the parameters needed to perform a rigorous, original cost analysis are unavailable or are confidential. Consequently, because of this limitation, I must adapt an existing analysis from a similar unit. This is a common approach and is in fact often used by contractors such as S&L, and Burns and McDonnell who have prepared a number of North Dakota BART determinations. For example, S&L's SCR cost analysis prepared to facilitate EPA's IPM modeling takes a similar approach.[70] Only basic inputs are required, which include the capacity of the unit (MW), the heat rate (BTU/kWh), the NOx inlet (lbs/MMBtu), the NOx removal efficiency (%), and various O&M costs. This cost model is accepted by EPA for use in regional haze work, and I would have used it if were not limited to high dust SCRs. In any case, this is adequate for the +/- 30% level of accuracy required.[71]

The surrogate unit I have chosen is the Leland Olds Unit 2, which is very similar. Below is a comparison of some of the key characteristics of both units:[72]

Table 5. Characteristics Comparison for Coyote Unit 1 and Leland Olds Unit 2

Parameter	**Coyote Unit 1**	**Leland Olds Unit 2**
Capacity (MWg)	450	440
Boiler type	cyclone	cyclone
Fuel	ND ignite	ND lignite
Volumetric flow rate (acfm)	2,485,000*	1,722,500**
Heat input (MMBtu/hr	4,900	5,130
NOx inlet rate (lbs/MMBtu)	0.46	0.48

Notes: * Reported at air heater outlet.
** Reported at WFGD outlet.

[70] IPM Model – Updates to Cost and Performance for APC Technologies, SCR Cost Development Methodology, Final, January 2017, Project 13527-001 Eastern Research Group, Inc.

[71] Note that EPA's Control Cost Manual states that BACT and BART cost analyses should be performed to a study-level accuracy of +/- 30%. See EPA's Control Cost Manual, Section 1, Chapter 2, November 2017, page 6.

[72] The Coyote-specific parameters that have not been previously referenced in this report are taken from the Coyote Station Unit 1, North Dakota Regional Haze Second Planning Period, Four-Factor Analysis, SL-014745 Final Rev 1, May 8, 2019 Project No. 12715-011. The Leland Olds Unit 2 parameters not previously referenced are taken from North Dakota Round Ii Regional Haze State, Implementation Plan Determination's Four-Factor, Analysis For Leland Olds Station Units 1 And 2, SL-014752 Final January 30, 2019, Project No. 13772-002.

As can be seen from the above table, most of the basic characteristics are very similar between the Coyote and Leland Olds units. However, one parameter not listed is the amount of reheat needed for each TESCR installation, which was not available to me for Coyote. Therefore, I have no choice but to assume it is similar to what was reported for the TESCR analysis for Leland Olds Unit 2. This is reflected in the amount of natural gas needed.[73] However, Coyote's TESCR cost-effectiveness is not very sensitive to reasonable changes in the amount of natural gas required. For instance, if I did increase the amount of natural gas required by 30%, the cost-effectiveness would only increase from $2,329/ton to $2,406/ton.

Also, it will be noticed that the Coyote unit has an approximately 30% higher rate of exhaust gas flow than Leland Olds Unit 2, although they are reported at different points in the pollution control train. This parameter is one input into the amount of catalyst required and points to the conclusion that the amount of catalyst required at Coyote may likely be slightly higher. However, Coyote's TESCR cost-effectiveness is not very sensitive to reasonable changes in catalyst volume. For example, if I did increase the amount of initial catalyst volume by 30%, the cost-effectiveness only increases from $2,329/ton to $2,343/ton.

Another potential error involves the amount of power consumed by the SCR system. Here, again, I relied on the value used in the Leland Olds analysis. As with the reheat and catalyst examples, Coyote's TESCR cost-effectiveness is not very sensitive to reasonable changes in SCR power consumption. For example, if I did increase the amount of power consumed by the SCR system by 30%, the cost-effectiveness only increases from $2,329/ton to $2,377/ton.

In summary, the cost-effectiveness is insensitive to most if not all of the input parameters that are carried over from the Leland Olds Unit 2 cost-effectiveness analysis without verification.

4.16 Use of the CEPCI to Escalate Costs Beyond Five Years

Dr. Fox's cost analysis for TESCR at Leland Olds was performed in March 2011 and was based on S&L's earlier cost analysis dated May 27, 2009. Therefore, some of the items in Dr. Fox's cost analysis are now likely over eleven years old. This brings up a potential criticism of my escalation of these items using the CEPCI. Regarding escalation, the Control Cost Manual states:[74]

> It should be noted that the accuracy associated with escalation (and its reverse, de-escalation) declines the longer the time period over which this is done. Escalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate. Thus, obtaining new price quotes for cost items is advisable beyond five years. If longer escalation periods are unavoidable due to limited recent cost data that is reasonably available, then the analysis should use the principles in this Manual

[73] As indicated earlier, I am aware that the necessary supply of reheat natural gas is not available at Coyote Station. However, for the reasoning discussed, I believe steam coil reheat has a similar capital cost and lower operating costs, although a valid point can be made concerning the continuing veracity of that conclusion considering the drop in natural gas pricing.

[74] See EPA's Control Cost Manual, Section 1, Chapter 2, November 2017, page 6.

> chapter to provide as accurate an escalation as possible consistent with the Manual given the limitations of the cost analysis. The appropriate length of time for escalation can vary as a result of significant changes in the cost of major production inputs (e.g., energy, steel, chemical reagents, etc.) and technological changes in control measures, particularly if these changes occur in an unusually short period of time. Hence, shorter time periods for escalation and de-escalation are clearly preferred over longer ones.

I acknowledge that my use of escalation is well beyond the five year window discussed above. However, as I indicated earlier, I do not have access to more recent information. As the Control Cost Manual indicates, if this is unavoidable, then the principles detailed therein should be followed. One of the overriding principles of the Control Cost Manual is the use of the "overnight" costing methodology, which as the name implies estimates capital cost as if no interest was incurred during construction and the project is completed "overnight."[75] I have followed that principle in my cost analysis. Nevertheless, I acknowledge this is a potential criticism.

5 Additional NOx Reasonable Progress Review Comments

The following comments pertain to Otter Tail's May 8, 2019 NOx reasonable progress analysis.[76]

5.1 S&L's Should Provide Documentation for its Assumed NOx Control Efficiencies

Beginning on page 5-23, S&L discusses the removal efficiency of various potential NOx controls that could be installed at the Coyote Station. For instance, on page 5-26, S&L states, "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 NOx emission rate of approximately 0.28 lb/MMBtu (approximately 39% below the baseline)." Regarding the use of Rich Reagent Injection with SNCR, S&L states, "Based on input from SNCR OEMs and engineering judgment, the control option is expected to achieve an average outlet NOx rate of approximately 0.20 lb/MMBtu with an ammonia slip of 10 ppmvd." S&L should provide the information which it used to produce these control estimates so they can be assessed.

5.2 S&L's Should Clarify the Coyote Station NOx Combustion Optimization Status

Beginning on page 5-23, S&L discusses the technical feasibility of NOx combustion optimization at Coyote Station. It states that following installation of SOFA in 2016, Coyote achieved average NOx emissions of 0.46 lbs/MMBtu. S&L then describes a boiler tuning procedure that was recently completed stating that following this, Coyote was able to lower its average NOx emissions to 0.42 lbs/MMBtu, resulting in an approximately 8% reduction. S&L concludes that this tuning is therefore a technically feasible control. If Coyote has been able to

---

[75] Ibid., page 11.

[76] Otter Tail Power Company, Coyote Station Unit 1, North Dakota Regional Haze Second Planning Period Four-Factor Analysis, SL-014745 Final Rev 1, May 8, 2019 Project No. 12715-011, Sargent & Lundy. Unless otherwise stated, all references to the Otter Tail's reasonable progress analysis refer to this report.

successfully perform this tuning, which S&L states in Table 6-3 requires no capital or operating costs, S&L should explain why it has not been implemented.

5.3 S&L's NOx Control Costs are Higher than They Should Be

As discussed previously, S&L does not provide any documentation for its cost items. It also uses an undocumented 5.25% interest rate, owner's costs disallowed by the Control Cost Manual, a 20 year equipment life which should be at least 30 years, and 20% contingency which should be 15% or lower. Substituting in the current Prime Interest Rate of 3.25%, a 30 year equipment life, a reasonable 15% contingency, and removing the disallowed owner's costs, results in the following updated NOx cost-effectiveness values for SNCR, and SNCR + Rich Reagent Injection (RRI):[77]

Table 6. Revised Coyote NOx Control Cost-effectiveness

	S&L SNCR	**Revised SNCR**	**S&L SNCR+RRI**	**Revised SNCR+RRI**
Total Direct Costs	$12,621,000	$12,621,000	$16,473,000	$16,473,000
Owner's Costs	$252,000	**$0**	$329,000	**$0**
Total Indirect Costs	$3,912,000	$3,660,000	$5,106,000	$4,777,000
Contingency (% of total direct + indirect costs)	20%	**15%**	20%	**15%**
Contingency Amount	$3,307,000	$2,442,150	$4,316,000	$3,187,500
Total Capital Investment (TCI)	$19,840,000	$18,723,150	$25,895,000	$24,437,500
Equipment Life (years)	20	**30**	20	**30**
Interest Rate(%)	5.25	**3.25**	5.25	**3.25**
CRF	0.0820	**0.0527**	0.0820	**0.0527**
Annualized Capital Cost	$1,626,000	$986,368	$2,122,000	$1,287,409
Annual Operating Cost	$3,128,000	$3,128,000	$6,495,000	$6,495,000
Total Annual Cost	$4,754,000	$4,114,368	$8,617,000	$7,782,409
NOx Removed (tpy)	2,847	2,847	4,137	4,137
Cost-effectiveness ($/ton)	$1,670	**$1,445**	$2,083	**$1,881**

As can be seen from the above comparison, even keeping S&L's undocumented direct and indirect costs (with the exception of the disallowed owner's costs) and substituting in more appropriate cost parameters for equipment life, contingency, and interest rate, results in significant improvement in cost-effectiveness.

[77] See the file, Coyote Revised NOx Control Costs.xlsx.