June 21, 2022 Submitted Electronically Via www.regulations.gov

U.S. Environmental Protection Agency
EPA Docket Center
Attn: EPA-HQ-OAR-2021-0668

Re: Docket ID No. EPA-HQ-OAR-2021-0668 – "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard," 87 Fed. Reg. 20,036 (April 6, 2022)

Berkshire Hathaway Energy Company (BHE) respectfully submits these comments in response to the U.S. Environmental Protection Agency's (EPA) proposed rule, "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard," (Proposed Rule). BHE is a global energy services provider serving more than 12 million electric and natural gas customers and end-users throughout the U.S., Great Britain and Alberta, Canada. BHE facilities generate electricity from geothermal, hydroelectric, wind, solar, natural gas, coal and nuclear resources. BHE's U.S. operating companies affected by the Proposed Rule include PacifiCorp, which provides regulated electric service in California, Idaho, Oregon, Utah, Washington and Wyoming; NV Energy Inc., which provides regulated electric and natural gas service in Nevada; BHE Renewables LLC, which owns natural gas, wind, geothermal, solar and hydroelectric projects as an independent power producer in New York, Arizona, Texas, California, Illinois, Nebraska, Kansas and Hawaii; and the BHE Pipeline Group, which includes six interstate natural gas pipeline companies: Carolina Gas Transmission, LLC, Cove Point LNG, LP, Modular LNG Holdings, Inc., Eastern Gas Transmission and Storage, Inc. (together referred to as BHE GT&S); Kern River Gas Transmission Company; and Northern Natural Gas. BHE is a member of several industry organizations that have provided comments in this docket, including the Edison Electric Institute, American Gas Association, and the Interstate Natural Gas Association of America.

The Proposed Rule addresses 26 states' significant contribution to nonattainment, or interference with maintenance, of the 2015 ozone National Ambient Air Quality Standard (NAAQS) in other states by establishing nitrogen oxides (NO_x) emissions budgets requiring fossil-fueled power plants in 25 states to participate in an allowance-based ozone season trading program beginning in 2023 and NO_x emissions limits for certain other industrial sources in 23 states beginning in 2026. BHE's operating companies have assets – including electric generating units (EGUs) and facilities associated with the pipeline transportation of natural gas – and customers and end-users in 18 of the 26 affected states. BHE is uniquely positioned to comment on the Proposed Rule.

BHE has first-hand experience with delivering a cost-conscious energy transition that both reduces emissions and maintains or improves reliable service for customers. BHE's approach centers

around increasing noncarbon generation and energy storage, investing in transmission infrastructure, and reducing utilization of coal units. BHE's operating companies continue to explore innovative ways to maintain system reliability and provide service to our customers in a more climate-friendly way. For example, through year-end 2021, BHE businesses had invested more than $30 billion in owned wind, solar and geothermal energy projects and financed nearly $6.9 billion for other operators. Few energy businesses have demonstrated this level of leadership and commitment to a sustainable future. BHE is building upon this strong foundation with additional investments in noncarbon generation and energy storage, the exploration of advanced technologies such as carbon capture and advanced nuclear, and the development of transmission infrastructure and evolving markets like the Western Energy Imbalance Market to integrate noncarbon resources more effectively into the electric grid. BHE's businesses are also preparing for the future by building electric vehicle infrastructure and evaluating new opportunities such as lithium extraction to support the electrification of vehicles. And to date, 16 coal-fueled units have been retired across the BHE businesses. Between 2022 and 2030, 16 additional units will be retired, resulting in a 50% reduction in greenhouse gas emissions across the fleet. As additional noncarbon generation is deployed and transmission is expanded, BHE plans to retire its remaining 14 coal units by 2049 and all natural gas units by 2050.

BHE supports reasonable, effective and achievable regulation that complements its ability to deliver affordable electric and natural gas service safely and reliably to customers and end-users. The Proposed Rule does not meet these criteria – in large part because EPA was compelled to take action via a settlement agreement after neglecting to respond to a number of State Implementation Plans (SIPs) for the interstate transport of ozone under the Clean Air Act's (CAA) good neighbor provisions. The relevant ozone standard was finalized in 2015, and states where BHE operates many affected EGUs submitted plans to address their good neighbor obligations shortly thereafter, with no action from EPA until after this Proposed Rule was issued. After delaying action for so long, EPA issued the Proposed Rule that falls short of a reasoned and balanced approach to interstate ozone transport and instead creates timing and logistical constraints that threaten electric reliability.

For reasons explained in detail in these comments, BHE believes that western states should be removed from a final federal implementation plan for the interstate transport of ozone under the CAA good neighbor provisions. Among other issues, the Cross-State Air Pollution Rule (CSAPR) on which the Proposed Rule is premised is not designed for western states, and EPA's incorporation of these states is based on flawed modeling. The Proposed Rule is likely to force early coal-unit retirements on a timeline that is expected to disrupt the reliable delivery of electricity and could directly result in electricity shortages throughout the West. If EPA will not remove western states in a final rule, recognizing that reliability concerns remain, EPA must undertake meaningful outreach with Western Electricity Coordinating Council (WECC), the North American Energy Reliability Corporation (NERC) and other affected regional transmission organizations to ensure that any final interstate transport rule is appropriately modeled to address reliability impacts. This effort should be similar to the outreach and engagement EPA implemented during development of the Clean Power Plan. If EPA will not remove western states in a final rule, BHE has also identified several elements of the Proposed Rule which must be addressed, including EPA's over-control analysis, the proposed "enhancements" to the CSAPR, and the need for greater flexibility. BHE has also identified several areas for improvement in the Proposed Rule's treatment of non-EGUs, specifically the pipeline transportation of natural gas, including the applicability

threshold, the proposed controls and monitoring requirements, and specific requested exemptions. Finally, BHE identifies a number of technical corrections and clarifications in EPA's dataset and baseline assumptions concerning affected facilities at BHE's operating companies that must be remedied.

BHE appreciates the opportunity to provide these comments to EPA and looks forward to additional collaboration on the issues identified herein. Please contact me with specific questions on these comments at 712-352-5434 or jennifer.mcivor@brkenergy.com.

Jennifer McIvor
VP & Chief Environmental Officer

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BHE COMMENTS ON THE PROPOSED INTERSTATE OZONE TRANSPORT RULE

EPA has presented the Proposed Rule as its best effort to implement the good neighbor provision of the Clean Air Act by adopting additional regulations to eliminate upwind contributions to nonattainment and interference with maintenance of the 2015 ozone standard in downwind states. While BHE appreciates these efforts, BHE believes that EPA's Proposed Rule goes too far, too fast, and imposes a program on western states that is not designed for them. BHE has identified significant concerns with the Proposed Rule and suggests potential solutions that would remedy those concerns and lead to a more reasonable, effective and achievable final rule that addresses the interstate transport of ozone while preserving the reliability of the bulk electric system and delivering a just and orderly transition for affected communities and western states.

I. Western States Should Be Removed from the Proposed Ozone Transport Rule.

EPA's attempt to incorporate western states into the Proposed Rule is a poor fit that is based on flawed modeling. The compliance timeline in the Proposed Rule severely limits compliance alternatives for affected EGUs, especially in the West. Installation of selective catalytic reduction (SCR) technology cannot be achieved at the scale and timing required by the Proposed Rule. Further, EPA has proposed restrictions and limitations on the NO_x allowance trading program that severely restrict, if not eliminate, market opportunities to achieve compliance. Consequently, the Proposed Rule sets the stage for early coal-unit retirements that will undermine the reliability of the bulk electric system and adversely impact affected coal communities as well as customers and electricity consumers in the West.

After evaluating the Proposed Rule and its impacts on both EGUs and non-EGUs, BHE has concluded that EPA's basis for including western states in the rule is inadequately supported and that the costs and other negative impacts of including these states will far outweigh the benefits of pulling them into the proposal. The Proposed Rule does not recognize the unique scientific considerations underpinning ozone transport in the West. Nor does it account for the significant uncertainty and learning curve for sources in states that have not historically been regulated under federal NO_x allowance trading programs. These sources must invest substantial time and effort to prepare for compliance in only 11 months with a rule still in its formative stage (and even less time than that once the rule is finalized). Most importantly, BHE's analysis indicates that the stringency and timeline of the rule will introduce catastrophic reliability risk in western states where there are numerous affected sources that do not currently have the kinds of controls EPA has deemed cost-effective in its proposal. As a result, the Proposed Rule lays out a path for potentially disastrous reliability events for the West.

Finally, BHE is deeply concerned about applying the pre-determined, one-size-fits-all CSAPR approach to western states given the administrative process EPA has employed. By proposing denial of SIPs in the western states where BHE operates affected EGUs (Nevada, Wyoming, and Utah) only after issuing a FIP that includes these states, EPA seems to signal that the outcome has been pre-determined. BHE believes states are best positioned to provide the right solutions to ozone transport and encourages EPA to follow the CAA procedures for states, not EPA, to act as the primary decision makers on how best to achieve the good neighbor provisions of the 2015 ozone NAAQS.

A. CSAPR is Not Well-Designed for Western States.

CSAPR is a longstanding regulatory program designed to address interstate ozone transport in eastern states. Now, for the first time, EPA proposes to expand CSAPR to four western states, with Nevada, Utah, and Wyoming included in the EGU trading program for the first time. While CSAPR has been a good fit for eastern states and has accomplished reductions in the transport of ozone to downwind states, there are a number of reasons that it does not make sense for EPA to pull western states into the CSAPR regulatory scheme. BHE urges EPA to reconsider inclusion of these states in the Proposed Rule.

As EPA is aware, the scientific underpinnings of ozone formation and transport in the West are fundamentally different from the East. First, background levels of ozone in the West are higher, in some cases just below the current 2015 ozone NAAQS of 70 parts per million (ppm). Some background ozone is naturally occurring due to nonanthropogenic sources of ozone precursors, including wildfires and stratospheric ozone intrusion, while some of it is directly attributable to international transport. Furthermore, in mountainous areas of the West, ozone formation is often attributable to, and exacerbated by, geographical and meteorological conditions, rather than the industrial source emissions targeted by EPA's ozone transport rule.[1]

Utah provided significant evidence, including preliminary photochemical modeling results, of how these factors influence ozone levels along the Northern Wasatch Front area of Utah.[2,3] Even if EPA does not recognize Utah's exceptional event arguments, it is beyond dispute that the ozone levels in western states are influenced by high background levels and international emissions. EPA has historically recognized the need to account for these additional factors when evaluating western states and that a case-by-case consideration of ozone impacts is necessary in the West.[4]

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[1] *See, e.g.*, *National Ambient Air Quality Standards for Ozone*, 80 FR 65,292, 65,300 (Oct. 26, 2015) ("observational and modeling analyses have concluded that O3 concentrations in some locations in the U.S. on some days can be substantially influenced by sources that cannot be addressed by domestic control measures. In particular, certain high-elevation sites in the western U.S. are impacted by a combination of non-U.S. sources like international transport, or natural sources such as stratospheric O3, and O3 originating from wildfire emissions."); Memorandum from Stephen D. Page, Director, OAQPS, EPA, "Information on Interstate Transport 'Good Neighbor' Provision for the 2008 Ozone National Ambient Air Quality Standards (NAAQS) under Clean Air Act (CAA) Section 110(a)(2)(D)(i)(I)", at 4, January 22, 2015 (recommending ozone transport in western states should be evaluated on a case-by-case basis); CARB, California Infrastructure State Implementation Plan (SIP) Revision, at 15, January 19, 2016 (finding that in contrast to the East, ozone transport in the West has a much smaller proportion of local emissions and that the larger states and complex terrain in the West make modeling less accurate and helpful); Lin M, Fiore AM, Cooper OR, Horowitz LW, Langford AO, Levy H, et al., "Springtime high surface ozone events over the western United States: quantifying the role of stratospheric intrusions", *J Geophys Res.* 2012;117:D00V22; Lefohn AS, Wernli H, Shadwick D, Oltmans SJ, Shapiro M., Quantifying the importance of stratospheric-tropospheric transport on surface ozone concentrations at high- and low-elevation monitoring sites in the United States. *Atmos Environ.* 2012;62:646–656; Lefohn AS, Wernli H, Shadwick D, Limbach S, Oltmans SJ, Shapiro M., The importance of stratospheric-tropospheric transport in affecting surface ozone concentrations in the western and northern tier of the United States. *Atmos Environ.* 2011;45:4845–4857.

[2] *See* Utah, Technical Support Document, Northern Wasatch Front (NWF), Utah: Failure to Attain 2015 Ozone National Ambient Air Quality Standard by Attainment Date; Reclassification and Disapproval of International Emissions Demonstration, January 2022, at 6-20.

[3] *See* Memorandum from Barron Henderson and Heather Simon (EPA, OAQPS) on Modeled U.S. and International Contributions for 2015 Ozone NAAQS Nonattainment Areas (December 10, 2021).

[4] 81 FR 74504, 74506, EPA, Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, Oct. 26, 2016.

Furthermore, EPA's analysis and modeling in support of the Proposed Rule are grounded in methods and data that presume conditions in eastern states.[5] For example, EPA conducted national-scale modeling using a 12-kilometer (km) resolution grid. However, that grid is too coarse to accurately model ozone in the mountainous western states where PacifiCorp and NV Energy operate.[6] This error is one reason that states are better suited to determine appropriate measures to address impacts on neighboring states. The most recent Denver ozone SIP used a 4-km grid to capture the meteorology and terrain more accurately in the very areas EPA claims are impacted by Utah and Wyoming.[7] The Denver modeling shows that the monitors EPA claims are significantly impacted by Utah and Wyoming will achieve or make significant progress towards attainment by 2026, without and before the most stringent requirements for EGUs go into effect under the Proposed Rule.[8]

Unlike eastern states, which have been subject to both CSAPR and its predecessor rules, the Clean Air Interstate Rule (CAIR) and the NO_x SIP Call, western states have a tremendous uphill climb to prepare for participation in a NO_x allowance market. Affected sources in these states face the requirement to install costly controls on an infeasible timeline, involving significant decisions that must be made before the rule is even finalized, and, even then, will still have insufficient lead time. Under the Proposed Rule, affected sources will have only a few months to comply once the rule is finalized, and so must start immediately to develop a compliance strategy and facilitate the possible purchase and sale of allowances by the 2023 ozone season. In addition, EPA forces utilities to make decisions within an unreasonably short timeframe about investments in fossil fuel retrofit technologies that will have major ramifications on customer rates, reliability, and system operations. The Proposed Rule simply does not account for the fact that western states are beginning at a very different starting point than states that have historically been regulated for more than a decade under interstate NO_x trading schemes.

Finally, western states are already taking significant regulatory actions that would accomplish the goals that the ozone transport rule is designed to achieve. For example, western states are identifying additional controls for certain units under the Regional Haze program, and various facilities in these states have committed to cease burning coal or to retire coal units under the Clean Water Act's effluent limitations guidelines and Resource Conservation and Recovery Act's coal combustion residuals programs.

B. EPA Inappropriately Incorporated Western States Based on Flawed Modeling.

PacifiCorp commissioned Ramboll Environment and Health (Ramboll)[9] to analyze the modeling EPA conducted and relied on in support of the Proposed Rule for the western states where

[5] 81 FR 74504, 74523-24 ("EPA is not addressing interstate emission transport in this action for the 11 western contiguous United States. The CSAPR framework builds on previous eastern-focused efforts to address collective contributions to interstate transport . . .")
[6] *See* Section I.B.
[7] *See* 87 FR 20036, 27050, Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard (Apr. 6, 2022).
[8] The problem of resolution is not solely a western state problem, but it is particularly pronounced in the mountainous western states where BHE businesses operate and where EPA claims significant impacts are occurring.
[9] Part of Ramboll US Consulting, Inc.

PacifiCorp operates (Utah and Wyoming). Within the time allowed by EPA for comment, Ramboll was able to identify six critical flaws in the modeling that EPA used to determine (1) whether Wyoming and Utah significantly contribute to downwind air quality issues, (2) the controls needed to eliminate any significant contribution, and (3) whether the Proposed Rule would overcontrol those states. While Ramboll's analysis focuses on Wyoming and Utah, the modeling issues Ramboll identifies call into question EPA's inclusion of all western states, including California and Nevada. Ramboll's report is attached as Exhibit A (Ramboll Report) to these comments.

As the Ramboll Report shows, if the Proposed Rule had used the same upwind state ozone contribution metrics as used in the 2011 CSAPR and 2015 CSAPR updates, then Wyoming would not have been included in the Proposed Rule, since its contribution to any nonattainment or maintenance receptors in downwind states is not significant by these metrics.

While the results of the alternative upwind state contribution metrics for Utah are less conclusive, if the Proposed Rule had conducted more refined and location-appropriate CAMx modeling, only a single nonattainment/maintenance receptor (the NREL monitor) would be impacted by Utah emissions in 2026 (Chapter 4). If EPA adopted the 1 ppb significance threshold consistent with EPA's own statistical analysis (Chapter 7), Utah's 2026 ozone contribution at the NREL monitor would be below the significance threshold (0.90 ppb) by 2026, voiding the need for the Proposed Rule's most stringent retrofit controls on Utah's EGU and non-EGU sources.

Six key flaws identified by Ramboll are summarized briefly below:

1. The Proposed Rule Is Flawed Because It Uses Inconsistent Emissions to Define Future-Year Nonattainment and State Contributions Versus Defining Controls and Conducting Over-Control Analysis. (Chapter 3).

The 2023 and 2026 EGU NO_x emissions data that EPA used in Steps 1 and 2 of its analysis to determine the nonattainment and maintenance receptors impacted by upwind states' contributions is different from the emissions data that EPA used in Step 3 of its analysis where it made control determinations. Specifically, EPA relied on its 2016v2 modeling platform for Step 1 and 2, whereas EPA conducted an "Engineering Analysis" using its Integrated Planning Model (IPM) to redefine the 2023 and 2026 EGU NO_x emissions for Step 3. The differences are substantial, especially for BHE units. For 2026, EPA's Step 3 analysis assumed approximately 16% greater emissions for both Wyoming and Utah than EPA assumed in its Step 1 and 2 analyses. The differences for 2023 EGU NO_x emissions from PacifiCorp EGUs is even greater. In Utah, the Engineering Analysis EPA used in Step 3 for PacifiCorp EGU NO_x emissions is 143% greater than the 2016v2 emissions that EPA used in Steps 1 and 2. In Wyoming, the difference is 293%. These differences represent a significant disconnect within EPA's four-step interstate transport policy framework that EPA has not explained.

2. The Proposed Rule Overcontrols Emissions in Utah and Wyoming. (Chapter 4).

EPA's analysis fails to consider additional emission reductions expected to occur within the Denver Metro / North Front Range (DM/NFR) ozone nonattainment area.[10] In addition, the coarse

[10] *See also* Section II.A.3 discussing EPA's obligation to consider these reductions.

grid resolution used in EPA's modeling fails to account for the benefit of the emission reductions that EPA did recognize. As a result, EPA's analysis relies on overstated future-year ozone design values at one of the monitors for the Colorado ozone nonattainment DM/NFR area in future years. The Denver Regional Air Quality Council (RAQC), in conjunction with the Colorado Department of Public Health and Environment (CDPHE), has conducted modeling that is more tailored to the area that shows much greater improvement by 2026. Since EPA determined that Wyoming only significantly contributes to a single receptor in the DM/NFR area, and the RAQC / CDPHE modeling confirms that receptor will attain the standard by 2026, the controls that EPA seeks to impose on Wyoming beginning in 2026 constitute overcontrol. The RAQC / CDPHE modeling also indicates that only one receptor in the DM/NFR area for which EPA identified Utah as a significant contributor remains in nonattainment in 2026, and Utah's contribution to that receptor is only 0.90 ppb. As noted in Chapter 7 of the Ramboll Report (see below), that contribution is not statistically significant, which suggests Utah is overcontrolled as well.

3. Upwind State Ozone Contributions at Downwind State Receptors are Overstated. (Chapter 5).

The Proposed Rule overstates upwind state 2023 and 2026 ozone contributions to ozone design values at receptors in downwind states in a number of ways. For example, EPA's modeling ignored certain emissions, such as NO_x formed by lightning, which occurs frequently in the Front Range area and can represent as much as 14% of summer ozone formation. EPA's coarse grid resolution, described in Chapter 4 of the Ramboll Report, also understates local emissions and ozone contributions, which has the ultimate effect of overstating upwind state contributions. Other choices made by EPA in conducting the Proposed Rule's CAMx ozone source apportionment modeling, such as the selected meteorological inputs and culpability assessment, further overstate upwind contributions.

4. EPA Used an Arbitrary Ozone Contribution Metric. Use of Other Reliable Metrics Show Wyoming Has an Insignificant Ozone Contribution. (Chapter 6).

Alternative ozone contribution metrics, including some used in previous CSAPR rules, would show that Wyoming's contribution is below the 1% *de minimis* threshold.

5. Wyoming's and Utah's Ozone Contribution Is Not Statistically Significant According to EPA's Statistical Analysis. (Chapter 7).

EPA has conducted a robust statistical analysis to demonstrate that two ozone design values (DV) that differ by less than 1 ppb are not statistically significantly different from each other. The analysis was performed to define the 1 ppb ozone Significant Impact Level (SIL) that is used as part of the Prevention of Significant Deterioration (PSD) permitting process to define an ozone level "for the permitting authority to conclude that the proposed source will not cause or contribute to a violation of a National Ambient Air Quality Standard (NAAQS)."[11] That analysis was peer-

[11] EPA. 2018a. Technical Basis for the EPA's Development of the Significant Impact Thresholds for PM2.5 and Ozone. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Quality Assessment Division, Research Triangle Park, NC. EPA-454/R-18-001. April. (https://www.epa.gov/sites/default/files/2018-04/documents/ozone_pm2.5_sils_technical_document_final_4-17-18.pdf).

reviewed by three independent economic statisticians employed as faculty at major U.S. universities. Therefore, EPA should not consider contributions to be significant unless they are greater than 1 ppb. At that threshold, Wyoming would not significantly contribute to any downwind receptor. Also, at that threshold, Utah would not significantly contribute to any downwind receptor based on the more tailored RAQC / CDPHE modeling discussed above (Chapter 4).

6. EPA Does Not Follow Its Own Modeling Guidelines by Using a Reduced Form Model With No Photochemistry for Ozone Contribution Assessments. (Chapter 8).

EPA's extensive use of the reduced form model Air Quality Assessment Tool (AQAT) is inappropriate and contrary to EPA's own air quality modeling guidelines and guidance for several reasons. First, the AQAT is a linear model that does not include a photochemical mechanism, and therefore is inappropriate for evaluating small changes in ozone, due to the nonlinear nature of ozone formation. Second, EPA has not shown that the AQAT is accurate at the level of precision for which it is used in the analyses underlying the Proposed Rule. Third, the AQAT was applied in Step 3 to different baseline emissions than EPA assumed in Steps 1 and 2, creating the disconnect noted above (Chapter 3).

The Ramboll Report also criticizes EPA for providing insufficient time for commenting on EPA's analysis, given the massive amounts of data to analyze and the delay by EPA in providing the modeling files for public review (Chapter 2).

EPA rejected the very type of modeling it relies on to support the Proposed Rule when it denied the state of Utah's recent request for an ozone exception. As the state of Utah has explained, EPA relies on the 2016v2 model, which has a high negative bias, to support the Proposed Rule. The negative bias indicates that EPA's model is underpredicting either transport or local photochemical production (or some combination of both). EPA cited a similar negative bias in Utah's recent 179B(b) demonstration as one reason for rejecting Utah's ozone demonstration. It is arbitrary and capricious for EPA to reject Utah's 179B(b) demonstration due to model underperformance while simultaneously using a model with similar underperformance limitations as justification to include Utah and other western states in the FIP.[12]

Finally, BHE understands that because of these significant errors EPA is considering remodeling for the Proposed Rule, and BHE supports any efforts to take into account the issues presented here and in more detail in the Ramboll Report. In addition, EPA must issue any revised modeling results and resulting modifications to the Proposed Rule for additional public comment. Given the complexity of the modeling and the requisite effort to analyze it, proper administrative procedure requires public review, and BHE requests that a minimum of 60 days be provided for public comment on any new modeling.

[12] *See* 87 FR 31470.

C. The Proposed Rule Undermines the Reliability of the Bulk Electric System in the West.

The Proposed Rule jeopardizes energy supply and reliability because it is simply not possible to either install SCR on so many units or retire and replace the energy generated and vital ancillary services provided by these units within the Rule's compliance timeline. The SCR-forcing provisions[13] of the Proposed Rule create untenable uncertainty and risk to the reliability of the bulk electric system in the West. Simply extending the timeline to install SCR a few years is not enough to resolve the cascading effects to system reliability described below. The proper solution is to allow states to work with all affected stakeholders to implement the CAA's good neighbor provision and achieve a clean energy transition in a manner that balances community interests, reliability, costs, and environmental impacts.

EPA's cost-effectiveness assumptions, combined with the imposition of a daily backstop limit on units burning coal during the ozone season, make the Proposed Rule an SCR-forcing regulation for affected EGUs. However, cost and timing considerations are likely to make SCR a non-viable compliance alternative for many units in the West. Installation of SCR on a coal or gas-fired power plant is a significant, long-term investment that, despite the cost-effectiveness calculations developed by EPA to support the Proposed Rule, will simply not make economic sense for customers. This is because, over time, customers will benefit more from investments in low-cost renewable resources, storage, and non-emitting dispatchable resources (i.e., advanced nuclear or hydrogen-fueled turbines).

The emission control installations, idling or retirements and replacements that will be forced by the Proposed Rule must take place simultaneously across significant numbers of units in a three-year time frame, with corresponding reductions in the energy and services these units supply to the grid, putting energy supply and reliability in jeopardy. Even if every unit installed SCR and SCRs could be installed within the proposed compliance timeline, each installation would require a six-week outage. The potential combined 84 total weeks[14] of outages before May 2026 would present its own set of concerns for grid reliability. However, even EPA does not anticipate every unit will install SCR. In the Regulatory Impact Assessment accompanying the Proposed Rule, EPA estimated that approximately 18 gigawatts (GW) of coal-fueled generation and 4 GW of gas steam generation would retire by 2030 as a result of the Proposed Rule. Across BHE's affected companies, for example, PacifiCorp has 8,18 total MW[15] impacted by the rule, with 3,813 MW in Wyoming, and 4,368 MW in Utah. This includes 16 coal units and 13 natural gas units. Of these, 3,362 MW in Wyoming and Utah are impacted by the Proposed Rule's SCR-forcing provisions. NV Energy has 6,844 MW of impacted capacity in Nevada. Given the stresses the electrical grid is facing[16] nationwide, and particularly in the West, BHE does not believe the grid can sustain the

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[13] *See* Section II.B.1 and 2.

[14] This assumes a projected 12 SCR installations for BHE coal-fueled units and 2 SCR installations for gas units.

[15] PacifiCorp-operated units.

[16] *See, e.g.*, NERC, 2022 Summer Reliability Assessment, May 2022 (2022 NERC Report) (finding Utah and the Pacific Northwest region are at elevated risk of an energy emergency in the summer of 2022), *available at* https://www.nerc.com/news/Pages/Extreme-Weather-Heightens-Reliability-Risks-this-Summer.aspx; Wall Street Journal, Electricity Shortage Warnings Grow Across U.S. (May 8, 2022) ("Power-grid operators caution that electricity supplies aren't keeping up with demand amid transition to cleaner forms of energy.").

impacts of such significant generation going offline over such a short time frame without reducing the stability of the grid, perhaps catastrophically.

Moreover, the compliance timeline in the Proposed Rule does not allow sufficient time to replace capacity and energy from affected EGUs that would need to retire, sit idle, or continue operating at significantly reduced levels if SCR cannot be timely installed.[17] Similarly, the compliance timeline in the Proposed Rule is not sufficient to make the transmission upgrades needed to add new resources and maintain reliable grid operations in the face of accelerated retirements or reduced operations from coal facilities. Absent modifications in the Proposed Rule to adjust compliance timelines to reflect these operational realities, the West will face capacity and energy shortfalls that will threaten reliable service for millions of customers.[18]

BHE is continuing to conduct a more detailed assessment of anticipated reliability events expected from the Proposed Rule and feasible compliance alternatives. BHE expects to complete this functional evaluation around January 2023, soon after EPA's projected timeline for finalizing the rule (November or December 2022). As discussed in Section II.C.3 below, if EPA continues to subject western states to the Proposed Rule, BHE requests that EPA include a procedure in the final rule that would allow electric utilities to demonstrate when additional compliance time is necessary to avoid real electric reliability events. This type of safety valve is necessary to ensure the Proposed Rule does not jeopardize reliability for BHE entities and their customers and the electricity grids where they operate.

Even now, prior to the loss of generation that would result from the Proposed Rule, the stability of the grid in the West is in question. The reliability assessment published for each summer season by the North American Electric Reliability Corporation indicates that the Western Interconnection is one of several systems at an "elevated risk" of energy emergencies during the summer of 2022 due to widespread drought and below-normal snowpack.[19] The assessment notes that grid operators will need all available tools to keep the system in balance this summer, and that over the long term, planners and stakeholders will need to plan for continuing extreme weather conditions in order to ensure there is a reliable and resilient bulk power system. The report also highlights specific challenges to ensuring adequate generation is online, including the active late summer wildfire season in the West.[20]

To put the grid reliability concerns in perspective, the Wyoming Public Service Commission (WPSC) found in 2021 that removing even one unit from service, PacifiCorp's Jim Bridger Unit 2, would increase the risk that utilities in the region would be unable to meet customer demand and would "disrupt and deoptimize generation resource dispatch."[21] As the WPSC explained, units like Jim Bridger serve an important role on the grid as "regulating resources," by balancing the

[17] Cessation of coal-fueled operations during the ozone season is not a realistic compliance option for most coal-fired EGUs due to limitations imposed by the proposed trading program and since the ozone season coincides with the hottest months of the year when electric load is highest and the need for energy is greatest.
[18] *See* 2022 NERC Report.
[19] *Id.* at 9.
[20] *Id*. at 8-9.
[21] In the Matter of the Commission's Investigation Pursuant to Wyo. Stat. § 37-2-117 to Determine the Effects on Rates, Generation Adequacy, System Reliability, and Other Aspects of Operations by the Potential Discontinuation of Operations at Jim Bridger Unit 2 on December 31, 2021, Due to the Environmental Protection Agency's Inaction on the State of Wyoming's Regional Haze State Implementation Plan; Preliminary Findings (January 14, 2021).

variations in renewable generation output. Since renewable generation varies with uncontrollable factors like wind and sunshine, integrating those variable resources into the electric grid requires sufficient regulating resources. In fact, as the WPSC explained, removing regulating resources from the grid to serve one environmental goal (in that case, regional haze) would have perverse unintended consequences by inhibiting the efficient integration of renewable resources onto the grid, thus increasing reliance on nonrenewable energy sources.[22]

In the limited time available to review the Proposed Rule, BHE has identified key reliability concerns for the western grid, including generation capacity, grid stability, transmission, and replacement power from markets.

1. Generation Capacity.

The energy generation system is undergoing a fundamental transformation. Fossil-fuel generation has traditionally been operated to provide baseload generation, meaning these assets provide a steady stream of energy while consistently operating at high capacities. As more and more renewable resources are added to the electric grid, fossil-fueled generation now plays a critical role in stabilizing the energy and transmission systems in a way that variable or intermittent resources cannot. A coal unit provides low-cost energy and capacity during times of scarcity. It is during these periods of low wind or lack of solar generation that coal units provide significant contributions to generation capacity and grid stability.

Sufficient electric generation is a key component to a reliable electrical system,[23] and one of the main responsibilities of a regulated utility is to maintain the stability of the electric grid by instantly delivering generation in response to demand as well as ensuring there are sufficient resources held in reserve to cover potential compromises in generation or transmission capabilities. Many of the coal-fueled units affected by the SCR requirement in the Proposed Rule can generate 400 MW or more of electricity at any moment in time. Recognizing the capacity factor for wind and solar resources is lower than a coal unit, about 2.25 times the amount of wind and solar capacity is needed to replace energy generated from each megawatt of coal capacity (assuming a 50/50 split between wind and solar resources, a 42% capacity factor for wind, a 30% capacity factor for solar, and an 80% capacity factor for coal). For a 400 MW coal unit, this equates to 445 MW of wind and 445 MW of solar.

Even this amount of generation is still not sufficient to replace 400 MW of coal, as it does not provide ramping capabilities needed to respond to intra-day and intra-hour changes in load. Assuming a 400 MW coal unit has a 100 MW operating minimum, that coal unit can provide 300 MW of ramping capability, which is often used to follow a typical evening ramp that occurs as the sun begins to set and energy from solar resources first declines and then falls to zero. A 300 MW battery with a four-hour discharge duration would be needed to supply the type of service that is lost with a retired 400 MW coal facility. And even then, the solar, wind, and battery portfolio of replacement resources is not capable of responding to periods where wind and solar output fall below expected levels. These events require a dispatchable resource, such as a natural-gas peaking unit, that can be turned on expeditiously when needed, even if infrequently and for short durations.

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[22] *Id*.
[23] *See* 2022 NERC Report.

Each of these generating assets also require incremental transmission upgrades to accommodate interconnection, and additional upgrades are often required to facilitate the flow of power on the transmission system. As discussed later in this section, these upgrades can be significant in both cost and time schedule.

In all, the retirement of a single 400 MW coal unit triggers the need for wind, solar, battery, dispatchable capacity, and transmission investments that require time for permitting, regulatory review, equipment procurement, and construction that is out of sync with the compliance timelines in the Proposed Rule. Further, BHE anticipates investing tens of billions of dollars towards energy transition for coal-fueled resources. The generation and other services of a single 400 MW unit will cost billions of dollars to replace, and, should multiple coal units be forced to retire under the Proposed Rule, the necessary resource replacement and transmission upgrades will cost tens of billions of dollars and require lead times of no less than a decade. Moreover, as wind, solar, and energy storage become a larger portion of BHE's portfolio, effective capacity contribution values will decline, meaning more wind and solar capacity or longer-duration energy storage capacity will be required.

2. Grid Stability.

Even if the necessary amount of renewable and other resource technologies to replace a fossil-fueled unit were available in the timeframe required in the Proposed Rule, the western energy system would still be impacted if one or more units were retired. In addition to replacing the electricity generated by the unit, the ancillary services provided by fossil-fueled units that support grid stability (frequency response, synchronicity, and transmission services) would have to be replaced. These services are vital in accommodating renewable generation, and the accelerated retirement of a fossil-fuel unit can restrict the level of renewables that can be accommodated until adequate replacements for those ancillary services can be constructed or purchased. Replacement resources must be adequately designed, tested and verified to ensure that the transmission system can accommodate variable resources.

i. Frequency response.

Fossil fuel generation currently plays a critical role in stabilizing the balance of energy generation and load requirements (frequency response) due to its ability to quickly and reliably ramp generation up or down depending on system needs. This ability is vital to accommodate highly variable resources, like solar and wind, while still ensuring grid stability. In other words, units that once provided baseload generation now follow renewable energy load and provide critical stability to the system, something that intermittent resources cannot do. In comparison with fossil-fueled plants, the frequency response required from renewable resources can be variable in nature.[24] For example, cloud cover over a solar resource will not only diminish the ability of the solar facility to produce power but will also hinder its frequency response under system-outage conditions. Fossil-fueled generation sources provide the stable frequency response that is necessary so that energy generated by variable resources can be balanced with changing loads on the system. This

[24] *See* FERC Order 842 (requiring new generation that is being interconnected to the transmission system to provide primary frequency response, even though renewable resources like wind and solar, by their nature, can only provide variable frequency response, which cannot completely substitute for the more stable frequency response provided by fossil fuel resources).

stability cannot be fully provided by variable resources but is vital to avoid blackouts or system oscillation.

Because of the vital role fossil-fuel units play in integrating variable generation, accelerated retirement of coal units could restrict the level of renewables that can be safely and reliably added to the grid. The voltage support and frequency response that fossil fuel units provide actually accommodates higher levels of variable resources and helps lessen the impact of a transmission system element being out of service. A deliberative approach to phasing out fossil-fueled resources that factors in these operational and implementation realities is needed so that the frequency response and ride-through services[25] these units provide can be adequately replaced.

ii. Synchronicity.

Existing fossil-fuel resources affected by the Proposed Rule also play a significant role in providing the synchronicity needed to stabilize the electrical grid. Synchronicity enables different parameters such as voltage, frequency, phase angle, phase sequence, and waveform to run appropriately across a system. For example, if a fault occurs in a transmission line or element, the transmission system undergoes oscillations. One of the factors that stabilizes oscillations in the system and brings it to a new stable state is damping, which is provided by inertia present in the transmission system. Fossil-fuel units have significant inertia that provides damping to stabilize the transmission system. Without replacing this inertia, a heavily loaded transmission system will have more oscillations during an outage, which can trip other transmission elements and degrade the reliability of the transmission system. Fossil fuel units also provide the majority of the fault current on the transmission system. The fault current enables the system to distinguish between normal and abnormal conditions. The fault current triggers the protection systems for transmission that will isolate a faulted transmission element and ensure the safety and reliability of the transmission system. The early retirement of coal units would reduce the fault current by as much as 60% on nearby transmission system buses.

One option to replace the synchronicity provided by fossil fuel units may be the use of synchronous condensers. However, the viability of replacing the synchronicity provided by a fossil fuel resource with synchronous condensers is highly uncertain. The use of such units requires extensive study before they could be implemented, and synchronous condensers take years to build, represent a major investment, and provide an inferior function to the resources they replace. Although estimated timelines vary, integrating a single synchronous condenser unit is expected to require nine to 12 months of study, followed by three to four years to build, with costs between $50 million and $100 million, depending on the size, location, and system components. Multiple condensers, including spares, may be needed to replace a single fossil-fueled unit. The system study for each unit cannot commence until a utility knows what the resource mix will look like, which would be based in part on obligations contained in a final rule and the feasibility and timing of compliance options such as SCR installation or replacement with renewables, storage, and other technologies as discussed above. The Proposed Rule does not provide adequate time to determine feasible options, conduct the necessary study and then construct replacement resources to provide system

[25] *I.e.*, services to absorb oscillation introduced by a fault; *see* Synchronicity subsection.

synchronicity. With the significant level of uncertainty caused by the Proposed Rule and its infeasible timelines, the reliability of the grid is threatened.

3. Transmission.

Transmission resources in the West, and indeed throughout the United States, are already constrained. The potential impacts on the transmission system of replacing even a few retired or idled units is under BHE review and will almost certainly require additional time, present barriers not considered by EPA, and increase the costs for replacement well beyond EPA's general cost-effectiveness calculations. The amount of renewable resources, such as wind and solar, that would need to be interconnected to replace the generation currently provided by one or more fossil-fuel units would be significant. Even if sufficient new non-fossil-fuel resources were available, transitioning the amounts of new energy to replace what is currently generated by the affected fossil fuel units into the system cannot be accomplished within the short timeframe provided by the Proposed Rule. In addition, renewable resources are often not at the same location as a retiring fossil fuel unit, which would require additional transmission lines and thus additional time.

The queues to access available transmission are also packed. For example, Wyoming has a significant potential to interconnect wind but that potential is limited due to transmission constraints. The last interconnection cluster study conducted by PacifiCorp required $1.7 billion in transmission investments from all new resources wishing to interconnect, including new renewable resources. Required upgrades take the form of new lines, rebuilds, synchronous condensers**,** and flexible alternating current transmission system devices. These upgrades require significant study, planning, testing, design, and construction timelines, and these processes often delay or lead to the abandonment of planned new resource development. Here are two examples from PacifiCorp's recent experience:

- Two recent major PacifiCorp transmission line projects (Gateway South[26] and Gateway West segments D.2 and D.1[27]) have so far taken from 12 to 15 years from planning to commencement of construction. While the 140-mile D.2 segment of the Gateway West system was completed in 2020, construction on the 416-mile Gateway South and the dual-circuit 75-mile D.1 segment of Gateway West has just begun and the lines are not expected to come online until late 2024. While these facilities have and will continue to facilitate the interconnection of additional generation, significant incremental transmission facilities (many of which have not been designed or begun, much less completed, the arduous permitting process) will be required to replace current generation if one or more fossil fuel units are retired or idled because of the Proposed Rule. The necessary incremental transmission facilities represent billions of dollars of additional investments, and it is simply not feasible to complete these facilities in the time horizon contemplated under the Proposed Rule.

- PacifiCorp's Carbon plant in Utah was closed in 2015. The necessary transmission upgrades to accommodate the closure included a new SVC at the Mathington substation, a new phase-shifting transformer at the Upalco substation, a series reactor on the Spanish

[26] https://www.pacificorp.com/transmission/transmission-projects/energy-gateway/gateway-south.html.
[27] https://www.pacificorp.com/transmission/transmission-projects/energy-gateway/gateway-west.html.

> Fork-Carbon 138-kV line, and multiple shunt capacitors at Mathington, along with reconfiguration of several substations. These transmission upgrades cost more than $39 million and took approximately three years to complete for two units totaling approximately 188 MW.

The scale, costs and timing of the yet-to-be determined projects required to maintain reliability due to anticipated early coal unit closures in response to the Proposed Rule (potentially thousands of megawatts in the West) would be significantly larger, more expensive, and require longer lead times than the example provided above. In aggregate, resource replacement and transmission investments needed to maintain reliability will cost tens of billions of dollars and take no less than a decade to complete.

4. Replacement Power from Markets.

If a utility were forced to retire or idle fossil-fueled units before 2026 under the Proposed Rule timeline it would immediately increase the risk of blackouts and grid instability for both the utility and the region, and procuring replacement power would be necessary. In the near-term the utility would most likely have to rely on the wholesale energy market for replacement power because the Proposed Rule does not provide sufficient time to build new resources and transmission. However, the loss of even a fraction of dispatchable generation in the region will strain energy markets by decreasing market depth and increasing wholesale energy prices. Costs to meet customers' energy needs would be immediately higher, as the lack of capacity would cause scarcity pricing to take hold. Finding replacement power would not be just a matter of price but also a matter of availability and deliverability. Even now, for example, with all of PacifiCorp's coal- and gas-fired resources online and fully dispatchable, there are times of heavy demand during the year when excess energy supply is simply is not available in the market. If supply is not available and new replacement capacity cannot come online, catastrophic reliability events are likely to occur.

D. Even If EPA Incorporates BHE's Recommended Improvements, the Western States' Contribution to Downwind Ozone Is De Minimis.

BHE believes that a proper modeling analysis will show that Nevada, Utah and Wyoming should be excluded from the final rule because they do not have a significant impact on downwind monitors, and further, that these states are overcontrolled in the Proposed Rule. EPA has actually *underestimated* the emission reductions that will be achieved by the three states, which is particularly improper because these states were "close calls" in EPA's own applicability determination. Based on EPA's current modeling, each of these states has impacts only slightly above the 1% threshold that EPA identified in its applicability determination, even under EPAs flawed modeling. However, as the Ramboll Report demonstrates, more accurate modeling and a more appropriate *de minimis* threshold would confirm that the three western states should not be covered under the Proposed Rule.

1. Nevada.

According to EPA's proposal, Nevada's largest 2023 contribution to a downwind nonattainment receptor is 0.89 ppb (just over 1%), with a 0.58 ppb contribution to a downwind maintenance receptor. Its largest 2026 contribution to a downwind nonattainment receptor is 0.81 ppb, with a

0.51 ppb contribution to a downwind maintenance receptor. However, Nevada's own modeling in support of its good neighbor SIP, which was based on EPA modeling available at the time of the submittal, showed that Nevada emission sources contribute only 0.9% of the NAAQS to any nonattainment or maintenance receptors. This discrepancy, based on two different models, is evidence that a slight change in assumptions will bring Nevada's impacts below EPA's 1% threshold. With Nevada being so close to the threshold for inclusion in the rule, the Proposed Rule is likely to overcontrol the state, since it will likely result in greater emission reductions than EPA has assumed in its modeling. For example, EPA's modeling does not account for two NV Energy units (North Valmy 1 and 2) for which the current air permit requires cessation of operations no later than December 31, 2028, as part of the Regional Haze SIP. The corresponding baseline NO_x emissions for Unit 1 are 609 tons per year (tpy) and 795 tpy for Unit 2. EPA failed to account for these large units in its modeling, and hence it inaccurately determined that Nevada should be subject to the Proposed Rule.

2. Utah.

For Utah, EPA's analysis in support of its proposal shows the largest 2023 contribution to a downwind nonattainment receptor is 1.37 ppb with a 0.10 ppb contribution to a downwind maintenance receptor, and that the largest 2026 contribution to a downwind nonattainment receptor is 0.95 ppb with a 1.18 ppb contribution to a downwind maintenance receptor. However, it is not apparent that EPA's assessment of Utah's impact reflects consideration of emission reductions that are planned by PacifiCorp in upcoming years, including NO_x reductions that will be required at both Hunter and Huntington under regional haze SIPs, or other emission reductions and contributing factors that were raised by Utah in its own analysis in support of its good neighbor SIP for the 2015 ozone standard.[28]

EPA's analysis appears to disregard factors the Utah Division of Air Quality identified in its good neighbor SIP submission that also contribute to those downwind nonattainment and maintenance receptors, including emissions from international and non-anthropogenic sources, emission reductions from new oil and gas control requirements in the downwind state (Colorado), and emission reductions projected in Utah itself. In EPA's recent proposed disapproval of Utah's good neighbor SIP, which was published *after* the Proposed Rule, EPA dismisses these impacts on the downwind receptors and seems to fault Utah for not doing more to quantify those impacts.[29] However, EPA's summary dismissal of these factors in determining that emission sources in Utah do in fact significantly contribute to downwind nonattainment and maintenance receptors is insufficient to satisfy its legal obligation to adequately support its proposed disapproval of Utah's good neighbor SIP and its rulemaking choices in the Proposed Rule. In fact, EPA's failure to consider all of the information that pointed to reduced ozone impacts in Colorado in future years is borne out by Colorado's most recent ozone nonattainment SIP, which projects several of the

[28] *See* Utah 2015 Ozone Infrastructure SIP Submittal, EPA-R08-OAR-2022-0315-0007, at C-007-008 (finding the combination of Utah's declining emissions of VOCs and NO_x, declining projected emissions reductions from oil and gas and other Colorado sources, and the high contribution from non-anthropogenic and international emissions affecting the relevant Colorado monitors result in less than a significant contribution from Utah).
[29] 87 FR 31470 (May 24, 2002).

monitors EPA has identified as impacted by Utah and Wyoming will actually achieve attainment by 2026, before the most stringent NO_x reductions begin.[30]

Further, EPA's underlying analysis for the Proposed Rule includes major errors in the emissions attributable to PacifiCorp's Utah units. EPA attempted to correct these errors through its engineered corrections at Step 3, which resulted in NO_x emissions in Utah that are almost four times larger than the NO_x emission estimates used in Steps 1 and 2. EPA also overstates upwind contributions and understates the impact of upwind ozone reductions at the Colorado monitors due to improperly coarse grid resolution and meteorological inputs.[31] These flaws in EPA's analysis and approach seriously undermine the credibility of its finding that Utah significantly contributes to downwind nonattainment and maintenance concerns in Colorado.

To the extent that evidence of downwind impacts remain after EPA has corrected its analyses, BHE asks EPA to consider a partial state approach for Utah consistent with the judicial precent set in *North Carolina v. EPA*, which recognizes that a partial state approach may be possible and appropriate in some circumstances.[32] Utah's Uinta Basin, which borders Colorado, is currently nonattainment for ozone and the significant reductions that must be made in the Uinta Basin to address its own ozone concerns are likely to produce more significant reductions at the impacted monitors in Colorado. Furthermore, it is not clear that further reducing NO_x emissions from EGUs will solve Colorado's ozone attainment issues. Recent analysis using data from the Proposed Rule's modeling platform shows that Utah and Wyoming EGUs contribute less than 0.4% to the Colorado nonattainment monitors EPA has identified as significantly impacted. Mobile sources and oil and gas sources are greater contributors (although still relatively small compared to background and natural sources).[33]

The Uinta Basin is closer to the affected Colorado monitors than Emery County, where PacifiCorp's Utah units are located, and the dual benefits for both Utah and Colorado nonattainment areas of reducing ozone in the Basin merit serious consideration by EPA. BHE believes that a nontraditional approach to resolving ozone issues in the Uinta Basin could even ultimately produce better results than installing controls on EGUs that are significantly further away from the affected monitors. For example, a recent academic study of ozone in the Uinta Basin found that ozone-contributing emissions could be significantly reduced if oil and gas industry equipment is electrified.[34] BHE requests that EPA support consideration of this and other potentially innovative solutions to the ozone problems in the West, including a partial-state solution for Utah focused on the Uinta Basin, and BHE stands ready to work on such innovative approaches in partnership with EPA and Utah.[35]

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[30] 87 FR 27050, May 6, 2022 (proposed approval of Colorado ozone SIP).
[31] Ramboll Report. *See also* 87 FR 27050.
[32] *North Carolina v. EPA*, 531 F.3d 896, 923 (D.C. Cir. 2008).
[33] *See* Ramboll Report at 7-13.
[34] Marc Mansfield and Robert Hammer, Projecting the Impact of Electrification of the Uinta Basin Oil and Gas Fields on Air Quality, March 1, 2022 (finding the potential for a 24-ppb reduction in peak ozone concentrations with full electrification).
[35] PacifiCorp is not the sole electricity provider in the Uinta Basin.

3. Wyoming.

EPA's modeling in support of the Proposed Rule shows that Wyoming's largest 2023 contribution to a downwind nonattainment receptor is 0.81 ppb, with a contribution of 0.19 ppb to a downwind maintenance receptor, and its largest 2026 contribution to a downwind nonattainment receptor is 0.46 ppb, with a contribution of 0.80 ppb to a downwind maintenance receptor. EPA's threshold is 0.70 ppb. EPA itself admits the state is close to the threshold for linkage, citing only one receptor in Colorado.

BHE has identified significant NO_x emission reductions that are not taken into account by EPA's analysis. There are a number of required and planned control projects and retirements scheduled at PacifiCorp units in the coming years that will accomplish significant emission reductions that EPA should consider when determining whether it is warranted to include Wyoming in the scope of the Proposed Rule. In particular, PacifiCorp will be converting Jim Bridger Units 1 and 2 to natural gas by 2024 and has committed to retire or cease burning coal at five other units: Naughton Units 1 and 2 prior to 2026, and Dave Johnston Unit 3 by the end of 2027, and Dave Johnston Units 1 and 2 by 2028. The cessation of coal combustion on Naughton Units 1 and 2 and Dave Johnston Units 1, 2 and 3 will provide NO_x reductions of 2,945 tons compared to 2021 ozone season emissions. As with Utah, EPA's underlying analysis for the Proposed Rule includes major errors in the emissions attributable to PacifiCorp's, which resulted in NO_x emissions in Wyoming that are several times larger than the NO_x emission estimates used in Steps 1 and 2.[36]

BHE requests that EPA revisit its decision to include Nevada, Utah and Wyoming in the Proposed Rule and determine that none of the three states significantly contributes to downwind nonattainment and maintenance issues.

E. The Proposed Rule Fails to Deliver on the Promise of a Just and Orderly Transition for Western States.

With all its emphasis on rapidly changing the country's energy portfolio, the Biden Administration also appropriately places considerable emphasis on ensuring a just transition from fossil-fuel resources, taking into account the coal communities and plant employees who have powered the nation for so many years. In addition to ensuring a reasonable and effective outcome that does not risk continued reliable delivery of affordable electricity to end users, the Proposed Rule must enable this just transition.

1. BHE understands that a just and orderly transition requires time and investment in the right resources.

Given BHE's commitment to and leadership in building a sustainable energy future, BHE is concerned that EPA has not taken all of the necessary considerations into account to deal with the impacts of the Proposed Rule and to facilitate a just and orderly outcome. The cost, timing and retrofit requirements of the Proposed Rule will result in reliability concerns while forcing regressive investments. In BHE's experience, and given the current direction of and demand for energy, installation of SCR on a coal or gas-fired power plant represents a significant cost that does not optimize investment on behalf of BHE's customers. Customers will benefit more from

[36] *See* Ramboll Report at 17-24.

investments in low-cost renewable resources, storage, and non-emitting dispatchable resources (i.e., advanced nuclear or hydrogen-fueled turbines) than a forced SCR installation. Allowing the time necessary to implement these alternative options to SCR will better protect reliability while also enabling the just transition supported by this administration and needed for the communities dependent on the regulated coal-fueled units. BHE believes there are better pathways than the Proposed Rule to achieve the ozone reductions necessary to meet the CAA good neighbor requirement while also better facilitating a just and orderly transition to a clean energy economy.

2. The Proposed Rule will directly interfere with a just transition for coal communities.

In developing the Proposed Rule, EPA did not give adequate consideration to its impacts on the communities that will be affected by accelerated coal-unit retirements. President Biden has committed that U.S. coal communities will experience a just transition as the energy economy changes: "We're never going to forget the men and women who dug the coal and built the nation. We're going to do right by them and make sure they have opportunities to keep building the nation . . ."[37] BHE is also committed to the principles of a just transition. The Proposed Rule is inconsistent with these principles because it sets out an inflexible regulatory scheme to be implemented on an unrealistic timeline. This approach creates disproportionate and adverse impacts for affected communities. Under its own guidelines, EPA must meaningfully engage with affected communities to clearly understand the barriers to a just transition that result from the Proposed Rule and incorporate provisions to remove those barriers in a final rule.

In the West, coal plants are very important to their surrounding local economies. Several of the potentially affected communities are rural, have significant low-income populations and/or have little economic diversity. These communities will face economic hardship if units are forced to close on the expedited timelines included in the Proposed Rule. The welfare of the affected communities, which is intertwined with and dependent upon the presence of the plants, should be more fully considered in EPA's decision-making and timeline to respect just transition principles and avoid undue economic hardship. These impacts are supported by a recent study. The Kem C. Gardner Policy Institute, part of the David Eccles School of Business at the University of Utah, recently issued a study on Utah's coal country (Coal Country Study).[38] The Coal Country Study finds that time is necessary to diversify the local economies and address the expected employment declines in the natural resource/coal sector.[39]

Local communities in Wyoming would also be significantly impacted if forced retirements occurred at units required to install SCR under the Proposed Rule. The state of Wyoming recently made findings about the impacts to communities and the state if a single Jim Bridger coal unit

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[37] Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization, "Initial Report to the President on Empowering Workers Through Revitalizing Energy Communities", April 2021, quoting President Joseph R. Biden, Jr. January 27, 2021 ("Interagency Initial Report").

[38] Kem C. Gardner Policy Institute, *Economic Challenges and Opportunities in Utah's Coal Country*, Max Backlund and Michael Hogue, May 2022 (Coal Country Study). *Available at* https://gardner.utah.edu/wp-content/uploads/CC-BrightFutures-May2022.pdf?x71849.

[39] *Id.* at 5.

were forced to cease operations prematurely. Wyoming's governor, with support from a university study, identified specific harms associated with the premature closure of Jim Bridger Unit 2.[40]

Several of the potentially affected power plant communities are appropriately considered disadvantaged communities due to low-income levels and high or persistent poverty as well as the high unemployment and underemployment that would result from plant closures and jobs lost through early unit retirements driven by the Proposed Rule. Accordingly, EPA should align the Proposed Rule with the Biden Administration's Justice40 Initiative,[41] as well as other state and Federal plans to facilitate a just transition. BHE encourages EPA to provide additional time for states to comply with the CAA's good neighbor provisions in a way and on a timeline that respects disadvantaged communities and demonstrates that the shared goals of a transition to a clean energy economy are truly just.

3. States are best suited to implement a just and orderly transition.

BHE supports the authority granted under the CAA to states as the entities best suited to develop and adopt implementation plans that are tailored to the geography, populations, meteorology and other localized conditions of the specific state. The "good neighbor" provision, at its core, is a state obligation. It is codified in Section 110 of the CAA, which is the section granting states the primary decision-making authority for developing state implementation plans to achieve the NAAQS. EPA's role under section 110 is to review and approve those plans, not to substitute its own policy decisions for those made by the states. As long as a state's plan is reasonable and complies with the requirements of the CAA, EPA must approve it. The D.C. Circuit has repeatedly endorsed this cooperative federalism approach codified in Section 110.[42] However, the Proposed Rule threatens to impose a one-size-fits-all approach onto this complex program rather than working with the western states to find the best solution, which must be tailored to the conditions and resources in each state. EPA may feel backed into a corner because of legal suits and its own delays in reviewing and approving each of the western state's SIPs. BHE believes the CAA provides, and in fact requires, a different and more effective approach.

4. EPA Should Work with Western States to Prepare SIPs that Achieve Necessary Ozone Reductions as Part of a Just and Orderly Transition.

The western states where BHE operates affected EGUs (Nevada, Wyoming, and Utah) submitted their good neighbor SIPs to EPA between October 2018 and October 2019, years in advance of EPA's Proposed Rule. Each of these SIPs, in reliance upon EPA guidance and modeling, demonstrated that there were no significant impacts on ozone nonattainment and maintenance in downwind states. Yet EPA took no action on these SIP submissions for two and a half to three and a half years. It was not until February 2022, when EPA signed the Proposed Rule imposing a FIP

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[40] The Governor of Wyoming issued an emergency order to prevent cessation of operations at the Jim Bridger Unit 2 based in part on evidence that the emergency order was necessary to prevent substantial increases in unemployment. *See* Letter from Wyoming Governor Mark Gordon to Michael Regan, EPA Administrator, RE: Temporary emergency suspension – Regional Haze 309(g) SIP for PacifiCorp Jim Bridger Power Plant Unit 2, December 27, 2021; Timothy Considine, "The Fiscal and Economic Impacts of Closing Unit 2 at the Jim Bridger Power Plant," December 26, 2021; both attached as Exhibit B.

[41] Executive Order 14008, Sec. 223 (Jan. 27, 2021) (Executive Order on Tackling the Climate Crisis at Home and Abroad).

[42] *Train v. NRDC*, 412 U.S. 60 (1975); *Union Elec. Co. v. EPA*, 427 U.S. 246 (1976); *Fla. Power & Light Co. v. Costle*, 650 F.2d 579 (5th Cir. 1981).

on these states (later publishing it for public notice and comment on April 6), that these states learned that EPA did not intend to approve their good neighbor SIPs. EPA did not even propose disapproval for these SIPs until May 23, 2022, a full month and a half after proposing its FIP. And EPA has yet to finalize disapproval (the proper legal predicate for a FIP). What's more, EPA's disapproval of these SIPs is based on a shift in its thinking in the years since the SIPs were originally submitted.

BHE can only conclude from this series of actions that EPA predetermined that these states would be subject to this FIP as its chosen policy outcome without following the required administrative procedure or working in good faith with the states to develop their SIPs. EPA's nonsequential process demonstrates serious disregard for the well-founded state determinations underlying their good neighbor SIPs.[43] In failing to observe the appropriate process, EPA has undermined western state authority in contravention of the cooperative federalism underpinning Section 110 of the Clean Air Act.

EPA attempts to paper over the role reversal of the Proposed Rule by saying that states can always prepare a SIP later for EPA approval. However, EPA has not yet finalized disapproval of the Nevada, Utah, and Wyoming SIPs. In the past, EPA has provided states sufficient time to implement the good neighbor provision via their own SIPs, even when supplemental information and analysis may have been required.[44] BHE asks EPA to do the same in this instance. Provisions in the Proposed Rule impose SIP requirements not found in the CAA and essentially eliminate any reasonable opportunity for states to make a future SIP submission.[45] BHE encourages EPA to respect the cooperative federalism principles in the CAA as the right way to achieve the best path forward.

States are uniquely positioned to identify the right mix of requirements for the unique emission sources in their jurisdictions and to determine how best to align those requirements with other regulatory efforts that target some of the same units and pollutants, like regional haze. In addition, states are best positioned, and have a sovereign duty, to evaluate and implement the measures necessary to ensure they achieve the required good neighbor provisions while also not jeopardizing their coal communities and the bulk electric systems that serve their citizens. Given the poor fit for western states and the serious modeling concerns with EPA's Proposed Rule, some expect that EPA will need to make substantive revisions before issuing a final rule. If so, EPA should work with the four western states during that time to supplement their good neighbor SIPs, including any necessary modeling and or other provisions to demonstrate sufficient emission reductions from sources within the state to eliminate the downwind impact that EPA has defined as significant. This will ensure the most appropriate measures to meet the 2015 ozone NAAQS are identified while both avoiding disruptions to the reliable delivery of electricity and taking local communities into account.

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[43] EPA has also put states and other stakeholders in a difficult position, as they have been forced to devote scarce resources to simultaneously digest and respond to both the voluminous Proposed Rule and the proposed SIP disapprovals.

[44] *See*, e.g., 84 FR 3389, 3390 (Feb. 12, 2019) (approving Wyoming's good neighbor SIP after Wyoming submitted supplemental information requested by EPA).

[45] *See* Section II.C.1.

II. If EPA Does Not Remove Western States from the Proposed Ozone Transport Rule, Improvements Are Vital.

A. EPA's Over-Control Analysis Is Flawed and Must Be Revisited.

EPA's over-control analysis in support of the Proposed Rule, which EPA is required to conduct under the Supreme Court's ruling in *EME Homer City*, evaluates two possible indicators that the rule could result in over control: (1) resolution of all linkages for any state by eliminating all downwind nonattainment and maintenance receptors, or (2) reduction of a state's contribution to downwind receptors below the minimum threshold for contribution. While the focus of EPA's over-control analysis for the Proposed Rule seems at a high level to be consistent with *EME Homer City*, EPA has ignored several key issues in concluding that its proposal will not result in over control. BHE recognizes that EPA must also avoid under control, and that the courts have granted EPA some leeway in trying to avoid either end of the spectrum in its efforts to address the complex problem of interstate transport of air pollution. But, due to the significant issues identified in this case, EPA must do more to ensure its proposal does not go too far.

1. EPA Should Reconsider the One Percent Threshold.

As an initial matter, BHE asks EPA to reconsider its decision to define a significant contribution based in part on a minimum screening threshold that represents one percent of the ozone standard, *i.e.*, 0.7 ppb. EPA determined the one-percent threshold was appropriate when it first adopted the original CSAPR rule based on a 2011 modeling analysis that compared results under a five-percent threshold, a one-percent threshold, and a half-percent threshold.[46] EPA's analysis compared the "capture rates" for the different options—*i.e.*, the percentage of total upwind contribution that would be regulated under the different thresholds under consideration. Based on its modeling analysis, EPA concluded that the capture rates under the one-percent and half-a-percent options were similar, indicating that little benefit would be achieved with the lower threshold, but that raising the threshold to five percent would leave too many upwind states and emission sources unregulated.

In 2018, EPA issued a guidance memorandum that re-analyzed the minimum threshold using a tighter range of options and more up-to-date modeling techniques and data.[47] Specifically, EPA evaluated the difference in capture rates between the previous threshold of 0.7 ppb (one percent), a threshold of 1 ppb, and a threshold of 2 ppb. Like the 2011 analysis, EPA's 2018 analysis again concluded that the difference between the two lower options—0.7 ppb and 1 ppb—was minimal, while the higher threshold left too many emissions unregulated. As a result, EPA considered capture rates at the 0.7 ppb and 1 ppb thresholds to be generally comparable, and thus concluded that "it may be reasonable and appropriate for states to use a 1 ppb contribution threshold, as an alternative to a 1 percent threshold," in addressing interstate transport under the Clean Air Act

[46] 76 FR 48208, 48237.

[47] EPA Memorandum, *Analysis of Contribution Thresholds for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards* (Aug. 31, 2018).

good neighbor provision.[48] Notably, a threshold of 1 ppb is 1.4 percent of the ozone standard of 70 ppb, and therefore rounds down to 1 percent if truncated.

Despite the fact that the 2018 analysis was based on the same principles as the 2011 analysis and was improved by use of a tighter range of options and more current data and modeling, EPA now all but disavows it. While technically retaining the 2018 memo, EPA has proposed to disapprove numerous state submissions that relied on the memo, claiming that those states should have somehow done more analysis than EPA did itself in writing the memo, and asserting without explanation that consistency is needed across the country. EPA also ignores the 2018 memo in its own over-control analysis for the Proposed Rule, focusing solely on its prior one percent (0.7 ppb) threshold instead of considering the 1 ppb threshold that EPA determined to be an appropriate alternative based on a more recent and narrowly focused modeling analysis.

In addition, as noted above, EPA has already determined in another context that two ozone design values (DV) that differ by less than 1 ppb are not statistically significantly different from each other, based on the statistical analysis use to define 1 ppb ozone as the Significant Impact Level (SIL) for the Prevention of Significant Deterioration (PSD) program. EPA's own demonstration that 1 ppb is not statistically significant confirms that 1 ppb is an appropriate *de minimis* threshold. Further discussion of this point is provided in the enclosed report from Ramboll evaluating the EPA modeling analysis underlying the Proposed Rule.[49]

BHE asks EPA to reconsider its minimum contribution threshold. Unless EPA can identify some rational basis for preferring its older and now outdated 2011 analysis, the 2018 analysis appears superior and more appropriate for both identifying significant contributions and evaluating the possibility of over-control.

2. EPA Must Explain How It Considered Its Trading Program "Enhancements" in Determining Whether the Proposal Will Result in Over-Control.

At the heart of EPA's over-control evaluation is a modeling analysis based on EPA's Ozone AQAT, a more limited modeling program than the photochemical grid modeling typically used to predict ozone concentrations at the regional level. EPA claims it had no choice but to use the AQAT due to "timing and resource limitations."[50] Even setting aside EPA's decision to use a less precise modeling technique for its over-control analysis and that the timing constraints are of EPA's own making, the assumptions underlying EPA's AQAT analysis may not be valid due to the trading enhancements that EPA has proposed.

In its AQAT analysis, EPA first identified the level of emission reductions resulting from the control stringencies EPA selected.[51] In other words, EPA determined the emission reductions that would be generated by the controls required under its proposal, and then determined whether those emission reductions will result in over-control. While this approach seems logical on its face, EPA

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[48] *Id*. at 4.
[49] *See* Ramboll Report at 62-64.
[50] Policy TSD, at 32.
[51] Policy TSD, at 33 ("[a] critical factor in the [AQAT] is the establishment of a relationship between ozone season NO_x emission reductions and reductions in ozone").

does not appear to have recognized that the emission reductions it assumed based solely on implementation of controls may be far less than will actually be forced due to the restrictions on trading EPA has proposed.

EPA's proposal contains a multitude of entirely new and overlapping constraints on trading that will affect how the program will operate and the level of emission reductions it will achieve. Those enhancements include new backstop daily limits, dynamic budgeting, banking recalibrations, modified assurance provisions, and a secondary emission limitation, which alone or combined could have a dramatic impact on the emission reductions that the proposal will achieve. In addition, the lack of flexibility resulting from the proposed enhancements eliminate any real possibility of achieving compliance through trading, and without meaningful trading, sources will be forced to choose between SCR and retirement. Since SCR is unlikely to be cost effective, based on EPA's own analysis, retirement will often be the only realistic option. As just one example, EPA's proposed dynamic-budgeting process would confiscate allowances from states, requiring more emission reductions than EPA may have predicted. Together, the enhancements remove the option of a trading as a way to achieve compliance, and force difficult choices that are likely to make the program more stringent than EPA has anticipated.

Since these enhancements will affect the stringency of the program, they will also affect the level of emission reductions achieved, which serve as the foundation of EPA's over-control analysis. After all, a retirement results in zero emissions from a source. BHE recommends that EPA explain how its over-control analysis accounts for the possibility that the enhancements will require greater emission reductions than expected. If EPA has not done so, BHE asks EPA to evaluate that possibility to ensure the assumptions underlying its over-control analysis are properly supported.

3. An Over-Control Analysis that Ignores Emission Reductions in Downwind Home-States Would Be Unreasonable and Unlawful.

In describing its over-control analysis, EPA seeks comment on a critical assumption: whether that analysis should consider the emission reductions likely to be required and implemented in the states that are home to the air quality problems the proposal seeks to address, which EPA refers to as "home states." In all of its prior interstate transport rules, EPA has reasonably assumed such home states will do their fair share in reducing ozone by employing control measures similar to those required from the upwind states significantly contributing to downwind ozone problems. For example, in the Revised CSAPR Update, which EPA adopted less than a year prior to the current proposal, EPA maintained its long-standing position on this important point.[52]

Assuming downwind states will pull their weight in improving air quality is reasonable. After all, the Clean Air Act requires states to attain ambient air quality standards,[53] and nothing in the Clean Air Act requires upwind states to carry the full burden of bringing a downwind state into attainment. In that sense, the assumption that downwind states, including Colorado, will do their fair share is also lawful, since EPA should presume that states will meet their legal obligations under the Clean Air Act, and EPA is required by law to consider all relevant information in crafting

[52] 86 FR 23054, 23115 (Apr. 30, 2021) (citing a TSD confirming its over-control analysis assumed "[e]missions were also reduced in the state that contained that receptor (regardless of the level of that state's contribution) at a level of control stringency consistent with the budget level applied in upwind states.").
[53] 42 U.S.C. § 7410.

its programs.[54] The fair-share assumption is also central to EPA's over-control analysis because it can be outcome-determinative in some cases. For instance, EPA recognizes that assuming home states will do their fair share results in over control for Wyoming, while reversing that assumption would not.[55] On that basis alone, Wyoming should be excluded from the final ozone transport rule.

At first, EPA's proposal suggests EPA will continue to follow its long-standing, reasonable, and lawful approach of recognizing the work downwind states are required to and will do to resolve their own air quality problems. Specifically, EPA indicates in footnote 206 of its proposal that it will "continue[ ] to assume, as it has in prior transport rules, that home-states (that are not otherwise linked) will make similar reductions as those assumed in this action for purposes of local attainment."[56] BHE supports this approach.

However, in that same footnote, EPA also indicates that it is willing to consider the opposite assumption—*i.e.*, that downwind home states will do absolutely nothing to address their own ozone nonattainment problems. EPA also incongruently states in its Policy Technical Support Document (TSD) that it "no longer believes it is a necessary part of the 'overcontrol' analysis to account for the downwind state's 'fair share.'"[57]

It is clearly established judicial precedent that to reverse a long-standing and relied-upon policy, EPA must provide a reasonable basis for the change. As the Supreme Court held in *FCC v. Fox TV*, an "agency must show that there are good reasons for the new policy. . . . [A] reasoned explanation is needed for disregarding facts and circumstances that underlay or were engendered by the prior policy."[58] However, the only justification EPA provides for ignoring downwind emission reductions is a reference to the recent decision of the D.C. Circuit in *Maryland v. EPA*.[59] EPA quotes a part of the *Maryland* decision as support for the proposition that EPA can and should ignore home-state reductions in its over-control analysis. EPA reads the decision as "calling into question" the need to assume downwind states will reduce emissions and even suggesting that such an assumption "may be inappropriate" in evaluating the potential for over control.[60]

Maryland does not support these points. Neither the quote provided by EPA nor anything else in the court's opinion offers any basis for assuming home states will do nothing to address their own air quality problems. The quote EPA offers is selectively plucked out of context from a discussion on timing of attainment deadlines, not whether home state reductions belong in an over-control analysis. The court introduces the quoted section of its opinion, which is entitled "Selection of Year to Measure Air Quality" by stating "[w]e next consider a question of timing."[61] The specific

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[54] *Michigan v. EPA*, 576 U.S. 743, 750 ("agency action is lawful only if it rests on a consideration of the relevant factors") (citing *Motor Vehicle Mfrs. Assn. v. State Farm Mut. Automobile Ins.* Co., 463 U.S. 29, (1983)).
[55] *See, e.g.*, 87 FR at 20099 ("when the assumption of commensurate downwind state reductions in Colorado is removed from the methodology, the downwind receptor to which Wyoming is linked does not resolve and there is no identified over-control estimated for Wyoming.").
[56] 87 FR at 20099, n. 206.
[57] Policy TSD, at 34.
[58] *FCC v. Fox TV*, 556 U.S. 502, 515-16 (2009) ("And of course the agency must show that there are good reasons for the new policy. … [A] reasoned explanation is needed for disregarding facts and circumstances that underlay or were engendered by the prior policy.").
[59] 958 F.3d 1185 (2020)
[60] 87 FR at 20099, n. 206.
[61] *Maryland*, 958 F.3d at 1201.

quote chosen by EPA comes from a subsection on "future nonattainment," in which the court rejected an argument from EPA that it could ignore the initial attainment deadline for "marginal" nonattainment areas because home-state efforts would achieve attainment by the next deadline for "moderate" nonattainment areas. The court rejected that argument because it was directly inconsistent with its recent *Wisconsin* decision, which requires EPA to ensure its transport programs consider all attainment deadlines unless it is impossible to do so. In other words, the court did not say EPA should ignore home-state efforts. Rather, it said that EPA cannot rely on those efforts to ignore an initial attainment deadline just because those efforts may result in attainment before a later deadline.

In fact, another portion of the court's opinion actually suggests EPA *should* recognize home-state efforts, not ignore them. In discussing states that are part of a multi-state nonattainment area, the court noted that such states have "the concomitant responsibility to limit their own emissions," even if their in-state monitors show attainment.[62] If EPA is looking for guidance from the *Maryland* decision about what assumptions it must use to justify its new transport proposal, it should focus on the court's recognition that home states are responsible for limiting their emissions, not the court's rejection of EPA's attempt to use that concept to ignore an attainment deadline that *Wisconsin* required EPA to meet.

In truth, the *Maryland* decision does not address over control directly at all. The case involved two petitions from the states of Maryland and Delaware asking EPA to impose upwind controls, but EPA denied that petition and refused to impose any new controls. Since the issue in the case was EPA's failure to impose controls, not a program to impose new controls, the court had no occasion to consider if over control might occur—there were simply no new controls to consider, and thus no over-control analysis to review. The only time the court even mentioned the phrase "over control" was in describing the procedural history of the case. In that section, the court recognized EPA's long-standing policy, not challenged in the case, that over control could occur if a home state's own efforts would achieve attainment by the *first* attainment deadline. The court did not reject that policy. Instead, the court simply refused to allow EPA to rely on home-state efforts to justify ignoring an attainment deadline, which the Clean Air Act does not allow, per *Wisconsin*.

EPA must not read more into the *Maryland* case than what is actually there, and its misinterpretation of the decision does not satisfy the burden it bears under *FCC v. Fox TV* to justify its departure from its own prior policy. EPA should instead follow its long-standing practice of recognizing home-state emission reductions in its over-control analysis. EPA continued to follow that approach in its 2021 Revised CSAPR Update Rule, even though EPA issued that proposal and final rule well after the *Maryland* decision, and EPA has offered no other basis for reversing course in this proposal.

B. EPA's Proposed Enhancements to CSAPR Will Eliminate the Benefits of Trading and Should Be Modified or Eliminated to Ensure Compliance Flexibility, Consistent with Past CSAPR Rules.

As EPA notes in the Proposed Rule, trading programs are highly effective at achieving significant emission reductions at low cost. The ability of a trading market to allocate resources to the most

[62] 958 F.3d at 1201.

cost-effective means of reducing emissions has been proven many times over. EPA's Proposed Rule touts the first air emission trading market—the Acid Rain Program developed by Congress—and rightly so, since that program achieved the emission reductions needed to address acid rain at much lower cost than originally expected.[63]

EPA has sought to replicate that success in its interstate transport programs, first with the NO_x SIP Call, then CAIR, and then with CSAPR and its updates. Like the Acid Rain Program, these EPA-designed trading programs have successfully reduced emissions and improved air quality at low cost via a market for emission allowances that allows some facilities to reduce emissions more than required, freeing up allowances for facilities that may not be able to reduce emissions as cost effectively.

EPA has recognized this important benefit of trading programs many times before. For example, in promulgating the NO_x SIP Call in 1998, EPA stated, "[s]ince EPA's determination for the core group of sources is based on the adoption of a broad-based trading program, average cost effectiveness serves as an adequate measure across sources because sources with high marginal costs will be able to take advantage of this program to lower their costs."[64] Similarly, in promulgating the original CSAPR, EPA stated, "the preferred trading remedy will allow source owners to choose among several compliance options to achieve required emission reductions in the most cost-effective manner, such as installing controls, changing fuels, reducing utilization, buying allowances, or any combination of these actions."[65]

The opportunity for individual facilities to *choose* between installing controls or buying allowances is what makes a market work; it allows resources to flow toward the most cost-effective actions available at an individual unit level. However, if all facilities must meet the same limits on individual emission units, there will be no choice between buying controls or buying allowances. The need for a market vanishes, along with the benefits of trading.

EPA's proposed enhancements eliminate the flexibility needed for an emission allowance market to work, thus eliminating the benefits of the market. The multiple layers of backstop limits proposed, combined with new restrictions on the holding and use of allowances themselves, are likely to leave individual facility owners with too few choices for trading to function properly. While some constraints are needed to ensure the program accomplishes its intended goals and satisfies Clean Air Act requirements, unnecessary and duplicative constraints will impede the formation of a viable market and the associated benefits of trading. The combined effect of the many proposed enhancements is also likely to result in over control, since the enhancements will tend to force greater emission reductions than the levels EPA evaluated in its over-control analysis.

With the comments provided below, BHE asks EPA to either eliminate the enhancements altogether, or demonstrate how the proposed enhancements will not impede the development of a viable trading market and result in unlawful over control.

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[63] *See, e.g.,* NO_x SIP Call Proposal, 69 FR 4629 ("Cap and trade under the Acid Rain Program has created financial incentives for electricity generators to look for new and low-cost ways to reduce emissions, and improve the effectiveness of pollution control equipment, at costs much lower than predicted.").
[64] 63 FR 57399 (emphasis added).
[65] 76 FR 48272 (emphasis added).

1. The New Daily Emissions Limit Proposed for Coal EGUs Is an Independent SCR-Forcing Requirement, Not Just a "Backstop" to the Trading Program.

The most restrictive enhancement that EPA has proposed is the requirement for all coal-fired EGUs with a generating capacity of greater than 100 MW to meet a new emission limitation of 0.14 lb/mmBtu on a daily basis. Failure to meet that limit results in a penalty of a 3-to-1 allowance ratio for each ton of NO_x actually emitted beyond what a unit would have emitted at an emission rate of 0.14 lb/mmBtu. EPA refers to this limit as merely a "backstop" to the primary emission limitation requiring a source to hold allowances equal to its emissions.[66]

Since incurring a 3-to-1 allowance penalty is unlikely to be an economic long-term solution for any EGU[67], this backstop limit will actually function as an independent mandatory requirement, forcing all coal-fired EGUs to either meet that limit on a daily basis, avoid operating during the ozone season, or otherwise cease operations. Although some exceptions may exist, the vast majority of coal-fired EGUs will need an SCR to achieve 0.14 lb/mmBtu on a daily basis, and indeed, EPA admits that is its ultimate goal, saying that "universal installation and operation of SCR technology at large coal-fired EGUs is appropriate."[68]

EPA's proposed backstop limit is more than its name would suggest. Instead of serving as a guardrail on the flexibility offered by the primary emission limitation of holding allowances, the 0.14 lb/mmBtu limit requires something entirely new—the installation of SCR—a specific action that would not otherwise be required by the primary limit. And this specific action is no small task; SCR installations cost hundreds of millions of dollars per EGU, which is enough to draw into question the future economic viability of any unit that does not already have one. As noted earlier in these comments, this threat to the viability of existing EGUs is exacerbated by the number of SCRs the backstop limit would require, which simply cannot be installed within the compliance timeline set forth in the Proposed Rule. As a result, the backstop limit is likely to driver significant EGU retirements, the replacement of which will present the significant reliability concerns that are described in more detail in the comments above.

Far from a mere backstop to the trading program, the 0.14 lb/mmBtu backstop limit is in fact a command-and-control requirement of uniform performance by all coal-fired EGUs, similar to the emission standards that EPA typically adopts under other authority, such as Sections 111 or 112 of the Clean Air Act. This requirement eliminates the element of choice that facilities need for allowance trading to work. Under all prior versions of CSAPR, individual EGUs could choose between installing SCR or installing less expensive controls and buying allowances from the EGUs that chose to install SCR. With this proposal, all alternatives but SCR are eliminated (other than retirement). EPA's own statements confirm this, stating that its "trading program improvements

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[66] 87 FR 20110 (section entitled "Unit-Specific *Backstop* Daily Emissions Rates") (emphasis added).

[67] As allowances become scarcer, the laws of supply and demand dictate that prices will increase correspondingly. According to information BHE has received from brokers and other sources, allowance prices, which hovered around $75 in 2019, dramatically increased in price in 2021 following the CSAPR update, ranging from $1,500-$4,000. BHE is now hearing estimates ranging from $10,000 to $28,000 per ton of NO_x under the Proposed Rule – figures that would likely eliminate the purchase of allowances as a viable compliance strategy and would make imposition of a 3 to 1 penalty overly punitive.

[68] 87 FR 20111.

also promote *consistent* emissions control performance across the power sector."[69] However, the whole point of emission allowance trading is to allow *inconsistent* performance, since market-based flexibility is precisely what promotes the efficient use of resources without the need for governmental dictates. CSAPR already includes assurance provisions adequate to reign in bad actors.

Rather than hide a universal command-and-control SCR requirement within the ill-fitting guise of a backstop limit to a trading program, EPA should recognize the benefits of its prior approach to allowance trading under CSAPR, which gave EGUs a choice between installing controls or buying allowances, while still achieving the emission reductions needed to address interstate transport. The allowance trading approach to solving interstate transport has functioned well in prior iterations of the program and should be employed to achieve similar success for the 2015 ozone standard. Accordingly, BHE asks EPA to eliminate the backstop limit from the rule.

2. The Backstop Daily Limit Drives Universal Installation of SCR by 2026. This Deadline Is Impossible.

EPA's required timeline of 36 months to install SCR is not feasible for most of BHE's coal-fueled units. EPA indicates that the 2023 deadline for the first round of control technology installations assumed under the Proposed Rule is based on the next attainment date of Aug. 3, 2024, for moderate states, and that the 2026 deadline for the second round of controls is based on the following attainment date of Aug. 3, 2027, for serious states. EPA accurately finds that requiring EGUs to install a new SCR by the 2023 ozone season to prevent impacts on neighboring states prior to the 2024 nonattainment deadline is not feasible.[70] However, EPA should exercise this same logic and discretion to find that installation of utility-level SCR prior to the 2027 Title I deadline for serious area attainment is also not feasible. Under the Proposed Rule, utilities would need to have SCR installed in time to meet the more stringent allowance allocations based on SCR for the 2026 ozone season, as well as the SCR-based 0.14 lb/mmBtu backstop limit that will apply beginning in the 2027 ozone season.

The proposed compliance timeline is inadequate and should be extended by at least three years, depending on the number of SCR installations required in a given region or for a given operator. Doing so is necessary to establish feasible timelines for SCR installation, and this timing would still provide significant NO_x reductions before the next ozone NAAQS attainment deadline of August 3, 2033. This additional time would have the side benefit of allowing exploration of more feasible alternative options to SCR that will meet the proposed NO_x reduction goals, better protecting reliability, and thereby better facilitating a just and orderly transition to a clean energy economy. Should EPA opt not to reconsider the SCR installation timeline requirements, the Proposed Rule will essentially function as a coal plant closure requirement.

i. Required processes and timelines must be taken into account.

Regulated utilities like NV Energy and PacifiCorp cannot unilaterally determine that an SCR should immediately be installed. They are required by state law to develop a least-cost, least-risk plan for customers and to ensure prudent decisions are made on behalf of their customers. In

[69] 87 FR 20045 (emphasis added).
[70] 87 FR 20101.

addition, the feasibility and long-term impacts of installing an SCR on a utility's energy system must be analyzed to ensure the system can continue to function consistently and reliably. BHE projects this initial analysis will take at least until January 2023.[71] Utilities must also obtain regulatory approvals for the costs associated with the operational changes and capital investments required for an SCR, as well as obtain a state air permit. These permitting processes can generally proceed concurrently with the procurement and construction processes, but they have set timelines of their own and are estimated to take 9-12 months.

EPA suggests that installation of controls to comply with the Proposed Rule would constitute a physical change that could trigger new source review (NSR) if installation of those controls resulted in emissions increases exceeding NSR thresholds.[72] Yet imposition of NSR permitting requirements on installation of SCR or other controls, such as Low NO_x Burners (LNB), will only further extend the time needed to install them to comply with the Proposed Rule, since NSR permits must be obtained before construction can begin. Costs for a project would also increase considerably if a source were required to undertake the extensive analysis and demonstrations required by NSR permitting, including air dispersion modeling and requirements to install best available control technology. To prevent such delays and additional costs, EPA should provide guidance on the permitting implications of control projects required by the Proposed Rule, including a streamlined approach for permitting installation of SCR or LNB.

The following table provides an illustration of the total time involved to effectuate the most recent SCR installation for two PacifiCorp units, Jim Bridger Units 3 and 4, in 2015 and 2016, respectively:[73]

Table 1: SCR Installation Timelines for Jim Bridger Units 3 and 4

SCR Installation Processes	Timeline
Development (baseline testing, specs, geotech, permits)	11 months
Procurement (requests for proposal and contract negotiations)	12 months
Construction Engineering/design; contractor procurement of materials, labor, subcontractor Construction and substantial completion	 6 months 25 months
TOTAL (JB U3)	54 months
TOTAL (JB U4)	67 months

The SCR installation processes began after internal analysis showing installation of SCR was feasible and prudent. The schedule represented an aggressive timeline, and even then Jim Bridger Unit 4 took an additional 13 months after Unit 3 was completed because, as explained in the next section, multiple units cannot be installed simultaneously at the same site or even in the same region.

[71] All of the timelines in these comments are rough projections and not a commitment to a specific timeline. More time and analysis are needed to provide more reliable figures.
[72] 87 FR 20140, n. 308.
[73] This timeline includes the time to obtain the required CPCN and air permits, which occurred concurrently with procurement and construction.

ii. The number of installations required by the Proposed Rule is not feasible.

BHE is one of the most impacted entities by the Proposed Rule.[74] While BHE plans to retire all of its coal units by 2049, including 16 units before 2030 (on top of another 16 already retired), the Proposed Rule requires installation of SCR on 16 existing coal units and potentially two natural gas units by 2026. PacifiCorp alone has 14 coal-fueled units subject to the SCR requirement.[75] Most of the units requiring SCR are large units in rural, often remote, locations, and would already fall on the high end of EPA's previously projected SCR timeline of 48 months.[76]

There are other insurmountable logistical challenges to installing multiple units within the small intermountain region where BHE's potentially affected units operate. Wyoming and Utah draw from the same general labor pool and resource suppliers. As an example, the five SCRs required for PacifiCorp's Hunter and Huntington plants would require essentially all the craft manpower from the intermountain area for multiple years and would be competing with other retrofit projects occurring in the region, and potentially across the country.

An SCR installation requires approximately 200 contractors working at the site, many of whom must possess specific skills and experience. Each installation requires these resources, and in general, these resources cannot be combined or shared. There is not enough skilled labor in the intermountain region to support multiple simultaneous SCR projects. In addition, the plant sites and surrounding communities where the SCRs must be installed cannot support double or triple the number of contractors with the associated truck traffic, residential needs and services, and entries and exits from the plant site. The Proposed Rule's compressed timeline and impossible SCR installation requirements raise reliability concerns. The potential combined 84 total weeks[77] of outages, the impossible logistical challenges of installing multiple units before May 2026, and the potential for retirements, temporary shutdowns, and delays beyond a company's control put the energy grids where these units operate in serious jeopardy. According to PacifiCorp's current estimates, an SCR will cost from $150-200 million per unit.[78] This translates to nearly $1.5-2.0 billion dollars for the ten PacifiCorp units potentially subject to the 2026 SCR requirement. EPA has previously recognized the unrealistic burden for a single company to install multiple SCR retrofits within a compressed timeframe and has authorized additional compliance time.[79]

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[74] *See* Anna Duquiatan, Zack Hale, "US EPA's plan for interstate smog might force even more early coal retirements," SNL POWER POLICY WEEK, April 20, 2022.

[75] Two of these units will convert to natural gas in 2024 and two others will cease burning coal by 2025, leaving ten units subject to the Proposed Rule's requirement to achieve SCR-like limits by 2026. Gas units are also subject to the Proposed Rule and may require control equipment or capacity reductions. BHE has 65 affected gas EGUs, including 45 at NV Energy, 13 at PacifiCorp and 7 at BHE Renewables.

[76] *See* Proposed Rule at 20081 (finding some SCRs require 39-48 months to install); CSAPR Close-Out, 83 FR 65878, 65895 (December 21, 2018). *See also* Final Report: Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA–600/R–02/073 (Oct. 2002), available at *https://nepis.epa.gov/Adobe/PDF/P1001G0O.pdf.*

[77] This is assuming a projected 12 SCR installations for BHE coal-fueled units and 2 SCR installations for gas units.

[78] Based on a recent professional study contracted by PacifiCorp.

[79] 79 FR 5032, 5048, 5188-89.

iii. Current market and labor constraints make EPA's timeline infeasible.

Beyond the logistical and cost hurdles, other constraints to meeting EPA's timeline include current market and labor conditions, which have developed and worsened since EPA conducted its cost and timeline analyses. BHE's broad operational footprint provides practical insight into current economic and market trends. Across the western states impacted by the Proposed Rule, supply constraints and labor shortages are delaying expected timelines for large projects like SCR installation. Supply chain constraints on many of the materials essential to an SCR installation are causing longer lead times and higher bid prices as suppliers must seek new and different options to purchase metal. Contractors cannot guarantee actual delivery of the plate steel and structural steel required for an SCR, and steel mills are not meeting their indicated target delivery dates, even when a premium is paid. With so many states and units affected by the Proposed Rule, the number of SCRs likely to be requested will also further exacerbate the shortages in labor and materials, especially within the heavily impacted intermountain region.

Based on a recent professional study contracted by PacifiCorp to evaluate the change in prices over the past four years, the price of copper has risen about 50%, the price of nickel has more than doubled, and the price of construction labor has risen significantly as well. BHE contractors report that costs for the components of an SCR are escalating up to 30% just between the time of bid and award, making project cost escalation and delay a certainty. In addition, based on BHE projections, these supply chain shortages and labor constraints are estimated to add 24 weeks to the total timeline for an SCR installation.

iv. Even best-case scenarios are infeasible.

Based on initial analysis, BHE believes it may be able to expedite the procurement process from 12 months to 6 months based on the emergency situation created by the Proposed Rule, and that it can expedite the pre-process timeline to reach a reasonable determination on the feasibility and advisability of installing SCR on specific units by the first quarter of 2023.[80] Applying an aggressive process timeline and adding on the 24 weeks for the supply chain and labor shortage delays, the best-case scenario to complete installation of a single SCR is December of 2027 for a single unit at a single location. However, as evidenced by the installation of SCR at Jim Bridger Units 3 and 4, discussed above, an additional year or more for successive installations of SCR at multiple units should be presumed, and additional delays beyond that are likely due to the significant number of SCRs projected to be constructed in the three western states newly subject to the Proposed Rule EGU requirements, particularly given the strain on the already stretched supply and labor markets.

BHE understands that the timing of the Proposed Rule is designed "to achieve reductions as expeditiously as practicable while adhering to the procedural requirements of CAA section 110" and to achieve a "full remedy."[81] BHE also appreciates that the CAA requires areas to meet the ozone NAAQS "as expeditiously as practicable." However, there are countervailing considerations that warrant extension of the time frame for installing SCRs. First, EPA has already acknowledged

[80] These timelines are rough projections and not a commitment to a specific timeline. More time and analysis are needed to provide more reliable figures.
[81] 42 USC 7511(a)(1).

that it cannot require the impossible by delaying the SCR-forcing requirements beyond the first attainment deadline in 2023. The same considerations warrant an extension beyond the attainment deadline in 2026. Second, the Supreme Court has recognized that the Clean Air Act, "by its express terms . . . grants the Administrator sufficient flexibility to avoid setting ambient air quality standards ruinous to industry."[82] By extension, implementation of the good neighbor rule in support of attaining those standards should be held to the same standard. Simply put, additional time is needed to enable utility-scale EGUs to evaluate compliance options and either install SCR or identify and adopt a feasible alternative that will not threaten the reliability of state and regional electricity systems and will minimize rate pressures on customers.

The 36 months that EPA settled on is not realistic for these units and is far shorter than the actual time required for the two most recent SCRs installed by PacifiCorp. Accordingly, BHE asks EPA to recognize that SCR cannot be installed in time to meet the more stringent 2026 allowance allocations based on SCR and the SCR-based 0.14 lb/mmBtu backstop limit that will apply beginning in the 2027 ozone season.

v. EPA Should Reconsider the Level and Form of the Proposed Backstop Limit.

If EPA retains its SCR-forcing limit, BHE also asks EPA to reconsider the level of that limit, since 0.14 lb/mmBtu may not be achievable by all EGUs, even with an SCR. While EPA has demonstrated that 0.14 lb/mmBtu should be achievable by most EGUs already equipped with SCR based on historical data, that historical dataset does not necessarily represent the capabilities of EGUs not yet equipped with an SCR. Indeed, EGUs that do not yet have an SCR are more likely to be units for which SCR may present site-specific challenges that make installation of SCR difficult for the unit, and those same challenges may make it difficult to match the level of performance achieved by prior SCR installations.

For example, if an EGU has previously decided against installing SCR due to spacing constraints, those same spacing constraints may force an SCR to be placed at a position in the exhaust gas path that is less than optimal, where gas temperatures or flow characteristics may make it difficult to achieve the same level of performance seen elsewhere. EPA did not take such considerations into account in relying solely on historical emission rates to determine that a limit of 0.14 lb/mmBtu is universally achievable, and BHE encourages EPA to evaluate that important concern.

In addition, BHE asks EPA to reevaluate the form of the 0.14 lb/mmBtu limit. Since EPA's primary justification for the limit is the asserted need to reduce downwind contributions to ozone formation, the mass of emissions released per unit of heat input (mmBtu) is not necessarily relevant. For instance, an EGU running at low load for a day with an emission rate of 0.15 lb/mmBtu may actually emit much less NO_x over the course of that day than an identical EGU running at a high load at an emission rate of 0.13 lb/mmBtu on that same day. The heat input-based form of the limit is not rationally related to EPA's ultimate purpose, but rather appears entirely focused on forcing the installation of SCRs regardless of the actual mass of NO_x emitted.

[82] *Whitman v. Am. Trucking Associations*, 531 U.S. 457, 494 (2001) (J. Breyer, concurring).

The form of the backstop limit also precludes use of existing EGUs at lower load as a potential strategy for reducing daily NO_x emissions. Many existing EGUs are already operating at reduced load to accommodate the integration of renewable resources that are naturally more variable in generation capacity and require support from dispatchable generation. While operating at reduced load is consistent with both the ongoing transition in the power sector and EPA's asserted need to reduce daily NO_x emissions, the backstop limit would effectively prohibit the alternative of low load operation because NO_x lb/mmBtu rates do not necessarily drop at low load, and in fact may actually increase.

As such, the form of the limit is arbitrarily disconnected from EPA's ultimate purpose and the legal authority underlying the proposal. A lb/mmBtu limit effectively forces universal SCR installations, and in doing so appears designed to force EGUs to choose between SCR and retirement. However, an inflexible lb/mmBtu limit is directly inconsistent with a trading program that employs an allowance market to expand compliance options and allow sources to cost-effectively reduce emissions in as many ways as possible.

BHE also asks EPA to consider adopting a work practice standard for events like startups and malfunctions, since those events might also make it impossible for existing EGUs to achieve a limit of 0.14 lb/mmBtu. Despite the averaging period of a day allowed in the proposal, startup events can take several hours to complete, and NO_x emission controls may not be fully effective during that time. In other recent rules imposing mandatory emission limitations, EPA has recognized the need for work practice standards during startup events to address the possibility of unavoidable exceedances due to the limitations of control equipment.[83] BHE encourages the same approach here.

BHE also encourages EPA to evaluate the possibility of adopting a work practice approach for malfunctions, which EPA has previously admitted are inevitable in large, complex stationary sources like power plants. While EPA has been hesitant to develop work practices for malfunctions in the past, given that they are by nature rare and cannot be predicted, EPA has recognized that the Clean Air Act does not preclude a malfunction work practice standard[84], and EPA has in fact adopted such a standard in at least one case.[85] EPA should consider providing for malfunctions that might result in exceedances of its proposed 0.14 lb/mmBtu limit as well.

vi. EPA's Own Analysis Confirms SCR Is Not Universally Cost-Effective.

EPA claims that SCR is universally cost-effective, but that one-size-fits-all conclusion ignores site-specific considerations that make SCR more costly at some facilities than others, depending on factors such as boiler and fuel type, complexity and height of SCR installation location, physical space to install SCR in existing ductwork pathways, and other previously installed NO_x emission controls. Even setting aside site-specific considerations, EPA recognizes that SCR will cost $11,000 per ton of NO_x removed[86], which is well above any other prior threshold relied upon by

[83] *See, e.g.*, 40 C.F.R. 63.10000(a) (requiring work practices during startup in lieu of the otherwise applicable emission limitations).
[84] *See* 80 FR 33865.
[85] *See* 80 FR at 75211–14.
[86] 87 FR 20081.

EPA to evaluate cost effectiveness for any other control in any other program. Although EPA has consistently refused to offer bright-line guidance on the topic, similar evaluations conducted under other programs do not typically consider $11,000 per ton of reduced emissions to be cost effective.

For example, in the evaluation of possible reasonable progress measures currently underway in the second round of the regional haze program (which EPA claims should focus on higher cost-effectiveness thresholds than the first round that focused on Best Available Retrofit Technology (BACT)), most states are applying cost-effectiveness thresholds below $11,000 per ton of reduced emissions.[87] Even BACT determinations under the New Source Review (NSR) program, which strives to regulate existing facilities as if they were new following a major modification, often rely on a cost-effectiveness threshold of only $10,000 per ton of reduced emissions.[88]

Moreover, a review of EPA's technical support document on the topic of SCR cost effectiveness confirms that the value of $11,000/ton actually underestimates the cost for many EGUs.[89] In that supporting document, EPA confirms that $11,000/ton is actually a weighted average, which means that for many units, the result will be even less cost effective than $11,000/ton. In fact, EPA's supporting analysis indicates a median cost-effectiveness value of $13,700/ton and a 90th percentile value of $20,900/ton.[90] Since EPA's backstop limit forces SCR on all coal-fired EGUs greater than 100 MW, these values mean that for half of the units affected, cost-effectiveness will be at least $13,700/ton, and ten percent of the units will see a cost-effectiveness of $20,900/ton or more. These values are even further out of step with EPA's prior cost-effectiveness evaluations than the $11,000 figure it cites and confirm that the SCRs required by EPA's one-size-fits-all backstop limit are not cost effective at all.

Additionally, EPA recognizes that its cost-effectiveness estimate of $11,000 per ton is likely to be low for units with pre-existing post-combustion NO_x controls, such as selective non-catalytic reduction (SNCR).[91] Since existing controls already reduce the NO_x remaining for an SCR to control, the cost of SCR is even less justified when elevating the per-ton cost of SCR for SNCR-equipped EGUs. Nevertheless, EPA simply assumes away any concerns regarding whether SCR installations would still be cost effective in such cases. In discussing the cost effectiveness of installing SCR on SNCR-equipped units, EPA cites a TSD, suggesting that an explanation can be found there.[92] But that TSD does not explain why EPA believes SCR remains cost effective on SNCR-equipped units. It simply provides additional calculations confirming that the cost effectiveness for such units would be $13,400/ton on a weighted average, with a median value of $14,100/ton and a 90th percentile value of $19,000/ton. These values confirm installing SCR on an EGU already equipped with SNCR is not in fact cost effective as defined by EPA or any reasonable person.

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[87] *See, e.g.*, National Park Service Comments on the Draft North Dakota Regional Haze State Implementation Plan, at 10 (indicating cost-effectiveness thresholds have been set at "$5,000/ton for EGUs in AR and TX, $7,000/ton in NM, and $10,000/ton in CO and OR").
[88] *See, e.g.*, EPA Final TSD for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, at 18 n.16 (Aug. 2016) ("$10,000 per ton represents the cost/ton for [BACT] determinations").
[89] EGU NO_x Mitigation Strategies Proposed Rule TSD.
[90] *Id.* at 25 (Feb. 2022).
[91] 87 FR 20081, n.156.
[92] *Id.*

Even at $11,000/ton, EPA's cost-effectiveness analysis confirms that SCR should not be required because it far outstrips cost-effectiveness values for SCRs in the past, which have typically been much lower. Longstanding EPA guidance indicates that "[c]ost effectiveness (dollars per ton of pollutant reduced) values above the levels experienced by other sources of the same type and pollutant[ ] are taken as an indication that unusual and persuasive differences exist with respect to the source under review."[93] In the past, EPA determinations finding SCR to be cost effective typically have been based on much lower cost-effectiveness values than $11,000/ton.[94] Since EPA now concludes that installing the additional SCRs required in 2026 by its proposal will cost $11,000/ton, which is disproportionately higher than the prior values it has deemed cost effective for SCR installation, EPA's own analysis confirms that additional SCRs are not in fact cost effective for the remaining EGU fleet that has not yet installed these controls.

3. The Proposed Secondary Assurance Limit Is Unnecessary.

The D.C. Circuit has made clear that interstate ozone trading programs must have assurance provisions so that a state may not rely entirely on allowance purchases and thereby avoid reducing its own contribution to downwind receptors. Specifically, in its *North Carolina v. EPA* decision, the court rejected CAIR because it failed to ensure that emission reductions needed to eliminate a particular state's significant contribution would come from within that state's jurisdiction.[95] EPA responded by incorporating assurance provisions into CSAPR that limited trading to within a variability limit to "ensure that the necessary emissions reductions occur within each covered state,"[96] and those provisions were not challenged in the subsequent litigation over EPA's CSAPR program.[97]

The assurance provisions found in the current CSAPR rules, which allow interstate trading within a variation of 21 percent from each state's emission budget, draw an appropriate balance between lawfully responding to the D.C. Circuit by assuring emission reductions come from within a state to eliminate that state's significant contribution, and maintaining the flexibility to accommodate year-over-year differences in actual EGU operations and emissions. In fact, the Proposed Rule explicitly recognizes the current assurance provisions have been effective in practice:

> EPA believes the assurance provisions have generally been successful in achieving that objective, as evidenced by the fact that since the assurance provisions took effect in 2017, out of the nearly 300 instances where a given state's compliance with the assurance provisions of a given CSAPR trading program for a given

[93] Draft NSR Workshop Manual, at B.31 (1990).
[94] *See, e.g.,* 80 FR 29953 (finding $9,900/ton not cost-effective for a Colorado unit); 77 FR 18052 (finding costs from $4,900 to $7,314/ton not cost-effective); 77 Fed. Reg. 57,864 (declining to set a "bright line rule" for SCR cost-effectiveness); National Park Service Regional Haze SIP Feedback for the Utah Division of Air Quality, at 3, Feb. 14, 2022 (indicating cost-effectiveness thresholds have been set at $5,000/ton for EGUs in Arkansas and Texas, $4,000 to $6,500/ton in Arizona, $6,100/ton in Idaho, $10,000/ton in Colorado and Oregon, between $5,000 to $10,000 in Nevada, and between).
[95] 531 F.3d 896, 907 (D.C. Cir. 2008) (requiring EPA to promulgate a rule that "achieves something measurable toward the goal of prohibiting sources 'within the State' from contributing to nonattainment or interfering with maintenance 'in any other State.'").
[96] 75 FR 45305.
[97] *See Wisconsin v. EPA*, 938 F.3d 303, 311 (D.C. Cir. 2019) (noting the assurance provisions in passing, but taking no issue with the approach).

> control period has been assessed, a state's collective emissions have exceeded the applicable assurance level only four times.[98]

Accordingly, the current assurance provisions are both lawful and effective.

The Proposed Rule contains one minor revision to these provisions that remains consistent with the prior precedent by simply allowing for an adjustment to the percent of variability that each state is allowed. While EPA proposes to retain a floor on that variability at 21 percent, EPA also recognizes that greater variability may be needed in some cases to account for the changes underway in the power sector that may significantly alter where and how power is generated. To avoid impeding that transition, EPA allows the variability limit for a state to rise to a level commensurate with any percentage increase in heat input of the state's affected EGUs that exceeds the heat input assumed in calculating the state's budget. This minor revision actually increases flexibility but remains within the bounds of the approach that has worked well before, and BHE supports that change.

However, EPA also seeks to try something entirely new in the Proposed Rule to "enhance" its current assurance provisions. Instead of retaining the proven approach, EPA seeks to add a brand-new secondary emission limitation. The contours of this new secondary limit are complex—if a state exceeds its variability limit (the higher of 21 percent or the adjusted variability limit based on heat input greater than assumed in the budget), any EGUs deemed to have caused that overage (by virtue of exceeding their own allocation by more than the relevant variability limit) become subject to enforcement and penalties if the EGU emits more than 50 tons over what the EGU would have emitted at a benchmark NO_x lb/mmBtu emission rate (defined as the higher of 0.10 lb/mmBtu or 125% above the unit's lowest emission rate in a previous control period).

This new secondary limit is unnecessary and raises significant concerns. Due to the sheer complexity of it, sources are unlikely to be aware of whether they are approaching the limit before the end of the control period, which will be too late to avoid an exceedance. To determine whether an exceedance may occur, EGUs would need to first determine the variability limit for their state, but that determination cannot be made until the end of the control period, since it may depend on whether the total heat input across the state at all affected EGUs exceeded budgeting assumptions by more than 21 percent. Even if the variability limit could be determined with certainty prior to the end of the control period, determining whether a state will exceed that variability limit prior to the end of the period will also be difficult. And even if a state-wide exceedance could be predicted, an EGU would need to predict whether its own emissions will exceed its allowances by more than the applicable variability limit, determine its historical rate to identify the benchmark rate, predict total emissions for the entire control period, and compare the resulting calculation to the 50-ton limit. With all of these moving parts, determining compliance prior to the end of the control period will be impossible.

For all these machinations, EPA provides very little justification for its secondary limit. Despite lauding the success achieved with its prior assurance provisions (from both a legal and practical perspective), EPA suddenly and inconsistently concludes "the assurance provisions' very good

[98] 87 FR 20122 (emphasis added).

historical compliance record is not good enough."[99] EPA's only basis for this conclusion is a reference to isolated examples from two states, Mississippi and Missouri. With regard to Mississippi, EPA recognizes that the historical exceedance of variability limits that triggered the assurance provisions was unintentional; for Missouri, EPA ascribes more deliberate and intentional motives. But even in these cases, the assurance provisions worked as designed—the EGUs involved were required to offset the exceedances of the variability limits by procuring allowances on a 3-to-1 basis, which ensured that overall emissions were actually lower than EPA previously determined necessary to accomplish the ultimate goals of the program.

BHE opposes the proposed secondary emission limitation for the same reasons it opposes the other enhancements that EPA has proposed—they will limit flexibility and impede (if not preclude) market trading without furthering the purpose of its proposal, which is to eliminate significant contributions to downwind receptors. This concern is particularly true for the proposed secondary limit. Since any exceedances of the new limit only trigger enforcement and penalties, not increased allowance holding requirements, the limit seems designed to discourage any exceedances, not remedy them. But the requirements of the limit are so complicated that the risk of a violation will not be known until the control period is already over. Source operators will not be able to alter their behavior without some notice of a need to do so, and the structure of the secondary limit will not provide any notice at all. Source owners are likely to find themselves unexpectedly facing penalties at the end of a control period once the required calculation can finally be run. Because the post-hoc payment of penalties will not affect actual emissions, it is not reasonably related to the purpose of the proposal and should be eliminated.

Since EPA's justification for the secondary limit is focused on a deliberate and intentional shutdown of controls to the point that the variability limits of a state are exceeded, BHE asks EPA to find a way to address that concern without saddling the entire sector with an enhancement of the assurance provisions. As proposed, the secondary limit presents compliance risk with no potential benefit.

4. The Proposed Dynamic Budgeting Process Eliminates Needed Flexibility.

Yet another unnecessary enhancement provided in EPA's proposal is quite literally a moving target. In the proposal, EPA seeks to adopt a dynamic budgeting process that would change a state's NO_x emissions budget each year based on the most recent heat input data available. EPA explains that the dynamic budgeting process is intended to ensure state budgets continue to reflect changes in the population and use of affected EGUs to maintain the stringency level that EPA has deemed is needed to eliminate significant contributions. However, EPA's justification for dynamic budgeting breaks down at its over-control analysis.

As addressed elsewhere in these comments, EPA conducted an over-control analysis based on assumptions about the level of emission reductions that its proposal would achieve in each state. EPA believes, based on that analysis, that the proposal will not result in over control, claiming that even after implementing the requirements in the proposal, all states will continue to exceed the one percent contribution threshold and contribute to at least one downwind nonattainment or

[99] 87 FR 20122.

maintenance receptor. But that analysis is only as good as the assumptions that went into it. If EPA adopts dynamic budgeting, the assumptions underlying the over-control analysis will not hold. Rather, these new moving targets are likely to achieve greater reductions than EPA has evaluated in its over-control analysis, and those greater reductions are then likely to result in over control that EPA has not attempted to evaluate.

As a simplified example, consider a state with two identical 100 MW EGUs that do not already have an SCR. EPA's proposal would require both units to install an SCR and set a state budget based on the assumption that both units will continue to operate and emit at levels consistent with SCR. EPA's over-control analysis thus appears based on the assumption that the state will have two SCR-equipped units in operation. But, if one unit retires, thus cutting total heat input from the two units in half, emission reductions will be significantly greater than EPA assumed.

If in this example the state's budget remains constant, the assumptions in the over-control analysis would continue to hold. Although the retirement of one unit would reduce emissions more than expected the allowances from that unit would remain in the state budget and available for use by the other EGUs, either to operate more to fill the generation gap left by the retired unit or to sell to others seeking to operate and fill that gap. In contrast, dynamic budgeting would confiscate those allowances, essentially codifying the unexpected emission reduction associated with the retirement, a reduction that does not appear accounted for in EPA's over-control analysis. Repeated many times over across all states in the program, these additional reductions will skew the assumptions in EPA's over-control analysis toward greater control than what EPA has evaluated.

BHE encourages EPA to maintain budgets as originally established so that its over-control analysis remains grounded in assumptions that will continue to hold over time. Otherwise, states that transition away from fossil fuels will be penalized by having their budgets cut, and those unanticipated cuts are likely to force reductions well beyond what EPA has evaluated for over control. Stated another way, EPA cannot both claim its proposal will not over control and then require the assumptions supporting that claim to change.

Static budgets have long been accepted practice for trading programs. EPA addressed this point in its preamble to CAIR by recognizing that Congress used static budgets in its Acid Rain Program, the model upon which EPA built its transport rule trading programs:

> Congress decided to allocate title IV allowances in perpetuity, realizing that the electricity sector would not remain static over this time period. Congress clearly did not choose a policy to regularly revisit and revise these allocations, believing that its allocations methodology for title IV allowances would be appropriate for future time periods.[100]

EPA has provided no justifiable reason for differing from the approach preferred by Congress and fails to explain why altering its prior approach is necessary now.

The threat of ratcheted-down budgets also creates the potential for inappropriate disincentives. It encourages states and EGUs to use up all of their allowances by emitting more than needed to

[100] 70 FR 25229.

make sure those allowances will not disappear the next year, and it discourages any efforts to voluntarily reduce emissions through efficiency, innovation, or implementation of renewable resources. Accordingly, BHE asks EPA to eliminate dynamic budgeting in any final ozone transport rule.

Even if EPA decides to finalize its proposed dynamic budgeting approach, BHE asks EPA to make some commonsense changes. First, EPA should use an average of several years in deciding whether a state's budget should be adjusted. Although initial budgets are based on a single year of data, adjustments should only be made if there is a clear indication that a fundamental and permanent shift in the power sector has occurred. To make that determination, EPA should rely on more than just a single year of data, since individual years could be unrepresentative of future years for a variety of reasons, including unusual weather conditions, demand fluctuations, extended outages, unanticipated operational issues, supply chain constraints, or other factors. For instance, a particularly good year for renewable energy with high winds and lots of sunny days could reduce EGU heat input levels, but reducing the budget to that level could leave EGUs without sufficient flexibility to support fluctuations in those same renewable energy resources during a subsequent calm and cloudy year. This need for flexibility and the potential for variation from year to year will only increase with expected increases in renewable energy capacity.

Second, to ensure the moving target of a dynamic budget does not move too erratically, making compliance planning difficult, EPA should adjust a state's budget only when data over a three-year period change beyond a minimal threshold that accounts for natural variability. In EPA's assurance provisions, EPA has already accepted a level of variability of 21 percent, so that same level of variability should be incorporated into the dynamic budgeting process. EPA should also use the same five-year look back and three-year average approach used in unit-level allocations to determine annual state budgets to smooth out variability in total heat input from year-to-year and ensure representativeness. EPA should adjust budgets by less than the total difference in heat input so that the adjustments are gradual and allow time for trends to develop (and potentially reverse).

Finally, EPA should increase the opportunity for stakeholder involvement in any adjustments to state budgets. In the proposal, EPA indicates that the adjustments will be "ministerial actions" that are essentially automatic since they will be based on an established formula.[101] EPA indicates stakeholders will be able to review any adjustments via a notice of data availability that will allow 30 days for comment.[102] Such a limited opportunity for engagement is insufficient. A review period of only 30 days is unlikely to allow enough time for stakeholders, including source operators, to identify and encourage EPA to correct any errors in the calculation, or to develop and present evidence that an adjustment is unwarranted, notwithstanding application of the prescribed adjustment formula.

5. The Proposed Banking Recalibration Confiscates the Value of Early Reductions.

The primary benefit of trading emissions allowances is flexibility, and banking allows flexibility not only across units and states, but across time. It allows facilities to elect to make greater

[101] 87 FR 20115.
[102] 87 FR 20117.

reductions before they are needed to prepare for a time when reductions may be more difficult to achieve. BHE has already demonstrated through its business planning processes a willingness to use operational flexibility to achieve emission reductions. With that flexibility comes a strong incentive for reductions ahead of schedule, hastening the benefits sought by the program in exchange for certainty of compliance in the future. Since only banking, not borrowing, is allowed, the only potential impact of banking is to speed up the reductions; it will never delay them.

Without banking, all reductions must fall in lockstep with the trajectory of the program design, even though progress toward a lower-emitting future rarely proceeds in such a straight-line fashion. Instead, the most efficient path of reducing emissions is often in fits and starts, depending on myriad factors, including the availability of resources, and banking allows the flexibility needed for that most efficient path to occur.

In its discussion of banking, EPA recognizes that it is "generally advantageous to place as few restrictions on the trading of allowances as possible." However, EPA then expresses concern that unrestricted banking "has a potentially significant disadvantage."[103] That disadvantage, according to EPA, is that banking "allows what might otherwise be temporary surpluses of allowances in some individual control periods to accumulate into a long-term allowance surplus that reduces allowance prices and weakens the trading program's incentives to control emissions." Based on this concern, EPA's proposal retains banking, but in a significantly more limited way than all prior emission allowance trading programs. As proposed, the new ozone transport rule would allow affected sources to bank as many allowances as they are able to, through early emission reductions, but any allowances banked beyond 10.5 percent of a state's budget will become worthless at the end of each control period.

EPA's concern over allowance prices and the trading program's incentives to control emissions does not appear well-founded, and it is certainly not well-explained. How a banked allowance converts from a temporary surplus to a long-term surplus is not at all clear since the amount of emission reductions represented by a banked allowance does not grow over time. Regardless of whether an allowance is used or banked, it represents the same quantity of reduced emissions, just at two different points of time, with banked allowances representing a reduction ahead of schedule. The assurance provisions also appear to provide sufficient protection against the concern EPA raises, but EPA does not explain why that protection is insufficient. EPA should provide a better explanation of its concerns before discounting the benefits of banking.

On the contrary, the *dis*incentives created by limiting banking are obvious. Without banking, emission allowances are only valuable if used, so restrictions on banking actually encourage the use of emission allowances, which encourages actual emissions. Thus, EPA appears to have it exactly backwards—it is the new restrictions on banking, not unrestricted banking, that weakens the trading program's incentives to control emissions. Restrictions on banking also hurt the market liquidity that is necessary to stabilize prices and avoid shocks. Without the flexibility to trade across time, some control periods are likely to face more significant price swings, potentially disrupting the orderly and efficient transition that trading is intended to foster.

[103] 87 FR 20109.

EPA argues that its proposal does not actually confiscate the value of allowances but is instead a mere "recalibration" of the bank to "reset the total quantity of banked allowances."[104] But calling its proposal a "recalibration" is mere euphemism. In truth, the proposed banking restriction confiscates allowances and will likely discourage banking in general, as well as the early emission reductions that banking represents. Providing multiple compliance tools in the name of flexibility, only to then restrict the use of those tools so tightly as to render them useless, is not flexibility at all – it is an arbitrary one-size-fits-all approach.

EPA must rethink its proposed restrictions on banking in light of the severe loss of flexibility that would result, particularly in combination with the other program enhancements already discussed above. If EPA nevertheless concludes that banking restrictions are needed, BHE requests EPA to provide an explanation of the actual harm those restrictions on banking are intended to address.

6. The Enhancements Unnecessarily Increase Legal Risk and Uncertainty.

The many enhancements in EPA's proposal also add significant and unnecessary legal risk and uncertainty because they raise new issues and concepts not previously tested in court. EPA claims the "proposed rule adheres closely to the legal and analytical framework that the EPA has applied in the past,"[105] but in fact, the enhancements are brand new and untested. And history shows they will be tested.

Each time EPA has adopted a new interstate transport trading program, the D.C. Circuit has accepted some of the changes, while rejecting others. For example, in *Michigan v. EPA*, while the court generally upheld EPA's NO_x SIP Call method of relying on cost effectiveness in determining a state's significant contribution, the court held that EPA failed to properly explain how some states were linked to downwind air quality problems.[106] In *North Carolina v. EPA*, the court identified so many flaws in CAIR that the court vacated the entire rule before reconsidering its decision at the request of parties and remanding it without vacatur. Those flaws included the lack of assurance that reductions would occur within the state contributing to downwind air quality issues, the lack of an analytical method for addressing maintenance areas, and the failure to meet statutory deadlines for downwind attainment or explain why they were impossible to meet.[107] In a remand from the Supreme Court of the original CSAPR, the D.C. Circuit held in *EME Homer City v. EPA* that EPA had unlawfully over controlled some states.[108] And in *Wisconsin v. EPA* and *New York v. EPA*, the court upheld some aspects of EPA's CSAPR update and close-out rules, including its over-control analysis, but held that the rules did not fully resolve the transport problems EPA had identified and that a partial solution was not acceptable.[109]

This judicial track record provides plenty of direction to EPA on how to establish a lawful and effective trading program to address interstate transport. It also confirms that new ideas from EPA

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[104] 87 FR 20109.
[105] 87 FR 20036, 20041.
[106] 213 F.3d 663, 676–85 (D.C. Cir. 2000).
[107] 531 F.3d 896, 907, 910-911 (D.C. Cir. 2008).
[108] 795 F.3d 118, 132 (D.C. Cir. 2015).
[109] 938 F.3d 303, 318-320 (D.C. Cir. 2019); 781 Fed. Appx. 4, 6-7 (D.C. Cir. 2019).

often founder in court. When that happens, both the environment and the regulated community suffer while EPA resolves the resulting uncertainty.

Rather than staying within the guardrails clearly set in judicial precedent, EPA is testing many new ideas in the proposal. The new enhancement concepts EPA has crafted unnecessarily present legal risks that are likely to generate significant uncertainty during the inevitable legal challenges to come. Even if EPA is ultimately successful in defending its enhancements, the short time allowed for compliance will require actions before the enhancements can be fully vetted in court, raising the risk of stranded costs for any sources left with no choice but to fall in line until the court review is completed.

BHE asks EPA to recognize that the legal risks it is taking with the new enhancements it has proposed would impose a cost on the industries it seeks to regulate. Unless EPA can better justify its conclusion that these enhancements are needed to accomplish the purpose of the program—eliminating significant contribution to downwind ozone nonattainment and maintenance areas—BHE asks EPA to consider adopting a program more clearly within the lines of what the D.C. Circuit has already reviewed and endorsed. In particular, BHE asks EPA to confirm that the enhancements it has proposed are not intended to accomplish purposes outside of the scope of EPA's authority under the good neighbor provision of the Clean Air Act.

C. Additional Flexibility Should Be Incorporated into Other Key Aspects of the Proposed Rule.

As discussed above, flexibility is critical to the success of a market-based trading program and the additional constraints on flexibility inherent in EPA's enhancements will likely stifle the market for allowances, robbing affected sources of the ability to choose their path to compliance based on unit-specific considerations regarding cost, feasibility, and other factors. However, even if those enhancements are eliminated, there are other aspects of EPA's Proposed Rule that should be reexamined to ensure that the rule accounts for state- and unit-specific considerations, while still accomplishing the goal of reducing the impacts of upwind activity on downwind nonattainment and maintenance.

1. States Should Be Provided More Flexibility to Prepare SIPs that Depart from the Proposed Rule as Long as Those SIPs Achieve Necessary Reductions.

BHE supports state authority to adopt a SIP to replace the FIP and recognizes the states' ability to ensure their SIP contains adequate provisions to prevent significant interference with attainment or maintenance of the NAAQS in a downwind state. The good neighbor provision, at its core, is a state obligation. It is codified in Section 110 of the Clean Air Act, which is the section granting states the primary decision-making authority for developing SIPs to achieve the NAAQS. EPA's role under section 110 is to review and approve those plans, not to substitute its own policy preferences or decisions for those made by the states. As long as a state's plan is reasonable and

complies with the requirements of the Clean Air Act, EPA must approve it. The D.C. Circuit has repeatedly endorsed this cooperative federalism approach codified in Section 110.[110]

The D.C. Circuit and the U.S. Supreme Court have confirmed in litigation over EPA's prior transport rules that EPA has authority under Section 110 to set the basic parameters of what states must do to comply with the good neighbor provision. Those courts have also confirmed that EPA may issue a FIP only if a state's SIP is deemed to be insufficient based on EPA's parameters. In addition, provisions in the Proposed Rule dictate SIP requirements not found in the CAA and essentially eliminate any reasonable opportunity for states to make a future SIP submission. EPA has undermined the central principles underlying both Section 110 and the Administrative Procedure Act by rejecting state good neighbor SIPs that *were* based on EPA's own guidance at the time those SIPs were written. For some states like Nevada, Utah, and Wyoming, EPA did not even propose to reject those SIPs until *after* it had already proposed a federal implementation plan with explicit requirements specifically targeted at those states. Even if EPA ultimately cures its failure to observe the proper sequencing of responding to a state SIP before proposing a FIP, its actions run roughshod over the states' primary role in addressing nonattainment under Section 110 and suggest that EPA never gave the state SIP submittals a considered review, preferring instead to impose its own solution, in violation of legal principles. Agency action "must be timely, and it must be taken objectively and in good faith, not as an exercise in form over substance, and not as a subterfuge designed to rationalize a decision already made."[111]

EPA has now disavowed its prior guidance without allowing states an opportunity to react. In doing so, EPA has claimed for itself the authority Congress granted to states, not to EPA. EPA attempts to paper over this role reversal by saying that states can always prepare a SIP later for EPA approval. BHE supports the opportunity for states to submit their own SIP to replace the proposed FIP, but unless EPA can approve the SIP prior to finalizing the Proposed Rule, the Proposed Rule will nevertheless force covered sources to begin compliance efforts almost immediately due to the incredibly tight timeframes in the rule. The tight deadlines for compliance in the Proposed Rule will essentially eliminate any reasonable opportunity for states to develop and EPA to approve a SIP in accordance with EPA's new approach to interstate transport unless EPA can commit to a more rapid review and approval process than it has conducted in the past.

For EPA's recognition of the states' authority to submit a replacement SIP to have any real meaning, EPA would need to move at least as quickly in reviewing and approving replacement SIPs as it has moved in imposing the federal plan contained in the Proposed Rule. In addition, states would need sufficient time to develop a replacement SIP, which would require the same kinds of complex analyses EPA conducted to develop the Proposed Rule. In the past, EPA has provided states sufficient time to implement the good neighbor provision via their own SIPs[112], and BHE asks EPA to do the same in this instance.

Regardless of timing, EPA should also acknowledge state authority to re-evaluate steps 3 and 4 of EPA's four-step methodology by identifying and implementing the measures needed to eliminate what EPA has defined to be a significant contribution to downwind receptors, rather than requiring

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[110] *Train v. NRDC*, 412 U.S. 60 (1975); *Union Elec. Co. v. EPA*, 427 U.S. 246 (1976); *Fla. Power & Light Co. v. Costle*, 650 F.2d 579 (5th Cir. 1981).
[111] *Metcalf v. Daley*, 214 F.3d 1135, 1142 (9th Cir. 2000).
[112] *See* 84 FR 3389, 3390 (Feb. 12, 2019).

states to demonstrate that their measures, along with federal measures, will achieve reductions commensurate with installation of SCR on coal-fired EGUs by the 2026 ozone season.[113] States are uniquely positioned to identify the right mix of requirements for the unique emission sources in their jurisdictions and to determine how best to align those requirements with other regulatory efforts that target some of the same units and pollutants, like regional haze. As long as a state can submit modeling to show that emission reductions from sources in its state will eliminate the downwind impact that EPA has defined as significant, its SIP should satisfy the requirements of the good neighbor provision and EPA must approve it.

2. BHE Supports Generation Shifting as a Market-Based Strategy to Cost-Effectively Reduce Emissions, but EPA Should Not Mandate Generation Shifting.

As EPA has recognized in the Proposed Rule, generation shifting can help reduce emissions in a cost-effective way. In fact, operating lower-emitting facilities in lieu of higher-emitting facilities is precisely what makes emission allowance trading work. Units able to cost-effectively reduce their emission rates with emission controls free up allowances for purchase by units for which controls may not be cost effective. That exchange of value is then taken into account by the electricity market via economic dispatch of generating units based on their marginal cost. The end result is both lower emissions and generation of electricity at the lowest cost under the regulatory constraints imposed to achieve EPA's emission reduction goals. Markets make generation shifting adjustments automatically without the need for dictates from regulatory authorities. Accordingly, BHE supports EPA's recognition of the value of generation shifting and the use of a market to efficiently allocate resources in reducing emissions from the power sector.

However, EPA's proposed methodology for setting state emission allowance budgets converts predicted market-based generation shifting into a regulatory mandate. Instead of recognizing that generation shifting can and will occur via the market to minimize costs, EPA has attempted to predict how much generation shifting *should* occur, based on various assumptions, and has manually adjusted state budgets to *force* that generation shifting to occur. Specifically, EPA used its Integrated Planning Model (IPM) to project shifts in utilization of affected sources in response to its Proposed Rule and then altered the calculation of state budgets for 2023 and 2024 to expressly require those predicted shifts.

For example, in Wyoming, EPA calculates a need for 9,559 allowances[114] in both 2023 and 2024, based on heat input, emission rates, control installations, and changes in the composition of the EGU fleet. But EPA then applies a factor based on its IPM-predicted generation shifting which reduces those budgets to 9,125 in 2023 and 8,573 in 2024. These reductions indicate that EPA believes generation will shift away from Wyoming by about 10% in 2023 and about 10% in 2024, so EPA determined to force that generation shifting to occur.

These required emission reductions fly in the face of how generation shifting decisions work in the market. Unlike generation shifting that occurs naturally through market forces, the generation shifting predictions that EPA has factored into its proposed state budgets for 2023 and 2024 are

[113] 87 FR 20151.

[114] BHE believes this amount is lower than the correct allowances that Wyoming should receive for 2023 and 2024. *See* Section IV.C.

hard wired into the rule based on information available today. But EPA's attempt to force generation shifting is less likely to provide the most efficient result, since EPA's generation shifting factor is static and cannot adjust to future circumstances that are likely to be different than EPA's assumptions. BHE requests EPA to eliminate generation shifting assumptions from its state budget calculation methodology.

BHE also asks EPA to reconsider aspects of its Proposed Rule that would inhibit generation shifting as a means of compliance. As noted elsewhere in these comments, EPA's regulatory impact analysis predicts the retirement of a significant amount of coal and gas steam generating capacity, as much as 22,000 MW combined. The task of replacing the dispatchable generation lost due to those retirements will likely fall to a large extent on gas-fired combustion turbines. However, under EPA's proposed emission allowance allocation methodology, those units will only receive, at most, the number of allowances equal to their historical ozone season NO_x emissions. That cap on allowances will prevent the increased utilization of combustion turbines to replace lost generation capacity. Gas turbines used to meet increased demand in the wake of coal and gas steam retirements are thus likely to face difficulty complying with the Proposed Rule, even though EPA has determined that additional controls are not cost-effective for these units. This concern is exacerbated by EPA's proposed dynamic budgeting process, which will reduce state budgets by the amount of any retirements, rather than allowing those allowances to remain available to units that must increase operations to meet the demand that can no longer be served by the retired units. BHE asks EPA to alter its proposed allowance allocation methodology to avoid inhibiting the shifting of generation to gas turbines that will be needed in light of the vast number of coal and gas steam EGU retirements EPA estimates will be caused by its Proposed Rule. BHE also asks EPA to recognize that its dynamic budgeting approach will inhibit generation shifting as yet another reason this proposed "enhancement" should be abandoned.

Additionally, BHE questions the accuracy of the IPM results underlying EPA's generation shifting assumptions. That model, like all models, is only an approximation and cannot be expected to provide results as accurate as an active, real-time market will provide. Moreover, EPA's IPM in particular has potential flaws, including (1) the inability of the model to account for the timing and granularity of generation and load, a concern particularly relevant to the integration of renewable and thermal generating resources, and (2) the inability of the model to account with sufficient granularity localized transmission constraints that can materially impact how energy production might shift among affected EGUs real world. EPA's IPM is also difficult to fully evaluate since EPA has not made the model fully available to the public.

In short, BHE opposes EPA's attempt to force generation shifting through assumptions based on its IPM. Instead, BHE asks EPA to allow market forces to provide for generation shifting when most efficient and cost effective for reducing emissions.

3. Due to the Inflexibility of the Proposed Rule, a Safety Valve Is Needed.

The Proposed Rule significantly constrains compliance options for affected units. For example, any one of the many enhancements addressed above has the potential to constrain allowance trading to the point that a functioning market may not develop, and when all proposed enhancements are considered, it is almost certain to have that effect. Without allowance trading as

a compliance mechanism, sources will be forced to install controls that are not cost-effective or simply cannot be installed on EPA's suggested time frame, or both, which in turn will force unit retirements, as EPA itself anticipates. This lack of compliance flexibility translates to a lack of operational flexibility that will challenge resource adequacy. And by leaving too few compliance options available, the Proposed Rule will threaten the reliability of the entire electricity system in the West.

When reliability concerns have been raised in the past in response to proposed rules with the potential to significantly impact the operational flexibility of the EGUs upon which the nation's bulk power system relies, EPA has considered the possibility for a limited safety valve. BHE asks EPA to adopt a safety valve for this rule, particularly given the breadth and untested nature of EPA's many enhancements to the trading program and in light of the aggressive compliance timeline. A safety valve could take many forms. For example, in the Clean Power Plan, EPA's final rule provided for a "reliability safety valve for individual sources where there is a conflict between the requirements the state plan imposes on a specific affected EGU and the maintenance of electric system reliability in the face of an extraordinary and unanticipated event that presents substantial reliability concerns."[115] The safety valve in the Clean Power Plan allowed a 90-day grace period during which a reliability-critical unit would be excused from compliance, allowing time for the unit owner and the state to develop a long-term solution through a revision to the state plan. EPA adopted that safety valve to "ensure the absence of adverse energy impacts" "where the built-in flexibilities are not sufficient to address an immediate, unexpected reliability situation."[116] While the CPP was never implemented, the safety value concept it included was reasonable and sound.

Most recently, EPA adopted a safety valve mechanism for the Revised CSAPR Update issued just last year that allowed the conversion of Group 2 to Group 3 allowances at a higher conversion ratio to help facilitate development of a viable market to support the Group 3 program. The stated purpose of that safety valve was to "further ensure allowance market liquidity and compliance flexibility."[117]

In footnote 293 of the Proposal, EPA states that it "is not proposing to create a 'safety valve mechanism' in this rulemaking analogous to the safety valve mechanism established under the Revised CSAPR Update," but EPA offers no explanation for that decision, and BHE asks EPA to reconsider and reverse it. A safety valve could prove critical if the lack of flexibility caused by EPA's many overlapping enhancements, combined with its mistaken assumptions about the cost-effectiveness and timing for SCR, lead to challenges that threaten the reliability of the electric system.

[115] 80 FR 64671.
[116] *Id*. at 64748, 64827.
[117] 86 FR 23137.

4. BHE Supports an Extension of Proposed Rule Requirements for EGUs Retiring by 2028.

BHE supports EPA's consideration of an extension of the currently proposed backstop limit that will take effect in 2027 for EGUs expected to retire in 2028. Specifically, EPA states the following in the proposal:

> EPA also recognizes that several coal-fired EGUs have been considering retirement by 2028 under compliance pathways available under Clean Water Act effluent guidelines and the coal combustion residuals rule under the Resource Conservation and Recovery Act. 2028 also represents the end of the second planning period under the Regional Haze program, and thus is a significant year in states' planning of strategies to make reasonable progress towards natural visibility at Class I areas. To facilitate a potentially economic and environmentally superior unit-level compliance response across these programs that nonetheless maintains the NO_x reductions required by the state budgets from 2026 forward in this proposed rule, the EPA is requesting comment on potentially deferring the application of the backstop daily rate for large coal EGUs that submit written attestation to the EPA that they make an enforceable commitment to retire by no later than the end of calendar year 2028.[118]

BHE supports this approach. However, BHE urges EPA to go further. As the rule is currently drafted, statewide ozone season allowance budgets, and thus individual unit allocations, will be significantly reduced for the 2026 ozone season to reflect EPA's assumption that SCR can be installed by that date. However, both state budgets and individual unit allocations should reflect the reality that SCR will not be installed on units that are scheduled to retire in 2028, as that technology will not be cost-effective due to the limited remaining useful life. It is nonsensical for EPA to propose extending the 2027 backstop limit without recognizing that units retiring by 2028 will simply not be able to meet their reduced 2026 allowance allocations without installation of SCR.[119] Accordingly, BHE strongly encourages EPA to retain pre-SCR emission level assumptions for units slated to retire in 2028 through the end of the 2028 ozone season in order to avoid unnecessarily constricting statewide budgets and negatively impacting both retiring units and non-retiring units. As EPA alluded to in its request for comments, aligning requirement timelines in the Proposed Rule with requirements in other federal rules is logical and allows for aligned compliance planning.

As EPA indicates, and as described in greater detail above, the utility sector is undertaking a decades-long reorganization that will fundamentally alter the resources utilized to generate electricity in this country. That transition needs time to work. Without an extension of SCR-forcing requirements to at least 2028, EGUs scheduled for retirement in or before that critical year to satisfy other rules will have to choose among incurring significant penalties for noncompliance, investing massive, stranded costs for installing controls to operate for only a few years, or early forced retirement with insufficient time to procure replacement resources and install critical transmission system upgrades, any of which would upset the orderly transition underway. A delay

[118] 87 FR 20122 (emphasis added and notes omitted).
[119] *See* Section II.B.

to 2028 for those units already scheduled to close on or before that date is a reasonable accommodation to avoid the highly negative impacts that would otherwise result from forcing units to install controls or retire on an earlier schedule.

5. The Requirement to Install LNB by 2023 Is Too Tight.

BHE requests that EPA provide a buffer for the requirement to install state-of-the-art combustion controls by 2023. While it is theoretically possible to install LNB within 10 months (meaning the process must begin immediately, before the Proposed Rule is finalized), this timeline presumes perfect execution of all required steps. BHE requests EPA to provide some type of allowance for units that make a good faith effort to install the required controls but may not achieve full compliance by May 2023. For example, perhaps some additional allocations or state budget adjustments could be provided for units that demonstrate additional time is justified to complete the installation for reasonably unavoidable delays or reliability considerations.

III. Non-EGUs: Pipeline Transportation of Natural Gas

BHE supports EPA's decision not to apply the CSAPR allowance trading program to non-EGUs, including reciprocating internal combustion engines (RICE) in the pipeline transportation of natural gas industry. Since non-EGU industries are more heterogeneous and less interconnected than EGUs, development of a trading program within or across these industries would be much more difficult and less likely to return any real efficiencies or benefits. Therefore, to the extent EPA determines that emission reductions from non-EGUs are needed to address interstate transport, BHE supports the use of more traditional emission reduction strategies based on the application of available and cost-effective control technologies and compliance flexibility.

BHE also supports EPA's decision to focus its regulation of pipeline RICE on NO_x emissions, not volatile organic compounds (VOCs) because the vast majority of the country is NO_x-limited for ozone formation.[120] As a result, regulating VOCs will not appreciably affect ozone concentrations.

However, the proposed requirements for natural gas pipeline RICE need significant improvement. In particular, EPA should reevaluate the current makeup of the existing fleet of RICE used in the pipeline transportation of natural gas, as EPA appears to have significantly underestimated the number of units to which the new requirements would apply. EPA should also consider changing the form of the proposed requirement to provide additional and necessary compliance flexibility. BHE offers several ideas, discussed below, for reducing the burden of the new requirements for pipeline RICE while still accomplishing the air quality goals of the Proposed Rule.

A. EPA Should Raise the Applicability Threshold for Pipeline RICE.

The Proposed Rule would apply new limits on NO_x emissions from pipeline RICE with a maximum rated capacity of 1,000 horsepower (hp) or greater. While BHE agrees that an applicability threshold is warranted, BHE does not believe that 1,000 hp is an appropriate threshold for several reasons described in more detail below.

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[120] 87 FR 20053.

1. The Applicability Threshold of 1,000 HP Is Not Justified.

As EPA notes in the preamble to the Proposed Rule, as well as in its TSDs, the 1,000 hp applicability threshold is based on a screening level that EPA used to approximate units likely to emit more than 100 tpy of NO_x. However, nowhere in the preamble or TSDs does EPA explain why 100 tpy is an appropriate threshold for identifying units warranting regulation. The preamble and TSD recognize that 100 tpy is below the 150 tpy screening threshold for non-EGUs that EPA relied on in the recent Revised CSAPR Update, but EPA offers no explanation for adopting the lower threshold.[121]

Unlike the 100 tpy threshold EPA used in the Proposed Rule, the 150-tpy threshold in the Revised CSAPR Update had a logical and well-explained basis. In a TSD for the Revised CSAPR Update, EPA provided the following explanation:

> EPA included units with pre-control NOx emissions > 150 tpy, which is an emissions threshold comparable to 25 MW for EGUs used in prior interstate transport rulemakings. To derive this emissions threshold, we used emissions expected from an average 25 MW EGU unit operating at a median heat rate, emission rate, and capacity factor for a coal-fired unit.[122]

In other words, EPA used pre-control NO_x emissions as a surrogate for converting the 25 MW capacity threshold for EGUs into a capacity threshold for evaluating non-EGUs. Since a typical 25 MW EGU would be expected to emit 150 tpy of NO_x, that emissions threshold served as an equivalent screening threshold for non-EGUs.

EPA nowhere explains why it chose to "broaden[ ] the scope" of its assessment in the Proposed Rule by reducing the threshold from 150 tpy to 100 tpy. In doing so, EPA captured a greater number of smaller RICE, but without providing any basis for its new approach. Since agency decisions are only lawful if they are rational and well-reasoned, BHE asks EPA to return to its 150 tpy threshold so that RICE are regulated on an equal footing with EGUs.

Although EPA did not explain why it chose 100 tpy as the screening level for non-EGUs, EPA did explain how it decided that pipeline RICE greater than 1,000 hp would be likely to emit more than that 100 tpy threshold. To make that conversion, EPA assumed that pipeline RICE emit at an uncontrolled emission rate of 16.8 grams per horsepower hour (g/hp-hr) and that such engines typically operate for 7,000 hours per year. With those assumptions, EPA determined that an 800 hp engine would hit 100 tpy, and EPA apparently rounded up to 1,000. EPA also compared this result to the National Emissions Inventory (NEI) and identified 200 engines above 1,000 hp that had emissions above 100 tpy, while only two engines smaller than 1,000 hp reported emissions above 100 tpy.[123]

Unfortunately, many of the assumptions EPA relied upon appear to be inaccurate. As an initial matter, BHE is concerned with EPA's reliance on the NEI to determine which engines emit more

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[121] 87 FR 20083, n. 163.
[122] EPA Technical Memorandum: Assessing Non-EGU Emission Reduction Potential – Update for Final Rulemaking, at 9 (Mar. 12, 2021).
[123] *Non-EGU Sectors TSD*, at 4 (Dec. 2021).

than 100 tpy because the NEI is prone to overestimation.[124] Second, even though EPA identified 200 engines above 1,000 hp that reported emissions over 100 tpy, EPA does not explain whether that relatively small subset of engines represents the bulk of the industry. For example, if there were 2,000 engines above 1,000 hp that reported emissions below 100 tpy, then the fact that only 200 emitted above that level would suggest the opposite of what EPA concluded. The fact that only two engines less than 1,000 hp reported emissions over 100 tpy likewise does not say much about the total population of engines.

Third, BHE disagrees with EPA's assumptions regarding emissions and operating hours for typical pipeline RICE. While EPA assumes an uncontrolled emission rate of 16.8 g/hp-hr, the vast majority of pipeline RICE today already have some built-in control measures, since EPA standards have required manufacturers to include those measures since the early 2000s. While an uncontrolled emission rate may have made sense when EPA first used it in an evaluation underlying the 2004 NO_x SIP Call Phase II final rule, it is no longer a rational means of evaluating the inherent emission characteristics of the vast majority of engines today. For example, BHE GT&S estimates that 90% of its fleet of engines operates well below EPA's assumed emission rate of 16.8 g/hp-hr and notes that most of those units are limited by their air permits to 3.0 g/hp-hr or less. Northern Natural Gas similarly estimates emission rates are well below 16.8 g/hp-hr. In fact, even EPA's AP-42 emission factors for pipeline RICE, which are typically conservative, indicate emissions are well below 16.8 g/hp-hr. For example, EPA's NO_x emission factor for four-stroke Lean burn (4SLB) engines is listed as high as 4.08 lb/mmBtu, depending on engine load, which is the highest lb/mmBtu emission factor listed in AP-42 for any type of RICE. That rate converts to 4.748 g/hp-hr, which is just over a quarter of the 16.8 g/hp-hr rate EPA relied upon in determining the appropriate applicability threshold for RICE in the Proposed Rule.

EPA's assumption regarding typical operating hours for a pipeline RICE of 7,000 hours per year is similarly off-base. BHE GT&S engines greater than 1,000 hp operate, on average, around 2,200 hours per year, a fraction of what EPA assumed. Northern Natural Gas RICE also operate well below 7,000 hours per year. EPA's own TSD even cites two different sources of information on RICE units indicating that average operating hours are 2,000 and 3,000 hours a year, respectively, but EPA instead relies on a third source that assumes 7,000 operating hours a year, without explaining its decision to do so.

By overestimating emission rates and operating hours, EPA has underestimated the size of pipeline RICE that would be expected to emit more than 100 tpy NO_x annually. Stated another way, if EPA had assumed a more realistic lower emission rate and average hours of operation, it would have concluded that only engines much larger than 1,000 hp are likely to emit at the level EPA deemed appropriate for regulation.

2. Because EPA Has Underestimated the Number of Pipeline Engines, It Must Re-Do Its Over-Control and Cost-Effectiveness Analyses.

As discussed in comments submitted by the Interstate Natural Gas Association of America (INGAA), EPA's estimates of the number of RICE units in the pipeline transportation of natural

[124] *See, e.g., Why do Models Overestimate Surface Ozone in the Southeast United States?*, Katherine Travis, et. al, *Atmos. Chem. Phys.* (Nov. 2016).

gas industry that would be covered by the Proposed Rule is out of line with the number of units that meet the 1,000 HP threshold industry-wide. While EPA's estimates show that 307 engines would be covered, there are actually more than 1,000 units that would become subject to the Proposed Rule at a threshold of 1,000 hp. BHE's individual pipeline companies have noted similar disparities in the number of engines EPA claims would be covered versus the number that actually meet the 1,000 hp threshold. Northern Natural Gas, for example, has 33 engines greater than 1,000 hp, but EPA only identifies 16 as being covered by the proposal.

Because EPA has *underestimated* the population of engines to which its proposal would apply, EPA has also *underestimated* the emission reductions its proposal will require. Accordingly, EPA's over-control analysis is based on underestimated emissions, which suggests that over-control is more likely to occur than EPA's analysis would indicate.

This point is particularly important for Wyoming. In this case, EPA noted a "potential over-control finding" if it assumes downwind emission reductions of commensurate stringency with upwind emission reductions, consistent with its past practice.[125] Using this assumption, the last affected downwind receptor for Wyoming, which is located in Colorado, is estimated to achieve attainment and maintenance of the ozone standard after full application of emission reductions from the EGU sector, meaning that no emission reductions from the non-EGU sector would be necessary. If emission reductions from the non-EGU sector are underestimated, as BHE believes, this would tip the over-control analysis for Wyoming, which is already borderline for inclusion of non-EGUs based on EPA's own analysis, even further away from being regulated by the non-EGU requirements in the proposal. Furthermore, as noted elsewhere in these comments, nothing in the recent *Maryland v. EPA* decision that EPA cites for its decision to include Wyoming non-EGUs in the proposal precludes EPA from assuming that Colorado will be taking its own steps to address ozone nonattainment near Denver. Based on its underestimate of emission reductions from pipeline RICE in Wyoming and its failure to account for downwind emission reductions in its over-control analysis, EPA should conclude that regulating non-EGUs in Wyoming will result in over-control and remove this state from the non-EGU requirements of its proposal.

EPA's underestimate of the population of pipeline RICE that would be affected by the Proposed Rule translates to an underestimation of the cost of required emission reductions to the industry. BHE urges EPA to reevaluate the total cost of its proposal using a more accurate count of the pipeline engines to which it will apply.

3. Raising the 1,000 HP Threshold to at least 2,000 HP Could Achieve Similar Reductions with Less Cost and Impact to the Industry.

Because EPA set an inappropriately low applicability hp threshold for RICE engines in the pipeline transportation of natural gas industry, while also underestimating the emission reductions to be achieved at that hp threshold, EPA should raise the hp threshold from 1,000 hp to at least 2,000 hp. This can occur without sacrificing the emission reductions EPA expects to achieve with the Proposed Rule. Doing so would provide the same environmental benefits at much lower cost to industry.

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[125] 87 FR 20099.

BHE recommends EPA use a screening threshold for non-EGUs of 150 tpy to be more consistent with the approach taken in previous CSAPR rules and to ensure parity between EGUs and non-EGUs. But even without returning to a 150 tpy benchmark, more representative assumptions on emission rates and operating hours, EPA could justify a hp higher applicability threshold. For example, BHE believes that EPA's emission rate and operating hour assumptions are both at least double what they should be. Therefore, if EPA corrects even one of these unrepresentative assumptions, the hp applicability threshold would, at a minimum, double as well.

Even at a higher hp applicability threshold, the Proposed Rule would likely apply to more engines than EPA currently expects because the population of pipeline RICE is much larger than EPA has indicated. As a result, the emission reductions required by the Proposed Rule would likely be greater than what EPA has assumed, but the proposal would only affect a smaller population of engines.

B. The Controls EPA Has Identified for Pipeline Transportation of Natural Gas RICE Are Not Achievable at All Units by 2026.

BHE has carefully evaluated the control measures that pipeline RICE would need to achieve the proposed NO_x limits and identified significant concerns regarding the availability of these controls and whether they could be installed before the 2026 ozone season. BHE believes EPA has vastly underestimated the amount of time necessary to retrofit existing units and failed to account for ongoing supply chain constraints and delays, both of which combine to make the proposed compliance timeframe unattainable.

Because EPA's proposal, as drafted, would affect over 1,000 units, it will impose an unprecedented strain on the supply chain for RICE NO_x controls. The types of control devices called for in the proposal—SCR, non-selective catalytic reduction (NSCR), and layered combustion—are not off-the rack, generic controls that can be installed on any given engine regardless of its age or other characteristics. Rather, these controls are unit-specific and must be tailored to engine vintage, type, cycle, size, and other specific attributes, all of which vary widely across BHE's fleet and across the industry. For example, BHE is aware of only two vendors that supply the high-pressure fuel injection systems that would be required on some units.

Compounding these concerns are the global supply chain constraints and nationwide labor shortages that could severely limit the availability of parts and equipment, as well as the workforce to design, install, and calibrate these new controls. Additionally, there is no evidence in the Proposed Rule that EPA considered what impacts a massive cross-industry effort to install controls on RICE would have on the reliability of the natural gas pipeline transmission system. To install the controls required to meet the emission limits established in the Proposed Rule, hundreds of pipeline RICE would need to come offline during a very short window of time, which would negatively impact reliability. BHE encourages EPA to take into account these reliability concerns, as well as concerns regarding availability and timing of controls installation, by revisiting its assumptions regarding the time frame over which it expects a large swath of the pipeline RICE fleet in affected states to install new controls.

C. Most of EPA's Proposed Limits Are Achievable.

If provided sufficient time to install controls, BHE believes that the emission limits in the rule are achievable with one exception: for 2SLB engines, the proposed 3.0 g/hp-hr limit may not be achievable by all of the RICE to which it would apply. BHE has evaluated its fleet of pipeline RICE and determined that most of those engines should be able to achieve the 3.0 g/hp-hr limit using layered combustion, which BHE understands to include turbocharging and high-pressure fuel injection.

However, given the wide range in vintage, size, and model of engines across the fleet, some uncertainty remains as to whether layered combustion will be sufficient to achieve the proposed emission limits at all BHE's engines because layered combustion is not a one-size-fits-all technology. Furthermore, the notion of layering multiple combustion controls is not proven across the wide variety of units within the BHE fleet. While the concept that additional controls will produce additional emission reduction benefits sounds good in theory, combustion controls functionally change the combustion parameters of the units on which they are employed — essentially amounting to an engine redesign. Since BHE has not attempted to layer these types of controls on each of the unique engines in its fleet, it simply cannot evaluate whether this is a viable control strategy. Accordingly, BHE asks EPA to consider a possible exception, particularly for 1960-vintage units and earlier, in the form of a site-specific emission limit based on testing following installation of the controls upon which EPA has based its proposal. That approach is appropriate because neither BHE nor EPA can determine at this time whether the proposed limit is achievable by such engines.

Finally, while BHE appreciates EPA's effort to seek all relevant information by requesting comment on alternative limits, BHE does not support a more stringent limit for four-stroke rich burn (4SRB) engines. Specifically, BHE opposes EPA's alternative limit of 0.5 g/hp-hr because significant uncertainty remains as to whether the control technology EPA chose for 4SRB engines—NSCR—can achieve 0.5 g/hp-hr across all units.

D. The Compliance Monitoring and Testing Proposed for Natural Gas Pipeline RICE is Overly Burdensome and Unnecessary.

The Proposed Rule would require semi-annual performance testing for non-certified units, as well as continuous monitoring, via either continuous parametric monitoring systems (CPMS) or continuous emissions monitoring systems (CEMS) for all affected RICE. As is detailed below, BHE does not believe CEMS are cost-effective and discourages EPA from imposing semi-annual performance testing requirements on non-certified units.

The costs associated with CEMS and frequent performance testing on affected RICE would be as much, if not more, than the costs associated with installation and operation of some of the control technologies EPA has considered in setting the proposed emission limits. However, EPA did not consider the significant expense associated with these compliance demonstration requirements in determining whether the proposal would be cost-effective for pipeline RICE. EPA expressly acknowledges that monitoring, testing, and recordkeeping costs are not reflected in its $7,500/ton control cost estimates, confirming it has not taken the substantial costs of demonstrating

compliance into account, despite the focus on cost-effectiveness as the key factor in determining the scope and stringency of the Proposed Rule.

EPA cites a total estimated cost of $11.45 million for monitoring, testing, and compliance at *all* affected non-EGU sources across several different industries.[126] Based on BHE's assessments regarding the potential costs for its own fleet, BHE believes this estimate to be well below actual costs to be borne by the pipeline industry alone. Accordingly, BHE asks EPA to reconsider its proposed compliance demonstration methods to avoid unnecessary costs and to incorporate the cost of all the requirements it plans to impose in determining whether the Proposed Rule is cost-effective.

1. CEMS Are Cost-Prohibitive for RICE and May Be Infeasible.

EPA has requested comment on whether it is feasible or appropriate to require pipeline RICE rule to be equipped with NO_x CEMs instead of requiring performance tests to demonstrate compliance with applicable emission limits. BHE strongly opposes the former approach. CEMS are not in general used on RICE in pipeline transportation of natural gas or any other industry. Based on BHE's research, CEMS may not even be feasible for some types of engines, and, even if feasible, the cost for installing and operating CEMS on any engine would be exorbitant. BHE estimates that the cost to design and install CEMS on a single engine would be about $350,000, which does not include ongoing costs for operation and maintenance of the system or costs for consumables, like calibration gas, that are necessary for operation of the system.

In addition to cost, there are other barriers to installing CEMS on RICE across the natural gas pipeline industry. Because these systems are not widely used for RICE, there are only a limited number of units even available for purchase, and BHE has determined that lead times for obtaining and installing a unit are currently about 40 weeks. Even if BHE were able to obtain CEMS, there are significant hurdles associated with operating these units on RICE. Many RICE in the natural gas pipeline industry are located at remote, unstaffed locations, meaning that there would be no staff available to respond and react to communication or alarms from CEMS. Additionally, because CEMS are in limited use in the industry, there are a limited number of third-party technicians available to assist in maintenance or repair of these systems. BHE expects that there could even be shortages of calibration gas if CEMS were implemented across the industry, as this would represent a relatively sudden and vast expansion of the number of CEMS in use on industrial sources. In fact, BHE GT&S is already experiencing extended lead times for certain calibration gases used in its portable monitoring systems, as well as shortages of the small aluminum cylinders used for those gases.

A requirement for all pipeline RICE greater than 1,000 hp to install and operate CEMS would be unnecessarily burdensome. EPA has provided no justification to demonstrate that CEMS are necessary to ensure proper operation of engines and their control systems and requiring CEMS would represent a significant departure from all prior practice in regulating these relatively low-emitting units. BHE encourages EPA to recognize that RICE have been regulated for decades without the need for CEMS, and that there is no justifiable reason for requiring CEMS now.

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[126] Technical Memorandum: Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026 (Feb. 28, 2022), at p. 8, n. 24.

2. BHE Supports EPA's Proposal to Rely on Manufacturer Certifications, but EPA Should Limit the Frequency of Performance Testing for Uncertified Engines.

As currently proposed, pipeline RICE that have been certified by the manufacturer to comply with EPA's proposed emission limitations may demonstrate compliance with those standards primarily by maintaining that certification through following manufacturer-recommended operation and maintenance practices. BHE agrees with this approach because it is consistent with the way EPA has regulated these types of engines in the past[127], and EPA has provided no justification for altering that longstanding approach now.

For non-certified RICE, EPA proposes to require performance tests to demonstrate that the engines will meet the applicable emission limits. However, the proposal would require testing far more frequently than currently required. While current federal RICE rules require owners and operators of non-certified engines to, at most, "conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first,"[128] EPA's proposal would require testing twice a year.

Such frequent testing would impose significant additional costs on the industry and is entirely unnecessary because past practice has shown that emission rates from RICE experience very low variability over time, and thus continuous emission monitoring is unnecessary, so long as operating parameters remain within manufacturer specifications. EPA has already proposed continuous parametric monitoring that will be capable of confirming the engines and emissions controls operate within the design parameters that will ensure good performance of the emission control systems. EPA's proposal for semi-annual performance testing is particularly inappropriate for an ozone-season program because it could inadvertently require units to run solely for the sake of testing during that season, unnecessarily increasing emissions, or it would require testing outside of the season to which the relevant limits apply.

Despite the lack of any real benefit, the cost of semi-annual testing would be significant. For companies that conduct their own performance testing, semi-annual testing requirements for all units in their fleet over 1,000 hp would require upfront capital costs for acquiring additional equipment necessary to conduct the testing. BHE GT&S, for example, estimates an additional cost of $400,000 per year to comply with the proposed testing requirements.

At a minimum, EPA must consider these costs, and similar costs that would be imposed industry-wide, in deciding which compliance demonstration methods to require. Given these costs, BHE strongly encourages EPA to follow the approach already used in current RICE rules of an initial performance test followed by subsequent tests at 8,760 hours of operation or three years, whichever occurs first. That frequency of testing, combined with continuous parametric monitoring (addressed in more detail below), should be more than sufficient to ensure emission control systems demonstrate good performance during the ozone season. BHE also encourages EPA to confirm that portable analyzers may be used to conduct any testing that is required by the Proposed Rule.

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[127] *See e.g.*, 40 C.F.R. § 60.4243(a)(1).
[128] 40 C.F.R. § 60.4243(a)(2)(iii).

Finally, BHE requests EPA to adopt reduced testing frequency for units with performance test results at or below 50% of the applicable emission limit. EPA has adopted similar provisions in the past for other industries, including in the hazardous air pollutant rule for EGUs.[129] Since pipeline RICE emit at much lower and more consistent rates, EPA should extend to them at least the same flexibility offered low-emitting EGUs.

3. BHE Supports the Use of CPMS.

BHE supports continuous parametric monitoring (CPMS) to demonstrate compliance with the emission limitations in the proposed ozone transport rule. BHE currently relies on parametric monitoring for many of its engines and thus has experience with that approach to demonstrating compliance. In many cases, the needed equipment and procedures are already in place.

However, BHE requests flexibility in the parameters EPA proposes to be monitored, as the number and type of specific parameters subject to monitoring could significantly impact feasibility and cost of the CPMS required. For units that will install SCR or NSCR, BHE understands that EPA proposes daily monitoring of inlet temperature and monthly monitoring of the pressure drop across the catalyst, consistent with current Subpart ZZZZ monitoring requirements for units subject to that standard. However, not all units are subject to the Subpart ZZZZ monitoring requirements because some units comply with Subpart ZZZZ through compliance with Subpart JJJJ and some units are not subject to either rule. Therefore, EPA should only impose monitoring requirements directly relevant to ensuring proper operation of the controls its proposal would require. In particular, BHE does not believe that monitoring of the pressure drop across the catalyst is relevant to the performance of natural-gas fired engines, as natural gas results in much less fouling of the catalyst than is typically experienced in diesel and gasoline-fired engines, like those regulated under Subpart ZZZZ. Accordingly, BHE encourages EPA to limit parametric monitoring for units with SCR and NSCR to daily monitoring of inlet temperature to confirm proper operation of the catalyst.

For units that do not employ SCR or NSCR, the rule requires development of a site-specific monitoring plan. BHE supports this approach since it will allow for the development of a monitoring program best-suited to each individual unit.

E. BHE Encourages EPA to Allow Emissions Averaging for Pipeline RICE.

As noted above, there are significant disparities in engine characteristics across the BHE fleet, and some of the NO_x control technologies selected by EPA in establishing emission limits for pipeline RICE are largely untested at some types of units. Accordingly, compliance flexibility should be allowed to account for units where the installation of controls is either infeasible or cost-ineffective. While BHE agrees with EPA's determination that including non-EGUs in the trading program is not the best approach to allowing compliance flexibility, emissions averaging will allow the needed flexibility without the complexity of trading.

Specifically, BHE recommends that EPA allow intra-state emissions averaging across all pipeline RICE owned or operated by the same company, as allowed under similar EPA and state programs. For example, in the NO_x SIP Call, EPA encouraged states to allow owners and operators of large

[129] *See, e.g.*, 40 CFR 63.10005(h)(1)(i).

internal combustion engines the flexibility to achieve the required NO_x tons/season reductions by selecting from among a variety of technologies or combinations of technologies, recognizing that "flexibility would be helpful as companies take into account that individual engines or engine models may respond differently to control equipment."[130] EPA acknowledged that "some individual engines that install the controls would be expected to be above and some below the average control level, simply because it is an average." States have successfully incorporated NO_x emissions averaging into their own rules for pipeline RICE as well.[131]

Since the emission limitations in the Proposed Rule are expressed in g/hp-hr, the calculation of an intra-state fleet-wide NO_x limit with a weighted average for different unit types should be relatively straightforward. EPA should also consider whether to allow companies to choose a mass-based alternative that would ensure emission reductions align with the tons per year reductions upon which EPA based its significant contribution and over-control analyses. Either approach would allow companies to choose, based on the individualized characteristics of the units within their fleets, how best to accomplish the emission reductions that are required to eliminate their state's significant contribution to downwind air quality issues. Given that EPA's analysis of how to eliminate those downwind contributions is made on a state-wide basis, rather than on emissions from individual units, BHE urges EPA to recognize that intra-state emissions averaging and the compliance flexibilities it offers to an industry composed of heterogenous engines is appropriate in the context of EPA's ozone transport rule.

F. Emergency Engines Should Be Excluded from the Rule.

BHE strongly encourages EPA to exclude emergency engines in the final rule. Doing so would not only be consistent with other regulations applicable to RICE, but it would also be more consistent with EPA's applicability analysis, which assumes RICE will operate for 7,000 hours a year, something emergency engines are prohibited from doing by federal regulation. Currently, emergency generators are exempt from requirements applicable to non-emergency RICE under both relevant NSPS (Subparts IIII and JJJJ), as well as the relevant NESHAP (Subpart ZZZZ). And for good reason—the units are only authorized to operate for 100 hours per year for maintenance, readiness testing, and other non-emergency purposes. Although the standards EPA has adopted for emergency RICE do not limit the amount of time they may run for emergency purposes, EPA has recognized in the past that states may assume a maximum of 500 hours of operation to estimate the "potential to emit" in issuing air permits for emergency RICE.[132]

Since RICE that qualify as emergency engines under other currently applicable standards only operate for emergencies or for a few hours at a time to periodically conduct regular maintenance, their emissions are low and accordingly, their contribution to the ozone transport issues EPA's proposal seeks to address is negligible. Pipeline engines that qualify as emergency RICE under Subparts JJJJ or ZZZZ should be excluded from the final rule entirely. Alternatively, if EPA remains concerned with the level of operation of emergency RICE during ozone season, BHE asks

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[130] NO_x SIP Call Phase II Final Rule, 77 FR 21621.
[131] *See e.g.,* Texas Rule § 116.779(b)(3) and Tennessee Rule 1200-03-27-.09(6)(v).
[132] EPA Memorandum from John Seitz, *Calculating Potential to Emit (PTE) from Emergency Generators* (Sept. 6, 1995).

EPA to allow only limited operation of emergency engines during the ozone season for purposes other than an emergency.

G. Units That Do Not Operate During the Ozone Season Should Be Excluded From the Rule.

BHE and many of its counterparts in the pipeline transportation of natural gas industry operate some RICE that would be subject to the Proposed Rule based on their size even though they only operate during the winter months and do not operate at all during the ozone season. These winter-peaking units operate only to meet demand on extreme winter system demand days. Since winter-peaking RICE do not operate during the ozone season, owners and operators of these engines should not be subject to limits designed to reduce NO_x emissions during the ozone season. BHE asks EPA to include provisions in the final rule to confirm that RICE subject to an enforceable requirement that prohibits operation during the ozone season are excluded from the ozone transport rule.

IV. Technical Corrections and Clarifications

BHE has identified a number of data and technical errors in the Proposed Rule that significantly impact its affected facilities. BHE asks EPA to correct these errors and account for the corrected information in setting final baseline emissions, state allocations, and unit distributions.

A. Budget Allocation Determinations Should Be Based on the Average of at Least Three Years of Actual Data.

The Proposed Rule establishes state budgets based on the actual heat input for each individual EGU during a single ozone season, which will cause inaccuracies based on single season anomalies and outliers. Under the procedures outlined in the Proposed Rule, the 2023-2024 state budgets are based on 2021 ozone season actual heat inputs, and 2025 budgets and beyond will be based on the heat input from the ozone season two years prior to the budgeted year. This methodology is flawed. If a facility has a scheduled or forced outage during the ozone season, the decrease in heat input due to the outage will limit the state budget two years later in a way not representative of future operations and emissions. For example, PacifiCorp's Naughton Unit 1 had a scheduled maintenance outage that ended May 29, 2021, which significantly reduced the unit's ozone season heat input used to determine Wyoming's state allocations for 2023. That unrepresentative outcome would continue under EPA's current methodology, penalizing companies for outages that occur during ozone season, even though the emission reductions and repairs that result from those outages further the purpose of the Proposed Rule.

BHE believes that the use of a single year to establish the 2023 allocation is short-sighted and unfair. It does not correctly account for routine events that should not penalize a unit or a state's budget. A methodology where state budgets are based on an average of the three highest heat inputs from the past five years during the ozone season will better represent actual operations and smooth out variations that occur year-to-year due to both routine outages and unexpected upsets or other unavoidable operating conditions.

B. NV Energy

1. Corrections to Table VI.C.1-1-EGU Ozone-Season Emissions and Reduction Potential (tons) – 2023 to Account for Fort Churchill Unit 2 and Existing SCRs.[133]

The Baseline 2023 Ozone Season NO_x column lists Nevada as having 2,346 tons. This value is in error as it wrongfully omits Fort Churchill Unit 2 (ORISP 2330) from the 2023 baseline. The Proposed Rule considers NV Energy's Fort Churchill Unit 2 retired for a given budget year (e.g., as of January 1, 2023, for 2023 budgets) and EPA did not determine allocations for Fort Churchill Unit 2 as an existing unit. Fort Churchill Unit 2 was operational in 2021 and furthermore will not be retired as of January 1, 2023. Neither the Air Markets Program Data (AMPD) nor the Energy Information Administration (EIA) survey form 860 has the unit retiring until 2028 at the earliest.

The 2021 ozone season NO_x emissions and corresponding heat input from Fort Churchill Unit 2 in 2021, as listed in the Clean Air Markets Division – AMPD database was 111.045 tons. This value should be added to the Nevada baseline of 2,346 tons to set a revised baseline of 2,457 tons (i.e., 2,346 plus 111). In addition, for purposes of unit allowance allocations, the table below shows Fort Churchill Unit 2 baseline heat input equal to the average of the 3 highest years from 2017-2021.

Table 2: Fort Churchill Unit 2 Average Heat Input

Year	Heat Input (mmBtu)
2018	1,875,065
2020	1,885,671
2021	1,860,836
Average	1,873,857

Adding this average value to the current 2023 proposed baseline of 108,449,874 mmBtu equates to 110,323,731 mmBtu.

The SCR optimization column, and in Nevada's case, all following columns, shows a reduction potential in tons for varying levels of technology inclusion. The Nevada value shown is 66 tons. Table VI.C.1-1 is misleading as the technology column headings refer to "potential" reductions. However, in Nevada's case, the 66 tons listed is the sum of all current units with SCR controlled to 0.08 lb/mmBtu or less. These reductions have already been realized and should not be subtracted from the Nevada budget. As a result, the new and correct baseline for Nevada should be 2,523 tons, which is the sum of the proposed baseline (2,346 tons), the missing Fort Churchill Unit 2 emissions (111 tons), and potential reductions (66 tons)

2. Ozone Season 2024 and 2025 Control Period

According to Table VII.B.3-1 of the Proposed Rule,[134] Nevada will likely see the addition of eight affected units, including Clark Generation Station Units 4-8, Nevada Solar One, and Saguaro Units CTG1 and CTG2. Using EPA's ozone season heat input and NO_x emission rates, the NO_x

[133] *See* 87 FR 20088.
[134] *Id.* at 20114 and 20115.

emissions for these units is equal to or greater than 140 tons. BHE understands the eight units were not initially included by EPA because the applicability criteria for the Acid Rain Program and the Group 3 trading program are not identical. Since these units do not report to the Acid Rain Program, they appear to have been overlooked. However, EPA also relies on EIA data, where correctly reported information indicates the eight identified units meet the Group 3 trading program applicability requirements.

The proposed Nevada ozone season 2024 NO_x budget is 2,230 (without the corrections identified above). This proposed budget reflects an increase of 87 allowances and incorrectly represents the 2021 ozone season NO_x emissions of 141 tons using EPA's Table VII.B.3-1 heat input values and NO_x emission rates. Once these eight units are included in the budget, the Nevada ozone season 2024 NO_x budget will be an additional 54 allowances short, on top of the shortage identified above. This again will cause an immediate decrease in operation and/or purchase of NO_x allowances to cover shortages. BHE requests the Nevada budget allocation be revised and unit distribution recalculated to account for EPA's mathematical errors.

3. EPA Should Recalculate Tracy Unit 6's 2026 Unit Allocations and Nevada's State Budget

NV Energy's Tracy Generating Station includes Unit 6, a 107 MW natural gas-fired combined cycle turbine. The "Unit-Level-Allocations-and-Underlying-Data-For-The-Proposed-Rule" Excel workbook[135] shows that Tracy Unit 6 goes from 136 tons of emissions in 2021 – assuming a 167-ton 5-year maximum and a 167-ton 2024/2025 allowance allocation – to a 66-ton allowance allocation for the 2026 control period (as shown in the "Underlying Data for FIP" tab). The proposed 2026 Tracy Unit 6 allocation of 66 tons equates to an emission rate of 0.07 lb/mmBtu. However, this emission rate does not agree with the table referenced in section 97.1010 (a)(iii)(A) that lists an emission rate of 0.151 lb/mmBtu. BHE requests the Tracy Unit 6 allowances for 2026 be recalculated using the 2021 heat input and the 0.151 lb/mmBtu emission rate, thus yielding 136 tons.

C. PacifiCorp

1. Potential Technical Errors in Proposal – Appendix A Proposed Rule State Emissions Budget Calculations and Engineering Analytics[136]

Some 2023 allocations appear to result from the assumption that LNB/OFA have not been installed for Hunter Unit 3 and Naughton Unit 1. Both units currently utilize LNB/OFA. Additional corrections are also requested for the Jim Bridger Units 1 and 2 and the Dave Johnston Unit 1.

i. Utah Hunter Unit 3

Hunter Unit 3's historic NO_x baseline emissions indicate a value of 2,178 tons and the 2023 allocation indicates 1,777 tons. This reduction appears to result from a projected 2023 NO_x rate of 0.26 lb/mmBtu upon the installation of BART (i.e., LNB/OFA) or other EPA limits. PacifiCorp

[135] *See* https://www.epa.gov/system/files/documents/2022-03/proposal-appendix-a-proposed-rule-state-emission-budget-calculations-and-engineering-analytics.xls.
[136] EPA-HQ-OAR-2021-0668-0133.

installed LNB/OFA[137] on Hunter Unit 3 in 2008 and has a permitted NO_x limit of 0.34 lb/mmBtu.[138] Hunter Units 1 and 2 also have LNB/OFA installed and are of similar heat input capacity to Unit 3. However, Units 1 and 2 are tangentially fired, while Hunter Unit 3 is wall-fired. Hunter Units 1 and 2 are permitted at a lower 0.26 lb/mmBtu NO_x rate. The different boiler configurations result in the different NO_x rates, but all three Hunter units are equipped with LNB/OFA. BHE requests that EPA reevaluate the Utah budget to account for Hunter Unit 3's NO_x rate and adjust the 2023 and 2024 ozone season allocations to reflect these controls.

ii. Wyoming Naughton Unit 1

Naughton Unit 1's historic NO_x baseline emissions indicate a value of 588 tons, and yet the 2023 allocation indicates only 312 tons. This reduction appears to result from an assumed requirement for this unit to install LNB/OFA. However, Naughton Unit 1 has already installed LNB/OFA.[139] BHE requests that EPA reevaluate the Wyoming budget to remove the LNB/OFA reduction for Naughton Unit 1's 2023 and 2024 ozone season allocations to reflect this information.

iii. Wyoming Jim Bridger Units 1 and 2.

The 2014 Wyoming Regional Haze SIP required installation of SCR on Jim Bridger Units 1 and 2 by December 31, 2022, and December 31, 2021, respectively. However, current orders by both Wyoming[140] and EPA[141] authorize continued coal-fired operation of these units in 2023 and subsequent revision of the Wyoming SIP to reflect future conversion to natural gas. BHE requests the 2023 allocations be adjusted to reflect coal-fired operation.

iv. Wyoming Dave Johnston Unit 1 should be rated at a capacity of 93 MW

EPA lists Dave Johnston Unit 1 with a capacity greater than 100 MW. However, the most recent data indicates the correct capacity during ozone season is 93 MW.[142] BHE asks EPA to correct the capacity of Dave Johnston Unit 1 and adjust the associated allocations for Wyoming accordingly.

D. BHE Pipeline Group

As indicated in Section III.A.2, above, EPA failed to identify numerous engines operated by the BHE Pipeline Group that would nonetheless be covered by the proposal if EPA retains its current 1,000 hp applicability threshold. BHE requests EPA to ensure that its analyses regarding the number of engines impacted by the rule are adjusted to accurately reflect the individual units that would be covered, regardless of the applicability threshold that EPA ultimately selects.

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[137] Utah DEQ Division of Air Quality Approval Order DAQE-AN0102370012-08.
[138] Hunter Title V Permit No. 1500101004.
[139] Wyoming Department of Environmental Quality BART Permit MD-6042.
[140] Wyoming Consent Decree, Docket No. 2022-CV-200-333 (February 14, 2022).
[141] In the matter of PacifiCorp - Jim Bridger Power Plant, Administrative Order on Consent, EPA Region 8 Docket No. CAA-08-2022-0006, June 9, 2022.
[142] EPA used 2018 summer net capacity values to establish unit capacities, as indicated in needs-v6_01-24-2022-2 and EPA-HQ-OAR-2021-0668-0133. The 2018 EIA 860 Report lists Dave Johnston Unit 1 as 105 MW. However, the 2019 – 2021 EIA 860 Reports list the generator summer net capacity value of Dave Johnston Unit 1 as 93 MW.

E. BHE Renewables.

1. EPA should account for capacity factors and ease or eliminate requirements for SCR optimization.

EPA did not consider a unit's actual historical capacity factor when it assumed that existing SCR on combined cycle units could be optimized. Optimization of existing SCR on combined cycle combustion turbines to consistently achieve 0.012 lb/mmBtu, irrespective of the unit capacity factor, is unreasonable. Appendix A of the Proposed Rule[143] assumes BHE Renewables' Cordova Unit 1 can optimize SCR even though it achieves 0.012 lb/mmBtu (2019-2021 average) at 48% capacity factor. EPA also assumes that BHE Renewables' Saranac Units 1 and 2 can optimize SCR based solely on average NO_x emissions in 2019-2021 of 0.03 lb/mmBtu, without respect to the fact that the capacity factor during those years was only 1%. EPA should consider the capacity factor of a unit with existing SCR prior to determining whether that unit should be required to optimize the existing SCR. BHE Renewables' experience in operating these facilities indicates that units at such low capacity factors cannot further optimize operation of SCR to "consistently achieve" EPA's assigned best-in-class emission factor of 0.012 lb/mmBtu.

2. EPA Should Recalculate the C.R. Wing Cogeneration Units 1 and 2 Allocations and Texas' State Budget.

Although EPA is not proposing retrofit technology breakpoints for combined cycle combustion turbines, EPA is driving additional emission controls for the combustion turbine units covered in Group 3 trading program that are not equipped with SCR retrofit control technology. Such units would have an incentive to reduce emission consistent with the ozone season NO_x allowance price.[144] BHE Renewables' C.R. Wing Cogeneration Units 1 and 2 currently have steam injection for NO_x control and based on the review of the underlying data for the Proposed Rule,[145] C.R. Wing unit-level ozone is reduced to 111 tons per unit equates to an average NO_x emission rate of 0.108 lb/MMBtu for 2023 allocations and further reduced to 43 tons per unit equates to a NO_x emission rate of 0.04 lb/MMBtu for 2026 allocations. However, this emission rate does not agree with the table referenced in section 97.1010 (a)(3)(iii)(A) that lists an average emission rate of 0.108 lb/mmBtu for C.R Wing Unit 1 and 2 (0.100 lb/mmBtu for Unit 1 and 0.116 lb/mmBtu for Unit 2). EPA in its "EGU NOX Mitigation Strategies Proposed Rule TSD" and "Combustion Turbine NO_x Control Technology Memo" states that "for combined cycle facilities originally built without SCR, if extra space in the HRSG was not dedicated for the future AIG and catalyst, it may be impossible to retrofit the facility with SCR." Given the post-combustion retrofit constraints and that C.R. Wing Unit 1 and 2 contribute to only 0.15 % of Texas state ozone season heat input, EPA should revise C.R. Wing Cogeneration Unit 1 and 2 Ozone season 2026 allowances from 43 tons to 111 tons and adjust the state budget accordingly.

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[143] *See* https://www.epa.gov/system/files/documents/2022-03/proposal-appendix-a-proposed-rule-state-emission-budget-calculations-and-engineering-analytics.xls.

[144] 87 FR 20082, 20095.

[145] *See* https://www.epa.gov/system/files/documents/2022-03/unit-level-allocations-and-underlying-data-for-the-proposed-rule.xlsx.

Exhibit A: Ramboll Report

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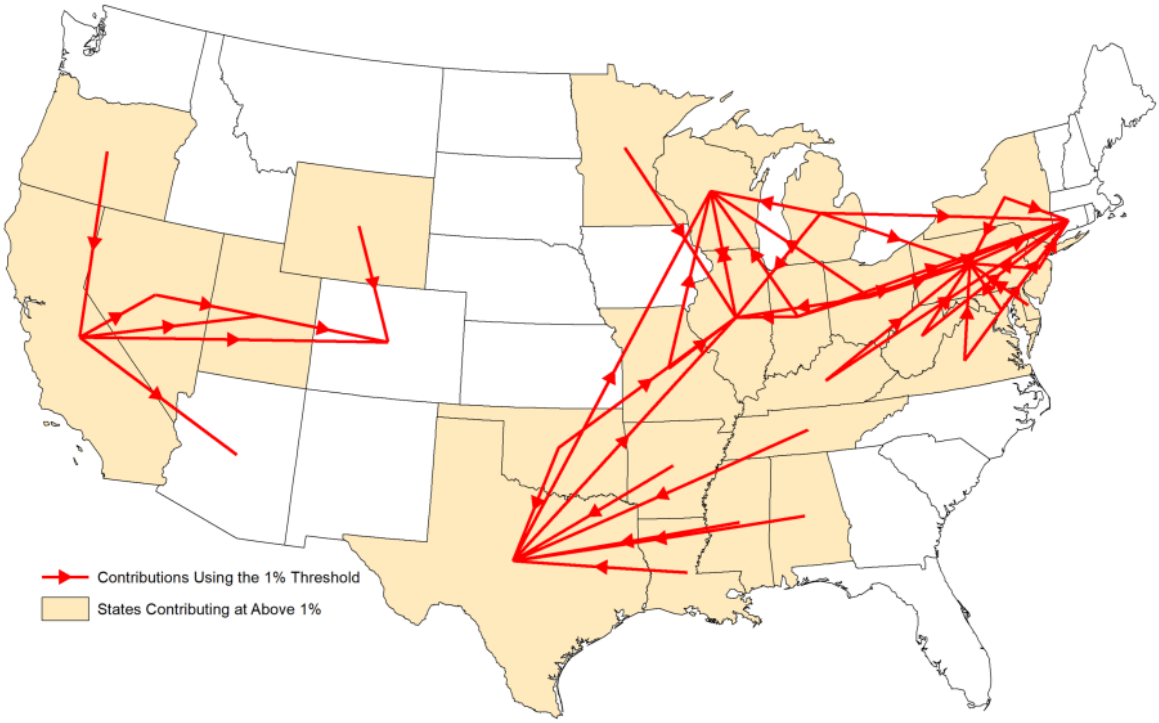
June 2022
1690027139

EVALUATION OF UTAH AND WYOMING OZONE CONTRIBUTIONS IN EPA'S PROPOSED GOOD NEIGHBOR PLAN FOR THE 2015 OZONE NAAQS



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Evaluation of Utah and Wyoming Ozone Contributions in EPA's Proposed Good Neighbor Plan for the 2015 Ozone NAAQS

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1.0 INTRODUCTION

EPA released initial information on the proposed Good Neighbor Plan for the 2015 ozone NAAQS (the "Proposed Transport Rule") via an EPA webpage[1] on February 28, 2022 and has subsequently added additional information. The Proposed Transport Rule was published on April 6th in the Federal Register[2] that started a 60 day comment period with comments to be received by June 6, 2022 that was extended to June 21, 2022.[3] The Proposed Transport Rule would reduce NO_X emissions in 26 upwind states to assist downwind states in achieving the 70 ppb 2015 ozone National Ambient Air Quality Standard (NAAQS). This is the latest Cross State Air Pollution Rule (CSAPR[4]) issued by EPA to satisfy the Good Neighbor provision in §110 of the Clean Air Act (CAA) to address emissions controls on upwind states that are found to contribute significantly to nonattainment or interfere with maintenance of attainment in a downwind state. Previous versions of Transport Rules were the 1997 NO_X SIP Call, 2005 CAIR, 2011 initial CSAPR, 2016 CSAPR Update, 2018 CSAPR Close-Out and 2021 Revised CSAPR Update. Each state must submit to EPA a "Good Neighbor" State Implementation Plan (SIP) (also called the interstate transport prong of the Infrastructure SIP[5]) within 3 years after a new NAAQS is promulgated. The Proposed Transport Rule would disapprove the affected states Good Neighbor provisions in their Infrastructure SIPs and replace them with a Federal Implementation Plan (FIP).

EPA's new Proposed Transport Rule expands both the geographic extent of their transport rules as well as the sources that are proposed for control. For the first time, states in the western U.S. are part of a transport rule with California, Nevada, Utah and Wyoming all included in the Proposed Transport Rule for NO_X emission controls on their sources. Past transport rules have addressed emission controls on Electrical Generating Units (EGUs) to address interstate transport of ozone and fine particulate matter ($PM_{2.5}$). The new Proposed Transport Rule also proposes to control NO_X emissions from certain industrial sources that are not EGUs (non-EGU sources) in some states.

1.1 Purpose

Ramboll Environment and Health (legal name Ramboll US Consulting, Inc.) is under subcontract to AECOM to analyze EPA's Proposed Transport Rule for PacifiCorp. PacifiCorp operates several fossil-fueled Electrical Generating Units (EGUs) in Utah and Wyoming, both of which were included for NO_X controls in the Proposed Transport Rule. The analysis will review, quality assure, evaluate and determine whether EPA conducted the air quality modeling and analysis correctly that determined Utah and Wyoming contributed significantly or interfered with maintenance of the 2015 ozone NAAQS at a downwind state receptor.

[1] https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaq
[2] https://www.federalregister.gov/documents/2022/04/06/2022-04551/federal-implementation-plan-addressing-regional-ozone-transport-for-the-2015-ozone-national-ambient
[3] https://www.govinfo.gov/content/pkg/FR-2022-05-12/pdf/2022-10124.pdf
[4] https://www.epa.gov/csapr
[5] https://www.epa.gov/air-quality-implementation-plans/infrastructure-sip-requirements-and-guidance

1.2 EPA's Proposed Good Neighbor Plan for the 2015 Ozone NAAQS Technical Approach

EPA has developed a four-step process to address interstate transport that has been used in their transport rules and other transport analysis (e.g., evaluation of Section 126 petitions[6]) that have been sustained by the Courts for central and eastern U.S. ozone nonattainment and maintenance areas. The four-step transport framework was used in the Proposed Transport Rule and consists of the following steps:

1. EPA evaluates whether a downwind receptor (monitoring site) is expected to have nonattainment or maintenance issue in the relevant future year(s).
2. EPA determines if an Upwind State is "linked" to the downwind nonattainment/maintenance receptor(s) by contributing above a significance threshold to a downwind nonattainment/maintenance issue.
3. For states linked to a downwind state nonattainment/maintenance receptor, EPA identifies highly cost-effective emission controls in the Upwind State.
4. EPA then may fashion a rule directing states to adopt plans to implement the identified controls.

Generally, the Proposed Transport Rule would establish emission reductions of oxides of nitrogen (NO_X) in linked Upwind States for:

> EGUs: NO_X emissions budgets requiring fossil-fueled Electrical Generating Units (EGUs) in 25 upwind states to participate in allowance-based ozone season trading program beginning in 2023 with additional control requirements/retrofits by the 2026 ozone season.
>
> Non-EGUs: NO_X emission limits for certain other industrial stationary sources in 23 upwind states with a proposed compliance date of 2026. Source sectors covered are:
>
> - Reciprocating internal combustion engines in pipeline transportation of natural gas.
> - Kilns in concrete and cement production facilities.
> - Boilers and furnaces in iron and steel mills and ferroalloy manufacturing.
> - Furnaces in glass and glass product manufacturing.
> - High-emitting, large boilers in basic chemical manufacturing, petroleum and coal products manufacturing, and pulp, paper and paperboard mills.

[6] https://www.epa.gov/ground-level-ozone-pollution/new-york-section-126-petition

Figure 1-1 displays the EGU and non-EGU NO_X emission reductions during the summer ozone season (May-September) in the Proposed Transport Rule in 2026 relative to emissions in 2021.

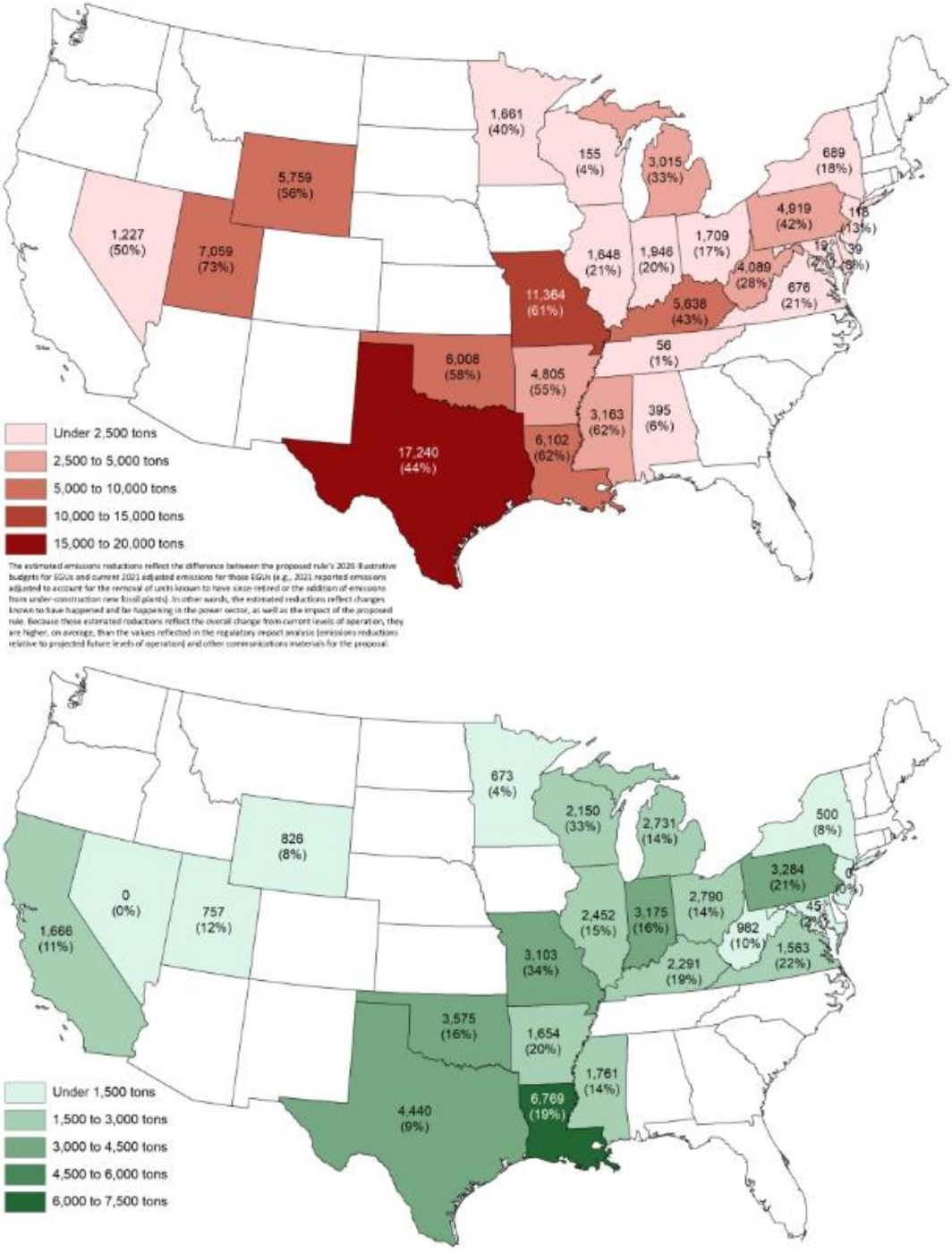

Figure 1-1. Proposed Transport Rule ozone season (May-Sep) NO_X reductions in 2026 relative to 2021 for the EGU (top) and EPA-selected non-EGU (bottom) source sectors (Source: https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs).

1.3 Application of Four-Step Transport Framework in the Proposed Transport Rule

Below we summarize how the four-step transport framework was applied in the Proposed Transport Rule.

1.3.1 Step 1 – Identification of Nonattainment/Maintenance Receptors

The Comprehensive Air Quality Model with extensions (CAMx[7]; Ramboll, 2020) photochemical grid model was used with EPA's 2016v2 modeling platform and the 2016, 2023 and 2026 emission scenarios to project 2023 and 2026 ozone design values (DV) at monitoring sites throughout the 48 contiguous states in the U.S. The procedures in EPA's current ozone modeling guidance (EPA, 2018) were used to project the observed base year ozone design value (DVB) to obtain the future year design value (DVF). EPA's recommended DV projection procedures use the CAMx modeling results in a relative fashion to scale the observed DVB to obtain the projected DVF. The model derived scaling factors are called Relative Response Factors (RRFs) and are the ratio of the future to current year CAMx Maximum Daily 8-hour (MDA8) ozone concentrations near the monitor averaged over the 10 highest MDA8 ozone days in the CAMx 2016 base case. For example, for projecting the 2023 future year DVF:

$$RRF_{2023/2016} = \Sigma\ CAMx\_Ozone_{2023} / \Sigma\ CAMx\_Ozone_{2016}$$

$$Ozone\ DVF_{2023} = Ozone\ DVB \times RRF_{2023/2016}$$

By near the monitor, the highest CAMx 2016 base case MDA8 ozone in a 3x3 array of grid cells around the monitor is used to define the highest 10 days and averaged for the denominator in the RRF. The same 10 days and grid cell in the 3x3 array of grid cells is used when developing the numerator in the RRF (i.e., average across 10 days of CAMx 2023 modeling results).

EPA guidance (EPA, 2018) recommends using an observed base year DVB based on an average of three observed ozone design values over 5-years centered on the base modeling year, which for 2016 would be as follows:

$$DVB_{2014\text{-}2018} = (DV_{2014\text{-}2016} + DV_{2015\text{-}2017} + DV_{2016\text{-}2018})$$

The Proposed Transport Rule 2023 and 2026 ozone DVF projections that are based on the projecting the $DVB_{2014\text{-}2018}$ is called the average DVF (AvgDV):

$$AvgDV_{2023} = DVB_{2014\text{-}2018} \times RRF_{2023/2016}$$

The Proposed Transport Rule also uses a projected future year maximum DVF (MaxDV) that projects the maximum of the 3 ozone DVs during the 2014-2018 5-year period:

$$MaxDV_{2023} = Max(DV_{2014\text{-}2016}, DV_{2015\text{-}2017}, DV_{2016\text{-}2018}) \times RRF_{2023/2016}$$

[7] https://www.camx.com/

The Proposed Transport Rule uses the projected future year 2023 and 2026 AvgDV and Max DV design values and the observed design value during 2018-2020 ($DV_{2018\text{-}2020}$) to define monitoring sites that are nonattainment or maintenance receptors in the 2023 and 2026 future years (EPA, 2022):

- Nonattainment receptors have future year AvgDV and MaxDV as well as observed $DV_{2018\text{-}2020}$ all above the 2015 ozone NAAQS (i.e., ≥ 71.0 ppb).
- Maintenance receptors have future year MaxDV above the 2015 NAAQS and either future year AvgDV below and/or observed $DV_{2018\text{-}2020}$ below the 2015 ozone NAAQS.

1.3.2 Step 2 – Determination of Which Upwind States Have a Significant Contribution so are Linked to a Nonattainment/Maintenance Receptor

EPA conducted CAMx 2023 and 2026 state-specific Anthropogenic Precursor Culpability Assessment (APCA[8]) ozone source apportionment modeling to estimate the contributions of an Upwind State's anthropogenic NO_X and VOC emissions to projected 2023 and 2026 ozone design values at nonattainment/maintenance receptors in downwind states. EPA used a significant contribution threshold of 1 percent of the 70 ppb ozone NAAQS (i.e., 0.70 ppb). If an Upwind State had a contribution of 0.70 ppb or higher to a nonattainment/maintenance receptor in a downwind state, then the Upwind State was "linked" to the nonattainment/maintenance receptor and was subject to the "cost effective" controls determined in Step 3. The state ozone contribution metric was defined using a Contribution Factor (CF) that is defined as the ratio of the average of the state ozone contribution to the average of the total ozone for the 10 highest CAMx 2023 maximum daily average 8-hour (MDA8) ozone concentrations days at the nonattainment/maintenance receptor. The CF was then multiplied by the future year DVF value at the receptor to obtain the Upwind State's ozone contribution to the receptor. Section 1.4 below shows an example state ozone contribution calculation used in the Proposed Transport Rule for the Wyoming Upwind State and Denver-Chatfield receptor linkage.

1.3.3 Step 3 – Determine Cost-Effective Control for Upwind State's Linked to a Nonattainment/Maintenance Receptor in a Downwind State

EPA developed an Air Quality Assessment Tool (AQAT) that is a linear spreadsheet tool using the CAMx 2023 and 2026 state-specific ozone contributions to downwind ozone DVFs to relate changes in a state's NO_X emissions to changes in ozone DVFs at receptors. The 2026 version of AQAT was calibrated using a CAMx 2026 30% EGU and non-EGU NO_X control scenario in an attempt to take into account some of the nonlinearity of ozone formation chemistry.

AQAT was used to evaluate the ozone impacts of alternative control scenarios. It was also used to conduct an "overcontrol" analysis to make sure that controls are

[8] The Anthropogenic Precursor Culpability Assessment (APCA) is one of two ozone source apportionment probing tools in CAMx. The Ozone Source Apportionment Technology (OSAT) is the other CAMx ozone source apportionment probing tool. More details on APCA and OSAT are provided in Chapter 5 of this report.

not being implemented in an Upwind States when all the receptors in downwind state it is linked to have become attainment receptors or the contribution of the Upwind State to all downwind receptors have fallen below EPA's significant threshold.

1.4 Proposed Transport Rule Wyoming's Significant Contribution to 2015 Ozone NAAQS

The Proposed Transport Rule determined that Wyoming (Upwind State) was linked to the Chatfield nonattainment/maintenance receptor that resides in the Denver Metro/North Front Range (DM/NFR) ozone nonattainment area (NAA) in Colorado (downwind state). The Proposed Transport Rule determined that Wyoming contributed 0.81 ppb to the Chatfield nonattainment and 0.80 ppb to the Chatfield maintenance monitor in, respectively, 2023 and 2026.

1.4.1 Calculation of Wyoming's Significant Contribution to 2015 Ozone NAAQS

Using their procedure based on the CAMx 2023 APCA ozone source apportionment modeling, EPA calculated that Wyoming had a 0.81 ppb ozone contribution to the 2023 ozone AvgDV that was greater than EPA's 1 percent of the 2015 ozone NAAQS (i.e., 0.70 ppb) significant contribution threshold (similar Wyoming ozone contribution to Chatfield in 2026 was 0.80 ppb).

Table 1-1 shows the data used in the Proposed Transport Rule to calculate Wyoming's ozone contribution to the 2023 average design value at the Chatfield nonattainment receptor. First the CAMx estimated 2023 daily total MDA8 ozone concentrations ("2023 SA MDA8 Bulk" in Table 1-1) at the Chatfield receptor are ranked and the CAMx total ozone and Wyoming ozone contribution results for the top 10 CAMx modeled MDA8 ozone days are used to calculate the state significant contribution metric. A Contribution Factor ($CF_{WY\text{-}CHAT}$) is then calculated as the ratio of the average Wyoming MDA8 ozone contribution (0.7582 ppb) to the average total MDA8 ozone (66.3314 ppb) average over the top 10 2023 modeled MDA8 ozone days:

$$CF_{WY\text{-}CHAT} = \sum WY\_Ozone_{CHAT} / \sum Total\_Ozone_{CHAT} = 0.7582 / 66.3314 = 0.0114$$

The Wyoming to Chatfield Contribution Factor is then applied to the 2023 average design value for Chatfield to obtain the Wyoming significant contribution metric (2023 $AvgDV_{WY\text{-}CHAT}$) that is truncated to the nearest hundredth of a ppb for comparison with the 1 percent of the NAAQS significance threshold:

$$2023\ AvgDV_{WY\text{-}CHAT} = CF_{WY\text{-}CHAT} \times 2023\ AvgDV_{CHAT} = 0.0114 \times 71.7 = 0.8185 = 0.81$$

Similar procedures are used for state contributions to the 2023 MaxDV and 2026 AvgDV and 2026 MaxDV where the same highest CAMx 2023 MDA8 ozone days are also used when calculating 2026 state ozone contributions.

Table 1-1. Details on how the Proposed Transport Rule calculated a 0.81 ppb contribution of Wyoming anthropogenic emissions to the 2023 average design value at the Chatfield nonattainment receptor in the DM/NFR ozone NAA using the Proposed Transport Rule CAMx 2023 APCA ozone source apportionment modeling.

AQS SiteID	State	County	Site Name	2023fj Avg DV	2023fj Max DV	Month	Day	2023 SA MDA8 Bulk	WY
080350004	Colorado	Douglas	Chatfield	71.7	72.3	8	3	68.5	0.8357
080350004	Colorado	Douglas	Chatfield	71.7	72.3	8	12	67.8	0.4457
080350004	Colorado	Douglas	Chatfield	71.7	72.3	7	27	67.5	0.7282
080350004	Colorado	Douglas	Chatfield	71.7	72.3	6	19	67.3	0.0016
080350004	Colorado	Douglas	Chatfield	71.7	72.3	7	15	66.1	0.3591
080350004	Colorado	Douglas	Chatfield	71.7	72.3	6	29	65.8	0.6882
080350004	Colorado	Douglas	Chatfield	71.7	72.3	6	17	65.7	1.4487
080350004	Colorado	Douglas	Chatfield	71.7	72.3	7	28	65.2	1.0276
080350004	Colorado	Douglas	Chatfield	71.7	72.3	7	14	64.8	1.4820
080350004	Colorado	Douglas	Chatfield	71.7	72.3	8	16	64.7	0.5652
Average Wyoming O3 Contribution on Top 10 2023 Modeled MDA8 Ozone Days									0.7582
Averaged Modeled MDA8 Ozone Concentration on Top 10 2023 Modeled MDA8 Ozone Days									66.3314
Contribution Factor (CF) Average Modeled WY Contribution / Average Total Modeled Ozone									0.0114
Projected 2023 Average Ozone Design Value									71.7
Wyoming 2023 Ozone Contribution to Chatfield									0.819564
Wyoming 2023 Ozone Contribution to Chatfield (truncated to two decimals)									**0.81**

1.5 Wyoming and Utah State EGU Contributions to 2023 Ozone at DM/NFR NAA Receptors

The results from the Proposed Transport Rule CAMx 2023 APCA ozone source apportionment modeling along with the contributions of EGU and PacifiCorp EGU NO_X emissions to the state total anthropogenic NO_X emissions are used to estimate the Wyoming and Utah EGU contributions to 2023 ozone design values at the nonattainment/maintenance receptors in the DM/NFR NAA.

1.5.1 Wyoming Contributions to the Chatfield Receptor

Figure 1-2 compares the Wyoming 0.81 ppb ozone contribution to the Chatfield 2023 average ozone design value with other sources. The pie chart on the left in Figure 1-2 shows the contributions from all sources to the 71.7 ppb 2023 ozone AvgDV at Chatfield with boundary conditions (ICBC, i.e., ozone emanating from sources outside of the 12-km continental U.S. modeling domain) being by far the biggest contributor at 62%, followed by Colorado anthropogenic emissions (23%), biogenic emissions (5%) and emissions from fires (2%). The Wyoming contribution to the 2023 ozone AvgDV at Chatfield is 1% (0.81 ppb).

The total U.S. anthropogenic emissions contribution to the 2023 ozone AvgDV at Chatfield is 21.5 ppb, which represents 30% of the 2023 ozone AvgDV (Figure 1-2, right panel). Colorado is the state with the largest (76%) fraction of the U.S. anthropogenic emissions ozone contribution to the 2023 ozone AvgDV at Chatfield

with Wyoming the state with the third highest fraction at 4% that is behind Utah (6%) and California (4%).

Figure 1-3 displays the relative contributions of major source sectors to 2023 anthropogenic NO_X emissions in Wyoming using the Proposed Transport Rule 2023 emissions from the EPA 2016v2 modeling platform that were used in in Steps 1 and 2 of the proposed rule that shows EGU NO_X emissions make up 17% of Wyoming's 2023 total anthropogenic NO_X emissions. Combing data in Figures 1-2 and 1-3 we estimate that Wyoming EGU NO_X contributes approximately 0.2% to the Chatfield 2023 ozone AvgDV.

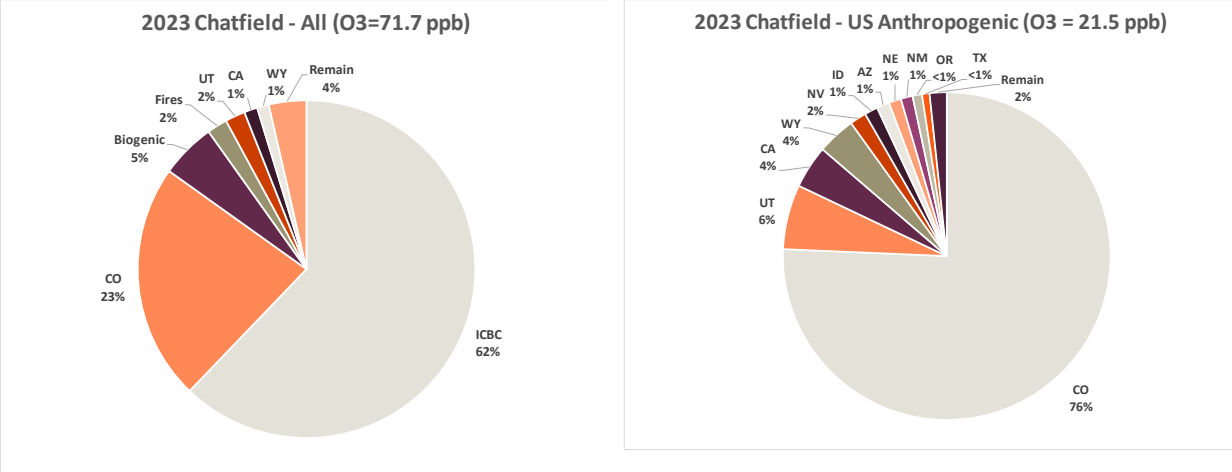

Figure 1-2. Proposed Transport Rule ozone contribution to 2023 ozone AvgDV at Chatfield due to all sources (left) and due to U.S. anthropogenic emission sources (right) based on the Proposed Transport Rule CAMx 2023 APCA ozone source apportionment simulation.

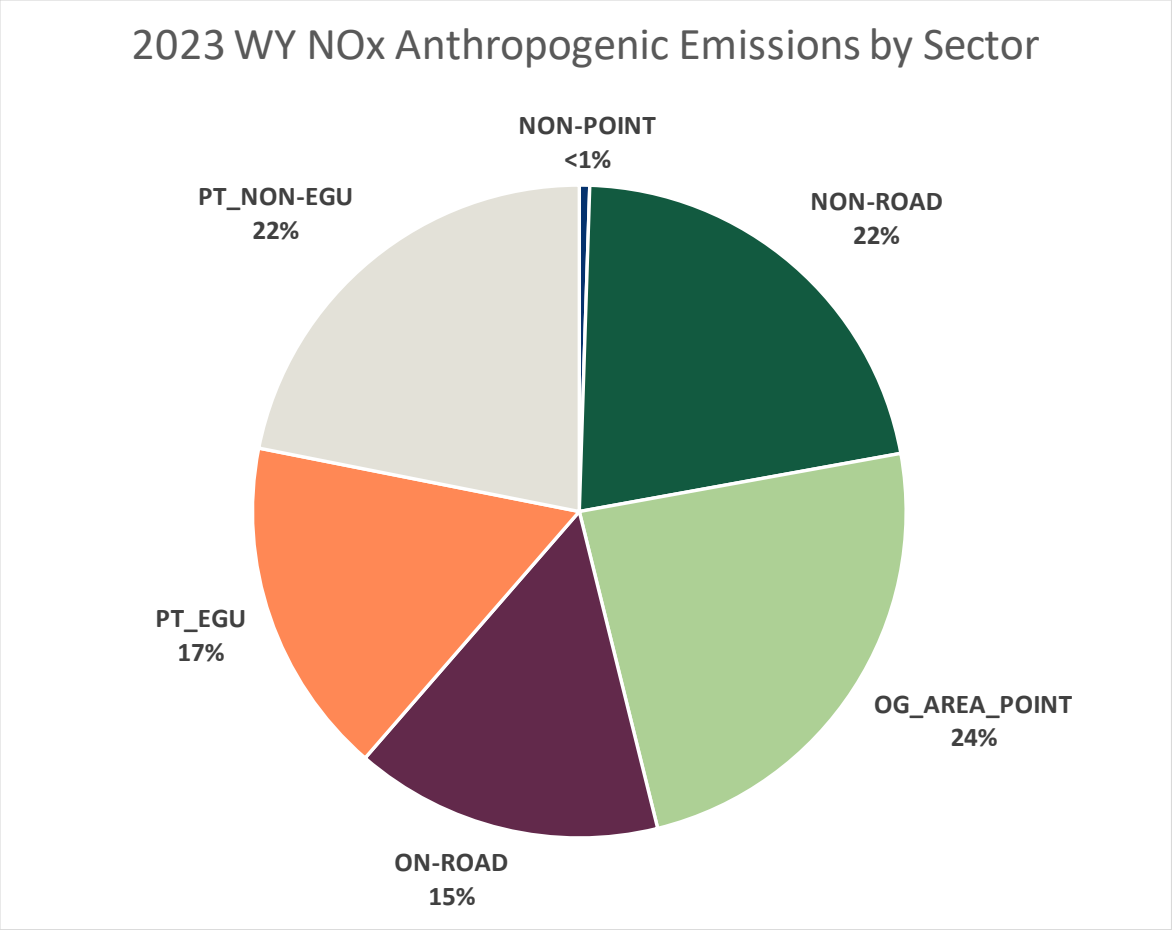

Figure 1-3. Relative contributions of major source sectors to anthropogenic NO_X emissions in Wyoming from Proposed Transport Rule 2023 Emissions used in the Step 1 and 2 CAMx modeling based on the EPA 2016v2 modeling platform.

1.6 Utah's Contribution to DM/NFR NAA Receptors

The proposed Transport Rule determined that Utah contributed significantly to three nonattainment/maintenance receptors in the DM/NFR ozone NAA: (1) Chatfield (CHAT); (2) Rocky Flats North (RFNO); and (3) National Renewable Energy Laboratory (NREL). The Utah 2023 and 2026 ozone contributions to these three receptors are shown in Table 1-2 with the highest contributions occurring at the CHAT receptor (1.37 and 1.18 ppb).

Table 1-2. Nonattainment/maintenance receptors where the Proposed Transport Rule determined that Utah had a significant contribution to the 2015 ozone NAAQS in 2023 and 2026.

Utah Ozone Contribution (ppb)	DM/NFR NAA Monitoring Site
2023 Contributions	
1.37	Chatfield Nonattainment Receptor
1.10	Rocky Flats North Nonattainment Receptor
1.06	NREL Nonattainment Receptor
2026 Contributions	
1.18	Chatfield Maintenance Receptor
0.95	Rocky Flats North Nonattainment Receptor
0.90	NREL Nonattainment Receptor

The left panels in Figures 1-2, 1-4 and 1-5 show the contributions of Utah, and other sources, to the total 2023 ozone AvgDV at the, respectively, CHAT, RFNO and NREL receptors. The right panels in these three figures show the contributions of Utah and other sources to the total U.S. anthropogenic emissions contribution of the 2023 AvgDV at the three DM/NFR NAA receptors. Utah's contribution to the total 2023 ozone AvgDV at the three DM/NFR NAA receptors is 1-2% and its contribution to the U.S. anthropogenic contribution to the 2023 ozone AvgDV at the three receptors is 5-6%. Figure 1-6 displays the relative contributions of major source sectors to the total Utah 2023 anthropogenic NO_X emissions used in Step 1&2 of the Proposed Transport Rule and shows Utah EGUs contributing 21% of the 2023 Utah anthropogenic NO_X emissions. Combing the data in these Figures we estimate that Utah EGUs contributes approximately 0.4%, 0.3% and 0.3% to the 2023 ozone AvgDV at, respectively, CHAT, RFNO and NREL receptors.

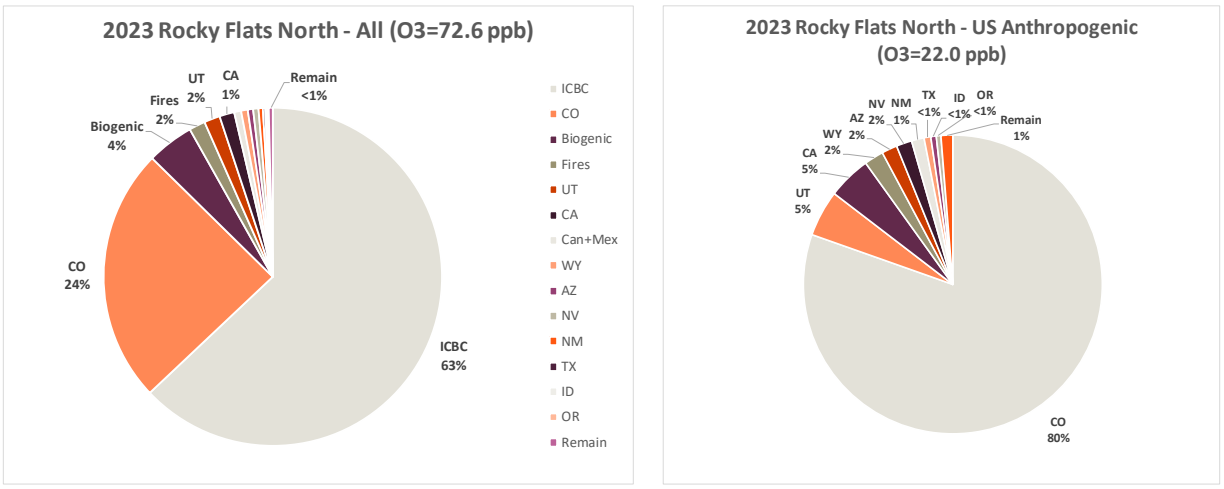

Figure 1-4. Proposed Transport Rule ozone contribution to 2023 ozone AvgDV at Rocky Flats North due to all sources (left) and due to U.S. anthropogenic emission sources (right) based on the Proposed Transport Rule CAMx 2023 APCA ozone source apportionment simulation.

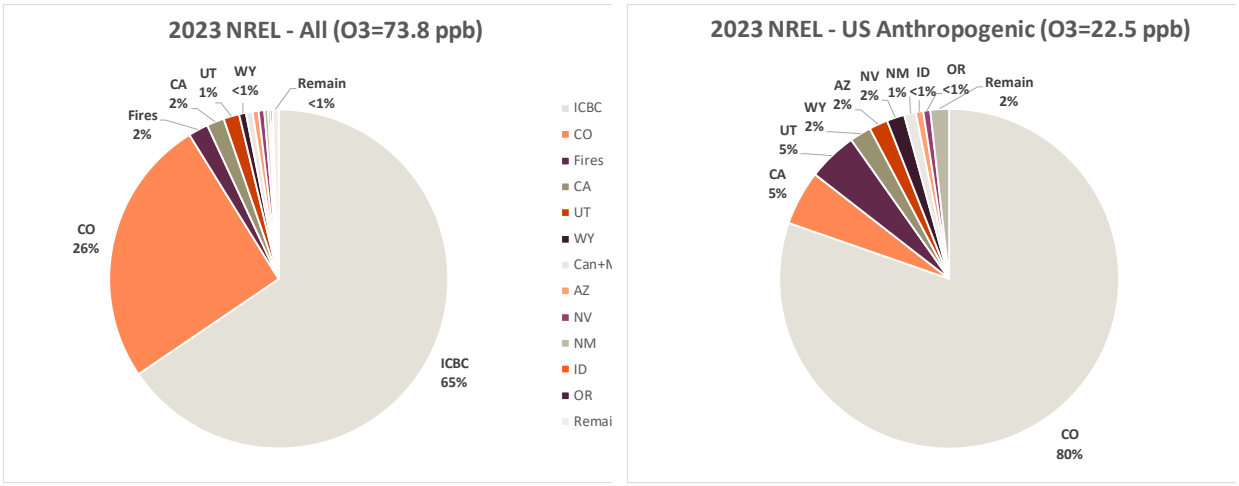

Figure 1-5. Proposed Transport Rule ozone contribution to 2023 ozone AvgDV at NREL due to all sources (left) and due to U.S. anthropogenic emission sources (right) based on the Proposed Transport Rule CAMx 2023 APCA ozone source apportionment simulation.

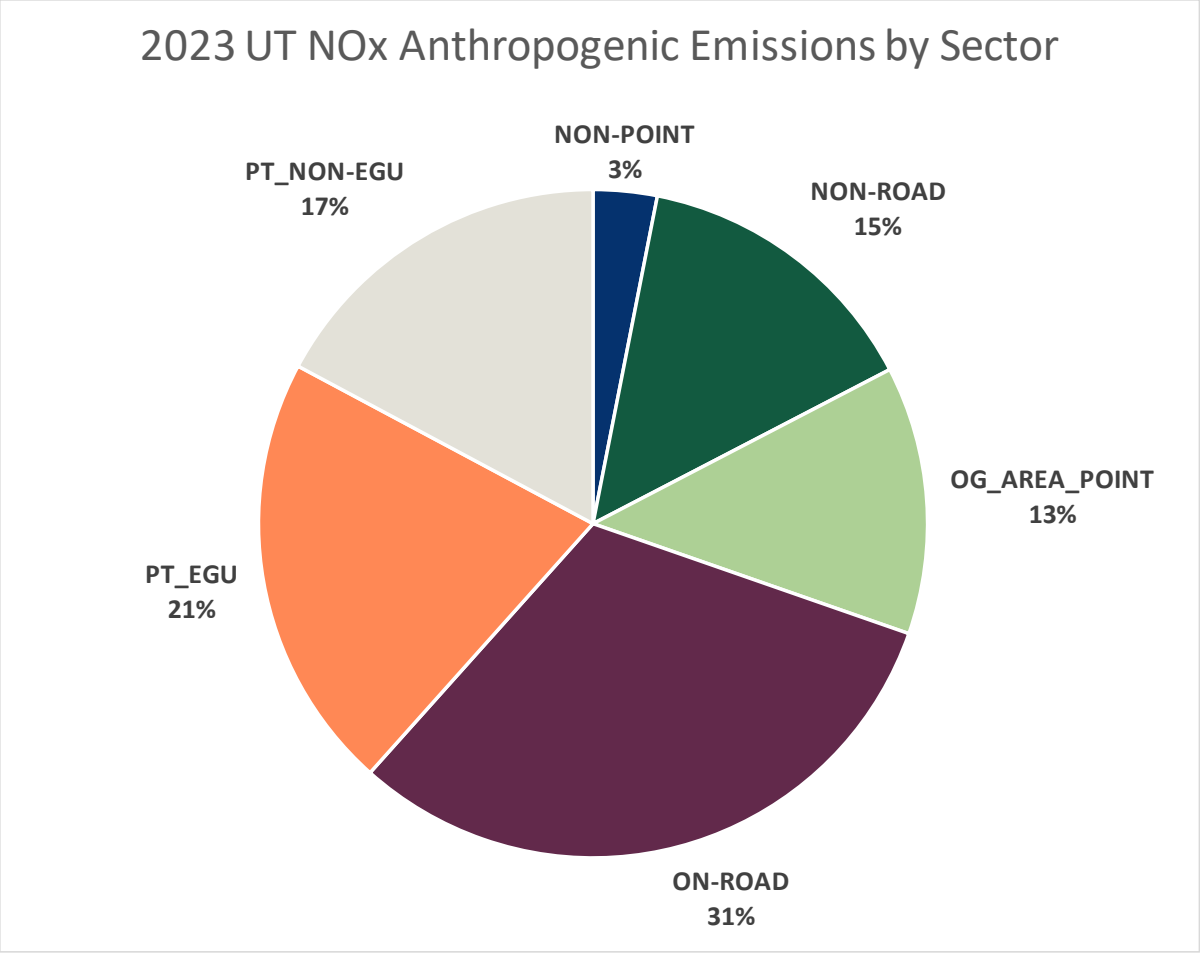

Figure 1-6. Relative contributions of major source sectors to anthropogenic NO_X emissions in Wyoming from Proposed Transport Rule 2023 Emissions used in the Step 1 and 2 CAMx modeling.

1.6.1 Contributions of Wyoming and Utah EGUs to 2023 Nonattainment in the DM/NFR NAA

Tables 1-3 and 1-4 summarize the contributions of Wyoming and Utah EGU and PacifiCorp EGU NO_X emissions to 2023 ozone design values at receptors in the DM/NFR ozone NAA. The EGU contributions were obtained using the Proposed Transport Rule Step 2 CAMx 2023 APCA ozone source apportionment modeling state ozone contributions assuming that the EGU fraction of that ozone contribution was proportional to the EGU NO_X emissions fraction to the state's total anthropogenic NO_X emissions. The EGU fraction of the Wyoming and Utah total anthropogenic NO_X emissions was taken from the pie charts above. The PacifiCorp EGU fraction of each of the states total EGU NO_X emissions is from Table 3-2 in Chapter 3.

The Wyoming EGU contribution to the 2023 ozone design at the CHAT monitor is 0.14 ppb, or 0.19%. Using the Proposed Transport Rule Step 1&2 data the PacifiCorp EGUs contribution to the 2023 ozone AvgDV at CHAT is 0.05 ppb, or 0.06%.

Utah EGUs are estimated to contribution 0.22 to 0.29 ppb to the 2023 ozone design values at the three sites in the DM/NFR NAA, which represents 0.30% to 0.40% of the design value (Table 1-3). PacifiCorp EGUs are estimated to contribute 0.10-0.12 ppb or 0.13-0.17% to the 2023 ozone AvgDV at the three sies in the DM/NFR NAA.

Thus, the Wyoming and Utah EGU and PacifiCorp EGU ozone contributions to the 2023 ozone design values in the DM/NFR NAA are quite small and probably not even measurable.

Table 1-3. Contributions of Wyoming and Utah EGU NO_X emissions to 2023 ozone design values at receptors in the DM/NFR ozone NAA.

Receptor	2023 Ozone AvgDV (ppb)	2023 State Ozone Contribution (ppb)	2023 State EGU Contribution		
			State Total Anthropogenic NO_X Emissions	EGU Ozone Contribution (ppb)	EGU Ozone Contribution (%)
Wyoming					
CHAT	71.7	0.81	17%	0.14	0.19%
Utah					
CHAT	71.7	1.37	21%	0.29	0.40%
RFNO	72.6	1.10	21%	0.23	0.32%
NREL	73.8	1.06	21%	0.22	0.30%

Table 1-4. Contributions of Wyoming and Utah PacifiCorp EGU NO_X emissions to 2023 ozone design values at receptors in the DM/NFR ozone NAA.

Receptor	2023 Ozone AvgDV (ppb)	State Ozone Contribution (ppb)	2023 PacifiCorp State EGU Contribution		
			State Total Anthropogenic NO_X Emissions	Pac-EGU Ozone Contribution (ppb)	PacifiCorp EGU Ozone Contribution (%)
Wyoming					
CHAT	71.7	0.81	6%	0.05	0.06%
Utah					
CHAT	71.7	1.37	9%	0.12	0.17%
RFNO	72.6	1.10	9%	0.10	0.14%
NREL	73.8	1.06	9%	0.10	0.13%

1.7 Organization of Report and Summary of Findings

Below we summarize some of the major findings of the analyses of EPA's Proposed Transport Rule as related to PacifiCorp EGU operations in Utah and Wyoming. The 2023 and 2026 emissions used in the Proposed Transport Rule for PacifiCorp EGU sources are clearly incorrect and inconsistent with different 2023 and 2026 EGU emissions used in different parts of the proposed rule. To determine the effects of this error in the Proposed Transport Rule we would have to correct the PacifiCorp and other Wyoming and Utah EGU NO_X emissions in proposed Transport Rule CAMx 2023 and 2026 modeling databases and rerun the CAMx 2023 and 2026 APCA ozone source apportionment simulations. Given delays in EPA providing the CAMx 2023 and 2026 ozone source apportionment modeling databases that was not possible given the short 75 day comment period.

The findings and organization of this report are as follows:

- Documentation of our efforts to acquire the CAMx 2023 and 2026 ozone source apportionment inputs and output files used in the Proposed Transport Rule and delays by EPA in providing the data until almost half-way through the 60-day comment period are discussed in Chapter 2.
- Chapter 3 discusses of why the Proposed Transport Rule is flawed because it changes 2023 and 2026 EGU NO_X emissions half-way through the rule between Steps 1&2 that determined the nonattainment/maintenance receptors and Upwind State's significant ozone contributions versus Step 3 controls analyses results in making the rule inconsistent and incoherent and breaks the four-step transport framework.
- The overcontrol of Utah and Wyoming emissions is discussed in Chapter 4 by presenting solid evidence that deficiencies in EPA's CAMx modeling and inconsistencies in the Proposed Transport Rule resulted in overstated future year ozone design values at the DM/NFR ozone NAA receptors so for Wyoming the 2026 additional EGU and non-EGU NO_X controls are not needed and revised analysis may also show similar results for Utah.
- The reasons why the Proposed Transport Rule is overstating Upwind State 2023 and 2026 ozone contributions to ozone design values at receptors in

downwind states due to missing emissions, missing emission controls and choices in conducting the Proposed Transport Rule CAMx ozone source apportionment modeling are discussed in Chapter 5.

- Chapter 6 explains why EPA's Upwind State ozone contribution metric is arbitrarily and presents alternative metrics, including some used in previous CSAPR rules, that show Wyoming's contribution is below the 1 percent of the NAAQS significance threshold and Utah's contributions are reduced as well.
- Why Wyoming's ozone contribution to 2023 and 2026 ozone design values at Chatfield are not statistically significant based on EPA's statistical analysis of ozone air quality data is discussed in Chapter 7. The Utah ozone contribution at the one remaining nonattainment/maintenance receptor in 2026 is also not statistically significant. Thus, Wyoming should not be subject to the 2023 and 2026 and Utah should not be subject to the 2026 controls in the Proposed Transport Rule.
- Chapter 8 documents why EPA's extensive use of the reduced form model Air Quality Assessment Tool (AQAT) is inappropriate, contrary to EPA's own air quality modeling guidelines and guidance and applied beyond the range of its applicability that it has been calibrated for.

1.8 References

EPA. 2018. Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

EPA. 2022. Air Quality Modeling Technical Support Document – Federal Implementation Plan Addressing Regional Ozone Transport for the 2025 Ozone National Ambient Air Quality Standards Proposed Rulemaking. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, 27711. (https://www.epa.gov/system/files/documents/2022-03/aq-modeling-tsd_proposed-fip.pdf).

Ramboll. 2020. User's Guide to the Comprehensive Air-quality Model with extensions Version 7.10. Ramboll Environment and Health, Novato, CA. December. (https://camx-wp.azurewebsites.net/Files/CAMxUsersGuide_v7.10.pdf).

2.0 EPA PROVIDED INSUFFICIENT TIME FOR COMMENTS GIVEN THE MASSIVE AMOUNTS OF DATA TO ANALYZE AND THEIR DELAYS IN PROVIDING THE MODELING FILES IN A TIMELY MANNER

For the Proposed Transport Rule, EPA conducted CAMx photochemical grid modeling using their 2016v2 modeling platform with a 12-km grid resolution domain covering the 48 contiguous states for the 2016, 2023 and 2026 emission years. CAMx APCA ozone source apportionment modeling was conducted for the 2023 and 2026 emission years to obtain estimates of state-specific ozone contributions at monitoring sites throughout the continental U.S. (CONUS). As discussed in Section 2.1 below, EPA made some data and modeling files used in the Proposed Transport Rule available prior to the publication of the proposed rule on April 6, 2022. But the actual CAMx 2023 and 2026 12-km APCA ozone source apportionment input and output files that formed the foundation for the Proposed Transport Rule were not made readily available and had to be requested with a large delay (over a month) between the initial request and the receipt of the modeling files (see Section 2.2 below).

2.1 Available Data for the Proposed Transport Rule

EPA used the 2016v2 modeling platform with 2016, 2023, 2026 and 2032 emission scenarios and the CAMx version 7.10 (v7.10) photochemical grid model for their Proposed Transport Rule modeling. The 2016v2 platform was released on September 21, 2021 and EPA requested comments by December 17, 2021.[9] Note that some components of the 2016v2 platform were no different than the 2016v1[10] platform (e.g., meteorology) that was used in the Revised CSAPR Update that was finalized on March 15, 2021[11], but some others (e.g., emissions) were significantly changed by EPA from 2016v1 to 2016v2.[12] CAMx v7.10 was released on January 5, 2021 and is available on the CAMx website.[13] So these components of the modeling used in the Proposed Transport Rule have been available for some time.

EPA first released information on the Proposed Transport Rule by notifying stakeholders of the availability of processed modeling results (including the state ozone contributions) and other data on January 9, 2022.[14] However, the data made available did not include the CAMx 2023 and 2026 ozone source apportionment modeling inputs and outputs that EPA later made available on request.

[9] https://www.epa.gov/air-emissions-modeling/2016v2-platform
[10] https://www.epa.gov/air-emissions-modeling/2016v1-platform

[11] https://www.epa.gov/csapr/revised-cross-state-air-pollution-rule-update

[12] https://www.epa.gov/csapr/revised-cross-state-air-pollution-rule-update
[13] https://www.camx.com/
[14] https://www.epa.gov/scram/photochemical-modeling-applications

2.2 Timeline for Requesting the Proposed Transport Rule 2023 and 2026 Ozone Source Apportionment Modeling Results

Below is a chronology of our request to EPA for the modeling data that was used in EPA's Proposed Transport Rule. Our original request was made on March 17, 2022 through e-mail to the rule's contact person on the website, well before the proposed rule was published in the Federal Register on April 6, 2022. EPA estimated that this is 37 Tb of data so will take some time to copy.

- March 17, 2022: Sent e-mail to Ms. Elizabeth Selbst (Selbst.elizabeth@epa.gov; 919.541.3918) at EPA requesting all of the modeling files related to the Proposed Transport Rule. Ms. Selbst was the contact person for the rule identified on EPA's website documents (e.g., https://www.epa.gov/system/files/documents/2022-03/fact-sheet_2015-ozone-proposed-good-neighbor-rule.pdf).
- March 21, 2022: Ms. Selbst replied that she is forwarding my request to Mr. Norm Possiel in the EPA/OAQPS modeling group (possiel.norm@epa.gov) who will let us know the size of the disk drives needed for the data transfer and whether some of the data may be transferred via e-mail or ftp.
- March 22, 2022: Mr. Possiel responded that he is putting together a list of the modeling files used in the 2015 ozone NAAQS Transport Rule so we can reply with which files we want.
- March 28, 2022: Mr. Possiel sends e-mail with forms to check off which files we are requesting.
- April 1, 2022: We replied to Mr. Possiel that we want all of the data as originally requested 2 weeks earlier. Mr. Possiel replied on the same day to send the disk drives to Tom Baker (U.S. E.P.A, 4930 Old Page Road, Durham, NC 2770; baker.thomas@epa.gov). We requested the size of the data so that we can send the right size of disk drives.
- April 6, 2022: Mr. Possiel responds that the total data is 37.5 terabytes (Tb).
- April 10, 2022: Received spreadsheet from Mr. Possiel that contains the 2023 daily ozone contributions of states to nonattainment receptors ozone design values (DV) whose average across the top 10 highest days is used in the Step 2 state ozone significant contribution assessment.
- April 11, 2022: Received 2023 SMAT ozone DV output used in Step 1 from Mr. Possiel. Responded that what we really need is the SMAT inputs (i.e., CAMx 2016 and 2023.ozone results processed for SMAT) that should be small enough to ftp.
- April 11, 2022: Disk drives arrive at EPA.
- April 15, 2022: We received 2016, 2023, 2026 and 2032 SMAT inputs via ftp transfer.

- April 18, 2022: E-mailed two FedEx overnight shipping labels with bill the recipient to EPA and asked when the estimated shipping date for the disk drives would be.
- April 19, 2022: EPA replied that the estimated date for shipping the disk drives with the Proposed Transport Rule modeling data was May 6, 2022.
- April 26, 2022: Received first set of disk drives with modeling files from EPA.
- May 3, 2022: Received final set of disk drives with modeling files from EPA.

A total of 48 days elapsed between the initial request for all the modeling files used in the Proposed Transport Rule and receipt of all the modeling data.

2.3 Delays in EPA Providing Proposed Transport Rule Modeling Files and Short Comment Period Provided Insufficient Time to Adequately Review and Comment on the Proposed Rule

EPA finally provided the Proposed Transport Rule CAMx 2023 and 2026 APCA ozone source apportionment modeling files on disk drives that arrived May 3, 2022, approximately half-way through the 60-day comment period and just 34 days before the original comment due date of June 6, 2022. To duplicate or conduct an alternative scenario to the 2023 or 2026 CAMx APCA ozone source apportionment simulations performed in the Proposed Transport Rule we estimate would take 80-100 days of computer time on Ramboll's high-performance Linux cluster, and that does not even include the time necessary to copy the files, set up the run and post-process the results. So even with EPA extending the comment end date 15-days to June 21, 2022, there was still insufficient time to conduct a confirmatory run and/or conduct alternative modeling to what was used in the Proposed Transport Rule to develop more meaningful comments.

In Chapter 3 we show that the 2023 NO_X emissions from PacifiCorp EGUs in Utah and Wyoming were drastically changed part way through the Proposed Transport Rule so that there is a disconnect between 2023 and 2026 CAMx ozone source apportionment modeling and the proposed rule's control requirements that needs to be investigated. However, there was insufficient time in the comment period to conduct modeling to examine this critical issue.

3.0 PROPOSED TRANSPORT RULE IS FLAWED BECAUSE IT USES INCONSISTENT EMISSIONS TO DEFINE FUTURE YEAR NONATTAINMENT AND STATE CONTRIBUTIONS VERSUS DEFINING CONTROLS AND CONDUCTING OVERCONTROL ANALYSIS

The Proposed Transport Rule used EPA's 2016v2 modeling platform 2023 and 2026 emissions in the Steps 1 and 2 CAMx modeling to define the, respectively, nonattainment/maintenance receptors and state ozone contributions. The proposed rule then conducted an "Engineering Analysis" for electrical generating units (EGUs) to define new 2023 and 2026 baseline NO_X emissions that were used in the Step 3 control measures, cost-effectiveness and overcontrol analyses using the Air Quality Assessment Tool (AQAT). The differences between the Step 1&2 CAMx 2023 and 2026 base case emissions and the Step 3 AQAT 2023 and 2026 Engineering Analysis baseline emissions were quite large with the changes in individual EGU NO_X emissions as much as 100%. These changes in the state NO_X future year emission projections between the Steps 1&2 and Step 3 in the Proposed Transport Rule four-step transport framework makes the proposed rule inconsistent and incoherent. The Step 3 control measures and overcontrol analysis are no longer connected to the nonattainment/maintenance receptors and the procedures used to link the Upwind States to the nonattainment/maintenance receptors making the proposed rule flawed and ineffective in accurately assessing and remedying ozone transport so that the proposed controls in the rule are not defensible.

3.1 2023 and 2026 Emissions used in the Step 1 and 2 CAMx Modeling

The 2016, 2023 and 2026 emissions used in the Proposed Transport Rule Step 1 and 2 CAMx modeling were derived from EPA's 2016v2 modeling platform.[15] The earlier 2016v1 version of these emissions were developed under a multi-year Inventory Collaborative program between multi-jurisdictional organizations (MJOs), states, tribes, local air agencies and EPA. The goal of the Inventory Collaborative was to jointly develop more accurate emissions modeling platforms for use in air quality planning nationwide. The Inventory Collaborative was structured around workgroups organized by emissions inventory sectors. The workgroups worked independently and in parallel on the inventory sectors in pursuit of the creation of 2016v1 base year and future year emissions inventories for air quality modeling. A coordination workgroup[16] provided logistical support and facilitation to the sector workgroups as they move toward the goal of well-documented model-ready emissions for use in air quality planning. No known additional regulatory planning specifications for the emissions projections were requested of states or MJOs for the final 2016v1 platform emission projections. States are co-regulators under the

[15] https://www.epa.gov/air-emissions-modeling/2016v2-platform

[16] https://views.cira.colostate.edu/wiki/wiki/9171/coordination

Clean Air Act. Additional details are available in the Inventory Collaborative Development Plan.[17]

After approximately two years of development and collaboration, input and review from numerous states, locals, tribes, and MJOs, the Inventory Collaborative released the 2016v1 emissions and its documentation on October 1, 2019.[18] EPA informally released its 2016v2 version of the 2016v1 modeling platform on September 21, 2021 and requested comments by December 17, 2021. All changes from the 2016v1 and associated projections data prepared by the Inventory Collaborative to the 2016v2 and associated projections data as used in the Proposed Transport Rule analysis were wholly decided by EPA with no verification or agreement by state co-regulators. EPA has appeared to have made many changes to the EGU emissions between the Inventory Collaborative 2016v1 emissions and EPA's 2016v2 platform emissions used in Steps 1 and 2 CAMx modeling in the Proposed Transport Rule.

3.2 2023 and 2026 Emissions used in the Step 3 AQAT Controls and Overcontrol Analyses

In Step 3, the Proposed Transport Rule used the AQAT linear ozone state contribution tool to evaluate the magnitude of the ozone air quality improvement at each receptor and each level of control and also examined whether the receptor's change status (i.e., from nonattainment to maintenance to attainment receptors) or a state's ozone contribution is reduced to below the significance threshold at all downwind receptors where it is linked (i.e., the overcontrol analysis). However, for reasons that are not explained well in the Proposed Transport Rule, rather than use the 2023 and 2026 emissions from the 2016v1 platform that represented almost four years of development and collaboration and review by states, tribes, locals, and MJOs or use the 2016v2 emissions used in Steps 1&2 of the Proposed Transport Rule, EPA instead elected to conduct an "Engineering Analysis" using the Integrated Planning Model (IPM) to redefine the 2023 and 2026 EGU NO_X emissions. IPM is a linear programing model of the electric power sector used to determine future year EGU emissions for various control options using a least cost solution (e.g., whether to retire or put SCR on an EGU to meet a state's EGU NO_X budget). IPM is a proprietary model that is opaque, so states and stakeholders have little knowledge or input on how EPA uses it, what it does and whether it will conform with the state, local or tribal air permitting program or air agency emissions inventory development or whether the controls selected by IPM are even feasible to implement at the individual EGU sources. The development of the Step 3 AQAT 2023 and 2026 Engineering Analysis baseline emissions is described in the Proposed Transport Rule policy document (EPA, 2022a). Details on how the new Engineering Analysis 2023 and 2026 EGU NO_X emissions were derived are not available due to the proprietary nature of the IPM model. This disconnect at Step 3, in conjunction with the lack of transparency of the IPM modeling, could render the

17 https://views.cira.colostate.edu/wiki/Attachments/Inventory%20Collaborative/coordination/2016%20Emissions%20Modeling%20Platform%20Development%20Plan_V1.0.pdf

18 http://views.cira.colostate.edu/wiki/wiki/10202#Overview

requirements of the proposed rule meaningless and result in lack of achievement of the goals of the proposed rule.

3.3 Differences in Step 1&2 CAMx and Step 3 AQAT Total State NO_X 2026 Emissions

Table 3-1 displays the differences in state total 2026 NO_X emission between the Step 1&2 CAMx and Step 3 AQAT analysis in the Proposed Transport Rule ranked by differences from the state with the largest increase to the state with the largest decrease in NO_X emissions. There are many more NO_X emission increases going from Step 1&2 to Step 3 with approximately 80% of the states having increases. Six states saw total NO_X emissions increases greater than 10% (UT, WY, MO, WV, AZ and NC). Of the 10 states that saw 2026 NO_X emissions go down, the reductions were minimal (up to -2.26%).

In particular, the state total 2026 NO_X emissions in Utah and Wyoming go up 16% in the Step 3 2026 Engineering Analysis Baseline compared to the 2026 base case emissions used in the Step 1&2 CAMx modeling. This is the largest increase of any state so make the Proposed Transport Rule estimates of Utah and Wyoming contributions to downwind ozone nonattainment/maintenance particularly suspect.

Table 3-1. Comparison of 2026 base case emissions used in the CAMx Step 1 and 2 ozone design value projections and state-specific ozone source apportionment modeling with the 2026 Engineering Analysis Baseline emissions used in the Step 3 AQAT cost-effectiveness and overcontrol analysis.

State	CAMx 2026 Modeled Anthro total	Enginnering Analysis 2026 total	Percent Difference
Utah	29,762	34,594	16.23%
Wyoming	32,928	38,169	15.92%
Missouri	67,664	78,153	15.50%
West Virginia	39,500	44,905	13.68%
Arizona	33,463	37,696	12.65%
North Carolina	51,986	57,791	11.17%
Oklahoma	83,411	91,472	9.66%
Mississippi	33,156	36,355	9.65%
Texas	280,717	305,833	8.95%
Arkansas	39,488	43,001	8.90%
Louisiana	100,361	108,185	7.80%
Tennessee	47,475	50,757	6.91%
Georgia	60,266	64,318	6.72%
Maine	12,918	13,771	6.60%
Virginia	46,496	49,549	6.57%
Florida	92,166	98,134	6.48%
Nevada	16,178	17,196	6.30%
New Hampshire	6,719	7,117	5.92%
Delaware	6,447	6,796	5.43%
Kansas	59,107	62,275	5.36%
Washington	47,754	49,974	4.65%
Kentucky	50,887	53,045	4.24%
Wisconsin	41,032	42,624	3.88%
Iowa	41,049	42,610	3.80%
South Carolina	38,939	40,348	3.62%
Vermont	3,378	3,491	3.35%
Maryland	23,671	24,435	3.22%
Minnesota	55,972	57,706	3.10%
North Dakota	55,294	56,963	3.02%
Massachusetts	26,353	27,099	2.83%
Idaho	17,321	17,714	2.27%
Rhode Island	4,187	4,268	1.94%
Ohio	78,681	79,980	1.65%
Alabama	61,759	62,689	1.51%
New Jersey	31,805	32,172	1.15%
South Dakota	11,084	11,204	1.08%
Colorado	49,825	50,152	0.66%
Nebraska	38,322	38,561	0.62%
Montana	25,642	25,730	0.34%
Illinois	91,069	90,944	-0.14%
Connecticut	10,887	10,867	-0.18%
Oregon	29,345	29,283	-0.21%
New Mexico	62,210	61,787	-0.68%
Michigan	75,940	75,410	-0.70%
New York	65,642	64,802	-1.28%
Indiana	68,291	67,403	-1.30%
District of Columbia	1,302	1,283	-1.41%
Pennsylvania	103,565	101,704	-1.80%
California	133,629	130,612	-2.26%
Total	2,485,043	2,600,924	4.66%

3.4 Differences in 2023 EGU NO_X emissions in Utah and Wyoming

Table 3-2 compares the 2023 NO_X emission projected for all EGUs and PacifiCorp EGUs in the states of Utah and Wyoming and their differences for the: (1) 2023 emissions from the Inventory Collaborative 2016v1 platform; (2) 2023 emissions from the EPA 2016v2 platform used in Steps 1&2 of the Proposed Transport Rule; and (3) Proposed Transport Rule 2023 Engineering Analysis emissions used in Step 3. The three sets of 2023 EGU emissions in the two states are very different. In general, the Proposed Transport Rule 2023 emissions used in Step 2 (2016v2 platform) are lower (-37% and -26%) but the Step 3 (2023 EA) are higher (+38% and +54%) than the Inventory Collaborative 2023 emissions (2016v1 platform) for Utah and Wyoming. The Proposed Transport Rule 2023 Engineering Analysis EGU emissions used in Step 3 are over a 100% greater than the 2023 2016v2 platform emissions used in Steps 1&2 in both Utah and Wyoming making the Proposed Transport Rule seriously flawed.

The differences in the PacifiCorp 2023 EGU NO_X emissions among the three 2023 emission inventories are even greater. In Utah the Proposed Transport Rule 2023 Engineering Analysis baseline, PacifiCorp EGU NO_X emissions are 187% greater than 2016v1 platform and 143% greater than 2016v2 platform (similar numbers for Wyoming are 132% and 293%).

The fact that future year EGU NO_X emission controls is one of the biggest elements of the Proposed Transport Rule and the proposed rule can't get them correct using estimates in different portions of the rule that differ by over a 100% illustrates how flawed the Proposed Transport Rule is. For Wyoming the PacifiCorp EGU NO_X emissions used in Step 3 of the Proposed Transport Rule controls analysis are almost 4 times larger than used in Step 1&2 of the Proposed Transport Rule.

Table 3-2. Total EGU and PacifiCorp 2023 EGU NO_X emissions in Utah and Wyoming for the Inventory Collaborative (IC) 2016v1 platform, EPA's 2016v2 platform used in the Step 1&2 CAMx modeling and EPA's 2023 Engineering Analysis used in the Step 3 AQAT controls analyses and their differences.

Sources	State 2023 EGU NO_X Emissions			Differences in 2023 EGU Emissions		
	Inventory Collab. 2016v1	Proposed Rule 2016v2 (Step 1&2)	Proposed Rule EA (Step3)	EPA 2016v2 minus IC 2016v1	Prop. Rule Engineer minus IC 2016v1	Prop. Rule Engineer minus EPA 2016v2
Utah						
Total EGU	11,229	7,118	15,500	-36.6%	38.0%	117.8%
PacifiCorp EGU	2,593	3,055	7,430	17.8%	186.6%	143.2%
Wyoming						
Total EGU	6,599	4,912	10,191	-25.6%	54.4%	107.5%
PacifiCorp EGU	2,740	1,615	6,344	-41.0%	131.6%	292.7%

3.5 Effects of Differences in 2026 Emissions used in Steps 1&2 and Step 3

The AQAT was used to estimate what the effects the 2026 Engineering Analysis baseline would have on the 2026 AvgDV and MaxDV calculated the Step 1 CAMx modeling at the nonattainment/maintenance receptors. Table 3-2 shows the Step 1 2026 MaxDV from CAMx modeling versus the Step 3 2026 MaxDV that were adjusted by AQAT based on changes in NO_X emissions introduced by the new 2026 Engineering Analysis baseline. At all receptors, the Step 3 2026 MaxDVs are higher than the 2026 MaxDVs obtained in the Step 1 CAMx modeling. At the three receptors in the DM/NFR ozone NAA linked to Utah and one linked to Wyoming the increases in 2023 ozone AvgDV due to using the Step 3 2023 Engineering Analysis NO_X emissions ranged from 0.38 to 0.45 ppb.

The increases in 2026 design values when the Proposed Transport Rule switched from the 2016v2 platform 2026 emissions used in Step 1&2 and the 2026 Engineering Analysis baseline used in Step 3 are significant. At the CHAT, RFNO and NREL receptors in the DM/NFR NAA that were linked to Utah (CHAT also linked to Wyoming), the 2026 MaxDVs are increased by +0.45, +0.39 and +0.38 ppb (Table 3-2). The decreases in 2026 MaxDV due to the full implementation of the Proposed Transport Rule 2023 EGU and 2026 EGU and non-EGU controls at these same three DM/NFR NAA receptors are -0.88, -0.83 and -0.82 ppb (EPA, 2022b, Table VI.D.2-2, pp.20096). That is, for receptors in the DM/NFR NAA the increases in 2026 ozone MaxDVs due to the switch in 2026 emissions between Steps 1&2 and Step 3 negates half of the benefits of the Proposed Transport Rule 2026 EGU and non-EGU NO_X controls.

As discussed in detail in the Chapter 4 overcontrol analyses, these differences when combined with other deficiencies in the Proposed Transport Rule CAMx modeling (e.g., missing emissions, using insufficient grid resolution and failure to consider all emission reductions in 2026) turn many nonattainment/maintenance receptors to attainment receptors. This results in overcontrol many Upwind States so that the 2026 controls on non-EGU sources, and in some states 2026 EGU sources, are not needed.

Table 3-3. Comparison of 2026 MaxDV at non-California nonattainment/maintenance receptors due to differences in state total anthropogenic NO_X emissions used in the Step 3 2026 Engineering Analysis (EA) baseline versus the 2026 base case NO_X emissions used in Steps 1 and 2 CAMx modeling.

Site	state	county	Step 3 2026 EA MaxDV	Step1&2 2026 CAMx MaxDV	Difference 2026 EA - 2026 CAMx
40278011	Arizona	Yuma	71.81	71.80	0.01
80350004	Colorado	Douglas	71.55	71.10	0.45
80590006	Colorado	Jefferson	72.69	72.30	0.39
80590011	Colorado	Jefferson	73.68	73.30	0.38
90010017	Connecticut	Fairfield	72.30	72.20	0.10
90013007	Connecticut	Fairfield	73.99	73.70	0.29
90019003	Connecticut	Fairfield	75.03	74.80	0.23
90099002	Connecticut	New Haven	72.78	72.40	0.38
170310001	Illinois	Cook	72.87	72.50	0.37
170310032	Illinois	Cook	71.98	71.70	0.28
170310076	Illinois	Cook	71.56	71.30	0.26
170314201	Illinois	Cook	72.61	72.40	0.21
170317002	Illinois	Cook	72.27	72.00	0.27
480391004	Texas	Brazoria	73.09	71.20	1.89
482010024	Texas	Harris	77.82	75.70	2.12
490110004	Utah	Davis	74.42	73.90	0.52
490353006	Utah	Salt Lake	74.61	74.10	0.51
490353013	Utah	Salt Lake	74.60	74.00	0.60
490570002	Utah	Weber	72.22	71.70	0.52
550590019	Wisconsin	Kenosha	72.91	72.60	0.31
550590025	Wisconsin	Kenosha	71.48	71.10	0.38
551010020	Wisconsin	Racine	72.42	72.10	0.32
Average					0.49

3.6 Data in the Proposed Transport Rule Imply that 2023 Ozone Air Quality in the DM/NFR Gets Worse After Implementing Controls in the Rule

Table 3-4 duplicates the 2023 ozone MaxDVs at DM/NFR NAA receptors from the Proposed Transport Rule for the 2023 base case conditions without the proposed rule controls and the 2023 control case after the Proposed Transport Rule 2023 EGU controls are implemented on sources in Utah, Wyoming and other Upwind States linked to nonattainment/maintenance receptors in downwind states. The 2023 base case 2023 ozone MaxDVs are from Table V.D-1 and V.D-2 of the Federal Register notice for the Proposed Transport Rule (EPA, 2022b, pp. 20069-20070). And the 2023 control case 2023 ozone MaxDVs are from Table VI.D.1-1 and represent 2023 maximum ozone design values after the implementation of the 2023 NO_X controls on EGU sources in Upwind States, including Utah and Wyoming (EPA, 2022b, pp.20092). Table 3-4 shows how illogical and nonsensible the Proposed Transport Rule is because after implementing the 2023 EGU NO_X controls data in the Proposed Transport Rule indicate that ozone air quality gets worse at receptors in the DM/NFR NAA; data in the Proposed Transport Rule imply that the 2023 MaxDV at sites in the DM/NFR NAA go up from 0.50 to 0.69 ppb after implementing the Proposed Transport Rule 2023 EGU NO_X controls in Upwind States.

Table 3-4. 2023 Ozone MaxDV from Proposed Transport Rule for Receptors in the DM/NFR NAA and 2023 Base Case and 2023 Control Case Conditions.

Site	State	County	2023 Base Case[a]	2023 Control Case[b]	Difference 2023 Control - 2023 Base Case
80350004	Colorado	Douglas	72.30	72.89	0.59
80590006	Colorado	Jefferson	73.30	73.80	0.50
80590011	Colorado	Jefferson	74.40	75.09	0.69

a. Source: EPA, 2022b, Table V.D-1, pp. 20069-20070
b. Source: EPA, 2022b, Table VI.D.1-1, pp. 20092

3.7 2026 Engineering Analysis Change in Emissions Done Without State Input

EPA's change in 2026 EGU NO_X emissions using the Engineering Analysis was done without consulting state agencies who co-regulate these sources. EPA essentially abandons over 2 years of consultation with MJOs, states, local agencies, tribes and stakeholders in the Inventory Collaborative to develop the 2016v1 platform emissions and conducted their own backroom analysis to develop the 2016v2 platform 2023 and 2026 emissions without allowing states to provide input and provide better emission estimates. And then they conduct a second backroom analysis and change the 2023 and 2026b emissions in mid-rule in the Step 3 2023 Engineering Analysis using a proprietary opaque model (IPM) again without any input from the states. And these changes were quite large, as discussed in Chapter 1, the PacifiCorp 2023 EGU NO_X emissions in Wyoming were increased by almost a factor of 4 between the Proposed Rule Step 1&2 CAMx modeling and the Proposed

Transport Rule 2023 Engineering Analysis emissions used in the Step 3 controls analysis.

As discussed in Chapter 4, these changes in 2026 emissions, and other factors, have a big effect on the Proposed Transport Rule findings of significant ozone contributions to nonattainment/maintenance and proposed control measures to alleviate the Upwind State significant contributions.

3.8 References

EPA. 2022a. Technical Support Document (TSD) for the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard. Docket ID No. EPA-HQ-OAR-2021-0668. Ozone Transport Policy Analysis Proposed Rule TSD. U.S. Environmental Protection Agency, Office of Air and Radiation. February. (https://www.epa.gov/system/files/documents/2022-03/ozone-transport-policy-analysis-proposed-rule-tsd.pdf).

EPA. 2022b. Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard. Federal Register / Vol 87, No. 66 / Wednesday, April 6, 2022 / Proposed Rules. Pp. 20036-2026. (https://www.govinfo.gov/content/pkg/FR-2022-04-06/pdf/2022-04551.pdf).

4.0 THE PROPOSED TRANSPORT RULE OVERCONTROLS EMISSIONS IN UTAH AND WYOMING

The Proposed Transport Rule links Wyoming and Utah to nonattainment/maintenance receptors in the Denver Metro/North Front Range (DM/NFR) ozone nonattainment area (NAA). However, EPA's CAMx modeling overstates the projected 2023 and 2026 ozone design values at the DM/NFR NAA receptors. By 2026, the Chatfield (CHAT) receptor in the DM/NFR NAA will be an attainment receptor so Wyoming should not be included in the proposed rule 2026 EGU and non-EGU NO_X controls as that is the only receptor Wyoming is linked to. By 2026 we estimate that the only remaining nonattainment/maintenance receptor in the DM/NFR NAA is NREL and Utah does not have a statistically significant contribution to the NREL receptor (see Chapter 7) so Utah also not be subject to the 2026 EGU and non-EGU controls in the Proposed Transport Rule.

4.1 Missing Anthropogenic Emission Controls in the DM/NFR NAA Will Result in Reductions in Future Year Ozone Design Values

EPA used the MOVES3[19] mobile source emissions model to define mobile source emissions for the 2016, 2023 and 2026 emission scenarios. MOVES3 uses vehicle sales through 2020 to define the level of Electric Vehicle (EV) sales penetration for each year. However, MOVES3 assumes zero EV sales in Colorado for year 2021 and newer years, presumably because EV sales are not a federally enforceable control measure. This is clearly an incorrect assumption as EV sales in 2021 were greater than previous years.[20]

On January 17, 2019, the Governor of Colorado issued Executive Order B 2019 002[21] to support a transition to zero emission vehicles. The Colorado Electric Vehicle Plan 2020[22] lays out the blueprint for increasing sales of EVs stablishing a target of almost a million EVs in the state by 2030, which is approximately half of how many vehicles are currently in Colorado. Thus, increased EV sales are a reality in Colorado and assuming no EV sales from 2021 on in MOVES3 will overstate future year NO_X and VOC emissions in the DM/NFR NAA and other areas in Colorado resulting in EPA overstating the 2023 and 2026 ozone design values in their Proposed Transport Rule.

The Clean Air Act (CAA) allows California to set its own motor vehicle emission emissions standards provided they are no less stringent than the Federal standards. Under Section 177 of the CAA (42 U.S.C. 7507), states are allowed to opt-in to California's Low-Emissions Vehicle (LEV) criteria pollutants and greenhouse gas (GHG) emissions regulations and Zero Emissions Vehicle (ZEV) regulations. Colorado is one of 14 Section 177 states that have adopted the California motor vehicle emission standards[23], which includes a ZEV mandate that is mainly EVs. Thus, EV sales in Colorado from 2021 are a reality and legally binding under Section

[19] https://www.epa.gov/moves/latest-version-motor-vehicle-emission-simulator-moves
[20] https://driveelectriccolorado.org/evs-on-the-road-may2021/
[21] https://www.colorado.gov/governor/sites/default/files/inline-files/b_2019-002_supporting_a_transition_to_zero_emissions_vehicles.pdf
[22] https://drive.google.com/file/d/1-z-INQMU0pymcTQEH8OvnemgTbwQnFhq/view
[23] https://ww2.arb.ca.gov/sites/default/files/2022-05/%C2%A7177_states_05132022_NADA_sales_r2_ac.pdf

177 of the CAA and assuming there are none, as in the Proposed Transport Rule, is incorrect and will overstate Colorado VOC and NO_X emissions in 2023 and 2026 resulting in overstating 2023 and 2026 ozone design values at nonattainment/maintenance receptors in the DM/NFR NAA.

On April 13, 2022, EPA proposed to redesignate the DM/NFR ozone NAA from Serious to Severe under the 2008 ozone NAAQS[24] due to failure to attain by the July 20, 2021 attainment date for a Serious ozone NAA. As a Severe ozone NAA, the DM/NFR NAA will be subject to additional requirements that will reduce NO_X and VOC emissions. One such mandatory requirement for a Severe ozone NAA is the implementation of reformulated gasoline (RFG) in the NAA that will reduce NO_X and VOC emissions resulting in reduced ozone concentrations. The Proposed Transport Rule 2026 ozone design value projections did not account for the fact that RFG will be mandatory in the DM/NFR NAA resulting in an overstatement of 2026 emissions and 2026 ozone design values.

4.2 EPA's Modeling Understates Ozone due to DM/NFR NAA Emissions so Understates the Amount of Ozone Reductions due to Local Emission Reductions in the DM/NFR NAA

The DM/NFR NAA has gone through several rounds of ozone SIPs over the last two decades. In order to account for the complex meteorology of the Front Range and to not overdilute the DM/NFR NAA urban and suburban emissions, the DM/NFR ozone SIPs CAMx photochemical modeling have used a 4-km grid resolution. EPA's CAMx modeling for the Proposed Transport Rule used a 12-km grid resolution so EPA's modeling grid cell sizes are almost an order magnitude (9 times) larger than used in the DM/NFR NAA SIP modeling. The 12-km grid resolution used in EPA's modeling instantaneously disperses the DM/NFR NAA emissions across a large volume thereby reducing ozone precursor concentrations and reducing the rate of ozone formation resulting in an inability of the CAMx 12-km modeling to simulate the highest observed ozone concentrations in the DM/NFR NAA. The DM/NFR NAA urban plume is diluted by the coarse 12-km grid thereby reducing ozone due to local sources so there are less ozone reductions between 2016 and future years due to the reductions of local NO_X and VOC emissions in the DM/NFR NAA.

Figure 4-1 presents NO_X emissions for the 9-county DM/NFR ozone NAA (includes whole counties) that was presented at the May 18, 2022 RAQC Ozone Modeling Forum that shows substantial reductions in NO_X emissions between the 2016 base and the 2023 (-23%) and 2026 (-27%) future years so the reduction in ozone due to local source emission reductions is very real. The biggest emission reductions (approximately -60%) come from on-road mobile sources. And these future year on-road mobile source emission estimates understate the emission reductions between the base and future years as they used MOVES3 so don't include the effects of EV sales in 2021 and newer years or RFG in 2026. Therefore, actual 2026 mobile source emissions will be lower than indicated in Figure 4-1.

[24] https://www.govinfo.gov/content/pkg/FR-2022-04-13/pdf/2022-07509.pdf

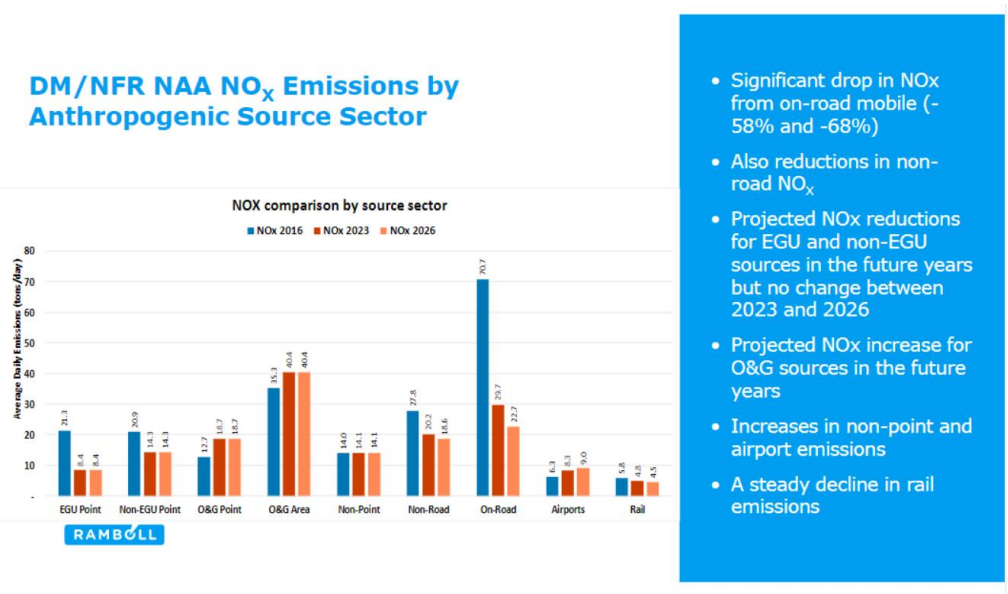

Figure 4-1. 2016, 2023 and 2026 NO_X emissions in the 9-county DM/NFR ozone NAA (Source: May 18, 2022 RAQC Ozone Modeling Forum[25]).

4.3 The Proposed Ozone Transport Rule Overcontrol Analysis Estimated that Chatfield Would be an Attainment Receptor in 2026

The Proposed Transport Rule conducted an overcontrol analysis for 2026 using the rule's Air Quality Assessment Tool (AQAT) to make sure that the controls implemented would not: (1) reduce the maximum 2026 ozone design value (MaxDV) to below the 70 ppb 2015 NAAQS at all receptors that an Upwind State has a significant contribution to so they are all attainment receptors; or (2) reduce an Upwind State's ozone contribution to below the 1 percent of the NAAQS significance threshold at all downwind state nonattainment/maintenance receptors.

4.3.1 Proposed Transport Rule Initial Overcontrol Analysis for Chatfield

When conducting the original 2026 overcontrol analysis, EPA assumed that the downwind state that contained the nonattainment/maintenance receptor(s) had a similar level of NO_X control as the Upwind State. This is a very reasonable assumption and likely conservative (i.e., tending to understate actual NO_X reductions in the downwind state) since most of the nonattainment/maintenance receptors are located in ozone NAAs that will be implementing VOC/NO_X controls and many of these nonattainment/maintenance receptors are highly influenced by ozone formed from local mobile sources whose emissions are overstated in EPA's modeling due to the EV and RFG issues discussed in Section 4.2 above.

When the Proposed Transport Rule original overcontrol analysis was applied for the Wyoming linkage to the Chatfield (site 080350004 in Douglas County) receptor they found the following:

[25] https://raqc.egnyte.com/dl/kzR8aJm0zl/2022_Modeling_Forum_-_2023_and_2026_Design_Value_Projections.pdf_

> *"In 2026, of the 22 receptors, three receptors have their maximum design values drop below 71 ppb. The maximum design value for monitor 80350004 in Douglas County Colorado drops below 71 ppb when EGU emission reductions associated with new SCR are applied (inclusive of comparable reductions in Colorado, which is not linked to a receptor in another state)."* (EPA, 2022, pp. 47).

Table 4-1 displays the 2026 maximum design value (MaxDV) at Chatfield from the Proposed Transport Rule original overcontrol analysis that shows the 2026 MaxDV being reduced to below the 2015 ozone NAAQS after implementation of the 2026 EGU controls so that the 2026 non-EGU controls in Wyoming are not needed.

Table 4-1. Proposed Transport Rule original 2026 overcontrol analysis for the Chatfield receptor showing the 2026 MaxDV being reduced to below the 2015 ozone NAAQS (yellow shading) (Source: EPA, 2022, Table C-9, pp. 52).

Maximum DV								
2026-Centered Max DV (ppb	**71.1**							
	Engineering Analysis Base	SCR Optimize + Generation Shifting	SCR Optimize + SOA CC + Generation Shifting	SCR Optimize + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1 + Tier 2
Maximum DV (ppb)	71.5456	71.4935	71.4791	71.4932	71.4787	70.8250	70.6713	70.6708
CA	0.8718	0.8693	0.8693	0.8693	0.8693	0.8693	0.8593	0.8589
CO	15.8078	15.7976	15.7976	15.7976	15.7976	15.4924	15.4128	15.4128
UT	1.3488	1.3377	1.3377	1.3377	1.3377	1.1746	1.1511	1.1511
WY	0.9161	0.8957	0.8835	0.8954	0.8832	0.7981	0.7811	0.7811

4.3.2 Proposed Transport Rule Revised Overcontrol Analysis for Chatfield

EPA modified their standard overcontrol analysis approach to conduct an "alternative assessment" where they assumed no additional emission reductions in the downwind state:

> *"Lastly, as an alternative assessment, it was possible to estimate air quality concentrations in the 'control scenario' at each downwind receptor using the ozone AQAT. Here, we apply a scenario where all states (regardless of whether they are linked to a particular receptor or to a different receptor in the geography) have the same cost threshold applied as do the 'linked' states. And, for these cases, we kept the states containing the receptor (such as Colorado and Connecticut) that are not linked to receptors in other states at base case emission levels (rather than modulate them up to the same threshold as the linked upwind states). This allows us to assess whether impacts from states that are not specifically linked to a receptor would result in potential overcontrol. It also allows us to assess whether the assumption that a receptor state makes 'fair share' emission reductions generates any*

> *instances of apparent 'overcontrol' that is not actually certain to occur. In general, the differences are relatively small (though, for the receptors in Colorado to which Wyoming is linked), this difference is larger and it affects whether or not the receptor has its maximum design value drop below 71 ppb."* (EPA, 2022, pp. 48).

The assumption that there would be no additional NO_X controls in 2026 in the downwind state is clearly incorrect (see EV discussion above). Most of these receptors, including Chatfield, are in an ozone NAA where additional emissions reductions will occur.

Table 4-2 displays the revised overcontrol analysis for Chatfield using the "alternative assessment" approach with the Chatfield 2026 MaxDV being above the 2015 ozone NAAQS at all levels of control because the contribution from Colorado is held constant at the 2026 Engineering Analysis baseline emissions level.

Table 4-2. Proposed Transport Rule "alternative assessment" 2026 overcontrol analysis for the Chatfield receptor and 2026 MaxDV (Source: EPA, 2022, Table C-14, pp. 57).

Maximum DV								
2026-Centered Max DV (ppb	**71.1**							
	Engineering Analysis Base	SCR Optimize + Generation Shifting	SCR Optimize + SOA CC + Generation Shifting	SCR Optimize + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1 + Tier 2
Maximum DV (ppb)	71.5456	71.5024	71.4875	71.5020	71.4871	71.1585	71.0947	71.0940
CA	0.8718	0.8693	0.8693	0.8693	0.8693	0.8693	0.8593	0.8589
CO	15.8078	15.8078	15.8078	15.8078	15.8078	15.8078	15.8078	15.8078
UT	1.3488	1.3377	1.3377	1.3377	1.3377	1.1746	1.1511	1.1511
WY	0.9161	0.8957	0.8835	0.8954	0.8832	0.7981	0.7811	0.7811

4.3.3 Even the Revised Alternative Overcontrol Assessment Shows Chatfield as an Attainment Receptor When the Overcontrol Analysis is Made Consistent with Step 1 of the Proposed Transport Rule

When developing AQAT (AQAT is discussed in more detail in Chapter 8), EPA did an "Engineering Analysis" for 2023 and 2026 EGU NO_X emissions using the Integrated Planning Model (IPM) to develop new 2023 and 2026 baseline emissions that were different than EPA's 2016v2 modeling platform 2023 and 2026 base case emissions used in Step 1 and 2 CAMx modeling of the four-step transport framework. These changes in 2026 NO_X emissions were quite large for some states, such as Utah and Wyoming where NO_X emissions increased by ~16% between the CAMx modeling used in Steps 1&2 and the AQAT analysis used in Step 3 (see Table 3-1). This creates inconsistencies and a disconnect between the Steps 1&2 of the Proposed Transport Rule, to define nonattainment/maintenance receptors and state ozone contributions, and the Step 3 controls analysis.

We adjusted the Proposed Transport Rule "alternative assessment" overcontrol analysis for the Chatfield monitor 2026 AvgDV and MaxDV to make them consistent with the Step 1 CAMx 2026 ozone design value projections as shown in Table 4-3. The original CAMx 2026 base case projected 2026 AvgDV and MaxDV at Chatfield were, respectively, 70.5 and 71.1 ppb (blue shading in Table 4-3). Using the Step 3 2026 Engineering Analysis baseline emissions, AQAT estimates 2026 AvgDV and MaxDV of, respectively, 70.9 ppb and 71.5 ppb, 0.4 ppb greater than the CAMx Step 1 values. When the 2026 AvgDV and MaxDV "alternative assessment" overcontrol analysis for Chatfield are adjusted to be consistent with the Step 1 CAMx projected design values, the 2026 MaxDV is reduced to below the 2015 ozone NAAQS after implementation of the 2026 EGU controls (70.72 ppb) resulting in overcontrol of Wyoming 2026 non-EGU sources.

Table 4-3. Overcontrol analysis "alternative assessment" for the Chatfield receptor using AQAT from the Proposed Transport Rule policy document (EPA, 2022, Tables C-13 and C-14, orange in the figure) that are adjusted to be consistent with the Proposed Transport Rule CAMx modeling from Step 1 (blue shaded data except 2026 MaxDV below the 2015 ozone NAAQS that are shaded yellow).

site	state	county						
80350004	Colorado	Douglas						
2026-Centered Avg DV (ppb	70.5		2026-Centered Max DV		71.1			
	Engineering Analysis Base	SCR Optimize + Generation Shifting	SCR Optimize + SOA CC + Generation Shifting	SCR Optimize + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1	SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1 + Tier 2
Average DV (ppb)	70.9419	70.8990	70.8843	70.8986	70.8838	70.5580	70.4947	70.4941
CA	0.8644	0.8620	0.8620	0.8620	0.8620	0.8620	0.8520	0.8516
CO	15.6744	15.6744	15.6744	15.6744	15.6744	15.6744	15.6744	15.6744
UT	1.3374	1.3264	1.3264	1.3264	1.3264	1.1647	1.1414	1.1414
WY	0.9083	0.8881	0.8760	0.8879	0.8757	0.7914	0.7746	0.7746
Maximum DV	71.5456	71.5024	71.4875	71.5020	71.4871	71.1585	71.0947	71.0940
Adjusted to CAMx								
Average DV (ppb)	70.50	70.46	70.44	70.46	70.44	70.12	70.06	70.06
Maximum DV	71.10	71.06	71.04	71.06	71.04	70.72	70.65	70.65

4.4 Modeling for the DM/NFR 2023 Severe/Moderate Ozone SIP Estimates Chatfield And Rocky Flats North will be Attainment Monitors in 2026

The Denver Regional Air Quality Council (RAQC), with the Colorado Department of Public Health and Environment (CDPHE), is preparing a 2023 Severe/Moderate ozone State Implementation Plan (SIP) for the DM/NFR ozone NAA that includes 2026 future year modeling to address attainment of the 2008 NAAQS as a Severe ozone NAA and 2023 future year modeling to address attainment of the 2015 NAAQS as a Moderate ozone NAA. The 2023 Severe/Moderate ozone SIP 2026 and 2023 ozone design value projections were presented at a May 18, 2022 RAQC Ozone Modeling Forum.[26] Tables 4-4 and 4-5 present the observed base year average and maximum ozone design values (Avg DVB and Max DVB) and future year average and maximum ozone design values (Avg DVF and Max DVF) from the, respectively, Proposed Transport Rule and RAQC 2023 Severe/Moderate ozone SIP modeling. The design values in Tables 4-4 and 4-5 are for the four key monitoring sites in the DM/NFR NAA that always have the highest ozone design values and include the three nonattainment/maintenance receptors from the Proposed Transport Rule: Chatfield (CHAT). Rocky Flats North (RFNO and the National Renewable Energy Laboratory (NREL). Design values that are above the 2015 ozone NAAQS are shaded yellow in Tables 4-4 and 4-5.

In 2023, the Proposed Transport Rule has CHAT receptor as a nonattainment receptor since the 2023 projected Avg DVF and Max DVF and the observed $DV_{2018-2020}$ are all above the 2015 ozone NAAQS (Table 4-4). On the other hand, the DM/NFR Severe/Moderate ozone SIP has CHAT as a maintenance receptor because the 2023 Avg DVF is below and the 2026 Max DVF is above the 2015 ozone NAAQS (Table 4-5). The Proposed Transport Rule also has the RFNO and NREL receptors as nonattainment receptors but the DM/NFR ozone SIP modeling has RFNO as a maintenance and NREL as a nonattainment receptor.==

In 2026, the Proposed Transport Rule has CHAT as a maintenance receptor since the 2026 Max DVF is above (71.1 ppb) and 2026 AvgDVF is below (70.5 ppb) the 2025 ozone NAAQS. The DM/NFR Severe/Moderate ozone SIP modeling has CHAT as an attainment receptor since the 2026 Max DVF (69.6 ppb) is below the 2015 ozone NAAQS. Similarly, in 2026 the RFNO receptor is a maintenance receptor in the Proposed Transport Rule but an attainment receptor in the DM/NFR ozone SIP modeling. Both the Proposed Transport Rule and the DM/NFR ozone SIP modeling have NREL as a nonattainment receptor in 2026.

[26] https://raqc.org/event/2022-raqc-modeling-forum/

Table 4-4. Observed 2014-2018 average and maximum ozone DVB and projected 2023 and 2026 average and maximum ozone DVF at sites in the DM/NFR ozone NAA from the Proposed Transport Rule using EPA's 2016v2 12-km CAMx modeling platform (yellow shading indicates design values above the 70 ppb 2015 ozone NAAQS).

EPA Proposed Transport Rule		2014-2018	2014-2018	2023	2023	2026	2026
Site ID	Name	Avg DVB	Max DVB	Avg DVF	Max DVF	Avg DVF	Max DVF
08035004	CHAT	77.3	78	71.7	72.3	70.5	71.1
080590006	RFNO	77.3	78	72.6	73.3	71.7	72.3
080590011	NREL	79.3	80	73.8	74.4	72.6	73.3
080690011	FTCW	75.7	77	71.3	72.6	70.6	71.8

Table 4-5. Observed 2014-2018 average and maximum ozone DVB and projected 2023 and 2026 average and maximum ozone DVF at sites in the DM/NFR ozone NAA from modeling for the 2023 DM/NFR Severe/Moderate ozone SIP using RAQC's 2016 36/12/4-km CAMx modeling platform (yellow shading indicates design values above the 70 ppb 2015 ozone NAAQS) (Source: May 18, 2022 RAQC Ozone Modeling Forum).

Draft 2023 Severe/Moderate SIP		2014-2018	2014-2018	2023	2023	2026	2026
Site ID	Name	Avg DVB	Max DVB	Avg DVF	Max DVF[a]	Avg DVF	Max DVFa
08035004	CHAT	77.3	78	70.6	71.3	68.9	69.6
080590006	RFNO	77.3	78	70.3	71.0	68.7	69.4
080590011	NREL	79.3	80	73.4	74.1	72.0	72.7
080690011	FTCW	75.7	77	70.4	71.6	69.1	70.4

- Source: RAQC May 18, 2022 Modeling Forum
- https://raqc.egnyte.com/dl/kzR8aJm0zl/2022_Modeling_Forum_-_2023_and_2026_Design_Value_Projections.pdf

a. Denver Max DVF estimated by ratio off of Avg DVF

4.5 Reasons Why DM/NFR Ozone SIP CAMx Modeling Estimates Lower Projected Future Year Ozone DVF than Proposed Transport Rule CAMx Modeling

The DM/NFR Severe/Moderate ozone SIP modeling likely estimates more reliable and accurate 2023 and 2026 ozone DV projections than the CAMx modeling in the Proposed Transport Rule for the following reasons:

- The Severe/Moderate ozone SIP CAMx modeling was tailored for simulating ozone in the DM/NFR ozone NAA, whereas EPA's Proposed Transport Rule CAMx modeling was national modeling not optimized to simulate ozone in the DM/NFR NAA.
- The DM/NFR Severe/Moderate ozone SIP CAMx modeling used a higher grid resolution (4-km) and 4-km WRF meteorological inputs for Colorado while EPA's Proposed Transport Rule CAMx and WRF modeling used a coarse 12-km grid resolution that does a poorer job in replicating the complicated meteorology in the Rocky Mountain region due to poor representation of terrain features.
- The DM/NFR ozone SIP CAMx modeling exhibited better ozone model performance at the key DM/NFR NAA monitoring sites estimated higher ozone concentrations that matched the observed ozone better while the EPA Proposed Transport Rule CAMx modeling had an ozone underestimation bias that fails to achieve the ozone Performance Goal.

- With the higher resolution grid size and meteorology, the DM/NFR ozone SIP CAMx modeling produces higher ozone due to local emissions resulting in more ozone reductions from the local emission controls (e.g., mobile sources) resulting in lower projected future year ozone DVs than the Proposed Transport Rule CAMx modeling.

Figure 4-2 displays the 36/12/4-km grid resolution modeling domains used in the DM/NFR Severe/Moderate ozone SIP CAMx modeling. CAMx was run using two-way grid nesting where pollutants can flow in and out of the different resolution domains. The 4-km grid resolution domain covered the state of Colorado and small portions of neighboring states. The Proposed Transport Rule used a single 12-km grid resolution domain that was identical to same 12-km grid resolution CONUS domain as used in the DM/NFR CAMx modeling shown as the red domain in Figure 3-2. The DM/NFR Severe/Moderate ozone SIP used the same 2016, 2023 and 2026 emissions in the 12-km CONUS domain and almost the same emissions in the 4-km Colorado domain as the Proposed Transport Rule CAMx 12-km modeling.

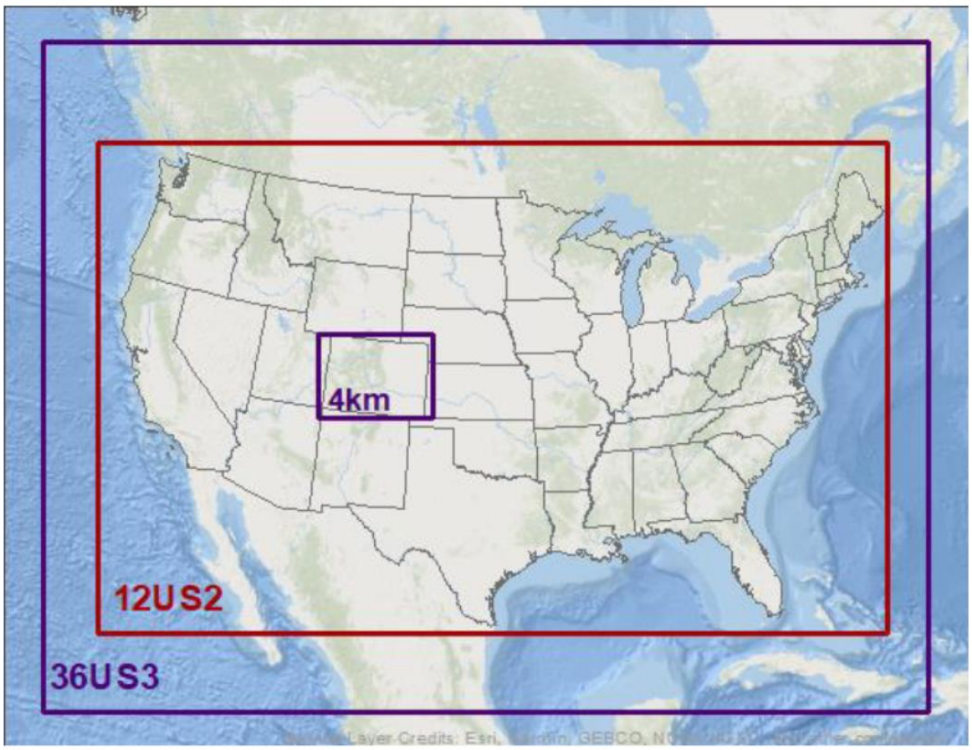

Figure 4-2. CAMx 36/12/4-km grid resolution modeling domains used in the DM/NFR Severe/Moderate ozone SIP modeling (Source: DM/NFR 2023 Severe/Moderate SIP Modeling Protocol available on RAQC website[27]).

[27] https://raqc.egnyte.com/dl/km9ImVMoM1/Modeling_Protocol_DM-NFR_Severe-Moderate_SIP.pdf_

4.5.1 Effects of Higher Resolution 4-km Grid in DM/NFR SIP Modeling

The DM/NFR ozone NAA roughly corresponds to the Front Range Urban Corridor that had a population of approximately 5 million and includes the Denver Metropolitan Statistical Area that had a population of almost 3 million people in the 2020 census. The DM/NFR ozone NAA also includes a portion of the Denver-Julesburg (D-J) oil and gas (O&G) basin. The urban and suburban areas and O&G production result in high density NO_X and VOC emissions in the DM/NFR NAA. Figure 4-3 displays the total NO_X and VOC emissions at 4-km resolution for the 2016 base case and differences between the 2016 and 2023 base cases. The high density NO_X and VOC emissions in the DM/NFR NAA and D-J O&G basin are clearly evident. In the CAMx model, emissions are emitted into and instantaneously dispersed evenly across the grid cell volume. In order to properly simulate ozone formation in the DM/NFR NAA, a high resolution grid cell size needs to be used. All of the Denver ozone SIPs in the past have used a 4-km grid resolution to simulate the correct meteorology and chemistry and resolve the urban plumes so that the model has a chance to reproduce the highest observed ozone concentrations. Use of a coarse 12-km grid will instantaneously disperse emissions across a grid cell volume that is almost an order magnitude larger than when a 4-km grid size is used making it difficult for the model to reproduce the high observed ozone peaks due to overdiluting the ozone concentrations and its precursors.

Note that use of a coarse 12-km grid resolution will also reduce ozone peaks due to local sources in the Upwind State due to failure to resolve urban and other highly concentrated ozone precursor emission sources (e.g., industrial facilities, O&G, etc.) and their resultant ozone plumes. However, by the time the ozone and precursor concentrations from the Upwind State travel 100s of miles to the receptor in the downwind state the "plumes" will be many 12-km grid cells across so that the effects of the coarse resolution on underestimating ozone concentrations at the receptor in the downwind state due to emissions in the Upwind State is less important.

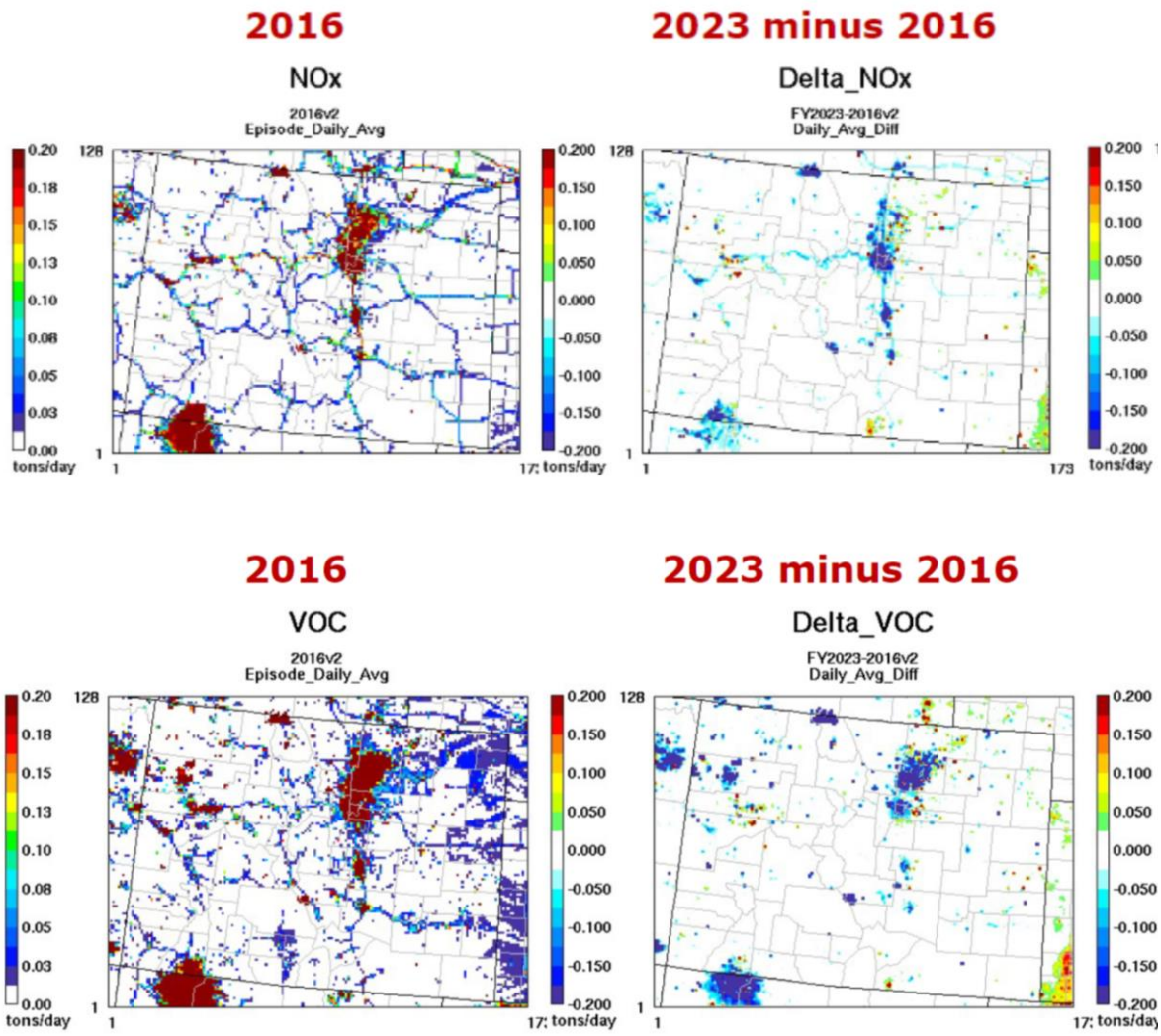

Figure 4-3. Total anthropogenic NO_X (top) and VOC (bottom) emissions (tons per day) within the CAMx 4-km Colorado domain used in the DM/NFR 2023 Severe/Moderate ozone SIP. Shown are emissions for the 2016 base case (left) and differences between the 2023 and 2016 base cases (right) (Source: RAQC Ozone Modeling Forum[28]).

[28] https://raqc.egnyte.com/dl/kzR8aJm0zl/2022_Modeling_Forum_-_2023_and_2026_Design_Value_Projections.pdf_

4.5.2 Effects of Higher Resolved Meteorological Inputs on Ozone Concentrations in the DM/NFR Ozone SIP Modeling

Obtaining the correct depiction of meteorology is critically important for simulating ozone formation in the complex terrain conditions of the DM/NFR NAA. To better understand this importance, we first discuss the conditions that lead to the highest ozone concentrations in the DM/NFR NAA.

4.5.2.1 Conceptual Model of Ozone Formation in the DM/NFR NAA

The DM/NFR 2020 Serious ozone SIP for the 2008 ozone NAAQS (RAQC and CDPHE, 2020) included a report "Conceptual Model of High Ozone for the Denver Metro/North Front Range" (Ramboll, 2020). The highest ozone concentrations in the DM/NFR NAA are due to a combination of ozone transport and locally generated ozone under specific meteorological regimes that favor ozone photochemistry and limited dispersion. Reddy and Pfister (2016) explored the relationships between meteorology and ozone in the Rocky Mountain states and concluded that increases in upper level high pressure strength "lead to high July ozone in much of the western U.S., particularly in areas of elevated terrain near urban sources with high emissions of NO_2 and other ozone precursors." In addition to bringing warmer temperatures, upper level ridges in this region reduce westerly winds at the surface and aloft to allow cyclic terrain-driven circulations that reduces transport away from sources. This includes the formation of thermally driven upslope flows along the Front Range in the DM/NFR NAA where ozone and ozone precursors are transported up the slopes during the day and can return at night to lower elevations in large scale basin drainage (downslope) flows. Upper level ridges can also increase background ozone concentrations within the ridge. Ozone and NO_X concentrations build locally, and deeper vertical mixing in this region provides a potential mechanism for recapture of ozone in layers aloft (e.g., from transport or remnants of the previous days ozone) that are mixed down to the surface.

The three key elements of a conceptual model for high-concentration ozone episodes along Colorado's Front Range are:

1. The presence of an upper-level high pressure system or ridge.
2. Reduced westerly winds, especially during the day.
3. Thermally-driven upslope flow towards the Continental Divide during the day and downslope drainage flows into the Platte Valley at night. This diurnal cycle of winds enhances the potential for the accumulation of ozone precursors and ozone within the region, especially when this cyclic pattern recurs over a period of several days.

4.5.2.2 Requirements for WRF Meteorological Model to Reproduce DM/NFR NAA Ozone Conceptual Model

In order for the Weather Research and Forecasting (WRF) meteorological model to reproduce the meteorological conditions that lead to the highest ozone concentrations in the DM/NFR NAA it needs to be able to simulate the high pressure system/ridge and the thermally driven slope flows. Getting the high pressure system or ridge correctly requires using analysis fields used in the WRF initial and

boundary conditions (IC/BC) and four-dimensional data assimilation (FDDA) inputs. Such analysis fields that contain the presence of the high pressure/ridges include the North American Mesoscale Forecast System (NAM[29]) analysis fields that were used in the WRF simulations to develop the CAMx 2016 meteorological inputs for both the DM/NFR 2023 Severe/Moderate ozone SIP and Proposed Transport Rule CAMx 2016 modeling platforms.

For WRF to obtain an accurate depiction of the thermally driven slope flows requires the terrain inputs for the model to be representative of actual terrain. Figure 4-4 shows the terrain heights (meters above mean sea level, MSL) using 12-km and 4-km grid resolutions. Use of a 12-km grid resolution smooths the terrain and greatly reduces the terrain heights and the elevation differences of the "slopes" of the terrain along the Front Range. The slope between western Denver County to the continental divide spans approximately 7,800 feet in elevation using a 4-km grid resolution but only approximately 4,500 feet in elevation change using the 12-km grid resolution. Thus, WRF's ability to reproduce the thermally driven daytime upslope and nighttime downslope flows will be severely compromised using a 12-km grid resolution and simulated much more accurately using a 4-km grid resolution because a 12-km grid resolution fails to resolve the terrain in the region.

The higher resolution complex terrain in the 4-km data, and in reality, will also affect transport of ozone and precursors from Wyoming to the DM/NFR NAA differently than if a 12-km grid resolution is used. The higher variable wind fields from more highly resolved terrain features will disperse ozone and precursors from Wyoming as they are transported to the DM/NFR NAA than if a 12-km grid resolution is used.

[29] https://www.ncei.noaa.gov/products/weather-climate-models/north-american-mesoscale

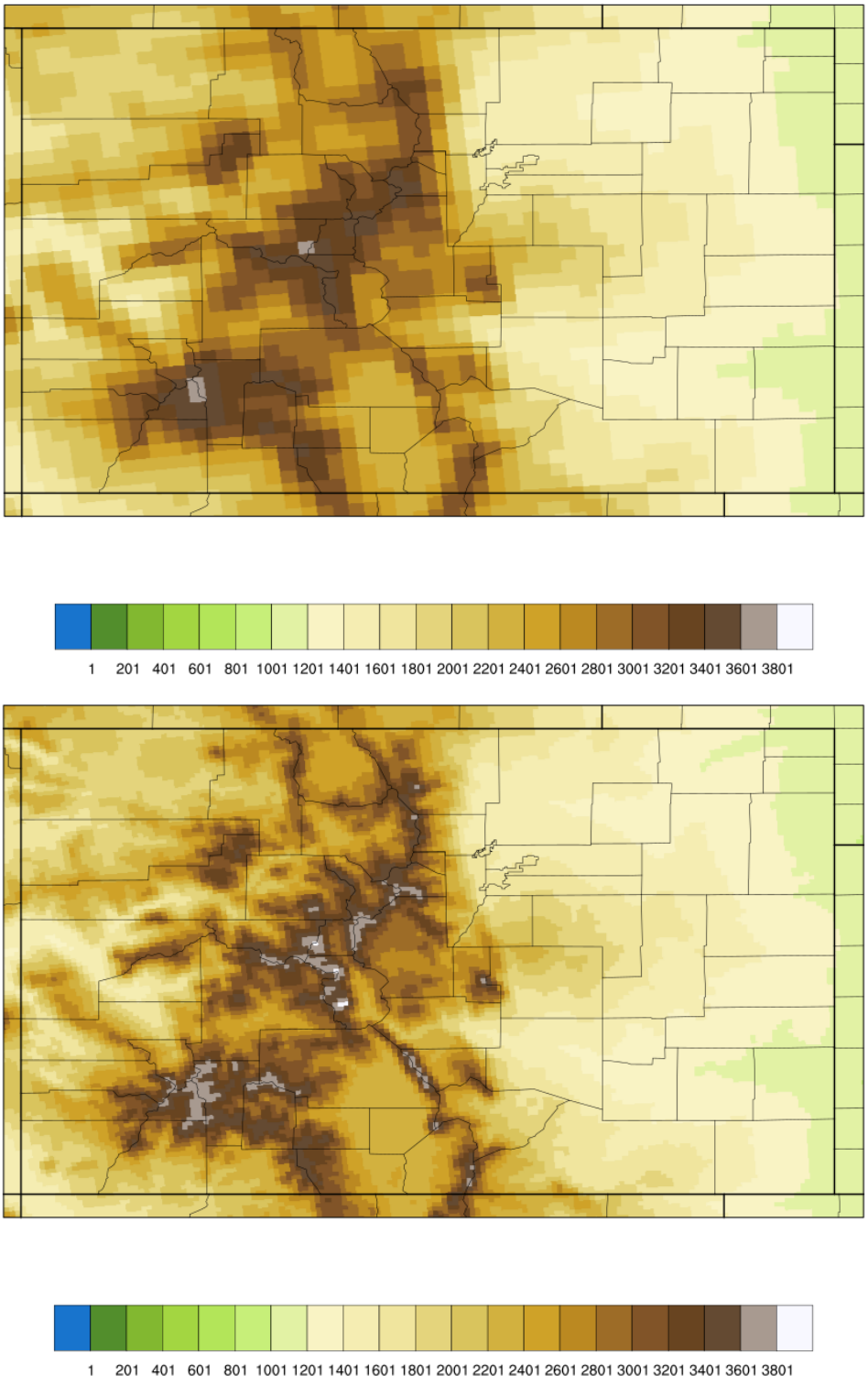

Figure 4-4. Representation of terrain (m MSL) over Colorado using a 12-km grid resolution (top) and 4-km grid resolution (bottom) (Note: domain is similar but not the same as the DM/NFR ozone SIP CAMx 4-km Colorado domain).

4.5.3 Comparison of CAMx Ozone Model Performance and Its Implications

We conducted an ozone model performance of the CAMx 2016 base case simulation used in the Proposed Transport Rule and compared it to the ozone performance of the DM/NFR 2023 Severe/Moderate ozone SIP CAMx S17 2016 base case simulation. At this time, only limited publicly available information is available on ozone model performance for the DM/NFR ozone SIP CAMx S17 2016 base case from presentations given at the May 18, 2022 RAQC Ozone Modeling Forum.[30]

Ozone model performance goals and criteria have been established by Emery and co-workers (2016) for the Normalized Mean Bias (NMB) and Normalized Mean Error (NME) model performance metrics. The NMB ozone model performance goal is ≤±5% and the NMB ozone performance criterion is ≤±15%. The NME ozone model performance goal and criterion are ≤15% and ≤25%, respectively.

Table 4-6 compare the NMB and NME performance statistics for the CAMx 2016 base case simulations performed as part of EPA's Proposed Transport Rule and as part of the DM/NFR 2023 Severe/Moderate ozone SIP. NMB and NME performance statistics that achieve the ozone model performance goals are colored green, and those that fall between the performance goals and criteria are colored yellow. The DM/NFR ozone SIP CAMx 2016 base case ozone performance is clearly performing better than the EPA Proposed Transport Rule CAMx 2016 base case at all four sites in the DM/NFR NAA. The EPA CAMx 2016 base case exhibits an ozone underestimation bias, which was expected given the coarse 12-km grid resolution used. At CHAT, the Proposed Transport Rule CAMx 2016 base case has an NMB underestimation of -7.6% while the DM/NFR 2023 Severe/Moderate ozone SIP has essentially zero bias (0.1%). The underestimation bias in the Proposed Transport Rule CAMx 2016 base case is even greater at the RFNO (-8.1%), NREL (-8.4%) and FTCW (-12.5%) sites while the DM/NFR ozone SIP CAMx 2016 base case bias achieves the bias performance goal by a wide margin.

Table 4-6. Comparison of NMB and NME ozone performance statistics (%) at the four key monitoring sites in the DM/NFR NAA and the CAMx 2016 base case simulations from EPA's Proposed Transport Rule and the DM/NFR Severe/Moderate ozone SIP. NMB/NME performance statistics that meet the ozone model performance goal are colored green.

Site	EPA Proposed Rule		DM/NFR Ozone SIP[a]	
	NMB	NME	NMB	NME
CHAT	-7.6%	11.6%	0.1%	9.2%
RFNO	-8.1%	11.3%	-0.4%	8.8%
NREL	-8.4%	11.9%	-2.0%	8.6%
FTCW	-12.5%	14.3%	-2.5%	7.8%

a. Source: https://raqc.egnyte.com/dl/8AGJMMksXC/2022_Modeling_Forum_-_2016_Base_Year_Modeling_Platform_Updates.pdf_

[30] https://raqc.org/event/2022-raqc-modeling-forum/

Ozone attainment/nonattainment is determined by the ozone design value (DV) that is defined as the three-year average of the fourth highest maximum daily average 8-hour (MDA8) ozone concentrations. Thus, how well the model simulates the four highest observed MDA8 ozone concentrations is an important model performance attribute. Table 4-7 compares the predicted and observed four highest MDA8 ozone concentrations at Chatfield during 2016 from the Proposed Transport Rule and DM/NFR Severe/Moderate ozone SIP CAMx 2016 base case simulations. The highest observed MDA8 ozone concentration at Chatfield during 2016 was 86.6 ppb that was underestimated by the Proposed Transport Rule CAMx 2016 base case (74.9 ppb) by 11.7 ppb (-13.5%). Whereas, the DM/NFR ozone SIP CAMx 2016 base case highest estimated ozone concentration at Chatfield (86.4) matched the observed value (86.6 ppb) almost exactly (within 0.2 ppb or 0.0% difference). The fourth highest observed MDA8 ozone concentration at Chatfield (78.0 ppb) is underestimated by the Proposed Transport Rule CAMx 2016 base case (71.9 ppb) by 6.1 ppb (-7.8%), while the DM/NFR ozone SIP CAMx base case fourth highest ozone at Chatfield (78.1 ppb) matches the observed fourth highest ozone very well (0.1 ppb and 0.0% difference).

Table 4-7. Comparison of the observed and modeled four highest MDA8 ozone concentrations at the Chatfield monitoring site in 2016 for the EPA Proposed Transport Rule and DM/NFR 2023 Severe/Moderate ozone SIP CAMx 2016 base case simulations.

Observed Ozone (ppb)	EPA Proposed Transport Rule		DM/NFR Ozone SIP[a]	
	Ozone (ppb)	Percent Difference	Ozone (ppb)	Percent Difference
86.6	74.9	-13.5%	86.4	-0.2%
81.0	73.1	-9.8%	81.6	0.7%
80.3	72.6	-9.6%	80.1	-0.2%
78.0	71.9	-7.8%	78.1	0.1%

a. Source: https://raqc.egnyte.com/dl/8AGJMMksXC/2022_Modeling_Forum_-_2016_Base_Year_Modeling_Platform_Updates.pdf_

Table 4-8 compares the predicted and observed four highest MDA8 ozone concentrations at the Rocky Flats North (RFNO) monitoring site in the DM/NFR NAA and the Proposed Transport Rule and DM/NFR Severe/Moderate ozone SIP CAMx 2016 base case simulations. The ozone under-prediction bias of the Proposed Transport Rule CAMx 2016 base case at RFNO is even greater than at CHAT with the four highest observed ozone concentrations underestimated by -11% to -19%. The DM/NFR ozone SIP CAMx 2016 base case also underestimates the four highest observed MDA8 ozone concentrations at RFNO but the underestimation bias (-4% to -10%) is approximately half of the Proposed Transport Rule underestimation bias. For example, the observed fourth highest MDA8 ozone at RFNO (79.5%) is underestimated by the Proposed Transport Rule by -11% (70.9 ppb) but is only underestimated by the DM/NFR ozone SIP CAMx 2016 base case by -4% (76.3 ppb), which achieves the ≤±5% ozone performance goal.

Table 4-8. Comparison of the observed and modeled four highest MDA8 ozone concentrations at the Rocky Flats North monitoring site in 2016 for the EPA Proposed Transport Rule and DM/NFR 2023 Severe/Moderate ozone SIP CAMx 2016 base case simulations.

Observed Ozone (ppb)	EPA Proposed Transport Rule		DM/NFR Ozone SIP[a]	
	Ozone (ppb)	Percent Difference	Ozone (ppb)	Percent Difference
89.6	72.9	-18.6%	81.1	-9.5%
82.4	72.7	-12.4%	77.8	-5.6%
81.6	72.6	-11.0%	77.5	-5.0%
79.5	70.9	-10.8%	76.3	-4.0%

a. Source: https://raqc.egnyte.com/dl/8AGJMMksXC/2022_Modeling_Forum_-_2016_Base_Year_Modeling_Platform_Updates.pdf_

The performance of the two CAMx 2016 base case simulations in predicting the highest ozone concentrations at NREL is shown in Table 4-9. Both CAMx 2016 base cases exhibit an underestimation of the four highest observed MDA8 ozone concentrations at NREL with the Proposed Transport Rule underestimation (-11% to -13%) being worse than the DM/NFR ozone SIP CAMx 2016 base case (-6% to -10%).

Table 4-9. Comparison of the observed and modeled four highest MDA8 ozone concentrations at the NREL monitoring site in 2016 for the EPA Proposed Transport Rule and DM/NFR 2023 Severe/Moderate ozone SIP CAMx 2016 base case simulations.

Observed Ozone (ppb)	EPA Proposed Transport Rule		DM/NFR Ozone SIP[a]	
	Ozone (ppb)	Percent Difference	Ozone (ppb)	Percent Difference
88.6	78.0	-12.0%	81.3	-8.2%
86.3	74.3	-13.9%	80.3	-9.5%
83.3	74.1	-11.0%	78.3	-6.0%
83.3	73.8	-11.4%	76.1	-8.6%

a. Source: https://raqc.egnyte.com/dl/8AGJMMksXC/2022_Modeling_Forum_-_2016_Base_Year_Modeling_Platform_Updates.pdf_

4.6 Conclusions On Future Year Projected Ozone Design Values at DM/NFR Nonattainment/Maintenance Receptors

Based on scientific technical arguments, the coarse 12-km grid resolution used in the Proposed Transport Rule CAMx modeling will likely overstate future year design value projections. This was confirmed by the DM/NFR 2023 Severe/Moderate ozone SIP CAMx 4-km grid resolution modeling that produced lower future year projected design values resulting in Chatfield and Rocky Flats North no longer being nonattainment/maintenance receptors in 2026. As Chatfield was the only receptor that Wyoming was linked to, the Proposed Transport Rule overcontrols Wyoming emissions by proposing 2026 EGU and non-EGU control in Wyoming even though it is not contributing to nonattainment or interfering in maintenance of the 2015 ozone NAAQS at any receptor in a downwind state.

Utah was linked to three receptors in the DM/NFR NAA (CHAT, RFNO and NREL). Two of these receptors (CHAT and RFNO) become attainment receptors based on the refined DM/NFR Severe/Moderate ozone SIP CAMx modeling, although NREL receptor remained a nonattainment receptor in the DM/NFR ozone SIP CAMx modeling (see Table 4-5). However, Utah has a 0.90 ppb ozone contribution to the NEWL receptor in 2026 and, as discussed in Chapter 7, this contribution is not a statistically significant contribution to an ozone design value. This argues that Utah should also not be subject to the 2026 EGU and non-EGU controls in the Proposed Transport Rule.

4.7 References

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5.0 UPWIND STATE OZONE CONTRIBUTIONS AT DOWNWIND STATE RECEPTORS ARE OVERSTATED

As described in detail in Chapter 1, an Upwind State 2023 and 2026 ozone contribution to an ozone design value at a nonattainment/maintenance receptor in a downwind State is based on the Contribution Factor (CF) that is the ratio of the Upwind State MDA8 ozone contribution to the receptor divided by the total MDA8 ozone at the receptor averaged over the top 10 CAMx 2023 modeled total MDA8 ozone days at the receptor. The Contribution Factor is multiplied by the 2023 and 2026 average ozone design value (AvgDV) to obtain the Upwind State 2023 and 2026 ozone contribution to the downwind receptor:

$$CF = \sum UpwindState\_Ozone / \sum Total\_Ozone$$

$$UpwindState\_Ozone\_Contribution = CF \times Ozone\_AvgDV$$

Thus, any assumptions, errors or omissions that would either: (1) increase the total MDA8 ozone concentrations at the receptor (i.e., increase the denominator in CF); or (2) reduce Upwind State's ozone contribution at the receptor (i.e., decrease the numerator in CF), would reduce the Contribution Factor and the Upwind State's ozone contribution to the downwind receptor 2023 and 2026 ozone design values.

5.1 Missing Emissions in Proposed Transport Modeling Results in Overstating Utah's and Wyoming's Ozone Contribution to Receptors in the DM/NFR NAA

The Proposed Transport Rule CAMx modeling failed to include NO_X emissions from lightning (LNOx). This is particularly important in the Front Range area of Colorado where summer thunderstorms regularly occur. Emissions from lightning can be a significant source of NO_X concentrations and resultant ozone formation. Zhang and co-workers (2003) estimate that 5% of the annual and 14% of the summer NO_X emissions in the U.S. comes from lightning. Kang and co-workers (2020) analyzed the effects of including LNOx emissions and found they were particularly important for simulating ozone in the U.S. Mountain West States (MWS), which include Colorado, Utah and Wyoming, and found LNOx emissions could increase MDA8 ozone concentrations by up to 17 ppb and concluded "summertime surface-level O3 levels in the MWS region could be significantly influenced by lightning NO_X." (Kang et al., 2020). If naturally occurring LNOx emissions were included in the Proposed Transport Rule CAMx modeling that would increase the total MDA8 ozone concentrations at the DM/NFR NAA receptors resulting in a reduced Utah and Wyoming Contributions Factors and lower Utah and Wyoming ozone contributions to 2023 and 2026 ozone design values at the DM/NFR NAA receptors.

EPA developed the 2016v2 modeling platform 2016, 2023, 2026 and 2032 model-ready emissions for the CMAQ model and converted them to the CAMx format using a CMAQ2CAMx emissions converter. In doing the CMAQ to CAMx emissions conversion for the Proposed Transport Rule CAMx modeling, EPA dropped methane (CH4) emissions and some secondary organic aerosol (SOA) precursor species. The SOA precursors probably have minimal effect on ozone formation but methane acts

like a low reactive VOC in ozone formation so in higher concentrations can affect and increase ozone concentrations. Since methane is not classified as a VOC it is not included in many criteria pollutant emissions inventories. Methane is treated two ways in CAMx. First, there is a global background value of 1.75 ppm was used in CAMx v7.1, which was the version in the Proposed Transport Rule. Note that the global background methane in CAMx was recently updated to 1.85 ppm in the April 2022 release of CAMx v7.2.[31] Second, there is an excess methane species (ECH4) in the CAMx model that is added to the global background methane in the photochemical mechanism. When running a CMAQ2CAMx converter, the CMAQ methane species is typically mapped to the CAMx ECH4 species, but EPA failed to do this and dropped the CMAQ methane emissions. The Denver-Julesburg (D-J) Basin is a large oil and gas (O&G) development and production area that partly resides in the DM/NFR ozone NAA. The D-J basin O&G sources emit methane emissions that should have been included in the Proposed Transport Rule CAMx modeling. If EPA had included ECH4 emissions in the Proposed Transport Rule CAMx modeling that would have increased the 2023 and 2026 total MDA8 ozone concentrations at receptors in the DM/NFR NAA thereby reducing the CF and Utah's and Wyoming's ozone contributions to 2023 and 2026 ozone design values at the three nonattainment/maintenance receptors in the DM/NFR NAA.

5.2 Coarse Grid Resolution Will Understate Ozone Contributions due to Local Sources Resulting in Overstating Utah's and Wyoming's Ozone Contribution at DM/NFR NAA Receptors

For all the reasons presented in Chapter 4 of this report, the use of the coarse 12-km grid resolution in the Proposed Transport Rule CAMx modeling will dilute the ozone and precursor concentrations in the DM/NFR ozone NAA resulting in an understatement of modeled ozone concentrations due to local sources than if a finer grid cell size was used (e.g., 4-km). With higher modeled ozone concentrations due to local sources at receptors in the DM/NFR NAA that would increase the total MDA8 ozone concentrations and reduce the Utah and Wyoming CF resulting in reductions in Utah's and Wyoming's contribution to 2023 and 2026 ozone design values at DM/NFR NAA receptors.

5.3 Coarse Grid Meteorological Inputs Understate Ozone Due to Local Emissions and Overstate Utah's and Wyoming's Contribution to Ozone in the DM/NFR NAA

As noted in Chapter 4, the coarse grid resolution WRF meteorological modeling used to develop the CAMx 2016 meteorological used in the Proposed Transport Rule will have difficulty in simulating the thermally driven slope flows that lead to the highest ozone concentrations in the DM/NFR NAA due to insufficient representation of the terrain in the Rocky Mountain region (see Figure 4-4). This will lead to lower modeled MDA8 ozone concentrations in the DM/NFR NAA thereby reducing the Utah and Wyoming CF resulting in lower contributions of Utah and Wyoming to the 2023 and 2026 ozone design values at receptors in the DM/NGR NAA.

[31] https://camx-wp.azurewebsites.net/Files/Release_notes.v7.20.txt

The complex terrain of the Rocky Mountain region will result in more wind variations and enhanced dispersion than if smoothed terrain in the WRF modeling is used, as when using a 12-km grid resolution in the WRF meteorological modeling. Higher resolved terrain would result in more dispersion of ozone and precursors from sources in Utah and Wyoming as they are being transported toward the DM/NFR NAA potentially reducing their ozone contributions at receptors in the DM/NFR NAA.

5.4 CAMx Ozone Source Apportionment Modeling Probing Tools

The ozone source apportionment probing tools in CAMx use reactive tracers (also called tagged species) from user defined Source Groups that run in parallel to the host model and conduct an accounting of which Source Group precursors caused the formation of ozone in the model. Tagged VOC (V_i) and NOx (N_i) emissions are emitted from each Source Group i and are transported, dispersed, deposition and chemically transformed using the same algorithms as in the host model. Source Groups may be geographic regions, source categories or both (e.g., anthropogenic NO_X and VOC emissions from Utah).

5.4.1 Overview of the OSAT Ozone Source Apportionment Probing Tool

The Ozone Source Apportionment Technology (OSAT) was the first source apportionment probing tool implemented in CAMx in the 1990s. OSAT tracks the ozone formed from each Source Group i using reactive tracers that not only represent the NO_X and VOC emissions from the Source Group (N_i and V_i) but also ozone formed under more NO_X-limited[32] ($O3N_i$) and VOC-limited ($O3V_i$) ozone formation conditions along with many intermediate species associated with the Source Group. When ozone is formed in the model ($\Delta O3$), OSAT determines whether ozone formation was more NO_X-limited or VOC-limited and assigns the ozone formed to the Source Groups based on their relative contribution of the limiting precursor. For example, if ozone formation was NO_X-limited:

$$O3N_i = O3N_i + \Delta O3 \times (N_i / \sum N_i)$$

When ozone is destroyed in the model, the fractional destruction rate is applied equally across all ozone reactive tracers. Over the years the OSAT ozone source apportionment probing tool has been refined and updated to better represent ozone source apportionment in the CAMx model. The above description is a simplified explanation of how OSAT works and the reader is referred to Section 7.1 of the CAMX v7.1 user's guide for more details (Ramboll, 2020).

5.4.2 CAMx APCA Probing Tool

When ozone is formed in the model in chemical reactions involving biogenic VOC reacting with anthropogenic NO_X under VOC-limited ozone formation conditions, the OSAT ozone source apportionment probing tool assigns the ozone formed to the biogenic VOC Source Group. Use of the OSAT ozone source apportionment probing

[32] We are using the historical NO_X-limited and VOC-limited terms to indicate ozone formation conditions that are more sensitive to NO_X concentrations and ozone formation that is more sensitive to VOC concentrations (radical limited), respectively.

tool can result in lots of ozone being attributed to biogenic VOC emissions, which are mostly not controllable.

The Anthropogenic Precursor Culpability Assessment (APCA) probing tool operates in a similar manner as OSAT only it recognizes that biogenic VOC emissions are not controllable. When ozone is formed due to biogenic VOC reacting with anthropogenic NO_X under VOC-limited ozone formation conditions, a case OSAT assigns the ozone formed to the biogenic VOC Source Group, APCA redirects the ozone formed to the anthropogenic NO_X Source Group recognizing biogenic VOCs are mostly not controllable. Thus, unlike OSAT, APCA is not a true ozone source apportionment because it expresses a bias toward assigning ozone formed to one type of Source Group over another, which is why it is called a culpability assessment and not an ozone source apportionment.

5.5 Proposed Transport Rule use of APCA Culpability Assessment Probing Tool Overstates Utah and Wyoming Ozone Contributions

The Proposed Transport Rule use of the APCA probing tool will overstate Utah's and Wyoming's ozone contribution to ozone design values at downwind receptors since it is allocating ozone formed from Utah and Wyoming anthropogenic NO_X emissions reacting with biogenic VOC emissions under VOC-limited ozone formation conditions to the Utah and Wyoming NO_X emissions when a true ozone source apportionment tool would allocate ozone formed under these conditions to the biogenic VOC emissions.

5.6 Independent CAMx 2023 APCA and OSAT Source Apportionment Simulation for the Western States

We received the final disk drives with the Proposed Transport Rule CAMx 2023 and 2026 ozone source apportionment input and output files on May 3, 2022. We began transferring the data to our high-speed Linux cluster with the intention of conducting 2023 APCA and OSAT source apportionment simulations using EPA's Proposed Transport Rule CAMx source apportionment configuration. EPA ran with 56 Source Groups corresponding to U.S. anthropogenic emissions from the 48 contiguous states plus DC and tribal, Mexico/Canada, Offshore, Fires, initial conditions (IC) and boundary conditions (BC). We estimate that a CAMx source apportionment simulation using the full 56 Source Groups would take approximately 80-100 days to complete.[33] Given that there was less than 50 days from when we got the disk drive of data from EPA on May 3 to the June 21, 2022 end of the comment period, we were unable to conduct a full CAMx source apportionment run identical to EPA's Proposed Transport Configuration. Instead, we reduced the number of Source Groups by focusing on the western states.

CAM 2023 12-km source apportionment simulations were conducted for the full May – September 2016 episode (with April spin-up days, 163 days total) using 12 Source Groups that consisted of anthropogenic emissions from 7 western states

[33] This time estimate was based on running CAMx for the entire May-September 2016 episode (plus April spin up days) all at once using multiprocessing with 24 CPUs. Some speed up could be obtained by using more CPUs and/or splitting the episode up into segments with appropriate amount of spin up time for each segment. But it would take time to change the model run configuration and if the configuration was changed it may not reproduce EPA's results in the Proposed Transport Rule.

(AZ, CA, CO, NM, NV, UT and WY), biogenic, fires, remainder anthropogenic emissions (remainder U.S. states, Mexico/Canada and Offshore), IC and BC. With 12 Source Groups instead of 56 used in EPA's modeling the CAMx 2023 12-km APCA ozone source apportionment run time should be 20-25% of the full configuration used in the Proposed Transport Rule.

The CAMx 2023 western states APCA modeling results were processed for the three nonattainment/maintenance receptors in the DM/NFR NAA and our Upwind state ozone contribution results exactly matched those in the Proposed Transport Rule (e.g., Wyoming had a 0.81 ppb ozone contribution to 2023 ozone design value at Chatfield). Table 5-1 compare the western state ozone contributions at the four key monitoring sites in the DM/NFR ozone NAA from our western states CAMx 2023 APCA and OSAT ozone source apportionment modeling. As expected, the state with the largest difference in the APCA and OSAT ozone source apportionment modeling ozone contributions was for Colorado (-18%) as there is more VOC-limited ozone formation in the Denver Metro urban area containing the receptors than in the more rural areas.

For Wyoming, the CAMx 2023 APCA ozone source apportionment had a 0.81 ppb contribution to CHAT that was 0.12 ppb above EPA's level needed to have an insignificant contribution (0.69 ppb) using the Proposed Transport Rule significant contribution threshold (0.70 ppb). Using the CAMx OSAT ozone source apportionment, Wyoming's contribution to CHAT is 0.75 ppb that is 0.06 ppb lower than APCA and half-way to being below EPA's significant contribution threshold so that is a significant effect.

For Utah, the CAMx 2023 OSAT ozone source apportionment modeling had a 0.02 to 0.04 ppb lower ozone contribution at DM/NFR NAA receptors compared to using the APCA probing tool.

Table 5-1. Comparison of western Upwind State 2023 ozone contributions at DM/NFR NAA nonattainment/maintenance receptors using the APCA and OSAT versions of the CAMx ozone source apportionment probing tool and the proposed Transport Rule CAMx modeling database. AvgUWS is average contributions across all Upwind States (i.e., excluded contributions from Colorado).

CHAT	O3_AZ	O3_CA	O3_CO	O3_NM	O3_UT	O3_WY	AvgUWS
APCA	0.27	0.91	16.24	0.25	1.37	0.81	0.722
OSAT	0.27	0.89	13.79	0.24	1.33	0.75	0.696
Diff (ppb)	0.00	-0.02	-2.45	-0.01	-0.04	-0.06	-0.026
Diff (%)	0.0%	-2.2%	-17.8%	-4.2%	-3.0%	-8.0%	-3.7%
RFNO	**O3_AZ**	**O3_CA**	**O3_CO**	**O3_NM**	**O3_UT**	**O3_WY**	**AvgUWS**
APCA	0.37	1.03	17.69	0.30	1.10	0.46	0.652
OSAT	0.36	1.00	14.95	0.29	1.07	0.44	0.632
Diff (ppb)	-0.01	-0.03	-2.74	-0.01	-0.03	-0.02	-0.02
Diff (%)	-2.8%	-3.0%	-18.3%	-3.4%	-2.8%	-4.5%	-3.2%
NREL	**O3_AZ**	**O3_CA**	**O3_CO**	**O3_NM**	**O3_UT**	**O3_WY**	**AvgUWS**
APCA	0.40	1.17	18.09	0.25	1.06	0.46	0.668
OSAT	0.38	1.13	15.31	0.24	1.03	0.44	0.644
Diff (ppb)	-0.02	-0.04	-2.78	-0.01	-0.03	-0.02	-0.024
Diff (%)	-5.3%	-3.5%	-18.2%	-4.2%	-2.9%	-4.5%	-3.7%
FTCW	**O3_AZ**	**O3_CA**	**O3_CO**	**O3_NM**	**O3_UT**	**O3_WY**	**AvgUWS**
APCA	0.48	0.86	15.44	0.34	0.91	0.78	0.674
OSAT	0.47	0.84	13.67	0.33	0.89	0.75	0.656
Diff (ppb)	-0.01	-0.02	-1.77	-0.01	-0.02	-0.03	-0.018
Diff (%)	-2.1%	-2.4%	-12.9%	-3.0%	-2.2%	-4.0%	-2.7%

5.7 Conclusions Utah and Wyoming Ozone Contributions are Overstated in the Proposed Transport Rule

The cumulative effects of missing emissions, use of coarse 12-km grid spacing in the CAMx modeling and WRF meteorological model inputs and use of the APCA culpability assessment probing tool instead of the OSAT true ozone source apportionment method would likely reduce Wyoming's contribution to 2023 and 2026 ozone design values at Chatfield to below the 1 percent of the 2015 ozone NAAQS significance threshold used in the Proposed Transport Rule. Given the short comment period for the Proposed Transport Rule, the only one of these issues we had time to quantitatively address was to use the OSAT true ozone source apportionment that reduced Wyoming's ozone contribution at Chatfield half-way to being below the significance threshold. The effects of the other deficiencies in the Proposed Transport Modeling CAMx modeling (e.g., missing emissions and coarse 12-km grid) would likely reduce Wyoming's ozone contribution to below EPA's significance threshold at Chatfield.

For Utah the case is not quite as clear whether the cumulative effects of the all the deficiencies in the Proposed Transport Rule would be sufficient to reduce the ozone

contributions at DM/NFR NAA receptors to below the significance threshold used in the Proposed Transport Rule. An explicitly CAMx ozone source apportionment simulation correcting these Proposed Transport Rule deficiencies is needed, but there was insufficient time to conduct such a simulation given the short comment period.

5.8 References

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6.0 EPA USED AN ARBITRARY OZONE CONTRIBUTION METRIC; USE OF OTHER METRICS SHOW WYOMING HAS AN INSIGNIFICANT OZONE CONTRIBUTION AND UTAH MAY HAVE LOWER OZONE CONTRIBUTIONS

The Proposed Transport Rule Upwind State ozone contribution metric to a downwind nonattainment/maintenance receptor used a contribution factor (CF) as the average of the Upwind State ozone contribution divided by the average total ozone at the receptor where the averaging was performed over the top 10 modeled 2023 ozone days. The CF was multiplied by the receptor's 2023 and 2026 ozone design values to obtain the Upwind State ozone contribution to the receptor (see Section 1.4 for detailed description of how Wyoming's ozone contribution to the 2023 ozone design value at Chatfield receptor was calculated). The use of 10 days in the ozone contribution metric is arbitrary and not supported by any standard, guidance or technical basis. Below we analyze alternative Upwind State ozone contribution metrics that are based on previous CSAPR rules, based on EPA guidance or based on the 2015 ozone NAAQS rather than the arbitrary selection of 10 days.

6.1 Previous CSAPR Upwind State Ozone Contribution Metrics

Some of the previous versions of CSAPR have used different Upwind State ozone contribution metrics. For example, the 2011 CSAPR[34] used at least 5 days by first selecting days in which the modeled base year MDA8 ozone is above an ozone threshold starting with the NAAQS (80 ppb for 2011 CSAPR) and reducing the threshold by 1 ppb until at least 5 days are obtained or a 70 ppb threshold floor is reached. If less than 5 days are available with the 70 ppb threshold no contribution metric is calculated (EPA, 2011, pp, 39-40).

The 2015 CSAPR Update[35] used an Upwind State ozone contribution metric for a downwind receptor based on days in which the modeled future year (2017 in this case) ozone is above the NAAQS (≥76 ppb for 2015 CSAPR). If there were fewer than 5 days with modeled 2017 ozone days above the NAAQS, then the Upwind State ozone contribution metric was based on the 5 highest 2017 modeled ozone days (EPA, 2016, pp. 17).

In the 2020 Revised CSAPR Update[36] EPA changed their Upwind State ozone contribution metric so that it was no longer related to the NAAQS as it was for the 2011 CSAPR and 2015 CSAPR Update. The 2020 CSAPR Update used an ozone contribution metric based on the top 10 modeled future year ozone days (EPA, 2020, pp.15) as used in the Proposed Transport Rule. No reason or technical justification was given in EPA's AQTSD on why the CSAPR contribution metric was changed in the 2020 Revised CSAPR Update so that it was no longer related to the NAAQS.

[34] https://www.epa.gov/csapr/cross-state-air-pollution-rule-csapr-regulatory-actions-and-litigation
[35] https://www.epa.gov/csapr/final-cross-state-air-pollution-rule-update
[36] https://www.epa.gov/csapr/revised-cross-state-air-pollution-rule-update

6.2 Alternative Ozone Contribution Metrics for Wyoming-Chatfield Linkage

We examined the contribution of Wyoming to the 2023 ozone design value at Chatfield using several alternative metrics that are described below.

6.2.1 Alternative Metric Number 1: Use of Highest 5 and 15 Modeled 2023 Ozone Days

The first alternative Upwind State ozone contribution metric procedure is like the one used in the Proposed Transport Rule only using the 2023 ozone source apportionment results for the highest 5 and highest 15 modeled ozone days instead of the highest 10 days 2023 modeled ozone days used in the Proposed Transport Rule. Using the 5 highest modeled ozone days will provide an Upwind State ozone contribution the same or very similar to what was used in the 2011 CSAPR and 2015 CSAPR Update rules.

6.2.2 Alternative Metric Number 2: Use Days in Which Ozone is Above the NAAQS

Both the 2011 CSAPR and 2015 CSAPR update used metrics starting with modeled ozone days that are above the NAAQS. This is logical and justifiable and ties the ozone contribution metric to the NAAQS. However, because of the Proposed Transport Rule CAMx modeling had ozone underprediction model performance problems, there are no days with the CAMx 2023 MDA8 ozone concentration at Chatfield above the 2015 ozone NAAQS (see Table 1-1 with highest modeled 2023 MDA8 ozone value of 68.5 ppb). Thus, we analyzed two Upwind State ozone contribution metrics based on days with MDA8 ozone above the NAAQS:

- Days in which the CAMx 2016 base case MDA8 ozone are above the NAAQS.
- Days in which the observed 2016 MDA8 ozone are above the NAAQS.

6.2.3 Alternative Metric Number 3: Use Same Days as Used to Make Future Year Ozone Design Value Projections

The Software for the Modeled Attainment Test (SMAT) was used to make the 2023 and 2026 ozone design value projections following EPA's ozone modeling guidance (EPA, 2018). These procedures use the top 10 modeled ozone days from the CAMx 2016 base case near the receptor (i.e., highest MDA8 ozone in a 3x3 array of grid cells around the receptor). The third ozone contribution metric was based on using the same days to make the Upwind State ozone contribution at the Chatfield as used by SMAT to make the Chatfield 2023 and 2026 ozone design value projections following EPA's ozone modeling guidance (EPA, 2018).

6.2.4 Alternative Metric Number 4: Use Best Performing Top 10 Modeled Days at the Receptor

The fourth alternative contribution metric is similar to the one use in the Proposed Transport Rule using the top 10 modeled 2023 ozone days but with a requirement that the model achieve a level of model performance on those days. By not checking the model performance, the Proposed Transport Rule may be use modeling results on days with poor model performance in their Upwind State ozone contribution metric potentially making it inaccurate and unreliable.

Three alternative metrics were defined using the top 10 2023 modeled ozone days in which the CAMx 2016 predicted and observed 2016 MDA8 ozone concentrations were required to be within ±5%, ±10% and ±15% of each other. Emery et. al., (2016) have developed ozone model performance goals and criteria for bias and error. The bias performance goal is ≤±5% and the bias performance criterion is ≤±15%. Thus, these model performance evaluation (MPE) alternative contribution metrics are tied to commonly used model performance goals and criteria.

Table 6-1 displays the Proposed Transport Rule CAMx modeling results at Chatfield for the top 25 CAMx 2023 MDA8 ozone days with the CAMx 2016 base case and observed MDA8 ozone concentrations also included. The last column in Table 6-1 is the bias expressed as a percent difference between the CAMx 2016 and observed MDA8 ozone concentrations and is color coded: (1) Green if the bias achieves the ozone bias performance goal (≤±5%), (2) Blue if the bias falls between ±5% and ±10%; (3) Yellow if the bias falls between ±10% and ±15%; and (4) Red if the bias fails to achieve the bias performance criterion (i.e., is not within ±15%). Of the top 10 modeled 2023 ozone days that are used in the Proposed Transport Rule Wyoming-Chatfield ozone contribution metric, there are three days that achieve the ozone bias performance goal (green) and three days that fail to achieve the bias performance criterion (red).

The three MPE contribution metrics in the alternative ozone contribution metrics procedure number 4 eliminates days from the top 10 modeled ozone days that fail to achieve the MPE threshold (i.e., within ±5%, ±10% or ±15%) and substitute the next highest modeled MDA8 ozone day that achieves the MPE threshold. For example, as seen in the data in Table 6-1, for the ±15% MPE alternative contribution metric, the July 27, June 19 and July 14 days from the top 10 days would be eliminated and substituted by August 15, July 16 and July 7 (i.e., the 11, 12 and 13 highest modeled days) so that all days had a bias that achieved the performance criterion (i.e., ≤±15%).

Table 6-1. CAMx results from the Proposed Transport Rule at the Chatfield receptor for the top 25 CAMx 2023 MDA8 ozone concentration days with CAMx 2016 base case and observed MDA8 ozone concentrations and their differences (percent bias).

Site Name	Month	Day	CAMx 2023 Total MDA8 Ozone	CAMx 2023 SA WY Ozone	CAMx 2016 MDA8 Ozone	Observed 2016 MDA8 Ozone	Percent Bias MDA8 Ozone
Chatfield	8	3	68.5	0.8357	74.9	80.3	-6.6%
Chatfield	8	12	67.8	0.4457	73.1	73.0	0.2%
Chatfield	7	27	67.5	0.7282	71.9	86.6	-17.0%
Chatfield	6	19	67.3	0.0016	72.6	61.5	18.1%
Chatfield	7	15	66.1	0.3591	69.2	69.1	0.1%
Chatfield	6	29	65.8	0.6882	68.3	66.0	3.5%
Chatfield	6	17	65.7	1.4487	69.9	74.3	-5.9%
Chatfield	7	28	65.2	1.0276	66.9	75.9	-11.8%
Chatfield	7	14	64.8	1.4820	67.7	81.0	-16.5%
Chatfield	8	16	64.7	0.5652	67.5	62.8	7.6%
Chatfield	8	15	64.4	1.0937	66.6	65.1	2.3%
Chatfield	7	16	64.3	0.0435	69.4	78.0	-11.0%
Chatfield	7	7	63.8	0.3137	66.9	71.4	-6.3%
Chatfield	6	26	63.0	0.2661	68.1	61.5	10.8%
Chatfield	7	12	63.0	0.0764	65.6	66.8	-1.7%
Chatfield	6	16	62.8	0.0001	64.5	75.5	-14.6%
Chatfield	8	11	62.6	0.0757	64.1	-999.0	-106.4%
Chatfield	7	25	62.4	0.2358	67.5	71.3	-5.2%
Chatfield	9	8	61.8	0.0075	64.6	57.1	13.1%
Chatfield	8	17	60.8	0.3751	64.5	67.1	-3.9%
Chatfield	7	3	60.4	0.5055	63.8	57.6	10.7%
Chatfield	6	27	60.1	0.4692	65.8	76.9	-14.5%
Chatfield	7	18	59.8	0.0206	61.6	60.1	2.4%
Chatfield	7	17	59.6	0.9518	63.8	71.9	-11.2%
Chatfield	6	7	59.4	0.2639	60.9	-999.0	-106.1%

6.2.5 Results of Alternative Wyoming Ozone Contribution Metrics at Chatfield

Table 6-2 displays the Wyoming ozone contribution to the 2023 ozone design value at Chatfield using the Proposed Transport Rule top 10 model ozone days and alternative Upwind State ozone contribution metrics. Of the 9 ozone contribution metrics analyzed, the ozone contribution metric used in the Proposed Transport Rule is the only one that has Wyoming's ozone contribution to Chatfield above the 1 percent of the 2015 NAAQS significance threshold.

Alternative metric number 1 using the top 5 modeled ozone days that was similar to what was used in the 2011 CSAPR and 2015 CSAPR Update has a Wyoming contributing to Chatfield of 0.50 ppb that is almost 30% lower than the 1 percent of the 2015 NAAQS significance threshold. Use of 15 days in the ozone contribution metrics also results in a value below EPA's significance threshold (0.68 ppb).

The two alternative metrics that use days in which either CAMx 2016 modeled (0.53 ppb) or days in which the 2016 observed (0.68 ppb) MDA8 ozone concentrations are above the NAAQS are also below 1 percent of the 2015 NAAQS. The alternative ozone contribution metric procedure number 2 are tied to the NAAQS so have a technical justification for their use.

Alternative metric number 3 results in consistency between the ozone design value projection procedures and the ozone contribution metric and is based on EPA's ozone modeling guidance (EPA, 2018) and also produces a Wyoming-Chatfield ozone contribution metric (0.50 ppb) that is below the significance threshold (≥0.70 ppb) used in the Proposed Transport Rule.

Finally, when days that the model has poor ozone model performance are excluded from the contribution metric, it reduces the Wyoming ozone contribution to below the significance threshold in all three cases. For the three alternative contribution metric procedure number 4, it is interesting to note that as you use better ozone performing days in the Wyoming ozone contribution metric, Wyoming's ozone contribution to CHAT is reduced such that it is only 0.49 ppb (i.e., 30% below the significance threshold) when you require all the days to achieve the most stringent ozone bias performance goal (≤±5%).

Table 6-2. Contribution of Wyoming to the 2023 ozone design value at Chatfield for the alternative ozone contribution metrics using the state contribution spreadsheet data provided by EPA of their Proposed Transport Rule CAMx modeling results (yellow shading indicate ozone contributions above the 1 percent of the 2015 NAAQS significance threshold).

Alt#	Description of Alternative Metric for CHAT	WY Ozone Contribution
#1	Top 5 CAMx 2023 MDA8 ozone days	0.50
#1	Top 10 CAMx 2023 MDA8 ozone days (EPA proposed rule metric)	0.81
#1	Top 15 CAMx 2023 MDA8 ozone days	0.63
#2	Days with CAMx 2016 Base Case MDA8 ozone above 2015 ozone NAAQS	0.53
#2	Days with observed 2016 MDA8 ozone above the 2015 ozone NAAQS	0.68
#3	Days used by SMAT to make future year ozone DV projections	0.50
#4	Top 10 CAMx 2023 MDA8 ozone days with percent bias ≤±5%	0.49
#4	Top 10 CAMx 2023 MDA8 ozone days with percent bias ≤±10%	0.61
#4	Top 10 CAMx 2023 MDA8 ozone days with percent bias ≤±15%	0.68

6.3 Alternative Ozone Contribution Metrics for Utah Linkages to DM/NFR NAA Receptors

Utah was linked to three nonattainment/maintenance receptors (CHAT, RFNO and NREL) in the DM/NFR ozone NAA. We calculated the same alternative state ozone contribution metrics for Utah linkages with the three DM/NFR NAA receptors as we did for the Wyoming-CHAT linkage discussed above with the exception of the two alterative metrics related to CAMx 2016 modeled ozone days and observed 2016 ozone days above the 2015 ozone NAAQS due to time constraints.

Tables 6-3, 6-4 and 6-5 displays the alternative state ozone contribution metrics for Utah and the three receptors in the DM/NFR NAA. For CHAT most of the alternative metrics were comparable to (1.20 – 1.52 ppb) to the EPA 10-day metric (1.37 ppb) with the exception of when the same days as used by SMAT to make future year DV projections that produced a much lower Utah contribution to the CHAT receptor (0.92 ppb).

The three model performance alternative state contributions produced Utah ozone contributions to the RFNO receptor comparable (1.10 – 1.14 ppb) to the EPA 10-day metric (1.10). But the other alternative metrics produced lower values: 0.72 ppb for 5-day metric; 0.96 for 15-day metric and 0.84 ppb for SMAT days metric.

The EPA 10-day contribution metric estimated that Utah contributed 1.06 ppb to the 2023 ozone AvgDV at the NREL monitor. Three of the alternative metrics were higher (1.18, 1.13 and 1.14 ppb) and three of the alternative metrics were lower (0.72, 0.95 and 0.94 ppb) than the EPA 10-day Utah-NREL linkage contribution.

Table 6-3. Contribution of Utah to the 2023 ozone design value at Chatfield for the alternative ozone contribution metrics using the state contribution spreadsheet data provided by EPA of their Proposed Transport Rule CAMx modeling results.

Alt#	Description of Alternative Metric for CHAT	UT Ozone Contribution
#1	Top 5 CAMx 2023 MDA8 ozone days	1.43
#1	Top 10 CAMx 2023 MDA8 ozone days (EPA proposed rule metric)	1.37
#1	Top 15 CAMx 2023 MDA8 ozone days	1.20
#2	Days with CAMx 2016 Base Case MDA8 ozone above 2015 ozone NAAQS	NA
#2	Days with observed 2016 MDA8 ozone above the 2015 ozone NAAQS	NA
#3	Days used by SMAT to make future year ozone DV projections	0.92
#4	Top 10 CAMx 2023 MDA8 ozone days with percent bias ≤±5%	1.52
#4	Top 10 CAMx 2023 MDA8 ozone days with percent bias ≤±10%	1.42
#4	Top 10 CAMx 2023 MDA8 ozone days with percent bias ≤±15%	1.27

Table 6-4. Contribution of Utah to the 2023 ozone design value at Rocky Flats North for the alternative ozone contribution metrics using the state contribution spreadsheet data provided by EPA of their Proposed Transport Rule CAMx modeling results.

Alt#	Description of Alternative Metric for RFNO	UT Ozone Contribution
#1	Top 5 CAMx 2023 MDA8 ozone days	0.72
#1	Top 10 CAMx 2023 MDA8 ozone days (EPA proposed rule metric)	1.10
#1	Top 15 CAMx 2023 MDA8 ozone days	0.96
#2	Days with CAMx 2016 Base Case MDA8 ozone above 2015 ozone NAAQS	NA
#2	Days with observed 2016 MDA8 ozone above the 2015 ozone NAAQS	NA
#3	Days used by SMAT to make future year ozone DV projections	0.84
#4	Top 10 CAMx 2023 MDA8 ozone days with percent bias ≤±5%	1.11
#4	Top 10 CAMx 2023 MDA8 ozone days with percent bias ≤±10%	1.14
#4	Top 10 CAMx 2023 MDA8 ozone days with percent bias ≤±15%	1.10

Table 6-5. Contribution of Utah to the 2023 ozone design value at NREL for the alternative ozone contribution metrics using the state contribution spreadsheet data provided by EPA of their Proposed Transport Rule CAMx modeling results.

Alt#	Description of Alternative Metric for NREL	UT Ozone Contribution
#1	Top 5 CAMx 2023 MDA8 ozone days	0.73
#1	Top 10 CAMx 2023 MDA8 ozone days (EPA proposed rule metric)	1.06
#1	Top 15 CAMx 2023 MDA8 ozone days	1.18
#2	Days with CAMx 2016 Base Case MDA8 ozone above 2015 ozone NAAQS	NA
#2	Days with observed 2016 MDA8 ozone above the 2015 ozone NAAQS	NA
#3	Days used by SMAT to make future year ozone DV projections	0.95
#4	Top 10 CAMx 2023 MDA8 ozone days with percent bias ≤±5%	0.94
#4	Top 10 CAMx 2023 MDA8 ozone days with percent bias ≤±10%	1.13
#4	Top 10 CAMx 2023 MDA8 ozone days with percent bias ≤±15%	1.14

6.4 Conclusions of Alternative Contribution Metric Analysis for Wyoming- and Utah

Several alternative ozone contribution metrics for Utah's and Wyoming's contribution to the 2023 ozone design values at nonattainment/maintenance receptors in the DM/NFR NAA using alternative set of days including: (1) some that were similar to contribution metrics used in past Transport Rules that used the top 5 or more modeled ozone days (i.e., 2011 CSAPR and 2015 CSAPR Update); (2) two metrics based days above the level of the 2015 ozone NAAQS; (3) a metric based on days in EPA guidance (EPA, 2018) that were the same days used to make the 2023 and 2026 ozone design value projections; and (4) requiring the ozone contribution metric to only use days in which the model meets a minimum level of model performance.

For each alternative metric, Wyoming's ozone contribution to Chatfield was less than the 1 percent of the 2015 NAAQS significance threshold. The Proposed Transport Rule contribution metric that was based on arbitrarily selecting the top 10 modeled 2023 ozone days was the only Wyoming-Chatfield ozone contribution metric that was above the 1 percent of the NAAQS significance threshold. If the Proposed Transport Rule had used the same Upwind State ozone contribution metrics as used in the 2011 CSAPR and 2015 CSAPR updates rules, Wyoming would have been found to not contribute to any nonattainment/maintenance receptors in downwind states.

The results of the alternative Upwind State contribution metric for Utah are not as conclusive as they were for Wyoming with some of the alternatives being higher and some lower than EPA's 10-day ozone contribution metric. Although if the Proposed Transport Rule had conducted more refined CAMx modeling so that NREL was the only remaining nonattainment/maintenance receptor in 2026 (see Chapter 4), had adopted a 1 ppb significance threshold consistent with EPA;'s statistical analysis (see Chapter 7) and used 5-day contribution metrics consistent with 2011 CSAPR and 2015 CSAPR, Utah's ozone contribution (0.73 ppb) would be below the significance threshold so the Proposed Transport Rule would not require 2026 controls on Utah's EGU and non-EGU sources.

6.5 References

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7.0 WYOMING'S AND UTAH'S OZONE CONTRIBUTION IS NOT STATISTICALLY SIGNIFICANT ACCORDING TO EPA'S STATISTICAL ANALYSIS

Wyoming's 2023 0.81 ppb and 2026 0.80 ppb ozone contributions to the Chatfield receptor is less than 1 ppb so are not statistically significant based on EPA's statistical analysis (EPA, 2018a) so Wyoming should not be included in the Proposed Transport Rule 2023 and 2026 control requirements.

For Utah, in Chapter 4 we showed that the only remaining nonattainment/maintenance receptor that Utah was linked to in 2026 was the NREL receptor in the DM/NFR NAA with a 2026 0.90 ppb ozone contribution. According to EPA's statistical analysis (EPA, 2018a), a 0.90 ppb contribution to an ozone design value is not statistically significant so Utah should not be subject to the Proposed Transport Rule 2026 EGU and non-EGU controls.

7.1 EPA's Determination that Ozone Contributions Less Than 1 ppb are Not Significant

EPA has conducted a robust statistical analysis to demonstrate that two ozone design values (DV) that differ by less than 1 ppb are not statistically significantly different from each other (EPA, 2018a). The analysis was performed to define the 1 ppb ozone Significant Impact Level (SIL) that is used as part of the Prevention of Significant Deterioration (PSD) permitting process to define an ozone level *"for the permitting authority to conclude that the proposed source will not cause or contribute to a violation of a National Ambient Air Quality Standard (NAAQS)"* (Tsirigotis, 2018a, pp. 1). EPA's statistical analysis is not just limited to PSD permitting. As stated in their statistical analysis report (EPA, 2018a, pp. 5):

> *"The statistical methods and analysis detailed in this report focus on using the conceptual framework of statistical significance to calculate levels of change in air quality concentrations that have a 'significant impact' or an 'insignificant impact' on air quality degradation. Statistical significance is a well-established concept with a basis in commonly accepted scientific and mathematical theory. This analysis examines statistical significance for a range of values measured by air quality monitors. The statistical methods and data reflected in this analysis may be applicable for multiple regulatory applications where EPA and state agencies seek to quantify a level of impact on air quality that they consider to be either 'significant' or 'not significant'."* (EPA, 2018a., pp. 5).

Clearly, determining whether an Upwind State has a significant contribution to nonattainment of the 2015 ozone NAAQS in a downwind state as part of a CAA Section 110 Good Neighbor demonstration is one of the many *"multiple regulatory applications where EPA and state agencies seek to quantify a level of impact on air quality that they consider to be either 'significant' or 'not significant'."*

EPA's statistical analysis concludes *"result in a SIL value for the ozone 8-hour ozone NAAQS of 1.47%. This corresponds to 1.0 ppb at the level of the 2015 ozone NAAQS (70 ppb)."* (EPA, 2018a, pp. 41). A peer review (EPA, 2018b) of EPA's statistical method for determining that an ozone contribution of less than 1 ppb *"will not cause or contribute to a violation of the applicable NAAQS"* (Tsirigotis, 2018a, pp. 17) was conducted by three independent economic statisticians on faculty of major U.S. universities. The peer reviewers were supportive of the methods, presentation, and results in EPA's determination of the ozone 1 ppb insignificance contribution to the 2015 70 ppb ozone NAAQS threshold. They did raise issues regarding a single national 1 ppb insignificant ozone contribution threshold given the spatial variability of the statistical analysis but recognized the policy issues associated with multiple ozone SIL thresholds based on geographic region.

7.2 EPA's Justification for the 1 Percent of the 2015 NAAQS Significance Threshold in the Proposed Transport Rule is Unfounded

On August 31, 2018, EPA released a Memorandum whose purpose was *"to provide analytical information regarding the degree to which certain air quality threshold amounts capture the collective amount of upwind contribution from upwind states to downwind receptors for the 2015 ozone National Ambient Air Quality standard (NAAQS)."* (Tsirigotis, 2018b, pp. 1). The 2018 Memorandum evaluated significant ozone contribution thresholds of 1 ppb, 2 ppb and 1 percent of the 2015 ozone NAAQS (0.70 ppb) and concluded *"Based on the data and analysis summarized here, the EPA believes that a threshold of 1 ppb may be appropriate for states to use to develop SIP revisions addressing the good neighbor provision for the 2015 ozone NAAQS."* (Tsirigotis, 2018b, pp. 3). This conclusion is technically justifiable given the statistical analysis EPA conducted to justify the 1 ppb SIL (EPA, 2018a).

In the Proposed Transport Rule, EPA discusses their 2018 Memorandum for states to use alterative ozone contribution thresholds in their good neighbor SIPs and offers a specious argument why use of a single threshold of 1 percent of the 2015 NAAQS is needed as *"the Agency now believes using different thresholds at Step 2 with respect to the 2015 ozone NAAQS raises substantial policy consistency and practical implementation concerns."* (EPA, 2022, pp. 20073). owever, EPA doesn't mention that their 2018 Memorandum believed that a 1 ppb threshold is appropriate for states to use and its use as the single significance threshold would also alleviate the policy concerns of using multiple significance thresholds that EPA was concerned about. The Proposed Transport Rule then goes on to note that the 1 ppb threshold *"has the disadvantage of losing a certain amount of total upwind contribution"* compared to the 1 percent of the NAAQS threshold and *"there does not appear to be a compelling policy imperative in moving to a 1 ppb threshold."* (EPA, 2022, pp. 20074). There is, however, a very powerful and compelling technical argument for moving to a 1 ppb significant contribution threshold based on EPA's statistical analysis to justify the 1 ppb ozone SIL that demonstrated two ozone DVs that differ by 1 ppb or less are not statistically significantly different from each other (EPA, 2018a).

7.3 Conclusions Regarding the Statistical Significance of Wyoming's and Utah's Significant Ozone Contribution to Receptors in the DM/NFR NAA

EPA's 2018 ozone statistical evaluation report presents compelling and sound technical arguments using powerful and robust procedures to determine that two ozone design values that differ by less than 1 ppb is not statistically significant (EPA, 2018a). EPA followed that analysis in their 2018 Memorandum by evaluating multiple alternative ozone contribution thresholds finding that the 1 ppb thresholds was most appropriate (Tsirigotis, 2018b). The Proposed Transport Rule estimated that Wyoming contributes 0.81 ppb and 0.80 ppb to the, respectively, 2023 and 2026 ozone design values at Chatfield. Therefore, Wyoming's ozone contribution to Chatfield is not statistically significant and Wyoming should not have been included in the Proposed Transport Rule 2023 EGU and 2026 EGU and non-EGU control program.

Using more refined modeling, the only remaining nonattainment/maintenance receptor in the DM/NFR NAA in 2026 was NREL (see Chapter 4). The Utah contribution to the NREL receptor in 2026 is 0.95 ppb that is below 1 ppb so is not statistically significant so Utah should not have been subject to the Proposed Transport Rule 2026 EGU and non-EGU NO_X controls.

7.4 References

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8.0 EPA DOESN'T FOLLOW ITS OWN MODELING GUIDELINES BY USING A REDUCED FORM MODEL WITH NO PHOTOCHEMISTRY FOR OZONE CONTRIBUTION ASSESSMENTS

8.1 Air Quality Assessment Tool (AQAT) Used in the Proposed Transport Rule

EPA developed an Air Quality Assessment Tool (AQAT) for the Proposed Transport Rule that is described in the "Ozone Transport Policy Analysis Proposed Rule TSD" (EPA, 2022a). AQAT is an Excel spreadsheet that consists of a collection of linear models that relate state-specific NO_X emission changes to corresponding changes in ozone design value (DV) contributions from each state and receptor analyzed in the Proposed Transport Rule. AQAT considers two main dynamical cases:

a) One that uses the 2023 and 2026 base case source apportionment modeling results (2023_scenario in spreadsheet).

b) One that uses the 2026 base case and the 2026 base case EGU and non-EGU emissions reduced by 30% (2026_scenario in spreadsheet).

AQAT was developed for use in Step 3 of EPA's four-step transport framework to evaluate ozone DV changes in response to state NO_X emissions changes for several purposes, including:

- Assess the potential of "overcontrol" from the proposed rule NO_X controls through either: (1) reducing an Upwind State's ozone contribution to less than the significant contribution threshold (i.e., 1 percent of the NAAQS) at all downwind receptors that the Upwind State is linked; or (2) reducing the future year maximum ozone DV (MaxDV) at all downwind receptors that the Upwind State is linked to below the 2015 ozone NAAQS so that all of the Upwind State linked receptors are no longer nonattainment/maintenance receptors.
- Assess the degree of ozone improvements at receptors due to NO_X controls at various control and cost levels.
- As a screening analysis for non-EGU sources where EPA identified two tiers of source sectors by NAICS code for potential inclusion in the proposed rule (EPA, 2022b):
    - Tier 1 source sectors have maximum contribution to any one receptor of >0.10 ppb and contribute ≥0.01 ppb to at least 10 receptors.
    - Tier 2 source sectors have either: (1) maximum contribution to one receptor of ≥0.10 ppb but have fewer than 10 receptors ≥0.01 ppb; or (2) maximum contribution < 0.10 ppb but have at least 10 receptors ≥0.01 ppb.
- Additional air quality analysis (e.g., impactful boilers)

For the 2026 version of AQAT (version b above), EPA used the 2026 CAMx 12-km APCA ozone source apportionment results to relate state NO_X emissions to 2026 average and maximum ozone DVs at nonattainment/maintenance receptors. Because ozone formation is nonlinear, an additional CAMx 2026 simulation was conducted that reduced state EGU/non-EGU NO_X emissions by 30% that was used to "calibrate" the AQAT state NO_X emissions relationship with the receptor 2026 ozone DVs on a receptor-by-receptor basis. The calibration takes into account that an X% reduction in an Upwind State's NO_X emissions will results in a less than X% reduction in the Upwind State's ozone contribution and was calibrated for estimating the ozone reductions at receptors due to 2026 EGU/non-EGU NO_X emission reductions between 0% and 30%.

8.2 EPA Air Quality Modeling Guidelines

On January 17, 2017, EPA released their latest revisions to the Guideline on Air Quality Models (Appendix W) that included their recommended air quality modeling *"approach to address the secondary chemical formation of ozone and fine particulate matter ($PM_{2.5}$) associated with precursor emissions from single sources."* (EPA, 2017, pp. 5182). EPA's Air Quality Modeling Guidelines recommends a two-tiered approach for addressing ozone impacts due to single source or groups of sources:

> *"The first tier involves use of technically credible relationships between precursor emissions and a source's impacts that may be published in the peer-reviewed literature, developed from modeling that was previously conducted for an area by a source, a governmental agency, or some other entity and that is deemed sufficient, or generated by a peer reviewed reduced form model. The second tier involves application of more sophisticated case-specific chemical transport models (CTMs) (e.g., photochemical grid models) to be determined in consultation with the EPA Regional Offices and conducted consistent with the EPA single-source modeling guidance."* (EPA, 2017, pp. 5192).

EPA's guidance for modeling ozone and secondary $PM_{2.5}$ stresses the need that a model for ozone must contain a photochemical mechanism because *"a realistic characterization of chemistry surrounding the project source is important for estimating secondary impacts."* (EPA, 2016, pp. 13).

8.3 Use of the AQAT Spreadsheet to Estimate Ozone Impacts due to Alternative NO_X Emissions Scenarios is Inconsistent with EPA's Modeling Guidelines and Guidance

The AQAT linear spreadsheet tool for estimating contributions of state NO_X emissions to downwind receptor ozone DVs violates the recommendations in EPA's Air Quality Modeling Guidelines (EPA, 2017) as it does not include a photochemical mechanism. It does not even satisfy the requirements of a Tier 1 screening tool from EPA's ozone single source ozone modeling guidelines as it has not been *"published in the peer-reviewed literature*" (EPA, 2017).

EPA's ozone modeling guidance (EPA, 2018) and guidelines (EPA, 2017; 2016) recommended a series of procedures for applying an ozone model that includes selecting a model that has been peer-reviewed, developing a Modeling Protocol and conducting a Model Performance Evaluation (MPE). EPA recommends that at a minimum an operational MPE be performed that compares the ozone model with concurrent observations, but also recommends a diagnostic evaluation. Given the way AQAT is applied in the Proposed Transport Rule, a dynamic evaluation that evaluates how the ozone model responds to changes in emissions would be especially useful (EPA, 2018). None of these standard steps in an ozone model application was done for the AQAT ozone modeling tool used in the Proposed Transport Rule.

8.4 AQAT is Used to an Accuracy and Precision That it has Not Been Demonstrated For

The Proposed Transport Rule is using AQAT to define the ozone contributions due to changes in NO_X emissions from Upwind State(s) for a variety of levels of NO_X emission changes and purposes. In some cases, AQAT is used to identify whether the change in NO_X emissions causes extremely small ozone changes at a receptor (e.g., 0.10 and 0.01 ppb), which assumes that AQAT has a level of accuracy and precision that has not been demonstrated it possesses. Since AQAT was never evaluated against observed ozone concentrations or independent CAMx simulations, its accuracy and reliability is unknown. But given the nonlinear nature of ozone formation and EPA's guideline and guidance stating that a model needs to have a photochemical mechanism to simulate ozone, AQAT fails a basic "fit for purpose" test as it does not include a chemical mechanism.

It should be noted that AQAT's use to include non-EGU sources in the Proposed Transport Rule based on ozone contributions as low as 0.01 ppb is illogical as 0.01 ppb is below the limit that ozone is measured by standard ozone monitoring equipment. Ozone measurements are typically reported to EPA's Air Quality System (AQS[37]) to the nearest tenth of a ppb (sometimes even integer ppb), thus non-EGU sources are being included in the Proposed Transport Rule when they contribute no measurable ozone concentrations to a nonattainment/maintenance receptor.

8.5 AQAT is used in the Proposed Transport Rule for the Sake of Expediency, Not because it is the Most Appropriate Tool

In the policy document for the Proposed Transport Rule, EPA admits that the AQAT is a highly simplified ozone tool and is not the optimal approach for obtaining ozone impacts, which would be a photochemical model as EPA recommends in their Guidelines and Guidance:

> *"Air quality modeling would be the optimal way to estimate the air quality impacts at each cost threshold level from EGUs and non-EGUs emissions reductions. However, due to time and resource limitations EPA was unable to use photochemical air quality modeling for all but a few emissions scenarios. Therefore, in order to estimate the air quality*

[37] https://www.epa.gov/aqs

> *impacts for the various levels of emission reductions and to ensure that each step of its analysis is informed by the evolving emissions data, EPA used a simplified air quality assessment tool (AQAT). The simplified tool allows the Agency to analyze many more levels of NO_X control stringency as implemented through emission budgets than would otherwise be possible. EPA recognizes that AQAT is not the equivalent of photochemical air quality modeling but in the Agency's view is adequate to this purpose."* (EPA, 2022b).

Although EPA states AQAT is *"adequate to this purpose"* they present no evidence to this effect. There is no evaluation of AQAT against measurements or evaluation against independent photochemical model simulations. There is no independent peer-review of AQAT or any peer-reviewed papers on the AQAT that was used the Proposed Transport Rule. Nothing is presented in the Proposed Transport Rule to support EPA's opinion that AQAT is an adequate tool to estimate the ozone impacts due to a state's NO_X emissions. Although there has been a history in the past to defer to EPA's opinions in many instances, in this case EPA presents conflicting opinions. On the one hand, after several years of development with reviews, comment periods, and refinements, EPA's Air Quality Modeling Guidelines and Guidance state than ozone models are required to have a photochemical mechanism that AQAT does not possess and lays out procedures for applying an ozone model that EPA did not follow with AQAT. And on the other hand, in the Proposed Transport Rule EPA states AQAT is *"adequate"* without any evaluation or technical justification just statements that they needed a tool to do the analysis fast. Clearly, EPA Guidelines and Guidance should take precedence over expediency.

8.6 AQAT Applied for Changes in State NO_X Emissions Outside of Its Range of Calibration

In the development of AQAT, EPA describes how changing the emissions would lead to corresponding changes in ozone concentrations using proportional relationships *"modified using calibration factors base on state-specific source apportionment"*. It further states, related to the relationship between ozone and its precursors, that *"a significant portion of the nonlinearity is accounted for by using the calibration factors and having the air quality estimates occur at levels of emissions between the 2026 base case and the other case used in the calibration (which were both modeled in CAMx)"*.

This is incorrect in two counts: The first is that one can demonstrate the linear expressions using the calibration factors are completely equivalent to the linear fit between two points. In one case the endpoints are the emissions and contributions between the 2023 and 2026 CAMx simulations, in the other the endpoints correspond to 2026 base case and 2026 30% EGU and non-EGU NO_X reduction CAMx simulation. It is implausible that these calibration factors suddenly could account for all the nonlinearities of ozone formation using a linear equation.

EPA is also incorrect because it uses AQAT in a way that in fact exceeds the levels of emissions between the CAMx 2026 base case and CAMx "calibration" case that

reduced EGU and non-EGU NO_X emissions by 30%. When EPA established the 2026 Engineering Analysis baseline used in the Step 3 AQAT analysis, the emissions are adjusted such that approximately 80% of the states exceed the modeled NO_X emissions for the CAMx 2026 base case (see Table 3-1). The AQAT calibration is designed to examine EGU and non-EGU emission reductions between the CAMx 2026 base case and a 30% EGU and non-EGU NO_X emission reductions from the CAMx 2026 base case, not for EGU NO_X emissions increases from the CAMx 2026 base case emissions. The AQAT application to NO_X emission increases in the 2026 Engineering Analysis baseline fall outside of the calibration range. And these EGU NO_X emission increases between the CAMx 2026 base case and the 2026 Engineering Analysis baseline can be quite substantial. For example, the 2026 Engineering Analysis baseline EGU NO_X emissions in Utah and Wyoming are over a 100% higher than in the CAMx 2026 base case so certainly fall out of the EGU NO_X emissions 0% to -30% range that AQAT was calibrated for.

Using AQAT outside of its calibration range is another reason why the Proposed Transport Rule entire Step 3 controls analysis is unreliable and flawed.

8.7 References

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EPA. 2018d. Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

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<u>Exhibit B</u>: Letter from Wyoming Governor Gordon
Temporary Emergency Suspension Under CAA § 309(g)
For Jim Bridger Unit 2 & Attached Considine Report

December 27, 2021

Michael Regan, Administrator
United States Environmental Protection Agency
Office of the Administrator
William Jefferson Clinton Federal Building
1200 Pennsylvania Avenue, NW
Washington, DC 20460

RE: Temporary Emergency Suspension – Regional Haze 309(g) SIP for PacifiCorp Jim Bridger Power Plant Unit 2.

Administrator Regan:

I hereby notify you that because of EPA's failure to act on Wyoming's Regional Haze 309(g) State Implementation Plan (SIP) revision for PacifiCorp's Jim Bridger Power Plant Unit 2 within the time prescribed by law, I must exercise my authority under 42 U.S.C. § 7410(g) to prevent the premature closing of Unit 2 and the dire economic impacts resulting therefrom. I hereby issue a temporary emergency suspension of that portion of Wyoming's existing SIP proposed to be revised and requiring additional controls of NOx emissions at Unit 2 by December 31, 2021. *See* 79 Fed. Reg. 5032 (Jan. 30, 2014). This emergency suspension is effective beginning January 1, 2022, and shall continue for the maximum period provided by law. As more fully explained below, Wyoming's proposed SIP revision meets the applicable requirements of Section 7410 of the Clean Air Act (CAA), and this emergency suspension is necessary to prevent Unit 2 from closing for one year or more and to prevent substantial increases in unemployment which would result from such closure.

Background

In 2014, EPA published a final Regional Haze Rule that approved the NOx portion of Wyoming's SIP requiring controls of NOx emissions from the Jim Bridger Power Plant Units 1-4. 79 Fed. Reg. 5032 (Jan 30, 2014). In particular, EPA approved Wyoming's requirement that PacifiCorp install low NOx burners (LNB) and separated overfire air (SOFA) plus selective catalytic reduction (SCR) at Jim Bridger Units 1-4 with NOx emission limits of 0.07 lb/MMBtu (30-day rolling average) as part of the State's Reasonable Progress Long Term Strategy. PacifiCorp installed these control technologies on Units 3 and 4 in 2015 and 2016. PacifiCorp has also installed LNB and SOFA at Units 1 and 2.

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Due to the significant cost of installing SCR at Units 1 and 2, on February 5, 2019, PacifiCorp submitted a Regional Haze Reasonable Progress Reassessment to the State of Wyoming proposing an alternative to installing SCR. This alternative regional haze compliance strategy for the Jim Bridger Power Plant included visibility enhancing emission limits, a four-factor "reasonable progress" analysis, reduced plant-wide month-by-month emissions limits for the two principle haze-causing pollutants, NOx and SO_2, and an annual total emissions cap for both pollutants for all four Units. Before submitting the reassessment to the State, PacifiCorp and the Wyoming Department of Environmental Quality worked cooperatively and directly with EPA to develop the alternative and to address all of EPA's questions and concerns.

PacifiCorp's proposed alternative was significantly better than the existing SCR requirement in every possible way. The proposed alternative was far more cost efficient than SCR. In fact, the capital cost of SCR was over $297 million compared to just over $16 million for the visibility enhancing emission limits. The visibility enhancing emission limits were also much more cost effective per ton at $349 per ton removed compared to $4,744 per ton removed for SCR, resulting in reduced cost to ratepayers during a time of increasing inflation nationally.

Moreover, the visibility enhancing emission limits would actually result in greater visibility improvement than SCR. First, even EPA agreed in 2014 that the visibility benefits from installing SCR in addition to LNB and SOFA at Units 1 and 2 were modest and imperceptible at 0.10 to 0.15 deciviews. Installing SCR would reduce NOx emissions from these units by 5,848 tons/year. But even EPA recognizes that it is SO_2, not NOx that is "the predominant cause of regional haze on the Colorado Plateau in the western US." 79 Fed. Reg. at 5097. By implementing the visibility enhancing emissions limits, the proposed alternative would reduce NOx and SO_2 emissions by 6,056 tons/year. Thus the proposed alternative would result in greater visibility improvement than the NOx only reductions associated with the installation of SCR. This conclusion was confirmed by updated CALPUFF modeling. Moreover, the plant-wide limit would cap all emissions from the source, including particulate matter, producing additional visibility benefits.

In addition, the proposed alternative had other significant benefits beyond getting better visibility for substantially less money. Implementing the visibility enhancing emission limits would also result in less impacts from mercury, carbon monoxide, carbon dioxide, particulate matter, sulfuric acid, coal consumption, coal combustion residual production and disposal, and raw water consumption. SCR also requires the use and storage of ammonia (a hazardous substance) while the proposed alternative does not. Moreover, SCR uses a significant amount of electricity which could otherwise be put to use elsewhere. The proposed alternative would save 10.4 MW or enough electricity to power approximately 8,761 homes. Finally, because the visibility enhancing emission limits are plant-wide, they provide the entire facility flexibility to "load follow" or accommodate the intermittent influx of renewable energy in the western power grid. Thus, the alternative would make the electricity grid more robust.

Presented with all these advantages, no known disadvantages, and EPA's buy-in, Wyoming began the SIP revision process. During the public comment period on the revision, EPA submitted minor technical comments, which Wyoming fully addressed. Notably, EPA did not express any

substantive concerns with the revision, the supporting data, the conclusions drawn from that data, or in any way signal that the revision would not meet the legal requirements of the regional haze program. The science was, and remains, clear. The environmental, social, and economic outcomes of the alternative are superior in every way.

Accordingly, Wyoming determined that the revision ensured reasonable progress as required by the CAA and submitted the revisions to EPA for approval on May 12, 2020. EPA acknowledged receipt of the revised SIP submission on May 14, 2020. EPA then began its formal review process. In fact, it appears that EPA actually finished that process last year. Wyoming was notified on November 23, 2020, that the former Region 8 Administrator, Gregory Sopkin, had signed the proposed action on November 20, 2020, and that Wyoming would be informed when the action would be published in the Federal Register. But that did not happen.

The CAA imposes a nondiscretionary duty on the Administrator to approve or disapprove a SIP revision within twelve months of being deemed complete. 42 U.S.C. § 7410(k)(2). On May 14, 2020, EPA acknowledged receipt of Wyoming's SIP revision. EPA did not make a completeness finding within six months as required by 42 U.S.C. § 7410(k)(1)(B). Thus, Wyoming's SIP revision was deemed complete by operation of law on November 14, 2020. 42 U.S.C. § 7410(k)(1)(B). EPA was required to act on Wyoming's SIP revision within twelve months, or by November 14, 2021, in accordance with 42 U.S.C. § 7410(k)(2)-(3), but failed to do so.

As a result of EPA's inaction, the current SIP requires PacifiCorp to install SCR on Unit 2 by December 31, 2021, which it can not do at this late hour. Thus, in several short days, PacifiCorp will be forced to shut down Unit 2, lay off employees, and buy power to make up for the lost generation. That cost will be passed on to consumers in Wyoming and across the west creating a social and economic injustice. All for no good reason.

Temporary Emergency Suspension Authority

As you know, when the EPA Administrator has not approved or disapproved a plan revision within twelve months of submission, the CAA vests the governor of each state with the authority to issue a temporary emergency suspension of the part of the applicable implementation plan which is proposed to be revised. 42 U.S.C. § 7410(g)(1). To exercise this authority, the State must determine that the proposed revision meets the requirements of Section 7410 and "is necessary (i) to prevent the closing for one year or more of any source of air pollution, and (ii) to prevent substantial increases in unemployment which would result from such closing[.]" *Id.*

A temporary emergency suspension remains in effect for a maximum of four months unless disapproved by order of the EPA Administrator. *Id.* at (g)(2). However the EPA Administrator may only disapprove "such suspension if he determines that it does not meet the requirements of this subsection." *Id.*

Neither the CAA nor any applicable federal regulation specifies a particular procedure or form for an emergency suspension issued under Section 7410. Accordingly, I assert that this notice to you, copied to the owner of the source at issue, is a proper form for the exercise of my authority. Moreover, any perceived procedural deficiency associated with the issuance of this emergency suspension does not provide cause to disapprove the emergency suspension as your disapproval authority is specifically limited by Section 7410.

This emergency suspension meets the requirements of Section 7410(g).

The first two requirements of Section 7410(g) are easily established and beyond dispute. EPA failed to act on Wyoming's proposed revision within twelve months of submission and the State determined that the proposed revision met the requirements of Section 7410 when it submitted the proposed revision. The remaining two requirements relate to the detrimental effects of compliance with the existing SIP. Those effects are immediate, long-term, significant, and in my view, also beyond reasonable dispute.

First, this emergency suspension is necessary to prevent the closing of Unit 2 for twelve months or more. As you know, PacifiCorp's 2021 Integrated Resource Plan filed with the Wyoming Public Service Commission (PSC) reflects the company's intention to continue operation of Units 1 and 2 until 2023 and to convert them to natural gas fueled peaking units in 2024. In light of this intention, it will never make sense for PacifiCorp to install SCR at Unit 2 for the purpose of restarting the Unit for the limited period of time until conversion. Accordingly, if EPA forces Unit 2 to shutdown, it will remain shut down until it can be restarted as a natural gas unit. Thus, the question becomes whether PacifiCorp can reasonably convert Unit 2 to natural gas within the next twelve months. It cannot.

At my suggestion, the Wyoming Public Service Commission (PSC) initiated an investigation into the effects of shutting down Unit 2 at the end of this year as a result of EPA's failure to act on Wyoming's SIP revision. While that investigation remains ongoing, the PSC has already collected a significant amount of data from PacifiCorp. This data includes information about the anticipated length of time before Unit 2 could convert to natural gas. In order to convert to natural gas, a new lateral pipeline to the Jim Bridger power plant will need to be constructed from nearby existing natural gas pipelines. I understand that even accelerating the construction schedule as much as possible, this pipeline could not be constructed until the last quarter of 2023. Accordingly, this emergency suspension is necessary to prevent the closing of Unit 2 for twelve months or more.

Second, this emergency suspension is necessary to prevent substantial increases in unemployment resulting from the shutdown. The Jim Bridger Power Plant employs 302 highly skilled craftsmen, engineers, professionals and managers in the operation of the four coal-fired units. The power plant is staffed with a combination of both union and non-union employees. The power plant is a mine-mouth operation, meaning a reduction in electric power generation results in a corresponding reduction in coal production. Shutting down Unit 2 imperils many of the jobs

at the plant, at the mines that supply it, with the outside companies that support it, and elsewhere throughout the community.

In light of your stated intention to let the impending compliance deadline come and go without acting on Wyoming's proposed revision, the State of Wyoming asked Professor Timothy J. Considine, Ph.D., Professor of Energy Economics at the University of Wyoming's School of Energy Resources, to study the fiscal and economic impacts resulting from closing Unit 2. A copy of Professor Considine's report is attached hereto for your convenience. As it relates to employment, Professor Considine estimates that shutting down Unit 2 would result in 404 lost jobs state-wide with 327 of those lost jobs occurring in Sweetwater County where the power plant is located. These estimates include direct, indirect, and induced job losses. By any measure within Wyoming and Sweetwater County's small rural economies this represents a substantial increase in unemployment.

The magnitude of the jobs lost resulting from the shutdown of Unit 2 is amply illustrated when translated into lost compensation. Professor Considine estimates that the lost employee compensation for Sweetwater County in 2021 dollars would be in excess of $30 million plus nearly $5 million in additional lost employee compensation in the rest of the state annually. This represents a tremendous loss for Wyoming workers and their families.

Of course, a shutdown would also cause other economic losses and adverse effects. Professor Considine estimates that the closure of Unit 2 would result in $148.6 million annual loss in value added to the State of Wyoming, which is the regional equivalent of gross domestic product. In addition, he estimates a loss in annual tax revenues at the federal, state, and local level of more than $33 million. Moreover, while the PSC has not yet issued findings related to its ongoing investigation, I understand that the information submitted by PacifiCorp suggests that closure of Unit 2 at the end of the year would result in an increase in both industrial and commercial electricity rates and residential electricity rates. I also fully anticipate that the PSC's investigation will reveal reliability concerns and even the possibility of adverse effects on new renewable generation.

As is readily apparent, this emergency suspension meets all the requirements of Section 7410(g) and it would be irresponsible either for me not to issue it or for you to attempt to disapprove it. The costs are simply too great socially, economically and environmentally to allow Unit 2 to shut down on January 1st.

The Status Quo Until May 1, 2022 and Beyond

I want to say a few words about the status quo during the period the emergency suspension is in place. As a precursor to the SIP revision submitted to EPA, PacifiCorp sought and Wyoming granted Permit No. P0025809 attached hereto for your convenience. That permit adopts the substance of the proposed SIP revision and requires PacifiCorp to begin operations in compliance with the proposed SIP revision on January 1, 2022. The Permit establishes:

monthly-block average pound per hour (lb/hr) NOx and SO2 emissions limits for Units 1-4 (EGU001-EGU004) combined and a 12-month rolling total NOx and SO_2 emission limit of 17,500 tons per year (tpy) for Units 1-4 (EGU001-EGU004) combined. This combined set of lb/hr and tpy limits will be enforced in lieu of installation of selective catalytic reduction technology (SCR) on Units 1-2 (EGU001-EGU002), and will effectively decrease the operating capacity of the plant, thereby reducing its emission of haze-causing pollutants, NOx and SO_2.

Accordingly, the environmental benefits associated with Wyoming's proposed SIP revision will begin to accrue on the day this emergency suspension becomes effective. While that is a good thing, it does not solve the problem for the long term. And I cannot solve this problem unilaterally, even with the assistance of the courts. EPA must take action on the proposed SIP revision to solve this problem, and I urge you again to approve the SIP revision immediately.

Alternatively, I previously suggested that EPA could avoid the catastrophic shutdown of Unit 2, by issuing a Federal Implementation Plan (FIP) in conjunction with a disapproval of the proposed SIP revision. I understand that your staff has asserted that EPA does not have that authority where an existing SIP has been approved. I am baffled by that assertion. Section 7410(c)(1)(B) of the CAA expressly provides the Administrator with authority to issue a FIP upon the disapproval of a SIP submission in whole or in part. That section makes no distinction between a plan and a plan revision. Instead it clearly applies to submissions of either kind.

Conclusion

I believe the effect of this emergency suspension is clear, but please contact me if you have any questions or concerns. I must again reiterate that unless you act on the proposed SIP revision within the sixty days following my notice to you of November 14, 2021, the State of Wyoming will file suit and seek all available relief from the court. In the meantime, this emergency suspension gives you an opportunity to approve Wyoming's revised SIP. I remain hopeful you will act on that opportunity. I remain willing to engage with you further on this matter.

Sincerely,

Mark Gordon
Governor of Wyoming

MG:rl:gf

cc: Attorney General Bridget Hill
Senator John Barrasso
Senator Cynthia Lummis
Representative Liz Cheney
Governor Brad Little

Dan Dockstader, President, Wyoming Senate
Eric Barlow, Speaker, Wyoming House of Representatives
Christopher Petrie, Chairman, Wyoming Public Service Commission
Michael Robinson, Deputy Chairman, Wyoming Public Service Commission
Mary Throne, Commissioner, Wyoming Public Service Commission
Todd Parfitt, Director, Wyoming Department of Environmental Quality
Robin Cooley, Director, Wyoming Department of Workforce Services
Brenda Hensen, Director, Wyoming Department of Revenue
Randy (Doc) Wendling, Chair, Sweetwater County Commissioners
Tim Kaumo, Mayor, City of Rock Springs
Pete Rust, Mayor, City of Green River
Jim Willox, President, Wyoming County Commissioners Association
Kathleen Becker, EPA Administrator for Region 8
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"The Fiscal and Economic Impacts of Closing Unit 2 at the Jim Bridger Power Plant"

by

Timothy J. Considine, Ph.D.
Professor of Energy Economics
School of Energy Resources
University of Wyoming

December 26, 2021

About the Author

Timothy Considine is a Professor of Energy Economics with the School of Energy Resources and the Department of Economics at the University of Wyoming.

Acknowledgements

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Disclaimer

The opinions, findings, and conclusions expressed in the report are those of the authors and are not necessarily those of the University of Wyoming, the Office of the Wyoming Attorney General, or the State of Wyoming.

Executive Summary

This study estimates the economic and fiscal impacts of closing Unit 2 of the Jim Bridger power plant for Sweetwater County, where the plant is located, and for the rest of Wyoming. This study does not estimate the increased costs of electricity to ratepayers, nor the economic costs associated with less electricity reliability that this closure may cause. The impacts estimated in this study include three parts. First, there are the direct economic impacts from lower electric power generation. The second component includes the indirect or supply chain impacts, such as reduced coal production. The third and final economic impact is lower spending on goods and services induced by the lower household and business income from the direct and indirect economic impacts. The total economic impact is the sum of these three components. These economic impacts also affect collections of tax revenues by federal, state, and local governments.

My main findings are as follows. First, closing Unit 2 results in a $148.6 million loss in value added to the State of Wyoming, which is the regional equivalent of gross domestic product, see Figure ES1. Secondly, closing Unit 2 reduces employee compensation by $34.9 million, see Figure ES1. Each of these impacts represent annual economic losses. If the plant were to remain open through the end of its expected lifetime in 2028, for example, the opportunity cost of closing Unit 2 increases to $1.0 billion and $245 million in cumulative foregone value added and employee compensation respectively.

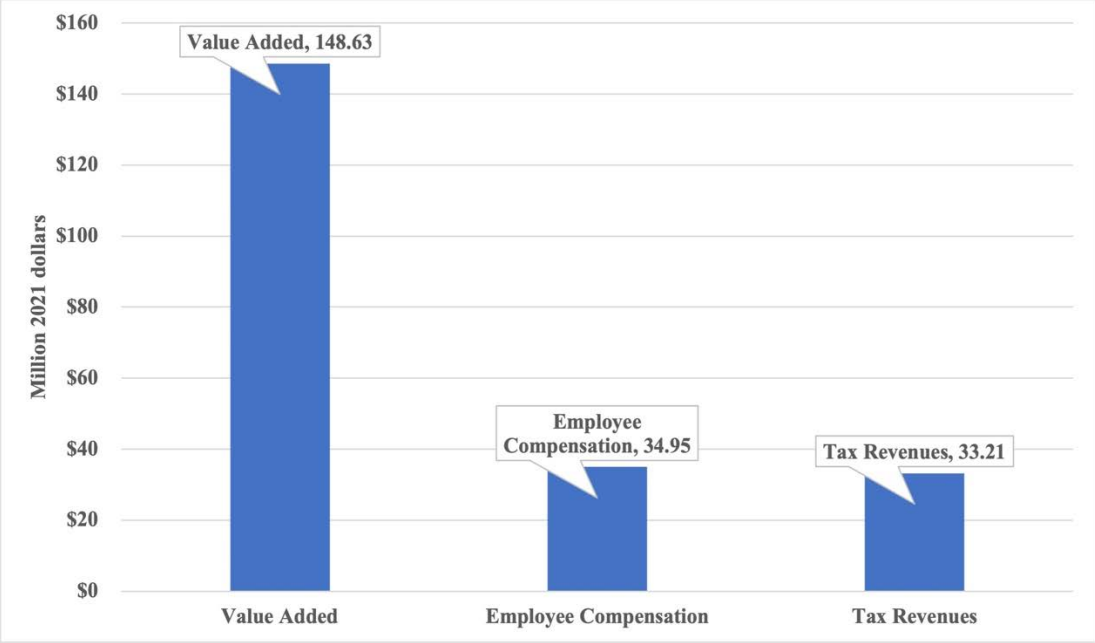

Figure ES1: Economic and fiscal losses from closing Unit 2 in million 2021 dollars

In addition, as Figure ES1 reports, annual tax revenues, which includes payments to federal, state, and local governments, declines $33.2 million. A breakdown of the tax revenues appears in Figure ES2. Federal tax revenues decline $13.15 million on an annual basis. Annual tax payments to the State of Wyoming decline $10.7 million. Tax payments to local governments

decline $9.36 million with special districts tax revenues declining $5.25 million, county tax revenues falling $3.56 million, and general county tax revenues dropping $540 thousand.

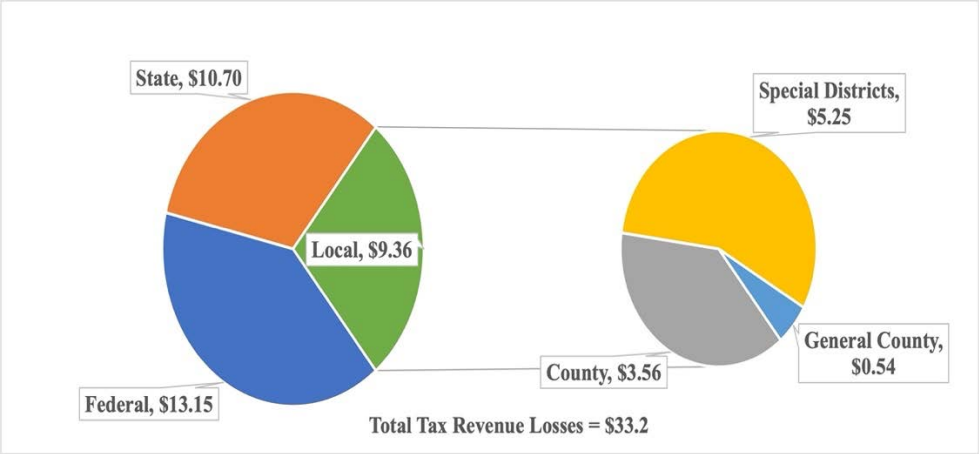

Figure ES2: Tax revenue losses from closing Unit 2 in million 2021 dollars

Lower economic output and tax revenues reduce the demand for labor. In Figure ES3, the direct, indirect, and induced employment losses from closing Unit 2 are reported for Sweetwater County and for the rest of Wyoming. Notice that the direct employment impacts include 65 full-time equivalents (FTEs) at the power plant and therefore, only occur in Sweetwater County. The indirect employment losses are 172 FTEs in Sweetwater County, including the loss of 108 coal-mining jobs. Combined with the 90 jobs lost from lower incomes associated with these direct and indirect impacts, closing Unit 2 reduces total employment by 327 in Sweetwater County. Total state employment declines by 404, which includes the losses in Sweetwater, 49 FTEs from indirect impacts and a loss of 28 FTEs from induced impacts in the rest of the state.

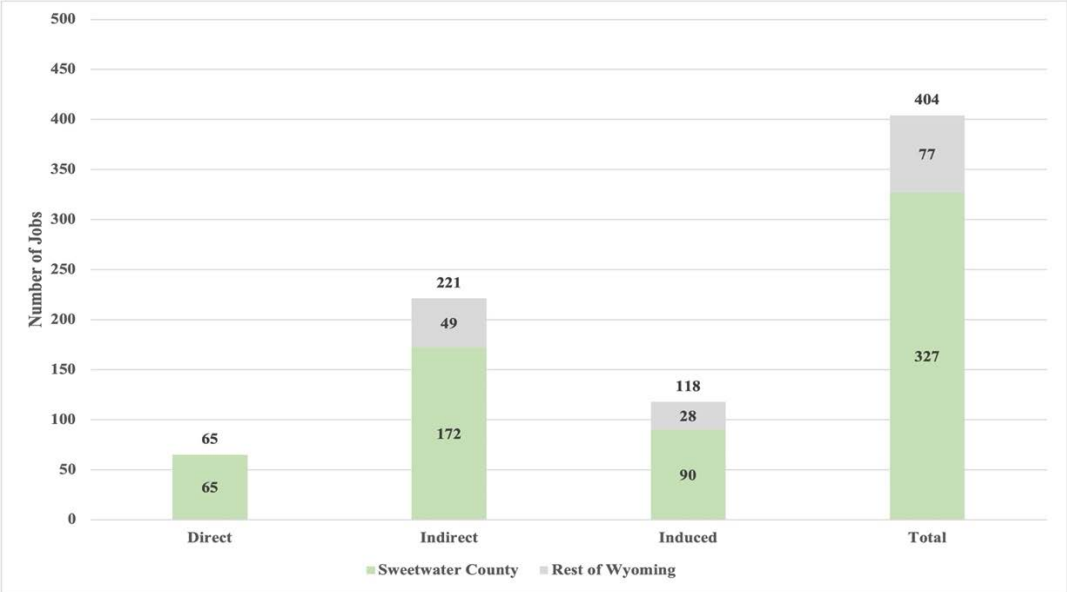

Figure ES3: Employment losses from closing Unit 2

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1. Introduction

The focus of this study, the Unit 2 electric power generator at the Jim Bridger power plant, is one of four units operating at the plant in Point of Rocks, Wyoming, which is 25 miles east of Rock Springs, Wyoming in Sweetwater County. The operator of the plant is PacifiCorp. This study will estimate the economic and fiscal contributions of Unit 2 to the economies of Sweetwater County and the rest of the State of Wyoming. The next section describes the assumptions made and the methods used to estimate these contributions. Section three of this report provides a discussion of these contributions for Sweetwater County, including value added, employee compensation, employment, and tax revenues. The fourth section presents estimates of the spillover contributions to the rest of the state. The fifth section summarizes the impacts for the entire State of Wyoming. The report concludes with a synopsis of the main findings and their implications for regional economic development, environmental policy, and energy security and reliability.

2. Definitions and Methodology

This study employs input-output analysis, which is an analytical framework developed by Professor Wassily Leontief in the late 1930s, for which he received the Nobel Prize in Economic Science in 1973. This framework is also known as interindustry analysis, since the fundamental purpose of the input-output framework is to analyze the interdependence of industries in an economy, according to Miller and Blair (2009). This framework is ideal for estimating how purchases by the electric power sector affect supporting industries, such as coal mining, and how these supply-chain relationships determine how events in one industry affect spending by business and households in a regional economy.

This modeling framework has been implemented by IMPLAN (2021) in an online platform that combines extensive databases, economic factors, and multipliers with a refined modeling system that is customizable. IMPLAN provides complete sets of economic accounts for every county and zip code in the United States. These accounts form the backbone for each regional input-output model. This model balances industry inputs with outputs and can be used to determine how these interindustry transactions change in response to an external shock to the regional economy, such as the closure of the Unit 2 electric power generator.

This shock is represented by the change in the value of gross electrical power output. According to the Energy Information Administration (2021), Unit 2 generated 2,956,511 megawatt hours of electricity during 2020, which is the last calendar year with complete data. To estimate gross value, I multiplied the gross value of electricity output for the fossil-fuel electric power sector in Sweetwater County reported by IMPLAN by the share of Unit 2 in total electricity generated by the Jim Bridger plant. Accordingly, the gross value of output from Unit 2 is estimated to be $151,608,193 for the analysis below. This estimate is conservative and reflects the historic cost-based value of electric power rather than the cost of replacement power, which is substantially greater. [1]

[1] I originally multiplied Unit 2 generation by the Palo Verde Hub peak price for electricity reported by Bloomberg (2021) from the data collected by the International Commodity Exchange. This approach yields an estimate for gross output from Unit 2 at $185.1 million.

To avoid double counting of industry impacts, this study conducts an industry contribution analysis (ICA) using the online IMPLAN tools. The ICA provides a more accurate picture of the relative extent and magnitude of the Unit 2 closure event.

The Jim Bridger power plant is a so-called mine-mouth power plant. For this configuration, coal is transported from the mines to the power generating units via a conveyer belt that is depicted in Figure 1. This somewhat unique arrangement requires a customization of the purchasing coefficients in the default IMPLAN input-output models. Specifically, the regional purchasing parameter is set to 100 percent and the interindustry purchases were rebalanced to reflect the captive nature of the coal mine so that if Unit 2 closes, the coal cannot be sold to another customer. In other words, the reduction in electric power production entails a corresponding reduction in coal production.

Figure 1: The Jim Bridger power plant

With these modifications to the default IMPLAN models for Wyoming, the final decision is to define the scope of the study region, which includes Sweetwater County and the remaining counties in Wyoming. An overview of value added and employee compensation for the study region in 2019 is provided in Figure 2. Total Wyoming value added in 2019 was $40.7 billion with $4.0 billion in Sweetwater County and the remaining $36.7 billion generated in the remaining counties. Employee compensation for the entire State of Wyoming was $19.1 billion with $1.8 billion earned in Sweetwater County and the remaining $17.2 billion earned in the rest of the state. An overview of employment in the study region is presented in Figure 3. Of the 409,295 total state employment, 7% or 28,502 is in Sweetwater County and the remaining 93% or 380,793 is in the rest of the state.

This study conducts a multi-regional input-output analysis that models how the Unit 2 closure would affect the purchases and sales of goods and services within Sweetwater County and between Sweetwater County and the rest of the state. Accordingly, the next three sections present and discuss the economic impacts for Sweetwater County, the rest of the state, and the entire State of Wyoming. These impacts include the direct, indirect, and induced impacts of the plant closure on value added, employee compensation, employment, and tax revenues in each of the three regions. Indirect impacts are essentially supply-chain impacts, such as coal purchases by the power plant and contractor services acquired by the power plant and the coal mine. Induced impacts arise from the spending of income earned from direct and indirect impacts on local goods and services, for example, workers throughout the supply-chain spending their wage and proprietor income to dine at local restaurants.

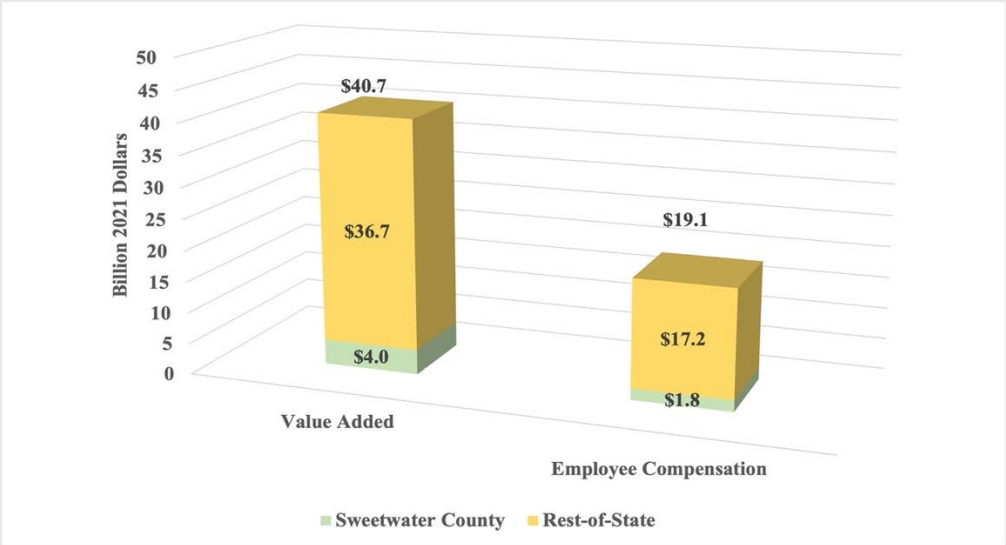

Figure 2: Value added in the study region in billion 2021 dollars

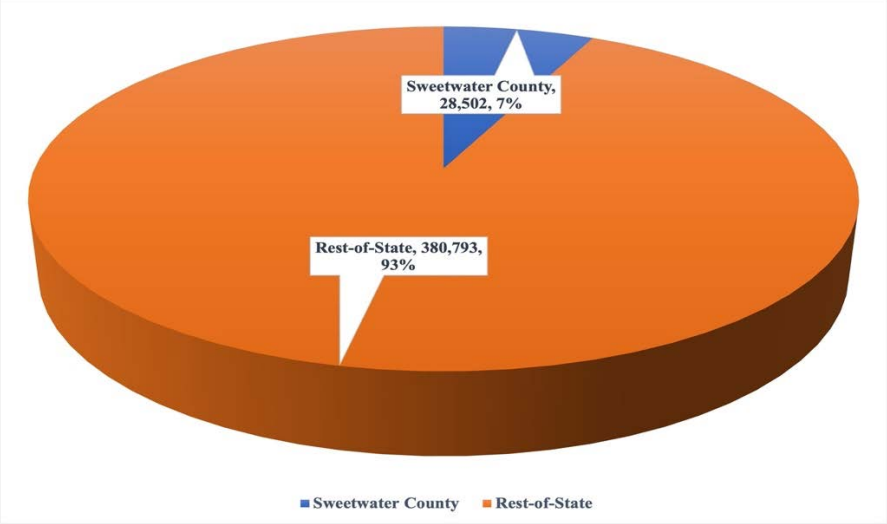

Figure 3: Employment in the study region

3. Economic and Fiscal Impacts on Sweetwater County

This section reports the estimated losses in value added, employee compensation, employment, and tax revenues for Sweetwater County. The total economic impacts are the sum of the direct, indirect, and induced impacts. For this study, the direct impacts stem from the reduced electricity output from closing Unit 2. The indirect impacts include the reduced purchases of coal and other intermediate inputs purchased by the power plant. Finally, the induced impacts capture the reduced spending on local goods and services that results from lower household and business income. This analysis assumes that prices for local goods and services are unaffected by the closure of Unit 2.

Gross output is equivalent to gross sales and includes purchases of intermediate inputs. Adding changes in gross output across industries due to an industry event, therefore, would double count economic inputs. Instead, economic impact analysis uses changes in value added to estimate total economic impacts. Value added for a particular industry is the difference between gross output and the cost of intermediate inputs, which are purchases from other industries or imports. Value added includes employee compensation, proprietor income, taxes on production and imports, and other property income. In short, value added for an industry is its net contribution to gross domestic product.

IMPLAN reports industry impacts for 546 sectors of the economy. This study aggregates these sectors into the two-digit aggregate industries defined by the North American Industry Classification System (NAICS) in the first column in Table 1. Notice that the value under the direct column in Table 1 for the utilities row is $47,787,405, which is the change in value added from the utilities sector due to the closure of Unit 2 at the Jim Bridger power plant. Notice that this is lower than the $151,608,193 of gross value of electricity output from closing Unit 2.

The indirect or supply-chain impacts are reported in column three in Table 1. The largest impact is $67,859,530 in the mining sector, which includes coal production. This means that the net contribution of coal mining falls by over $67 million due to the closure of Unit 2. Once again, we are assuming that the captive coal mine cannot sell the coal that would have gone to Unit 2 to another buyer. This is a reasonable assumption because to do so would require capital investments for coal handing and transportation to ship coal to buyers outside of Point of Rocks.

The next largest indirect impacts occur in transportation and warehousing, $4,105,515, utilities, $2,282,231, which is primarily electric transmission, wholesale trade, $1,324,684, and waste management, $657,841. Real estate and rentals, professional scientific and technical services, government enterprises as well as many other sectors also would be adversely affected by closing Unit 2.

Also reported in Table 1 in column 4 are the induced losses in value added by sector. Unlike the indirect or supply-chain impacts, the sectors hit hardest by the shutdown include real estate, $3,053,939, retail trade, $1,024,676, and health care and social assistance, $810,563, within Sweetwater County. The sectoral allocation of these impacts represents how the local economy would be affected as households and business reduce their spending due to lower incomes in the county after closure of Unit 2.

Table 1: Lost value added for Sweetwater County in 2021 dollars

NAICS Aggregated Industries	Direct	Indirect	Induced	Total
Ag, Forestry, Fish & Hunting	$0	$1,652	$2,967	$4,619
Mining	$0	$67,859,530	$31,984	$67,891,514
Utilities	$47,787,405	$2,282,231	$95,355	$50,164,992
Construction	$0	$216,698	$87,543	$304,241
Manufacturing	$0	$59,437	$1,203	$60,640
Wholesale Trade	$0	$1,324,684	$283,601	$1,608,285
Retail trade	$0	$169,532	$1,024,676	$1,194,208
Transportation & Warehousing	$0	$4,105,515	$205,274	$4,310,789
Information	$0	$71,007	$94,541	$165,549
Finance & insurance	$0	$218,116	$323,053	$541,169
Real estate & rental	$0	$719,950	$3,053,939	$3,773,889
Professional- scientific & tech	$0	$421,081	$132,901	$553,982
Management of companies	$0	$221,453	$35,464	$256,916
Waste Management	$0	$657,841	$107,704	$765,545
Educational Services	$0	$3,092	$55,934	$59,025
Health Care and Social Assistance	$0	$4	$810,563	$810,567
Arts, entertainment & recreation	$0	$3,928	$89,962	$93,890
Accommodation & food services	$0	$90,857	$670,777	$761,634
Other services	$0	$100,865	$459,823	$560,688
Government Enterprises	$0	$152,534	$83,366	$235,900
Total	$47,787,405	$78,680,007	$7,650,630	$134,118,042

The total losses of value added by sector in Sweetwater County from closing Unit 2 are reported the last column of Table 1. Notice that the loss of value added in utilities and the mining sector are $50,164,992 and $67,891,514 respectively. These two sectors alone account for 88% of the total loss in value added of $134,118,942. The loss of value added in the transportation and warehousing sector is the next largest at $4,310,789. The real estate sector loses $3,773,889 in value added. Losses in value added exceed $1 million in the wholesale and retail trade, while losses in waste management, health care and social assistance, and accommodation and food services are between $761and $810 thousand.

The changes in employee compensation are reported in Table 2. Employee compensation is fully loaded payroll or the total payroll cost of wage and salary employees to the employer, including wages and salaries, all benefits such as health and retirement, and payroll taxes. The direct payroll loss in the utility sector from closing Unit 2 is $10,114,444. Employee compensation in mining declines by $13,499,151. Induced impacts are reported in column three of Table 2. Total employee compensation in Sweetwater County declines $30,483,345 with 80 percent of this decline occurring in the utility and mining sectors.

The impacts on employment are reported in Table 3. Total employment losses in the utility sector are 65 full-time equivalent jobs, see column 1 in Table 3. The loss in mining employment is estimated to be 108 FTEs. Total indirect job losses are 172 FTEs and induced job losses are 90. Hence, the total loss in employment in Sweetwater County is 327 FTEs. Dividing the loss of 327 in total employment by the direct loss of 65 jobs in the utility sector plus the closely related 108 lost coal-mining jobs implies a multiplier of 1.89, which means that for every job lost from shutting down Unit 2, almost 2 total jobs are lost, which is conservative.

Table 2: Lost employee compensation for Sweetwater County in 2021 dollars

NAICS Aggregated Industries	Direct	Indirect	Induced	Total
Ag, Forestry, Fish & Hunting	$0	$965	$1,711	$2,676
Mining	$0	$13,499,151	$9,444	$13,508,594
Utilities	$10,114,444	$766,408	$34,351	$10,915,203
Construction	$0	$108,747	$45,657	$154,404
Manufacturing	$0	$36,523	$651	$37,174
Wholesale Trade	$0	$484,780	$131,011	$615,791
Retail trade	$0	$72,197	$572,030	$644,227
Transportation & Warehousing	$0	$1,110,332	$143,513	$1,253,845
Information	$0	$23,945	$30,652	$54,597
Finance & insurance	$0	$124,777	$175,580	$300,357
Real estate & rental	$0	$222,766	$54,998	$277,764
Professional- scientific & tech	$0	$274,006	$88,516	$362,521
Management of companies	$0	$164,848	$26,399	$191,246
Waste Management	$0	$412,428	$73,032	$485,459
Educational Services	$0	$2,101	$39,334	$41,434
Health Care and Social Assistance	$0	$3	$641,717	$641,720
Arts, entertainment & recreation	$0	$1,302	$34,340	$35,642
Accommodation & food services	$0	$61,892	$430,995	$492,887
Other services	$0	$65,477	$250,071	$315,548
Government Enterprises	$0	$93,832	$58,421	$152,254
Total	$10,114,444	$17,526,478	$2,842,423	$30,483,345

Table 3: Lost employment for Sweetwater County in 2021 dollars

NAICS Aggregated Industries	Direct	Indirect	Induced	Total
Ag, Forestry, Fish & Hunting	0	0	0	0
Mining	0	108	0	108
Utilities	65	5	0	71
Construction	0	2	1	3
Manufacturing	0	0	0	0
Wholesale Trade	0	8	2	10
Retail trade	0	3	20	23
Transportation & Warehousing	0	12	3	15
Information	0	0	1	1
Finance & insurance	0	3	5	7
Real estate & rental	0	5	5	10
Professional- scientific & tech	0	5	2	7
Management of companies	0	1	0	2
Waste Management	0	12	2	14
Educational Services	0	0	1	1
Health Care and Social Assistance	0	0	16	16
Arts, entertainment & recreation	0	0	2	3
Accommodation & food services	0	3	21	24
Other services	0	1	8	9
Government Enterprises	0	1	1	2
Total	65	172	90	327

With lower economic output and employment from closing Unit 2, tax revenues decline. Table 4 presents the IMPLAN model estimates of these losses in tax revenues. Federal tax revenues decline $11,623,589, see the top panel of Table 4. Federal personal tax revenues decline $3,441,724 and employee and employer contributions for social security are $2,513,520 and $1,815,681 lower respectively. State tax revenue losses are nearly $9.5 million with most of these losses coming from lower sales and severance tax revenues of $4,107,204 and $3,238,258 respectively. Tax revenues for Sweetwater County and its special districts decline $8.7 million with 86.6 percent of this loss coming from reduced property taxes, which include ad valorem taxes on mineral and industrial properties.

Table 4: Lost tax revenue for Sweetwater County in 2021 dollars

Federal	***Employees & Proprietors***	***Production & Imports***	***Households & Business***	***Total***
Social Ins. Tax- Employee	$2,513,520			$2,513,520
Social Ins. Tax- Employer	$1,815,681			$1,815,681
Excise Taxes		$944,044		$944,044
Custom Duty		$765,179		$765,179
Corporate Profits Tax			$2,143,441	$2,143,441
Personal Tax: Income Tax			$3,441,724	$3,441,724
Sub-total	$4,329,201	$1,709,224	$5,585,165	$11,623,589
State				
Social Ins. Tax- Employee	$138,594			$138,594
Social Ins. Tax- Employer	$212,010			$212,010
Sales Tax		$4,107,204		$4,107,204
Property Tax		$1,105,460		$1,105,460
Motor Vehicle License		$158,919		$158,919
Severance Tax		$3,238,258		$3,238,258
Other Taxes		$300,693	$209,388	$510,081
Sub-total	$350,604	$8,910,534	$209,388	$9,470,526
County				
Sales Tax		$752,484		$752,484
Property Tax		$2,506,320		$2,506,320
Motor Vehicle License		$40,451		$40,451
Other Taxes			$27,445	$27,445
Sub-total		$3,299,255	$27,445	$3,326,700
Special Districts				
Sales Tax				
Property Tax		$4,749,607		$4,749,607
Other Taxes		$89,624	$31,672	$121,296
Sub-total		$4,839,231	$31,672	$4,870,903
General County				
Sales Tax		$77,144		$77,144
Property Tax		$278,444		$278,444
Other Taxes		$144,844	$1,857	$146,701
Sub-total		$500,432	$1,857	$502,289
Government Totals	$4,679,805	$19,258,676	$5,855,527	$29,794,008

4. Economic and Fiscal Impacts on the Rest of the State

The economic impacts on the rest of the state only include indirect and induced effects from trade between Sweetwater County and other counties in Wyoming. These impacts are reported in the next four tables. The total impact of closing Unit 2 on value added for the rest of the state is $14.5 million with $12.2 of this arising from indirect or supply-chain impacts and the remaining $2.3 induced by changes in household and business income, see Table 5. The largest impacts occur in the mining, utility, transportation and warehousing, real estate and rentals, and government enterprises. These impacts are much smaller than those estimated for Sweetwater County.

Table 5: Value added losses for rest of state in 2021 dollars

NAICS Aggregated Industries	Indirect	Induced	Total
Ag, Forestry, Fish & Hunting	$31,615	$4,023	$35,638
Mining	$5,724,283	$16,014	$5,740,297
Utilities	$1,071,662	$39,564	$1,111,226
Construction	$158,299	$25,033	$183,332
Manufacturing	$644,291	$24,088	$668,379
Wholesale Trade	$326,590	$69,959	$396,550
Retail trade	$42,687	$247,794	$290,481
Transportation & Warehousing	$1,612,329	$69,229	$1,681,558
Information	$81,148	$55,961	$137,110
Finance & insurance	$165,351	$163,418	$328,769
Real estate & rental	$218,411	$720,567	$938,978
Professional- scientific & tech	$624,568	$76,594	$701,161
Management of companies	$41,156	$7,132	$48,288
Waste Management	$166,067	$48,732	$214,799
Educational Services	$604	$15,988	$16,592
Health Care and Social Assistance	$21	$322,595	$322,615
Arts, entertainment & recreation	$7,695	$37,778	$45,473
Accommodation & food services	$27,925	$146,962	$174,887
Other services	$44,400	$132,744	$177,144
Government Enterprises	$1,247,722	$54,037	$1,301,759
Total	$12,236,825	$2,278,213	$14,515,038

Employee compensation in the rest of the state follows the same pattern across sectors as the decline in value added, see Table 6. Total employee compensation declines $4.5 million, see Table 6. The largest losses occur in mining, government enterprises, utilities, and professional scientific and technical services.

Employment in the rest of the state declines by 77 FTEs with 49 arising from supply chain impacts and the remaining 28 lost FTEs induced by lower income, see Table 7. The largest, although modest in absolute terms, employment losses are in the mining, utilities, transportation and warehousing, scientific and professional services, and government enterprises.

Lost tax revenues in the rest of the state are reported in Table 8. The IMPLAN model estimates total lost tax revenues in the rest of the state are $3.4 million, much smaller than the $29.8 million in Sweetwater County.

Table 6: Losses of employee compensation for rest of state in 2021 dollars

NAICS Aggregated Industries	Indirect	Induced	Total
Ag, Forestry, Fish & Hunting	$6,135	$1,513	$7,647
Mining	$1,252,045	$3,672	$1,255,717
Utilities	$355,921	$13,248	$369,169
Construction	$75,796	$12,268	$88,064
Manufacturing	$198,064	$8,592	$206,656
Wholesale Trade	$96,452	$31,313	$127,765
Retail trade	$17,397	$132,037	$149,434
Transportation & Warehousing	$253,766	$37,516	$291,282
Information	$28,337	$19,122	$47,458
Finance & insurance	$88,929	$89,635	$178,564
Real estate & rental	$44,904	$19,083	$63,987
Professional- scientific & tech	$291,116	$41,795	$332,911
Management of companies	$35,905	$6,222	$42,126
Waste Management	$107,981	$32,318	$140,299
Educational Services	$436	$12,620	$13,055
Health Care and Social Assistance	$15	$256,211	$256,227
Arts, entertainment & recreation	$2,243	$15,965	$18,208
Accommodation & food services	$18,671	$95,482	$114,153
Other services	$28,135	$80,700	$108,835
Government Enterprises	$627,509	$32,431	$659,941
Total	$3,529,755	$941,744	$4,471,498

Table 7: Lost employment for rest of state in 2021 dollars

NAICS Aggregated Industries	Indirect	Induced	Total
Ag, Forestry, Fish & Hunting	0	0	0
Mining	14	0	14
Utilities	3	0	3
Construction	2	0	2
Manufacturing	1	0	1
Wholesale Trade	1	0	2
Retail trade	1	5	6
Transportation & Warehousing	4	1	4
Information	1	0	1
Finance & insurance	2	3	5
Real estate & rental	2	2	4
Professional- scientific & tech	6	1	7
Management of companies	1	0	1
Waste Management	3	1	4
Educational Services	0	0	1
Health Care and Social Assistance	0	5	5
Arts, entertainment & recreation	0	1	1
Accommodation & food services	1	4	5
Other services	1	3	3
Government Enterprises	7	0	7
Total	49	28	77

Table 8: Lost tax revenues for rest of state in 2021 dollars

Federal	***Employees & Proprietors***	***Production & Imports***	***Households & Business***	***Total***
Social Ins. Tax- Employee	$390,309			$390,309
Social Ins. Tax- Employer	$292,864			$292,864
Excise Taxes		$78,048		$78,048
Custom Duty		$63,261		$63,261
Corporate Profits Tax			$184,091	$184,091
Personal Tax: Income Tax			$522,259	$522,259
Sub-total	$683,173	$141,309	$706,350	$1,530,832
State				
Social Ins. Tax- Employee	$20,443			$20,443
Social Ins. Tax- Employer	$31,272			$31,272
Sales Tax		$525,659		$525,659
Property Tax		$141,532		$141,532
Motor Vehicle License		$20,346		$20,346
Severance Tax		$414,593		$414,593
Other Taxes		$38,498	$32,935	$71,432
Sub-total	$51,716	$1,140,628	$32,935	$1,225,278
County				
Sales Tax		$50,488		$50,488
Property Tax		$175,199		$175,199
Motor Vehicle License		$2,726		$2,726
Other Taxes		$5,031	$2,929	$7,960
Sub-total		$233,444	$2,929	$236,373
Special Districts				
Sales Tax		$783		$783
Property Tax		$363,763		$363,763
Other Taxes		$13,706	$2,690	$16,396
Sub-total		$378,252	$2,690	$380,942
General County				
Sales Tax		$13,521		$13,521
Property Tax		$20,822		$20,822
Other Taxes		$7,096	$153	$7,248
Sub-total		$41,439	$153	$41,591
Government Totals	$734,889	$1,935,071	$745,057	$3,415,016

5. Total State Economic and Fiscal Impacts

This section simply provides summary tables for the economic and fiscal impacts for the entire State of Wyoming. The closure of Unit 2 reduces state-wide value added by $148.6 million with $51.3 and $73.6 million from the utility and mining sectors respectively, see Table 9. Value added declines $6 million in transportation and warehousing and $4.7 million in the real estate and rental sector. The next largest losses occur in wholesale trade with $2 million, government enterprises at $1.5 million, retail trade at $1.5 million, professional scientific and professional services at $1.3 million, and $1 million from the waste management sector.

Table 9: State-wide lost value added in 2021 dollars

NAICS Aggregated Industries	Direct	Indirect	Induced	Total
Ag, Forestry, Fish & Hunting	$0	$33,267	$6,990	$40,257
Mining	$0	$73,583,813	$47,998	$73,631,811
Utilities	$47,787,405	$3,353,893	$134,919	$51,276,218
Construction	$0	$374,997	$112,576	$487,573
Manufacturing	$0	$703,728	$25,291	$729,019
Wholesale Trade	$0	$1,651,274	$353,560	$2,004,835
Retail trade	$0	$212,219	$1,272,470	$1,484,689
Transportation & Warehousing	$0	$5,717,844	$274,504	$5,992,348
Information	$0	$152,156	$150,502	$302,658
Finance & insurance	$0	$383,467	$486,470	$869,937
Real estate & rental	$0	$938,361	$3,774,507	$4,712,868
Professional- scientific & tech	$0	$1,045,648	$209,495	$1,255,143
Management of companies	$0	$262,609	$42,596	$305,204
Waste Management	$0	$823,909	$156,436	$980,344
Educational Services	$0	$3,696	$71,922	$75,617
Health Care and Social Assistance	$0	$25	$1,133,158	$1,133,183
Arts, entertainment & recreation	$0	$11,623	$127,741	$139,363
Accommodation & food services	$0	$118,782	$817,740	$936,521
Other services	$0	$145,265	$592,567	$737,832
Government Enterprises	$0	$1,400,256	$137,403	$1,537,660
Total	$47,787,405	$90,916,832	$9,928,843	$148,633,080

Employee compensation in the State of Wyoming declines $34.9 million with $10.1 million coming directly from the utility sector, another $21 million from reduced business activity in the supply chain, and the remaining $3.8 million induced by lower spending in the economy from lower wage, salary, and proprietor income, see Table 10.

Nearly 75 percent of the losses in employee compensation are from losses in the utility and mining sectors. The corresponding losses in employment are 74 and 122 FTEs respectively in these two sectors. Dividing the loss in employee compensation by the loss the employment indicates that the lost average employee compensation per FTE for these two sectors are $121,019 and $152,492 for the mining and utility sectors respectively. Total employment losses are 404 with 65 from direct impacts, 221 from indirect effects, and 118 from induced impacts, see Table 11.

Table 10: State-wide lost employee compensation in 2021 dollars

NAICS Aggregated Industries	Direct	Indirect	Induced	Total
Ag, Forestry, Fish & Hunting	$0	$7,099	$3,224	$10,323
Mining	$0	$14,751,196	$13,116	$14,764,312
Utilities	$10,114,444	$1,122,328	$47,599	$11,284,372
Construction	$0	$184,543	$57,925	$242,468
Manufacturing	$0	$234,587	$9,243	$243,830
Wholesale Trade	$0	$581,231	$162,324	$743,555
Retail trade	$0	$89,594	$704,067	$793,661
Transportation & Warehousing	$0	$1,364,098	$181,029	$1,545,127
Information	$0	$52,282	$49,774	$102,056
Finance & insurance	$0	$213,706	$265,216	$478,921
Real estate & rental	$0	$267,669	$74,082	$341,751
Professional- scientific & tech	$0	$565,121	$130,311	$695,432
Management of companies	$0	$200,752	$32,621	$233,373
Waste Management	$0	$520,409	$105,350	$625,758
Educational Services	$0	$2,536	$51,954	$54,490
Health Care and Social Assistance	$0	$18	$897,929	$897,947
Arts, entertainment & recreation	$0	$3,545	$50,305	$53,850
Accommodation & food services	$0	$80,564	$526,477	$607,040
Other services	$0	$93,611	$330,771	$424,382
Government Enterprises	$0	$721,342	$90,853	$812,194
Total	$10,114,444	$21,056,233	$3,784,167	$34,954,844

Table 11: State-wide lost employment in number of jobs

NAICS Aggregated Industries	Direct	Indirect	Induced	Total
Ag, Forestry, Fish & Hunting	0	0	0	1
Mining	0	122	0	122
Utilities	65	8	0	74
Construction	0	4	1	5
Manufacturing	0	2	0	2
Wholesale Trade	0	9	3	11
Retail trade	0	3	25	29
Transportation & Warehousing	0	16	4	20
Information	0	1	1	2
Finance & insurance	0	5	7	12
Real estate & rental	0	8	7	15
Professional- scientific & tech	0	11	3	14
Management of companies	0	2	0	2
Waste Management	0	16	3	19
Educational Services	0	0	2	2
Health Care and Social Assistance	0	0	21	21
Arts, entertainment & recreation	0	1	3	4
Accommodation & food services	0	4	25	29
Other services	0	2	10	12
Government Enterprises	0	8	1	9
Total	65	221	118	404

Total tax revenues generated in Wyoming decline by $33.2 million from the closure of Jim Bridger's power generation Unit 2. Federal tax revenues decline $13.1 million. State tax revenues decline $10.7 million primarily from a $4.6 million reduction in sales tax revenues and $3.7 million in lost severance tax revenues. County tax revenues decline $9.4 million with 86 percent of this decline coming from lower property tax revenues due to lower mineral ad valorem tax revenues.

Table 12: State-wide lost tax revenue in 2021 dollars

	Employees & Proprietors	*Production & Imports*	*Households & Business*	*Total*
Federal				
Social Ins. Tax- Employee	$2,903,829			$2,903,829
Social Ins. Tax- Employer	$2,108,545			$2,108,545
Excise Taxes		$1,022,093		$1,022,093
Custom Duty		$828,440		$828,440
Corporate Profits Tax			$2,327,532	$2,327,532
Personal Tax: Income Tax			$3,963,983	$3,963,983
Sub-total	$5,012,374	$1,850,532	$6,291,515	$13,154,422
State				
Social Ins. Tax- Employee	$159,037			$159,037
Social Ins. Tax- Employer	$243,283			$243,283
Sales Tax		$4,632,863		$4,632,863
Property Tax		$1,246,992		$1,246,992
Motor Vehicle License		$179,265		$179,265
Severance Tax		$3,652,851		$3,652,851
Other Taxes		$339,191	$242,322	$581,513
Sub-total	$402,320	$10,051,162	$242,322	$10,695,804
County				
Sales Tax		$802,972		$802,972
Property Tax		$2,681,519		$2,681,519
Motor Vehicle License		$43,177		$43,177
Other Taxes		$5,031	$30,374	$35,405
Sub-total		$3,532,699	$30,374	$3,563,073
Special Districts				
Sales Tax		$783		$783
Property Tax		$5,113,370		$5,113,370
Other Taxes		$103,329	$34,363	$137,692
Sub-total		$5,217,483	$34,363	$5,251,845
General County				
Sales Tax		$90,665		$90,665
Property Tax		$299,266		$299,266
Other Taxes		$151,940	$2,009	$153,949
Sub-total		$541,871	$2,009	$543,880
Government Totals	$5,414,694	$21,193,747	$6,600,583	$33,209,024

6. Conclusions

Closing Unit 2 at the Jim Bridger reduces value added, or gross state product, in the State of Wyoming by $148.6 million per annum. Annual total federal, state, and local tax revenues decline $33.2 million. Closing Unit 2 also reduces employment, and our estimates indicate a loss of 404 full-time equivalent positions.

Most of these losses occur in Sweetwater County where Unit 2 is located. Value added or gross county product is reduced by $134.1 million and 327 jobs are lost. Sweetwater County tax revenues are reduced by nearly $8.7 million.

These are annual losses from closing the Unit 2. If the Unit 2 were to operate through the then end of its expected life, these losses, except the employment losses, would accumulate for seven years. From this perspective, the economic and fiscal impacts would be 7-fold larger, or $1 billion in lost value added and $245 million in foregone tax revenues.

A complete cost-benefit analysis of the air quality benefits from closing Unit 2 is beyond the scope of this study. Nevertheless, the cost of closing Jim Bridger Unit 2 in terms of lost value added per ton of avoided carbon dioxide and particulate pollution are $73 and over $35,000 per ton respectively, which both seem rather high.

Finally, closing Unit 2 may have significant impacts on maintaining the reliability of electricity service to the thousands of customers consuming electric power generated at the Jim Bridger plant. While estimating the impact of closing Unit 2 on the reliability of the electric grid is also beyond the scope of this study, readers should keep in mind that the social costs of unreliable electricity service are significant.

References

Bloomberg (2021) "Bloomberg Terminal: Bloomberg Professional Services, https://bba.bloomberg.net.

Energy Information Administration (2021) "EIA-923 Monthly Generating Unit Net Generation Time Series File," 202 Revision, https://www.eia.gov/electricity/data/eia923/.

IMPLAN (2021) "Economic Impact Analysis for Planning," https://implan.com.

Miller, R.E. and P.D. Blair (2009) Input-Output Analysis: Foundations and Extensions, Cambridge University Press, 750 pages.

Date: May 5, 2020

Mr. James Owen
Director, Environmental Services
PacifiCorp
1407 W North Temple, Ste 210
Salt Lake City, UT 84116

Permit No. **P0025809**

Dear Mr. Owen:

The Division of Air Quality of the Wyoming Department of Environmental Quality has completed final review of PacifiCorp's (CMP000574) application to modify operations at the Jim Bridger Plant (F000645) by establishing monthly-block average pound per hour (lb/hr) NO_x and SO_2 emissions limits for Units 1-4 (EGU001-EGU004) combined and a 12-month rolling total NO_x and SO_2 emission limit of 17,500 tons per year (tpy) for Units 1-4 (EGU001-EGU004) combined. This combined set of lb/hr and tpy limits will be enforced in lieu of installation of selective catalytic reduction technology (SCR) on Units 1-2 (EGU001-EGU002), and will effectively decrease the operating capacity of the plant, thereby reducing its emission of haze-causing pollutants, NO_x and SO_2. The Jim Bridger Plant is located in Section 3, T20N, R101W, approximately four (4) miles north of Point of Rocks, in Sweetwater County, Wyoming.

Following this agency's proposed approval of the request as published July 20, 2019 and in accordance with Chapter 6, Section 2(m) of the Wyoming Air Quality Standards and Regulations, the public was afforded a 30-day period in which to submit comments concerning the proposed modification, and an opportunity for a public hearing. A public hearing was conducted on August 23, 2019, in the Pilot Butte Conference Room of the Rock Springs BLM Field Office, located at 280 Highway 191 North, Rock Springs, in Sweetwater County, Wyoming. Comments received were considered in the final permit. Therefore, on the basis of the information provided to us, approval to modify the Jim Bridger Plant as described in the application is hereby granted pursuant to Chapter 6, Section 2 of the regulations with the following conditions:

1. That authorized representatives of the Division of Air Quality be given permission to enter and inspect any property, premise or place on or at which an air pollution source is located or is being constructed or installed for the purpose of investigating actual or potential sources of air pollution and for determining compliance or non-compliance with any rules, standards, permits or orders.

2. That all substantive commitments and descriptions set forth in the application for this permit, unless superseded by a specific condition of this permit, are incorporated herein by this reference and are enforceable as conditions of this permit.

3. That PacifiCorp shall file a complete application to modify their Operating Permit within twelve (12) months of commencing operation, in accordance with Chapter 6, Section 3(c)(i)(B) of the WAQSR. Where an existing operating permit would prohibit such construction or change in operation, the owner or operator must obtain a permit revision before commencing operation.

4. That all notifications, reports, and correspondence required by this permit shall be submitted to the Stationary Source Compliance Program Manager. Submissions may be done electronically through https://airimpact.wyo.gov to satisfy requirements of this permit.

5. That written notification of the anticipated date of initial startup of the Reasonable Progress Reassessment Project, in accordance with Chapter 6, Section 2(i) of the WAQSR, is required not more than sixty (60) days or less than thirty (30) days prior to such date. Notification of the actual date of startup is required within fifteen (15) days after startup.

6. That the date of commencement of construction of the Reasonable Progress Reassessment Project shall be reported to the Administrator within thirty (30) days of commencement. In accordance with Chapter 6, Section 2(h) of the WAQSR, approval to construct or modify shall become invalid if construction is not commenced within twenty-four (24) months after receipt of such approval or if construction is discontinued for a period of twenty-four (24) months or more. The Administrator may extend the period based on satisfactory justification of the requested extension.

7. Units 1-4 shall be limited to the following monthly-block average pound per hour (lb/hr) NO_x and SO_2 emissions limits. Compliance with the limits shall be determined using continuous emissions monitoring systems (CEMS) certified in accordance with 40 CFR part 75. The NO_x and SO_2 limits will be effective on January 1, 2022 and initial compliance shall be determined on February 1, 2022.

Month	**NO_x**	**SO_2**
January	2,050	2,100
February	2,050	2,100
March	2,050	2,100
April	2,050	2,100
May	2,200	2,100
June	2,500	2,100
July	2,500	2,100
August	2,500	2,100
September	2,500	2,100
October	2,300	2,100
November	2,030	2,100
December	2,050	2,100

8. Compliance with the monthly-block average lb/hr NO_x and SO_2 emissions limits set forth in Condition 7 of this permit shall be determined with data from certified CEMS as follows:

   i. Exceedance of the limit shall be defined as follows:

      1. Any monthly-block average which exceeds the lb/hr NO_x and SO_2 limits as calculated using the following formula:

$$Eavg = E_{U1} + E_{U2} + E_{U3} + E_{U4}$$

Where:

E_{avg} = Monthly-block average emission rate (lb/hr)
E_{U1} = Monthly-block average Unit 1 emission rate (lb/hr)
E_{U2} = Monthly-block average Unit 2 emission rate (lb/hr)
E_{U3} = Monthly-block average Unit 3 emission rate (lb/hr)
E_{U4} = Monthly-block average Unit 4 emission rate (lb/hr)

$$E_{U1} = \frac{\sum_{h=1}^{n}(C_1)h}{n}$$

$$E_{U2} = \frac{\sum_{h=1}^{n}(C_2)h}{n}$$

$$E_{U3} = \frac{\sum_{h=1}^{n}(C_3)h}{n}$$

$$E_{U4} = \frac{\sum_{h=1}^{n}(C_4)h}{n}$$

C1 = Unit 1 1-hour average emission rate (lb/hr) for hour "h" calculated using valid data (output concentration and average hourly volumetric flowrate) from the CEM equipment certified and operated in accordance with Part 75. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedure of Part 75. C1 shall be determined for each calendar month used to demonstrate compliance with the emission limits set forth in Condition 7.

C2 = Unit 2 1-hour average emission rate (lb/hr) for hour "h" calculated using valid data (output concentration and average hourly volumetric flowrate) from the CEM equipment certified and operated in accordance with Part 75. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedure of Part 75. C2 shall be determined for each calendar month used to demonstrate compliance with the emission limits set forth in Condition 7.

C3 = Unit 3 1-hour average emission rate (lb/hr) for hour "h" calculated using valid data (output concentration and average hourly volumetric flowrate) from the CEM equipment certified and operated in accordance with Part 75. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedure of Part 75. C3 shall be determined for each calendar month used to demonstrate compliance with the emission limits set forth in Condition 7.

C4 = Unit 4 1-hour average emission rate (lb/hr) for hour "h" calculated using valid data (output concentration and average hourly volumetric flowrate) from the CEM equipment certified and operated in accordance with Part 75. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedure of Part 75. C4 shall be determined for each calendar month used to demonstrate compliance with the emission limits set forth in Condition 7.

n = The number of unit operating hours monitored during the monthly-block period with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j).

ii PacifiCorp will comply with all monitoring, recordkeeping, and reporting requirements in Section 8.3.3 of Wyoming's 309(g) Regional Haze SIP in addition to the reporting and recordkeeping requirements as specified in WAQSR, Chapter 5, Section 2(g).

9. Units 1-4 shall be limited to a combined limit for NO_x plus SO_2 of 17,500 tons per year based on a 12-month rolling total. Compliance with the limit shall be determined using a CEMS certified in accordance with 40 CFR part 75. Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75. The NO_x plus SO_2 limit will be effective on January 1, 2022 and initial compliance shall be determined on January 1, 2023.

10. PacifiCorp shall retain a copy of all records necessary to determine compliance with the limits established in Conditions 7 and 9 for five (5) years from the date of such record.

11. All conditions from previously issued permits and authorization letters/waivers for the Jim Bridger Plant shall remain in effect unless specifically superseded by a condition of this permit.

It must be noted that this approval does not relieve you of your obligation to comply with all applicable county, state, and federal standards, regulations or ordinances. Special attention must be given to Chapter 6, Section 2 of the Wyoming Air Quality Standards and Regulations, which details the requirements for compliance with Conditions 3, 5 and 6. Any appeal of this permit as a final action of the Department must be made to the Environmental Quality Council within thirty (30) days of permit issuance per Section 8, Chapter 1, General Rules of Practice and Procedure, Department of Environmental Quality.

If we may be of further assistance to you, please feel free to contact this office.

Sincerely,

Nancy E. Vehr
Administrator
Air Quality Division

Todd Parfitt
Director
Dept. of Environmental Quality