May 31, 2022

Bryce Bird, Director
Utah Division of Air Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820
By email: rwood@utah.gov

Re: Comments on Utah's Proposed Regional Haze State Implementation Plan for the 2nd Implementation Period

Dear Director Bird:

On behalf of the National Parks Conservation Association, Sierra Club, Utah Physicians for a Healthy Environment, The Coalition to Protect America's National Parks, the Healthy Environment Alliance of Utah, and O2 Utah (the "Conservation Organizations"), we respectfully submit the following comments and attached expert report[1] regarding Utah Department of Environmental Quality Division of Air Quality's ("UDAQ") Proposed Utah State Implementation Plan, Regional Haze Second Planning Period ("Proposed SIP").

National Parks Conservation Association ("NPCA") is a national organization whose mission is to protect and enhance America's National Parks for present and future generations. NPCA performs its work through advocacy and education, with its main office in Washington, D.C. and 24 regional and field offices. NPCA has over 1.5 million members and supporters nationwide, with 14,391 in Utah. NPCA is active nationwide in advocating for strong air quality requirements to protect our parks, including submission of petitions and comments relating to visibility issues, regional haze State Implementation Plans, climate change and mercury impacts on parks, and emissions from individual power plants and other sources of pollution affecting National Parks and communities. NPCA's members live near, work at, and recreate in all the national parks, including those directly affected by emissions from Utah's sources.

Sierra Club is a national nonprofit organization with 67 chapters and more than 830,000 members dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. The Sierra Club has

[1] Victoria R. Stamper, "Review and Comments on Reasonable Progress Four-Factor Analyses for Sulfur Dioxide and Nitrogen Oxide Pollution Controls Evaluated as Part of the Utah Regional Haze Plan for the Second Implementation Period" (May 2022) ("Stamper Report") (Exhibit A). Ms. Stamper is an independent air quality consultant and engineer with extensive experience in the regional haze program.

long participated in Regional Haze rulemaking and litigation across the country in order to advocate for public health and our nation's national parks.

Utah Physicians for a Healthy Environment ("UPHE") was formed in 2007 during one of Utah's worst inversions. The organization consists of approximately 400 medical professionals within Utah, and another 4,000 supporting members of the public. UPHE is dedicated to protecting the health and well-being of the citizens of Utah by promoting science-based health education and interventions that result in progressive and measurable improvements to the environment and our health.

The Coalition to Protect America's National Parks ("Coalition") is a non-profit organization composed of over 2,100 retired, former, and current employees of the National Park Service ("NPS"). The Coalition studies, speaks, and acts for the preservation of America's National Park System. As a group, the Coalition collectively represent over 40,000 years of experience managing and protecting America's most precious and important natural, cultural, and historic resources.

For over 20 years the Healthy Environment Alliance of Utah ("HEAL Utah")—a 501 (c)(3) non-profit organization—has fought to protect Utah's health and our natural world from environmental threats. HEAL Utah pushes for positive progress that will help Utah and the Utahns in it prosper by promoting renewable energy and clean air, and protects public health and the environment from dirty, toxic, and nuclear energy threats. HEAL Utah has a track record of tackling some of the biggest threats to Utah's environment and public health—and succeeding—by empowering grassroots advocates, using science-based solutions, and developing common-sense policy. HEAL Utah animates its mission through educating citizens, building their civic skills, and mobilizing individuals to protect families, communities, and the natural world.

O2 Utah is a 501(c)(4) environmental nonprofit whose mission is to clean our state's air through election involvement, policy development, and community education and advocacy. Our team of campaigning experts gets involved in key competitive races throughout the state, partnering with candidates who prioritize issues focused on cleaning up our air quality, transportation, and energy sector. At the same time, we work with legislators to craft bold, innovative policies and facilitate grassroots advocacy efforts.

The Conservation Organizations have serious concerns regarding UDAQ's Proposed SIP for the second implementation period. As discussed in these comments, the National Park Service's consultation comments to UDAQ echo many of the concerns raised in this letter. UDAQ's assertions that no emissions controls are necessary at sources like the highly polluting Hunter and Huntington coal-fired power plants and that some sources are exempt from full review are misplaced. Utah will not fulfill its Regional Haze obligations under the Clean Air Act if it does not require emissions controls on polluting sources and require review of sources exempted such as Lisbon Natural Gas Processing Facility, Intermountain Generation Station, and Kennecott Utah Copper facility.

The Proposed SIP will not result in reasonable progress towards improving visibility at the region's Class I areas or Utah's five Class I areas impacted by the state's sources, including:

- Arches National Park;
- Bryce Canyon National Park;
- Canyonlands National Park;
- Capitol Reef National Park; and
- Zion National Park.

We support UDAQ's decision to request source evaluations of the following sources:

1. Ash Grove Cement Company-Leamington Cement Plant (Cement Manufacturing)
2. Graymont Western U.S. Incorporated-Cricket Mountain Plant (Lime Manufacturing)
3. PacifiCorp's Hunter Power Plant (Coal Power Plant)
4. PacifiCorp's Huntington Power Plant (Coal Power Plant)
5. Sunnyside Cogeneration Associates-Sunnyside Cogeneration (Coal Power Plant)
6. U.S. Magnesium LLC-Rowley Plant (Magnesium Manufacturing)

But none of these sources conducted a complete and accurate statutory Four-Factor Analysis, and UDAQ arbitrarily refused to propose cost-effective emission reductions at these facilities to ensure reasonable progress. Despite the thousands of tons of controllable pollution from Utah's sources including coal-fired power plants and cement kilns, among others, and the many opportunities for cost-effective controls, Utah improperly concludes that no new emissions reductions are warranted. More disturbing still is the state's decision to entirely ignore oil and gas sector operations which emit significant amounts of visibility impairing pollutants and were overlooked in source selection and evaluation for reasonable progress measures. Thus, UDAQ must revisit its approach and analyses, conduct Four-Factor Analyses for additional sources it wrongfully exempted, and require pollution controls to cut emissions from the polluting sources.

According to NPCA's analysis of polluting sources in Utah, 96% of visibility impairing pollution from stationary sources comes from Utah's coal-fired power plants and three of Utah's coal plants—Hunter, Huntington, and Intermountain Power—are among the top twenty worst park polluters in the nation.

To comply with the Clean Air Act ("CAA" or "Act"), 42 U.S.C. § 7401 et seq., and the Regional Haze Rule, 40 C.F.R. § 51.300 et seq., UDAQ must correct the flaws identified in these comments and in the attached technical report by Victoria R. Stamper. To make these corrections, UDAQ must:

- Implement strong and significant emission-reducing measures (Selective Catalytic Reduction technology, upgraded SO2 scrubbers) for PacifiCorp's Hunter and Huntington coal-fired power plants where controls are missing, and emissions are long overdue to be cleaned up or set enforceable retirement dates;
- Set an enforceable shut down date of December 31, 2025 for Intermountain Generation Station;
- Require actual, measurable emission reductions from Sunnyside Cogeneration, Cricket Mountain lime processing plant, Rowley magnesium production facility, and the Leamington Cement Plant;

- Require statewide NOx requirements for flaring, engines, and other oil and gas sector sources;
- Revisit and conduct comprehensive analyses for the wrongly exempted Lisbon Natural Gas Processing Facility, Intermountain Generation Station, and Kennecott Utah Copper facility;
- Establish a cost-effectiveness threshold for reasonable progress and one that is in line with other state thresholds; and
- Thoroughly assess environmental justice impacts as EPA recommended in its 2021 Clarification Memo.

These comments also explain that UDAQ's Proposed SIP suffers from numerous flaws, which include:

- Wrongfully exempting sources from full Four-Factor Analysis review;
- Failing to evaluate whether additional emission reductions from sources are necessary via the Four-Factor Analysis reasonable progress determinations to ensure reasonable progress toward the Clean Air Act's visibility goal;
- Relying on closure dates without considering emissions reductions prior to closure dates;
- Failing to set a cost-effectiveness threshold by which to consider cost effectiveness for controls;
- Failing to consider oil and gas sector emissions from flaring, engines, and other operations that contribute to haze. Many of these sources also contribute to the Uinta Basin ozone non-attainment area problems;
- Relying on current emissions data despite no requirement in the SIP that prevents emissions from increasing and despite past higher emissions from such sources;
- Relying on source retirements to exempt sources from Four-Factor Analysis review despite no enforceable requirement in the SIP preventing sources from resuming operations;
- Relying on voluntary proposals to install controls to exempt sources from Four-Factor Analysis review when the SIP does not require use of that control;
- Relying on flawed and incomplete consultations with other states and Tribes; and
- Failing to adequately respond to comments from the Federal Land Managers ("FLMs").

The Clean Air Act requirements present a significant opportunity to not only improve visibility at Utah's five Class I areas, and other treasured Class I areas across the region, but also to improve the air quality in communities across the state, including some of the most disproportionately affected by health harming pollution. Despite this opportunity and the legal requirements necessary to ensure reasonable progress, UDAQ's Proposed SIP contains fundamental flaws and improperly concludes that no new reductions in pollution are warranted for most of Utah's sources.

Our comments present these issues and offer detailed suggestions to ensure that the SIP Utah submits to EPA will be in line with the Clean Air Act's legal requirements and federal regulations, and address visibility impairing emissions.

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INTRODUCTION

The Conservation Organizations represent thousands of Utahns and hundreds of thousands of people throughout the nation that care deeply about protecting the air quality in our national parks and wilderness areas in Utah, Wyoming, Idaho, Colorado, Nevada, Arizona, and the Southwest and Intermountain West. The Clean Air Act imposes a legal obligation on states and EPA to abate haze pollution and its adverse visibility effects[2] in our Class I Areas—large, iconic national parks and wilderness areas. 42 U.S.C. § 7491.

Utah is home to five iconic and treasured Class I areas: Arches National Park, Bryce Canyon National Park, Canyonlands National Park, Capitol Reef National Park, and Zion National Park. Congress set aside these and other national parks and wilderness areas to protect our natural heritage for generations. These protected areas provide habitat for a range of wildlife species, provide year-round recreational opportunities for residents and visitors, and generate millions of dollars in tourism revenue. These Class I areas preserve the region's inspiring landscapes, rare geologic formations, and diverse wildlife and vegetation. They also serve as living museums of our nation's history. Visitors from across the nation and globe are drawn to these lands and their tourist dollars benefit state and local economies. Given the value of these Class I areas, the Clean Air Act requires the highest level of protection for national parks and wilderness areas.

Emissions of sulfur dioxide ("SO2") and nitrogen oxide ("NOx") from Utah sources contribute significantly to visibility impairment in the region's Class I areas both within Utah and in neighboring states. While most haze pollution does not originate in Class I areas, it can travel hundreds of miles from its source, impacting Class I areas and nearby communities. In fact, nearly 90% of national parks are plagued by haze pollution, and on average, park visitors miss out on 50 miles of scenery because of haze—a distance equal to the length of Rhode Island.[3] According to the National Park Service, there are 25 Class I areas (11 national parks) within 500 km (about the length of New York State) of the PacifiCorp's Hunter and Huntington facilities alone that all exceed UDAQ's selection threshold and likely contribute to visibility impairment in those 25 Class I national parks and wilderness areas. In addition to impairing visibility, these same pollutants are harmful to human health and the environment.

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[2] Regional haze results from small particles in the atmosphere which impair a viewer's ability to see long distances, color, and geologic formation. While some haze causing particles result from natural processes, most result from anthropogenic sources of pollution. Haze forming pollutants including sulfur dioxide ("SO2"), nitrogen oxides ("NOx"), particulate matter ("PM"), volatile organic compounds ("VOCs"), and ammonia ("NH_3") contribute directly to haze or form haze after being converted in the atmosphere. Visibility impairment is measured in deciviews, which is understood as the perceptible change in visibility. The higher the deciview value, the worse the impairment.

[3] NPCA, Polluted Parks: How America is Failing to Protect Our National Parks, People and Planet from Air Pollution 12 (2019), https://npca.s3.amazonaws.com/documents/NPCAParksReport2019.pdf.

UDAQ originally identified 10 sources for consideration in the emission control analyses, but only six sources were required to conduct a full review of emissions-reducing measures in its implementation plan. Despite the many opportunities for cost-effective controls, **UDAQ improperly concludes that no new reductions in pollution are warranted for most of Utah's sources**. UDAQ's proposal results in thousands of tons of SO2 and NOx pollution annually that could otherwise be avoided through feasible and cost-effective controls, and many of the polluting sources in Utah are affecting communities that have borne the brunt of anthropogenic-caused pollution. If left unchanged, the state's plan will not comply with the Clean Air Act and EPA's Regional Haze Rule as it does little to limit haze-causing air pollution and fails to help restore naturally clean air.

For the reasons detailed below, the Conservation Organizations request that UDAQ revisit the emission limitations and pollution control requirements for sources in Utah. In order for Utah to fulfill its regional haze obligations under the Clean Air Act, UDAQ must revise the Proposed SIP to: (1) Implement strong and significant emission-reducing measures for PacifiCorp's Hunter and Huntington coal-fired power plants where controls are missing, and emissions are long overdue to be cleaned up or set enforceable retirement dates; (2) set an enforceable shut down date of December 31, 2025 for Intermountain Generation Station; (3) require actual, measurable emission reductions from Sunnyside Cogeneration, Cricket Mountain lime processing plant, Rowley magnesium production facility, and the Leamington Cement Plant; (4) require statewide NOx requirements for flaring, engines, and other oil and gas sector sources; (5) revisit and conduct comprehensive analyses for the wrongly exempted Lisbon Natural Gas Processing Facility, Intermountain Generation Station, and Kennecott Utah Copper facility; (6) establish a cost-effectiveness threshold for reasonable progress and one that is in line with other state thresholds; and (7) thoroughly assess environmental justice impacts as EPA recommended. These steps are necessary to comply with the reasonable progress requirements of the CAA.

The EPA submission deadline for the regional haze plan revision for the second implementation period was July 31, 2021.[4] For the second implementation period, Utah must evaluate what emission control measures are necessary for sources, groups of sources, and/or source sectors within the state to comply with the reasonable progress requirement of the CAA.

In April of 2022, UDAQ made available its draft plan for addressing reasonable progress toward the national visibility goal for Class I areas.[5] UDAQ based its selection of sources for review on a Q/d analysis.[6] "The analysis is a ratio of a source's emissions in tons per year (Q) in 2014 divided by the distance (d) in kilometers to any Class I area. Emissions in tons per year of SO2, NOx, and PM were included in the analysis."[7] UDAQ then focused on those facilities with a "Q/d" value greater than or equal to 6.[8] UDAQ then employed a "secondary screening" that

[4] 40 C.F.R. § 51.308(f). Utah's SIP submission to EPA will be untimely.
[5] Utah Department of Environmental Quality Division of Air Quality, Draft Utah State Implementation Plan, Regional Haze Second Implementation Period ("Proposed SIP").
[6] Proposed SIP at 92.
[7] Id.
[8] Id. at 93.

further narrowed down the list of sources required to undergo the Four-Factor Analysis based on current emissions, projected emissions in 2028, closure and controls put in place after the 2014 base year inventory."[9] Based on this "secondary screening," UDAQ determined that The CCI Paradox Midstream, LLC—Lisbon Natural Gas Processing Plant, Intermountain Power Service Corporation—Intermountain Generation Station, Kennecott Utah Copper LLC—Mine & Copperton Concentrator, and Kennecott Utah Copper LLC—Power Plant Lab Tailings Impoundment did not need to undergo Four-Factor Analysis review.[10] Thus, UDAQ required Four-Factor Analyses of regional haze controls for only six facilities.[11] The four factors that must be considered in determining appropriate emissions controls for the second implementation period are (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of any source being evaluated for controls.[12]

I. UTAH POLLUTANT SOURCES' IMPACT ON CLASS I AREAS

Emissions from Utah sources of haze pollutants impact in-state Class I areas (Arches National Park, Bryce Canyon National Park, Canyonlands National Park, Capitol Reef National Park, and Zion National Park). Utah emissions also impact Class I areas in other states, including Bandelier National Monument in New Mexico, Craters of the Moon National Monument in Idaho, Grand Teton and Yellowstone National Parks in Wyoming, Mesa Verde National Park in Colorado, and Grand Canyon and Petrified Forest National Parks in Arizona.[13]

Pollutants that cause or contribute to visibility impairment also harm Utahns' health. Haze pollutants include NOx, SO2, PM, ammonia, and sulfuric acid. NOx is a precursor to ground level ozone, which is associated with respiratory diseases, asthma attacks, and decreased lung function. In addition, NOx reacts with ammonia, moisture, and other compounds to form particulates that can cause and worsen respiratory diseases, aggravate heart disease, and lead to premature death.[14] Similarly, SO2 increases asthma symptoms, leads to increased hospital visits, and can form particulates that aggravate respiratory and heart diseases and cause premature death.[15] PM can penetrate deep into the lungs and cause a host of health problems, such as aggravated asthma, chronic bronchitis, and heart attacks.[16] Emissions reductions from Utah's sources will ease the impact of pollution related health problems and costs.

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[9] Id. at 93-94.
[10] Id. at 93-96.
[11] Id. at 114-41.
[12] 40 C.F.R. § 51.308(f)(2)(i).
[13] Proposed SIP at Appendix D, PDF page 436.
[14] EPA, Nitrogen Dioxide (NO2) Pollution, https://www.epa.gov/no2-pollution/basic-information-about-no2 (last visited May 27, 2022).
[15] EPA, Sulfur Dioxide (SO2) Pollution, https://www.epa.gov/so2-pollution (last visited May 27, 2022).
[16] EPA, Particulate Matter (PM) Pollution, https://www.epa.gov/pm-pollution (last visited May 27, 2022).

These same haze-causing emissions also harm terrestrial and aquatic plants and animals, soil health, and moving and stationary waterbodies—entire ecosystems—by contributing to acid rain, ozone formation, and nitrogen deposition. Nitrogen deposition, caused by wet and dry deposition of nitrates derived from NOx emissions, causes well-known, adverse impacts on ecological systems; in some places, saturation of the soil already exceeds the "critical load" the ecosystem can tolerate.[17] Acid rain causes acidification of lakes and streams and can damage certain types of trees and soils. In addition, acid rain accelerates the decay of building materials and paints, including irreplaceable buildings, statues, and sculptures that are part of our nation's and this state's cultural heritage.[18] Ground-level ozone formation, for which haze pollutants are precursors, impacts plants and ecosystems by: "interfering with the ability of sensitive plants to produce and store food, making them more susceptible to diseases, insects, other pollutants, competition, and harsh weather; damaging the leaves of trees and other plants, negatively impacting the appearance of urban vegetation, as well as vegetation in national parks and recreation areas; and reducing forest growth and crop yields, potentially impacting species diversity in ecosystems."[19]

In rigorously addressing visibility and, more specifically, visibility-impairing pollutants, Utah stands to reap significant benefits and avoid serious consequences. Across the country, national parks and wilderness areas provide great natural and cultural value and are also engines for sustainable local capital. For example, in 2021, National Park Service units received over 297 million visits,[20] and in 2020, 237 million visitors contributed $28.6 billion in economic output in the national economy, and $14.5 billion in local gateway regions.[21] This tourism is a critical component of Utah's economy. For example, in 2016, Utah's five national parks saw nearly 14.5 million visitors that generated almost 1.6 billion dollars in economic benefit to the state and supported 17,914 jobs.[22]

Despite these benefits, national parks and wilderness areas remain affected by regional haze. The view in western national parks on bad pollution days is on average 73 miles, versus

[17] See NPS, Air Quality, https://www.nps.gov/romo/learn/nature/airquality.htm (last visited May 27, 2022).
[18] EPA, Effects of Acid Rain, https://www.epa.gov/acidrain (last visited May 27, 2022).
[19] EPA, Ground-level Ozone Pollution, https://www.epa.gov/ground-level-ozone-pollution (last visited May 27, 2022).
[20] National Park Service, Annual Summary Report, https://irma.nps.gov/STATS/SSRSReports/National%20Reports/Annual%20Summary%20Report%20(1904%20-%20Last%20Calendar%20Year) (last visited May 27, 2022).
[21] National Park Service, 2020 National Park Visitor Spending Effects: Economic Contributions to Local Communities, States, and the Nation, Natural Resource Report NPS/NRSS/EQD/NRR—2021/2259, https://www.nps.gov/subjects/socialscience/vse.htm (last visited May 27, 2022); National Park Service, Economic Contributions to the National Economy, https://www.nps.gov/subjects/socialscience/vse.htm (last visited May 27, 2022).
[22] National park tourism creates nearly $1.6 billion in economic benefit in Utah. St. George News (April 21, 2017), https://www.stgeorgeutah.com/news/archive/2017/04/21/national-park-tourism-creates-nearly-1-6-billion-in-economic-benefit-in-utah/#.YoPwdqjMLPB.

more than two times that distance naturally.[23] Studies have shown visitors value clean air in national parks, are able to tell when it is hazy, and enjoy their visit less when haze is bad.[24] Visitors are also willing to alter their length of stay based on their perception of air quality.[25] Shorter park visits, or none at all, means less time and money spent in gateway communities.

Because of the significant negative impacts caused by regional haze, Utah must limit emissions to enable national parks and wilderness areas affected by Utah sources to achieve reasonable progress towards Congress' stated visibility goal; likewise, Utah has a duty to take all reasonable measures to adequately temper Utah sources' contribution to visibility impairment. As discussed below, states must also engage in efforts to achieve reasonable progress towards the national visibility goal.

II. LEGAL FRAMEWORK

A. The Clean Air Act's Regional Haze Program

To improve air quality in our most treasured landscapes, Congress passed the visibility protection provisions of the CAA in 1977, establishing "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in the mandatory class I Federal areas which impairment results from manmade air pollution."[26] "Manmade air pollution" is defined as "air pollution which results directly or indirectly from human activities."[27] To protect Class I areas' "intrinsic beauty and historical and archeological treasures," the CAA's regional haze program establishes a national regulatory floor and requires states to design and implement programs to curb haze-causing emissions within their jurisdictions. Each state must submit for EPA review a state implementation plan ("SIP") designed to make reasonable progress toward achieving natural visibility conditions.[28] When a state plan fails to establish a program that is at least as stringent as the national floor, EPA has an obligation to promulgate a Federal Implementation Plan ("FIP").[29]

A regional haze SIP must provide "emissions limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal."[30] Two of the most critical features of a regional haze SIP are the requirements for installation of Best Available Retrofit Technology ("BART") limits on pollutant emissions <u>and a long-term</u>

[23] EPA, Report on the Environment, Regional Haze, https://cfpub.epa.gov/roe/indicator.cfm?i=21 (last visited May 27, 2022).
[24] NPCA, Polluted Parks: How America is Failing to Protect Our National Parks, People and Planet from Air Pollution 12 (2019), https://npca.s3.amazonaws.com/documents/NPCAParksReport2019.pdf.
[25] Abt Associates, Out of Sight: The Science and Economics of Visibility Impairment. August 2000.
[26] 42 U.S.C. § 7491(a)(1).
[27] <u>Id.</u> § 7491(g)(3).
[28] <u>Id.</u> § 7491(b)(2).
[29] 42 U.S.C. § 7410(c)(1).
[30] 42 U.S.C. § 7491(b)(2).

strategy for making reasonable progress toward the national visibility goal.[31] Although many states addressed the CAA's BART requirements in their regional haze plans for the first planning period (2008-2018), EPA's 2017 revisions to the Regional Haze Rule make clear that BART was not a once-and-done requirement. Indeed, states "will need" to reassess "BART-eligible sources that installed only moderately effective controls (or no controls at all)" for any additional technically achievable controls in the second planning period.[32] The haze requirements in the CAA present an unparalleled opportunity to protect and restore regional air quality by curbing visibility-impairing emissions from a variety of polluting sources. Additionally, the Regional Haze Rule is a time-tested, effective program that has resulted in real, measurable, and noticeable improvements in national park visibility and air quality. The Regional Haze Rule requires all states, including Utah, to do their share by reducing pollution in their borders to help restore clean and clear skies at protected national parks and wilderness areas.

B. Requirements for Periodic Comprehensive Revisions for Regional Haze SIPs

1. First Implementation Period

Two of the most critical features of a regional haze SIP/FIP for the first planning period (2008-2018) were requirements for (1) the installation of BART technology for delineated major stationary sources of pollution and (2) a long-term strategy for making reasonable progress towards the national visibility goal.[33]

In their initial SIPs, states were required to evaluate potential BART limits for major stationary sources that were in existence on August 7, 1977, and began operating after August 7, 1962, and that emit air pollutants that may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area.[34] The term "major stationary source" is defined as a source that has the potential to emit 250 tons or more of any pollutant and falls within one of 26 categories of industrial sources defined by the CAA.[35] A BART-eligible source is one that meets the above criteria and is responsible for an impact on visibility in a Class I area of 0.5 deciview or more.[36] BART must be installed and operated no later than five years after the SIP/FIP approval.[37]

BART is defined by the CAA and EPA regulation as:

> [A]n emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established,

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[31] Id. § 7491(b)(2)(B); 40 C.F.R. § 51.308(d)(1)(i)(B).
[32] 82 Fed. Reg. 3,078, 3,083 (Jan. 10, 2017); see also id. at 3,096 ("states must evaluate and reassess all elements required by 40 CFR 51.308(d)").
[33] 40 C.F.R. § 51.308(d)(1)(i)(B).
[34] 42 U.S.C. § 7491(b)(2)(A).
[35] Id. § 7491(g)(7).
[36] 40 C.F.R. Part 51, Appendix Y.
[37] Id. § 51.302(c)(4)(iv).

> on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality (sic) environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[38]

This definition establishes a framework for conducting a BART analysis. First, the agency must identify the "best system of continuous emission reduction," or the best technology, for each relevant pollutant. Once the best technology is selected, the agency should then apply the five-factor test to determine the best emission limitation achievable by that technology.

Under the Regional Haze Rule, states also were required to establish goals that provide for "reasonable progress" towards achieving natural visibility conditions in national parks and wilderness areas.[39] In establishing reasonable progress goals ("RPGs"), states were required to evaluate the rate of progress necessary to achieve natural visibility by 2064 (the uniform rate of progress) and evaluate measures that would achieve that goal.[40] Only if states affirmatively demonstrated that such measures—including and in addition to the application of BART—are not reasonable, could they adopt alternative "reasonable progress goals."[41] The SIP/FIP was required to include a long-term (10 to 15 years) strategy that identified "such emission limits, schedules of compliance and other measures as may be necessary" to achieve reasonable progress.[42]

2. Second Implementation Period

The Regional Haze Rule requires states to adopt periodic, comprehensive revisions to their implementation plans for regional haze on 10-year increments to achieve reasonable progress towards the national visibility goal. As part of the comprehensive revisions to their regional haze plan, states must submit a long-term strategy that includes enforceable emission limits and other measures as may be necessary to make reasonable progress towards the national visibility goal.[43]

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

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[38] 40 C.F.R. § 51.301; 42 U.S.C. § 7491(g).
[39] 42 U.S.C. § 7491(b)(2).
[40] Id.
[41] 40 C.F.R. § 51.308(d)(1)(ii).
[42] 42 U.S.C. § 7491(b)(2); see also 40 C.F.R. § 51.308(d)(3).
[43] 40 C.F.R. § 51.308(f)(2) ("long-term strategy must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress").

(a) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
(b) Measures to mitigate the impacts of construction activities;
(c) Emissions limitations and schedules for compliance to achieve the reasonable progress goal;
(d) Source retirement and replacement schedules;
(e) Smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the State for these purposes;
(f) Enforceability of emission limitations and control measures; and
(g) The anticipated net effect on visibility due to projected changes in point, area, and mobile emissions over the period addressed by the long-term strategy.[44]

Additionally, a state "[m]ust include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy."[45] States must also document the technical basis for the SIP, including monitoring data, modeling, and emission information, including the baseline emission inventory upon which its strategies are based. All of this information is part of a state's revised SIP and subject to public notice and comment.

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

On January 10, 2017, the EPA revised the Regional Haze Rule to strengthen and clarify the reasonable progress and consultation requirements of the rule. A state's reasonable progress analysis must consider the four-factors identified in the Clean Air Act and regulations. EPA's 2017 Revisions to the Regional Haze Rule made clear that states are to <u>first</u> conduct the required Four-Factor Analysis for its sources, and <u>then</u> use the results from its Four-Factor Analyses and determinations to develop the reasonable progress goals. Thus, the rule "codif[ies]" EPA's "long-standing interpretation" of the SIP "planning sequence" states are required to follow:

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

[44] 40 C.F.R. § 51.308(f)(2)(iv).
[45] Memorandum from Peter Tsirigotis, Director, EPA Office of Air Quality Planning and Standards, to Regional Air Division Directors, Region 1-10, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," at 19 (Aug. 20, 2019), https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf ("2019 Guidance") (citing 40 C.F.R. § 51.308(f)(2)(i)).

- [A]dopt a monitoring strategy and other measures to track future progress and ensure compliance.

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

> The CAA requires states to determine what emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors. The CAA does not provide that states may then reject some control measures already determined to be reasonable if, in the aggregate, the controls are projected to result in too much or too little progress. Rather, the rate of progress that will be achieved by the emission reductions resulting from all reasonable control measures is, by definition, a reasonable rate of progress. … [I]f a state has reasonably selected a set of sources for analysis and has reasonably considered the four factors in determining what additional control measures are necessary to make reasonable progress, then the state's analytical obligations are complete if the resulting RPG for the most impaired days is below the URP line. The URP is not a safe harbor, however, and states may not subsequently reject control measures that they have already determined are reasonable.[46]

Moreover, for each Class I area within its borders, a state must determine the uniform rate of progress—which is the amount of progress that, if kept constant each year, would ensure that natural visibility conditions are achieved in 2064.[47] If a state establishes reasonable progress goals that provide for a slower rate of improvement in visibility than the uniform rate of progress, the state must provide a technically "robust" demonstration, based on a careful consideration of the statutory reasonable progress factors, that "there are no additional emission reduction measures for anthropogenic sources or groups of sources" that can reasonably be anticipated to contribute to visibility impairment in affected Class I areas.[48]

Although many states addressed the Act's BART requirements in their initial regional haze plans, EPA's 2017 revisions to the Regional Haze Rule make clear that BART was not a once-and-done requirement, as discussed above. Indeed, states "will need" to reassess "BART-eligible sources that installed only moderately effective controls (or no controls at all)" for any additional technically achievable controls in the second planning period.[49]

To the extent that a state declines to evaluate additional pollution controls for any source relied upon to achieve reasonable progress based on that source's planned retirement or decline in utilization, it must incorporate those operating parameters or assumptions as

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[46] 82 Fed. Reg. 3,093 (emphasis added).
[47] 40 C.F.R. § 51.308(d)(1)(i)(B).
[48] Id. § 51.308 (f)(2)(ii)(A).
[49] 82 Fed. Reg. at 3,083; see id. at 3,096 ("states must evaluate and reassess all elements required by 40 CFR 51.308(d)").

enforceable limitations in the second planning period SIP. The Act requires that "[e]ach state implementation plan . . . shall" include "enforceable limitations and other control measures" as necessary to "meet the applicable requirements" of the Act.[50] The Regional Haze Rule similarly requires each state to include "enforceable emission limitations" as necessary to ensure reasonable progress toward the national visibility goal.[51] Therefore, where the state relies on a source's plans to permanently cease operations or projects that future operating parameters (e.g., limited hours of operation or capacity utilization) will differ from past practice, or if this projection exempts additional pollution controls as necessary to ensure reasonable progress, then the state "must" make those parameters or assumptions into enforceable limitations.[52]

In addition, the 2017 Regional Haze Rule revisions further clarified that regional haze SIPs meet certain procedural and consultation requirements.[53] The state must consult with the Federal Land Managers and look to the FLMs' expertise of the lands and knowledge of the way pollution harms them to guide the state to ensure SIPs do what they must to help restore natural skies. The Regional Haze Rule also requires that in "developing any implementation plan (or plan revision) or progress report, the State must include a description of how it addressed any comments provided by the Federal Land Managers."[54]

Finally, the duty to ensure reasonable progress requirements are met for purposes of the SIP rests with the state. While the Western Regional Air Partnership ("WRAP") plays an important role in providing support in regional haze planning, the state is ultimately accountable for preparing, adopting, and submitting a compliant SIP to EPA. Further, as discussed more fully below, UDAQ has an obligation to make available to the public and cite to the technical support documentation it proposes to rely on and use as part of its SIP revision so that the public can review and comment.

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[50] 42 U.S.C. § 7410(a)(2)(A).

[51] See 40 C.F.R. § 51.308(d)(3) ("The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established by States having mandatory Class I Federal areas.").

[52] Id. §§ 51.308(i); (d)(3) ("The long-term strategy must include enforceable emissions limitations, compliance schedules . . . ."); (f)(2) (the long-term strategy must include "enforceable emissions limitations"); see 2019 Guidance, at 22 ("in selecting sources for control measure analysis," the state may choose to "not select[] sources that have an enforceable commitment to be retired or replaced by 2028"); id. at 34 (To the extent a retirement or reduction in operation "is being relied upon for a reasonable progress determination, the measure would need to be included in the SIP and/or be federally enforceable.") (citing 40 C.F.R. § 51.308(f)(2)); id. at 43 ("[i]f a state determines that an in-place emission control at a source is a measure that is necessary to make reasonable progress and there is not already an enforceable emission limit corresponding to that control in the SIP, the state is required to adopt emission limits based on those controls as part of its long-term strategy in the SIP via the regional haze second planning period plan submission.").

[53] For example, in addition to the Regional Haze Rule requirements, states must also follow the SIP processing requirements in 40 C.F.R. §§ 51.104, 51.102.

[54] 40 C.F.R. § 51.308(i)(3).

D. EPA's 2021 Regional Haze Clarification Memorandum

On July 8, 2021, EPA issued a memo which clarified certain aspects of the revised Regional Haze Rule and provided further information to states and EPA regional offices regarding their planning obligations for the Second Planning Period.[55] In particular, EPA made clear that states must secure additional emission reductions that build on progress already achieved. There is an expectation that reductions are additive to ongoing and upcoming reductions under other CAA programs.[56] In evaluating sources for emission reductions, EPA emphasized that:

> Source selection is a critical step in states' analytical processes. All subsequent determinations of what constitutes reasonable progress flow from states' initial decisions regarding the universe of pollutants and sources they will consider for the second planning period. States cannot reasonably determine that they are making reasonable progress if they have not adequately considered the contributors to visibility impairment. Thus, while states have discretion to reasonably select sources, this analysis should be designed and conducted to ensure that source selection results in a set of pollutants and sources the evaluation of which has the potential to meaningfully reduce their contributions to visibility impairment.[57]

Thus, it is generally not reasonable to exclude from further evaluation large sources or entire sectors of visibility impairing pollution.

Moreover, the 2021 Clarification Memo reiterates that the fact that a Class I area is meeting the Uniform Rate of Progress is "not a safe harbor" and does not excuse the state from its obligation to consider the statutory reasonable progress factors in evaluating reasonable control options.[58] In addition, the 2021 Clarification Memo makes clear that a state should not reject cost-effective and otherwise reasonable controls merely because there have been emission reductions since the first planning period owing to other ongoing air pollution control programs or merely because visibility is otherwise projected to improve at Class I areas.[59] Ongoing air pollution controls, otherwise improved visibility, and/or air modeling results must not be used to summarily assert that a state has already made sufficient progress and, as a result, no sources need to be selected or no new controls are needed regardless of the outcome of Four-Factor Analyses.[60] As noted above, the reasonable progress Four-Factor Analysis is the vehicle for identifying reasonable control measures, limitations, etc., necessary during this second implementation period, and a statutory Four-Factor Analysis must specifically include consideration of:

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[55] 2021 Clarification Memo at 3.
[56] Id. at 2.
[57] Id. at 3.
[58] Id. at 2.
[59] Id. at 13.
[60] Id.

1. The costs of compliance,
2. The time necessary for compliance,
3. The energy and non-air quality environmental impacts of compliance, and
4. The remaining useful life of any potentially affected sources.[61]

Notably, Congress did not include visibility, modeling results, or emission inventories as one of these four statutory factors. Thus, to the extent a state relies on purportedly insufficient air quality benefits because of visibility, emission inventories, and/or modeled impacts from a source as a justification for refusing to require cost-effective emission reductions, the state's analysis is inconsistent with the CAA and the Regional Haze Rule.

The 2021 Clarification Memo also instructs that, for sources that have previously installed controls, states should still evaluate the "full range of potentially reasonable options for reducing emissions," including options that may "achieve greater control efficiencies, and, therefore, lower emission rates, using their existing measures."[62] Moreover, "[i]f a state determines that an in-place emission control at a source is a measure that is necessary to make reasonable progress and there is not already an enforceable emission limit corresponding to that control in the SIP, the state is required to adopt emission limits based on those controls as part of its long-term strategy in the SIP via the regional haze second planning period plan submission."[63] This also means that so-called "on-the-way" measures, including anticipated shutdowns or reductions in a source's emissions or utilization, that are relied upon to forgo a Four-Factor Analysis or to shorten the remaining useful life of a source "<u>must</u> be included in the SIP" as enforceable emission reduction measures.[64]

Finally, the 2021 Clarification Memo confirms EPA's recommendation that states take into consideration environmental justice concerns and impacts in issuing any SIP revision for the second planning period.

EPA's 2021 Clarification Memo makes clear that the states' regional haze plans for the second planning period must include meaningful emission reductions to make reasonable progress towards the national goal of restoring visibility in Class I areas. The 2021 Clarification Memo confirms that UDAQ's efforts to avoid emission reductions are at odds with Utah's haze obligations under the CAA and the Regional Haze Rule. "[A] state should generally not reject cost-effective and otherwise reasonable controls merely because there have been emission reductions since the first planning period owing to other ongoing air pollution control programs or merely because visibility is otherwise projected to improve at Class I areas."[65]

[61] 42 U.S.C. § 7491(g)(1); 40 C.F.R. § 51.308(f)(2)(i).
[62] 2021 Clarification Memo at 7.
[63] <u>Id.</u> at 8.
[64] <u>Id.</u> at 8-9 (emphasis added).
[65] <u>Id.</u> at 13.

E. States Must Ensure the SIP Satisfies the Requirements of the Regional Haze Rule

States—not the source—bear the duty to ensure that a SIP satisfies the requirements of the Regional Haze Rule.[66] If Utah, another state, or the FLMs identify a source as impacting visibility in a Class I area, thereby warranting a Four-Factor Analysis of potential reasonable progress controls, UDAQ must conduct such an analysis or provide a demonstration that any emission reductions or controls would be futile to inform its reasonable progress determination.[67] For those sources that submit their own Four-Factor Analysis, UDAQ has an obligation to independently review that analysis and cannot simply "rubber stamp" a source's analysis. If a source prepares an inaccurate, incomplete, or undocumented Four-Factor Analysis, the state must either require the source to make the necessary corrections or the state must make the corrections itself. Where a source is unwilling to conduct the required reasonable progress analysis, the responsibility must be met by the state.

F. Emission Reductions to Make Reasonable Progress Must Be Included in Practically Enforceable SIP Measures

As state cannot rely on an unspecified permit and other provisions as providing emission reductions necessary to ensure reasonable progress. The CAA requires states to submit implementation plans that "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal" of achieving natural visibility conditions at all Class I Areas.[68] The Regional Haze Rule requires that states must revise and update its regional haze SIP, and the "periodic comprehensive revisions" must include the "enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress as determined pursuant to [40 C.F.R. §§ 51.308](f)(2)(i) through (iv)."[69] EPA's Guidance further explains these requirements:

> This provision requires SIPs to include enforceable emission limitations and/or other measures to address regional haze, deadlines for their implementation, and provisions to make the measures practicably enforceable including averaging times, monitoring requirements, and record keeping and reporting requirements.[70]

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[66] 40 C.F.R. § 51.308(d).

[67] 2021 Clarification Memo § 2.2.

[68] 42 U.S.C. §§ 7491(a)(1), (b)(2).

[69] 40 C.F.R. § 51.308(f)(2); 40 C.F.R. § 51.308(d)(3)(v)(F) (enforceability of emission limitations and control measures).

[70] 2019 Guidance at 42-43 (While NPCA and Sierra Club filed a Petition for Reconsideration regarding EPA's issuance of the 2019 Guidance, it does not dispute the information in the Guidance referenced here regarding enforceable limitations, which cite to the "General Preamble for the Implementation of Title I of the Act Amendments of 1990, 74 Fed. Reg. 13,498 (Apr. 16, 1992)).

While the SIP is the basis for demonstrating and ensuring state plans meet Regional Haze Rule requirements, state-issued permits must complement the SIP.[71] To the extent that a state relies on any expected retirement, reduction in utilization, or reduction in emissions as a result of a permit provision in its reasonable progress analysis, those emission reductions must be included as enforceable emission limitations in the SIP itself.[72] Finally, reasonable progress requirements apply to all sources, and states must not rely on existing permits (e.g., construction permits issued under Title I of the Act, operating permits issued under Title V of the Act) to allow sources to avoid the Four-Factor Analysis; there is no off-ramp for sources that hold permits.

III. REGIONAL HAZE PLANNING IN UTAH

Utah's history with regional haze planning has been problematic since the beginning. In the first regional haze planning period, UDAQ failed to control sources causing serious pollution to Class I areas in the state and region, and that legacy continues.

Utah is a member of WRAP, formed in September 1997. Instead of submitting an implementation plan containing emission limitations applying BART for each BART-eligible source impairing visibility in a Class I area under 40 C.F.R. § 51.308(e), 40 C.F.R. § 51.309, states could use a regional cap-and-trade program ("309 program") regulating SO2 emissions if participants would expect better results than they would have had under BART regulations.[73]

> The 309 program establishes voluntary measures to reduce [sulfur dioxide] emissions through milestones providing "steady and continuing emissions reductions through 2018." 40 C.F.R. § 51.309(d)(4)(i). After 2018, the milestone remains constant until the states submit revised implementation plans. Id. § 51.309(d)(4)(vi)(A). These milestones must provide a "50 to 70 percent reduction in [sulfur dioxide] emissions from 1990 actual emission levels by 2040." Id. § 51.309(d)(4)(i).
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> If sulfur-dioxide emissions surpass the milestone, a backstop regional emission trading program would be triggered. Under the program, sources are given a set volume of emissions. Any source exceeding its allowance must pay a penalty and suffer a loss in its allotted emissions . . . . . To encourage early reductions in emissions, the trading program provided additional allocations to sources that reduce emissions ahead of schedule.
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> Upon approval of an implementation plan, the EPA would regard the state to be in compliance through 2018 with the reasonable-progress requirement for the sixteen Class I areas encompassed in the 309 program. 40 C.F.R. § 51.309(a). For additional Class I areas not covered in the 309 program, the state had to show long-term strategies under § 308. Id. § 51.309(g).[74]

[71] 74 Fed. Reg. at 13,568.
[72] 42 U.S.C. §§ 7410(a)(2), 7491(b)(2); see also 40 C.F.R. § 51.308(d), (f).
[73] WildEarth Guardians v. U.S. E.P.A., 770 F.3d 919, 925 (10th Cir. 2014).
[74] Id. at 925-26.

After the D.C. Circuit Court of Appeals invalidated part of the § 51.308(e) methodology—requiring evaluation of progress by considering emission reductions in the aggregate[75]—EPA revised the Regional Haze Rule to make the evaluation of the final BART factor a source-by-source determination requiring Utah to resubmit a SIP. In 2011, Utah revised its SIP adopting the 309 program, which EPA approved the following year. EPA's approval was challenged in court on grounds that it did not achieve actual reductions of SO2 emissions from covered sources, but the Tenth Circuit upheld EPA's approval largely on grounds that it resulted in earlier emissions reductions from covered sources than would have been achieved through BART.[76] As a result, Utah's four large coal plant units that are subject to the CAA's BART requirements—Hunter Units 1 and 2 and Huntington Units 1 and 2—have not been subject to source-specific BART analyses or control requirements for SO2.

At the same time EPA approved Utah's reliance on the 309 program for SO2, EPA rejected Utah's proposed SIP for NOx and PM BART requirements based on Utah's failure to conduct five-factor BART analyses for those pollutants.[77] EPA later imposed a FIP for Hunter Units 1 and 2 and Huntington Units 1 and 2 NOx pollution in July 2016..[78] The 2016 Final Rule required the plants' operator, PacifiCorp, to achieve NOx emissions reductions associated with the installation and operation of selective catalytic reduction ("SCR") technology, which EPA found would yield significant, cost-effective visibility benefits.[79] In promulgating the FIP, EPA rejected Utah's proposed alternative to BART, finding that it would not achieve greater reasonable progress toward eliminating human-caused visibility impairment than would BART.[80]

After initially defending its 2016 Final Rule before the Tenth Circuit Court of Appeals against state and industry challenges, EPA announced in 2017 that it was granting administrative petitions for reconsideration filed by Utah and PacifiCorp. Subsequently, in January 2020, EPA proposed a complete reversal of its 2016 Final Rule: EPA proposed withdrawing its FIP requiring SCR on Hunter Units 1 and 2 and Huntington Units 1 and 2, and approving the exact same Utah BART Alternative EPA previously rejected.[81] EPA's actions are currently being litigated before the Tenth Circuit Court of Appeals. Thus, as with SO2, Hunter Units 1 and 2 and Huntington Units 1 and 2 have never been required to install and operate BART controls for NOx.

Utah's haze pollution sources also were not required in the first regional haze planning period to reduce SO2 or NOx emissions as part of a long-term strategy to comply with the

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[75] Am. Corn Growers Ass'n v. EPA, 291 F.3d 1, 8-9 (D.C.Cir.2002); Center for Energy & Economic Development v. EPA, 398 F.3d 653, 660 (D.C.Cir.2005).
[76] WildEarth Guardians v. EPA, 770 F.3d 919 (10th Cir. 2014).
[77] Final Rule, Approval, Disapproval and Promulgation of State Implementation Plans; State of Utah; Regional Haze Rule Requirements for Mandatory Class I Areas Under 40 CFR 51.309, 77 Fed. Reg. 74,355 (Dec. 14, 2012) ("2012 309 Rule").
[78] See Final Rule, Utah Regional Haze, 81 Fed. Reg. 43,894 (July 5, 2016) ("2016 Final Rule").
[79] Id. at 43,904-07.
[80] Id. at 43,901.
[81] See Proposed Rule, Utah Regional Haze, 85 Fed. Reg. 3,558 (Jan. 22, 2020).

Regional Haze Rule's reasonable progress requirements. Instead, EPA explained that its approval of Utah's SIP for the 309 program for BART "deems it as meeting reasonable progress requirements for the in-state Class I areas, as they are all on the Colorado Plateau. With respect to non-Colorado Plateau Class I areas, in this case 40 CFR 51.309(g) does not impose any separate obligations on Utah to analyze or impose emissions controls on non-BART sources to demonstrate reasonable progress at such areas."[82]

At issue in these comments is UDAQ's latest proposal to allow these and other Utah pollution sources to continue emitting NOx and SO2 at current, unnecessarily high, levels.

DISCUSSION OF UDAQ'S DRAFT PROPOSED SIP

UDAQ improperly and incorrectly concluded that no new reductions in pollution are warranted for most of Utah's sources of pollution in the second regional haze planning period—after failing to control pollution from these facilities during the first planning period—including from Utah's power plants under the Regional Haze Rule. Many opportunities for cost-effective controls exist. Because the Proposed SIP does little to limit haze-causing air pollution and fails to help restore naturally clean air, Utah's Proposed SIP will not comply with the Federal Clean Air Act and the Regional Haze Rule as currently drafted. The CAA requires reasonable progress towards the national visibility goal. Yet, the Proposed SIP fails to comply with the reasonable progress goals requirement. In order for Utah to fulfill its Regional Haze obligations under the CAA, UDAQ must revise the Proposed SIP to: (1) implement strong and significant emission-reducing measures (Selective Catalytic Reduction technology, upgraded SO2 scrubbers) for PacifiCorp's Hunter and Huntington coal-fired power plants where controls are missing, and emissions are long overdue to be cleaned up or set enforceable retirement dates; (2) set an enforceable shut down date of December 31, 2025 for Intermountain Generation Station; (3) require actual, measurable emission reductions from Sunnyside Cogeneration, Cricket Mountain lime processing plant, Rowley magnesium production facility, and the Leamington Cement Plant; (4) require statewide NOx requirements for flaring, engines, and other oil and gas sector sources; (5) revisit and conduct comprehensive analyses for the wrongly exempted Lisbon Natural Gas Processing Facility, Intermountain Generation Station, and Kennecott Utah Copper facility; (6) establish a cost-effectiveness threshold for reasonable progress and one that is in line with other state thresholds; and (7) thoroughly assess environmental justice impacts as EPA recommended. The sections below and the attached Stamper Report provide further detail regarding the changes UDAQ must make to make the Proposed SIP comport with the legal requirements of the CAA and Regional Haze Rule.

I. UDAQ's COMBUSTION SOURCES AND EMISSIONS UNITS SELECTION IS FLAWED

States must identify sources for the Four-Factor Analysis, and the screening threshold a state applies must ensure that the threshold is low enough to bring in most sources harming a Class I area. EPA's July 2021 Clarification Memo emphasizes this requirement explaining that:

[82] 2012 309 Rule, 77 Fed. Reg. at 74,368.

> [W]hile states have discretion to reasonably select sources, this analysis should be designed and conducted to ensure that source selection results in a set of pollutants and sources the evaluation of which has the potential to meaningfully reduce their contributions to visibility impairment.[83]

The Regional Haze Rule requires each state to submit a long-term strategy that addresses the regional haze visibility impairment resulting from emissions from within that state and for each mandatory Class I Federal area located outside the state that may be affected by emissions from the state.[84] Regarding a state's source selection methodology EPA's Guidance explained:

> Whatever threshold is used, the state must justify why the use of that threshold is a reasonable approach, i.e., why it captures a reasonable set of sources of emissions to assess for determining what measures are necessary to make reasonable progress.[85]

As EPA has further explained:

- [I]t may be difficult to show reasonableness of a threshold set so high that an uncontrolled or lightly controlled source that is one of the largest contributors to anthropogenic light extinction at a Class I area is excluded;[86]
- [A] threshold that captures only a small portion of a state's contribution to visibility impairment in Class I areas is more likely to be unreasonable;[87] and
- [A] threshold that excludes a state's largest visibility impairing sources from selection is more likely to be unreasonable.[88]

Contrary to the requirement to meaningfully reduce haze pollution, which requires that states comprehensively identify sources of human-caused visibility-impairing emissions across source categories, UDAQ's SIP fails to analyze controls for numerous units at the sources selected for review. For example, UDAQ only analyzed controls for five units at the Cricket Mountain Lime Plant leaving 250 tons per year ("tpy") of the facility's 916.5 tpy of NOx emissions unaccounted for.[89] To comply with the requirement that states comprehensively identify sources of human-caused visibility-impairing emissions across source categories, UDAQ should identify all of the emission units at these facilities, and the units' actual and allowable emissions.

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[83] July 2021 Clarification Memo at 3.
[84] 40 C.F.R. § 51.308(f)(2).
[85] 2019 Guidance at 19 (citing 40 C.F.R. § 51.308(f)(2)(i)) ("The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy.").
[86] Id.
[87] July 2021 Clarification Memo at 3.
[88] Id.
[89] Stamper Report at 58-59.

II. UDAQ FAILED TO REQUIRE APPROPRIATE FOUR-FACTOR ANALYSES FOR SELECTED UTAH SOURCES

The Regional Haze Rule specifically identifies four statutory factors which must be considered when evaluating potential emission control measures to make reasonable progress for Utah's Class I visibility goals: (1) cost of compliance; (2) time necessary for compliance; (3) energy and non-air quality environmental impacts of compliance; and (4) remaining useful life of any existing source subject to such requirements.[90] UDAQ required four-factor analyses for six sources in its proposed SIP.[91]

As demonstrated and discussed throughout these comments and the attached Stamper Report, UDAQ neglected to require reasonable cost-effective controls on the state's power plants and non-power plant sources that would ensure reasonable progress for this second regional haze implementation period. UDAQ's reasonable progress analyses are arbitrary because without an articulated and justified cost effectiveness threshold, it has not provided a reasoned basis for rejecting the adoption of additional regional haze controls.

Accordingly, UDAQ must revise its Proposed SIP and require that the sources discussed in these comments conduct reasonable progress evaluations, including proper statutory Four-Factor Analyses, to accurately assess and identify cost-effective control measures (e.g., optimization of equipment efficiency, equipment upgrades, etc.) necessary during this implementation period. The duty to ensure that a SIP satisfies the requirements of the Regional Haze Rule ultimately rests with the state, not the source.[92] Because these sources failed to conduct legally compliant Four-Factor Analyses, UDAQ must meet its responsibility. These steps are essential to comply with the Regional Haze Rule and make reasonable progress towards improving visibility as required by the CAA.

A. UDAQ Failed to Follow Four-Factor Analysis Legal Requirements

1. <u>UDAQ's control cost analyses are legally deficient due to numerous flaws</u>

The duty to ensure reasonable progress requirements are met for purposes of submitting a SIP to EPA rests with the state, not the source. The Regional Haze Rule makes clear, the <u>state</u> has a duty to conduct a "robust" analysis of potential reasonable progress controls, and must "document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects."[93] Therefore, if a source is unwilling to prepare the analysis, the state must conduct the analysis to inform its reasonable progress determination.

[90] 40 C.F.R. § 51.308(f)(2)(i).
[91] Proposed SIP at 113-40.
[92] 40 C.F.R. § 51.308(d).
[93] <u>Id.</u> § 51.308(f)(2)(iii).

The state also bears the responsibility to independently review, evaluate, and verify a draft Four-Factor Analysis submitted by a source, and states must propose and submit a SIP that complies with the CAA.[94] As part of its proposed SIP revisions, UDAQ must not only follow the requirements in the Regional Haze Rule, but also the requirements for preparation, adoption and submittal of SIPs.[95] A state must not "rubber stamp" a source's analysis.[96] If a source prepares a flawed, incomplete, or undocumented Four-Factor Analysis, the state must either require the source to make the necessary corrections or make the corrections itself and ensure that the Four-Factor Analyses is accurately and completely documented before the start of the public notice and comment period.[97] Lack of basic documentation not only precludes the state and any independent reviewer from verifying the respective utility modeling or control cost analyses, but is also contrary to the CAA and the Regional Haze Rule.[98]

a. UDAQ failed to provide sufficient cost documentation.

UDAQ failed to provide documentation for costs.[99] The Regional Haze Rule requires states to document the technical basis, including the costs and engineering information, that it is relying on to determine the emission reduction measures necessary to make reasonable progress towards the national visibility goal pursuant to 40 C.F.R. 51.308(f)(2)(iii).[100] UDAQ failed to do so in the Proposed SIP. For example, PacifiCorp used a weighted cost of capital of 7.303% as the interest rate in determining annualized capital costs of control without providing sufficient information on its 7.303% interest rate to demonstrate that the rate is consistent with the requirements of the EPA Control Cost Manual. As discussed below and in the Stamper

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[94] Id. § 51.308(f)(2)(i) ("The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment. The State should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress.") (emphasis added); see also 42 U.S.C. § 7491(g)(1); 40 C.F.R. §§ 51.308(d)(3), (f)(2)(i); 42 U.S.C. §§ 7410(a)(2)(A); 7491(b)(2) (SIP must include among other things, requiring enforceable emission limitations necessary to ensure reasonable progress).
[95] See e.g., 40 C.F.R. §§ 51.100, 51.102, 51.103, 51.104, 51.105, and Appendix V to Part 51.
[96] See 40 C.F.R. § 51.308(f)(2)(iii) (requirement for documentation). Indeed, throughout the regulations and EPA guidance, the state is tasked with the responsibility of complying with the Regional Haze Rule. See id.; 2019 Guidance; 2021 Clarification Memo.
[97] 40 C.F.R. § 51.308(f)(2)(iii).
[98] 2019 Guidance at 22.
[99] Stamper Report at 21-24.
[100] 2019 Guidance at 22.

Report,[101] UDAQ's SIP lacks sufficient cost documentation, which should include vendor quotes, actual costs from a similar facility, cost estimates that are generally accepted, and specific knowledge of the pollution control technology being considered.

b. UDAQ failed to consider control efficiency and performance optimization.

UDAQ failed to consider control efficiency and performance optimization. Even for sources with recent pollution controls installed or that are otherwise effectively controlled, EPA's 2019 Guidance still requires that a state that does not select such a source for evaluation of controls to meet reasonable progress to "explain why the decision is consistent with the requirement to make reasonable progress, i.e., why it is reasonable to assume for the purposes of efficiency and prioritization that a full four-factor analysis would likely result in the conclusion that no further controls are necessary."[102] Moreover, UDAQ must assume that scrubber, selective catalytic reduction ("SCR"), and selective noncatalytic reduction ("SNCR") control systems are capable of operating at the high end of their efficiencies, as demonstrated by other similarly configured units, unless UDAQ can verify documentation provided by the source. The Stamper Report presents details that show UDAQ failed to consider control upgrades and assumed lower control efficiency.[103] UDAQ must consider control efficiency and performance optimization.

c. UDAQ relied on artificially truncated equipment life for pollution controls and unsupported high firm-specific interest rates.

UDAQ used a 20-year equipment life for pollution controls in its cost effectiveness calculations despite EPA's justification for 30-year equipment life to be assumed. By using a 20-year equipment life of controls instead of a 30-year equipment life, UDAQ artificially inflated the costs of controls in its Four-Factor Analyses. EPA's Control Cost Manual states that:

> The life of the control is defined in this Manual as the equipment life. This is the expected design or operational life of the control equipment. This is not an estimate of the economic life, for there are many parameters and plant-specific considerations that can yield widely differing estimates for a particular type of control equipment.[104]

UDAQ also relied on artificially high interest rates resulting in higher costs of controls. As the CCM states:

[101] Stamper Report at 21-24.
[102] 2019 Guidance at 22.
[103] Stamper Report at 44.
[104] EPA, "Control Cost Manual," Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, at 22 (Nov. 2017) ("CCM").

> For input to analysis of rulemakings, assessments of private cost should be prepared using firm-specific nominal interest rates if possible, or the bank prime rate if firm-specific interest rates cannot be estimated or verified.[105]

UDAQ accepted a firm-specific interest rate of 7% and 7.303% for some sources when amortizing capital costs of controls in its four-factor analyses without sufficient justification.[106] But, as the Stamper Report explains, "while EPA describes the Control Cost Manual as taking the 'viewpoint of an owner,' that does not mean that the cost methodology is intended to take into account all costs in the viewpoint of the owner without question or justification, especially because the cost methodology used by the Control Cost Manual has limitations on costs that can be taken into account."[107] At the time the Stamper Report was compiled, the bank prime rate was 4%, which is significantly lower than the 7% or 7.303% interest rate that UDAQ accepted for some sources.

As the Stamper Report also explains:

> With respect to the interest rate to be taken into account in financing costs, EPA's Control Cost Manual states: "[t]he appropriate interest rate in private cost assessment is the private interest rate for each firm affected. Determining private interest rates may be difficult due to the firm-specific nature of the private nominal interest rate faced by firms. If firm-specific interest rates are available, then the appropriate rates are simply the difference between the nominal interest rate minus the prevailing inflation in the industry." EPA's Control Cost Manual also states "[i]f firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates given the potential difficulties in eliciting accurate private nominal interest rates since these rates may be regarded as confidential business information or difficult to verify."[108]

UDAQ's use of a higher interest rate and a shorter pollution control amortization period effectively allows Utah sources a much higher cost effectiveness threshold than similar sources being evaluated in nearby states. UDAQ has not provided any rational justification supporting the use of firm-specific interest rates and shortened equipment life.[109] Thus, by accepting the sources' truncated equipment life assumptions and high interest rates, UDAQ artificially raised the cost-effectiveness figures (higher $/ton), resulting in higher costs.[110]

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105 CCM, Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, at 16 (emphasis added).
106 Stamper Report at 21, 51, 68.
107 Id. at 22-23.
108 Id. at 24.
109 Id.
110 Id. at 20, 40, 69.

d. UDAQ improperly accepted elevated retrofit factors without adequate justification.

Another flaw in the Proposed SIP is the use of unjustified elevated retrofit factors, which act as a multiplier to increase the costs of installing pollution controls. The Stamper Report found that UDAQ accepted use of a retrofit factor greater than 1.0.[111] A retrofit factor of 1.0 represents the usual situation in which all of the alleged issues identified by the sources are addressed.[112] UDAQ's SIP lacks documentation of why a higher retrofit factor was justified for Sunnyside Cogeneration Facility. Without documentation justifying higher retrofit factors, UDAQ must use a retrofit factor of 1.0.

e. UDAQ erroneously included taxes and insurance.

UDAQ included property taxes and insurance in its control cost analysis for Sunnyside Cogeneration Facility. As noted in the Stamper Report, Sunnyside Cogeneration took into account costs for property taxes and insurance even though EPA's Control Cost Manual does not typically include costs for property taxes or insurance for pollution controls.[113] UDAQ must remove the property taxes and insurance costs from the Sunnyside Cogeneration Facility analysis.

UDAQ must also collect more information on PacifiCorp's calculations for cost of capital to ensure that the cost of equity does not account for the cost of income taxes.

f. UDAQ failed to provide a complete SIP for public review.

To comply with public notice and comment requirements, UDAQ must ensure that the Four-Factor Analyses are accurately and completely documented before the start of the public notice and comment period.[114] UDAQ must also provide the public with a completed SIP for review. Here, UDAQ has failed to do so. For example, UDAQ failed to provide the "Four-Factor Analysis Summary" on page 140 of the Proposed SIP and instead only included a statement that said "[a]dd 4-factor analysis summary matrix to show that each have been addressed for all sources[.]"[115] To comply with public notice and comment requirements, UDAQ must provide the public with a complete Proposed SIP.[116] The failure to do so undermines the purpose of public notice and comment requirements, which is to inform the public and solicit public comment. If the public is not provided a completed SIP for review, the public will not receive notice for the information that is not included in the Proposed SIP and cannot provide comments on that information. Because a completed Proposed SIP is essential to the public's informed review and comment on the Proposed SIP, UDAQ should reissue a revised and completed draft for public comment.

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[111] Id. at 44.
[112] Id. at 52.
[113] Id. at 45.
[114] 40 C.F.R. § 51.308(g).
[115] Proposed SIP ta 140.
[116] 40 C.F.R. § 51.308(g).

B. UDAQ Failed to Require Emissions Reductions from Utah Power Plants

UDAQ must revise its Proposed SIP to appropriately evaluate pollution controls for Utah power plants to reduce NOx and SO2 emissions. Given that coal-fired power plants account for 96% of the total visibility impairing emissions from stationary sources in Utah, the revised SIP must require feasible, cost-effective emissions reductions from these sources to demonstrate reasonable progress.

1. PacifiCorp–Hunter and Huntington Power Plants

PacifiCorp operates the coal-fired Hunter and Huntington Power Plants located in Castle Dale and Huntington, Utah (respectively). The Hunter Power Plant has three coal-fired units, and the Huntington Power Plant has two coal-fired units. Hunter Units 1 and 2 and Huntington Units 1 and 2 are subject to BART.[117] The Hunter Power Plant had the highest combined (SO2+NOx+PM10) Q/d value of 216.1 of all the facilities evaluated by UDAQ, and the Huntington Power Plant had the third highest combined Q/d value of 105.5.[118] Capitol Reef National Park, is the closest Class I area at 74.9 km from the Hunter Plant and 95.8 km from the Huntington Plant.

It would be unreasonable and unlawful to allow the Hunter and Huntington plants to continue polluting at current, excessive levels when significant emissions reductions are achievable and cost effective. As noted, despite being BART sources, Hunter Units 1 and 2 and Huntington Units 1 and 2 have never been subject to federally enforceable obligations to reduce their SO2 and NOx emissions to comply with the Clean Air Act's BART requirements. Instead, Utah relied on an emissions trading program (that never was triggered) to satisfy SO2 BART requirements. And EPA approved a BART Alternative for NOx that allowed Hunter Units 1 and 2 and Huntington Units 1 and 2 to escape NOx-pollution control requirements despite having found SCR to be capable of achieving some of the most significant and highly cost-effective visibility improvements of any BART determination across the regional haze program. UDAQ must now, at long last, secure significant reductions from these facilities.

PacifiCorp claimed that SCR and SNCR were not cost effective for Hunter and Huntington and proposed alternative emission limits, which it called reasonable progress emission limits ("RPELs").[119] PacifiCorp proposed a plantwide NOx and SO2 limit of 10,000 tpy for the Huntington plant and 17,000 tpy for the Hunter plant. Instead of the RPELs, UDAQ proposed to adopt plantwide NOx emission limits for the Hunter and Huntington plants that are reflective of the NOx emissions modeled by WRAP, and to adopt the Hunter and Huntington SO2 emission limits for their air permits as part of the regional haze plan.

Conservation Organizations agree with UDAQ that PacifiCorp's RPELs for Huntington and Hunter power plants should not be adopted. First, the RPELs likely do not constitute a

[117] Stamper Report at 14.
[118] Id.
[119] Id. at 15.

reasonable progress control measure. Second, as detailed in the Stamper Report, the RPELs will not ensure any reduction in actual emissions of either NOx or SO2 because the limits are intended to cap emissions from any future modifications to each plant that would increase emissions and are not designed to reduce emissions from the existing plants.[120] Thus, PacifiCorp inappropriately compared its proposed RPEL limits to the Plantwide Applicability Limits ("PAL") to claim that the RPELs reflect emission reductions.[121]

Conservation Organizations also agree with UDAQ's conclusion that it does not concur with PacifiCorp's four-factor analysis calculations for PacifiCorp's proposed RPELs for the following reasons:

- The emissions reductions that the RPELs are based on are SNCR controls, which PacifiCorp claimed were not cost effective.
- The control costs associated with the RPELs were based solely on the cost of additional scrubbing of SO2, while the estimated emission reductions were both NOx and SO2.
- PacifiCorp used the PALs as its emission baseline in its RPEL cost effectiveness analysis when it used a different actual emissions baseline for its SCR and SNCR cost effectiveness analyses. UDAQ cannot compare the cost effectiveness of the proposed RPEL limits to the costs of SNCR or SCR due to the use of different baselines.
- The RPELS will not reduce actual emissions from either the Hunter or Huntington plant compared to what the plants have actually emitted in the past eight years. The RPEL limits are, at best, a reduction in allowable emissions.
- Because the RPELs will not reduce actual emissions below what the plants have emitted in at least the past eight years, they will not require operation of either SNCR or enhanced SO2 removal. Thus, estimating costs for compliance with the RPELs—that will not require any changes in pollution controls—is illogical.
- The RPELs also will not ensure emission reductions at or below what was modeled for the Hunter and Huntington plants.

PacifiCorp proposed adoption of its RPELs to meet regional haze requirements because it claimed that traditional NOx controls of SCR and SNCR were not cost effective for the Hunter and Huntington units based on cost effective analyses it prepared. As explained in the Stamper Report and listed below, there are numerous flaws in PacifiCorp's cost-effective analyses that must be corrected:

- Used a 7.303% interest rate for determining annualized capital costs of control, which has not been adequately justified as consistent with the EPA's control cost manual;
- Assumed an annual average NOx rate of 0.05 lb/MMBtu at the Hunter and Huntington units in determining the annual reduction in NOx emissions for its cost evaluation of SCR resulting in understated annual reduction in NOx emissions with SCR and making SCR seem less cost effective;

[120] Id. at 16-19.
[121] Id. at 17-18.

- Failed to provide sufficient justification for including costs for air preheater modifications in its costs for SNCR when the cost effectiveness of SNCR should be calculated without including costs for air preheater modifications; and
- Assumed a twenty-year life of SNCR rather than a thirty-year life in its SNCR Cost Analysis.

The Stamper Report corrected these flaws—rather than using PacifiCorp's weighted cost of capital as the interest rate which has not been properly justified as consistent with the Control Cost Manual methodology, the Stamper Report used the current bank prime rate of 4.0% in both the SCR and SNCR cost effectiveness calculations and revised PacifiCorp's SNCR cost effectiveness calculation to assume SNCR would have a 30-year life—and conducted revised cost-effectiveness calculations for SO2 controls and NOx controls (Tables 8-9).[122]

Table 8. Revised SCR Cost Effectiveness at Hunter and Huntington Units Based on PacifiCorp's Cost Estimates and Using the Current Bank Prime Rate of 4.0% to Calculate Annualized Capital Costs.[123]

Plant/Unit	SCR Capital Cost	Revised Annualized Capital Costs, $/year	Total Annual Costs (with O&M Costs), $/year	NOx reduced, tons per year	Revised Cost Effectiveness
Hunter Unit 1	$146,192,000	$5,847,680	$7,618,680	2,130	$3,577/ton
Hunter Unit 2	$146,192,000	$5,847,680	$7,654,680	2,149	$3,561/ton
Hunter Unit 3	$162,432,000	$6,497,280	$8,761,280	3,579	$2,448/ton
Huntington Unit 1	$141,923,256	$5,676,930	$7,439,930	2,266	$3,283/ton
Huntington Unit 2	$141,923,256	$5,676,930	$7,396,930	2,146	$3,446/ton

Table 9. Revised SNCR Cost Effectiveness at Hunter and Huntington Units Based on PacifiCorp's Cost Estimates, Using the Current Bank Prime Rate of 4.0% and Assuming a 30-year Life of SNCR to Calculate Annualized Capital Costs.[124]

Plant/Unit	SNCR Total Capital Investment	Revised Annualized Capital Costs, $/year	Total Annual Costs (with O&M	NOx reduced, tons per year	Revised Cost Effectiveness

[122] Stamper Report at 31-32.
[123] SCR cost data and NOx reductions from August 31, 2021 PacifiCorp Submittal to UDAQ, Attachment B at 1.
[124] Id.

			Costs), $/year		
Hunter Unit 1	$16,004,000	$640,160	$2,808,560	569	$4,936
Hunter Unit 2	$16,004,000	$640,160	$2,848,960	580	$4,912
Hunter Unit 3	$16,004,000	$640,160	$3,816,760	872	$4,377
Huntington Unit 1	$16,152,000	$646,080	$2,902,280	594	$4,886
Huntington Unit 2	$16,152,000	$646,080	$2,802,080	565	$4,959

The Stamper Report demonstrates that using the current bank prime rate and a 30-year life of SNCR brings the cost effectiveness of SNCR below $5,000/ton. SCR should be considered as a cost effective control for Hunter Units 1, 2, and 3 and Huntington Units 1 and 2.[125] These costs that range from as low as $2,500/ton (if the current bank prime rate is used) to as high as $6,500/ton (if PacifiCorp's claimed cost of capital of 7.303% is used in the cost analysis) are within the range of dollar per ton values that other states consider as cost effective under the second round regional haze plans.[126] If the interest rate was decreased to 6.0%, the cost effectiveness of SCR at all of the Hunter units would be under $5,000/ton.

UDAQ's sensitivity analysis using PacifiCorp's costs and weighted cost of capital shows that the less that a unit operates, the less cost effective (i.e., higher annual costs per tons of NOx removed) a control is, and the more a unit operates, the more cost effective a control is. UDAQ states that the electricity generation industry is experiencing significant change and that there is great uncertainty in the near and medium-term operation of the Hunter and Huntington units. UDAQ's presentation of Hunter and Huntington plant capacity factors on a facility-wide basis to show that the plants are being utilized less in recent years compared to how the plants were utilized in 2008-2013, [127] is not relevant to an evaluation of PacifiCorp's cost effectiveness analysis for NOx controls at each unit which was based on the average of 2015-2019 emissions. Less utilization would only be relevant if it was joined by a requirement to limit capacity to the rates assessed. Additionally, UDAQ should not have evaluated capacity factors on a plantwide basis when cost effectiveness is determined on a unit-specific basis.

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[125] Stamper Report at 32-33.

[126] As FLM comments note:

> Many of the controls identified in the four-factor analyses for Utah sources are cost-effective based on cost criteria/thresholds identified by other states. For example, other states have set the following cost-effectiveness thresholds in their draft proposals:
> - $5,000/ton in Arkansas (EGUs) and Texas
> - $6,100/ton in Idaho
> - $10,000/ton in Colorado and Oregon
> - A range between $5,000 to $10,000/ton in Nevada
> - A range between $4,000 to $6,500/ton in Arizona

Proposed SIP at Appendix D, PDF page 437.

[127] Proposed SIP at 131.

Furthermore, Table 10 in the Stamper Report demonstrates, while 2020 operating capacity factors were lower for some units compared to the 2015-2019 average operating capacity factors, the operating capacity factor in 2021 was higher for all five units compared to the 2015-2019 average capacity factors. This analysis shows that the average operating capacity factor upon which PacifiCorp's NOx control cost effectiveness analyses are based were reasonably reflective of current operations. Further, UDAQ's statements that the five coal-fired units capacity factors could decrease in the future are speculative and cannot legally be relied upon for not requiring emissions limits in its Proposed SIP.

We request that Utah correct these errors and require reasonable controls for NOx reductions from Hunter and Huntington power plants.

2. Sunnyside Cogeneration Associates–Sunnyside Cogeneration Facility

The Sunnyside Cogeneration Associates operates the Sunnyside Cogeneration Facility ("Sunnyside Cogen"), a power production facility and qualifying cogeneration facility, in Carbon County, Utah, 97 km from Canyonlands National Park. This facility has a coal-fired circulating fluidized bed ("CFB") boiler that drives a turbine-generator with a baghouse and a limestone injection system.[128] The facility also has a diesel engine and diesel emergency generator.[129] The Sunnyside Cogen facility is considered by UDAQ to be a major source of SO2, NOx, PM10, as well as carbon monoxide and hazardous air pollutants.[130]

As explained in the Stamper Report, there are numerous flaws in the facility's four-factor analysis that must be corrected:

- Assumed too high of an interest rate in determining annualized costs of control, which overstated the annualized capital costs by amortizing the capital costs over the life of controls at an unreasonably high interest rate;
- Dismissed wet scrubbers and spray dry scrubbers from consideration as an SO2 control because it does not have the water rights that would be needed for operation of the wet scrubber or a spray dry absorber;
- Eliminating DSI as an SO2 control technology without justification; and
- Claimed without documenting justification that there was not enough space to utilize DSI technology of a circulating dry scrubber.

a. SO2 Controls

First, Sunnyside's review of SO2 controls was flawed because it overstated the costs of circulating dry scrubbers ("CDS") as explained in the Stamper Report and outlined below:

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[128] Id. at 133.
[129] Id.
[130] See Title V Operating Permit Number 700030004, April 30, 2018, Sunnyside Cogeneration Associates, at 2.

- Used too high of an interest rate of 7% instead of the bank prime lending rate, which is currently 4.0%;
- Assumed only a 20-year life of a circulating dry scrubber even though EPA's Control Cost Manual states that wet and dry scrubbers should have a useful life of 30 years or even longer;
- Used a 1.3 retrofit cost factor because Sunnyside claimed it must install a new baghouse within the currently allocated space even though it did not adequately justify that its baghouse would need to be replaced;
- Included costs for baghouse replacement because Sunnyside claims the baghouse is at the end of its useful life despite the fact that if the baghouse is at the end of its useful life, it will need to be replaced whether or not regional haze control requirements are imposed;
- Double counted installation costs by using projected equipment cost of $66,600,000 for a CDS scrubber, based on the EPA Control Cost Manual equations, which include the scrubber installation costs, engineering, construction management, etc., while also including costs for direct installation and indirect costs such as engineering and construction in its analysis;
- Included costs for property taxes and insurance—annual costs equating to 2% of the total capital investment for taxes and insurance—which are not justified under the Control Cost Manual; and
- Assumed too low of an SO2 removal efficiency with a CDS of only 74% SO2 removal efficiency even though CDS can achieve up to 98% removal efficiency.

The Stamper Report corrected these flaws and conducted revised cost-effectiveness calculations for SO2 controls (Tables 14).[131]

Table 14. Cost Effectiveness of a Circulating Dry Scrubber (Using the Existing Baghouses) at Sunnyside Cogen CFB Based on 30-Year Life of Controls and the EPA Control Cost Manual Spreadsheets[132]

Controlled Annual SO2 Rate, lb per MMBtu	Capital Cost (2019$)	O&M Costs	Total Annualized Costs	SO2 Reduced from 2018-2019 Baseline, tpy	Cost Effective-ness, $/ton
0.03	$33,666,198	$2,051,596	$4,032,451	388	$10,396/ton

The Stamper Report shows that circulating dry scrubber ("CDS") is a cost-effective control, especially given that the Sunnyside Cogen CFB boiler has used high sulfur content coal, had much higher SO2 emissions in the recent past, and has no limit on coal sulfur content in its

[131] Stamper Report at 47.
[132] See Cost Effectiveness Workbook for CDS without baghouse for Sunnyside Cogen (attached as Ex. 12 to Stamper Report).

permit.[133] The cost effectiveness of CDS would be in the range of $7,395/ton to $10,396/ton. CDS would reduce SO2 emissions from current emission levels by 388 tons per year.

The Stamper Report and table below also show that dry sorbent injection ("DSI") with lime would be a very cost effective SO2 control for the Sunnyside Cogen CFB boiler, achieving a 50% SO2 reduction at a cost effectiveness of $3,169/ton.[134] Sunnyside Cogen has stated that DSI could not be installed at the CFB boiler due to space restrictions. However, Sunnyside Cogen appears to refer to a spray dryer absorber and not DSI that is injected into the flue gas between the air preheater and the baghouse. There is no documentation in the draft regional haze plan that DSI could not be used at the Sunnyside Cogen CFB boiler to achieve improved SO2 reductions.

Table 15. Cost Effectiveness of Dry Sorbent Injection at Sunnyside Cogen's CFB Boiler, Assuming 50% SO2 Control with Lime[135]

Sorbent	SO2 Removal Efficiency Assumed	Capital Cost (2019 $)	Operational Costs	Total Annualized Cost, Assuming 3.25% Interest Rate and 30-Year Life	SO2 Reduced, tpy	Cost Effectiveness (2019 $)
Lime	50%	$5,946,031	$402,530	$746,390	236	$3,169/ton

While a circulating dry scrubber would achieve a much higher level of SO2 removal as discussed above, dry sorbent injection should also be considered as a cost-effective control technology to require as a measure to make reasonable progress towards the national visibility goal.

b. NOx Controls

For NOx controls, Sunnyside Cogen's cost analyses found that SCR would have a cost effectiveness of $13,445/ton to achieve 90% NOx control and that SNCR would have a cost effectiveness of $9,268/ton to achieve 15% NOx control.[136] Sunnyside's analyses contain numerous flaws listed below and discussed in detail in the Stamper Report:

- Used too high of an interest rate of 7% instead of the bank prime lending rate, which is currently 4.0%;

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[133] Id.
[134] Id. at 49.
[135] See Spreadsheet with cost for Sunnyside Cogen CFB -DSI with Lime (attached as Ex. 14 to Stamper Report).
[136] Stamper Report at 51-52.

- Assumed a 1.3 retrofit factor for SCR without providing documentation justifying and showing that a low dust configuration at its CFB boiler would increase costs over a typical retrofit by 30%;
- Assuming a 20-year life of controls even though EPA has found that the useful life of an SCR system at a power plant would be 30 years, and EPA cited one analysis that assumed a design lifetime of 40 years; and
- Assumed too high of an annual coal throughput of 883,413,174 pounds of coal per year for the CFB boiler in both the SCR and the SNCR cost effectiveness analyses even though this amount of coal use would equate to operating 8,924 hours per year at maximum heat input capacity—which is not possible given that there are only 8,760 hours available hours in a year (8,784 in a leap year)—and the average annual operating hours of the CFB boiler were even lower at 8,031 hours per year.[137]

The Stamper Report corrected these flaws and conducted revised cost-effectiveness calculations for NOx controls (Tables 16) below.

Table 16. Cost Effectiveness of SNCR and SCR at Sunnyside Cogen's CFB Boiler Based on EPA's SCR and SNCR Cost Spreadsheets, a 4% Interest Rate, and a 30-Year Life of Controls[138]

Control Evaluated	NOx Emission Rate, lb/MMBtu	Capital Cost of Control, 2019 $	Operating and Maintenance Costs	Total Annual Costs, 2019 $	Tons of NOx removed, tpy	Cost Effectiveness, 2019 $
SCR	0.015	$38,970,217	$695,701	$2,952,303	388	$7,611/ton
SNCR	0.12	$6,591,483	$419,539	$803,493	86	$9,321/ton

Based on the Stamper Report, SCR is a very cost-effective NOx control that could be used at the Sunnyside Cogen CFB boiler to achieve 90% reduction in NOx at a cost effectiveness of $7,600/ton to a worst-case cost effectiveness of $9,500/ton (based on Sunnyside's 1.3 retrofit factor).[139] The cost effectiveness of SCR at the CFB boiler is within the range that other states have found to be cost effective in the second-round regional haze planning. SCR would reduce NOx emissions from the Sunnyside Cogen CFB boiler by 90%, removing 388 tons per year from the air. Thus, UDAQ must go back and revise these flawed analyses and must consider adopting a requirement for the Sunnyside CFB boiler to implement these highly effective NOx controls to achieve reasonable progress towards the national visibility goal.

The Stamper Report demonstrates that there are cost-effective SO2 and NOx controls for the Sunnyside Cogen facility. UDAQ's analyses are deficient: it must go back, correct these

[137] Proposed SIP, October 2021 Sunnyside Cogen Submittal to UDAQ, Appendix A at 1.
[138] See Spreadsheets with costs for Sunnyside SNCR and for Sunnyside SCR (attached as Ex. 16 and Ex. 17 to Stamper Report).
[139] Stamper Report at 54.

errors, and require actual measurable emission reductions at Sunnyside Cogen as required by the Regional Haze Rule and CAA.

C. UDAQ Must Require Emissions Reductions from Selected Non-Power Plants and Ensure that Complete and Accurate Four-Factor Analyses Are Submitted to EPA

In addition to requiring Utah power plants reduce NOx and SO2 emissions, UDAQ must revise its Proposed SIP to appropriately evaluate pollution controls on non-power plant sources, including manufacturing plants. The revised SIP must require feasible, cost-effective emission reductions from these sources to demonstrate reasonable progress.

1. Ash Grove Cement Company—Leamington Cement Plant

The Ash Grove Cement plant, in Leamington, Utah, produces cement using inorganic raw materials, primarily limestone quarried on-site. UDAQ considers the plant to be a major source of particulate matter (both PM2.5 and PM10), NOx, as well as CO and hazardous air pollutants, and the facility has a combined Q/d of 6.9.[140] The Leamington cement kiln is equipped with SNCR and a baghouse, and the Four-Factor Analysis also states that the kiln is equipped with a low NOx burner, although the Title V permit for the facility does not mention that NOx control. The Proposed SIP accepts Ash Grove's conclusion that no additional pollution controls or strengthening of emission limits are required.

UDAQ's analysis is insufficient because it has not adequately evaluated control measures for SO2 or for NOx at the Leamington Cement Plant. UDAQ must reconsider imposing control measures on SO2 emissions from the cement kiln to ensure that emissions do not increase from the current baseline emissions of 8.0 tons per year to the allowable potential to emit 192.5 tons per year. As the Stamper Report explains, Leamington Cement Plan is permitted to use several fuels, including coal, natural gas, coke, fuel oil, and other types of fuels including waste fuels such as tire derived fuel and diaper-derived fuel.[141] The Stamper Report states that:

> While the four-fact[or] report identifies 2019 SO2 emissions as 8.0 tpy, it is not clear what fuels were used in the kiln, pre-heater and calciner in 2019. For example, did the plant primarily use lower sulfur fuels in 2019 from the list of authorized fuels, such as natural gas, and not use coal or oil? The four-factor analysis indicates that SO2 emissions in 2019 were approximately 0.02 lb/ton of clinker. In contrast, the Approval Order for the Leamington Cement Plant allows 0.4 lb SO2 per ton of clinker. In addition, the Approval Order lists the total potential SO2 emissions for the Leamington Cement Plant as 192.50 tons per year, which is considerably more than the 8.0 tons per year reported for 2019. [142]

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[140] Proposed SIP at 93.
[141] Stamper Report at 75.
[142] Id.

UDAQ should request information on the quantities of each type of allowed fuel that were used in 2019 as well as on the tons of clinker produced in 2019, so that it can determine what factors lead to the low 2019 SO2 emissions. If the reason for the source's low SO2 emissions in 2019 is due at least in part to using low sulfur fuels such as natural gas, or not using the highest sulfur fuels such as petroleum coke or tire-derived fuel, then revising the permitted list of approved fuels to eliminate the higher sulfur fuels should be considered as a control strategy. Without this information and enforceable requirements, SO2 emissions could be as high as 192.50 tons per year based on the terms of the existing permit, an annual rate that is 24 times as high as the current level of SO2 emissions in 2019. Thus, UDAQ must reconsider imposing as a control measure the methods being used to keep SO2 emissions at or near 2019 levels.

For NOx controls, UDAQ must collect more information on the NOx removal efficiency being achieved by the SNCR at the Leamington Cement Plant kiln, and more fully evaluate whether the current SNCR's NOx removal efficiency could be improved. Additionally, UDAQ must evaluate the installation of ceramic catalytic filtration bags in the existing baghouse at the Leamington Cement Plant kiln, because the controls will significantly and cost-effectively reduce NOx emissions from the cement kiln as evidenced by the GCC Pueblo Cement Plant four-factor cost assessment and discussed at length in the Stamper Report.[143]

UDAQ's failure to consider cost-effective controls for the Leamington Cement Plant runs afoul of the Regional Haze Rule and CAA. UDAQ must go back and correct its flawed analysis as described in these comments and the Stamper Report.

2. Graymont Western U.S. Incorporated-Cricket Mountain Plant

The Graymont Western U.S. Incorporated Cricket Mountain Plant in Millard County, Utah consists of quarries and a lime processing plant, which includes five rotary kilns that are fired by petroleum coke and coal which convert crushed limestone into quicklime. The plant is a major source for particulate matter (PM10 and PM2.5), NOx, SO2, VOCs, and other air pollutants.[144] The plant has five rotary lime kilns, each controlled by a baghouse.[145] The plant also has several other sources of air emissions including, but not limited to, kiln drives, generators, crushers, coal storage silos, and lime handling and transfer equipment.[146] According to the most recent Approval Order for the facility, the Cricket Mountain Plant has the potential to emit 3,879.77 tpy of NOx, 760.28 tpy of SO2, and 610.37 tpy of PM10.[147] The potential to emit these visibility-impairing pollutants is much higher than the emission data from the 2014 National Emissions Inventory used for the Q/d analysis.

[143] Id. at 76-78.
[144] Id. at 58-59.
[145] Id. at 59.
[146] Id.
[147] January 30, 2018 Approval Order DAQE-AN103130041-18 for Graymont Western U.S. Incorporated at 2.

The Proposed SIP evaluated NOx controls only for the five lime kilns.[148] As noted by the Stamper Report, emissions from the five lime kilns account for 639.0 tpy of NOx and the plant has total NOx emissions of 916.5 tpy, [149] meaning that other emissions sources at the plant must contribute over 250 tpy of NOx to the plant's total NOx emissions.[150] Yet, the Cricket Mountain Plant Four-Factor Analysis did not identify other emission units or evaluate reasonable progress controls for other emission units. UDAQ should require that Graymont Western provide an emissions inventory for every emission unit that emits visibility-impairing pollutants, and UDAQ must require a Four-Factor Analysis for other significant emission sources at the Cricket Mountain Plant.

UDAQ must also require Graymont Western to consider NOx controls that are cost effective including SNCR and the use of catalytic ceramic filtration bags in the existing baghouse.

First, UDAQ must consider SNCR as a NOx control. Graymont Western's claim that SNCR is not technically feasible for its preheater rotary lime kilns is not justified given that successful retrofit of such controls to several rotary lime kilns exists at: the Lhoist North America O'Neal Plant in Alabama, which achieved monthly NOx rates less than 3 lb/ton of lime and annual average NOx rates between 1.2 to 1.8 lb/ton; the Unimin Corporation lime plant in Calera, Alabama, which installed SNCR on its rotary lime kiln in 2010 to achieve compliance with a 3.2 lb NOx per ton of lime emission limit; and the rotary lime kilns of the Lhoist North America Nelson Lime Plant in Arizona which was required to install SNCR to meet BART.[151] Additionally, Graymont Western incorrectly evaluated a 20% NOx reduction for SNCR even though EPA adopted emission limits reflective of 50% control with SNCR at the Nelson Lime Plant and Graymont Western stated in its initial Four-Factor Analysis that the average NOx removal at cement kilns with SNCR was 40%, with the range of NOx removal efficiency between 35%-58%.

Second, UDAQ must evaluate the use of catalytic ceramic filtration bags in the existing baghouse. As explained in the Stamper Report, several vendors offer catalytic ceramic filtration systems for baghouses that can remove NOx through embedded catalysts in the filter, as well as particulate matter and SO2 (with the use of dry sorbent injection). Some catalytic filtration bags can provide much higher NOx removal rates (up to 90% NOx reduction) compared to SNCR and are used successfully at other lime kilns.[152] Thus, UDAQ must evaluate the use of catalytic ceramic filtration bags as a top NOx control option for the Cricket Mountain Lime Plant.

UDAQ must correct the deficiencies in the Proposed SIP by requiring review of more than the five lime kilns at the Cricket Mountain Plant and requiring cost-effective NOx controls.

[148] Proposed SIP at 116.
[149] Id.
[150] Stamper Report at 58.
[151] Id. at 61.
[152] Id.

3. U.S. Magnesium LLC—Rowley Plant

U.S. Magnesium LLC ("U.S. Magnesium") operates the Rowley Plant located in Tooele County, Utah that is a primary magnesium production facility producing a magnesium metal from the waters of the Great Salt Lake.[153] UDAQ states that the facility has a combined Q/d of 7.4.[154] The closest Class I area is Capitol Reef National Park which is 288.7 km away.

The plant is a major source for particulate matter (PM10), NOx, VOCs, and other air pollutants. Even though the Rowley Plant has multiple fuel combustion sources emitting NOx on site, UDAQ has proposed to adopt an enforceable requirement for U.S. Magnesium to install a flue gas recirculation ("FGR") system at only the Riley boiler by January 1, 2028 and for the boiler to not exceed 22.6 tons per 12-month rolling period.

The Stamper Report identified and detailed multiple flaws in the Rowley Plant Four-Factor Analysis. Some of the flaws are listed below and discussed in-depth in the Stamper Report. In particular, UDAQ's analysis of NOx pollution controls is incomplete for the following emission units:

- Gas turbines: Given that the turbines (with the duct burners) are responsible for about 80% of the Rowley Plant's NOx emissions, UDAQ must evaluate all possible options to reduce NOx emissions from the gas turbines. UDAQ must evaluate placing the SCR downstream of the spray dryer where the temperatures either would be low enough for SCR operation or could be lowered with cooling air skids.[155]
- Diesel engines: UDAQ did not evaluate several very effective NOx control options for the diesel engines used at the Rowley Plant, including electrification and replacement of Tier 0 or Tier 1 engines with Tier 4 engines or with natural gas-fired lean burn RICE. In addition, U.S. Magnesium's analysis of SCR and EGR is flawed because analysis relied on an average engine, rather than considering these controls at engines taking into account engine size, tier rating, and operating hours.[156]
- Riley boiler: UDAQ improperly dismissed installation of low NOx burners and ultra-low NOx burners as not technically feasible without gathering boiler-specific data on what burner upgrades could be installed at the Riley boiler. The Stamper Report notes that low or ultra-low NOx burners with FGR is the most effective and most cost-effective NOx control for the Riley boiler. UDAQ's revised cost calculations for SCR cost effectiveness are incorrect, and SCR should be considered cost effective for the boiler at a cost effectiveness of $4,800/ton.[157]

Even if UDAQ finds that FGR is the only control required at the Riley boiler, it must revise its proposed regulatory language to ensure the proposed 22.6 ton per rolling 12-month emission limit is enforceable. First, to be consistent with EPA's regional haze guidance, UDAQ

[153] Proposed SIP at 137-38.
[154] Id. at 138.
[155] Stamper Report at 65-66.
[156] Id. at 69-71.
[157] Id. at 66-69.

must impose a rate-based NOx limit in terms of lb/MMBtu because EPA states that, when a state "has determined that a technology-based measure is necessary to make reasonable progress," emission limits should be expressed in a rate-based format (such as pounds of pollutant per throughput).[158] Second, UDAQ must include enforceable regulatory language requiring more frequent testing—testing at least once a year—because the current three year stack test cycle is insufficient to ensure that the 50-year old boiler is regularly and properly maintained. Third, the proposed regulatory language must identify which units require stack test results reporting. If UDAQ continues to only impose a mass-based emission limit, the regulatory language must also specify recordkeeping on the amount of fuel used per month at the Riley boiler so that 12-month heat input can be calculated. The proposed regulatory language should also make clear that compliance with the 12-month rolling total emission limit shall be calculated based on the fuel use or heat input over that time period and based on the NOx emission rates from the most recent stack test.

UDAQ must revisit the analysis for U.S. Magnesium's Rowley Plant and correct the errors detailed above and in the Stamper Report.

D. UDAQ Must Review Sources Exempted from Four-Factor Analysis.

The NPS identified several other facilities for which technically feasible and cost-effective emissions controls are available and should be required. Conservation Organizations incorporate those recommendations by reference in their entirety and provide further comments below.

1. <u>The CCI Paradox Midstream, LLC—Lisbon Natural Gas Processing Plant</u>

CCI Paradox Midstream, LLC operates the Lisbon Natural Gas Processing Plant located in La Sal, Utah.[159] According to UDAQ, the facility has a combined Q/d of 20.9.[160] The closest Class I area is Canyonlands National Park which is 35.8 km away. UDAQ did not require a Four-Factor Analysis from the facility because "[i]n 2009 the plant received a permit modification to lower the SO2 emissions from 1,593 tons down to 111 tons . . . as it had installed both primary and secondary control systems to limit emissions of SO2."[161] However, UDAQ noted that the plant "mistakenly restored the original 1,593 tons of SO2 emissions without explanation" when it requested a modification the following year.[162] Even though the plant can emit 1,539 tons of SO2 emissions, UDAQ claims that actual SO2 emissions are "more in line with the proper 2009 [potential to emit] of 111 tons."[163]

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[158] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 44.
[159] Proposed SIP at 93.
[160] <u>Id.</u>
[161] <u>Id.</u> at 94.
[162] <u>Id.</u>
[163] <u>Id.</u> at 93-94.

The National Park Service recommended that "UDAQ revise the permit limits for this facility to reflect actual emission assumptions used to exclude this facility from four-factor analysis."[164] Conservation Organizations agree and also emphasize that UDAQ must adopt a regional haze SIP requirement specifying the "proper" SO2 limit on the Lisbon Gas Plant of 111 tons per year, along with appropriate testing, recordkeeping, and reporting, and incorporate such requirements into the applicable permit for the Lisbon Gas Plant. Failing incorporation of a lower rate, the state needs to do a Four-Factor Analysis.

2. Intermountain Power Service Corporation—Intermountain Generation Station

The Intermountain Generation Station, owned by Intermountain Power Service Corporation ("IPSC" or "Intermountain Power"), is located in Delta, Utah, and consists of two coal-fired EGUs, each with generating capacity of 1,800 MW.[165] UDAQ identified the source as having the highest total NOx, SO2, and PM10 emissions, and has the second highest Q/d value of 193.6.[166] The closest Class I area to the plant is Capitol Reef National Park, which is 149.5 km away.

Because UDAQ expects the coal-fired units to cease operation by mid-2025, and UDAQ is proposing to adopt a requirement that the owner/operator of the Intermountain Generation Station must permanently close and cease operation of Intermountain Generation Station Units #1 and #2 by December 31, 2027, it did not require a Four-Factor Analysis from the facility.[167]

UDAQ must conduct a full review of pollution-reducing measures at Intermountain Generation Station. As NPS commented, NOx emission reduction opportunities and improvement to the efficiency of the existing SO2 scrubbers for Intermountain Power warrant further evaluation. In particular, while upgrades to existing SO2 scrubbers may be a cost-effective way to reduce haze causing emissions, UDAQ did not require or itself prepare a full Four-Factor Analysis of these options because of an assumed closure date of no later than December 31, 2027.[168] The Conservation Organizations concur with NPS that "cost-effective and quick to implement" SO2 scrubber upgrades exist and should be investigated.[169] Conservation Organizations also agree with NPS that NOx reduction opportunities should be investigated for the remaining useful life of the facility.[170] UDAQ must require a Four-Factor Analysis to evaluate these options.

UDAQ must also set an enforceable shutdown date of December 31, 2025 for Intermountain Generation Station. IPSC plans to replace the coal-fired units with two natural

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[164] Proposed SIP, Appendix D, at PDF page 440.
[165] Stamper Report at 36.
[166] See https://deq.utah.gov/air-quality/regional-haze-in-utah#planning.
[167] Draft Revisions to Utah State Implementation Plan, Emission Limits and Operating Practices, Section IX.H.23.a.
[168] Id. at Appendix D, PDF page 7.
[169] Id.
[170] Id.

gas and hydrogen fuel-fired combined cycle combustion turbines that will begin operation in December 2024. To prevent significant emission increase of NOx and other regulated new source review pollutants subject to prevention of significant deterioration permitting as a major modification, the coal-fired EGUs will need to cease operating by the time any one of the new gas-fired combined cycle combustion turbines starts operating.[171] Thus, UDAQ must revise the Proposed SIP to mandate that the Intermountain Generation Station Units #1 and #2 permanently close and cease operation by no later than December 31, 2025.

UDAQ must also document and evaluate the regional haze pollution controls proposed for the two new combined cycle combustion turbines in a Four-Factor Analysis given that the WRAP assumed 100% reduction in emissions from the Intermountain Generation Station in its 2028 regional haze modeling and yet the new combustion turbines are projected to emit significant quantities of regional haze pollutants.

The Stamper Report explains that there are additional NOx control options that UDAQ should evaluate and include in the Proposed SIP for the proposed new combined cycle combustion turbines:

> First, the permit should limit the amount of natural gas that can be fired per year to require maximum amount of hydrogen firing in each turbine per year, which IPSC indicated will initially be 30% hydrogen. As previously stated, the draft permit as currently written does not require any combination of hydrogen firing with natural gas at the new combustion turbines. Second, UDAQ should require that the combustion turbines operate in combined cycle mode, which is the most efficient operation of the units in terms of pollution emitted per megawatt-hour. Third, UDAQ should evaluate methods to minimize NOx emissions during startup and shutdown from the combustion turbines, including imposing more restrictive limits on the allowed number of startups and shutdowns per year. UDAQ should adopt these requirements as part of its regional haze plan to ensure that regional haze emissions are minimized from the new turbines to the maximum extent possible.[172]

UDAQ must revisit and conduct comprehensive analyses for the Intermountain Generation Station—for both the existing coal-fired units and the new proposed combined cycle combustion turbines—and must set an enforceable shut down date of December 31, 2025 for the coal-fired units.

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[171] UDAQ's draft Intent to Approve the IPP Renewal Project states that the project is not major modification under the PSD program. The only way that conclusion can be reached is if IPSC is planning to concurrently cease operation of the coal-fired units when at least one combined cycle combustion turbine becomes operational, so as to ensure no significant net emission increase would be projected from the IPP Renewal Project. See UDAQ, Intent to Approve, Modification to Approval Order DAQE-AN103270026-14 for the IPP Renewal Project, Project Number: N103270029, April 29, 2022, at 3 (attached as Ex. 10 to Stamper Report).

[172] Stamper Report at 40.

3. Kennecott Utah Copper LLC—Mine & Copperton Concentrator

The Conservation Organizations agree with the National Park Service's recommendations for the Kennecott Utah Copper LLC's Bingham County mine and copper concentrator in Bingham Canyon, Utah.[173] UDAQ proposes no controls and did not require a Four-Factor Analysis because the Kennecott Mine and Copperton Concentrator recently underwent BACT analysis as a part of the Salt Lake PM2.5 nonattainment SIP and because it claimed that NOx is the predominant visibility-impairing pollutant that comes from this facility and that the vast majority of NOx emissions is from mine haul trucks and other non-road equipment, which UDAQ claims it cannot regulate.[174]

NPS's review and the Stamper Report demonstrate that further explanation and review by UDAQ is necessary.[175] Specifically, UDAQ must "provide a breakdown of emissions from emission units it can regulate versus those it cannot regulate" and "explain how its PM2.5 SIP includes in-use requirements for this equipment."[176] For non-road engines at the Kennecott Utah Copper LLC Mine and Copperton facility, UDAQ should consider electrification of engines. If electrification is not possible, then UDAQ should consider adopting requirements to incentivize the replacement of existing nonroad engines with Tier 4 engines. Tier 4 engines have been manufactured since 2008 and have significantly lower NOx and PM emissions than Tier 0 through 3 engines, and thus the replacement of older, higher emitting engines could significantly reduce regional haze-impairing emissions from this facility.

To comply with the requirements in the Regional Haze Rule, UDAQ must go back and conduct a comprehensive analysis for the wrongly exempted mine and concentrator, and require necessary controls.

4. Kennecott Utah Copper LLC—Power Plant, Lab, and Tailings Impoundment

The Kennecott Utah Copper LLC Power Plant, Lab, and Tailings Impoundment is located in Magna, Utah, and the facility has a combined Q/d of 11.8.[177] Citing to an Approval Order and claiming that the coal-fired boilers at the facility were decommissioned, UDAQ did not require a Four-Factor Analysis or any controls for this facility.[178] UDAQ must go back and require a Four-Factor Analysis for Unit 4 of the power plant because it could potentially resume operations at some point in the future as the unit was "voluntarily decommissioned."[179] To exempt Unit 4 of the Kennecott Utah Copper power plant from a Four-Factor Analysis and to

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[173] Proposed SIP at Appendix D, PDF pages 441-42.
[174] Id. at 95.
[175] Id. at Appendix D, PDF pages 442.
[176] Id.
[177] Stamper Report at 56.
[178] Proposed SIP at 95.
[179] See Approval Order DAQE-AN105720040-20, February 4, 2020, at 4 (attached as Ex. 18 to Stamper Report), available at https://daqpermitting.utah.gov/DocViewer?IntDocID=117327&contentType=application/pdf.

ensure legal clarity, UDAQ must impose a requirement in the Proposed SIP stating that Units 1-4 of Kennecott Utah Copper LLC Power Plant shall remain permanently closed.

5. Holcim Devil's Slide Cement Plant

The Holcim Devil's Slide Cement Plant in Morgan, Utah was not identified by UDAQ as source for a Four-Factor Analysis, even though this facility is one of Utah's top five sources of visibility-impairing pollution, impacting up to 10 Class I areas.[180]

UDAQ should have conducted a Four-Factor Analysis of controls for the Devil's Slide Cement Plant, as its 2017 actual emissions are similar to or higher than several other sources that UDAQ did evaluate. UDAQ cannot exclude the plant from Four-Factor Analysis of controls based on the company's voluntary proposal to install SNCR.[181] As detailed in the Stamper Report, the requirement to operate an SNCR system is not required by the permit and the plant's permit does not impose a NOx emission limit reflective of SNCR system operation. Therefore, UDAQ must establish an enforceable requirement in the SIP for Holcim to install and operate the SNCR system, set a NOx emission limit reflective of the capabilities of the SNCR system, and add appropriate testing, recordkeeping, and reporting requirements to ensure continuous compliance with the emission limit.

As explained in the Stamper Report, UDAQ must also evaluate the cost effectiveness of installing catalytic ceramic filters in the existing baghouse that would work in concert with the ammonia injection of the SNCR system to achieve 90% reduction in NOx emissions.[182] The Devil's Slide cement kiln emitted 1,406 tons of NOx in 2017, and thus 90% reduction would equate to a reduction in NOx emissions of 1,265 tons per year (assuming there was no SNCR operating and reducing NOx from the Devil's Slide cement kiln in 2017). The Stamper Report showed that the Tri-Mer catalytic ceramic filtration bags would be very cost-effective at $1,804/ton of NOx removed to achieve 90% NOx removal.[183] Thus, to comply with the Regional Haze Rule, UDAQ must more fully evaluate the use of catalytic ceramic filtration bags. If catalytic ceramic filtration bags are selected as the control, it would displace the need for an SNCR system. If catalytic ceramic filtration bags are not selected as the control, then UDAQ must require the SNCR system be installed and operated year-round, and set a NOx limit reflective of SNCR operation at the Devil's Slide cement kiln.

UDAQ failed to meet the requirements of the Regional Haze Rule and CAA when it excluded review of the Holcim Devil's Slide Cement Plant. UDAQ must go back and review the source and require actual, measurable emission reductions from the facility.

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[180] Stamper Report at 79-80.

[181] Id. at 79-81. According to permits issued in March of 2022 for the Devil's Slide Plant, the company is voluntarily installing SNCR at its cement kiln. Id.

[182] Stamper Report at 81.

[183] Id.

III. UDAQ FAILED TO CONSIDER OIL AND GAS AREA SOURCES, DESPITE THEIR SIGNIFICANT NO_X EMISSIONS

The Proposed SIP fails to include legally sufficient consideration of area (nonpoint) sources and how those sources contribute to impairment both in-state and out-of-state and contribute to the Uinta Basin ozone non-attainment area problems. States should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources.[184] Yet, UDAQ did not discuss impairment caused by area sources and did not evaluate any NOx controls for this source category. UDAQ's own Proposed SIP shows that NOx emissions from the oil and gas industry (point and non-point sources) represent collectively the third largest anthropogenic source category of NOx emissions in the state of Utah after on-road mobile sources and EGUs, with 2014 combined emissions of 16,447 tons per year.[185] Given that significant air quality issues result from extensive oil and gas development occurring in the Uinta Basin, as noted by NPS, UDAQ's Proposed SIP fails to satisfy section 51.308(f)(2)(i). UDAQ's claim that "80% of emissions in the [Uinta Basin] result from areas under EPA control"[186] does not obviate Utah's obligation to evaluate reasonable progress control requirements for this significant source of NOx emissions in Utah.

UDAQ cannot rely on potential requirements including a future ozone SIP to avoid addressing the oil and gas sector in its Proposed SIP; the oil and gas sector is a significant contributor to regional haze pollution in Utah and in the region and thus the haze SIP is the instrument where reductions must be required and secured in the current planning period. An ozone SIP does not replace the Regional Haze Rule requirements that UDAQ must give sufficient consideration of and emission reduction measures for area sources, including oil and gas area sources that contribute to impairment both in-state and out-of-state.

UDAQ must revise its Proposed SIP to require statewide NOx requirements for flaring, engines, and other oil and gas sector sources. As documented in the technical report (attached to the Stamper Report) containing comprehensive Four-Factor Analyses for the oil and gas sector, there are numerous opportunities for technically feasible and cost-effective control of oil and gas area sources, summarized below.[187]

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[184] 40 C.F.R. § 51.308(f)(2)(i).
[185] Proposed SIP at 62.
[186] Id. at 106.
[187] Stamper, V. and M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, at ES-2 (March 6, 2020) (attached as Ex. 24 to Stamper Report).

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

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

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

UDAQ must analyze and impose such reasonable progress controls for oil and gas sector haze pollution.

IV. UDAQ FAILED TO ADEQUATELY RESPOND TO COMMENTS FROM THE FEDERAL LAND MANAGERS

Utah must consult with the Federal Land Managers and look to the FLMs' expertise regarding their resources and harms from air pollution to guide the state to ensure SIPs help restore natural skies.[188] The CAA and the Regional Haze Rule require states to consult with the Federal Land Managers that oversee the Class I Areas impacted by a state's sources.[189] Specifically, the state "must provide the Federal Land Manager with an opportunity for consultation, in person at a point early enough in the State's policy analyses of its long-term strategy emission reduction obligation so that information and recommendations provided by the Federal Land Manager can meaningfully inform the State's decisions on the long-term strategy."[190] The "consultation must be early enough for state officials to meaningfully consider the views expressed by the FLMs."[191]

The Regional Haze Rule requires that in "developing any implementation plan (or plan revision) or progress report, the State must include a description of how it addressed any comments provided by the Federal Land Managers.[192] The Regional Haze Rule further requires states to provide for "continuing consultation" between the state and the Federal Land Manager, and to meaningfully address the FLM's comments in the proposed SIP.[193] Thus, the FLM consultation process is not a mere box checking exercise; instead, it is a mandatory, iterative, and substantive process, requiring the state to meaningfully consider and incorporate into the SIP the concerns of the agencies responsible for managing the Class I resources impacted by pollution from the state and ensure the public has an opportunity to review and comment on those efforts.

Here, UDAQ failed to adequately respond to comments submitted to the state by the National Park Service.[194] In particular, the National Park Service submitted extensive technical comments, including revised cost analyses.[195] Those comments critiqued UDAQ's proposal to not require emissions reductions to satisfy the reasonable progress requirement for sources and critiqued UDAQ's exemption of some sources from full review.[196] NPS also identified a host of feasible, cost-effective technologies that would satisfy the reasonable progress requirement for sources.[197] While the Proposed SIP includes these comments as an appendix, Utah did not

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[188] FLMs have affirmative duties under 42 U.S.C. §§ 7492(a), (d) as well as mandates to protect and manage public lands under the Wilderness Act (16 U.S.C. §§ 1131-1136) and the Organics Act (54 U.S.C. § 100101).
[189] 42 U.S.C. § 7491(d); 40 C.F.R. § 51.308(i)(2).
[190] 40 C.F.R. § 51.308(i)(2) (emphasis added).
[191] EPA, Responses to Comments at 445, Protection of Visibility: Amendments to Requirements for State Plans; Proposed Rule, 81 Fed. Reg. 26,942 (May 4, 2016), Docket No. EPA-HQ-OAR-2015-0531 (Dec. 2016) ("Regional Haze Rule Revision Response to Comment").
[192] 40 C.F.R. § 51.308(i)(3); 40 C.F.R. § 51.308(f)(4); July 2021 Clarification Memo at 16-17.
[193] 40 C.F.R. § 51.308(i)(2); Regional Haze Rule Revision Response to Comment at 445.
[194] Proposed SIP, Appendix D.
[195] Id., PDF at 434-82.
[196] Id.
[197] See id.

substantively modify its draft Proposed SIP in response to many of these comments or provide any reasoned justification for not doing so. Thus, UDAQ must revise its Proposed SIP to respond—fully and meaningfully—to NPS's serious concerns and analysis.

V. UDAQ'S CONSULTATION WITH OTHER STATES AND TRIBES WAS FLAWED AND INCOMPLETE

A. UDAQ Failed to Properly Consult with Other States

UDAQ failed to meet its state-to-state consultation obligations, and its Proposed SIP lacks the information, documentation, and necessary enforceable measures. Instead of proper consultation with other states, Utah took an "agree to ask for nothing" approach to consultation.

EPA's regulations require that each applicable implementation plan for a state in which any mandatory Class I Federal area is located, contains such emission limits, schedules of compliance, and other measures as may be necessary to make reasonable progress toward meeting the national goal.[198] The CAA further requires states to determine the measures necessary to make reasonable progress towards preventing future, and remedying existing, anthropogenic visibility impairment in all Class I areas.[199] Thus, "Congress was clear that both downwind states (i.e., 'a State in which any [mandatory Class I Federal] area . . . is located') and upwind states (i.e., 'a State the emissions from which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area') must revise their SIPs to include measures that will make reasonable progress at all affected Class I areas."[200]

"This consultation obligation is a key element of the regional haze program. Congress, the states, the courts and the EPA have long recognized that regional haze is a regional problem that requires regional solutions. Vermont v. Thomas, 850 F.2d 99, 101 (2d Cir. 1988)."[201] Congress intended this provision of the CAA to "equalize the positions of the States with respect to interstate pollution," (S. Rep. No. 95-127, at 41 (1977)), and EPA's interpretation of this requirement accomplishes this goal by ensuring that downwind states can seek recourse from EPA if an upwind state is not doing enough to address visibility transport.[202]

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

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

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[198] 42 U.S.C. § 7491(b)(2).
[199] Id. § 7491(a)(1).
[200] 82 Fed. Reg. at 3,094.
[201] 82 Fed. Reg. at 3,085.
[202] Id.

> (A) The State must demonstrate that it has included in its implementation plan all measures agreed to during state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement.
> (B) The State must consider the emission reduction measures identified by other States for their sources as being necessary to make reasonable progress in the mandatory Class I Federal area.[203]

EPA's regulations further require that:

> Where the State has emissions that are reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another State or States, the State must consult with the other State(s) in order to develop coordinated emission management strategies.[204]

Moreover, plan revisions:

> [M]ust provide procedures for continuing consultation between the State . . . on the implementation of the visibility protection program required by this subpart, including development and review of implementation plan revisions and progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas.[205]

In its 2017 amendments to the Regional Haze Rule, EPA explained that "states <u>must</u> exchange their four-factor analyses and the associated technical information that was developed in the course of devising their long-term strategies. This information includes modeling, monitoring and emissions data and cost and feasibility studies."[206] In the event of a recalcitrant state, "[t]o the extent that one state does not provide another other state with these analyses and information, or to the extent that the analyses or information are materially deficient, the latter state should document this fact so that the EPA can assess whether the former state has failed to meaningfully comply with the consultation requirements."[207]

Finally, "[i]f a State contains sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another State" that has established reasonable progress goals that are slower than the Uniform Rate of Progress, "the State must demonstrate that there are no additional emission reduction measures for anthropogenic sources

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[203] 40 C.F.R. § 51.308(f)(2); <u>see also</u>, 64 Fed. Reg. 35,765, 35,735 (July 1, 1999) (In conducting the Four-Factor Analysis, EPA explained that "…the State <u>must</u> consult with other States which are anticipated to contribute to visibility impairment in the Class I area under consideration . . . any such State <u>must</u> consult with other States before submitting its long-term strategy to EPA.") (emphasis added).
[204] 40 C.F.R. § 51.308(f)(3)(i).
[205] <u>40 C.F.R.</u> § 51.308(f)(4).
[206] 82 Fed. Reg. at 3,088 (emphasis added).
[207] <u>Id.</u>

or groups of sources in the State."[208] To that end, the "State must provide a robust demonstration, including documenting the criteria used to determine which sources or groups or sources were evaluated and how the four factors required by paragraph (f)(2)(i) were taken into consideration in selecting the measures for inclusion in its long-term strategy."[209] In any event, "[a]ll substantive interstate consultations must be documented."[210]

UDAQ's purported state-to-state consultation fell short of these obligations. UDAQ's Proposed SIP lists its meetings with other states.[211] That list shows that Utah and other "Four corners states do not expect to require other states to enforce controls for emissions affecting their Class I Areas" and that for its consultation with Arizona, Utah and Arizona agreed that "[n]either state is looking for additional controls in the other."[212] Thus, in its communications with these states, UDAQ agreed to not request additional controls for sources in other states, such as in Arizona, impacting Utah Class I areas. UDAQ's process and results do not follow the legal requirements.[213]

UDAQ states that Appendix B and pages 149 to 150 of the Proposed SIP demonstrate it met its state-to-state consultation requirements. However, Conservation Organizations share concerns about the lack of documentation regarding what occurred at these consultation meetings given that UDAQ simply stated in its "meeting summary" of state-to-state communication that "[s]tates discussed RH modeling resources and gave progress updates. No parties identified, requested, or agreed to any measures during the meeting." Furthermore, Conservation Organizations have concerns regarding state authority to agree to "ask nothing of one another" like Utah has agreed to with other Four Corners states including Arizona. UDAQ treated the state-to-state consultation requirement as a mere box-checking exercise. Thus, UDAQ must go back and properly consult with other states and thoroughly document that consultation for public review.

B. UDAQ Failed to Properly Consult with Tribes

UDAQ's consultation with Tribes was also flawed, and the Proposed SIP does not provide sufficient information regarding those consultations. The Proposed SIP states the following Tribes are in Utah: Ute, Dine' (Navajo), Paiute, Goshute, and Shoshone.[214] UDAQ states that it "sent the regional haze SIP draft to the tribes in Utah on December 8th, 2021, concurrently with submission to EPA and FLMs for a 60-day review. UDAQ has received no

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[208] 40 C.F.R. § 51.308(f)(3)(ii)(B).
[209] Id. § 51.308(f)(3)(ii)(B).
[210] Id. § 51.308(f)(2)(ii)(C).
[211] Proposed SIP at 149-50.
[212] Id.
[213] Id.
Conservation Organizations point out that some of the impacted states have yet to provide for public notice and comment on the respective SIPs, and thus the Conservation Organizations' comments on efforts by the other states will come at a later time and are not included here.
[214] Id. at 159.

feedback from the tribes as of the submittal of this SIP."[215] UDAQ fails to provide more information regarding its outreach efforts with Tribes or share any details regarding its outreach.

UDAQ titles a section in its Proposed SIP "Coordination with Tribes" and another section "Collaboration with Tribes" yet fails to explain how collaboration or coordination occurred when it simply sent the Proposed SIP to Tribes without further engagement: coordination requires working together and collaboration requires meaningful and equal engagement.[216] Thus, UDAQ's claim that it collaborated and coordinated with Tribes appears to be both incorrect and disingenuous.

The Proposed SIP states that "sources located on tribal lands are considered federal jurisdiction" and seems to assume that this justifies what appears to be a single outreach effort to Tribes regarding the Proposed SIP.[217] This is insufficient because sources under UDAQ's jurisdiction can have impacts on Tribal lands and airsheds even if they are not on Tribal lands.

Moreover, in 2014, Utah's then-governor issued an executive order, EO/2014/005: Executive Agency Consultation with Federally-Recognized Indian Tribes that requires each state agency develop a formal tribal consultation policy to ensure Tribes have input when the state contemplates actions that have implications on Tribes.[218] When issuing the executive order, then-governor Gary R. Herbert stated that "communication, and cooperation between state agencies and Utah's tribal nations are already taking place and yielding positive results . . . . This consultation executive order will build upon these successes and shows our strong commitment to strengthening the government-to-government relationship between the state and the tribes."[219] The executive order defines "consultation" to mean "the process by which the State and the Tribes may have the opportunity to exchange views and information, in writing or in person, regarding implementation of proposed state action that has, or may have, substantial tribal implications, such as impacts on . . . tribal lands [and] tribal resources[.]"[220] UDAQ's lack of cooperation with Tribes does not appear to meet this commitment.

UDAQ's Proposed SIP involved the agency formulating or implementing policies or administrative rules that have direct tribal implications. UDAQ is the agency charged with drafting the Proposed SIP and sources covered in the Proposed SIP may impact tribal air quality. UDAQ has a duty to <u>meaningfully</u> consult with Tribes and failed to do so. It must rectify this failure and meaningfully consult Tribes prior to finalizing the state's SIP.

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[215] <u>Id.</u>
[216] Coordination is defined as "the process of organizing people or groups so that they work together properly and well." <u>Coordination</u>, Merriam-Webster Dictionary, https://www.merriam-webster.com/dictionary/coordination (last visited May 29, 2022).
[217] Proposed SIP at 34.
[218] EO/2014/005: Executive Agency Consultation with Federally-Recognized Indian Tribes.
[219] Utah Division of Indian Affairs, https://indian.utah.gov/resources/state-agency-liaisons/ (last visited May 29, 2022).
[220] EO/2014/005: Executive Agency Consultation with Federally-Recognized Indian Tribes.

VI. UDAQ'S LONG-TERM STRATEGY IS INCONSISTENT WITH LEGAL REQUIREMENTS

A. UDAQ Must First Conduct the Required Four-Factor Analyses and Then Develop Its Reasonable Progress Goals

As drafted, Utah's reasonable progress goals are based on modeling results that do not reflect the outcome of requirements in adequate Four-Factor Analyses and therefore do not meet the Regional Haze Rule requirement that the RPGs are to be based on enforceable SIP measures. Specifically, Utah's proposed long-term strategy sets reasonable progress goals based on the WRAP's modeling results <u>before and in lieu of</u> conducting the required Four-Factor Analysis—it has impermissibly reversed the order of the requirements. The RPGs are not to be developed <u>before</u> the Four-Factor Analyses but <u>as a result of</u> the Four-Factor Analyses.[221] UDAQ must first conduct the Four-Factor Analyses, determine measures for reducing visibility impairing emissions based on the Act's Four-Factor Analysis and then use the results to develop proposed revisions to the RPGs.

B. UDAQ Must Establish and Provide a Basis for a Cost Effectiveness Threshold.

UDAQ has not clearly provided a reasoned basis for rejecting the adoption of additional regional haze controls for the second planning period because it has not defined a cost effectiveness threshold. In its Proposed SIP, UDAQ determined that additional controls were not necessary for most sources for its long-term strategy—other than the source shutdowns/retirements, or unenforceable emission decreases.[222] UDAQ did not define any cost effectiveness threshold to decide whether the costs of the controls evaluated were cost effective. And while the Clean Air Act does not mandate that UDAQ "explain its cost-effectiveness decisions through use of a 'bright line' rule," the Ninth Circuit explained that "the law does require EPA to cogently explain why it has exercised its discretion in a given manner."[223] Absent such an explanation, UDAQ's reasonable progress analyses are arbitrary.

UDAQ discounted cost-effective controls—which are already inflated due to use of too high of an interest rate and too short equipment life, discussed above—without explaining why. To provide a reasoned basis for its decisions, UDAQ must first establish a cost-effectiveness threshold or explain and justify some other objective measure for requiring reasonable progress that is in line with other states. As NPS noted in its comments:

> Many of the controls identified in the four-factor analyses for Utah sources are cost-effective based on cost criteria/thresholds identified by other states. For example, other states have set the following cost-effectiveness thresholds in their draft proposals:

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[221] <u>See e.g.</u>, 82 Fed. Reg. at 3090-91.
[222] Proposed SIP at 147-48.
[223] <u>Nat'l Parks Conservation Ass'n v. E.P.A.</u>, 788 F.3d 1134, 1142–43 (9th Cir. 2015) (citation and quotation omitted).

- $5,000/ton in Arkansas (EGUs) and Texas
- $6,100/ton in Idaho
- $10,000/ton in Colorado and Oregon
- A range between $5,000 to $10,000/ton in Nevada
- A range between $4,000 to $6,500/ton in Arizona[224]

C. UDAQ Must Include Enforceable Emission Limitations in Its SIP Where It Relies on Retirements to Justify No Controls and No Upgrades.

As discussed elsewhere in these comments and in the Stamper Report, where UDAQ is either relying on—or plans to rely on—retirements or operation changes to justify a no control and no upgrade option, it must make those changes enforceable as SIP measures. UDAQ states that the electricity generation industry is experiencing significant change and that there is great uncertainty in the near and medium-term operation of the Hunter and Huntington units, but UDAQ cannot rely on headwinds to the electric generation industry as a basis for rejecting emissions controls.

To the extent that a state declines to evaluate additional pollution controls for any source based on that source's planned retirement or decline in utilization, it must incorporate those operating parameters or assumptions as enforceable limitations in the second planning period SIP. The CAA requires that "[e]ach state implementation plan . . . shall" include "enforceable limitations and other control measures" as necessary to "meet the applicable requirements" of the CAA.[225] The Regional Haze Rule similarly requires each state to include "enforceable emission limitations" as necessary to ensure reasonable progress toward the national visibility goal.[226] Moreover, where a source plans to permanently cease operations or projects that future operating parameters (e.g., limited hours of operation or capacity utilization) will differ from past practice, and if this projection affects whether additional pollution controls are cost-effective or necessary to ensure reasonable progress, then the state "must" make those parameters or assumptions into enforceable limitations.[227]

Underscoring this requirement of enforceability, reasonable progress goals adopted by a state with a Class I area must be based only on emission controls measures that have been adopted and are enforceable. Thus, where UDAQ has relied on any proposed retirements or operation changes as part of its long-term strategy to ensure reasonable progress, the agency must, at a minimum, make those retirement decisions federally enforceable with compliance deadlines for retirement by the end of the second planning period.

Further, even where a source has a federally enforceable retirement date, UDAQ is obligated to consider whether there are cost-effective control measures that could be implemented in the meantime. As discussed elsewhere in these comments, UDAQ should set an

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[224] Proposed SIP at Appendix D, PDF page 437.
[225] 42 U.S.C. § 7410(a)(2)(A) (emphasis added).
[226] See generally 40 C.F.R. § 51.308(d)(3).
[227] See 40 C.F.R. pt. 51, App. Y § (IV)D.4.d.2.

enforceable shut down date of December 31, 2021 for the Intermountain Generation Station and should require emission control measures prior to the facility's shut down. Once again, EPA's Clarification Memo is instructive. There, the agency made clear that in evaluating reasonable progress for all sources, states should consider the "full range of potentially reasonable options for reducing emissions . . . [that] may be able to achieve greater control efficiencies, and, therefore, lower emission rates, using their existing measures."[228] As mentioned throughout these comments, there are some types of control measures that are likely to be cost-effective even within shorter timeframes.

D. UDAQ's Cannot Avoid Addressing Oil and Gas Sector Reduction Requirements Through an Ozone SIP.

UDAQ's reliance on an ozone SIP to avoid addressing emissions from the oil and gas sector in its Proposed SIP, contradicts Regional Haze Rule and Clean Air Act requirements. As discussed above, because the oil and gas sector is a significant contributor to regional haze pollution in Utah and in the region, UDAQ must consider oil and gas sector emissions. An ozone SIP does not replace the requirement that UDAQ must give sufficient consideration of area sources, including oil and gas area sources, and how those sources contribute to impairment both in-state and out-of-state. Therefore, UDAQ must revise its Proposed SIP to require statewide NOx requirements for flaring, engines, and other oil and gas sector sources

E. UDAQ's Anticipated Additional Emissions Reductions from "Ongoing Pollution Control Programs" Are Neither Justified Nor Secured by Enforceable SIP Measures.

UDAQ's anticipated additional emissions reductions from "Ongoing Pollution Control Programs" are neither justified nor secured by enforceable SIP measures. UDAQ identifies multiple federal and state control programs aimed at reducing emissions across various sectors.[229] UDAQ fails to provide the details and quantify emission reductions from these ongoing programs, and lacking this required information, UDAQ cannot take credit for "other programs" that are unsupported and not quantified.

F. UDAQ's Proposed SIP Does Not Contain Provisions to Ensure Emission Limitations Are Permanent and Enforceable and That Permits <u>Complement</u> the Clean Air Act's Reasonable Progress Requirements.

The Clean Air Act requires states to submit implementation plans that "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal" of achieving natural visibility conditions at all Class I areas.[230] The Regional Haze Rule requires that states must revise and update their regional haze SIPs, and the "periodic comprehensive revisions" must include the "enforceable emissions limitations, compliance schedules, and other measures that are necessary to make

[228] 2021 Clarification Memo at 7.
[229] Proposed SIP at 285.
[230] 42 U.S.C. §§ 7491(a)(1), (b)(2).

reasonable progress as determined pursuant to [40 C.F.R. § 51.308](f)(2)(i) through (iv)."[231] The emission limitations and other requirements of the Regional Haze Rule must be adopted into the SIP. Furthermore, under the Regional Haze Rule, RPGs adopted by a state with a Class I area must be based only on emission controls measures that have been adopted and are enforceable in the SIP.[232]

There are several issues with UDAQ's proposed approach. First, as discussed above, its Proposed SIP does not meet the Regional Haze Rule requirement that the RPGs are based on enforceable SIP measures.[233] This does not fulfill the legal requirements. Consistent with EPA's longstanding positions regarding enforceable SIP provisions, EPA's 2019 Guidance explains the requirements in 40 C.F.R. § 51.308(d)(3)(v)(F), which:

> [R]equires SIPs to include enforceable emission limitations and/or other measures to address regional haze, deadlines for their implementation, and provisions to make the measures practicably enforceable including averaging times, monitoring requirements, and record keeping and reporting requirements.[234]

Moreover, the reasonable progress requirements apply to all sources, thus to the extent UDAQ plans to, it must not rely on existing permits to allow sources to avoid the Four-Factor Analysis because there is no off-ramp for sources that hold permits. EPA's Guidance recognizes EPA's long-standing position that while the SIP is the basis for demonstrating and ensuring state plans meet the regional haze requirements, state-issued permits must complement the SIP and SIP requirements.[235] State-issued permits must not frustrate SIP requirements.[236] For example, sources with Prevention of Significant Deterioration ("PSD") permits under Title I must not hold permits that allow emissions that conflict with SIP requirements.[237]

Additionally, the Act's Title V operating permits collect and implement all the Act's requirements—including the requirements in the SIP—as applicable to the particular permittee. Furthermore, Title V permits are only good for a period of five years and may expire under certain conditions. There is no assurance that Title V permit terms and conditions will be

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[231] 40 C.F.R. § 51.308(f)(2); 40 C.F.R. § 51.308(d)(3)(v)(F) (enforceability of emission limitations and control measures).
[232] 40 C.F.R. § 51.308(f)(3).
[233] See, e.g., Stamper Report at 7.
[234] 2019 Guidance at 42-43. (While NPCA filed a Petition for Reconsideration regarding EPA's issuance of the 2019 Guidance, it does not dispute the information in the Guidance referenced here regarding enforceable limitations, which cite to EPA's longstanding statements found in the "General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990," 74 Fed. Reg. 13,498 (April 16, 1992)).
[235] 74 Fed. Reg. 13,498, 13,568 (April 16, 1992).
[236] Furthermore, to the extent stationary sources are granted permits by rule or other mechanisms, these other categories of state approval mechanisms that allow construction, operation, and increases in emissions must also complement SIP requirements.
[237] Additionally, the proposed SIP revisions fail to contain source-specific "measures to mitigate the impacts of construction activities." 40 C.F.R. § 51.308(d)(3)(v)(B).

permanent since they may lapse. It is not enough that the Title V permits are reviewable by EPA, Title V permits are <u>not</u> part of the SIP and <u>not</u> approved through EPA's SIP process. Therefore, to the extent UDAQ relies on Title V or other permits for its sources under the regional haze program, those emission limitations and monitoring, recordkeeping, and reporting requirements must be in the SIP. Finally, Title V permittees must not hold such permits if they contain permit terms and conditions that conflict with the SIP and CAA requirements, which could happen here in the event the permits UDAQ relies on are Title V permits.

Of significant concern is that UDAQ's Proposed SIP lacks the required "enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress" and would therefore allow the sources to modify operations, increase emissions that impact Class I areas for many years without first meeting reasonable progress emission limitations and other necessary requirements. Contrary to the requirement to ensure permits complement the SIP, UDAQ's proposed SIP does not contain the enforceable emissions limitations, monitoring, recordkeeping, and reporting requirements consistent with the statements in the Proposed SIP and assumptions used in preparing and generating the 2028 emission inventory. UDAQ must include in its SIP the emission limitations from the permits it relies on for its reasonable progress SIP, along with the required monitoring, recordkeeping, and reporting provisions necessary to make the limitations practically enforceable.

VII. UDAQ MUST ANALYZE ENVIRONMENTAL JUSTICE IMPACTS OF ITS REGIONAL HAZE SIP, AND SHOULD ENSURE THE SIP WILL REDUCE EMISSIONS AND MINIMIZE HARMS TO DISPROPORTIONATELY IMPACTED COMMUNITIES

UDAQ has both state and federal obligations to meaningfully consider and advance environmental justice in its regional haze SIP. The same sources of pollution causing haze in our national parks are also disproportionately affecting communities near those sources. State agencies and the EPA can and should consider the benefit that controls on haze-causing sources have for disproportionately affected communities and ensure that those benefits are considered and prioritized in developing implementation plans. Unfortunately, the Proposed SIP entirely ignores environmental justice concerns, contrary to EPA guidance.

A. UDAQ Disregarded Communities Impacted by Utah's Polluting Sources.

Utah's air pollution sources that harm Class I area visibility also harm air quality in the communities where they are located, especially in areas affected by environmental justice concerns. By evaluating the vulnerable communities and counties impacted by these sources, we believe UDAQ would identify emission-reducing options that could improve air quality and help achieve reasonable progress in this round of regional haze rulemaking. Historically, conservation and environmental work has concerned itself with protecting nature from people and has thus "siloed" its work (e.g., mainstream conservation vs. environmental justice). While this siloed approach has led to the protection of many vulnerable habitats, it ignores the reality that people live in concert with and are a part of nature; to protect one and not the other is a job half done. The paradigm of human and nature as separate is incompatible with holistic environmental work. By considering viewshed protection and environmental justice at the same time, we can collectively begin to dismantle the silos that exist in conservation and environmental work and chart a new path forward that is inclusive of needs for all communities.

B. UDAQ Can Facilitate EPA's Consideration of Environmental Justice To Comply with Federal Executive Orders.

There are specific legal grounds for considering environmental justice when determining reasonable progress controls. Under the Clean Air Act, states are permitted to include in a SIP, measures that are authorized by state law but go beyond the minimum requirements of federal law.[238] Ultimately, EPA will review the Final Haze Plan that Utah submits, and EPA will be required to ensure that its action on Utah's Haze Plan addresses any disproportionate environmental impacts of the pollution that contributes to haze. Executive Orders in place since 1994, require federal executive agencies such as EPA to:

> [M]ake achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations[239]

On January 27, 2021, the current Administration signed "Executive Order on Tackling the Climate Crisis at Home and Abroad."[240] The new Executive Order on climate change and environmental justice amended the 1994 Order and provides that:

> It is the policy of [this] Administration to organize and deploy the full capacity of its agencies to combat the climate crisis to implement a Government-wide approach that reduces climate pollution in every sector of the economy; . . . protects public health . . . delivers environmental justice . . . [and that] . . . [s]uccessfully meeting these challenges will require the Federal Government to pursue such a coordinated approach from planning to implementation, coupled with substantive engagement by stakeholders, including State, local, and Tribal governments.[241]

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

[239] Exec. Order No. 12898, § 1-101, 59 Fed. Reg. 7629 (Feb. 16, 1994), as amended by Exec. Order No. 12948, 60 Fed. Reg. 6381 (Feb. 1, 1995).

[240] Exec. Order No. 14008, 86 Fed. Reg. 7619 (Jan. 27, 2021).

[241] Id. § 201.

Utah can facilitate EPA's compliance with these Executive Orders by considering environmental justice in its SIP submission.

C. UDAQ Ignores EPA's Regional Haze Guidance and Clarification Memo, Which Direct States To Take Environmental Justice Concerns and Impacts into Consideration.

EPA's 2021 Clarification Memo directs states to take into consideration environmental justice concerns and impacts in issuing any SIP revision for the second planning period.[242] EPA's 2019 Regional Haze Guidance for the Second Planning Period specifies, "States may also consider any beneficial non-air quality environmental impacts."[243] This includes consideration of environmental justice in keeping with other agency policies. For example, EPA also pointed to another agency program that states could rely upon for guidance in interpreting how to apply the non-air quality environmental impacts standard:

> When there are significant potential non-air environmental impacts, characterizing those impacts will usually be very source- and place-specific. Other EPA guidance intended for use in environmental impact assessments under the National Environmental Policy Act may be informative, but not obligatory to follow, in this task.[244]

Additionally, a collection of EPA policies, guidance and directives related to the National Environmental Policy Act ("NEPA") is available at https://www.epa.gov/nepa/national-environmental-policy-act-policies-and-guidance. One of these policies concerns environmental justice.[245] UDAQ should consider these sources of information in conducting a meaningful environmental justice analysis.

D. EPA Has a Repository of Directives and Material Available for UDAQ to Use in Considering Environmental Justice.

In addition to the NEPA guidance directives referenced above, EPA provides a wealth of additional material.[246] The most important aspect of assessing environmental justice is to identify the areas where people are most vulnerable or likely to be exposed to different types of pollution. EPA's EJSCREEN tool can assist in that task. The tool uses standard and nationally

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[242] 2021 Clarification Memo at 16.
[243] 2019 Guidance at 49.
[244] Id. at 33.
[245] See EPA, "EPA Environmental Justice Guidance for National Environmental Policy Act Reviews," https://www.epa.gov/nepa/environmental-justice-guidance-national-environmental-policy-act-reviews (last visited May 29, 2022).
[246] See EPA, "Learn About Environmental Justice," https://www.epa.gov/environmentaljustice/learn-about-environmental-justice (last visited May 29, 2022).

consistent data to highlight places that may have higher environmental burdens and vulnerable populations.[247]

E. EPA Must Consider Environmental Justice When It Reviews and Takes Action on Utah's SIP.

If a state fails to submit a SIP on time, or if EPA finds that all or part of a state's SIP does not satisfy the Regional Haze regulations, then EPA must promulgate its own Federal Implementation Plan to cover the SIP's inadequacy. Should EPA promulgate a FIP that reconsiders a state's Four-Factor Analysis, it is completely free to reconsider any aspect of that state' analysis. The two Presidential Executive Orders referenced above require that federal agencies integrate environmental justice principles into their decision-making. EPA has a lead role in coordinating these efforts, and recently EPA Administrator Regan directed all EPA offices to clearly integrate environmental justice considerations into their plans and actions.[248] Consequently, should EPA promulgate a FIP for Utah sources, it has an obligation to integrate environmental justice principles into its decision-making. The non-air quality environmental impacts of compliance portion of the third factor, is a pathway for doing so.

F. UDAQ Must Consider Environmental Justice Under Title VI of the Civil Rights Act.

As EPA must consider environmental justice, so must UDAQ and all other entities that accept federal funding. Under Title VI of the Civil Rights Act of 1964, "no person shall, on the ground of race, color, national origin, sex, age or disability be excluded from participation in, be denied the benefits of, or be subjected to discrimination under any program or activity . . . ." UDAQ has an obligation to ensure the fair treatment of communities that have been environmentally impacted by sources of pollution. That means going beyond the flawed analysis conducted and ensuring "meaningful involvement" of impacted communities. Environmental justice also requires the "fair treatment" of these communities in the development and implementation of agency programs and activities, including those related to the SIP.

UDAQ must conduct a thorough analysis of the current and potential effects to impacted communities from sources considered in the SIP as well as those sources identified by commenters and other stakeholders but not reviewed by UDAQ. By not conducting this analysis and failing to include the benefits of projected decline in emissions to these communities in its determination of the included emission sources, UDAQ is not fulfilling its obligations under the law. Moreover, the state is making a mockery of Title VI by not using the SIP requirements to

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[247] See EPA, "EPA EJSCREEN: Environmental Justice Screening and Mapping Tool, Additional Resources and Tools Related to EJSCREEN," https://www.epa.gov/ejscreen/additional-resources-and-tools-related-ejscreen (last visited May 25, 2022).
[248] See EPA News Release, "EPA Administrator Announces Agency Actions to Advance Environmental Justice, Administrator Regan Directs Agency to Take Steps to Better Serve Historically Marginalized Communities" (April 7, 2021), https://www.epa.gov/newsreleases/epa-administrator-announces-agency-actions-advance-environmental-justice (last visited May 25, 2022).

bring about the co-benefits of stronger reductions measures and reduce harms based on continued emissions.

G. UDAQ's Disregard of Environmental Justice Fails To Protect People Living in Communities Affected by Utah's Sources.

Utah's Proposed SIP lacks any meaningful consideration of environmental justice. UDAQ simply stated in the Proposed SIP that "[i]n order to further the environmental justice initiative in Utah, UDAQ shared its RH SIP draft with the tribes of Utah[.]"[249] UDAQ misunderstands that a meaningful consideration of environmental justice requires a thorough analysis of the current and potential effects to impacted communities from sources considered in the SIP as well as those sources identified by commenters and other stakeholders but not reviewed by UDAQ. Simply sharing its Proposed SIP with Tribes of Utah is insufficient and demonstrates a misunderstanding of the purpose of thoroughly assessing and addressing environmental justice impacts. UDAQ must review any sources that impact Utah's vulnerable communities and overburdened areas throughout the state. UDAQ's Proposed SIP also fails to include enforceable emission limitations for the polluting sources that impact these communities. Consistent with the legal requirements, government efficiency, and the years of injustice these communities have been subjected to from Utah's sources, we urge UDAQ to fully and meaningfully consider all sources that impact these communities in environmental justice areas. In establishing emission limitations in its SIP, UDAQ must reduce impacts at both the Class I areas and overburdened areas affecting vulnerable communities.

CONCLUSION

When viewed as a whole, the Utah Proposed SIP fails to meet the intent, purpose, and direction of the Clean Air Act. Of the sources UDAQ selected for review, UDAQ improperly concludes that no new reductions in pollution are warranted for most of Utah's sources, or retirement commitments such as at PacifiCorp's Hunter and Huntington coal-fired power plants. As a result, significant amounts of SO2, NOx and PM will continue to be released into the air without further controls for the next decade, affecting national parks, wilderness areas, and communities throughout the region. As drafted, the Proposed SIP does not meet the reasonable progress goals requirement of the Regional Haze Rule and does not comply with the Clean Air Act. Even though pollution control tools exist to address regional haze causing sources in Utah and those pollution controls are cost-effective and would otherwise satisfy a Four-Factor Analysis, Utah has chosen to halt the progress on reducing regional haze in our national parks and wilderness areas—while ignoring serious harms to vulnerable communities—by not requiring new reductions in pollution. The Conservation Organizations urge UDAQ to reassess its determination not to require new pollution reduction from sources in the Utah Proposed SIP, to ensure that it is on the path of reasonable progress to natural conditions in Class I areas by 2064 as set forth in these comments.

Thank you for the opportunity to submit comments and please do not hesitate to contact the undersigned with any questions.

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[249] Proposed SIP at 34.

Sincerely,

Stephanie Kodish
Senior Director and Counsel
Clean Air and Climate Programs
National Parks Conservation Association
706 Walnut Street, Suite 200
Knoxville, TN 37919
865.329.2424
skodish@npca.org

Gloria D. Smith
Managing Attorney
Sierra Club Environmental Law Program
2101 Webster Street, Suite 1300
Oakland, CA 94612
gloria.smith@sierraclub.org

Michael B. Murray
Chair
Coalition to Protect America's National Parks
2 Massachusetts Avenue NE, Unit 77436
Washington, DC 20013
editor@protectnps.org

Jonny Vasic
Executive Director
Utah Physicians for a Healthy Environment
423 W 800 S, Suite A108
Salt Lake City, UT 84101
jvasic@uphe.org

Eliza Cowie
Policy Director
O2 Utah
357 S 200 E, #312
Salt Lake City, UT 84111
eliza@o2utah.org

Lexi Tuddenham
Executive Director
Healthy Environment Alliance of Utah
824 400 W, #111
Salt Lake City, UT 84101
lexi@healutah.org

/s/ Emily Qiu
Emily Qiu
Jenny Harbine
Earthjustice
Northern Rockies Office
313 East Main Street
P.O. Box 4743
Bozeman, MT 59772-4743
406.426.9625
eqiu@earthjustice.org
jharbine@earthjustice.org

Exhibit A

Review and Comments on
Reasonable Progress Four-Factor Analyses
for Sulfur Dioxide and Nitrogen Oxide Pollution Controls
Evaluated as Part of the Utah Regional Haze Plan
for the Second Implementation Period

By Victoria R. Stamper

May 27, 2022

Prepared for
National Parks Conservation Association,
Sierra Club, and Earthjustice

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I. Introduction

The Clean Air Act's regional haze provisions require states to adopt periodic, comprehensive revisions to their implementation plans for regional haze on 10-year increments to achieve reasonable progress towards the national visibility goal. The deadline for the regional haze plan revision for the second implementation period to be submitted to EPA was July 31, 2021.[1] As part of the comprehensive revisions to their regional haze plan, states must submit a long-term strategy that includes enforceable emission limits and other measures as may be necessary to make reasonable progress towards the national visibility goal.[2]

To that end, in April of 2022, the Utah Division of Air Quality (UDAQ) made available its plan for addressing reasonable progress toward the national visibility goal for Class I areas.[3] UDAQ selected sources for review based on two criteria: 1) those facilities with a "Q/d" value (i.e., total of NOx, SO2, + PM emissions in tons per year (tpy) divided by distance to nearest Class I area in kilometers (km)) greater than or equal to 6.[4] 2) UDAQ narrowed down the list of sources to undergo a four-factor analysis of controls "based on current emissions, projected emissions in 2028, closure and controls put in place after the 2014 base year inventory."[5] Using these criteria, UDAQ identified six facilities for which it required four-factor analyses of regional haze controls.[6] After review and evaluation of the companies' four-factor analyses of control, UDAQ has proposed to adopt as part of its regional haze plan a) 12-month rolling plantwide limits on NOx emissions for the Hunter power plant and for the Huntington Power Plants that essentially reflect current NOx emissions, b) SO2 emission limits that current apply to each Hunter and Huntington electrical generating unit (EGU) under their current air permits, c) a requirement that the 60 MMBtu/hour Riley boiler at the US Magnesium Rowley Plant install flue gas recirculation to reduce NOx emissions by 50% to meet a 12-month rolling total NOx limit of 22.6 tons per 12-month period, and d) a requirement that the Intermountain Generating Station cease operation of and permanently close coal-fired Units #1 and #2 by January 31, 2028.[7]

The four factors that must be considered in determining appropriate emissions controls for the second implementation period are as follows: (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of any source being evaluated for controls.[8] EPA has stated that it anticipates the

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[1] 40 C.F.R. §51.308(f).

[2] 40 C.F.R. §51.308(f)(2)(i); 42 U.S.C. § 7491(b)(2). Under the Clean Air Act, state implementation plans must include "include enforceable emission limitations and other control measures, means, or techniques . . . , as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of this chapter." 42 U.S.C. § 7491(a)(2)(A). An emission limitation is a "requirement" that "limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction." *Id*. § 7602(k).

[3] April 2022 Utah State Implementation Plan, Regional Haze Second Implementation Period, Section XX.A. (hereinafter referred to as April 2022 Draft Utah Regional Haze Plan").

[4] *Id.* at 93

[5] *Id.* at 94.

[6] *Id.* at 93-95.

[7] Utah State Implementation Plan, Emission Limits and Operating Practices, Section IX, Part H.23.

[8] 40 C.F.R. §51.308(f)(2)(i).

cost of controls being the predominant factor in the evaluation of reasonable progress controls and that the other factors will either be considered in the cost analysis or not be a major consideration.[9] Specifically, the remaining useful life of a source is taken into account in assessing the length of time the pollution control will be in service to determine the annualized costs of controls. If there are no enforceable limitations on the remaining useful life of a source, the expected life of the pollution control is generally considered the remaining life of the source.[10] In addition, costs of energy and water use of regional haze controls such as wet and dry flue gas desulfurization (FGD), selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR) at a particular source are considered in determining the annual costs of these controls, which means that the bulk of the non-air quality and energy impacts are generally taken into account in the cost effectiveness analyses as is the remaining useful life of a unit. The length of time to install controls is not generally an issue of concern for pollution controls, as FGD systems, SCR, and SNCR all can be and have been installed within three to five years of promulgation of a requirement to install such controls.[11] In any event, EPA's August 20, 2019 regional haze guidance states that, with respect to controls needed to make reasonable progress, the "time necessary for compliance" factor does not limit the ability of EPA or the states to impose controls that might not be able to be fully implemented within the planning period; more specifically, when considering the time necessary for compliance, a state may not reject a control measure because it cannot be installed and become operational until after the end of the implementation period."[12]

This report evaluates the four-factor analyses of pollution controls for the following facilities: Hunter Power Plant, Huntington Power Plant, Intermountain Generating Station, Sunnyside Cogeneration Facility, Kennecott Utah Copper LLC – Mine and Copperton Concentrator, Kennecott Utah Copper LLC – Power Plant, Lab, and Tailings Impoundment, Graymont Western- Cricket Mountain Lime Plant, US Magnesium LLC – Rowley Plant, Ash Grove – Leamington Cement Plant, Holcim Devils Slide Cement Plant, and the Lisbon Gas Processing Plant. In brief, this report finds the following issues with the four-factor analyses for these facilities:

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[9] *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 37.

[10] *Id.* at 33. While we are aware that some EGUs evaluated in this report have planned decommission dates, we are not aware that any of those dates are enforceable. Thus, for all of the EGUs evaluated for add-on NOx controls in this report, we assumed that the expected useful life of the pollution control being evaluated was the remaining useful life of the source, as directed to by EPA in its August 2019 guidance.

[11] For example, in Colorado, SCR was operational at Hayden Unit 1 in August of 2015 and at Hayden Unit 2 in June of 2016, according to data in EPA's Air Markets Program Database, within 3.5 years of EPA's December 31, 2012 approval of Colorado's regional haze plan. In Wyoming, SCR was operational at Jim Bridger Units 3 and 4 in 2015 and 2016, less than three years from EPA's January 30, 2014 final approval of Wyoming's regional haze plan. In addition, FGDs were installed in 3-4 years from design to operation at several coal-fired power plants, including Dan E Karn Units 1 and 2, Gallatin Units 1-4, Homer City Units 1 and 2, JH Campbell Units 2 and 3, La Cygne Units 1 and 2, Michigan City Unit 12, and RM Schahfer Units 14 and 15. As will be discussed below, SNCR installation are much less complex than SCR and FGD, requiring primarily a sorbent storage and distribution system and boiler/ductwork injection ports, and thus installation of SNCR will take less time than FGD and SCR.

[12] *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 41 (it would be inconsistent with the regional haze regulations to discount an otherwise reasonable control "simply because the time frame for implementing it falls outside the regulatory established implementation period.").

PacifiCorp – Hunter and Huntington Power Plants

- PacifiCorp's "Reasonable Progress Emission Limits" (RPELs) are not justified as reasonable haze control measures because they will not result in a reduction in actual emissions from the Hunter and Huntington Plants.
- PacifiCorp's cost effectiveness analyses of SCR shows that SCR should be considered a cost-effective control for Hunter Units 1-3 and Huntington Units 1 and 2, based on the fact that several other states have used similar or higher cost effectiveness thresholds in their regional haze plans for the second implementation period and also based on the fact that PacifiCorp's SCR cost estimates do not indicate any usual costs of SCR installation at the Hunter and Huntington units compared to the many other coal-fired EGUs that have installed SCR.
- PacifiCorp's cost effectiveness analyses likely understated the cost effectiveness of SCR by not evaluating a controlled annual NOx emission rate of 0.04 lb/MMBtu which has been achieved at several EGUs with SCR.
- PacifiCorp's cost effectiveness analyses did use a high interest rate of 7.303% based on the average weighted cost of capital that has been approved by several utility commissions where PacifiCorp does business, but PacifiCorp has not provided the background to how the cost of capital was calculated and so it cannot be confirmed whether the 7.303% is consistent with the EPA Control Cost Manual methodology.
- Revised SCR cost effectiveness analyses based on the current bank prime rate of 4% but otherwise using all of PacifiCorp's site-specific cost estimates show that SCR would have a cost effectiveness ranging from $2,500/ton to $3,600/ton.
- Thus, UDAQ should find that SCR is cost effective and require SCR to make reasonable progress towards the national visibility goal, rather than simply proposing to adopt emission limits reflective of current emission rates as has been proposed by UDAQ.

Intermountain Generation Station

- UDAQ has proposed a regional haze requirement that the coal-fired units at the Intermountain Generating Station cease operation by December 31, 2027. However, the facility is in the process of getting a permit to construct a new combined cycle power plant at the site which has been proposed to avoid major new source review permitting by taking credit for the emission reductions from shutting down the existing coal-fired units. UDAQ should revise its proposed regional haze requirement to mandate that the Intermountain Generation Station Units #1 and #2 permanently close and cease operation by no later than December 31, 2025 to be consistent with its proposed permitting action for the new combined cycle units.

- UDAQ should also impose requirements on the new combined cycle units to minimize regional haze-impairing emissions, including a requirement to burn no more than 70% of its fuel from natural gas and the remainder from hydrogen, consistent with the company's plans.

Sunnyside Cogeneration Facility

- The company eliminated dry sorbent injection (DSI) (i.e., injection of sorbent into the ductwork between the air heater and the baghouse) as not technically feasible for the CFB boiler but did not provide support for that claim. DSI with lime to achieve 50% control would be cost effective at costs of $3,169/ton and could reduce SO2 emissions by 236 tons per year.

- The company's cost estimates of a circulating dry scrubber (CDS) and also of SCR and SNCR included an unjustified retrofit factor to increase costs by 30%, used an interest rate of 7% instead of the current bank interest rate of 4%, and assumed too short of a life of controls.

- Revised cost effectiveness analyses show the costs of CDS at Sunnyside's CFB boiler would be around $10,300/ton based on current SO2 emissions, but that would reduce to around $7,400/ton if higher sulfur coal is used. Thus, if in the future, the unit will be burning as high of sulfur coal as it had in the past ten years, then CDS should be considered as the superior SO2 control to DSI.

Kennecott Utah Copper – Mine and Copperton Concentrator

- UDAQ should consider requirements to incentivize the replacement of existing nonroad engines at this facility, which are the bulk of the NOx emissions from this facility, with Tier 4 engines. Tier 4 engines have been available since 2008 and have significantly lower NOx and PM emissions.

Kennecott Utah Copper LLC – Power Plant, Lab, and Tailings Impoundment

- Because UDAQ is relying on the closure of Units 1-4 of the power plant to exempt this facility from a four-factor analysis. UDAQ should impose a requirement in the Utah regional haze SIP stating that Units 1-4 of Kennecott Utah Copper LLC Power Plant shall remain permanently closed, because it is not clear that the permit mandates permanent closure of Unit 4.

Graymont Western- Cricket Mountain Lime Plant

- UDAQ should more fully evaluate selective noncatalytic reduction (SNCR) for NOx removal at Kiln 5 of the Cricket Mountain plant at a NOx removal efficiency of at least 35%, including an evaluation of whether the SNCR technology used at similar kilns is a proprietary control as speculated by Graymont Western.

- UDAQ should also evaluate the use of catalytic ceramic filtration bags in the existing baghouse to reduce NOx from the lime kilns by up to 90%, as this would reduce NOx to a much greater extent than SNCR.

US Magnesium LLC – Rowley Plant

- US Magnesium should not have eliminated use of SCR at the gas turbines as not technically feasible with the operation of the lime spray dryer that uses the hot exhaust from the gas turbines for spray drying magnesium chloride slurry to magnesium chloride power. UDAQ and US Magnesium should have evaluated placing SCR downstream of the spray dryer where the temperature of the flue gas either would be low enough for SCR operation or could be lowered with cooling air skids and where it would not interfere with the magnesium production process. SCR, which is widely used at gas turbines, could reduce NOx by 90% from the gas turbines that emit over 800 tons per year at the Rowley Plant.

- UDAQ did not fully evaluate whether ultra-low NOx burners could be retrofit to the Riley boiler or whether low NOx burners plus flue gas recirculation (FGR) could be used at Riley boiler, both of which could achieve up to 90% NOx reduction. Cost effectiveness of 90% control with SCR at the Riley boiler was calculated incorrectly and should be $4,800/ton which should be considered cost effective given what other states are considering as cost effective in their second round regional haze plans. While UDAQ has proposed to require FGR at the Riley boiler to achieve 50% control, these other controls could reduce NOx by 90% control and would likely also be cost effective.

- UDAQ should evaluate other options to reduce NOx from the numerous diesel engines used at the Rowley Plant including electrification of the engines, replacing older Tier 0 engines with much lower emitting Tier 4 engines, and replacing diesel engines with lower emitting natural gas-fired engines. Further, the evaluation of SCR was flawed because it was for an average size and emissions engine used at the facility, instead of focusing on the specific engines with the highest emission rates and higher operating hours at the plant.

<u>Ash Grove – Leamington Cement Plant</u>

- UDAQ should consider imposing a limit on SO_2 emissions from the cement kiln that is more consistent with the current actual emissions of 8.0 tons per year, given that the permit allows the cement kiln to emit as much as 192.5 tons per year

- More information should be collected on the NOx removal efficiency being achieved by the existing SNCR at the cement kiln to fully evaluate whether the NOx removal efficiency can be improved with the SNCR system.

- An estimate of cost effectiveness for use of Tri-Mer catalytic ceramic filtration bags for the Leamington cement kiln shows that they would be very cost effective at $2,540/ton of NOx removed and could improve NOx removal efficiency to 90% control. Thus, UDAQ should more fully evaluate this control option.

<u>Holcim Devil's Slide Cement Plant</u>

- UDAQ should have evaluated the Holcim Devil's Slide Cement Plant for controls in a four-factor analysis, particularly for NOx controls for the cement kiln.

- While the facility is voluntarily installing SNCR, its permits do not impose requirements to operate the SNCR or to meet any NOx emission limit reflective of the SNCR. Thus, at the minimum, UDAQ should establish a firm requirement for Holcim to install and operate the SNCR system at the Devil's Slide cement kiln and set a NOx emission limit reflective of the capabilities of the SNCR system.

- UDAQ should also investigate the cost effectiveness of installing catalytic ceramic filters in the existing baghouse for the Devil's Slide cement kiln that would work in concert with the ammonia injection of the SNCR system to achieve 90% reduction in NOx emissions. It is estimated that such controls would be very cost effective at $1,804/ton.

Lisbon Gas Processing Plant

- UDAQ eliminated the Lisbon Gas Plant from a four-factor analysis of controls because of its reduced SO2 emissions which apparently had been adopted as a permit requirement for the Lisbon Gas Plant but was subsequently relaxed for seemingly no reason. UDAQ should thus reimpose a limitation on the plant's SO2 emissions of 111 tons per year to be consistent with what as previously required in the facility's permit but inexplicably relaxed.

In issuing the draft Utah Regional Haze Plan for public review and comment, the Utah Air Quality Board specifically requested input on five topics – three of those topics pertain to facilities evaluated in this report (Intermountain Generation Station, US Magnesium, and Sunnyside Cogeneration Plant)[13] and are addressed in the section of this report on each of those plants. The Utah Air Quality Board also asks for public input on "the need for a cost threshold" and "whether a mass-based limit or a rate-based limit would be more appropriate."[14] Below I provide my comments on these issues.

A. The Need for a Threshold for Determining Cost-Effective Controls

The Utah Air Quality Board has asked for comment on the need for UDAQ to set a cost effectiveness threshold. First, based on my review of the draft Utah Regional Haze plan for the second implementation period, it appears that UDAQ is using an unstated cost effectiveness threshold. While UDAQ does not directly state its cost effectiveness threshold, I infer from the draft Utah Regional Haze plan that the state assumes a control is cost effective if it has a cost effectiveness of less than $4,500/ton. I based this on the following statements:

- Regarding selective noncatalytic reduction (SNCR) cost effectiveness analysis at Graymont Western – Cricket Mountain Lime Plant, UDAQ stated that based on its revised cost effectiveness analysis of SNCR "may appear to be feasible, at least for Kiln #5."[15] The revised cost effectiveness of SNCR for Kiln #5 was $3,977/ton.[16]
- Regarding selective catalytic reduction (SCR) at the Hunter and Huntington Power Plant units, in which UDAQ states "UDAQ's remaining cost-effectiveness evaluation centers around the

[13] *See* https://deq.utah.gov/air-quality/air-quality-rule-plan-changes-open-public-comment.
[14] *Id.*
[15] April 2022 Draft Utah Regional Haze Plan at 118.
[16] *Id.*

> potential application of SCR at one or more units at the Hunter and Huntington power plants. In particular, the relatively lower estimated $/ton for SCR at Hunter 3 merits further evaluation of whether this control could be cost effective."[17] UDAQ calculated cost effectiveness of SCR for Hunter Unit 3 of $4,401/ton and UDAQ's calculation of the cost-effectiveness of SCR at the other Hunter units and at the Huntington units ranged from $5,979/ton to $6,533/ton.[18]

In its July 5, 2016 Federal Implementation Plan (FIP) finding SCR as justified to meet best available retrofit technology (BART) requirements at Hunter Units 1 and 2 and Huntington Units 1 and 2, EPA detailed other FIP and SIP BART and reasonable progress determinations in which EPA found SCR at coal-fired EGUs to be cost effective and justifiable, including at Laramie River station (where cost effectiveness ranged from $4,375/ton to $4,461/ton), Hayden Station (in which cost effectiveness of SCR ranged from $3385/ton to $4,064/ton), and the Cholla Power Plant (which cost effectiveness of SCR ranged from $3,114/ton to $3,472/ton).[19] It appears that UDAQ may be using the top end of this range of cost effectiveness numbers that EPA cited in its 2016 Utah BART rulemaking, to define its cost effectiveness threshold for its regional haze plan for the second implementation period. However, UDAQ has not stated any cost effectiveness threshold in its draft regional haze plan.

UDAQ must articulate and justify an objective rationale for finding controls cost effective or not. While EPA's regional haze guidance for the second implementation period does not expressly require that a state set a cost effectiveness threshold, but such a threshold appears to be necessary to provide such an objective basis for the control measures it decides to include, or not include, in its regional haze plan. In any event, the guidance provides that if a state "applies a threshold for cost/ton to evaluate control measures…the SIP [should] explain why the selected threshold is appropriate for that purpose and consistent with the requirement to make reasonable progress."[20] If UDAQ is applying a cost effectiveness threshold, UDAQ should explain why its cost effectiveness threshold (which appears to be ~$4,500/ton) is appropriate for defining its regional haze control measures for the second implementation period. UDAQ has not provided such a justification in its draft plan.

If UDAQ is basing its determination of what is a cost effective control on the examples provided by EPA in its July 5, 2016 proposed Utah FIP, that would not be sufficient justification for Utah's cost effectiveness threshold. EPA's regional haze guidance provides several recommendations regarding states comparing cost effectiveness values to past cost effectiveness values used in regulatory determinations, including what the particular baseline scenario was and how the comparison is affected by changes in prices for equipment, construction, and operation. For example, in the BART and reasonable progress determinations for the first round regional haze plans, the baseline periods were typically from 2000-2005 timeframe. Many EGUs at which SCR was found to be cost effective to meet BART or reasonable progress had installed low NOx burners (LNB) and overfire air (OFA) after the 2000-2005 baseline period, so the SCR cost effectiveness analyses included the costs of installing LNB/OFA and also considered the NOx emission reductions from the suite of NOx controls starting from a much higher level of baseline emissions. But today, in the regional haze plans being developed for the second

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[17] *Id.* at 127.
[18] *Id.*
[19] 81 Fed. Reg. 43,894 at 43905-6 (July 5, 2016).
[20] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 39.

implementation period, baseline emissions for cost analyses reflect recent emissions. Most coal-fired EGUs have at least installed upgraded LNB and OFA and thus have reduced emissions compared to 2000-2005. As a result of starting with a lower emissions baseline, the cost effectiveness of SCR is going to be higher than the cost effectiveness values of SCR plus LNB/OFA calculated in the first round regional haze plans.[21] For that reason, UDAQ should not use cost effectiveness values that were relied on for the first round regional haze plans as defining the cost effectiveness threshold for the second round regional haze plan.[22]

EPA further states in its regional haze guidance that "[w]hen the cost/ton of a possible measure is within the range of the cost/ton values that have been incurred multiple times by sources of similar type to meet regional haze requirements or any other [Clean Air Act] requirement, this weighs in favor of concluding that the cost of compliance is not an obstacle to the measure being considered necessary to make reasonable progress."[23] This is a very important point, as this is how EPA has decided cost effectiveness of controls in best available control technology (BACT) analyses in new source review permitting for decades.[24] According to EPA, SCR has been installed at 60% of the coal-fired EGUs in the 26 states that would be addressed by its recently proposed Good Neighbor Plan, and almost all coal-fired EGUs of capacity greater than 100 megawatts (MW) constructed in the past 30 years have installed SCR as it has been required to meet BACT.[25] Thus, SCR has been installed pursuant to Clean Air Act requirements at multiple coal-fired EGUs. However, the costs for these SCR retrofits and installations aren't always known. Many EGUs voluntarily installed SCR systems under the Clean Air Interstate Rule (CAIR) and/or Cross State Air Pollution Rule (CSAPR), which would not have required a cost effectiveness analysis (except for each company's own bookkeeping and weighing out of the cost and benefits of installing the control). And when a new coal-fired EGU selects the top pollutant control (which SCR is for NOx) as BACT, no cost analysis has to be done. The lack of the full range of cost effectiveness numbers for the numerous SCR installations that have been done at coal-fired EGUs should not mean that SCR should be deemed not cost effective for a particular EGU only because the cost effectiveness of SCR is higher than the highest SCR cost/ton value that has been required under the regional haze program.

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[21] Note that LNB/OFA have a significantly lower capital cost than SCR and very little operating expenses, so the bulk of the annualized cost of SCR plus LNB/OFA was due to SCR, but the emission reductions (due to comparing to a 2000-2005 baseline) reflected the effect of LNB/OFA plus SCR. Thus, with greater emission reductions in the denominator of the cost per ton calculation, the cost effectiveness of the controls would have a lower value than a cost effectiveness calculation of SCR considering a more recent baseline reflective of operation of LNB/OFA.

[22] There are other reasons for a state not to rely on cost effectiveness thresholds from the first round regional haze SIPs as defining cost effectiveness of controls for the second round plans, including the impacts of inflation on cost effectiveness thresholds used in SIPs and FIPs from several years ago, the fact that many big emitters were (or should have been) addressed through BART in the first regional haze plans, and that, to make reasonable progress towards the national visibility goal will require addressing more diverse and/or lower-emitting facilities for which the cost effectiveness value of a control may be higher than it was for a large emitter like a coal-fired power plant.

[23] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019 at 40.

[24] *See* EPA, New Source Review Workshop Manual, October 1990, at B29 ("In the absence of unusual circumstances, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category.")

[25] 87 Fed. Reg. 20036 at 20080 (Apr. 6, 2022).

For these reasons, if UDAQ is essentially using a $4,500/ton cost effectiveness threshold and if UDAQ's justification for such a threshold is that it is based on the highest cost effectiveness threshold that EPA cited in its July 5, 2016 proposed Utah FIP, that is not a sufficient justification for the cost effectiveness threshold.

In addition, UDAQ must also consider the cost effectiveness thresholds that other states are using to define control requirements to adopt in their second round regional haze plans. Several other states have adopted much higher cost effectiveness reasonableness thresholds than UDAQ's apparent cutoff of $4,500/ton. For example, Oregon has adopted a much higher regional haze control cost threshold of $10,000/ton.[26] Colorado is also using a reasonableness cost threshold of $10,000/ton.[27] New Mexico is using a reasonableness cost effectiveness threshold of $7,000/ton.[28] Washington is using $6,300/ton for Kraft pulp and paper power boilers.[29] Arizona identified a cost effectiveness range of $4,000 to $6,500/ton, although the state has not issued its draft regional haze plan yet.[30] These states all point to cost effectiveness thresholds that are higher, in several cases significantly higher, than what appears to be UDAQ's cost effectiveness threshold of $4,500/ton.

In summary, while Utah is not required to adopt a cost effectiveness threshold, the state seems to be relying primarily on cost effectiveness to decide which controls to require for this regional haze implementation period. It appears that UDAQ is applying a cost effectiveness threshold of $4,500/ton. If that is the case, UDAQ has not provided any justification for its apparent cost effectiveness threshold, and if it is based on what EPA considered as cost effective in the first round regional haze FIP for Utah, then that is not sufficient justification. Further, in setting a cost effectiveness threshold, UDAQ should consider the costs that other similar sources have had to bear to meet Clean Air Act requirements, particularly if multiple similar sources have installed the top pollution control despite the cost.

B. Whether a Mass-Based Emission Limit or a Rate-Based Emission Limit Would Be More Appropriate for Regional Haze Requirements.

The Utah Board of Air Quality Board has also asked for comment on whether a mass-based limit or a rate-based limit would be more appropriate for regional haze requirements. EPA's guidance on regional

[26] *See* Oregon Regional Haze State Implementation Plan for the Period 2018-2028, Submitted for Adoption: Oregon Environmental Quality Commission, February 3, 2022, Appendix D at Item C pages 000190 and 000249 (pdf pages 60 and 119 of file), available at https://www.oregon.gov/deq/EQCdocs/020322_ItemC_AttachmentD_NoAppendices.pdf.

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

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

[29] *See*, e.g., Washington Department of Ecology, Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, attached as Ex. 1.

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

haze plans for the second implementation period states that, when a state "has determined that a technology-based measure is necessary to make reasonable progress," emission limits should be expressed in a rate-based format (such as pounds of pollutant per throughput).[31] This is especially important for pollution controls that can be operated at various control efficiencies like a flue gas desulfurization (FGD) system (i.e., SO2 scrubber), dry sorbent injection (DSI), selective catalytic reduction (SCR), or selective noncatalytic reduction (SNCR). All of these controls can be operated to varying control efficiencies, and thus a rate-based limit can ensure the pollution controls must be operated in an optimal manner to reduce regional haze emissions.

EPA's regional haze guidance also allows SIPs to contain mass-based limits during a particular time period (such as a cap on mass emissions over a 30-day period), although EPA cautions that mass-based limits can have the effect of allowing a source to not operate a pollution control system that the state determined to be reasonable under a four-factor analyses and instead lower the source's operating capacity factor.[32] EPA states that "[i]f the state has determined, independent of the forecasted operating level, that operation of the emission control equipment (or the use of cleaner fuel) is necessary to make reasonable progress, a mass-based emission limit may not be appropriate."[33]

These EPA statements argue for rate-based emission limits whenever a regional haze control technology, or when an operational control such as a fuel switch, is determined by a state to be cost-effective and justified as a component of the state's regional haze plan.

On the other hand, when a state is exempting an emission unit from a four-factor analysis of pollution controls or otherwise is finding a pollution control technology to not be cost-effective based on future lower operating hours or lower capacity factor, then a mass-based limit reflective of the lower operating hours/capacity factor may be most appropriate assuming the emission unit in question has continuous emissions monitoring systems (CEMs) to adequately account for actual emissions. Alternatively, if the emission unit is not equipped with CEMs, limits on hours of operation, on production, or on fuel use could be imposed.

While a mass-based limit (assuming CEMs or otherwise adequately testing, monitoring, and recordkeeping) could be designed to align with the regional haze goal of reducing visibility-impairing pollution, states often impose such limits on a long term basis such as a 30-day average basis or a 12-month rolling average basis, which allows a facility more flexibility in day-to-day operations. However, such long term averaging times do not ensure consistent reduction of visibility-impairing pollutants, including during periods of the greatest impairment.

For all of these reasons, rate-based emissions limits are generally most appropriate to ensure reduction in regional haze impairment in Class I areas.

The following provides comments and analysis on the facilities for which UDAQ requested four-factor analyses of controls to address regional haze.

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[31] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 44.

[32] *Id.*

[33] *Id.* at 45.

II. Hunter and Huntington Power Plants

The Hunter and Huntington Power Plants are two coal-fired power plants located in Castle Dale and Huntington, Utah (respectively). The Hunter Power Plant has three coal-fired units, and the Huntington Power Plant has two coal-fired units. Both power plants are owned and operated by PacifiCorp. Hunter Units 1 and 2 and Huntington Units 1 and 2 are subject to BART. PacifiCorp submitted its four-factor analyses for these two power plants in one comprehensive submittal to UDAQ.[34]

According to UDAQ, the Hunter Power Plant had the highest combined (SO2+NOx+PM10) Q/d value of 216.1 of all the facilities evaluated by UDAQ, and the Huntington Power Plant had the third highest combined Q/d value of 105.5.[35] The closest Class I area to these plants is Capitol Reef National Park, which is 74.9 km from the Hunter Plant and 95.8 km from the Huntington Plant. Each facility's emissions were identified by UDAQ as follows:

Table 1. Emissions Considered by UDAQ for Hunter and Huntington Power Plants for the Q/d Analysis[36]

Power Plant	NOx, tpy	SO2, tpy	PM10, tpy
Hunter	11,491.2	3,939.3	747.4
Huntington	6,871.6	2,479.2	755.4

While each of the Hunter and Huntington units have wet scrubbers for SO2 control, baghouses for particulate control, and LNB/OFA for NOx control, none of the Hunter or Huntington units have post-combustion NOx controls such as selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR). PacifiCorp provided four-factor analyses of these NOx controls, and the company concluded that neither SCR nor SNCR were cost effective at any Hunter and Huntington unit.[37] To meet regional haze requirements, PacifiCorp proposed alternative emission limits, which it has called "reasonable progress emission limits (RPELs)" for Huntington and Hunter power plants. Specifically, PacifiCorp has proposed a plantwide NOx + SO2 limit of 10,000 tpy for the Huntington plant and a plantwide NOx + SO2 limit of 17,000 tpy for the Hunter plant. UDAQ has not proposed to adopt the RPELs. UDAQ also did not propose to require SCR or SNCR. Instead, UDAQ has proposed to adopt plantwide NOx emission limits for the Hunter and Huntington plants that are reflective of the NOx emissions modeled by the Western Regional Air Partnership (WRAP), and UDAQ is also proposing to adopt the Hunter and Huntington SO2 emission limits for their air permits as part of the regional haze plan.[38]

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[34] PacifiCorp, Utah Coal Generation Facilities, Regional Haze-Second Planning Period, Reasonable Progress Analysis, April 2020 (hereinafter "April 2020 PacifiCorp Reasonable Progress Analysis").
[35] *See* https://deq.utah.gov/air-quality/regional-haze-in-utah#planning.
[36] *See* April 2022 Draft Utah Regional Haze Plan at 93 (Table 27).
[37] April 2020 PacifiCorp Reasonable Progress Analysis. at 6 and 18.
[38] April 2022 Draft Utah Regional Haze Plan at 126 and 132.

A. Comments on PacifiCorp's Proposed Reasonable Progress Emission Limits (RPELs)

Although UDAQ has not proposed to adopt PacifiCorp's RPELs, the following comments are provided in the event that UDAQ reconsiders adoption of the RPELs as a result of the public comment period on this regional haze plan.

PacifiCorp's proposed RPELs were based on the following:[39]

- NOx emissions were calculated based on the potential annual heat input (assuming each unit operates at maximum hourly heat input capacity (i.e., coal throughput) for each hour of the year) and an "SNCR-equivalent" lb/MMBtu NOx emission rate to calculate the potential annual NOx emissions if SNCR was installed and operated.
- PacifiCorp assumed that Huntington Units 1 and 2 and Hunter Units 1 and 2 would meet a 0.17 lb/MMBtu NOx rate with SNCR, and that Hunter Unit 3 would meet a 0.24 lb/MMBtu NOx rate.[40]
- PacifiCorp summed the total plantwide potential NOx emissions if SNCR was installed, which totaled 12,235 tons per year for the Hunter Plant and totaled 7,386 tons per year for the Huntington Plant.
- Each facility's SO2 Plantwide Applicability Limit (PAL) (i.e., 5,537,5 tons per year for Hunter and 3,105 tons per year for Huntington) were added to the total plantwide potential NOx emissions with SNCR at each plant. The sum of the SO2 PALs with the SNCR-equivalent potential NOx emissions was 17,773 tons per year for Hunter and 10,491 tons per year for Huntington.
- PacifiCorp then rounded down these summed values to the nearest 1,000 tons per year to arrive at its proposed 17,000 ton per year RPEL limit on SO2 plus NOx emissions from the Hunter plant and its proposed 10,000 tons per year RPEL limit on SO2 plus NOx emissions from the Huntington Plant.
- PacifiCorp claims that the proposed RPELs are both less than the plants' existing PALs and that emissions would be lower than would be achieved through installation of SNCR on all units.

It is questionable whether such emission limits based on the sum total of SO2 plus NOx emissions would constitute a reasonable progress control measure, but what is clear is that the "RPELs" proposed by PacifiCorp will not ensure any reduction in actual emissions of either NOx or SO2.

It is first important to discuss the existing Plantwide Applicability Limits (PALs) that are currently in effect for SO2 and for NOx at both the Hunter and Huntington plants in the context of PacifiCorp's proposed RPELs, because the SO2 PALs form the basis of PacifiCorp's proposed RPELs. PALs are limits on a particular pollutant that are authorized under the prevention of significant deterioration (PSD) permitting program, for the purpose of allowing facilities to modify their facilities without triggering PSD permitting requirements (such as the requirement to meet BACT) as long as total plantwide actual emissions of the pollutant do not exceed the PAL.[41] PALs apply for 10-year periods and can be renewed for an additional ten years. The SO2 and NOx PALs applicable to the Hunter and Huntington units were

[39] Unless otherwise noted, this information is in PacifiCorp's August 31, 2021 submittal to UDAQ at pp. 6-8.
[40] April 2020 PacifiCorp Reasonable Progress Analysis at Attachments 1 and 4 (pdf pages 33 and 64 of file).
[41] 40 C.F.R. § 52.21(aa)(1)(ii), incorporated by reference into Utah Rule R307-405-21.

first established in 2008 for the Hunter plant and in 2010 for the Huntington plant.[42] In the initial PAL permits, PALs are generally set at the maximum two-year average emissions of SO2 or NOx for the five years prior to the permit plus the PSD significance level of 40 tons per year.[43] For the Hunter plant, the initial PALs were established before Units 1 and 2 upgraded the existing SO2 controls to eliminate scrubber bypass, before the units installed low NOx burners and overfire air, and before baghouses were installed to replace existing electrostatic precipitators (in 2014 and 2011, respectively). For the Huntington plant, the initial PALs were established before Huntington Unit 1 upgraded its wet scrubber to eliminate bypass, before the unit installed low NOx burners and overfire air, and before replacement of Unit 1's ESP with a baghouse (which all occurred in 2010). Thus, the SO2 and NOx PAL limits were set much higher than subsequent actual plantwide SO2 emissions at the Hunter and Huntington plants. UDAQ issued PAL renewal permits for the Hunter and Huntington plants in approximately 2018 and 2019, respectively.[44] Although UDAQ reduced the SO2 and NOx PALs in those PAL renewal permits, they are still much higher than actual emissions for the Hunter and Huntington Plants. To illustrate this, the table below shows the for SO2 and NOx at each plant, compared to the past years of actual emissions at each plant.

[42] *See* Approval Order DAQE-AN0102370012-08 issued March 13, 2008 for the Hunter plant and Approval Order DAQE-AN0102380020-10 for the Huntington plant issued January 4, 2010.

[43] *See* 40 C.F.R. §52.21(aa)(2)(i); §52.21(b)(48) (definition of "baseline actual emissions").

[44] The timeframes for issuance of the PAL renewal permits are approximate, based on the 10-year expiration date of the initial PAL limits and the dates of the draft Approval Orders to renew the PALs (e.g., March 8, 2018 Intent to Approve DAQE-IN102370027-18 for the Hunter Plant, June 14, 2019 for the Huntington Plant (Intent to Approve DAQE-IN102380031-19). The final Approval Orders that renewed the PAL limits do not appear to be available on UDAQ's air permits website.

Table 2. Comparison of Hunter and Huntington's Actual SO2 and NOx Emissions to their Plantwide Applicability Limits (PALs).[45]

Plant	PAL Limits, tpy	Year	SO2 Actual Plantwide Emissions, tpy	NOx Actual Plantwide Emissions, tpy
Hunter	***2008 SO2 PAL: 7,187 tpy***	2008	6,072	20,416
	2008 NOx PAL: 19,319 tpy	2009	5,120	17,287
		2010	4,558	16,205
		2011	4,661	14,034
		2012	4,532	13,577
		2013	5,055	14,556
		2014	3,939	11,595
		2015	4,238	11,591
		2016	3,197	8,869
		2017	3,512	9,773
	Renewed (~2018) SO2 PAL: 5,537.5 tpy	2018	3,133	9,770
	Renewed (~2018) NOx PAL: 15,095 tpy	2019	3,546	10,514
		2020	2,957	9,287
		2021	3,848	11,041
Huntington	***2010 SO2 PAL: 5,260 tpy***	2010	3,117	8,283
	2010 NOx PAL: 11,396 tpy	2011	2,529	6,252
		2012	2,300	7,391
		2013	2,409	7,482
		2014	2,478	6,864
		2015	2,524	6,462
		2016	2,364	6,210
		2017	2,282	5,931
		2018	2,202	5,153
	Renewed (~2019) SO2 PAL: 3,105 tpy	2019	2,144	5,206
	Renewed (~2018) NOx PAL: 7,971 tpy	2020	1,626	4,814
		2021	2,690	6,604

PacifiCorp claims that the RPELs reflect a reduction from the PAL limits by comparing its proposed SO2 plus NOx RPELs to the sum of the currently effective SO2 and NOx PALs (i.e., 17,000 ton per year RPEL compared to 20,632 ton per year total SO2 plus NOx PAL limits for the Hunter Plant, and 10,000 ton per year RPEL compared to 11,076 ton per year total SO2 plus NOx PALs for the Huntington Plant).[46] However, it is not appropriate to compare the proposed RPEL limits to the PAL limits to claim that the RPELs reflect emission reductions, because the PALs are not designed to reduce emissions from the

[45] Plantwide SO2 and NOx emissions for each year from EPA's Air Markets Program Database.

[46] PacifiCorp's August 31, 2021 submittal to UDAQ at 7.

existing Hunter and Huntington plants. Instead, the PALs are intended to cap emissions from any future modifications to each plant that would increase emissions, in order to allow PacifiCorp to avoid PSD permitting for any such modifications.

Rather than comparing to the PALs, the RPELs should be compared to actual emissions to determine if the proposed RPELs would reduce emissions. As shown in the table below, PacifiCorp's proposed RPELs would not reduce overall SO2 plus NOx emissions at either the Hunter Plant or the Huntington Plant.

Table 3. Huntington Power Plant's Actual SO2 Plus NOx Emissions Compared to PacifiCorp's SO2 + NOx RPEL[47]

Year	Plantwide Actual SO2, tpy	Plantwide Actual NOx, tpy	Plantwide Actual SO2 + NOx, tpy	Proposed SO2+NOx RPEL, tpy
2014	2,478	6,864	9,342	10,000
2015	2,524	6,462	8,986	
2016	2,364	6,210	8,575	
2017	2,282	5,931	8,212	
2018	2,202	5,153	7,356	
2019	2,144	5,206	7,350	
2020	1,626	4,814	6,440	
2021	2,690	6,604	9,295	

Table 4. Hunter Power Plant's Actual SO2 Plus NOx Emissions Compared to PacifiCorp's SO2 + NOx RPEL[48]

Year	Plantwide Actual SO2, tpy	Plantwide Actual NOx, tpy	Plantwide Actual SO2 + NOx, tpy	Proposed SO2+NOx RPEL, tpy
2014	3,939	11,595	15,534	17,000
2015	4,238	11,591	15,829	
2016	3,197	8,869	12,066	
2017	3,512	9,773	13,285	
2018	3,133	9,770	12,903	
2019	3,546	10,514	14,059	
2020	2,957	9,287	12,244	
2021	3,848	11,041	14,889	

PacifiCorp's proposed RPELs cannot be considered as measures to achieve reasonable progress towards the national visibility goal because the limits would not result in reductions in visibility-impairing

[47] Actual emissions data from EPA's Air Markets Program Database at https://ampd.epa.gov/ampd/.
[48] Actual emissions data from EPA's Air Markets Program Database at https://ampd.epa.gov/ampd/.

emissions. As previously stated, the fact that the RPELs are lower than the total of each plant's SO2 PAL plus NOx PAL is irrelevant, because those SO2 and NOx PALs were not limits designed to reduce emissions from the existing Hunter and Huntington Plants.

PacifiCorp submitted a cost analysis for compliance with the RPELs. UDAQ states that it does not concur with PacifiCorp's four-factor analysis calculations for its proposed RPELs for the following reasons:[49]

- The emissions reductions that the RPELs are based on are SNCR controls, which PacifiCorp claimed was not cost effective.
- The control costs associated with the RPELs were based solely on the cost of additional scrubbing of SO2, while the estimated emission reductions were both NOx and SO2.
- PacifiCorp used the PALs as its emission baseline in its RPEL cost effectiveness analysis, when it used a different actual emissions baseline for its SCR and SNCR cost effectiveness analyses. UDAQ cannot compare the cost effectiveness of the proposed RPEL limits to the costs of SNCR or SCR due to the use of different baselines.

I concur with UDAQ's findings regarding the RPELs proposed by PacifiCorp and would also add the following comments:

1) The RPELs will not reduce actual emissions from either the Hunter or Huntington plant compared to what the plants have actually emitted in the past eight years. The RPEL limits are, at best, a reduction in allowable emissions.
2) Because the RPELs will not reduce actual emissions below what the plants have emitted in at least the past eight years, they will not require operation of either SNCR or enhanced SO2 removal. Thus, it does not make sense to estimate costs for compliance with the RPELs that will not require any changes in pollution controls.
3) An exception to the above comment is if PacifiCorp is projecting that 2028 emissions and operational levels will increase above recent past emissions. If an increase in operational levels (capacity factor) is a possibility for the Hunter and/or Huntington units, it is imperative that UDAQ verify this with PacifiCorp for the purpose of the four-factor analysis of controls. As UDAQ has discussed in its draft regional haze plan and as will be discussed further below, the operating capacity factor does have an impact on the cost effectiveness of a pollution control with, generally, pollution controls having lower cost per ton values when a unit's capacity factor is higher due to the ability to reduce higher quantities of pollutants for a pollution control's capital cost. Thus, UDAQ must verify with PacifiCorp if it is projecting to operate at higher capacity factors and higher emission rates in the future.
4) The RPELs also will not ensure emission reductions below what was modeled for the Hunter and Huntington plants. Specifically, the 2028 NOx and SO2 emissions modeled for Hunter Units 1-3 sum up to 9,992 tons per year of SO2 and 3,497 tons per year of NOx,[50] or a total of NOx plus SO2 of 13,489 tons per year, which is significantly less than PacifiCorp's proposed RPEL of 17,000 tons per year. The 2028 NOx and SO2 emissions modeled for Huntington Units 1 and 2 sum up

[49] April 2022 Draft Utah Regional Haze Plan at 126-7.

[50] *See* Center for the New Energy Economy Project Report for WESTAR-WRAP, Analysis of EGU Emissions for Regional Haze Planning and Ozone Transport Commission, Final Report, June 14, 2019, at 17-18 (Table 3), available at http://www.wrapair2.org/pdf/Final%20EGU%20Emissions%20Analysis%20Report.pdf. *See also* April 2022 Draft Utah Regional Haze Plan at 130.

to 6,083 tons per year of NOx and 2,448 tons per year of SO2,[51] or a total of NOx plus SO2 of 8,531 tons per year, which is less than PacifiCorp's proposed RPEL of 10,000 tons per year. If UDAQ were to adopt PacifiCorp's proposed RPELs as part of its regional haze plan, it would allow for an increase in emissions from what the WRAP modeled from the Hunter and Huntington Plants.

Thus, for the reasons enumerated in the draft Utah regional haze plan as well as for the reasons detailed above, there is no justification to adopt PacifiCorp's RPELs as regional haze control measures.

Although PacifiCorp proposed adoption of RPELs to meet regional haze requirements, PacifiCorp also presented cost effectiveness analyses for the addition of SNCR and SCR at each of the Hunter and Huntington units. The next section of this report provides comments on PacifiCorp's cost effectiveness and UDAQ's revisions to those cost effectiveness analyses.

B. Cost Effectiveness of SNCR and SCR at the Hunter and Huntington Units

PacifiCorp proposed plantwide RPELs to meet regional haze requirements because it claimed the traditional NOx controls of SCR and SNCR were not cost effective for the Hunter and Huntington units, based on cost effectiveness analyses conducted by Sargent & Lundy on behalf of PacifiCorp.[52] EPA has previously found that SCR *was* cost effective to justify requiring the control to meet BART at Huntington Units 1 and 2 and Hunter Units 1 and 2.[53] One of the main changes in PacifiCorp's analysis compared to EPA's is that PacifiCorp used a different baseline (average of 2015-2019 emissions) than the 2001-2003 baseline period used by EPA. In addition, EPA's NOx control cost analyses considered the costs and emission reduction benefits of low NOx burners and separated overfire air plus SCR from 2001-2003 emission levels. Below, I provide a review and comments on PacifiCorp's SCR and SNCR cost effectiveness analyses.

PacifiCorp submitted site-specific cost analyses of SCR and SNCR conducted by Sargent & Lundy to UDAQ in its April 2020 Reasonable Progress Analysis, and the company submitted revisions to those cost analyses in response to comments from UDAQ in a submittal dated August 31, 2021. UDAQ presents the results of those revised cost analyses in its April 2022 Draft Regional Haze Plan, which are reprinted below.

[51] *Id.*

[52] April 2020 PacifiCorp Reasonable Progress Analysis at 6 and 18.

[53] 81 Fed. Reg. 43,894 at 43,906 (July 5, 2016).

Table 5. PacifiCorp's/UDAQ's Cost-effectiveness of SNCR and SCR at the Hunter and Huntington Power Plant Units (from Table 42 of May 2022 Draft Utah Regional Haze Plan)[54]

Unit	SNCR, $/ton	SNCR NOx Reductions, tons per year	SCR, $/ton	SCR NOx Reductions, tons per year
Hunter 1	$6,536	569	$6,533	2,130
Hunter 2	$6,469	580	$6,488	2,149
Hunter 3	$5,417	872	$4,401	3,579
Huntington 1	$6,431	594	$5,979	2,266
Huntington 2	$6,579	565	$6,294	2,146

At the outset, it is important to note that PacifiCorp's calculations show that SCR is more cost effective than SNCR at all Hunter and Huntington units except Hunter Unit 2 at which the cost effectiveness is virtually the same. Yet, SCR will result in close to four times as much NOx reductions as PacifiCorp indicates will be achieved with SNCR. Thus, just taking PacifiCorp's cost effectiveness evaluations at face value, SCR should be the top-ranked NOx control in terms of cost effectiveness for the Hunter and Huntington units.

In addition, PacifiCorp's cost effectiveness numbers show that SCR is a cost effective control for the Hunter and Huntington units. While UDAQ has not clearly identified a cost effectiveness threshold as part of its draft regional haze plan, UDAQ acknowledged that "the relatively lower estimated $/ton for SCR at Hunter 3 merits further evaluation of whether this control would be cost effective."[55] As discussed in Section I.A, all of these costs are in the range that other states consider to be cost effective for the second round regional haze plans. For example, Arizona identified a cost effectiveness range of $4,000 to $6,500/ton.[56] New Mexico's cost threshold is $7,000 per ton.[57] Washington is using $6,300/ton for Kraft pulp and paper power boilers.[58] Oregon has adopted a much higher regional haze cost-effectiveness threshold of $10,000/ton.[59] Colorado is also using a cost-effectiveness threshold of $10,000/ton.[60]

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[54] *See also* August 31, 2021 PacifiCorp Submittal to UDAQ at Attachment B.

[55] May 2022 Draft Utah Regional Haze Plan at 127.

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

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

[58] *See*, e.g., Washington Department of Ecology, Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, attached as Ex. 1.

[59] *See* Oregon Regional Haze State Implementation Plan for the Period 2018-2028, Submitted for Adoption: Oregon Environmental Quality Commission, February 3, 2022, Appendix D at Item C pages 000190 and 000249 (pdf pages 60 and 119 of file), available at https://www.oregon.gov/deq/EQCdocs/020322_ItemC_AttachmentD_NoAppendices.pdf.

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

However, a review of PacifiCorp's revised cost effectiveness analyses shows that some of the assumptions that went into the company's analysis would tend to overpredict annual costs and have not been adequately justified.

1. PacifiCorp's Interest Rate Used in Determining Annualized Capital Costs of Control Has Not Been Adequately Justified as Consistent with the EPA's Control Cost Manual.

PacifiCorp used a weighted cost of capital of 7.303% as the interest rate in determining annualized capital costs of control.[61] PacifiCorp's justification for using its actual weighted cost of capital as the interest rate is a) that it is based on the EPA's Control Cost Manual total capital investment (TCI) methodology, b) that it provided this information to EPA within the past year, and b) that it understands that the interest rate should be set using the TCI methodology.[62] UDAQ states that it "accepts the resulting 7.303% interest rate as an appropriate source-specific rate across the company's service territory."[63] However, PacifiCorp has not provided sufficient information on its 7.303% interest rate to demonstrate that it is consistent with the requirements of the EPA Control Cost Manual.

First, if PacifiCorp has received concurrence from EPA that it is consistent with the EPA's Control Cost Manual to use its weighted cost of capital as its interest rate in determining annualize capital costs of control, that concurrence or approval should be included in Utah's regional haze record.

Second, although EPA's Control Cost Manual states that "[i]n assessing the total capital investment, this [Control Cost] Manual takes the viewpoint of an owner, the firms making the investment, or those who have a material interest in the project," [64] this does not mean that the Control Cost Manual methodology includes <u>all</u> costs that a public utility would consider to be its total capital investment. As EPA explains, the Control Cost Manual uses an "overnight" estimation method, as if no interest was incurred during construction and thus estimates capital as if the project was completed "overnight."[65] Accordingly, Allowance for Funds Used During Construction (AFUDC), which is defined as "the amount credited to a firm's statement of income and charged to construction in progress on the firm's balance sheet" and which EPA acknowledges is considered a cost item within the electric power industry, should not be included in cost effectiveness analyses under the Control Cost Manual methodology.[66] In addition, owner's costs (for owner activities related to engineering, management, and procurement) are not included in the EPA Control Cost Manual methodology.[67] Thus, while EPA describes the Control Cost Manual as taking the "viewpoint of an owner," that does not mean that the cost methodology is

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[61] August 31, 2021 PacifiCorp Submittal to UDAQ at 1-2.
[62] *Id.*
[63] May 2022 Draft Utah Regional Haze Plan at 126.
[64] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 8.
[65] *Id.* at 11.
[66] *See* EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017 at 11 and Section 4, Chapter 2 Selective Catalytic Reduction, June 2019 at pdf page 65, available at https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.
[67] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017 at 11 and Section 4, Chapter 2 Selective Catalytic Reduction, June 2019 at pdf page 65.

intended to take into account all costs in the viewpoint of the owner without question or justification, especially because the cost methodology used by the Control Cost Manual has limitations on costs that can be taken into account.

Third, EPA has previously not accepted use of a utility's weighted cost of capital in a regional haze cost analysis. Specifically, in its 2011 action on the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan (FIP),[68] EPA did not agree with comments from Oklahoma Gas & Electric (OG&E) that EPA should have used OG&E's discount rate. OG&E argued that "'[b]ecause OG&E is an investor-owned utility company and not a governmental agency, the Control Cost Manual suggests that it use an appropriate discount rate that more accurately reflects OG&E's capital structure." According to EPA, OG&E also argued that "the [capital recovery factor] includes not only recovery of principal but also a return on the principal, with the rate of return equal to the discount rate" and that "for an investor-owned utility such as OG&E, which is financed by a mix of debt and equity, the discount rate is equal to the weighted average of the equity return and debt return." EPA's response was as follows:

> The calculation of capital costs in the Control Cost Manual includes two separate steps. First, the TCI is determined based on overnight costs with no inflation or interest during construction. Second the TCI is turned into an annual cost by multiplying it by a carrying charge that in normal utility practice would include the interest, equity return, recovery of the initial investment, and taxes, plus operating and maintenance expenses of the plant, once built. However, the Control Cost Manual does not seek to duplicate normal utility practice. Section 2.4.2. of the Manual [dated January 2002] states:
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>> [T]he industrial planner must…understand how the cost of each device fits into the financial structure of their business…. [T]he source may find it useful to apply their own interest rate to the calculation of control costs. Common interest rates used by industry and accepted by the EPA for source petitions include the business' current borrowing rate, the current prime rate, and other acceptable industrial rates of return.
>
> Only debt is specifically listed in the allowed carrying costs. "Industrial rates of return" might include the utility's debt and equity, but there is no reference to taxes.

EPA, Response to Technical Comments for Sections E. through H. of the Federal Register Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan, Docket No. EPA-R06-OAR-2010-0190, at 33-34 (Ex. 2 to this report).[69]

EPA goes on to state that, in the OG&E documentation submitted to support its proposed cost of capital, income taxes as a significant component of the cost in levelized interest rate and that the Control Cost

[68] 76 Fed. Reg. 81,728 at 81,745 (Dec. 28, 2011).
[69] *See also* EPA, Control Cost Manual, , Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 13 [explaining that "taxes are not uniformly applied, and subsidies, tax moratoriums, and deferred tax opportunities distort how the direct application of a tax works," which was EPA's justification in its January 2002 version of Chapter 2 in stating that income taxes are not included in the Control Cost Manual methodology). Available at https://www.epa.gov/sites/default/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

Manual does not include income taxes.[70] The Control Cost Manual Cost Estimation chapter has been revised since EPA issued the final Oklahoma regional haze and visibility transport rulemaking, but the methodology of the Control Cost Manual has not changed.

Thus, while the Control Cost Manual does allow for the justification of using a firm-specific interest rate, the methodology of how the firm-specific interest rate was established must be reviewed to ensure it is consistent with the methodology of the Control Cost Manual. PacifiCorp has not explained the details of how its cost of capital is calculated, other than to refer to the utility commission docket numbers in which the cost of capital was approved. UDAQ must collect more information on PacifiCorp's calculations for cost of capital to ensure that the cost of equity does not account for the cost of income taxes and to ensure that the cost of debt and the cost of equity does not take into account inflation. UDAQ should not simply rely on the utility commissions' approval of a cost of capital for PacifiCorp to use in ratemaking cases to prove that PacifiCorp's stated cost of capital is consistent with the methodology and requirements of the EPA Control Cost Manual.

With respect to the interest rate to be taken into account in financing costs, EPA's Control Cost Manual states: "[t]he appropriate interest rate in private cost assessment is the private interest rate for each firm affected. Determining private interest rates may be difficult due to the firm-specific nature of the private nominal interest rate faced by firms. If firm-specific interest rates are available, then the appropriate rates are simply the difference between the nominal interest rate minus the prevailing inflation in the industry."[71] EPA's Control Cost Manual also states "[i]f firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates given the potential difficulties in eliciting accurate private nominal interest rates since these rates may be regarded as confidential business information or difficult to verify."[72]

For the purpose of the Hunter and Huntington cost effectiveness analysis, this report will present cost both based on the current bank prime lending interest rate and on PacifiCorp's 7.303% cost of capital. As of the date of this report, the current bank prime lending rate is 4.0%.[73] However, until PacifiCorp and UDAQ present sufficient documentation on the assumptions and costs underlying PacifiCorp's stated cost of capital that ensures that the company's firm-specific interest rate is consistent with the requirements and methodology of EPA's Control Cost Manual, only the cost analyses done based on the prime lending rate should be considered in determining whether there are cost-effective controls for the Hunter and Huntington units.

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[70] *See* EPA, Response to Technical Comments for Sections E. through H. of the Federal Register Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan, Docket No. EPA-R06-OAR-2010-0190, at 34 (Ex. 1). *See also* 76 Fed. Reg. 81,728 at 81,745 (Dec. 28, 2011).

[71] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017 at 20.

[72] *Id.* at 15.

[73] https://fred.stlouisfed.org/series/DPRIME.

2. Comments on PacifiCorp's Cost Assessments of Selective Catalytic Reduction and Selective Noncatalytic Reduction for the Hunter and Huntington Plants

The following provides comments on PacifiCorp's SCR and SNCR cost assessments submitted in its April 2020 Reasonable Progress Analysis, as modified by its August 31, 2021 submittal to UDAQ.

a) PacifiCorp's SCR Cost Effectiveness Analysis Does Not Reflect the NOx Removal Capabilities of SCR.

Selective Catalytic Reduction is the top post-combustion control technology for the control of NOx from coal-fired EGUs like the Hunter and Huntington units. SCR uses an ammonia-type reagent to reduce NOx to nitrogen gas and NOx removal is greatly enhanced with the use of a metal-based catalyst with activated sites which increase the rate of NOx removal. The ammonia-type reagent is injected into the flue gas downstream of the combustion process through injection sites in the ductwork, which then goes into an SCR reactor chamber that includes the catalyst. The hot gases and ammonia-type reagent diffuse through the catalyst and contact activated sites where NOx is reduced to nitrogen and water with the hot flue gases providing energy for the reaction.[74] SCR systems are routinely designed to achieve 90% or greater NOx control efficiency.[75] Annual average NOx emissions with SCR, along with existing low NOx burners and overfire air, can achieve 0.04 lb/MMBtu or even lower.[76]

In PacifiCorp's April 2020 cost effectiveness analysis for SCR at the Huntington and Hunter power plants, it was assumed that a 0.05 lb/MMBtu NOx "emission limit" would apply with SCR installation.[77] The PacifiCorp submittal does not indicate over which averaging time the 0.05 emission limit would apply. It is assumed the company was evaluating a 30-day average 0.05 lb/MMBtu NOx limit because, typically, BART limits were applied over a 30-boiler operating day average time.[78] In addition, EPA's August 2019 guidance for the second regional haze implementation period also states that, for sources with continuous emission monitoring systems (CEMs) like those that are installed at most power plant units as required under acid rain regulations and new source performance standard rules, a 30-day averaging period is a common averaging period.[79]

While PacifiCorp assumed a 0.05 lb/MMBtu "emission limit" would apply, it also used the same 0.05 lb/MMBtu NOx rate in calculating annual emissions reductions for the cost effectiveness analysis. Cost effectiveness calculations are based on an annual timeframe – specifically, annual costs of control are divided by annual emission reductions expected with a control. When an emission unit is subject to an emission limit applicable on a 30-day average basis, the longer term average emission rate, such as the

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[74] *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 13, available at https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.
[75] *Id.* at pdf page 5.
[76] *Id.*
[77] April 2020 PacifiCorp Reasonable Progress Analysis, Attachment 2 at 19, and Attachment 5 at 19.
[78] *See* 40 C.F.R. Part 51, Appendix Y-Guidelines for BART Determinations Under the Regional Haze Rule at Section V.
[79] EPA, August 20, 2019, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, at 44.

annual average rate, is lower. For example, in its regional haze revision for the Laramie River Station in Wyoming, EPA assumed 0.04 lb/MMBtu would be achieved with SCR on an annual average basis under a 0.06 lb/MMBtu NOx limit applicable on a 30-day average basis.[80] Thus, by assuming that a 0.05 lb/MMBtu "emission limit" would only reduce annual emissions to a 0.05 lb/MMBtu annual rate, PacifiCorp understated the NOx emissions that would be reduced on an annual basis with SCR, which would result in an understatement of the cost effectiveness of SCR because a lower annual NOx emission rate can be achieved at the Hunter and Huntington units with SCR than 0.05 lb/MMBtu.

UDAQ raised this issue to PacifiCorp in commenting on the Company's April 2020 reasonable progress analysis for the Huntington units and stated that "annual emission rates lower than the estimates provided by PacifiCorp have been achieved at similar facilities."[81] It is not clear why UDAQ did not also raise this issue for the Hunter units, as PacifiCorp assumed the same controlled NOx rate for all of the Hunter units as well as the Huntington units. In its August 31, 2021 submittal to UDAQ responding to UDAQ's questions on PacifiCorp's regional haze analysis of controls, PacifiCorp cited to statements made by EPA in EPA's November 2020 rulemaking on Utah's regional haze SIP for the Hunter and Huntington units to support its assumption that the lowest annual NOx rate that could be achieved was 0.05 lb/MMBtu. Specifically, PacifiCorp quotes EPA as stating that a thorough review of emissions data for existing EGUs that have been retrofitted with SCR supports EPA's conclusion that "an annual emission rate of no lower than 0.05 lb/MMBtu is representative of what can be achieved when retrofitting SCR to an existing boiler."[82]

There are a few things to note about EPA's analysis of annual NOx emission rates to support this statement in its November 2020 Utah regional haze SIP rulemaking. First, EPA conducted this analysis based on the NOx emission rates that are reported by the Air Markets Program Database when one does a search for annual emissions data, but in my experience, those reported NOx rates do not always match with the annual NOx rates calculated by taking the annual reported NOx emissions (in tons, converted to pounds) divided by the annual heat input (in MMBtu). I obtained the file that EPA relied on for its statements in the 2020 Utah SIP rulemaking and calculated the annual NOx rates (based on reported annual NOx emissions divided by reported annual heat input) for all EGUs that EPA evaluated (i.e., EPA analyzed the NOx emission rates for those coal-fired EGUs with SCR that emitted below 0.10 lb/MMBtu). I found that a higher percentage of EGUs were achieving annual NOx rates of 0.04 lb/MMBtu in 2019. Specifically, EPA found that only 2 units (or 1.3% of the EGUs) has actual annual NOx emission rates less than or equal to 0.04 lb/MMBtu, but I found that 11 units (or 7.2% of the EGUs) had annual NOx emission rates less than or equal to 0.04 lb/MMBtu in 2019.[83] EPA decided that its evaluation of the 2019 NOx emissions data, which showed NOx rates of 0.05 lb/MMBtu or lower for 12.9% of the EGUs with SCR, that an annual emission rate of 0.05 lb/MMBtu was appropriate for the cost evaluation of SCR at the Hunter and Huntington units.[84] Based on my calculations of actual annual

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[80] 83 Fed. Reg. 51,403 at 51,408 (Oct. 11, 2018).

[81] UDAQ, Regional Haze – Second Planning Period SIP Evaluation Report, PacifiCorp Huntington Power Plant, May 31, 2021, at 8.

[82] August 31, 2021 PacifiCorp Submittal to UDAQ at 5. *See also* 85 Fed. Reg. 75,860 at 75,868 (11/27/2020).

[83] *See* spreadsheet of EPA's "SCR Actual Annual Emissions by Range.xlsx" (from Docket ID EPA-R08-OAR-2015-0463-1157) modified to calculate annual NOx emission rates, at tab entitled "Ann NOx Rate Calcs Ranked" at row 273, attached as Ex. 3.

[84] *See* 85 Fed. Reg. 75,868 (11/27/20).

NOx emission rates, more than half of the units reported to be emitting at 0.05 lb/MMBtu or lower are actually emitting NOx at 0.04 lb/MMBtu or lower. While EPA implied that coal-fired EGUs with SCR integrated into the original construction and design were more likely to be able to achieve the lowest NOx rates, SCR retrofits can achieve equally low NOx rates. In fact, 7 of the 11 units that achieved annual NOx emission rates of 0.04 lb/MMBtu or lower in 2019 were SCR retrofits, not new units built and designed with SCR from the start. This revised analysis of actual annual NOx rates, which I have attached to this report as Exhibit 3, shows that annual NOx rates of 0.04 lb/MMBtu are clearly achievable at coal-fired EGUs with SCR retrofits.

EPA also stated in the November 2020 Utah SIP rulemaking that "site-specific characteristics of each SCR installation must be taken into account when determining the anticipated actual annual emission rate."[85] One of those site-specific characteristics is the NOx emission limit that needs to be met at each unit which will define how the SCR is operated. Many of the coal-fired EGUs that have installed SCR did so under the Clean Air Interstate Rule (CAIR) or under the Cross State Air Pollution Rule (CSAPR). The coal-fired EGUs that installed SCR under CAIR or CSAPR likely are not subject to unit-specific emission limits reflective of the operational capabilities of SCR and thus may not operate the SCR systems to achieve the emission limits that the controls are capable of achieving. Consequently, the percentage of coal-fired EGUs that are actually achieving 0.04 lb/MMBtu annual NOx rates cannot be considered by itself to define the capabilities of SCR.

Back in 2003, Sargent & Lundy described the NOx removal capabilities of SCR as follows:

> [A]ll Sargent & Lundy-designed SCR reactors at coal-fired units, which have been placed into service, have achieved their guaranteed NOx reduction efficiencies within the specified ammonia slip limits. The minimum design NOx reduction efficiency was 85% and the maximum reduction efficiency was in excess of 90%. Design ammonia slip levels ranged between 2 ppm and 3 ppm at the end of catalyst life. Although no SCR installations have yet operated for the guaranteed catalyst life duration, it is anticipated that the NOx reduction and ammonia slip performance guarantees will continue to be met over that period. Operational installations include pulverized coal units burning PRB coal, Illinois low- to high-sulfur coal, and eastern low to high-sulfur coal; one cyclone unit burning PRB coal; and two cyclone units burning Illinois low-sulfur coal. SCR reactor designs have included 2+1 and 3+1 catalyst level installation sequences and have used plate, honeycomb, and corrugated type catalysts. Design of SCR reactors for removal efficiencies greater than 90% at ammonia slip levels less than 2 ppm to 3 ppm has been demonstrated and should be considered as a feasible design criterion.[86]

The Hunter and Huntington units should be assumed to be able to achieve 0.04 lb/MMBtu on an annual basis, because a 0.04 lb/MMBtu annual NOx rate reflects 80%-82% NOx removal at Hunter Units 1 and 2 and at Huntington Units 1 and 2 and, at most, 86.5% NOx removal at Hunter Unit 3. This is demonstrated in the table below. Note that the highest annual NOx rate over 2015 through 2021 at each Hunter and Huntington unit was evaluated to assess a worse case annual NOx removal efficiency that would be required to achieve an annual 0.04 lb/MMBtu NOx rate, but there are other years with

[85] *Id.*

[86] Kurtides, T., Sargent and Lundy, Lessons Learned from SCR Reactor Retrofit, COAL-GEN, Columbus, OH, August 6-8, 2003 (Ex. 4).

lower annual NOx rates that would have to achieve lower NOx removal efficiencies to achieve an annual rate of 0.04 lb/MMBtu. Clearly, SCRs are routinely designed to meet these and even higher levels of NOx removal efficiency.

Table 6. Annual NOx Removal Efficiency Required to Achieve Annual NOx Rate of 0.04 lb/MMBtu with SCR Based on Maximum Annual Baseline NOx Emission Rates Over 2015-2021 for Hunter Units 1, 2, and 3 and Huntington Units 1 and 2[87]

Unit	Max Annual NOx rate over 2015-2021, lb/MMBtu	Assumed Annual NOx Rate Achievable with SCR, lb/MMBtu	Annual NOx Removal Efficiency to be Achieved by SCR
Hunter Unit 1	0.206	0.04	80.6%
Hunter Unit 2	0.203	0.04	80.3%
Hunter Unit 3	0.296	0.04	86.5%
Huntington Unit 1	0.223	0.04	82.0%
Huntington Unit 2	0.224	0.04	82.1%

Vendor data support the design of SCR systems to be retrofit to existing coal-fired EGUs to meet NOx emission rates of 0.04 lb/MMBtu.[88] In addition, the SCR retrofit done in 2002 at Trimble County was guaranteed to meet an outlet NOx rate of 0.032 lb/MMBtu and greater than 90% NOx removal from NOx inlet rates of 0.030 lb/MMBtu or higher.[89] Given that SCRs designed to achieve an annual NOx rate of 0.04 lb/MMBtu reflect at most 80.3% to 86.5% NOx removal at Hunter Units 1-3 and Huntington Units 1-2, it is more than reasonable to assume that SCR retrofits would achieve annual NOx rates of 0.04 lb/MMBtu at all of the Hunter and Huntington units, particularly with a controlled NOx "permit limit" of 0.05 lb/MMBtu.

While PacifiCorp's August 2021 submittal to UDAQ gave examples of EPA statements supporting a 0.05 lb/MMBtu NOx rate for SCR retrofits, those statements provided EPA's support of a 0.05 lb/MMBtu 30-day average *emission limit*.[90] Yet, as discussed above, cost effectiveness is based on annual emission reductions and annual costs. Given that EPA has assumed that a 0.06 lb/MMBtu 30-day average NOx limit at Laramie River equated to a 0.04 lb/MMBtu annual NOx rate at Laramie River,[91] it is more than

[87] Maximum Annual NOx Rate was calculated from data reported to EPA's Air Markets Program Database and is based on the annual reported NOx emissions (converted from tons to pounds) divided by annual reported heat input to each unit.

[88] *See*, e.g., May 2009, White Paper, Selective Catalytic Reduction (SCR) Control of NOx Emissions from Fossil Fuel-Fired Electric Power Plants, Institute of Clean Air Companies, at 7 (referring to SCR retrofits designed to meet NOx emission rates of 0.04 lb/MMBtu), available at https://cdn.ymaws.com/www.icac.com/resource/resmgr/Standards_WhitePapers/SCR_WhitePaper_final_2009.pdf, attached as Ex. 5.

[89] *See*, e.g., SCR System Performance at LG&E's Trimble County Generating Station, Babcock Power Inc. Technical Publication, presented at EPRI Workshop on Selective Catalytic Reduction, October 22-23, 2002, at 1, 3 (Ex. 6), available at https://www.babcockpower.com/wp-content/uploads/2018/02/scr-system-performance-at-lges-trimble-county-generating-station.pdf.

[90] August 2021 PacifiCorp submittal to UDAQ at 5 (examples for Arkansas and New Mexico).

[91] 83 Fed. Reg. 51,403 at 51,408 (Oct. 11, 2018).

reasonable to assume the Hunter and Huntington units would achieve a 0.04 lb/MMBtu annual NOx rate with SCRs designed to meet a 0.05 lb/MMBtu 30-day average emission limit.

Thus, PacifiCorp should not have assumed an annual average NOx rate any higher than 0.04 lb/MMBtu at the Hunter and Huntington units in determining the annual reduction in NOx emissions for its cost evaluation of SCR. PacifiCorp's assumption of a 0.05 lb/MMBtu annual average NOx rate with SCR understated the annual reduction in NOx emissions with SCR, which resulted in SCR seeming less cost effective than it actually is.

b) PacifiCorp's SNCR Cost Effectiveness Calculations Understate the NOx Removal Capabilities of SNCR and Unnecessarily Include the Costs for Air Preheater Modifications.

PacifiCorp's SNCR cost effectiveness analysis overstated the costs of SNCR and understated the tons of NOx removed with SNCR, improperly inflating the cost effectiveness of SNCR. With respect to the NOx removal efficiency of SNCR, EPA's Control Cost Manual indicates that most coal-fired boilers are achieving between 20%-40% NOx control with SNCR. While the Sargent & Lundy SNCR cost analyses for the Hunter and Huntington units claimed to be based on a 20% NOx reduction efficiency with SNCR,[92] a review of the baseline annual average NOx rates and controlled SNCR NOx rates used in PacifiCorp's cost effectiveness analyses shows that a lower NOx removal efficiency was assumed – particularly for the Hunter units. In addition, SNCR should be able to achieve somewhat greater than 20% NOx reduction efficiency at the Hunter and Huntington units. In its Control Cost Manual, EPA provided a graph indicating the relationship between the NOx inlet emission rate and expected SNCR control efficiency, with higher NOx removal efficiencies achieved with higher inlet NOx emission rates.[93] EPA provided a best fit equation to estimate NOx removal efficiency achievable with SNCR based on NOx inlet level. That is, NOx Reduction Efficiency, %, = 22.554*Inlet NOx Rate, lb/MMBtu + 16.725.[94] EPA also relied on that Control Cost Manual formula in determining the controlled NOx emission limit for the cost effectiveness of SNCR in its 2016 Utah BART rulemaking.[95] The table below shows annual average NOx removal efficiency calculated using that formula and using 2015-2019 annual average NOx rates compared to the actual annual NOx removal efficiency used in the PacifiCorp SNCR cost effectiveness analysis for calculating the annual tons of NOx removed with SNCR.

[92] April 2020 PacifiCorp Reasonable Progress Analysis, Attachment 2 at 9 (Table 2) and Attachment 5 at 9 (Table 2).
[93] EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, 4/25/2019, at 1-3 to 1-4.
[94] *Id.* at Figure 1.1c (on page 1-4).
[95] 81 Fed. Reg. 2004 at 2034, 2038,2042, and 2046 (1/14/2016).

Table 7. Comparison of PacifiCorp's Assumptions for NOx Removed with SNCR to EPA's Control Cost Manual Formula for Expected NOx Removal at Hunter and Huntington Units.[96]

Plant & Unit	PacifiCorp's Baseline Ann. Avg. NOx Rate, lb/MMBtu	PacifiCorp's Assumed NOx Reductions with SNCR at 20% NOx Removal, tpy	Ann. Avg. NOx Removal Efficiency Calculated from EPA Control Cost Manual Formula	NOx Reductions with SNCR at NOx Removal Efficiency of EPA Control Cost Manual Formula, tpy
Hunter 1	0.200	569	21.2%	604
Hunter 2	0.193	580	21.1%	612
Hunter 3	0.280	872	23.0%	1,004
Huntington 1	0.212	594	21.5%	638
Huntington 2	0.208	565	21.4%	605

As the above table demonstrates, PacifiCorp's assumed annual average NOx rate, which was used in determining annual NOx reductions for input into cost effectiveness calculations, understated the NOx reduced with SNCR for the Hunter and Huntington units.

In addition to understating annual NOx reductions with SNCR, PacifiCorp's cost analysis for SNCR also included costs for air heater modifications.[97] EPA's SNCR chapter of its Control Cost Manual states that "[a]n air pre-heater modification is necessary for the control of SO3 for boilers that burn bituminous coal where the SO2 content of the coal is 3 lb/MMBtu or greater."[98] A review of the coal used in the past five years at the Hunter and Huntington Power Plants, based on data in the Energy Information Administration's Coal Data Browser, shows that the coal sulfur content is typically under 1%, and for many coals used (because the two plants obtain coal from a variety of mines), sulfur content is under 0.55%.[99] Based on the typical heating value of the coals burned at the Hunter and Huntington plants, the sulfur content would need to exceed 1.7% for an uncontrolled SO2 rate of 3 lb/MMBtu or greater.[100] Thus, based on EPA's statements in its SNCR Control Cost Manual chapter, there is not sufficient justification for Sargent & Lundy's inclusion of costs for air preheater modifications in the SNCR cost effectiveness analyses for any of the Hunter or Huntington units.

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[96] PacifiCorp's baseline NOx rate and assumed NOx reductions at 20% control are from Attachment B to PacifiCorp's August 2021 submittal to UDAQ. NOx Control Efficiency with EPA Control Cost Manual Formula from EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at Figure 1.1c (on page 1-4). NOx Reductions with EPA Control Cost Manual SNCR NOx Removal Efficiency calculated by applying EPA NOx Removal Efficiency to PacifiCorp's Annual NOx Baseline Emissions.

[97] April 2020 PacifiCorp Reasonable Progress Analysis at Attachment 2 at 10 and Attachment 5 at 10.

[98] EPA, Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, April 2019, at 1-44.

[99] *See* Energy Information Administration, Coal Data Browser information for the coal received at the Hunter Power Plant and at the Huntington Power Plant, attached as Exs. 7 and 8.

[100] Assuming heat value of the coal of 11,500 Btu/lb.

In response to UDAQ's comments that including the costs for air preheater modifications in the SNCR costs may not be justified, PacifiCorp states that it believes it is reasonable to assume that air preheater upgrades will be necessary with SNCR because of "excess ammonia from the SNCR process which has a potential to corrode and/or plug the existing air preheater equipment."[101] Not only do the Hunter and Huntington units not burn high sulfur coal to warrant such a concern, but the amount of ammonia slip at a NOx reduction efficiency of 20-23% should be under 5 parts per million according to EPA's Control Cost Manual.[102] Thus, PacifiCorp has not provided sufficient justification for including costs for air preheater modifications in its costs for SNCR. UDAQ should request that PacifiCorp re-evaluate the cost effectiveness of SNCR without including costs for air preheater modifications.

c) A Longer Life of SNCR than Twenty Years Should Have Been Assumed in the SNCR Cost Analysis.

PacifiCorp assumed a life of SNCR of 20 years and a life of SCR of 30 years in its cost effectiveness analyses.[103] This is consistent with what EPA states in its Control Cost Manual.[104] According to EPA, SCR has been used to control NOx emissions from fossil fuel-fired combustion units since the 1970's and has been installed on more than 300 coal-fired power plants in the U.S.[105] Thus, in its Control Cost Manual, EPA has found that the useful life of an SCR system at a power plant would be 30 years, and EPA cited one analysis that assumed a design lifetime of 40 years.[106] With respect to SNCR, there is also ample support for assuming a useful life for SNCR of 30 years, so that is what I assumed in the revised SNCR cost effectiveness analysis presented herein. While EPA states in the SNCR Control Cost Manual chapter that it is assumed than an SNCR would have a life of 20 years, EPA also states: "As mentioned earlier in this chapter, SNCR control systems began to be installed in Japan the late 1980's. Based on data EPA collected from electric utility manufacturers, at least 11 of approximately 190 SNCR systems on utility boilers in the U.S. were installed before January 1993. In responses to another ICR, petroleum refiners estimated SNCR life at between 15 and 25 years."[107] Therefore, based on a 1993 SNCR installation date, these SCNR systems that EPA refers to are at least 29 years old which, all other considerations aside, strongly argue for a 30-year equipment life for SNCR. Furthermore, an SNCR system is much less complicated than a SCR system, for which EPA clearly indicates the life should be 30 years. In an SNCR system, the only parts exposed to the exhaust stream are lances with replaceable nozzles. The injection lances must be regularly checked and serviced, but this can be done relatively quickly, if necessary, is relatively inexpensive, and should be considered a maintenance item. In this regard, the lances are analogous to SCR catalyst, which is not considered when estimating equipment life. All other items, which comprise the vast majority of the SNCR system capital costs, are outside the exhaust stream and should be considered to last the life of the facility or longer. Moreover, EPA has assumed a 30-year life

[101] April 2021 PacifiCorp Submittal to UDAQ at 4.

[102] *See* EPA, Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, April 2019, at 1-12 (Figure 1.7).

[103] *See* August 2021 PacifiCorp submittal to EPA, Attachment B at 1.

[104] *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80, and *see* EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-54.

[105] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 5.

[106] *Id.* at pdf page 80.

[107] EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-54.

of SNCR in control cost calculations for coal-fired EGUs in the context of the regional haze program.[108] For all of these reasons, it is reasonable to assume a 30-year life of SNCR for application to the Hunter and Huntington units, as well as for SCR.

3. Revisions to PacifiCorp's SCR and SNCR Cost Effectiveness Calculations Show Both SCR and SNCR are Cost Effective.

To address just two of the issues discussed above, I revised PacifiCorp's SCR and SNCR cost effectiveness calculations. Specifically, rather than use PacifiCorp's weighted cost of capital as the interest rate which has not been properly justified as consistent with the Control Cost Manual methodology, I used the current bank prime rate of 4.0% in both the SCR and SNCR cost effectiveness calculations. Second, I revised PacifiCorp's SNCR cost effectiveness calculation to assume SNCR would have a 30-year life. The results of these revised analyses are given in the tables below.

Table 8. Revised SCR Cost Effectiveness at Hunter and Huntington Units Based on PacifiCorp's Cost Estimates and Using the Current Bank Prime Rate of 4.0% to Calculate Annualized Capital Costs.[109]

Plant/Unit	SCR Capital Cost	Revised Annualized Capital Costs, $/year	Total Annual Costs (with O&M Costs), $/year	NOx reduced, tons per year	Revised Cost Effectiveness
Hunter Unit 1	$146,192,000	$5,847,680	$7,618,680	2,130	$3,577/ton
Hunter Unit 2	$146,192,000	$5,847,680	$7,654,680	2,149	$3,561/ton
Hunter Unit 3	$162,432,000	$6,497,280	$8,761,280	3,579	$2,448/ton
Huntington Unit 1	$141,923,256	$5,676,930	$7,439,930	2,266	$3,283/ton
Huntington Unit 2	$141,923,256	$5,676,930	$7,396,930	2,146	$3,446/ton

Table 9. Revised SNCR Cost Effectiveness at Hunter and Huntington Units Based on PacifiCorp's Cost Estimates, Using the Current Bank Prime Rate of 4.0% and Assuming a 30-year Life of SNCR to Calculate Annualized Capital Costs.[110]

Plant/Unit	SNCR Total Capital Investment	Revised Annualized Capital Costs, $/year	Total Annual Costs (with O&M Costs), $/year	NOx reduced, tons per year	Revised Cost Effectiveness
Hunter Unit 1	$16,004,000	$640,160	$2,808,560	569	$4,936
Hunter Unit 2	$16,004,000	$640,160	$2,848,960	580	$4,912
Hunter Unit 3	$16,004,000	$640,160	$3,816,760	872	$4,377
Huntington Unit 1	$16,152,000	$646,080	$2,902,280	594	$4,886
Huntington Unit 2	$16,152,000	$646,080	$2,802,080	565	$4,959

[108] *See*, e.g., 80 Fed. Reg. 18944 at 18968 (April 8, 2015).
[109] SCR cost data and NOx reductions from August 31, 2021 PacifiCorp Submittal to UDAQ, Attachment B at 1.
[110] SCR cost data and NOx reductions from August 31, 2021 PacifiCorp Submittal to UDAQ, Attachment B at 1.

As Table 8 demonstrates, PacifiCorp's use of a weighted cost of capital of 7.303% has a significant impact on the cost effectiveness of SCR. Using the current bank prime rate of 4.0%, the cost effectiveness of SCR is $3,500/ton or less at each unit and as low as $2,500/ton at Hunter Unit 3. Note that these revisions to PacifiCorp's SCR cost effectiveness analysis does not take into account that a lower annual NOx rate of 0.04 lb/MMBtu is achievable with SCR at these units. In comparison, PacifiCorp's cost effectiveness of SCR using its PUC-approved weighted cost of capital of 7.303% shows SCR cost effectiveness ranging from $4,400/ton at Hunter Unit 3 and from $6,000/ton to $6,500/ton at Hunter Units 1 and 2 and Huntington Units 1 and 2. (See Table 4 above).

As shown in Table 9, using the current bank prime rate and a 30-year life of SNCR brings the cost effectiveness of SNCR below $5,000/ton. Yet, when compared to SCR evaluated at the same 4.0% interest rate, SCR is still much more cost effective and would reduce three to four times more NOx emissions than SNCR.

4. SCR is a Cost-Effective NOx Control for the Hunter and Huntington Units.

Regardless of whether the current bank prime rate is used or PacifiCorp's PUC-approved weighted cost of capital is used, SCR should be considered as a cost effective control for Hunter Units 1, 2, and 3 and Huntington Units 1 and 2. As discussed in Section II.B. above, these costs that range from as low as $2,500/ton (if the current bank prime rate is used) to as high as $6,500/ton (if PacifiCorp's claimed cost of capital of 7.303% is used in the cost analysis) are within the range of dollar per ton values that other states consider as cost effective under the second round regional haze plans.

UDAQ has acknowledged that it likely would consider SCR at Hunter Unit 3 to be cost effective, stating that "the relatively lower estimated $/ton for SCR for Hunter Unit 3 merits further evaluation of whether this control could be cost-effective."[111] Although UDAQ has not identified a cost-effectiveness threshold for its regional haze plan for the second implementation period, this statement implies that UDAQ at least considers cost effectiveness values of $4,400/ton (i.e., PacifiCorp's cost effectiveness calculation for SCR at Hunter Unit 3 using a 7.303% interest rate) as cost effective.

In an attempt to discount the cost effectiveness of SCR, UDAQ conducted a sensitivity analysis to examine how the cost effectiveness of SCR (using PacifiCorp's costs and weighted cost of capital) would vary with lower or higher utilization rates of the EGUs.[112] UDAQ's analysis shows that the less that a unit operates, the less cost effective (i.e., higher annual costs per tons of NOx removed) a control is, and the more a unit operates, the most cost effective a control is. UDAQ states that the electricity generation industry is experiencing significant change and that there is great uncertainty in the near and medium-term operation of the Hunter and Huntington units. While UDAQ presented Hunter and Huntington plant capacity factors on a facility-wide basis to show that the plants are being utilized less in recent years compared to how the plants were utilized in 2008-2013, [113] that analysis is not relevant to an evaluation of PacifiCorp's cost effectiveness analysis for NOx controls at each unit which was based on

[111] April 2022 Draft Utah Regional Haze Plan at 127.
[112] *Id.* at 130.
[113] *Id.* at 131.

the average of 2015-2019 emissions. In addition, it is not clear why UDAQ evaluated capacity factors on a plantwide basis, when cost effectiveness is determined on a unit-specific basis.

I calculated each unit's average operating capacity factors for the five years that PacifiCorp used to estimate baseline emissions (2015-2019) and compared that to the capacity factor of the most recent two years (2020 and 2021). This analysis is shown in the table below.

Table 10. Averaging Operating Capacity Factor over 2015-2019 Compared to 2020 and 2021 Operating Capacity Factors at Hunter Units 1,2, and 3 and at Huntington Units 1 and 2.[114]

Plant Unit	2015-2019 Average Operating Capacity Factor	2020 Operating Capacity Factor	2021 Operating Capacity Factor
Hunter Unit 1	72.8%	74.1%	77.4%
Hunter Unit 2	73.8%	74.4%	78.1%
Hunter Unit 3	74.2%	56.9%	81.2%
Huntington Unit 1	72.3%	59.5%	80.6%
Huntington Unit 2	66.5%	58.2%	80.9%

As the data in the above table demonstrates, while 2020 operating capacity factors were lower for some units compared to the 2015-2019 average operating capacity factors, the operating capacity factor in 2021 was higher for all five units compared to the 2015-2019 average capacity factors. This analysis shows that the average operating capacity factor upon which PacifiCorp's NOx control cost effectiveness analyses are based were reasonably reflective of current operations.

UDAQ's statements that the five coal-fired units capacity factors could decrease in the future are speculative at this point. There currently are a lot of unknowns that could result in increased generation from existing coal-fired EGUs (such as increases in natural gas prices, loss of available hydropower in the West due to drought) or that could result in decreases in generation from coal-fired EGUs (such as from increased renewable energy sources coming online). EPA has acknowledged that the capacity factor of EGUs varies over time and has found that a five-year timeframe is adequate to reflect the business cycle of an EGU.[115] PacifiCorp's use of a recent five-year average of emissions and operating characteristics appears to be a reasonable estimate of expected operations in 2028. Unless PacifiCorp takes enforceable restrictions on the future operating capacity factor of the Hunter or Huntington units that would negate the need for additional reasonable progress controls, UDAQ should not exclude cost-effective controls from its regional haze plan based on speculation about how the units may be operated in the future.

For all of the above reasons, UDAQ should consider SCR to be a cost-effective control at all of the Hunter and Huntington units.

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[114] Capacity factor was calculated based on each unit's annual gross load in megawatts as reported to EPA's Air Markets Program Database for each year and divided by the product of each unit's hourly generating capacity (480 MW for all units except Hunter Unit 3 which has a generating capacity of 495 MW) multiplied by the potential operating hours in a year (i.e., 8,760 hours for all years except leap years when the total hours in a year are 8,784).
[115] *See* 57 Fed. Reg. 32,314 at 32,325 (July 21, 1992).

C. Consideration of the Time Necessary for Compliance, the Energy and Non-Air Quality Related Environmental Impacts of Compliance, and the Remaining Useful Life of the Hunter and Huntington Units.

While the costs of compliance support NOx controls for the Hunter and Huntington units, the other reasonable progress factors are either neutral or further support such controls. PacifiCorp has stated that SCR or SNCR could be installed and operated by the end of the second regional haze planning period in 2028.[116] Thus, the time necessary for compliance with NOx controls should not be an issue.

PacifiCorp did raise concerns with the parasitic load of SCR, as well as the water that would be used to generate the additional power, the coal combustion residue waste that would be generated and need to be disposed of, and the additional greenhouse gas emissions that would be emitted from the additional coal burned.[117] It is true that there is a parasitic load with SCR, but the costs for the energy penalty, water, and wastes generated are already taken into account in the cost analysis. They should not be double-counted by including them as a penalty against SCR elsewhere in the four-factor analyses. PacifiCorp also raised the concern of using ammonia with SCR and urea with SNCR, because both are hazardous substances.[118] However, these pollution controls and reagents have been used at numerous EGUs and proper procedures for handling and storing ammonia and urea have been long established. PacifiCorp has not identified any unique energy or non-air impact with the use of SNCR or SCR at the Hunter and Huntington units that would justify excluding either of the controls in a four-factor analysis.

Although PacifiCorp did not provide any cost analyses based on a shortened remaining useful life of the Hunter and Huntington units, PacifiCorp did point out that Huntington Units 1 and 2 have a projected retirement date of 2036 in PacifiCorp's Integrated Resource Plan (IRP) and that Hunter Units 1, 2, and 3 have a projected retirement date of 2042.[119] But to properly take into account a shorter useful life of an emissions unit than the life of the pollution control in a cost effectiveness analysis, the requirement to cease operation must be enforceable.[120] The "end of life year" listed in PacifiCorp's IRP is not an enforceable requirement.

D. Summary: There are Cost Effective NOx Control Options for the Hunter and Huntington Units that Should Warrant Adoption of Control Measures as Part of UDAQ's Long Term Strategy for Achieving Reasonable Progress Towards the National Visibility Goal

As shown in Table 5 above, SCR at Hunter Units 1, 2, and 3 and at Huntington Units 1 and 2 would be cost effective, with SCR achieving greater than 2,100 to 3,600 tons per year of NOx reductions at each unit at costs ranging from $4,400/ton to $6,500/ton (based on PacifiCorp's cost analysis including its

[116] April 2020 PacifiCorp Four-Factor Analysis, Attachment 1 at 12 and 24 (pdf pages 14 and 24 of submittal).
[117] *Id.* at 13-14 and at 24-26.
[118] *Id.* at
[119] PacifiCorp Reasonable Progress Analysis at 16 and 28.
[120] *See* EPA's August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 33.

7.303% cost of capital). Based on UDAQ's criteria for selecting sources to evaluate for controls in its regional haze plan for the second implementation period, the Hunter and Huntington facilities are the second and third highest emitters of regional haze pollutants, the Hunter plant has the highest Q/d value and the Huntington plant has the third highest Q/d value.[121] Given that cost-effective NOx controls exist for these units and that none of the other three factors (remaining useful life, non-air and energy impacts, and time to install controls) would be an impediment to the successful and cost-effective implementation of controls, UDAQ should reconsider its proposed action to not require any NOx controls at the Hunter and Huntington units as part of its long term strategy for the second implementation period and impose NOx reduction requirements for these units.

It also must be noted that these units will likely be required to install SCR in the next three years to comply with EPA's recently proposed Good Neighbor Plan. On April 6, 2022, EPA proposed a Federal Implementation Plan (FIP) that would impose requirements on 26 states, including the state of Utah, to meet their Clean Air Act obligation to eliminate significant contribution to nonattainment or interference with maintenance of the 2015 ozone National Ambient Air Quality Standards (NAAQS).[122] This rule, when finalized, will set ozone season NOx emission budgets that, starting in 2026, would reflect the installation of SCR at large coal-fired EGUs at the approximately 30% of EGUs that do not currently have SCR systems.[123] While this rule is not proposed to specifically mandate installation of SCR at all coal-fired EGUs in the 26 states covered by the rule, it will set ozone season NOx budgets in 2026 and beyond that will be calculated as if SCR was installed and an emission rate of 0.05 lb/MMBtu was achieved.[124] In addition, the Good Neighbor rule would set a 0.14 lb/MMBtu backstop limit to ensure that SCR systems that are installed are routinely operated.[125] I reviewed the EPA's proposed ozone season NOx budgets for Utah and, even with the coal-fired units at the Intermountain Generating Station ceasing operation, the NOx budgets would necessitate SCR installation at all of the Hunter and Huntington units.

The forthcoming Good Neighbor plan should not be considered as negating the need for UDAQ to adopt its regional haze plan now, including reasonable progress controls for the PacifiCorp units, as UDAQ's obligations to adopt a long term strategy to achieve reasonable progress towards the national visibility goal is now overdue to EPA, and it is not known for certain when the Good Neighbor plan will be promulgated and if any plans regarding implementation of the plan might change between the proposed and final rule. But the proposed Good Neighbor is another factor to consider in deciding whether it is cost-effective for PacifiCorp to install SCR at the Hunter and Huntington units. EPA has

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[121] *See* https://deq.utah.gov/air-quality/regional-haze-in-utah#planning.
[122] 87 Fed. Reg. 20,036 (Apr. 6, 2022). *See also* https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs.
[123] *See* EPA's Proposed "Good Neighbor" Plan to Address Ozone Pollution – Overview," available at https://www.epa.gov/system/files/documents/2022-03/fact-sheet_2015-ozone-proposed-good-neighbor-rule.pdf.
[124] 87 Fed. Reg. 20,036 at 20,081 (Apr. 6, 2022).
[125] *Id.* at 20,105-6 and 20,110-1.

stated that roughly 60% of the coal-fired EGUs in the 26 states covered by the Good Neighbor plan already have installed SCR.[126] This shows that multiple similar sources have installed SCR, which weighs heavily in favor of UDAQ findings that SCR is cost effective for the Hunter and Huntington units.

For all of these reasons, UDAQ should find that SCR is a cost-effective regional haze control for the Hunter and Huntington EGUs.

III. Intermountain Generating Station

The Intermountain Generating Station consists of two coal-fired EGUs, each with generating capacity of 1,800 MW. The power plant is owned by Intermountain Power Service Corporation (IPSC) and is located in Delta, Utah. In UDAQ's list of sources initially selected to perform a four-factor analysis, the Intermountain Generating Station is identified as having the highest total NOx, SO2, and PM10 emissions, and has the second highest Q/d value of 193.6.[127] The closest Class I area to the plant is Capitol Reef National Park, which is 149.5 km away.

As UDAQ discusses in its draft Regional Haze plan, IPSC plans to replace the coal-fired boilers with a natural gas combined cycle power plant.[128] California Senate Bill (SB) 1368, enacted in 2008, directed the California Energy Commission to establish a greenhouse gas (GHG) emission performance standard for electricity generation. UDAQ states "[b]ecause approximately 98 percent of the power generated at the Intermountain Generation Station (IGS) is consumed by customers of California utilities and because the power generated by the IGS's two coal-fired units exceeds California's GHG EPS, the current contract for coal-fired generation, which expires in 2025, will not be renewed for power from those units. Instead, the permittee, Intermountain Power Service Corporation (IPSC), plans to replace the coal-fired units with an EPS-compliant combined-cycle natural gas plant, which will be highly thermally efficient, and which will include state-of-the-art emissions controls such as SCR."[129]

In fact, IPSC submitted a permit application to UDAQ in August 2021 to replace the coal-fired units with two natural gas- and hydrogen fuel-fired combined cycle combustion turbines,[130] and UDAQ recently proposed issuance of a permit modification to authorize the construction of the combined cycle power plant.[131] According to IPSC's permit application, the company plans to being construction this year, in the second or third quarter of 2022, and indicates the shutdown of the existing coal-fired units and the first firing of the new combined cycle combustion turbines would be in December 2024.[132]

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[126] 87 Fed. Reg. 20036 at 20080 (Apr. 6, 2022).
[127] *See* https://deq.utah.gov/air-quality/regional-haze-in-utah#planning.
[128] April 2022 Draft Utah Regional Haze Plan at 94.
[129] *Id*.
[130] August 2021, Air Construction Permit Application – Technical Support Document, IPP Renewal Project, Intermountain Generating Station, Ex. 9, available at https://daqpermitting.utah.gov/DocViewer?IntDocID=130215&contentType=application/pdf.
[131] UDAQ, Intent to Approve, Modification to Approval Order DAQE-AN103270026-14 for the IPP Renewal Project, Project Number: N103270029, April 29, 2022, Ex. 10, available at https://daqpermitting.utah.gov/DocViewer?IntDocID=130215&contentType=application/pdf.
[132] August 2021, Air Construction Permit Application – Technical Support Document, IPP Renewal Project, Intermountain Generating Station, at 2-4 (Ex. 9).

UDAQ indicates in its draft regional haze plan that the coal-fired units are expected to cease operation by mid-2025. As part of its regional haze rulemaking, UDAQ is proposing to adopt a requirement that the owner/operator of the Intermountain Generation Station must permanently close and cease operation of Intermountain Generation Station Units #1 and #2 by December 31, 2027.[133] However, the Intermountain Generating Station coal-fired EGUs will need to cease operating by the time any one of the new gas-fired combined cycle combustion turbines starts operating, which IPSC projected would occur by December 2024. Otherwise, the new combined cycle combustion turbines would cause a significant emission increase of NOx and other regulated new source review pollutants and would be subject to prevention of significant deterioration (PSD) permitting as a major modification.[134] UDAQ states in its draft Regional Haze Plan that it is establishing a closure date for the coal-fired units of no later than December 31, 2027 "to provide flexibility for closing the plant and the rescinding of the permit and approval order."[135] Yet, there will not be a need to rescind the permit and approval order, because in the current draft permit action for the new combustion turbines, UDAQ has proposed a condition that requires the existing coal-fired units to cease operation and be removed from service by the time the new combustion turbines are installed and operational.[136] For all of these reasons, UDAQ should revise its proposed regional haze requirement to be consistent with the requirements of its proposed permitting action for the new combined cycle combustion turbines. Specifically, UDAQ should revise its proposed regional haze requirement to mandate that the Intermountain Generation Station Units #1 and #2 permanently close and cease operation by no later than December 31, 2025.

In addition, as part of its four-factor analysis for the Intermountain Generating Station, UDAQ should document and evaluate the regional haze pollution controls proposed for the two new combined cycle combustion turbines in a four-factor analysis. UDAQ states in the draft regional haze plan that "[a]dditional data from [this] source, including 2018 emissions, projected 2028 emissions, and planned closure, allowed [this source] to be exempt from a 4-factor analysis."[137] However, UDAQ did not elaborate further on the projected 2028 emissions from the Intermountain Generating Station, and there are not any submittals from IPSC posted to UDAQ's "Current Regional Haze Planning" website.[138]

It appears that the Western Regional Air Partnership (WRAP) has assumed zero emissions from the Intermountain Generating Station in its 2028 modeling, because the plant is not listed in either the WRAP's "2028 coal scenarios" spreadsheet or in its "2018 and 2028 gas units" spreadsheet that are available on the WRAP's "EGU Emissions Analysis Project" website.[139] Yet, IPSC identified the emissions

[133] Draft Revisions to Utah State Implementation Plan, Emission Limits and Operating Practices, Section IX.H.23.a.
[134] UDAQ's draft Intent to Approve the IPP Renewal Project states that the project is not major modification under the PSD program. The only way that conclusion can be reached is if IPSC is planning to concurrently cease operation of the coal-fired units when at least one combined cycle combustion turbine becomes operational, so as to ensure no significant net emission increase would be projected from the IPP Renewal Project. *See* UDAQ, Intent to Approve, Modification to Approval Order DAQE-AN103270026-14 for the IPP Renewal Project, Project Number: N103270029, April 29, 2022, at 3 (Ex. 10).
[135] April 2022 Draft Regional Haze Plan at 94.
[136] See UDAQ, Intent to Approve, Modification to Approval Order DAQE-AN103270026-14 for the IPP Renewal Project, at 15 (Condition II.B.5.a.) (Ex. 10).
[137] April 2022 Draft Utah Regional Haze Plan at 93, note †.
[138] *See* https://deq.utah.gov/air-quality/regional-haze-in-utah#planning.
[139] *See* http://wrapair2.org/EGU.aspx. *See also* Ramboll, Run Specification Sheet, Representative Baseline (RepBase2) and 2028 On-the-books (2028OTBa2) Simulations at 2 (fn 5), available at

of the new combined cycle combustion turbines as 311.66 tons per year of NOx, 128.9 tons per year of SO2, and 112.62 tons per year of PM10.[140]

Although the new combined cycle combustion turbines are to be equipped with SCR to reduce NOx, UDAQ's draft permit allows the units to be exempt from the NOx emission limits that reflect SCR in the draft permit during startup and shutdown for up to 114.9 hours per 12-month period per turbine.[141] In addition, although IPSC's permit application indicates an intent to use a 30% hydrogen fuel blend and 70% natural gas in each turbine,[142] UDAQ's draft permit does not require that combination of fuels. Specifically, the draft permit would allow the new combustion turbines to use natural gas OR hydrogen as fuel in the combustion turbines, and it does not require that the units use any percentage of hydrogen as fuel for the combustion turbines.[143]

I calculated the allowable NOx emissions just from the new combined cycle combustion turbines, considering UDAQ's proposed allowable NOx emissions during startup and shutdown, to be 344.7 tons per year. The basis for that calculation is as follows:

UDAQ's draft permit requires each turbine to meet a 2.0 parts per million (ppmvd at 15% oxygen) NOx emission limit at "steady state" operation, which does not include startup and shutdown.[144] That 2.0 ppmvd NOx limit equates to 0.01 lb/MMBtu for natural gas firing.[145] The draft permit does not identify or limit the heat input capacity of each combustion turbine, but based on the information in the permit application, each combustion turbine has a maximum natural gas firing rate of 3,777,353 standard cubic feet per hour (scf/hr),[146] which equates to a maximum hourly heat input at each combustion turbine of

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https://views.cira.colostate.edu/docs/iwdw/platformdocs/WRAP_2014/EmissionsSpecifications_WRAP_RepBase2_and_2028OTBa2_RegionalHazeModelingScenarios_Sept30_2020.pdf.

140 August 2021, Air Construction Permit Application – Technical Support Document, IPP Renewal Project, Intermountain Generating Station, Appendix C at 2 (Ex. 9).

141 UDAQ, Intent to Approve, Modification to Approval Order DAQE-AN103270026-14 for the IPP Renewal Project, Project Number: N103270029, April 29, 2022, at 14, Condition II.B.3.d.2 (Ex. 10).

142 *See* Air Construction Permit Application – Technical Support Document, IPP Renewal Project, Intermountain Generating Station, August 2021, at 2-3 (Ex. 9).

143 UDAQ, Intent to Approve, Modification to Approval Order DAQE-AN103270026-14 for the IPP Renewal Project, Project Number: N103270029, April 29, 2022, at 13, Condition II.B.3.b (Ex. 10). The draft permit also does not have a limit on natural gas consumption at the turbines.

144 *Id.* at 14, Condition II.B.3.c.

145 Converted to lb/MMBtu based on formula in EPA's 1993 Alternative Control Techniques for Stationary Gas Turbines, Appendix A, available at https://www3.epa.gov/airquality/ctg_act/199301_nox_epa453_r-93-007_gas_turbines.pdf.

146 August 2021, Air Construction Permit Application – Technical Support Document, IPP Renewal Project, Intermountain Generating Station, Form 22 (Combustion Turbines) at 1 (at pdf page 121 of the Project File for the new Combined Cycle Combustion Turbine permit) (Ex. 10).

3,852.9 MMBtu/hour.[147] Thus, under the terms of UDAQ's draft permit, the two new combined cycle combustion turbines at the Intermountain Generating Station have the potential to emit NOx as follows:

> 0.01 lb/MMBtu NOx limit (reflective of 2.0 ppmvd) x 3,852.9 MMBtu/hour x (8,760 hours/yr excluding 114.9 hrs/yr for startup and shutdown) x 2 combustion turbines x (1 ton/2000 lb) =
>
> 333 tons NOx per year.
>
> Plus
>
> 100.8 lb NOx/hour limit during startup and shutdown x 114.9 hours of startup and shutdown allowed per rolling 12-month period x 2 combustion turbines x (1 ton/2000 lb) =
>
> 11.58 of allowable NOx emissions for startup and shutdown per year for the two turbines
>
> Which Totals
>
> 344.67 tons per year of allowable NOx emissions from the two new combustion turbines under the terms of UDAQ's proposed permit.

Thus, the NOx emissions from the Intermountain Generation Station are not going to be zero, as assumed by the WRAP, in 2028. Although UDAQ currently has a draft permit for the new combined cycle permits out for public review, regional haze requirements are not being factored into that permit decision. Given that the WRAP assumed 100% reduction in emissions from the Intermountain Generating Station in its 2028 regional haze modeling and yet the new combustion turbines are projected to emit significant quantities of regional haze pollutants, UDAQ must conduct a four-factor analyses of the new combined cycle units in the context of this draft regional haze plan and ensure that emission limitations and other permit conditions reflective of the most effective controls are required to be met by the new units.

There are additional NOx control options that UDAQ should evaluate for the proposed new combined cycle combustion turbines that have not been incorporated into the draft permit. First, the permit should limit the amount of natural gas that can be fired per year to require maximum amount of hydrogen firing in each turbine per year, which IPSC indicated will initially be 30% hydrogen.[148] As previously stated, the draft permit as currently written does not require any combination of hydrogen firing with natural gas at the new combustion turbines. Second, UDAQ should require that the combustion turbines operate in combined cycle mode, which is the most efficient operation of the units in terms of pollution emitted per megawatt-hour. Third, UDAQ should evaluate methods to minimize NOx emissions during startup and shutdown from the combustion turbines, including imposing more restrictive limits on the allowed number of startups and shutdowns per year. UDAQ should adopt these requirements as part of its regional haze plan to ensure that regional haze emissions are minimized from the new turbines to the maximum extent possible.

[147] This was calculated based on a heating value of natural gas of 1,020 Btu/scf.
[148] August 2021, Air Construction Permit Application – Technical Support Document, IPP Renewal Project, Intermountain Generating Station, at 2-3 (Ex. 9).

IV. Sunnyside Cogeneration Facility

The Sunnyside Cogeneration facility in Sunnyside, Utah ("Sunnyside Cogen") is a power generating station that has been in operation since 1993.[149] According to the Sunnyside four-factor analysis, it is considered to be a small power production facility and qualifies as a cogeneration facility under the Public Utility Regulatory Policy Act of 1997 ("PURPA").[150] This facility has a coal-fired circulating fluidized bed (CFB) boiler with a baghouse and a limestone injection system.[151] The CFB boiler produces steam that drives a turbine-generator. The facility also has a diesel engine and diesel emergency generator.[152]

The Sunnyside Cogen plant is considered by UDAQ to be a major source of SO2, NOx, PM10, as well carbon monoxide (CO) and hazardous air pollutants.[153]

According to UDAQ, the Sunnyside Cogen facility was selected for a four-factor analysis with a combined Q/d of 15.2. The closest Class I area is Canyonlands National Park which is 97 km away. The facility's emissions were identified by UDAQ as follows:

Table 12. Emissions Considered by UDAQ for the Sunnyside Cogen Plant for its Q/d Analysis[154]

	NOx, tpy	SO2, tpy	PM10, tpy
Facility Emissions	348.9	1,054.8	73.4

In the Sunnyside Cogen four-factor analysis of controls, the assumed baseline emissions for NOx were higher than reflected in Utah's Q/d analysis at 431 tons per year, and the SO2 were reported as lower than the emissions used in UDAQ's Q/d analysis at 471 tpy. No PM10 emissions were listed in the four-factor analysis. Less than 1 ton per year was identified as the baseline emissions for the emergency diesel engine and the emergency generator. This baseline emissions for the CFB Boiler (Emission Unit #1) provided in the company's four-factor analysis are shown in the table below.

Table 13. Sunnyside Cogen Annual Baseline Emission Rates[155]

Pollutant	CFB Boiler EU #1
NOx	**431**
SO2	**471**

The Sunnyside four-factor analysis states that the baseline emissions are based on average annual emissions for NOx and SO2 between 2016-2018.[156]

149 Sunnyside Cogeneration Associates, Sunnyside, UT, Sunnyside Cogeneration Facility Four-Factor Analysis, April 8, 2020 (hereinafter referred to as "April 2020 Sunnyside Cogen Four-Factor Analysis"), at 3-1.
150 *Id.*
151 *Id.*
152 *Id.*
153 *See* Title V Operating Permit Number 700030004, April 30, 2018, Sunnyside Cogeneration Associates, at 2.
154 *See* https://deq.utah.gov/air-quality/regional-haze-in-utah.
155 From Table 4-1 of the Sunnyside Cogen Four-Factor Analysis.
156 *Id.* at 4-1.

UDAQ has proposed to find that there are no cost-effective control options to reduce either SO2 or NOx from the Sunnyside Cogen facility.[157] UDAQ's determination is based on Sunnyside Cogen's initial four-factor analysis submitted in April of 2020 and revisions to its four-factor analyses submitted to UDAQ on October 15, 2021.[158] Below I provide a review and comments on Sunnyside's four-factor analyses as revised.

A. Sunnyside Cogen Assumed Too High of an Interest Rate in Determining Annualized Costs of Control.

Sunnyside Cogen assumed a 7% interest rate to determine annualized capital costs of the pollution controls it evaluated. Sunnyside provided its justification for this assumed interest rate in its October 2021 submittal to UDAQ. First, Sunnyside states that "it is important to ensure that the selected interest rate represents a longer-term view of corporate borrowing rates" because this analysis is evaluating equipment costs that may take place in the future.[159] However, this approach of attempting to take into account what interest rates may be in the future is inconsistent with the overnight cost methodology of the EPA Control Cost Manual.[160] Sunnyside also cites to OMB Circular A-94 to support a 7% interest rate, because it states that a discount rate of 7% should be used as a base-case for regulatory analyses.[161] However, EPA's Control Cost Manual states these interest rates are to be used when addressing the societal effect of regulations, but should not be used in evaluating an individual facility's costs of pollution controls.[162]

While the Control Cost Manual does allow for use of firm-specific interest rates, the methodology of how the firm-specific interest rate was established would need to be reviewed to ensure it is consistent with the methodology of the Control Cost Manual. With respect to the interest rate to be taken into account in financing costs, EPA's Control Cost Manual states: "[t]he appropriate interest rate in private cost assessment is the private interest rate for each firm affected. Determining private interest rates may be difficult due to the firm-specific nature of the private nominal interest rate faced by firms. If firm-specific interest rates are available, then the appropriate rates are simply the difference between the nominal interest rate minus the prevailing inflation in the industry."[163] Sunnyside has not identified any firm-specific interest rate to apply for its regional haze control cost effectiveness evaluation. EPA's Control Cost Manual states "[i]f firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates given the potential difficulties in eliciting accurate private nominal interest rates since these rates may be regarded as confidential business

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[157] April 2022 Draft Utah Regional Haze Plan at 147.
[158] October 15, 2021 Submittal from Sunnyside Cogeneration Associations to UDAQ Regarding "Response to UDAQ Questions on Sunnyside Cogeneration Associates Four-Factor Analysis" (hereinafter referred to as "October 2021 Sunnyside Submittal).
[159] October 2021 Sunnyside Submittal at 11.
[160] *See* EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017 at 11.
[161] October 2021 Sunnyside Submittal at 11.
[162] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017 at 16.
[163] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017 at 20.

information or difficult to verify."[164] Thus, because Sunnyside has not provided or justified any firm-specific nominal interest rate, the most appropriate interest rate to use in determining annualized capital costs is the current bank prime rate. As of the date of this report, the current bank prime lending rate is 4.0%.[165] Thus, a much lower interest rate than 7% should have been used to amortize capital costs of pollution controls. Sunnyside Cogen's use of a higher interest rate would overstate the annualized capital costs by amortizing the capital costs over the life of controls at an unreasonably high interest rate.

B. Sunnyside Cogen's Evaluation of SO2 Controls

The Sunnyside Cogen four-factor analysis for SO2 eliminated both wet scrubbers and spray dry scrubbers from consideration as an SO2 control because it does not have the water rights that would be needed for operation of the wet scrubber or a spray dry absorber.[166] It must be stated that the lack of water rights should not necessarily disqualify a pollution control technology as not technically feasible, and instead the costs of purchasing the necessary water rights (or municipal water) should be incorporated into the cost effectiveness analyses.

Sunnyside Cogen initially evaluated dry sorbent injection (DSI) as an SO2 control technology, but subsequently found that DSI could not be installed "due to space limitations requiring significant reconfiguration of existing equipment."[167] It appears that Sunnyside Cogen was using the term DSI to refer to a dry scrubber such as a spray dryer absorber. However, DSI consists of injection of sorbent into the flue gas duct between the air preheater and the baghouse, which does not present any space demands. Sunnyside has not presented information to indicate that DSI could not be injected in the flue gas duct work, in conjunction with the hydrated lime injected into the circulating fluidized bed boiler, to improve SO2 removal. Thus, Sunnyside had not justified eliminating DSI as an SO2 control technology.

In its October 2021 submittal to UDAQ, Sunnyside Cogen did evaluate use of a circulating dry scrubber (CDS) as an SO2 control to be used with the existing CFB boiler. The company claimed that "[g]iven the configuration of the existing units, there is not enough space between the CFB boiler and existing baghouse for the addition of a further CDS/CFBS unit without significant reconfiguration of existing equipment," but nonetheless Sunnyside Cogen also said a circulating dry scrubber is the only potentially feasible SO2 control option.[168]

It must be noted that Sunnyside Cogen did not provide any site photos or diagrams to justify why there was not enough space for it to utilize DSI technology or a circulating dry scrubber. Thus, UDAQ should not accept such claims without verifying what the space constraints are for the facility. Below I provide comments on Sunnyside's circulating dry scrubber analysis and provide a cost effectiveness analysis for DSI at the Sunnyside CFB boiler.

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[164] *Id.* at 15.
[165] https://fred.stlouisfed.org/series/DPRIME.
[166] April 2020 Sunnyside Cogen Four-Factor Analysis at 5-3 to 5-4.
[167] October 2021 Sunnyside Submittal at 7.
[168] October 2021 Sunnyside Submittal at 6.

1. Cost Effectiveness of a Circulating Dry Scrubber at the Sunnyside Cogen

Sunnyside Cogen submitted a cost analysis for a CDS that found the control would have a cost effectiveness of $68,027/ton of SO2 removed to achieve 74% removal.[169] There are several flaws in Sunnyside Cogen's analysis that would overstate the costs of control. Further, a CDS should be able to achieve 90% removal of SO2 from the Sunnyside CFB boiler, so the company underestimated SO2 removal efficiency.

Some of the deficiencies that would overstate costs of a circulating dry scrubber including the following:

<u>Use of too high of an interest rate</u>: For the reasons discussed in Section IV.A., the 7% interest rate is too high. Instead, Sunnyside Cogen should have used the bank prime lending rate, which is currently 4.0%.[170]

<u>Assuming too short of a life of a circulating dry scrubber</u>: Sunnyside Cogen assumed only a 20-year life of a circulating dry scrubber. EPA's Control Cost Manual states that wet and dry scrubbers should have a useful life of 30 years or even longer.[171]

<u>Use of a 1.3 Retrofit Cost Factor</u>: Sunnyside Cogen assumed a 1.3 retrofit factor for the circulating dry scrubber.[172] To justify this high retrofit factor, the company states: "In order to install a CDS/CFBS system the site would need to decommission the existing baghouse and utilize architectural and mechanical experts to fit both the CDS/CFBS and a new baghouse within the currently allocated space. Additionally, because the flow mechanics, namely turbulence, are key to the control efficiency, an outside contractor would need to ensure fluid mechanics were compatible. Sunnyside anticipates that these considerations would likely lead to a custom design and would justify the 1.3 retrofit factor."[173] However, Sunnyside has not adequately justified that its baghouse would need to be replaced. This is discussed further below. Sunnyside Cogen has not submitted site diagrams or other information to justify such a high retrofit factor, particularly for a CDS. CDS such as the Novel Integrated Desulfurization (NID™) scrubbers are known to have a compact footprint, less than 50% of the size of a typical spray dryer absorber.[174]

<u>Including Costs for Baghouse Replacement</u>: The costs for a CDS typically include the cost of a baghouse.[175] However, if a facility has an existing baghouse, that cost would not need to be incurred. Yet, Sunnyside Cogen claims it would need to replace its baghouse for any SO2 control installed. Its justification for having to replace the baghouse is that it is at the end of its useful life, stating that "[t]he current baghouse was made operational in January 1993 and is in marginal condition based on its age,

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[169] October 2021 Sunnyside Submittal, Attachment A at 1-2.
[170] https://fred.stlouisfed.org/series/DPRIME.
[171] EPA, Control Cost Manual, Section 5, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, April 2021, at 1-8, available at https://www.epa.gov/sites/default/files/2021-05/documents/wet_and_dry_scrubbers_section_5_chapter_1_control_cost_manual_7th_edition.pdf.
[172] October 2021 Sunnyside Submittal, Attachment A at 1.
[173] October 2021 Sunnyside Submittal at 10.
[174] *See* https://www.andritz.com/products-en/pulp-and-paper/environmental-solutions/combined-flue-gas-cleaning/novel-integrated-desulfurization.
[175] Refer to EPA CCM

requiring periodic repair to tubesheets, seals, and shell of the baghouse."[176] If the baghouse at Sunnyside Cogen is at the end of its useful life, it will need to be replaced whether or not regional haze control requirements are imposed. Thus, it is not justifiable for Sunnyside Cogen to include the costs of a new baghouse in its evaluation of SO2 controls for the regional haze plan.

Double counting of installation costs: Sunnyside Cogen projected an equipment cost of $66,600,000 for a CDS, based on the EPA Control Cost Manual, Section 5, Chapter 1 (Wet and Dry Scrubbers for Acid Gas Control) equations.[177] Those EPA cost equations include the scrubber installation costs, engineering, construction management, etc.[178] Yet, Sunnyside Cogen's cost analysis also includes costs for direct installation and indirect costs such as engineering and construction.[179] Thus, Sunnyside Cogen's capital costs double counted costs for these activities that are already included in the Control Cost Manual equations.

Costs for property taxes and insurance are not justified under the Control Cost Manual: Sunnyside Cogen took into account costs for property taxes and insurance.[180] Yet, in its Control Cost Manual, EPA does not typically include costs for property taxes or insurance for pollution controls, stating that "[i]n many cases, property taxes do not apply to capital improvements such as air pollution control equipment" and stating that "[a]n SCR system is not viewed as a risk-increasing hardware…[c]onsequently, insurance on an SCR system is on the order of a few cents per thousand dollars annually."[181] If an SCR system is not considered a risk-increasing hardware, a CDS also would not be viewed as a risk-increasing system, and thus there should not be much of an insurance increase for the addition of circulating dry scrubber. Thus, there is no justification for Sunnyside Cogen's inclusion of annual costs equating to 2% of the total capital investment for taxes and insurance.

Assumed too low of an SO2 removal efficiency with a CDS: Sunnyside Cogen only assumed 74% SO2 removal efficiency with a CDS.[182] Yet, a CDS can achieve up to 98% removal efficiency.[183] A review of the EPA's RACT/BACT/LAER Clearinghouse shows that, for the Spiritwood CFB boiler which is equipped with an add-on dry scrubber, an SO2 BACT limit reflective of 98.8% removal from worst case coal was established.[184] Applying a 98.8% removal to the worst case sulfur content coal used at the Sunnyside Cogen plant in the past 5 years equates to a controlled SO2 rate of 0.03 lb/MMBtu,[185] which would

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[176] October 2021 Sunnyside Submittal at 7.
[177] October 2021 Sunnyside Submittal, Attachment at 1.
[178] *See* EPA, Control Cost Manual, Section 5, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, April 2021, at 1-28 to 1-30, available at https://www.epa.gov/sites/default/files/2021-05/documents/wet_and_dry_scrubbers_section_5_chapter_1_control_cost_manual_7th_edition.pdf.
[179] October 2021 Sunnyside Submittal, Attachment at 1.
[180] *Id.*
[181] *See*, e.g., EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80 (Equation 2.69). See also EPA Control Cost Manual, Section 4, Chapter 1 (SNCR), at 1-54.
[182] October 2021 Sunnyside Submittal, Attachment at 1.
[183] *See*, e.g., Sargent & Lundy, IPM Model – Update to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, January 2017, at 2, available at https://www.epa.gov/system/files/documents/2021-09/attachment_5-2_sda_fgd_cost_development_methodology.pdf.
[184] See EPA's RACT/BACT/LAER Clearinghouse, RBLC ID ND-0024, available at https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information.
[185] *See* Energy Information Administration, Coal Data Browser, Shipments to Sunnyside Cogen, attached as Ex. 11. According to this data, the worst case uncontrolled SO2 in the coal over the past five years was 2.4 lb/MMBtu.

reflect an SO2 removal efficiency across the CDS of 82% from the baseline SO2 emission rate of 0.17 lb/MMBtu. Thus, Sunnyside should not have assumed an SO2 removal efficiency of any lower than 82% across the CDS, which should be readily achievable.

To address these issues, I re-calculated the cost effectiveness for a CDS at the Sunnyside Cogen CFB boiler. Sargent & Lundy have stated that "[r]ecent industry experience has shown that a CDS FGD system has a similar installed cost to a comparable SDA FGD system and has been the technology of choice in the last four years."[186] Accordingly, I used the EPA's cost spreadsheet made available with its Control Cost Manual for Spray Dryer Absorbers (SDA) to estimate cost effectiveness for a CDS at Sunnyside Cogen. For SDA costs, the EPA cost spreadsheet made available with its wet and dry scrubber Control Cost Manual update includes the costs of a baghouse which is a necessary part of an SDA system to achieve the highest levels of SO2 control.[187] Because Sunnyside Cogen has an existing baghouse, the capital and operating cost of a baghouse was subtracted from capital and operating costs of a dry FGD system. EPA's Integrated Planning Model cost module for particulate control provides cost algorithms for a baghouse,[188] which was used for this purpose. A worksheet was created that incorporated the costs for a full-scale baghouse for the Sunnyside Cogen CFB boiler with an air-to-cloth ratio of 4.0 or lower. I then subtracted the capital costs of a baghouse from the estimated cost of an SDA FGD system calculated by EPA's Control Cost Manual Wet and Dry Scrubbing Cost Spreadsheet, and I also subtracted variable and fixed operation and maintenance costs of a baghouse from the variable and fixed operation and maintenance cost of an SDA FGD system, to arrive at a capital and operational/maintenance cost estimate for a CDS system at the Sunnyside Cogen CFB Boiler.

In EPA's cost spreadsheet, I input specific data for the Sunnyside Cogen CFB boiler from the company's April 2020 four-factor analysis and from the company's October 2021 updated submittal to UDAQ. I assumed a 4% interest rate and a 30-year life of controls to determine annualized capital costs. I used Sunnyside Cogen's costs for lime from its limestone supplier, its total busbar costs for electricity, and its employee hourly pay, and used EPA default values for all other cost inputs. Based on the baseline emissions information provided by Sunnyside Cogen, I input the CDS inlet SO2 rate of 0.17 lb/MMBtu and assumed an SO2 outlet emission rate of 0.03 lb/MMBtu, reflective of 82% control across the CDS. The results of this cost analysis are provided in the table below.

[186] Sargent & Lundy, IPM Model – Update to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, January 2017, at 2.
[187] *See* EPA, Control Cost Manual, Section 5, Chapter 1, Wet and Dry Scrubbers for Acid Gas Control, at 1-49.
[188] Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Particulate Control Cost Development Methodology, April 2017, available at https://www.epa.gov/airmarkets/retrofit-cost-analyzer.

Table 14. Cost Effectiveness of a Circulating Dry Scrubber (Using the Existing Baghouses) at Sunnyside Cogen CFB Based on 30-Year Life of Controls and the EPA Control Cost Manual Spreadsheets[189]

Controlled Annual SO2 Rate, lb per MMBtu	Capital Cost (2019$)	O&M Costs	Total Annualized Costs	SO2 Reduced from 2018-2019 Baseline, tpy	Cost Effective-ness, $/ton
0.03	$33,666,198	$2,051,596	$4,032,451	388	$10,396/ton

These costs are much lower than the cost effectiveness calculated by Sunnyside of $68,000/ton. The revised cost of $10,396/ton is at the top end of cost thresholds that some other states have found to be cost effective in their regional haze plans, including Oregon and Colorado as discussed in Section I.A. above. However, this cost effectiveness calculation is based on the baseline SO2 emissions provided by Sunnyside Cogen of 471 tons per year. UDAQ's Q/d analysis indicates that the Sunnyside Cogen's SO2 emissions in 2014 were much higher at 1,054.8 tons per year.[190] A review of the coal sulfur content in 2014 shows that it was much higher as well. Indeed, in 2013-2015, the uncontrolled SO2 emissions in the coal used at Sunnyside Cogen ranged from 3.23 to 3.29 lb/MMBtu whereas, from 2017 to 2021, the uncontrolled SO2 in the coal ranged from 2.20 to 2.41 lb/MMBtu.[191] If a higher SO2 baseline emissions were evaluated, that would make a CDS even more cost effective due to greater quantities of SO2 removed.

To determine how much more cost effective a CDS would be at Sunnyside Cogen if the facility used higher sulfur coal, I revised the CDS cost analysis to use a higher inlet SO2 emission rate. I first determined that the CFB boiler is achieving about 93% SO2 removal across the CFB boiler based on Sunnyside Cogen's stated baseline emission rate of 0.17 lb/MMBtu, which it said reflected emissions over 2016-2018,[192] and the uncontrolled SO2 in the coal over that time of 2.41 lb/MMBtu.[193] I then estimated the Sunnyside Cogen CFB boiler's SO2 emission rate when burning coal of average uncontrolled emissions reflective of coal burned in 2013-2015 of 3.26 lb/MMBtu,[194] assuming 93% control across the CFB boiler, which would equate to an SO2 emission rate emitted from the boiler of 0.23 lb/MMBtu. I used this as the CDS scrubber inlet emission rate and a 0.03 lb/MMBtu controlled SO2 emission rate as the scrubber outlet emission rate. This would reflect 87% SO2 removal across the CDS, which is capable of over 98% removal as discussed above. I did not otherwise change baseline operational characteristics of the CFB boiler from what Sunnyside Cogen assumed in its four-factor submittal to UDAQ. I found that assuming a higher sulfur coal was being used at the Sunnyside Cogen CFB boiler would reduce the cost effectiveness value of CDS to achieve a controlled 0.03 lb/MMBtu annual rate from $10,258/ton to $7,395/ton.

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189 *See* Cost Effectiveness Workbook for CDS without baghouse for Sunnyside Cogen, attached as Ex. 12.
190 April 2022 Draft Utah Regional Haze Plan at 93.
191 *See* Energy Information Administration, Coal Data Browser, Shipments to Sunnyside Cogen, attached as Ex. 11.
192 April 2020 Sunnyside Cogen Four-Factor Analysis at 4-1.
193 *See* Energy Information Administration, Coal Data Browser, Shipments to Sunnyside Cogen, attached as Ex. 11.
194 *Id.*

If Sunnyside Cogen's coal sulfur content is expected to increase again in the future, that should be a factor in UDAQ's decision regarding the SO2 control requirements to impose on the Sunnyside Cogen boiler. Installing a CDS system could ensure the maximum SO2 reductions are achieved irrespective of the sulfur content of the coal used at the plant.

2. Cost Effectiveness of Dry Sorbent Injection for SO2 Control.

In its October 2021 submittal to UDAQ, Sunnyside Cogen stated that that DSI could not be installed "due to space limitations requiring significant reconfiguration of existing equipment."[195] It appears that Sunnyside Cogen was using the term DSI to reflect a dry scrubber such as a spray dryer absorber. However, DSI consists of injection of sorbent into the flue gas duct between the air preheater and the baghouse, which does not create space demands. DSI could be used in the flue gas duct work, in conjunction with the hydrated lime injected into the circulating fluidized bed boiler, to improve SO2 removal. Thus, Sunnyside had not justified eliminating DSI as an SO2 control technology.

In my report submitted by Conservation Organizations to UDAQ in October 2020, in which I provided a review and comments on various companies' initial four-factor analyses of controls including the Sunnyside Cogen Plant, I provided cost effectiveness analyses for DSI at the CFB boiler using lime to achieve 50% control and using unmilled trona to achieve 70% control.[196] UDAQ subsequently requested that Sunnyside Cogen evaluate use of sodium-based sorbent such as trona for use in DSI. Sunnyside Cogen responded that it did not evaluate changing the sorbent because "changing the sorbent chemistry will not address the integration of the baghouse with the CDS/CFBS control device, the need for computational fluid dynamic engineering to ensure proper operation of the CDS/CFBS" and also stated that "sodium-based sorbents have not been considered the best industry practice for at least the last 20 years."[197] These statements reflect that Sunnyside Cogen was using the term DSI to refer to a dry scrubber. However, it is acknowledged that trona is not typically used for sorbent injection along with lime being used in the CFB boiler. Below I provide the documentation for analysis I did in my October 2020 report of DSI with lime at the Sunnyside Cogen CFB boiler to achieve 50% SO2 control. I have updated my original cost effectiveness analysis to reflect the current bank prime rate of 4.0% and to reflect Sunnyside Cogen's stated busbar cost for electricity.

For these cost effectiveness analysis of dry sorbent injection, I used DSI cost spreadsheet templates from a cost spreadsheet used by EPA for evaluating cost effectiveness of DSI at coal-fired power plants in Texas as part of its December 16, 2014 Texas regional haze rulemaking.[198] EPA's DSI cost spreadsheet was based on the Sargent & Lundy IPM documentation for dry sorbent injection that existed at that time.[199] Since 2014, the IPM cost documentation for DSI and some of the cost equations were updated, and thus I updated the relevant formulas in the EPA spreadsheet template to reflect the April 2017

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[195] October 2021 Sunnyside Submittal at 7.
[196] Stamper, V., Comments on Company Submittals to the Utah Division of Air Quality on Air Pollution Controls to Make Reasonable Progress Towards the National Visibility Goal, October 28, 2020, at 31.
[197] October 2021 Sunnyside Cogen Submittal to UDAQ at 8.
[198] 79 Fed. Reg. 74,818 (Dec. 16, 2014).
[199] *Id.*at 74,876. *See also* the spreadsheet with filename: TX166-008-086_Costing_-_DSI Cost IPM 5-13_TX Sources_ver_2.xlsx in EPA Docket ID. EPA-R06-OAR-2014-0754 available at www.regulations.gov.

Sargent & Lundy documentation for dry sorbent injection.[200] In addition, some aspects of the EPA spreadsheet cost template were made specific to cost data that was provided in the Sunnyside Cogen DSI cost analysis, including the hourly cost for labor, the busbar cost for electricity, and the site-specific cost for lime.[201]

One cost that was not included in the DSI cost effectiveness analyses was the cost for fly ash waste at the Sunnyside CFB boiler, for the following reasons. First, the fly ash waste rate for the Sunnyside CFB is quite significant because of the high ash coal (41.425%) that is utilized in the boiler. According to Utah's Statement of Basis for a recent groundwater permit for Sunnyside Cogen facility, the burning of waste coal at the CFB boiler generates about 800 to 1000 tons per day of ash that is landfilled onsite.[202] The Sargent & Lundy documentation estimates a sorbent feed rate of 0.16 tons per hour for lime (or 3.84 tons per day) and a sorbent waste rate of 0.21 tons per hour (or 5 tons per day). Thus, the addition of fly ash waste with sorbent injection to the 800 to 1000 tons of ash currently disposed of per day at Sunnyside would be minimal. The Sargent & Lundy DSI documentation makes it optional to include the fly ash waste rate in the costs for DSI, and thus the fly ash waste rate was not included in the DSI cost effectiveness calculations presented herein.

The results of the DSI cost analysis are presented in the table below.

Table 15. Cost Effectiveness of Dry Sorbent Injection at Sunnyside Cogen's CFB Boiler, Assuming 50% SO2 Control with Lime[203]

Sorbent	SO2 Removal Efficiency Assumed	Capital Cost (2019 $)	Operational Costs	Total Annualized Cost, Assuming 3.25% Interest Rate and 30-Year Life	SO2 Reduced, tpy	Cost Effectiveness (2019 $)
Lime	50%	$5,946,031	$402,530	$746,390	236	$3,169/ton

As the above table demonstrates, dry sorbent injection with lime would be quite cost effective for the Sunnyside Cogen CFB boiler, achieving a 50% SO2 reduction at a cost effectiveness of $3,169/ton. While a circulating dry scrubber would achieve a much higher level of SO2 removal as discussed above, if nothing else, dry sorbent injection should be considered as a cost effective control technology to require as a measure to make reasonable progress towards the national visibility goal.

[200] Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology, April 2017, at 8, available at https://www.epa.gov/system/files/documents/2021-09/attachment_5-5_dsi_cost_development_methodology.pdf.
[201] *See* April 2021 Sunnyside Cogen Submittal to UDAQ at 8 and Attachment A at 2.
[202] Utah Statement of Basis, Ground Water Quality Discharge Permit UGW570002, April 2020, at 2 (Ex. 13).
[203] *See* Ex. 14 to this report, spreadsheet with cost for Sunnyside Cogen CFB -DSI with Lime.

3. Review of the Energy and Non-Air Environmental Impacts, the Time Necessary for Compliance, and the Remaining Useful Life of the CFB Boiler for the SO2 Controls Analyses.

For the factor regarding energy and non-air quality impacts of a pollution control being considered, it must be noted that the SO2 controls that have been evaluated for Sunnyside Cogen's CFB boiler are widely used by coal-fired EGUs and have been for many years. Thus, in general, these SO2 controls do not pose any unusual energy and non-air quality impacts. Further, the energy and non-air quality impacts are typically taken into account by including costs for additional energy use or for things like scrubber waste disposal is the analyses of the costs of control.

Of all of the types of add-on flue gas desulfurization systems, circulating dry scrubbers have the lowest energy usage, as well as low freshwater usage and zero liquid discharge.[204] The Southwestern Electric Power Company (SWEPCO) has recently installed a NID™ system at the Flint Creek Power Plant in Arkansas. Flint Creek is a 528 MW unit that burned low sulfur Powder River Basin coal with a 0.8 lb/MMBtu uncontrolled SO2 rate.[205] After evaluating several SO2 control systems, SWEPCO selected a NID™ system for SO2 control for the following benefits of a NID™ system: lowest capital and operation and maintenance costs on a 30-year cumulative present worth basis, lowest water consumption, lowest auxiliary power usage, lowest reagent usage, smallest footprint, best for mercury reduction with activated carbon injection, best for SO3 removal, and best for future National Pollution Discharge Elimination System (NPDES) permit compliance.[206] Dry sorbent injection will have lower energy needs and costs than a CDS, but CDS will have the other pollutant control reduction benefits and NPDES compliance benefits.

In terms of time necessary for compliance, DSI can be installed in 21 – 24 months. [207] During the adoption of the Mercury and Air Toxics Standards (MATS), EPA found that EGUs could install required controls, including scrubbers, within 3 years. Specifically, EPA stated in 2011 that "[u]nits that choose to install dry or wet scrubbing technology should be able to do so within the compliance schedule required by the [Clean Air Act] as this technology can be installed within the 3-year window."[208] In support of this claim, EPA referenced a letter to Senator Carper dated November 3, 2010, in which David Foerter, executive director of the Institute of Clean Air Companies (ICAC), stated that wet scrubbers could be

[204] *See* https://www.babcock.com/products/circulating-dry-scrubber-cds.

[205] *See* February 8, 2012 Direct Testimony of Christian T. Beam on behalf of Southwestern Electric Power Company, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding that Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Before the Arkansas Public Utilities Commission, Docket 12-008-U, at 5, 18 (Ex. 15).

[206] *Id.* at 19-21.

[207] *See*, e.g., Staudt, James, Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants, prepared for Northeast States for Coordinated Air Use Management, March 31, 2011, at 4, available at https://www.nescaum.org/documents/nescaum-comments-nj-s126-petition-to-epa-20110525-combo-final.pdf. *See also* https://www.downtoearth.org.in/news/energy/in-a-first-a-thermal-power-plant-decides-to-use-dsi-technology-to-curb-so2-emission-60823. Also see a number of consent decrees that require that DSI be operational in less than two years from the date of execution, such as this one: https://www.epa.gov/enforcement/consent-decree-cinergy-corporation-et-al-duke-energy-civil-action-no-199-cv-01693-ljm.

[208] 76 Fed. Reg. 24976, 25054 (May 3, 2011).

installed in 36 months, dry scrubbing technology could be installed in 24 months, and dry sorbent injection could be installed in 12 months.[209]

In its October 2021 submittal to UDAQ, Sunnyside Cogen indicated that "it is estimated that the CFB boiler will not be operating beyond an additional 20 years."[210] However, UDAQ has not proposed to make this estimated 20 year life an enforceable requirement for the Sunnyside Cogen CFB boiler. EPA states that, if there are no enforceable limitations on the remaining useful life of a source, the expected life of the pollution controls is generally considered the remaining life of the source.[211] Thus, it is appropriate to assume that the remaining useful life of the CFB boiler is the same as the useful life of the controls evaluated, which in this case is 30 years as discussed in Section IV.B.1. above.

4. Summary – There are Cost Effective SO2 Controls for the Sunnyside Cogen CFB Boiler that Should be Considered as Part of UDAQ's Long Term Strategy for Achieving Reasonable Progress Towards the National Visibility Goal.

As discussed above in the analyses provided herein, DSI is a very cost effective SO2 control that could be used at the Sunnyside Cogen CFB boiler to achieve 50% reduction in SO2 emission rates and a reduction of 236 tons of SO2 per year at a cost effectiveness of $3,169/ton. Sunnyside Cogen has stated that DSI could not be installed at the CFB boiler and as stated above, it seems that Sunnyside Cogen was referring to a spray dryer absorber and not DSI that is injected into the flue gas between the air preheater and the baghouse. There is no documentation in the draft regional haze plan that dry sorbent injection could not be used at the Sunnyside Cogen CFB boiler to achieve improved SO2 reductions from the coal-fired CFB boiler.

Further, a circulating dry scrubber should also be considered cost effective, especially when considering that the Sunnyside Cogen CFB boiler has utilized coal of higher sulfur content, and had much higher SO2 emissions, in the recent past. With no limit in its permit on coal sulfur content, there is no reason to think that the coal sulfur content could not increase again and, with a higher coal sulfur content consistent with what has historically been used at the CFB boiler, the cost effectiveness of a CDS would be in the range of from $7,395/ton to $10,396/ton. A CDS would reduce SO2 emissions from current emission levels by 388 tons per year.

C. NOx Four-Factor Analysis for the Sunnyside Cogen CFB Boiler.

Sunnyside Cogen evaluated two control technologies for NOx control at its CFB boiler: SCR and SNCR. The company used EPA's SCR and SNCR cost effectiveness spreadsheets made available with the EPA Control Cost Manual.[212] Sunnyside Cogen's cost analyses of these controls found that SCR to achieve 90% NOx control would have a cost effectiveness of $13,445/ton and that SNCR to achieve 15% NOx

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[209] *Id.*, fn 172.
[210] October 2021 Sunnyside Cogen Submittal to UDAQ at 11.
[211] *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 33.
[212] October 2021 Sunnyside Cogen Submittal to UDAQ at pdf pages 22 and 29.

control would have a cost effectiveness of $9,268/ton.[213] However, there are several deficiencies in Sunnyside's cost analyses for these controls. As previously discussed in Section IV.A. of this report, one of those deficiencies is using a 7% interest rate that has not been justified as a firm-specific nominal interest rate. Without such justification, the most appropriate interest rate to use in determining annualized capital costs is the current bank prime rate. As of the date of this report, the current bank prime lending rate is 4.0%.[214]

Other issues with Sunnyside Cogen's SCR and SNCR cost analysis including the following:

<u>1.3 Retrofit Factor for SCR</u>: Sunnyside Cogen incorporated a 30% increase in costs of SCR as a retrofit factor. The company's justification for this was because the SCR would need to be used in a low dust location, downstream of the baghouse, because otherwise the particulate loadings from the CFB boiler with limestone would be too high.[215] The company explained that this would require the installation of a combustion device and reheating of the flue gas.[216] However, the company has not provided justification to show that a low dust configuration at its CFB boiler would increase costs over a typical retrofit by 30%. First, installation of the SCR after the baghouse should presumably be easier than retrofitting an SCR upstream of the particulate control device (as most SCR retrofits are done at coal-fired EGUs) because there are likely less space constraints. It also must be noted that EPA's SCR chapter in its Control Cost Manual already provides for a 25% increase above the cost of SCR at a new greenfield coal-fired boiler in its SCR cost spreadsheet, because EPA's spreadsheet calls for use of a 0.8 retrofit factor for an SCR installation at a new facility and a "1" retrofit factor for an average SCR retrofit.[217] Third, the cost of the fuel for reheating the flue gas for an SCR in a low dust location should be taken into account as an operational expense, not as an increase in capital expenditures. UDAQ must request that Sunnyside Cogen provide more specific documentation for its use of a 1.3 retrofit factor to reflect the installation of a combustion device due to the SCR having to be installed downstream of the baghouse.

<u>Life of Controls:</u> Sunnyside Cogen only assumed a 20-year life of controls, stating that "it is estimated that CFB boiler will not be operating beyond an additional 20 years."[218] As previously stated, EPA states that, if there are no enforceable limitations on the remaining useful life of a source, the expected life of the pollution controls is generally considered the remaining life of the source.[219] UDAQ has not proposed to limit the remaining life of the Sunnyside Cogen CFB boiler, thus the life of the control equipment should be used in the cost analysis. In its Control Cost Manual, EPA has found that the useful life of an SCR system at a power plant would be 30 years, and EPA cited one analysis that assumed a design lifetime of 40 years.[220] While Sunnyside Cogen's October 2021 submittal indicates in the EPA SCR and SNCR cost spreadsheets that the CFB boiler is an industrial boiler, the unit is considered an electric utility steam generating unit as it is subject to 40 C.F.R. Part 60, Subpart Da per UDAQ's Title V permit for

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[213] *Id.* at 6-6.
[214] https://fred.stlouisfed.org/series/DPRIME.
[215] April 2020 Sunnyside Cogen Four-Factor Submittal at 6-4.
[216] October 2021 Sunnyside Cogen Submittal to UDAQ at 10.
[217] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 66.
[218] October 2021 Sunnyside Cogen Submittal to UDAQ at 11.
[219] *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 33.
[220] *Id.* at pdf page 80.

the plant.[221] Thus, it is reasonable to assume a 30-year life for an SCR installed at the Sunnyside Cogen CFB boiler.

Although EPA states in the SNCR Control Cost Manual chapter that it is assumed than an SNCR would have a life of 20 years, EPA also states: "As mentioned earlier in this chapter, SNCR control systems began to be installed in Japan the late 1980's. Based on data EPA collected from electric utility manufacturers, at least 11 of approximately 190 SNCR systems on utility boilers in the U.S. were installed before January 1993. In responses to another ICR, petroleum refiners estimated SNCR life at between 15 and 25 years."[222] Therefore, based on a 1993 SNCR installation date, these SCNR systems that EPA refers to are at least 28 years old, which all other considerations aside, strongly argue for a 30-year equipment life. Furthermore, an SNCR system is much less complicated than a SCR system, for which EPA clearly indicates the life should be 30 years. In an SNCR system, the only parts exposed to the exhaust stream are lances with replaceable nozzles. The injection lances must be regularly checked and serviced, but this can be done relatively quickly, if necessary, is relatively inexpensive, and should be considered a maintenance item. In this regard, the lances are analogous to SCR catalyst, which is not considered when estimating equipment life. All other items, which comprise the vast majority of the SNCR system capital costs, are outside the exhaust stream and should be considered to last the life of the facility or longer. Given that EPA has assumed a 30-year life of SNCR in control cost calculations for coal-fired EGUs in the context of the regional haze program,[223] it is reasonable to assume a 30-year life of SNCR for application to the Sunnyside Cogen CFB boiler, as well as for SCR.

<u>Too High of an Annual Coal Throughput Assumed</u>: In both the SCR and the SNCR cost effectiveness analysis, Sunnyside Cogen assumed an unreasonably high annual coal throughput of 883,413,174 pounds of coal per year for the CFB boiler.[224] However, given the 700 MMBtu/hour maximum heat input capacity of the boiler and the company's stated high heating value of the coal of 7,072 Btu/lb,[225] this amount of coal use assumed by Sunnyside would equate to operating 8,924 hours per year at maximum heat input capacity, which is not possible. There are only 8,760 hours available hours in a year (8,784 in a leap year). Further, the Sunnyside Cogen Four-Factor Analysis indicates that the average annual operating hours of the CFB boiler were even lower at 8,031 hours per year.[226] The annual coal throughput is used for various parts of the costs of SCR and SNCR, including size of the SCR reactor and operational expenses of both SCR and SNCR, so the use of too high of a coal throughput would result in an overestimate of both capital and annual costs of SCR and SNCR.

1. Revised Cost Effectiveness of SCR and SNCR at the Sunnyside Cogen CFB Boiler

To address these issues, I revised the cost effectiveness calculations using EPA's SCR and SNCR spreadsheets. Specifically, revised analyses were done that assumed a 4.0% interest rate for amortizing

[221] *See* Title V Operating Permit Number 700030004, Sunnyside Cogeneration Facility, April 30, 2018, at 12, Condition I.A.2.
[222] EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-54.
[223] *See*, e.g., 80 Fed. Reg. 18944 at 18968 (April 8, 2015).
[224] See October 2021 Sunnyside Cogen Submittal to UDAQ at pdf page 16 and at pdf page 23.
[225] *Id.*
[226] October 2021 Sunnyside Cogen Submittal to UDAQ, Appendix A at 1.

capital costs and a 30-year life for an SCR and for SNCR. The spreadsheets were used to calculate costs for a utility boiler rather than an industrial boiler, which requires an input of annual megawatt-hours rather than coal throughput. To estimate annual megawatt-hours, I first calculated the annual heat input that would equate to Sunnyside Cogen's baseline NOx emissions of 431 tons per year and the baseline NOx emission rate of 0.15 lb/MMBtu, which equates to 5,746,667 MMBtu/year. Then, I divided the annual heat input by Sunnyside Cogen's stated heat rate of the unit of 12 MMBtu/MW, to arrive at 478,889 MW-hrs per year. I used the same busbar cost of electricity and the cost for 19% aqua ammonia that Sunnyside Cogen provided in its April 2021 submittal to UDAQ. The results of these revised cost effectiveness analyses are provided in the table below.

Table 16. Cost Effectiveness of SNCR and SCR at Sunnyside Cogen's CFB Boiler Based on EPA's SCR and SNCR Cost Spreadsheets, a 4% Interest Rate, and a 30-Year Life of Controls[227]

Control Evaluated	NOx Emission Rate, lb/MMBtu	Capital Cost of Control, 2019 $	Operating and Maintenance Costs	Total Annual Costs, 2019 $	Tons of NOx removed, tpy	Cost Effectiveness, 2019 $
SCR	0.015	$38,970,217	$695,701	$2,952,303	388	$7,611/ton
SNCR	0.12	$6,591,483	$419,539	$803,493	86	$9,321/ton

The company's cost effectiveness analyses were much higher than shown in the table above, with the company estimating $9,268/ton of NOx removed for SNCR and at $13,445/ton for SCR.[228] As the above table demonstrates, the cost for SCR is much more cost effective than represented in Sunnyside's four-factor analysis for the reasons discussed above. However, it is acknowledged that the above SCR cost analysis does not take into account costs for reheating the flue gas as would be needed to install the SCR in a low dust location, after the baghouse. Yet, even if the retrofit factor is increased to the 1.3 retrofit factor that Sunnyside Cogen used (which has not been adequately justified by the company), the cost effectiveness of SCR at the CFB boiler would increase to $9,506/ton. This conservative cost estimate still falls within the range that other states have found to be cost effective for the second round regional haze plans, even with a 30% retrofit factor. Oregon has adopted a much higher regional haze cost-effectiveness threshold of $10,000/ton.[229] Colorado is also using a cost-effectiveness threshold of $10,000/ton.[230] Thus, SCR should be considered as a cost effective control technology to require as a measure to make reasonable progress towards the national visibility goal.

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[227] *See* Exhibits 16 and 17 this report, spreadsheets with costs for Sunnyside SNCR and for Sunnyside SCR.
[228] October 2021 Sunnyside Cogen Submittal to UDAQ at pdf pages 22 and 29.
[229] *See* Oregon Regional Haze State Implementation Plan for the Period 2018-2028, Submitted for Adoption: Oregon Environmental Quality Commission, February 3, 2022, Appendix D at Item C pages 000190 and 000249 (pdf pages 60 and 119 of file), available at https://www.oregon.gov/deq/EQCdocs/020322_ItemC_AttachmentD_NoAppendices.pdf.
[230] *See* Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, November 17 to 19, 2021 Public Hearing, Prehearing Statement, at 7, available at https://drive.google.com/drive/u/1/folders/1TK41unOYnMKp5uuakhZiDK0-fuziE58v.

2. Review of the Energy and Non-Air Environmental Impacts, the Time Necessary for Compliance, and the Remaining Useful Life of the CFB Boiler for the SO2 Controls Analyses.

The use of SCR and SNCR presents several non-air quality and energy impacts, most of which are taken into account in EPA's SCR and SNCR cost spreadsheets in estimating the annualized costs of control. For SCR, those issues include the parasitic load of operating an SCR system, which requires additional energy (fuel and electricity) to maintain the same steam output at the boiler.[231] The costs for the additional fuel and electricity are taken into account in EPA's SCR cost spreadsheet. The spent SCR catalyst must be disposed of in an approved landfill if it cannot be recycled or reused, although it is not generally considered hazardous waste.[232] Further, the use of regenerated catalyst can reduce the amount of spent catalyst that needs to be disposed.[233] The EPA's SCR cost spreadsheet assumed regenerated catalyst will be used and includes costs for catalyst disposal. SCR technology is widely used at coal-fired EGUs. There are typically not overarching non-air quality or energy concerns with this technology, and many of the concerns are addressed in the cost analysis.

SNCR reduces the thermal efficiency of the boiler, which requires additional energy (fuel and electricity) to maintain the same steam output at the boiler.[234] The EPA's cost spreadsheet also takes into consideration increased ash disposal as a result of burning more fuel, as well as increased water consumption and treatment costs.[235] SNCR technology is also widely used at coal-fired EGUs, and there are typically not overarching non-air quality or energy concerns with this technology.

SCR systems are typically installed within a 3- to 5-year timeframe. For example, in Colorado, SCR was operational at Hayden Unit 1 in August of 2015 and at Hayden Unit 2 in June of 2016, according to data in EPA's Air Markets Program Database, within 3.5 years of EPA's December 31, 2012 approval of Colorado's regional haze plan. In Wyoming, SCR was operational at Jim Bridger Units 3 and 4 in 2015 and 2016, less than three years from EPA's January 30, 2014 final approval of Wyoming's regional haze plan.

SNCR installation is much less complex than an SCR installation, and thus it can typically be installed more quickly. In a 2006 document, the Institute of Clean Air Companies indicated that SNCR could be installed in 10-13 months.[236]

With respect to the remaining useful life, in its October 2021 submittal to UDAQ, Sunnyside Cogen indicated that "it is estimated that the CFB boiler will not be operating beyond an additional 20

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[231] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf pages 15-16, and 48.
[232] *Id. a*t pdf 18.
[233] *Id.* at pdf 18-19.
[234] EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-28 to 1-29.
[235] *Id.* at 1-46, 1-49 to 1-53.
[236] Institute of Clean Air Companies, Typical Installation Timelines for NOx Emission Control Technologies on Industrial Sources, December 4, 2006, at 4-5, available at https://cdn.ymaws.com/www.icac.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.

years."[237] However, UDAQ has not proposed to make this estimated 20 year life as an enforceable requirements for the Sunnyside Cogen CFB boiler. EPA states that, if there are no enforceable limitations on the remaining useful life of a source, the expected life of the pollution controls is generally considered the remaining life of the source.[238] Thus, it is appropriate to assume that the remaining useful life of the CFB boiler is the same as the useful life of the controls evaluated, which in this case is 30 years as discussed in Section IV.C. above.

3. Summary – There are Cost Effective NOx Controls for the Sunnyside Cogen CFB Boiler.

As discussed above in the analyses provided herein, SCR is a very cost effective NOx control that could be used at the Sunnyside Cogen CFB boiler to achieve 90% reduction in NOx at a cost effectiveness of \$7,600/ton to a worst case cost effectiveness of \$9,500/ton (based on Sunnyside's 1.3 retrofit factor). The cost effectiveness of SCR at the CFB boiler is within the range that other states have found to be cost effective in the second round regional haze plans. SCR would reduce NOx emissions from the Sunnyside Cogen CFB boiler by 90%, removing 388 tons per year from the air. Thus, UDAQ should consider adopting a requirement for the Sunnyside CFB boiler to implement this highly effective NOx control to achieve reasonable progress towards the national visibility goal.

V. Kennecott Utah Copper LLC – Mine and Copperton Concentrator

Kennecott Utah Copper, LLC operates the Bingham County mine and copper concentrator in Bingham Canyon, Utah. According to UDAQ, the facility has a combined Q/d of 22.1.[239] The closest Class I area is Capitol Reef National Park which is 237.2 km away. The facility's emissions were identified by UDAQ as follows:

Table 17. Emissions Considered by UDAQ for the Kennecott Utah Copper LLC – Mine and Copperton Concentrator for its Q/d Analysis[240]

	NOx, tpy	SO2, tpy	PM10, tpy
Facility Emissions	4,199.6	2.0	1,032.9

UDAQ's draft regional haze plan does not include a four-factor analysis or require any controls for this facility. UDAQ's justification was that the facility recently underwent a BACT analysis as part of the Salt Lake PM2.5 nonattainment SIP, and that "there are no additional controls that can be applied at this time."[241] UDAQ also states that NOx is the predominant visibility-impairing pollutant that comes from this facility and that the vast majority of NOx emissions is from mine haul trucks and other non-road equipment which UDAQ claims it cannot set emission standards for under Section 209 of the Clean Air

237 October 2021 Sunnyside Cogen Submittal to UDAQ at 11.
238 *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 33.
239 April 2022 Draft Utah Regional Haze Plan at 93.
240 *Id.*
241 *Id.* at 95.

Act.[242] UDAQ further states that its SIP does include "in-use requirements capping total mileage per calendar day for this equipment in relation to both PM10 and PM2.5 emissions" and states that it "does not anticipate emission reductions from this equipment until such time as the fleet turns over to more recent Tier 4 standards."[243]

According to EPA, a diesel engine is considered a nonroad engine if it is self-propelled or propelled while performing its function or portable or transportable (if it has wheels, skids, carrying handles, a dolly, trailer, or platform), although a nonroad engine becomes a stationary engine if it stays in one location for more than 12 months (or for a full annual operating period of a seasonal source).[244] EPA generally does not allow states to set emission standards for nonroad engines except through a specific process outlined in Section 209 of the Clean Air Act.[245]

UDAQ indicates the "vast majority" of the NOx emissions are from non-road engines at the Kennecott Utah Copper – Mine and Concentrator facility, and UDAQ provided a table separating out the "haul truck (non-road)" emissions from the "non-truck" emissions, to demonstrate that the Q/d from the "non-truck" emissions was 3.9 (less than its threshold for selecting sources for a four-factor analysis of 6.0).[246] UDAQ should identify what year of emissions was used for this analysis and provide the underlying emission inventory and calculations. UDAQ should also identify the sources that are not "non-road engines" at the facility and evaluate whether any control or operational limitations could be required of those emission units.

With respect to the non-road engines at the Kennecott Utah Copper LLC – Mine and Copperton facility, UDAQ should consider adopting requirements to incentivize the replacement of existing nonroad engines with Tier 4 engines at this facility. Tier 4 engines have been manufactured since 2008 and have significantly lower NOx and PM emissions than Tier 0 through 3 engines,[247] and thus the replacement of older, higher emitting engines could significantly reduce regional haze-impairing emissions from this facility.

VI. Kennecott Utah Copper LLC – Power Plant, Lab, and Tailings Impoundment

The Kennecott Utah Copper LLC – Power Plant, Lab, and Tailings Impoundment is located in Magna, Utah. According to UDAQ, the facility has a combined Q/d of 11.8. The closest Class I area is Capitol Reef National Park which is 250.4 km away. The facility's emissions were identified by UDAQ as follows:

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242 *Id.*
243 *Id.*
244 *See* EPA's "Understanding the Stationary Engines Rules," at https://www.epa.gov/stationaryengines/understanding-stationary-engines-rules. *See also* 40 C.F.R. §89.2.
245 Section 209(e)(2) of the Clean Air Act.
246 *Id.*
247 *See* https://dieselnet.com/standards/us/nonroad.php.

Table 18. Emissions Considered by UDAQ for the Kennecott Utah Copper LLC – Power Plant, Lab, and Tailings Impoundment for its Q/d Analysis

	NOx, tpy	SO2, tpy	PM10, tpy
Facility Emissions	1,322.5	1,500.3	126.8

UDAQ's draft regional haze plan does not include a four-factor analysis or require any controls for this facility. UDAQ's justification was that the coal-fired boilers at the facility were decommissioned and cited to an Approval Order from February 4, 2020.[248]

The 2020 Approval Order states that Units 1, 2, and 3 at the power plant are prohibited from operating under the PM SIP, but Unit 4 is listed as "voluntarily decommissioned."[249] The Approval Order states that the potential to emit for the source "is now below the small source exemption thresholds in R307-401-9; however, "Kennecott Utah Copper" has elected to retain the [Approval Order] for current operations."[250] In addition, under Section II.A. "The Approved Equipment" in the Approval Order, "Utah Power Plant" is listed.[251] Taken together, it seems as if Unit 4 of the power plant could potentially resume operations at some point in the future. For Utah to properly exempt Unit 4 of the Kennecott Utah Copper power plant from a four-factor analyses and to ensure legal clarity on this issue, UDAQ should impose a requirement in the Utah regional haze SIP stating that Units 1-4 of Kennecott Utah Copper LLC Power Plant shall remain permanently closed.

VII. Graymont Western US Incorporated – Cricket Mountain Lime Plant

Graymont Western US Incorporated ("Graymont Western") operates the Cricket Mountain Lime Plant located in Millard County, Utah. According to UDAQ, the facility has a combined Q/d of 9.0.[252] The closest Class I area is Bryce Canyon National Park which is 130.8 km away. The facility's emissions were identified by UDAQ as follows:

Table 19. Emissions Considered by UDAQ for the Graymont Western Cricket Mountain Plant for its Q/d Analysis[253]

	NOx, tpy	SO2, tpy	PM10, tpy
Facility Emissions	916.5	40.8	223.4

[248] April 2020 Draft Utah Regional Haze Plan at 95.
[249] See Approval Order DAQE-AN105720040-20, February 4, 2020, at 4, attached as Ex. 18 and available at https://daqpermitting.utah.gov/DocViewer?IntDocID=117327&contentType=application/pdf.
[250] *Id.* at 3.
[251] *Id.* at 6.
[252] April 2022 Draft Utah Regional Haze Plan at 93.
[253] *Id.*

The Cricket Mountain plant consists of quarries and a lime processing plant, which includes five rotary kilns (Kilns 1 through 5) which convert crushed limestone into quicklime. The kilns are fired by petroleum coke and coal.

The plant is a major source for particulate matter (PM10 and PM2.5), NOx, SO2, VOCs and other air pollutants.[254] The plant has five rotary lime kilns, each controlled by a baghouse.[255] The plant also has several other sources of air emissions including, but not limited to, kiln drives, generators, crushers, coal storage silos, and lime handling and transfer equipment.[256]

According to the most recent Approval Order for the facility, the Cricket Mountain Plant has the potential to emit 3,879.77 tpy of NOx, 760.28 tpy of SO2, and 610.37 tpy of PM10.[257] The potential to emit of these visibility-impairing pollutants is much higher than the emission data from the 2014 National Emissions Inventory used for the Q/d analysis.

In the four-factor analysis submitted for the Cricket Mountain Plant, Graymont Western only evaluated NOx controls for the five lime kilns.[258] The Cricket Mountain Plant four-factor analysis identifies the actual NOx emissions of the five kilns as totaling 639.0 tpy of NOx.[259] Based on the NOx emissions relied on by UDAQ to identify the Cricket Mountain Plant for review of 916.5 tpy, that means other emissions sources at the plant must contribute over 250 tpy of NOx to the plant's total NOx emissions. Yet, the Cricket Mountain Plant four-factor analysis did not identify other emission units or evaluate reasonable progress controls for other emission units. UDAQ should require that Graymont Western provide an emissions inventory for every emission unit that emits visibility-impairing pollutants, and UDAQ must require a four-factor analysis for other significant emission sources at the Cricket Mountain Plant.

UDAQ has proposed to find that no additional NOx controls beyond what the lime kilns were already implementing are technically feasible for the five lime kilns.[260] The lime kilns are currently equipped with low NOx burners. UDAQ's proposed finding was based on additional information submitted by Cricket Mountain to UDAQ in August of 2022 in which it claimed that SNCR might not be technically feasible for its lime kilns and that it would not be cost effective.[261] The following provides a review and comment on Graymont's August 2022 submittal to UDAQ and an evaluation of control options for the lime kilns at the Cricket Mountain Plant.

A. NOx Control Options for the Graymont Cricket Mountain Lime Kilns

Graymont Western provided the following information on the five lime kiln's actual NOx emission rates, based on 2014. A review of the most recent air permit for the Cricket Mountain Plant provides

[254] Title V Operating Permit Number 2700005003 issued April 11, 2018 for Graymont Western US Inc., Cricket Mountain Plant, at 2.
[255] *Id.* at 14.
[256] January 30, 2018 Approval Order DAQE-AN103130041-18 for Graymont Western US Incorporated at 3-7.
[257] January 30, 2018 Approval Order DAQE-AN103130041-18 for Graymont Western US Incorporated at 2.
[258] Reasonable Progress Four-Factor Analysis, Graymont Western US Inc., Cricket Mountain, UT, April 2020 (hereinafter referred to as the "Cricket Mountain Plant Four-Factor Analysis"), at 1-1
[259] *Id.*at 4-1.
[260] April 2022 Draft Utah Regional Haze Plan at 119.
[261] August 31, 2021 submittal from Graymont - Cricket Mountain to UDAQ (hereinafter "August 2021 Graymont Submittal to UDAQ").

information to estimate the best case emission limit that apply to the Cricket Mountain lime kilns in terms of pounds of NOx per ton of lime produced for kilns #1 through #4, as only kiln #5 has a NOx limit in terms of lb/ton of lime produced. These actual emissions and emission limitations are shown in the table below.

Table 20. Cricket Mountain Lime Kilns and Current NOx Emission Limits[262]

Kiln Number	Lime Production Capacity	NOx Emission Limits	Best Case NOx Emissions in lb/ton of lime (assuming kiln operated at max capacity)[263]	2014 Actual NOx emission Rate, lb/ton lime[264]
1	600 tons/24 hours	90 lb/hr	3.6 lb/ton	2.15 lb/ton
2	600 tons/24 hours	120 lb/hr	4.8 lb/ton	2.15 lb/ton
3	840 tons/24 hours	160 lb/hr	4.6 lb/ton	0.93 lb/ton
4	1266 tons/24 hours	200 lb/hr	3.8 lb/ton	2.33 lb/ton
5	1400 tons/24 hours	210 lb/hr AND 3.60 lb/ton of lime	(Permit imposes 3.60 lb/ton limit for Kiln 5)	2.42 lb/ton

The NOx emission rates in terms of lb/ton of lime produced are considered "best case" limits because, if a kiln operates at less than capacity in a 24-hour period, the NOx lb/hr limit would actually equate to an even higher limit in terms of lb/ton of lime produced. That is why a NOx limit in terms of pounds of NOx allowed per amount of lime produced is important, as such a limit ensures NOx emissions are minimized over all levels of production. The actual NOx emission rates in 2014 provided by Graymont Western demonstrate that the current permit does not impose NOx emission limits reflective of the capability of the existing low NOx burners.

A comparison of the "best case" NOx limits in units of lb/ton of lime produced allows for a comparison to the emission limits from the EPA's RACT/BACT/LAER Clearinghouse that were provided in the Cricket Mountain four-factor analysis. There are two NOx BACT determinations for rotary kilns at lime plants with lower NOx emission limits: The Chemical Lime Plant Rotary Kiln 3 in Texas with a NOx limit of 2.6 lb/ton of lime and the Graymont (WI) plant with a NOx limit of 1.83 lb/ton on a 24-hour average.[265] These are significantly lower NOx limits than the 3.60 lb/ton NOx limit that applies to Kiln # 5 and are also lower than the best case NOx emission rates for the other lime kilns at the Cricket Mountain Plant. Yet, there are no different controls listed for these lime kilns compared to the NOx controls that the Cricket Mountain Four-Factor analysis claims are in place at its five lime kilns. UDAQ should require Graymont Western to evaluate whether the limits of its air permit truly reflect the capabilities of the existing NOx controls. Indeed, a comparison of the actual emission rates achieved in 2014 to the

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[262] Lime production capacities and NOx emission limits from January 30, 2018 Approval Order DAQE-AN103130041-18 for Graymont Western US Incorporated at 3-4 and at 8-9.
[263] The "best case" NOx emission rates in lb/ton were calculated assuming the kiln emits NOx at the stated lb/hr limit for 24 hours and dividing that by the tons of lime that are allowed to be produced by the kiln in 24 hours.
[264] August 2021 Graymont Submittal to UDAQ at 4.
[265] As discussed in Cricket Mountain Plant Four-Factor Analysis, Appendix A at A-2.

permitted/allowable NOx emission limits shows that lower NOx emission limits are justified for the Cricket Mountain kilns as shown in the table above. At the minimum, UDAQ should evaluate imposing lower NOx emission limits for each of the five Cricket Mountain lime kilns as part of its regional haze plan.

1. Cost Effectiveness of SNCR at the Cricket Mountain Lime Kilns

Graymont Western evaluated SNCR as a NOx control for the Cricket Mountain lime kilns. In its initial four-factor analysis submitted in April of 2020, Graymont Western appeared to use the SNCR cost spreadsheet made available with EPA's Control Cost Manual. In its August 2021 submittal to UDAQ, Graymont Western stated that it obtained a "Class 4 engineering estimate" performed by a third party engineer.[266] The company states that it did not receive a vendor guarantee for the Class 4 engineering cost estimate and that its vendors are not "in any position to make guarantees of the removal efficiency at the current conceptual stage of this project."[267] However, it is not clear why Graymont Western would obtain a site-specific cost estimate, but not also obtain a site-specific evaluation of achievable NOx removal efficiencies with SNCR. Graymont Western only assumed a NOx removal efficiency with SNCR of 20% in the Class 4 engineering cost estimate.[268] Yet, in its initial four-factor analysis, Graymont Western stated that the average NOx removal at cement kilns with SNCR was 40%, with the range of NOx removal efficiency between 35%-58%.[269]

The company stated in its initial four-factor analysis that SNCR was not technically feasible for its preheater rotary lime kilns.[270] Part of the reason for the company's claim that SNCR was not technically feasible was that Graymont Western claimed that SNCR was only required in one BACT determination in the EPA's RACT/BACT/LAER Clearinghouse (the Mississippi Lime Company plant in Illinois (RBLC ID IL-0117)). However, that is not accurate as there have been other SNCR retrofits done at preheater rotary lime kilns. Those lime kilns include the Lhoist North America O'Neal Plant in Alabama, which achieved monthly NOx rates less than 3 lb/ton of lime and annual average NOx rates between 1.2 to 1.8 lb/ton; the Unimin Corporation lime plant in Calera, Alabama, which installed SNCR on its rotary lime kiln in 2010 to achieve compliance with a 3.2 lb NOx per ton of lime emission limit; and the rotary lime kilns of the Lhoist North America Nelson Lime Plant in Arizona which was required to install SNCR to meet BART.[271] EPA's BART requirements at the Lhoist North America Nelson Lime Plant in Arizona called for an optimization period and imposes NOx limits equating to no higher than 3.80 lb/ton for Kiln 1 and 2.61 lb/ton for Kiln 2.[272] The EPA's BART requirement for the Nelson Lime Plant reflected a NOx reduction

[266] August 2021 Graymont Submittal to UDAQ at 1.
[267] *Id.* at 7.
[268] *Id.* at 8.
[269] Cricket Mountain Plant Four-Factor Analysis at 5-8.
[270] *Id.* at 5-7 to 5-9.
[271] *See* Illinois Environmental Protection Agency, September 2015, Responsiveness Summary for the Public Comment Period on the Issuance of a Construction Permit/PSD Approval for Mississippi Lime Company to Construct a Lime Plant in Prairie du Rocher, Illinois, at 21-22, attached as Ex. 19 and available at https://www2.illinois.gov/epa/Documents/epa.state.il.us/public-notices/2014/mississippi-lime/responsiveness-summary.pdf.
[272] 79 Fed. Reg. 52,420 at 52,424 (Sept. 3, 2014).

efficiency of 50% with SNCR.[273] Thus, the claim that SNCR is not technically feasible for preheater rotary lime kilns is not justified, given the successful retrofit of such controls to several rotary lime kilns.

In its August 2021 submittal to UDAQ, Graymont Western provided observations about the SNCR used at the LHoist North America lime plants. Specifically, Graymont Western stated that the Lhoist North America SNCR technology for rotary lime kilns is "proprietary and not unconditionally available to Graymont," claiming that it "appears to be patented."[274] However, SNCR has not just been used at LHoist North America lime plants, as it is also used at the Unimin Corporation lime plant in Calera, Alabama as discussed above. Graymont Western acknowledged that Lhoist North America's intellectual property holdings to SNCR at preheater rotary lime kilns is "not fully understood at this time."[275] UDAQ should investigate this issue more fully to determine if SNCR at preheater rotary lime kilns is considered a proprietary control. Even if it is, that does not mean it cannot be used by Graymont Western, but that there likely would be a cost of using it. If so, that cost can be taken into account in the cost effectiveness analysis.

In addition, the 20% NOx reduction evaluated for SNCR by Graymont Western seems low, given that EPA adopted emission limits reflective of 50% control with SNCR at the Nelson Lime Plant. In addition, Graymont Western stated in its initial four-factor analysis that the average NOx removal at cement kilns with SNCR was 40%, with the range of NOx removal efficiency between 35%-58%, which is higher than the 20% NOx removal efficiency that it assumed in evaluating SNCR for the Cricket Mountain lime kilns.[276] Given the low NOx limits imposed on other lime kilns with SNCR and the 50% NOx reduction efficiency evaluated by EPA to meet BART at the Nelson Lime Plant, Graymont Western has not adequately justified considering a 20% control efficiency for SNCR. At the minimum, Graymont Western should have at least evaluated cost effectiveness of SNCR at the minimum NOx removal efficiency achieved at cement kilns of 35%.

Graymont Western points out that EPA's Control Cost Manual indicates that a residence time of flue gas "of 1 second is required for sources to be considered well-suited for SNCR"[277] and cites "an ideal temperature range [for SNCR operation] of 1,550 F to 1,950 F," and the company presented data on residence time and temperature at each of its kilns to claim its lime kilns do not meet these requirements.[278] However, it must be noted that EPA's Control Cost Manual states that these conditions "are generally well suited to SNCR *and attain the highest levels of NOx control*,"[279] but EPA did not say that SNCR does not work, or cannot be designed to work well, at residence times and flue gas temperatures below those levels. EPA also states that reagent injection ports can be designed at different locations to address the optimal temperature needs for the most effective SNCR systems. While EPA does not specifically address lime kilns, it does refer to different injection ports for different types of cement kilns.[280] It is likely that such optimal injection ports can be found for preheater rotary

[273] *Id.*at 52,438.
[274] August 2021 Graymont Western Submittal to UDAQ at 2.
[275] *Id.* at 9.
[276] Cricket Mountain Plant Four-Factor Analysis at 5-8.
[277] August 2021 Graymont Western Submittal to UDAQ at 11.
[278] *Id.* at 11.
[279] EPA, Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, April 2019, at 1-5 [emphasis added].
[280] *Id.*

lime kilns like those at the Cricket Mountain Plant.   It also must be noted that Graymont Western's data on residence time and flue gas temperature at each kiln shows that its Kiln 5's flue gas has the characteristics closest to the optimal ranges for successful SNCR operation, with an estimated residence time of 0.9 seconds and flue gas temperature of 1,020 to 1,385 F.[281] Kiln 5 also has the highest NOx emissions of the five kilns at the Cricket Mountain Plant and, as a result, is the kiln for which SNCR would be most cost effective. Given that SNCR has been required at several rotary lime kilns as discussed above, UDAQ should more fully evaluate SNCR for NOx removal at Kiln 5 of the Cricket Mountain plant at a NOx removal efficiency of at least 35%.

There is another NOx control option that Graymont Western and UDAQ should evaluate that would be even more effective at NOx removal than SNCR: the use of catalytic ceramic filtration bags in the existing baghouse. Several vendors offer catalytic ceramic filtration systems for baghouses that can remove NOx through embedded catalysts in the filter, as well as particulate matter and SO2 (with the use of dry sorbent injection), such as Tri-Mer's UltraCat and Haldor Topsoe's CataFlex™ catalytic filter bags that can be installed in place of or inside a standard filter bag at an existing baghouse. Such vendors claim that catalytic filters can achieve 90% or greater NOx removal.[282]   Haldor Topsoe's CataFlex™ catalytic filter bags are "especially designed to treat off-gases in the high-dust environments of lime and cement kilns, glass and steel manufacturing, waste incineration and pulp and paper manufacturing."[283] For NOx removal, the CataFlex™ bag "employs SCR to remove NOx from exhaust gases, either by using ammonia present in the exhaust or flue gas as a reducing agent, or via ammonia injection upstream from the filter."[284] However, with the catalytic filtration bags, much higher NOx removal rates can be achieved compared to SNCR. Haldor Topsoe states that its CataFlex™ can achieve 90% NOx reduction.[285] Haldor Topsoe also states that its CataFlex™ filter bags "are a well-proven solution that is easy to implement" and that the bags "are currently in operation in multiple lime kilns with outstanding results."[286] Thus, UDAQ must evaluate the use of catalytic ceramic filtration bags as a top NOx control option for the Cricket Mountain Lime Plant.

If ultimately, UDAQ does not find either of these top NOx controls to be cost effective to adopt as reasonable progress control measure, UDAQ should evaluate whether the existing NOx emission limits applicable to the Cricket Mountain lime kilns truly reflect the NOx reduction capabilities of the existing NOx controls at these units. Given that the kilns are all using low NOx burners, setting a NOx emission limit reflective of the NOx emission rates that the low NOx burners can achieve will ensure that Graymont Western maintains and operates its burners and the lime kilns to minimize NOx emissions to the maximum extent possible with the existing controls.

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[281] August 2021 Graymont Western Submittal to UDAQ at 19 (in Appendix E).
[282] *See*, e.g., https://cemteks.com/wp-content/uploads/2019/08/nox_reduction_by_scr_with_ceramic_filters_rod_gravely.pdf. *See also* Exhibit 20, Haldor Topsoe CataFlex™ brochure available; and GEA BisCat – Ceramic catalyst filter information available at https://www.gea.com/en/news/trade-press/2019/biscat-ceramic-catalyst-filter.jsp.
[283] *See* Haldor Topsoe Cataflex brochure, "Single-step dust, NOx, Sox, and NH3 removal in lime kilns," at 2, attached as Ex. 21, available at https://www.topsoe.com/hubfs/Cataflex-ICR%20Oct%202020.pdf?hsCtaTracking=09cea75c-9e14-4dd4-b664-de6c359f5f0c%7C3f38080c-6d23-4d7e-9608-0c3ac2638544.
[284] *Id.*
[285] *Id.* (Table 1).
[286] *Id.*

VIII. U.S. Magnesium LLC – Rowley Plant

US Magnesium LLC operates the Rowley Plant in Tooele County, Utah. The Rowley Plant is a primary magnesium production facility. According to UDAQ, the facility has a combined Q/d of 7.4.[287] The closest Class I area is Capitol Reef National Park which is 288.7 km away. The facility's emissions were identified by UDAQ as follows:

Table 21. Emissions Considered by UDAQ for the U.S. Magnesium Rowley Plant for its Q/d Analysis[288]

	NOx, tpy	SO2, tpy	PM10, tpy
Rowley Plant Emissions	1,052.1	17.9	1,054.2

The Title V permit for the Rowley plant describes the plant as follows:

> US Magnesium produces a magnesium metal from the waters of the Great Salt Lake. Some of the water is evaporated in a system of solar evaporation ponds and the resulting brine solution is purified and dried in the spray dryers to produce a magnesium chloride powder. The magnesium chloride powder is then melted and further purified in the melt reactor before going through an electrolytic process to separate magnesium metal from chlorine. The magnesium is then refined and/or alloyed and cast into molds. The chlorine from the melt reactor is combusted with natural gas in the chlorine reduction burner (CRB) and converted into hydrochloric acid (HCl). The HCl is removed from the gas stream through a scrubber train. The chlorine generated in the electrolytic cells is collected and piped to the chlorine plant where it is liquefied for reuse or sale. A portion of the purified chlorine is converted into concentrated hydrochloric acid. US Magnesium also produces battery grade lithium carbonate. The process steps convert the lithium salts into lithium carbonate. The lithium carbonate liquor is filtered, dried, and milled into lithium carbonate powder.

Title V Operating Permit Number 450003003, US Magnesium LLC – Rowley Plant, January 22, 2021, at 2.

The plant is a major source for particulate matter (PM10), NOx, VOCs and other air pollutants.[289] The Rowley Plant has multiple fuel combustion sources on site that are sources of NOx emissions and that is what the company focused on in its four-factor analysis of controls. Specifically, the company's four factor analysis identifies the following fuel combustion sources:[290]

- Three 12,700 kW natural gas-fired turbines, with the exhaust stream of each turbine equipped with a 15.3 MMBtu/hr duct burner to increase the temperature of the exhaust gas for use in the spray dryers.

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[287] April 2022 Draft Utah Regional Haze Plan at 93.
[288] *Id.*
[289] Title V Operating Permit Number 450003003, US Magnesium LLC – Rowley Plant, January 22, 2021, at 2.
[290] Regional Haze 2nd Implementation Period Four-Factor Analysis, US Magnesium LLC, Rowley Plant – Tooele County, August 2020, at 9-11 (hereinafter "August 2020 Rowley Plant Four-Factor Analysis").

- Chlorine Reduction Burner, fired with natural gas and with a maximum firing rate of 42 MMBtu/hr.
- Riley boiler that was installed in 1972 and has a heat input of 60 MMBtu/hr
- Several diesel-fired engines:
  - 14 Caterpillar 3406 (420 hp) engines
  - 13 Caterpillar 3208 (225 hp) engines
  - 1 Cummings C-9 (285 hp) engines
  - 1 Caterpillar 3306 (225 hp) engines
  - 1 Caterpillar 3304 (90 hp) engines
  - 1 fire pump engine (292 hp) engines
- Hydrochloric acid plant that produces food grade hydrochloric acid by reducing purified chlorine in a natural gas flame to produce hydrogen chloride gas.
- Eleven natural gas-fired crucible furnaces, which each have six 1 MMBtu/hour burners, used in the cast house.
- Four natural gas-fired boilers used in the Lithium Carbonate Plant (63 MMBtu/hr, 84 MMBtu/hr, 50 MMBtu/hr, and 100 MMBtu/hr).
- Other sources – small propane heater, and numerous mobile sources (trucks, track hoes, bulldozers, cranes, skid loaders and forklifts).

US Magnesium August 2020 Four-Factor Submittal indicated the units had the following baseline emissions:

Table 22. Annual NOx Baseline Actual Emissions from 2018, tons/year[291]

Equipment	NOx Baseline Emissions, tons/year
Turbines/Duct Burners	813.58
Chlorine Reduction Burner	101.66
Riley Boiler	45.25
Diesel Engines	71.65
HCl Plant	4.32
Casting House	14.7
Lithium Plant	26.61 *
Other Sources	0.02
Mobile Sources	73.01
TOTAL	1,060.79

*Lithium Plant Emissions are based on Potential to Emit because it was not in operation in 2018 and is newly permitted in 2020.

US Magnesium evaluated NOx controls for all of the above equipment (except the "other sources" (heater) and the mobile sources) in its 2020 four-factor analysis, but only found flue gas recirculation (FGR) as a potential technologically and economically feasible control for the Riley boiler.[292] UDAQ revised the company's cost effectiveness analyses due to using too high of an interest rate and to change the assumed life of the controls.[293] However, even with those changes, UDAQ only found one

[291] August 2020 Rowley Plant Four-Factor Analysis at 14.
[292] *Id.*at 40.
[293] April 2022 Draft Utah Regional Haze Plan at 139.

control as appropriate for a control at the Rowley plant – that is, installation of FGR at the Riley boiler.[294] In a subsequent submittal to UDAQ in September 2021, the company claimed the AP-42 emission factor that it used to estimate 2018 NOx emission for the Riley boiler overstated NOx emissions and that the baseline NOx emissions should be 11.9 tons per year rather than 45.25 tons per year.[295] US Magnesium claimed that using a lower baseline for the Riley boiler would increase the cost effectiveness of FGR from $1,880/ton calculated by UDAQ to $7,050/ton.[296] UDAQ did not accept the company's claims that NOx emissions from the Riley boiler should be assumed to be lower than AP-42 emission factor, and UDAQ has proposed to adopt an enforceable requirement for US Magnesium to install an FGR system at the Riley boiler by January 1, 2028 and for the boiler to not exceed 22.6 tons per 12-month rolling period.[297]

The following provides my review and comment on the Rowley Plant four-factor analyses and UDAQ's proposed findings.

A. NOx Control Evaluation for the Gas Turbines

The gas turbines at the Rowley Plant are used for electrical generation, and the exhaust from the turbines is routed to a duct burner to increase the flue gas temperature before being routed to a spray dryer which dries magnesium chloride slurry into a magnesium chloride powder.[298] The company states that "[f]or the spray dryer to work properly the inlet temperature of the exhaust stream needs to reach 1,000 F."[299] US Magnesium then eliminated all potential turbine NOx controls (water or steam injection, dry low NOx combustors, and SCR) from consideration because of the impact that operation of the controls would have on reducing flue gas temperatures, which would impede the ability to use the turbine exhaust for drying magnesium chloride slurry into magnesium chloride powder.[300]

UDAQ and US Magnesium should have evaluated placing the SCR downstream of the spray dryer. The high temperature of the flue gas stream is important to the magnesium production process only until the point of the spray dryer. The flue gas after the spray dryer would likely be a more optimal temperature for successful SCR operation or, if necessary, cooling air skids could be used to reduce the flue gas temperature to the optimal range. For example, the Buckingham Compressor Station which was proposed to be constructed in Virginia would be equipped with Solar turbines with SoLoNOx, SCR, and cooling air skids.[301] Essentially, the cooling air skids provide for the injection of tempering air at the turbine discharge (upstream of the SCR) to cool the exhaust temperature to the optimal temperature of

[294] *Id.*
[295] September 17, 2021 Email from Rob Hartman, US Magnesium, to Chelsea Cancino, UDAQ (hereinafter "September 2021 Submittal from US Magnesium to UDAQ").
[296] *Id.*
[297] April 2022 Draft Utah Regional Haze Plan at 139.
[298] August 2020 Rowley Plant Four-Factor Analysis at 15.
[299] *Id.*
[300] *Id.* at 17-18.
[301] *See* May 25, 2018 Permit Application for Atlantic Coast Pipeline LLC, Buckingham Compressor Station, at pdf page 129 (Design Summary), attached as Ex. 22.

the SCR catalyst.[302] In addition, depending on the proximity of the equipment, it is possible that the exhaust from the spray dryers could be routed to one SCR system, which would reduce capital costs of control. Given that the turbines (with the duct burners) are responsible for about 80% of the Rowley Plant's NOx emissions, UDAQ and US Magnesium must evaluate all possible options to reduce NOx emissions from the gas turbines.

B. NOx Controls for the Riley Boiler

US Magnesium found that low NOx burners were not feasible as a retrofit to its Riley boiler, claiming that the low NOx burners "would require substantial modifications and would not really fit the definition of a retrofit."[303] The company also ruled out ultra-low NOx burners for similar reasons.[304]
US Magnesium did not provide any boiler-specific information to indicate whether low NOx burner retrofits were available for its Riley boiler. In its 1998 AP-42 emission factor documentation, EPA identified retrofitting existing natural gas-fired boilers with low NO burners as one of the two most prevalent control techniques, along with flue gas recirculation (FGR).[305] At that time, EPA stated that "NOx emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NOx burners."[306] EPA further states that, "[w]hen low NOx burners and FGR are used in combination, these techniques are capable of reducing NOx emissions by 60 to 90 percent."[307] Even earlier, in 1991, the California Air Resources Board (CARB) concluded that, for boilers of 5 MMBtu/hour or larger, a NOx emission limit of 30 ppmv [0.036 lb/MMBtu] could be achieved by installing new burners with FGR.[308] The San Joaquin Valley Air Pollution Control District (SJVAPCD) determined that ultra-low NOx burners had been successfully retrofit on boilers as small as 2 MMBtu/hour and were meeting NOx emission rates of 9 ppm (0.011 lb/MMBtu) or lower.[309] Recently, the SJVAPCD determined the cost effectiveness of ultra-low NOx burner upgrades to existing small gas-fired boilers to meet an even lower NOx emission rate of 6 ppm. Based on that data, it is estimated that the cost effectiveness of such ultra-low NOx burners at a 60 MMBtu/hour boiler would range from $908/ton to $1,635/ton, depending on the operating capacity factor and would reduce NOx emissions by 93% from uncontrolled NOx emissions.[310]

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[302] *See* e.g., Buzanowski, Mark A. and Sean P. McMenamin, Peerless Mfg. Co., Automated Exhaust Temperature Control for Simple Cycle Power Plants, available at https://www.powermag.com/automated-exhaust-temperature-control-for-simple-cycle-power-plants/ and attached as Ex. 23.
[303] August 2020 Rowley Plant Four-Factor Analysis at 22.
[304] *Id.*
[305] EPA, AP-42, Section 1.4.4 (last revised 1998), available at: https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf.
[306] *Id.*
[307] *Id.*
[308] CARB Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, July 18, 1991, p. 7 available at: https://ww3.arb.ca.gov/ractbarc/boilers.pdf.
[309] As discussed in Stamper, V. and M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, March 6, 2020, at 121 (Ex.23 to this report).
[310] *Id.* at 125.

There are several emerging combustion technologies that demonstrate the potential for even lower levels of NOx, including the following:[311]

- SOLEX™ Burner is an emerging technology designed to achieve 5 ppm NOx. This burner technology is available as a burner-only alternative to SCR for units "with heat releases between 1 MMBtu/hr and +20 MMBtu/hr."[312]
- ClearSign Ultra Low NOx Technology is designed to achieve below 5 ppm NOx.[313] This technology is reportedly less costly than traditional ultra-low NOx controls with no FGR, lower fuel use, and can be retrofit to existing units.
- Altex Technology Corporation Near Zero NOx Burner has been applied to an 8 MMBtu/hr unit and is capable of achieving 5 ppm under some operating conditions.[314]

Because so many California air districts have been requiring NOx reductions on smaller boiler and heaters for quite some time,[315] there is significant experience with retrofitting smaller gas-fired boilers with low NOx burners and with ultra-low NOx burners. It is very likely that there are low NOx burners or ultra-low NOx burners that can be successfully and cost-effectively installed at the Riley boiler at the Rowley Plant. Thus, UDAQ should not simply accept US Magnesium's statements that such controls are not feasible without the company providing boiler-specific information and without performing a due diligence analysis of the types of burner retrofits that would be available for the Riley boiler. Ultra-low NOx burners should be able to achieve 90% reduction or more from current NOx rates from the Riley boiler. Alternatively, if ultra-low NOx burners are truly not available or cannot be cost-effectively retrofit to the Riley boiler, then low NOx burners in conjunction with FGR should be evaluated for NOx control at the Riley boiler because such controls in combination could reduce emissions by up to 90%.[316]

US Magnesium also evaluated SCR for the Riley boiler, using EPA's SCR cost spreadsheet. US Magnesium determined the cost effectiveness of SCR would be $9,726/ton,[317] but the company's analysis assumed a 7% interest rate, which would overestimate the annual costs. UDAQ's review of US Magnesium's SCR cost analysis included that the company used too high of an interest rate instead of using the current bank prime rate and that the company should have assumed a 30-year life of controls.[318] UDAQ presented revised SCR cost effectiveness numbers for the Riley boiler: If potential to emit NOx is used as baseline, SCR would reduce NOx by 188 tons per year at 90% control, resulting in a cost effectiveness of $4,073/ton. But then UDAQ adjusted this cost effectiveness number to account for 90% removal

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[311] *Id.* at 123.
[312] John Zink Hamworthy Combustion, SOLEX™ Burner, *see* https://www.johnzinkhamworthy.com/wpcontent/uploads/solex-burner.pdf.
[313] ClearSign https://clearsign.com/. *See also* SJVAPCD presentation "ClearSign Ultra Low NOx Technology" November 7-8, 2017, available at: https://ww3.arb.ca.gov/enf/training/sympo/ppt2017/0830-b-scandura.pdf.
[314] California Energy Commission Report, Near Zero NOx Burner, July 2018, available at: https://ww2.energy.ca.gov/2018publications/CEC-500-2018-016/CEC-500-2018-016.pdf.
[315] *See* Stamper, V. and M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, March 6, 2020, at 139-144 (Ex. 24 to this report).
[316] EPA, AP-42, Section 1.4.4 (last revised 1998), available at: https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf.
[317] August 2020 Rowley Plant Four-Factor Analysis at 24.
[318] UDAQ, Letter to US Magnesium with UDAQ's review of US Magnesium's Four-Factor Analysis, July 27, 2021, at 20.

from the actual baseline NOx emissions of 45.25 tons per year to arrive at a cost effectiveness of SCR of $18,800/ton.[319] There are several problems with UDAQ's analysis. First, if UDAQ was simply adjusting US Magnesium's cost effectiveness analysis – which was based on the Riley boiler's actual NOx emissions as baseline - to reflect a lower interest rate and longer useful life, UDAQ's revised cost effectiveness based on an actual emission baseline should be lower than the $9,726/ton calculated by US Magnesium. Instead, UDAQ's recalculated SCR cost effectiveness for the Riley boiler based on actual emissions was about double the value calculated by US Magnesium. The reason for this is because UDAQ appears to have used the annualized cost of SCR based on removing 188 tons per year of NOx from the potential to emit of the boiler and divided that by the 40.7 tons per year of NOx that would be removed from the boiler's actual emissions with SCR. However, UDAQ's annualized costs (both capital costs and operating costs) are much higher because they are based on removing close to five times as much NOx.

I recalculated cost effectiveness of SCR to achieve 90% NOx control from the company's stated actual emissions baseline of 45.25 tons per year using EPA's SCR cost spreadsheet, the current bank prime rate which is 4.0%, and a 30-year life of controls. The results are provided in the table below.

Table 23. Revised Cost Effectiveness of SCR at US Magnesium Rowley Plant's Riley Boiler, Assuming 90% NOx Control from 2018 Actual Emissions, 4% Interest Rate, and 30-Year Life of SCR.[320]

Capital Cost of SCR	Operating and Maintenance Cost of SCR, $/year	Total Annualized Costs of SCR, $/year	NOx Reduced with SCR, tpy	Cost Effectiveness of SCR, 2019 $
$2,644,128	$40,588	$196,176	41.72	$4,817/ton

The analysis presented above shows that SCR is also a cost effective NOx control for the Riley boiler at US Magnesium's Rowley Plant.

With respect to the NOx control that UDAQ found to be cost effective for the Riley boiler, i.e., flue gas recirculation, UDAQ recalculated US Magnesium's cost effectiveness to reflect a lower interest rate than the 7% assumed by US Magnesium but also to assume a shorter life of FGR of 15 years (compared to the 20 years assumed by US Magnesium).[321] UDAQ's revised cost effectiveness for FGR at the Riley boiler is $1,880/ton.[322] UDAQ did not provide any citation or basis for its assumption that FGR would only have a useful life of 15 years. EPA has assumed a life of 30 years for FGR in at least one BART evaluation for a gas-fired boiler.[323] Revising US Magnesium's cost effectiveness of FGR to assume the current bank prime interest rate of 4%, a 30-year life, and 50% NOx removal from baseline emissions equates to a cost effectiveness of FGR of $1,710/ton.[324]

[319] *Id.* at 21.
[320] *See* Ex. 25, US Magnesium Rowley Plant Riley Boiler SCR Cost Manual Spreadsheet.
[321] UDAQ, Letter to US Magnesium with UDAQ's review of US Magnesium's Four-Factor Analysis, July 27, 2021, at 21.
[322] *Id.*
[323] 80 Fed. Reg. 18,944 at 18,953 (Apr. 8, 2015).
[324] Based on FGR cost numbers in August 2020 Rowley Plant Four-Factor Analysis at 25.

While FGR is a cost effective NOx control for the Riley boiler, SCR should also be considered a cost effective control for the Riley boiler, and SCR would reduce NOx by 90% control compared to the 50% NOx control that would be achieved with FGR. In addition, for the reasons discussed above, US Magnesium and UDAQ should not have dismissed installation of low NOx burners or ultra-low NOx burners without gathering boiler-specific data on what burner upgrades could be installed. It is very likely that low or ultra-low NOx burners with FGR is the most effective and most cost-effective NOx control for the Riley boiler.

C. NOx Control Evaluation for Diesel Engines

US Magnesium evaluated SCR and Exhaust Gas Recirculation (EGR) as potential NOx controls for the numerous diesel engines that are used at the Rowley Plant. After conducting a limited cost analysis for the average of the numerous diesel engines used at the plant, the company concluded that neither SCR nor EGR were cost effective.[325] However, there were two viable NOx reduction options that US Magnesium did not evaluate – electrification of engines and replacement of engines with Tier 4 engines. Second, US Magnesium should not have simply evaluated cost effectiveness for an average size diesel engine at the facility. Instead, US Magnesium should have identified characteristics of all of the diesel engines used at the facility by horsepower, NOx emission rates if known, which tier engine standards the engine reflects, and typical annual hours of operation of each engine. From that list, the company should have begun with evaluation of NOx pollution reduction options for the highest emitting engines.

EPA has required manufacturers of diesel-fired engines to decrease emissions over time. EPA has grouped engines into “tiers” which define the emission standards the engines must meet. The table below shows the NOx emission rates that are required to be met by EPA for the various size engines used at the Rowley Plant.

[325] August 2020 Rowley Plant Four-Factor Analysis at 29-31.

Table 24. Comparison of NOx Emission Rates for Various Engine Sizes and Tier Engines.[326]

ENGINE SIZE, HP	TIER ENGINE	NOX EMISSIONS, G/HP-HR
75	0	6.89
	1	5.58
	2	4.72
	3	3.00
	4	3.50[327]
174	0	8.39
	1	5.58
	2	4.00
	3	2.50
	4	0.30
600	0	8.39
	1	5.58
	2	4.10
	3	2.50
	4	0.30

As the above table demonstrates, the NOx reductions from a Tier 0 engine to a Tier 4 engine are quite significant, reflective a 96% reduction in NOx. If US Magnesium averaged NOx emission rates across engines at its Rowley plant for its engine cost effectiveness analysis, and if the facility operates Tier 0 engines and also higher tiered engines, that average NOx rate will be significantly understated for the Tier 0 engines at the facility. US Magnesium's approach to calculating cost effectiveness for the diesel engines by determining costs for an average engine used at the plant could be very inaccurate, depending on the age of engines that it uses at the facility. Thus, it is imperative that UDAQ require US Magnesium to identify each engine by size and Tier rating, as well as typical operating hours, so UDAQ and the public can understand which engines are the highest NOx emitters at the plant.

The top control for reducing NOx emissions from the diesel fired engines at the Rowley Plant is to replace the engines with electric engines that are powered by an EGU. This would eliminate the NOx emissions from the engines at the Rowley plant. UDAQ must require US Magnesium to evaluate this NOx reduction measure.

UDAQ must also consider requiring US Magnesium to replace its Tier 0 or Tier 1 diesel engines with Tier 4 engines. Replacing Tier 0 engines with Tier 4 engines can be quite cost effective, depending on the size of the engine being replaced and its annual operating hours. Even at 1,000 operating hours per year, replacing a Tier 0 engine of 174 hp or greater with a Tier 4 engine could cost $2,600 per ton of NOx removed.[328] If the engines operate at 4,000 hours per year, the cost effectiveness of replacing a Tier 0

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[326] Data from EPA's Alternative Control Techniques Guideline Stationary Diesel Engines, March 5, 2010 at 58 and 61 (Tables 5-2 and 5-3), and from May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1.
[327] This limit applies to NMHC plus NOx. *See* https://nepis.epa.gov/Exe/ZyPDF.cgi/P10001RN.PDF?Dockey=P10001RN.PDF.
[328] *See* Stamper, V. and M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, March 6, 2020, at 99-100 (Ex. 24 to this report). Note that the

engine with a Tier 4 engine would be under $1,000/ton.[329] There are also other benefits of replacing Tier 0 with Tier 4 engines, including reduction of particulate matter emissions. Thus, UDAQ must not ignore this very effective control option for reducing NOx emissions from the diesel-fired engines at the Rowley plant.

Yet another option that US Magnesium failed to evaluate was to replace some of its diesel-fired engine with natural gas-fired engines. The Four Corners Air Quality Task Force evaluated this control option for using natural gas-fired drill rigs in the Four Corners region of the U.S. rather than diesel engines. The Task Force found that the switch from diesel engines to lean burn reciprocating internal combustion engines (RICE) would result in approximately 91% NOx reduction from a Tier 0 diesel engine and 85% reduction from a Tier 1 diesel engine.[330] Given that the Rowley Plant has natural gas piped to the site for use in its combustion turbines, the use of natural gas rather than diesel which is brought in by truck would reduce NOx emissions from mobile source tailpipe emissions as well.[331] Thus, UDAQ must also require that this option of replacing diesel engines with natural gas-fired lean burn RICE be evaluated for the diesel engines used at the Rowley Plant.

While US Magnesium did generically evaluate SCR as a control option for its diesel engines, that analysis is flawed because, as discussed above, US Magnesium calculated SCR retrofit costs for an "average" engine used at the plant. Instead, US Magnesium should have evaluated cost effectiveness of SCR (as well as EGR) by size of engine, Tier of the engine, and typical operating hours. SCR will be more cost effective at the higher horsepower rating, lower Tiered engines,[332] but it still may be more cost effective (and with less time for onsite construction) to replace the diesel engines with Tier 4 diesel engines that are already equipped with SCR or with lean burn natural gas-fired RICE.

For all of these reasons, UDAQ's and US Magnesium's analysis of NOx controls for the Rowley Plant's diesel-fired engines is significantly flawed and incomplete. Exhibit 24 to this report compiles EPA and state documentation of control cost options for diesel-fired engines, cost effectiveness analyses by size of engine and by engine operating hours, and also compiles examples of state and local air district rules on NOx emissions from diesel-fired engines. [333] While that information was compiled for reasonable progress four-factor control analyses for diesel engines used in the oil and gas industry, the information presented on diesel fired engines is also relevant to the Rowley Plant. UDAQ and US Magnesium should use that information, along with a detailed inventory of the engines used at the Rowley Plant, tier ratings, and typically operating hours, to determine the cost effect controls that are available to reduce NOx emissions from the Rowley Plant diesel engines.

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cost effectiveness of replacing Tier 0 with Tier 4 engines in Table 32 of this report reflects a 2010 cost basis, but even accounting for inflation in the cost of new engines (based on the Bureau of Labor Statistics CPI Inflation calculator at https://www.bls.gov/data/inflation_calculator.htm), the cost effectiveness of replacing a Tier 0 engine with a Tier 4 engine of size 174 hp or higher would be under $3,500/ton.

[329] *Id.*

[330] As discussed in Stamper, V. and M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, March 6, 2020, at 103 (Ex. 24).

[331] *Id.*

[332] *Id.* at 104-106.

[333] *Id*. at 92-116 (Section VI of report).

D. Summary – US Magnesium and UDAQ Have Not Fully Evaluated All Available NOx Control Options for the Rowley Plant, and UDAQ's Proposed NOx Control Requirements Should be Strengthened.

For the reasons discussed above, the US Magnesium and UDAQ analysis of NOx pollution controls is incomplete for the following emission units:

<u>Gas turbines</u>: UDAQ and US Magnesium should have evaluated placing the SCR downstream of the spray dryer where the temperatures either would be low enough for SCR operation or could be lowered with cooling air skids. Given that the turbines (with the duct burners) are responsible for about 80% of the Rowley Plant's NOx emissions, UDAQ and US Magnesium must evaluate all possible options to reduce NOx emissions from the gas turbines.

<u>Diesel engines</u>: UDAQ and US Magnesium did not evaluate several very effective NOx control options for the diesel engines used at the Rowley Plant, including electrification and replacement of Tier 0 or Tier 1 engines with Tier 4 engines or with natural gas-fired lean burn RICE. In addition, US Magnesium's analysis of SCR and EGR is flawed because of analyzing these controls for an average engine, rather than evaluating these controls at specific engines taking into account the engine size, tier rating and operating hours. It makes most sense to begin with a focus on the highest operating hour engines that are lowest tiered and highest in horsepower capacity.

<u>Riley boiler</u>: US Magnesium and UDAQ summarily dismissed installation of low NOx burners and ultra-low NOx burners as not technically feasible without gathering boiler-specific data on what burner upgrades could be installed at the Riley boiler. It is very likely that low or ultra-low NOx burners with FGR is the most effective and most cost-effective NOx control for the Riley boiler. In addition, UDAQ's revised cost calculations for SCR cost effectiveness appear to be in error. SCR should be considered cost effective for the boiler at a cost effectiveness of $4,800/ton.

Last, to the extent that UDAQ does not ultimately revise its finding that FGR is the only control that is justified to require at the Riley boiler, the proposed regulatory language should be revised. UDAQ should impose a rate-based NOx limit in terms of lb/MMBtu, to be consistent with EPA's regional haze guidance. Specifically, EPA states that, when a state "has determined that a technology-based measure is necessary to make reasonable progress," emission limits should be expressed in a rate-based format (such as pounds of pollutant per throughput).[334] Whether or not UDAQ imposes a rate-based limit or a mass-based limit, UDAQ must require more frequent testing than the currently proposed three-year stack test cycle. Stack testing should be required at least once per year, which would help ensure that the 50-year old boiler is regularly and properly maintained. In addition, the proposed regulatory language must identify the units in which the stack test results are to be reported, which presumably should be in lb/MMBtu or in lb/MMscf of natural gas burned. If UDAQ continues to only impose a mass-based emission limit, the regulatory language must also specify recordkeeping on the amount of fuel used per month at the Riley boiler so that 12-month heat input can be calculated. The proposed regulatory language should also make clear that compliance with the 12-month rolling total emission

[334] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 44.

limit shall be calculated based on the fuel use or heat input over that time period and based on the NOx emission rates from the most recent stack test. These revisions are to ensure the proposed 22.6 ton per rolling 12-month emission limit is enforceable as a practical matter.

IX. Ash Grove Cement Company – Leamington Cement Plant

Ash Grove Cement Company operates the Leamington Cement Plant in Leamington, Utah. The Leamington Cement Plant is a cement manufacturing plant that has been in operation since 1981.[335] The following description of the processes at the facility is provided in the Title V permit for the Ash Grove Leamington plant:

> At the Leamington cement plant, cement is produced when inorganic raw materials, primarily limestone (quarried on site), are correctly proportioned, ground and mixed, and then fed into a rotating kiln. The kiln alters the materials and recombines them into small stones called cement clinker. The clinker is cooled and ground with gypsum and additional limestone into a fine powdered cement. The final product is stored on site for later shipping. The major sources of air emissions are from the combustion of fuels for the kiln operation, from the kiln, and from the clinker cooling process.

Title V Operating Permit Number 23000015004 issued September 26, 2018 for Ash Grove Cement Company, Leamington Cement Plant, at 2. The Leamington Cement Plant is considered by UDAQ to be a major source of particulate matter (both PM2.5 and PM10), NOx, as well as CO and hazardous air pollutants.[336]

According to UDAQ, the facility has a combined Q/d of 6.9.[337] The closest Class I area is Capitol Reef National Park which is 134 km away. The facility's emissions were identified by UDAQ as follows:

Table 25. Emissions Considered by UDAQ for Leamington Cement Plant for its Q/d Analysis[338]

	NOx, tpy	SO2, tpy	PM10, tpy
Facility Emissions	845.5	5.9	79.1

In its four-factor analysis of controls, the assumed baseline emissions for NOx and SO2 were much higher than the emissions used in UDAQ's Q/d analysis. This is shown in the table below.

Table 26. Leamington Cement Plant Annual Baseline Emission Rates[339]

	NOx, tpy	SO2, tpy
Kiln	1198	8.0

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335 Title V Operating Permit Number 23000015004 issued September 26, 2018 for Ash Grove Cement Company, Leamington Cement Plant, at 2.
336 *Id.*
337 April 2022 Draft Utah Regional Haze Plan at 93.
338 *See* https://deq.utah.gov/air-quality/regional-haze-in-utah.
339 From Table 4-1 of the March 2020 Regional Haze 2nd Implementation Period Four-Factor Analysis, Ash Grove Cement – Leamington, UT (hereinafter referred to as "Leamington Four-Factor Analysis") at 4-1.

The Leamington four-factor analysis did not provide any revised emissions for PM10. However, simply revising the Q/d to be based on the NOx and SO2 annual emissions to be based on the above table and adding 79.1 tpy of PM10, the facility's Q/d value increases to 9.6.

The Leamington cement kiln is equipped with SNCR and a baghouse.[340] The Leamington four-factor analysis also states that the kiln is equipped with a low NOx burner,[341] although the Title V permit for the facility does not mention that NOx control. Ash Grove did not propose any additional pollution controls or strengthening of emission limits, and UDAQ has proposed to accept that analysis and not require any change in controls or emission limits. The following provides my review and comments on the four-factor analysis of controls for the Leamington Cement Plant.

A. SO2 Four-Factor Analysis for the Leamington Cement Kiln

The Leamington Cement Plant four-factor analysis identified three control options for SO2: Fuel substitution, wet scrubbing, and semi-wet/dry scrubbing.[342] Each of these controls were dismissed from further review as unlikely to have significant impact on SO2 emissions (i.e., fuel substitution) or as being unlikely to have significant impact on SO2 emissions and being technically infeasible (i.e., wet scrubbing and semi-wet/dry scrubbing).[343] With respect to fuel substitution, the Leamington four-factor analysis states that the plant "already has restrictions on fuel sulfur content, and does not anticipate that further restrictions would have any impact on SO2 emissions levels from the main stack…."[344]

The cement kiln system at the Leamington Cement Plan is permitted to use several fuels, including coal, natural gas, coke, fuel oil, and other types of fuels including waste fuels such as tire derived fuel and diaper-derived fuel.[345] While the four-fact report identifies 2019 SO2 emissions as 8.0 tpy, it is not clear what fuels were used in the kiln, pre-heater and calciner in 2019. For example, did the plant primarily use lower sulfur fuels in 2019 from the list of authorized fuels, such as natural gas, and not use coal or oil? The four-factor analysis indicates that SO2 emissions in 2019 were approximately 0.02 lb/ton of clinker.[346] In contrast, the Approval Order for the Leamington Cement Plant allows 0.4 lb SO2 per ton of clinker.[347] In addition, the Approval Order lists the total potential SO2 emissions for the Leamington Cement Plant as 192.50 tons per year,[348] which is considerably more than the 8.0 tons per year reported for 2019. While UDAQ did request Ash Grove to "revisit" its annual potential to emit for SO2 "given the seeming disparity with the current actual annual emission rate values for SO2," Ash Grove's response was that "there are still factors that could cause actual SO2 emission levels to increase and thus it would be a concern for Ash Grove to lower the [potential to emit] limit."[349] The company did state "[c]urrently,

[340] Title V Operating Permit Number 23000015004 issued September 26, 2018 for Ash Grove Cement Company, Leamington Cement Plant, at 13.
[341] Leamington Four-Factor Analysis at 6-2.
[342] March 2020 Leamington Four-Factor Analysis at 5-1 to 5-2.
[343] *Id.*at 5-1 to 5-3.
[344] *Id.*at 5-2.
[345] *Id.*at 3-1.
[346] *Id.*at 5-3.
[347] *See* 9/20/2019 Approval Order DAQE-AN103030028-18 for Ash Grove Cement's Leamington Plant.
[348] *Id.*at 4.
[349] Ash Grove Cement Company, Leamington Plant, Four-Factor Analysis – Supplemental Information, August 26, 2021, at 1-2 (hereinafter "August 2021 Ash Grove Leamington Submittal").

the sulfur contents in the raw materials are relatively low," but then also stated that sulfur contents of raw materials "are so low that from an overall process chemistry standpoint, it would actually be beneficial if the sulfur levels were slightly higher."[350]

UDAQ should request information on the quantities of each type of allowed fuel that were used in 2019 as well as on the tons of clinker produced in 2019, so that it can determine what factors lead to the very low SO2 emissions. If the reason for the low SO2 emissions in 2019 at the plant is due at least in part to using low sulfur fuels such as natural gas, or not using the highest sulfur fuels such as petroleum coke or tire-derived fuel, then revising the permitted list of approved fuels to eliminate the higher sulfur fuels should be considered as a control strategy. Currently, there is no guarantee that SO2 emissions couldn't be as high as 192.50 tons per year based on the terms of the existing permit, an annual rate that is 24 times as high as the current level of SO2 emissions in 2019. UDAQ must reconsider imposing as a control measure the methods being used to keep SO2 emissions at or near 2019 levels.

B. NOx Four-Factor Analysis for Leamington Cement Plant

According to the four-factor analysis, the Leamington cement kiln is equipped with a low NOx burner and a SNCR.[351] However, the four-factor analysis did not provide any information on when either the low NOx burner or the SNCR were installed, or on the level of NOx control achieved with each control. In a recent air permit for a new cement plant to be constructed in Georgia – the US Cement Plant to be constructed in Houston County, Georgia – a NOx BACT limit of 1.5 lb/ton of clinker on a 30-day rolling average basis was established based on the controls of staged and controlled combustion, low NOx burners, and SNCR.[352] The NOx emission limit for the Leamington Cement Plant is 2.8 lb per ton of clinker based on a 30-day rolling average.[353] The US Cement NOx limit is 46% lower than the NOx emission limit for Leamington Cement Plant, despite having similar controls including SNCR. This indicates that there are improvements that could be made to existing processes and NOx controls that could significantly reduce NOx emissions from the Leamington Plant.

While UDAQ asked Ash Grove to provide more information on improvements to the existing SNCR system at the Leamington cement kiln, the company simply said, "it is not aware of any changes that could be made to achieve a higher level of control with the system."[354] UDAQ should request more information on the NOx removal efficiency of the SNCR installed at the Leamington Cement Plant kiln. Further, UDAQ should request Ash Grove to specifically evaluate increasing the NOx removal efficiency of the SNCR system.

There are additional regional haze control options that UDAQ should have considered. Most notable is the option of ceramic catalytic filtration systems. Several vendors are offering ceramic catalytic filter systems for baghouses that can remove NOx through embedded catalysts in the filter and that also can

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[350] *Id.* at 2.
[351] March 2020 Leamington Four-Factor Analysis at 6-3.
[352] *See* Georgia Environmental Protection Division Permit No. 3241-153-0075-P-01-0 for US Cement, LLC, issued 6/29/2020, at 1 and at 15, available at https://permitsearch.gaepd.org/.
[353] *See* 9/20/2019 Approval Order DAQE-AN103030028-18 for Ash Grove Cement's Leamington Plant at 9 (Condition II.B.1.b).
[354] August 2021 Ash Grove Leamington Submittal at 2.

remove SO2 with the use of dry sorbent injection, such as Tri-Mer UltraCat and Haldor Topsoe CataFlex™ catalytic filter bags that can be installed in place of or inside a standard filter bag at an existing baghouse. Such vendors claim that catalytic filters can achieve 90% or greater NOx removal.[355] Notably, the ceramic catalytic filters have been geared towards cement kilns, among other facilities, to help meet the Portland cement maximum achievable control technology (MACT) standards.[356]

Recently, a four-factor cost assessment for the use of a ceramic catalytic filtration system was done for a cement plant in Colorado – the GCC Pueblo Cement Plant.[357] That cost information can be used to estimate the costs of using a ceramic catalytic filtration system at the Leamington Cement plant. The GCC Pueblo Plant has a higher cement production rate at 3,750 tons/day compared to the average daily 2,636 tons per day production rate at the Ash Grove Leamington cement plant,[358] thus the capital and operational expenses of ceramic catalytic filters at the GCC Pueblo Plant will presumably be higher than at the Leamington Cement Plant.[359] The GCC Pueblo Plant kiln is equipped with SNCR and a fabric filter baghouse,[360] similar to the Leamington Cement Plant kiln. Thus, the Leamington Cement Plant is already equipped with an ammonia storage and injection system, as is the GCC Pueblo Plant. The kilns at both facilities are preheater/precalciner kilns. The cost estimate of the use of a ceramic catalytic filtration system at GCC Pueblo would be higher than the costs of such a system at the Leamington Cement plant due to the larger size of the Pueblo plant.

There are a few options for using a ceramic catalytic filtration system at the Leamington Cement Plant: 1) install a stand-alone ceramic catalytic filtration system that would be used after the existing baghouse, 2) replace an existing baghouse with a stand-alone ceramic catalytic filter system, and 3) install catalytic filter bags within the existing baghouse. Tri-Mer provided a cost estimate for the third option - to replace the existing bags of the baghouse at the GCC Pueblo cement plant with ceramic catalytic filter elements (referred to as the "Bag-to-Ceramic Filter Retrofit Solution").[361] Tri-Mer determined that the cost for a bag-to-ceramic filter retrofit would cost $800/ton of NOx removed at the GCC Pueblo Plant and would reduce NOx by 90%, as well as continuing to remove PM10 and PM2.5 at very high efficiencies (greater than 99.9%).[362] Tri-Mer's cost effectiveness value reflects a capital cost of $8,999,200 for bag replacement with ceramic catalytic filters and an annual operating expense cost for

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[355] *See,* e.g., https://cemteks.com/wp-content/uploads/2019/08/nox_reduction_by_scr_with_ceramic_filters_rod_gravely.pdf. See also Exhibit 20, Haldor Topsoe CataFlex™ brochure available; and GEA BisCat – Ceramic catalyst filter information available at https://www.gea.com/en/news/trade-press/2019/biscat-ceramic-catalyst-filter.jsp.

[356] *See* Air & Waste Management Association, The Magazine for Environmental Managers, Sponsored Content, "Catalytic Filter Technology Provides Important Flexibility for Controlling PM, NOx, SOx, O-HAPS," October 2018, attached as Ex. 26 and available at https://pubs.awma.org/flip/EM-Oct-2018/sponsoredcontent_trimer.pdf.

[357] Klafka, Steve, Wingra Engineering, GCC Rio Grande – Pueblo Cement Plant, Four-Factor Reasonable Progress Analysis, September 23, 2021, hereinafter "GCC Pueblo Four Factor Analysis," attached as Ex. 27.

[358] Calculated from the permitting production limit 962,265 tons per 12-month period assuming 365 days of operation per 12-month period. *See* Condition II.B.4.j of Title V Operating Permit Number 2300015004.

[359] *See* GCC Pueblo Four Factor Analysis, Appendix B at 2 (Ex. 27); *see also* max permitted annual clinker production limit of 962,265 tons per 12-month period specified at Condition II.B.4.j of Title V Operating Permit Number 2300015004.

[360] *See* GCC Pueblo Four Factor Analysis, Appendix B at 5 (Ex. 27).

[361] GCC Pueblo Four Factor Analysis Appendix F at 5 (Ex. 27).

[362] *Id.* at 5-6 (Ex. 27).

the control system of $1,620,000/year.[363] The capital costs also include the costs to upgrade the existing baghouse if necessary for upgraded structural support and upgraded internals.[364] The annual operating costs take into account power costs, use of aqueous ammonia (19% by weight), maintenance, and replacement of the filters every 10 years.[365] The use of aqueous ammonia is safer than using anhydrous ammonia, and there is not a federal requirement for an accidental release plan.

Ash Grove's four-factor analysis identified the Leamington Cement kiln having baseline NOx emissions of 1,198 tons per year.[366] This presumably reflects some level of NOx removal from the SNCR system, but Ash Grove did not identify the NOx removal efficiency being achieved by the SNCR. For the purpose of estimating the amount of NOx removed that would occur with replacing the existing SNCR system with ceramic catalytic filtration bags, it is assumed that the baseline NOx emissions from the Leamington Cement Plant kiln reflect 40% NOx control. EPA has identified the median reduction of NOx with SNCR at cement kilns as 40% NOx reduction efficiency.[367] Assuming NOx removal efficiency increases from 40% with SNCR to 90% with ceramic catalytic filtration bags which would essentially replace SNCR equates to a reduction from NOx baseline of 898.5 tons per year of NOx.

Using Tri-Mer's cost estimates for the GCC Pueblo Plant as a starting point (which is likely an overestimate of costs given that the GCC Pueblo plant is a larger capacity kiln that the Leamington Cement Plant kiln), assuming the current bank prime rate of 4.0% interest rate and a 20-year life of the ceramic filtration system, a ceramic catalytic filtration system at the Leamington Cement Plant could have a cost effectiveness of $2,540/ton of NOx removed and would remove 898.5 tons of NOx per year.

It must be noted that some of the costs reflected in the Tri-Mer cost assessment regarding an ammonia storage and injection system have already been incurred by the Leamington Cement Plant, and the facility is also already incurring an annual operational expense for the ammonia or urea reagent purchased for implementation of SNCR. Thus, the use of a ceramic catalytic filtration system at Leamington Cement Plant would be even more cost effective than shown here.

Tri-Mer states that some of the added benefits of using a ceramic catalytic filtration system for control of NOx, as well as particulate, include that there is minimal catalyst plugging, reduced ammonia slip (well below 10 parts per million), and negligible catalyst deactivation.[368] Tri-Mer states that "a ceramic filter has no deactivation of the catalyst in a continuous operation for 10 years+."[369] In addition, with the use of sorbent injection, the ceramic catalytic filtration system could also be used to reduce SO2 emissions by 90% or more.[370] This could be an additional benefit of a ceramic catalytic filtration system,

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[363] *Id.*, Appendix F at 6. Note that the annual operating expense was calculated by subtracting the estimated Capital Investment of $8,999,200 from estimated lifetime cost (Capital expense plus 20 years of operating expenses) of $41,399,200 provided for the GCC Pueblo plant by Tri-Mer.

[364] *Id.* at 5.

[365] *Id.*, Appendix F at 6.

[366] March 2020 Leamington Four-Factor Analysis at 4-1.

[367] EPA, Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, at 1-5, available at https://www.epa.gov/sites/default/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf.

[368] GCC Pueblo Four Factor Analysis Appendix F at 7 (Ex. 27).

[369] *Id.*

[370] *Id.,* Appendix F at 5.

particularly if the fuels to the Leamington Cement Plant kiln change in the future and SO2 emissions increase.

The four-factor reasonable progress analysis of a ceramic catalytic filtration system at the GCC Pueblo cement kiln estimated the time necessary for compliance would be 12 months, from the time needed to obtain a quote to the installation of the equipment.[371] In terms of energy and non-air quality impacts of compliance, the ceramic catalytic filtration system would use electricity, which is taken into account in the cost analysis. The ammonia reagent, which the Leamington Cement Plant is currently using with SNCR, could pose risk management concerns and be subject to EPA's accidental release requirements. However, the four-factor analysis for the GCC Pueblo Cement Plant assumed 19% aqueous ammonia would be used, which is likely not be subject to EPA's accidental release requirements, unlike use of anhydrous ammonia.[372] Further, with use of a ceramic catalytic filtration system instead of SNCR, the Leamington Cement Plant will likely use less ammonia than it is currently using with SNCR.

For all of these reasons, UDAQ should require Ash Grove to evaluate the installation of ceramic catalytic filtration bags in its existing baghouse at the Leamington Cement Plant kiln, because it will significantly and cost-effectively reduce NOx emissions from the cement kiln.

C. Summary - UDAQ Must Reconsider Imposing Requirements to Ensure SO2 Emissions Remain Low ,and UDAQ Must Evaluate Likely Cost Effective NOx Controls for the Leamington Cement Plant Kiln

For the reasons discussed above, UDAQ has not adequately evaluated control measures for SO2 or for NOx at the Leamington Cement Plant. UDAQ must reconsider imposing as control measures on SO2 emissions from the cement kiln to ensure that emissions don't increase from the current baseline emissions of 8.0 tons per year to the allowable/potential to emit of 192.5 tons per year. In addition, UDAQ must collect more information on the NOx removal efficiency being achieved by the SNCR at the Leamington Cement Plant kiln, and more fully evaluate whether the current SNCR's NOx removal efficiency could be improved. In addition, UDAQ must evaluate the installation of ceramic catalytic filtration bags in the existing baghouse at the Leamington Cement Plant kiln, because the controls will significantly and, very likely, cost-effectively reduce NOx emissions from the cement kiln.

X. Holcim Devil's Slide Cement Plant

The Holcim Devil's Slide Cement Plant is located in Morgan, Utah, to the northeast of Salt Lake City and about 30 kilometers west of the Wyoming border. UDAQ did not identify this source for a four-factor analysis. However, the National Parks Conservation Association has identified this facility in the state's top five sources of visibility-impairing pollution in Utah, impacting up to 10 Class I areas.[373] The National Parks Conservation Association calculated a cumulative Q/d value for the Devil's Slide plant of 57.1.

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[371] *Id.* at 13.
[372] *Id.*
[373] *See* National Parks Conservation Association Regional Haze Fact Sheet, Utah, at 2, attached as Ex. 28.

According to the most recent permit issued for the cement plant, the Devil's Slide cement plan kiln has the following emission limits:

Table 27. Allowable Emissions of Holcim Devil's Slide Cement Plant Kiln[374]

NOx	SO2	PM10
1,817 tons per rolling 12-month period	457 tons per rolling 12-month period	14 lb/hr

Based on allowable emissions, the Devil's Slide cement kiln has a combined NOx+SO2+PM10 emissions of 2,335 tons per year. In Utah's 2017 emissions inventory, the Holcim Devil's Slide Plant was reported to have 1,427 tons per year of NOx emissions, 196 tons per year of SO2 emissions, and 72 tons per year of PM10 emissions,[375] for a combined total of 1,695 tons per year.

It is not clear why UDAQ did not conduct a four-factor analysis of controls for the Devil's Slide Cement Plant, as its 2017 actual emissions are similar to or higher than several other sources evaluated by UDAQ. According to permits issued in March of 2022 for the Devil's Slide Plant, the company is (or maybe already has) voluntarily installing SNCR at its cement kiln. Specifically, Approval Order DAQE-AN100070031-22, issued March 10, 2022, states that Holcim submitted an exemption notification on October 4, 2021 for the "permanent installation of a selective non-catalytic reduction (SNCR) system on the kiln" and that "[o]n July 21, 2021, Devil's Slide received permission to temporarily operate a SNCR system on the kiln to reduce NOx emissions."[376] The most recent Title V permit issued for the Devil's Slide Cement Plant has a September 10, 2023 deadline for Holcim to submit documentation to UDAQ on the status of the construction of the SNCR system and states that the Approval Order "may become invalid if construction is not commenced by September 10, 2023 or if construction is discontinued for 18 months or more."[377] UDAQ's summary of "Reviewer Comments" in the Devil's Slide Title V permit states the following about the SNCR installation at the Devil's Slide Cement Kiln:

> During the engineering review process for the referenced approval order, it was noted that the permittee is voluntarily installing SNCR, not as the result of a BACT determination. The SNCR will be operated as needed to meet the NOx limit on the kiln but it is not required to operate at all times. [2/22/2022] [Last updated March 17, 2022]

Title V Operating Permit Number 2900001004, Holcim (US) Inc. – Devil's Slide Plant, revised March 25, 2022, at 69 (Ex. 30 to this report).

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[374] Approval Order DAQE AN100070031-22, Holcim (US) Incorporated - Devil's Slide Plant, March 10, 2022, at 7 (Condition II.B.1.a), attached as Ex. 29.

[375] Based on total of reported emissions for all emission units at the Holcim Devil's Slide Plant in Utah's 2017: Statewide Emissions Inventories, available at https://deq.utah.gov/air-quality/2017-statewide-emissions-inventories.

[376] Approval Order DAQE AN100070031-22, Holcim (US) Incorporated - Devil's Slide Plant, March 10, 2022, at 4 (under Project Description), attached as Ex. 29.

[377] Title V Operating Permit Number 2900001004, Holcim (US) Inc. – Devil's Slide Plant, revised March 25, 2022, at 54 (Condition II.B.6.o), attached as Ex. 30.

Based on a review of the Title V permit for the Devil's Slide Plant, the only NOx emission limit is the requirement for no more than 1,817 tons of NOx per rolling 12-month period from the cement kiln.[378] There is no production-based NOx limit in the Devil's Slide air permit. The permit does set a production limit of 930,000 tons of clinker per rolling 12-month period.[379] Based on the mass-based NOx limit and clinker production limit, this equates to an effective NOx limit of 3.91 lb/ton of clinker. In comparison, the Leamington Cement Plant kiln (which is a preheater/precalciner kiln as is the Devil's Slide kiln and which is also equipped with SNCR) is designed to emit 2.8 lb/ton of clinker with SNCR.[380] Based on this comparison, it is clear that the NOx limit applicable to the cement kiln at the Devil's Slide plant does not reflect operation of SNCR. That conclusion is supported by the fact that UDAQ's response to comments specifically states that the permit does not require operation of the SNCR and, instead, its operation is voluntary. If the company's recently proposed installation of SNCR is the reason why UDAQ did not require a four-factor analysis of controls for this plant, UDAQ was not justified in excluding the Devil's Slide cement plant from a four-factor analysis when the requirement to operate an SNCR system is not required by the permit or when the permit does not impose a NOx emission limit reflective of operation of the SNCR system. For all of these reasons, UDAQ should evaluate NOx controls and emission limits for the Holcim Devil's Slide cement plant.

At the minimum, UDAQ should establish a firm requirement for Holcim to install (if not already installed) and operate the SNCR system at the Devil's Slide cement kiln. In addition, UDAQ should set a NOx emission limit reflective of the capabilities of the SNCR system at the Devil's Slide Cement Kiln (which should be between 35% - 63% NOx control, or higher)[381] and add appropriate testing, recordkeeping, and reporting requirements to ensure continuous compliance with the emission limit.

In addition, UDAQ should evaluate the cost effectiveness of installing catalytic ceramic filters in the existing baghouse for the Devil's Slide cement kiln that would work in concert with the ammonia injection of the SNCR system to achieve 90% reduction in NOx emissions. The Devil's Slide cement kiln emitted 1,406 tons of NOx in 2017, and thus 90% reduction would equate to a reduction in NOx emissions of 1,265 tons per year (assuming there was no SNCR operating and reducing NOx from the Devil's Slide cement kiln in 2017). Indeed, using the Tri-Mer cost analysis that was provided for the GCC Pueblo Cement Plant,[382] which is discussed in detail in Section IX.B. of this report, to estimate costs of control for the Devil's Slide cement kiln that has a lower capacity than the GCC Pueblo Cement Plant,[383] it is estimated that the Tri-Mer catalytic ceramic filtration bags would have a cost effectiveness of $1,804/ton of NOx removed to achieve 90% NOx removal at the Devil's Slide cement kiln. Thus, use of

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[378] *Id.* at 31 (Condition II.B.6.d).
[379] *Id.* at 54 (Condition II.B.7.a).
[380] August 2021 Ash Grove Leamington Submittal at 2.
[381] *See* EPA, Alternative Control Techniques Document Update, NOx Emissions from New Cement Kilns, November 2007, at 72, available at https://www3.epa.gov/ttncatc1/dir1/cement_updt_1107.pdf.
[382] Klafka, Steve, Wingra Engineering, GCC Rio Grande – Pueblo Cement Plant, Four-Factor Reasonable Progress Analysis, September 23, 2021, hereinafter "GCC Pueblo Four Factor Analysis," attached as Ex. 27.
[383] Based on the 930,000 tons of clinker per 12-month period that applies to the Devil's Slide Cement Plant, its average daily production rate would be 2,548 tons of clinker per day, whereas the GCC Pueblo Cement Plant (for which Tri-Mer provided a cost estimate for use of catalytic ceramic filtration bags) has a daily production capacity of 3,750 tons of clinker per day. *See* GCC Pueblo Four Factor Analysis, Appendix B at 2 (Ex. 27); *see also* max permitted annual clinker production limit of 930,000 tons per 12-month period specified at Condition II.B.7.a of Title V Operating Permit Number 2900001003.

catalytic ceramic filtration bags at the Holcim Devil's Slide Cement Plant is likely a very cost effective NOx control for the cement kiln. Thus, UDAQ should more fully evaluate the use of catalytic ceramic filtration bags at the Devil's Slide cement kiln. But, at the minimum, UDAQ should require the SNCR system to be installed at the Devils' Slide cement kiln to be operated year-round and UDAQ should set a NOx limit reflective of its operation.

XI. Lisbon Gas Processing Plant

CCI Paradox Midstream, LLC operates the Lisbon Natural Gas Processing Plant located in La Sal, Utah. According to UDAQ, the facility has a combined Q/d of 20.9.[384] The closest Class I area is Canyonlands National Park which is 35.8 km away. The facility's emissions were identified by UDAQ as follows:

Table 28. Emissions Considered by UDAQ for the Lisbon Gas Processing Plant for its Q/d Analysis[385]

	NOx, tpy	SO2, tpy	PM10, tpy
Facility Emissions	188.6	499.6	59.0

UDAQ eliminated the Lisbon Gas Plant from the requirement to submit a four-factor analysis of controls. UDAQ's justification for this was as follows:

> In 2009 the plant received a permit modification to lower the SO2 emissions from 1,593 tons down to 111 tons. The plant requested a reduction in emissions as it had installed both primary and secondary control systems to limit emissions of SO2.

April 2022 Draft Utah Regional Haze Plan at 94.

However, UDAQ also states that "[U]nfortunately, in 2010 the plant requested a new modification and mistakenly restored the original 1,593 tons of SO2 emissions without explanation."[386] UDAQ claims that despite the potential to emit value being carried forward in more recent permitting actions, actual SO2 emissions are "more in line with the proper 2009 [potential to emit] of 111 tons."[387]

Given that UDAQ considers 111 tons per year to be the "proper potential to emit" SO2 from the Lisbon Gas Plant and given that 111 tons per year were presumably what was modeled for the Lisbon Gas Plant in the WRAP's 2028 modeling, UDAQ must adopt a regional haze SIP requirement specifying the "proper" SO2 limit on the Lisbon Gas Plant of 111 tons per year, along with appropriate testing, recordkeeping and reporting, and subsequently incorporate such requirements into the applicable permit for the Lisbon Gas Plant.

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[384] April 2022 Draft Utah Regional Haze Plan at 93.
[385] *Id.*
[386] April 2022 Draft Utah Regional Haze Plan at 94.
[387] *Id.*

XII. UDAQ Must Consider Reasonable Progress Controls for the Oil and Gas Industry to Make Reasonable Progress Towards the National Visibility Goal.

According to the draft Utah regional haze plan, NOx emissions from the oil and gas industry (point and non-point sources) represent collectively the third largest anthropogenic source category of NOx emissions in the state of Utah after on-road mobile sources and EGUs, with 2014 combined emissions of 16,447 tons per year.[388] Yet, UDAQ did not evaluate any NOx controls for this source category in its draft regional haze plan. UDAQ's draft regional haze plan acknowledges the high level of air emissions from the oil and gas sector in the Uintah Basin, although UDAQ states that "80% of emissions in the [Uintah Basin] result from areas under EPA control" in Indian Country.[389] Assuming that is accurate, that does not negate Utah's obligation to evaluate reasonable progress control requirements for this significant source of NOx emissions in Utah.

As discussed in detail in a March 2020 report providing a four-factor analysis of controls for sources in the oil and gas industry, attached as Exhibit 24 to this report, there are cost effective control technologies available for at least the following source categories within the oil and gas development industry: natural gas-fired reciprocating internal combustion engines (RICE); natural gas-fired combustion turbines; diesel-fired RICE; natural gas-fired heaters and boilers; and flaring. [390] The attached report provides information on federal, state, and local air emission limitations that were required to be met by existing sources and thus required a retrofit of pollution controls or upgrade to the source category.[391] This assessment includes an evaluation of the lowest emission limits required of existing sources by state and local agencies and correlates those emission limits to specific pollution controls.[392] A brief summary of those cost-effective controls is provided below.

A. Natural Gas-Fired Reciprocating Internal Combustion Engines

Reciprocating Internal Combustion Engines (RICE) are one of the primary emission sources of NOx and VOCs in oil and gas development. RICE are used in a variety of applications, including gas compression, pumping, and power generation. RICE can be lean-burn engines (meaning they operate with a higher air-to-fuel ratio) or lean burn (meaning they operate with a lower air-to-fuel ratio). These engines can operate lean (i.e., with a higher air-to-fuel ratio) or rich (i.e., with a lower air-to-fuel ratio).

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[388] April 2022 Draft Utah Regional Haze Plan at 62.

[389] *Id.* at 106.

[390] Stamper, V. and M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, March 6, 2020 (hereinafter "March 2020 Report on Oil and Gas Sector – Four-Factor Analysis of Controls"), attached as Ex. 24 to this report.

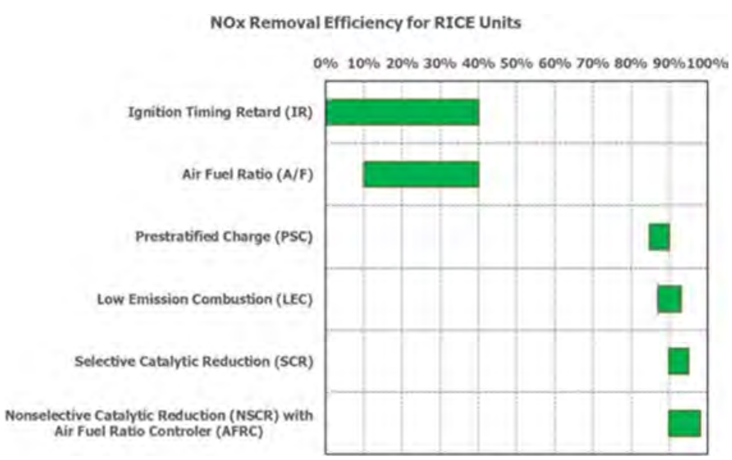
[391] *Id.* at ES-1.

[392] *Id.* at ES-1.

The top method to reduce NOx (and other pollutants) directly emitted from RICE engines is to replace the engines with electric engines. Replacement of reciprocating internal combustion engines with an electric motor can be cost effective for all size engines.[393]

Where electrification is infeasible, there are different available controls to reduce NOx emissions from RICE units. The best available and most cost-effective controls to reduce emissions from this source type are Nonselective Catalytic Reduction (NSCR), which is usually also accompanied by an air/fuel ratio controller (AFRC), for rich burn units, whereas Low Emission Combustion (LEC) and SCR are the top controls for lean burn units. Figure 1 below shows the various controls that can be used to reduce NOx emissions from natural gas-fired RICE and the expected removal efficiency of those controls.

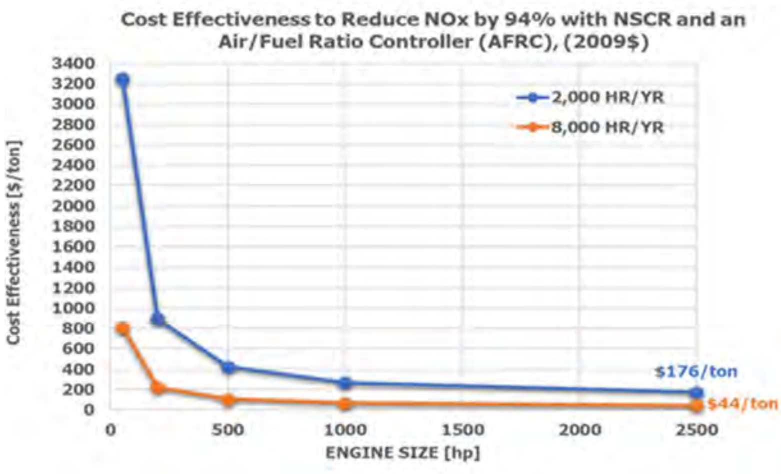
Figure 1. NOx Controls and Removal Efficiency for Gas-Fired RICE Units[394]



While there are cost-effective NOx controls for lean burn engines, NSCR with AFRC for rich-burn engines is very cost-effective, even for units that do not operate frequently.[395] This is illustrated in Figure 2.

[393] *Id.* at 44.
[394] *See* National Parks Conservation Association, "Controlling Regional Haze Pollution from the Oil and Gas Sector," at 2 (March 2019) ("NPCA Fact Sheet"), attached as Ex. 31.
[395] March 2020 Report on Oil and Gas Sector – Four-Factor Analysis of Controls at 19.

Figure 2. Range of Cost-Effectiveness Values for NSCR plus AFRC at Rich-Burn RICE Units.[396]



The oil and gas four-factor report in Exhibit 24 includes tables summarizing the NOx emission limits required of existing gas-fired stationary RICE units in states and local air districts across the United States.[397] The lowest NOx limit for natural gas-fired RICE greater than 50 horsepower is 11 parts per million by dry volume (ppmvd) (approximately equivalent to 0.15 grams per horsepower-hour (g/hp-hr)).[398] The available NOx controls for natural gas-fired RICE could significantly reduce NOx emissions from this source category.

B. Natural Gas-Fired Combustion Turbines.

Gas-fired combustion turbines are another primary source of NO_X emissions in the oil and gas industry. These turbines are used to provide on-site power to gas processing facilities, or they are used to drive compressors. There are several points in the oil and gas production process where compression of the gas is required to move the gas in the pipeline. SCR is the top NOx control for gas turbines and is cost effective for many gas turbines.[399] Dry low NOx combustion (DLNC) is also cost effective and can achieve similar NOx rates as SCR for some turbine models.[400] Water or steam injection can also be a very effective NOx control measure for gas turbines.[401]

Several state and local air agencies have adopted NOx limits for gas turbines that required retrofitting of NOx controls, with emission limits as low as 2.5 ppmv.[402] Figures 3 and 4 provide information on NOx

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[396] *See* National Parks Conservation Association, "Controlling Regional Haze Pollution from the Oil and Gas Sector," at 2 (March 2019) ("hereinafter NPCA Oil and Gas Fact Sheet"), attached as Ex. 31.
[397] March 2020 Report on Oil and Gas Sector – Four-Factor Analysis of Controls at 47-55 (Ex. 24).
[398] *Id.* at ES-2, 49-50.
[399] *Id.* at 75, 78-79.
[400] *Id.* at 70-72.
[401] *Id.* at 65-66.
[402] *Id.* at ES-2, 83-88, and 90.

removal efficiencies for combustion turbines and the cost effectiveness of SCR on a 75 MW simple cycle gas turbine.

Figure 3. Removal Efficiencies of NOx Controls for Natural Gas-Fired Combustion Turbines [403]

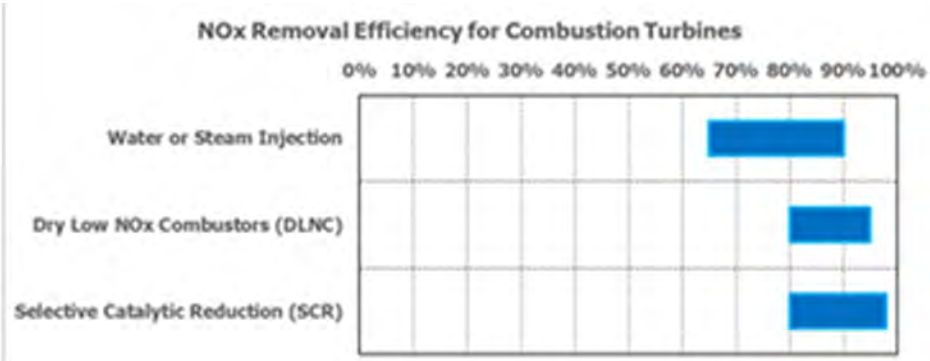
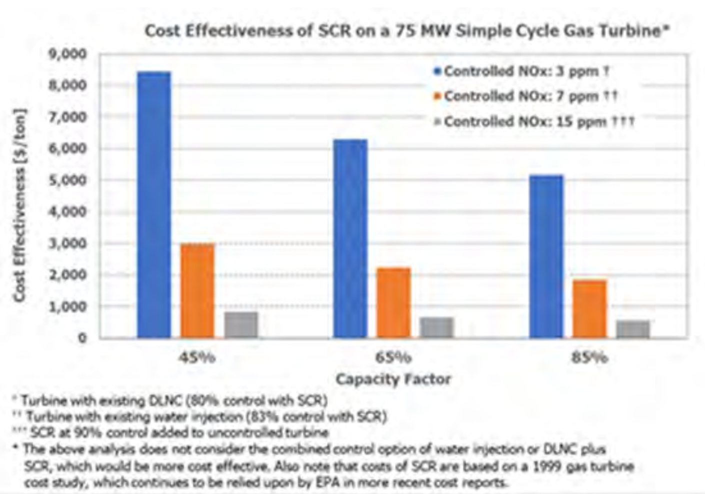


Figure 4. Range of Cost Effectiveness Values for SCR at a Gas-Fired Combustion Turbine [404]



The data, rules, and analyses in the March 2020 Report on Oil and Gas Sector (Ex. 24) show that numerous state and local air agencies have found water/steam injection, dry low NOx combustors, and SCR as cost effective controls for natural gas-fired combustion turbines, with costs ranging from $128/ton to $13,500/ton (1999$) to meet NOx limits ranging from 42 ppmv down to 2.5 ppmv.[405]

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[403] NPCA Oil and Gas Fact Sheet at 2 (Ex. 31).

[404] *Id.*

[405] March 2020 Report on Oil and Gas Sector – Four-Factor Analysis of Controls at 82-89, 90 (Ex. 24).

Although there are some states that limited applicability of NOx emission limits to larger turbines (e.g., greater than 10 MW (or greater 13,500 hp or 100 MMBtu/hour)), there are several states and local air pollution control agencies that set NOx limits requiring NOx controls for turbines smaller than 10 MW.[406] In fact, several California districts set a NOx limit reflective of water or steam injection (i.e., 42 ppmv) for turbines as small as 0.3 MW.[407]

SCR should be considered the control technology of choice for NOx removal at gas-fired combustion turbines of 0.3 MW size or larger, including those that operate compressor stations and/or that operate at lower capacity factors. Combustion turbines with SCR should be able to meet NOx limits in the range of 2.5 to 9 ppmv NOx.[408] For those turbines for which SCR is not technically or economically feasible, DLNCs should be the next control technology with NOx emission limits achievable in the 7.5 to 25 ppm range.[409] It also must be recognized that, in some cases, it may be more effective for NOx control – and more cost effective – to require replacement of existing gas-fired turbines with new turbines designed with state-of-the-art dry low NOx combustion controls, as such controls can achieve much lower NOx rates than water or steam injection and do not require water usage.[410]

C. Diesel-Fired RICE

Compression-ignited (i.e., diesel-fired) RICE are generally used in the oil and gas industry for on-site power generation, as well as to power or to drive drill rigs, drive hydraulic fracturing pumps, and to power other pumping and compression applications. As previously discussed in Section VIII.C. above, EPA has required diesel engines be manufactured to meet lower emission standards since 2015 (called "Tier 4 engines"), which reflect use of SCR.[411] It is likely most cost effective to consider the replacement of existing older engines with new Tier 4 engines rather than requiring retrofitting of pollution controls.[412]

Another option for reducing emissions from diesel RICE is to replace the engines with gas-fired or dual fuel RICE. This would result in approximately a 91% reduction in NOx from use of Tier 0 diesel engines and approximately an 85% reduction in NOx from use of Tier 1 diesel engines.[413]

For drill rigs, it is most preferable from an air emissions perspective to replace existing older diesel-fired drill rigs with electric-motor drill rigs that are powered by a Tier 4 Electrical Generating Set. Tier 4 Electrical Generating Set engines greater than 1,500 hp are required to meet the lowest NOx and PM emission rates, significantly lower than large non-electrical generating engines.[414] Thus, installing electric drill rigs that are powered by Tier 4 electrical generating diesel RICE will result in the greatest reduction in visibility-impairing emissions if the only option is to continue to power the engines with diesel fuel.

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[406] *Id.*
[407] *Id.*
[408] *Id.*
[409] *Id.*
[410] *Id.*
[411] *Id.* at 95, 98.
[412] *Id.* at 99-100.
[413] *Id.* at 103.
[414] *Id.* at 98, 115.

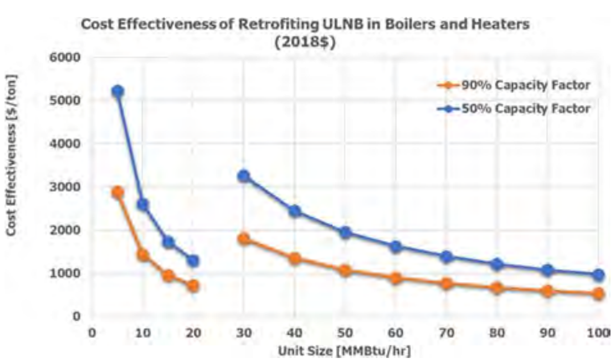
Diesel-fired RICE can also be retrofit with SCR, which is most cost-effective for Tier 0 or Tier 1 engines, due to their high NOx emission rates. Several California air districts have adopted NOx emission limitations that would require retrofitting of SCR to diesel RICE.[415]

D. Natural Gas-Fired Boilers, Reboilers, and Heaters

Gas-fired boilers and heaters are used in a variety of applications, including power generation and the production of process heat and steam. In oil and gas production and processing, heaters can be used to aid in separation (e.g., heater- treaters, gas production units (GPUs), heated flash separator units), to maintain temperatures within pipes and connectors (e.g., line heaters), to maintain storage tank temperatures (e.g., tank heaters), and as regenerators and/or reboilers (e.g., dehydrators). Gas-fired external combustion units are sources of NOx, CO, VOC, and particulate matter emissions. SO_2 emissions may also occur if the field-gas used to fire the heaters contains hydrogen sulfide (H_2S), which converts to SO_2 during combustion.

Combustion modification – such as flue gas recirculation (FGR), low-NOx burners (LNB), and ultra-low NOx burners (ULNB)—reduce NOx formation by controlling the combustion process. NOx emission reductions of 40 to 85% can be achieved using low NOx burners. When low NOx burners and FGR are used in combination NOx emission reductions of 60 to 90% can be achieved. Figure 5 shows the cost effectiveness of retrofitting ultra-low NOx burners to meet a NOx limit of 6 ppm at various sized gas-fired boilers and heaters.

Fig. 5. Range of Cost-Effectiveness Values for Retrofitting ULNBs at Natural Gas-Fired Boilers and Heaters.[416]



[415] *Id.* at 105, 111-113, 116.

[416] NPCA Oil and Gas Fact Sheet at 4 (Ex. 28).

SCR systems can be used on gas heaters and boilers which can achieve NOx removal efficiencies in the range of 80 to 90+% and are cost effective for larger units.[417] The San Juan Valley Air Pollution Control Division (SJVAPCD) in California has found that SCR is cost effective for larger units with costs ranging from $1,025/ton to $6,149/ton to meet NOx levels as low as 2.5 ppm.[418] SNCR is also a post-combustion control option that can achieve 30-75% NOx reduction at boilers and heaters. Additionally, NOx emission can be reduced by lowering combustion temperatures in heater-treaters.

Numerous state and local air agencies have found that low NOx burner technology is a cost-effective retrofit NOx control for boilers and heaters >5 MMBtu/hr, with costs ranging from $545/ton to $5,232/ton.[419] Smaller units ≤5 MMBtu/hr can be replaced with new units with low NOx burner technology at costs ranging from $4,055/ton to $10,809/ton.[420] Low NOx burner technologies can generally meet limits down to 5‑6 ppm, with the potential for emerging technologies to meet NOx levels lower than 5 ppm.[421]

E. Flaring and Thermal Incineration.

Gas flaring and incineration both mitigate excess or waste gases from oil wells, gas processing plants, or oil refineries. A thermal incinerator is a thermal oxidation process that occurs in an enclosed combustion chamber. The purpose of both a flare and a thermal incinerator is to combust the excess or waste gas and reduce VOC emissions.

According to EPA studies, flares "can operate at a wide range of Destruction and Removal Efficiency (DRE)."[422] As a result, although flares are a VOC control device, flares are also a source of VOC emissions especially when not designed or operated in a manner to achieve high levels of DRE. Further,"[s]mall amounts of uncombusted vent gas will escape the flare combustion zone along with products of incomplete combustion,"[423] which can add to VOC emissions as well as methane emitted from the flare. Flaring of natural gas also results in emissions of NOx, as well as particulate matter emissions of carbon particles (soot) and unburned hydrocarbons.

For flaring of waste gases, the following control options should be evaluated:[424]

- Prevent flaring of excess gases through capture and use requirements instead of flaring
- Prevent flaring at gas sweetening and other processing plants by proper maintenance, training, installing duplicative equipment to minimize upsets
- Require documentation of flaring episodes with all relevant info to estimate emissions and to assess causes and actions to mitigate

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417 March 2020 Report on Oil and Gas Sector – Four-Factor Analysis of Controls at 132-135 (Ex. 24).
418 *Id.*
419 *Id.* at 124-126.
420 *Id.* at 127.
421 *Id*. at 124-125.
422 *Id.* at 147; *see also* EPA, Air Pollution Control Fact Sheet, Flare, EPA-452/F-03-019, available at: https://www3.epa.gov/ttn/catc/dir1/fflare.pdf.
423 *Id.*
424 March 2020 Report on Oil and Gas Sector – Four-Factor Analysis of Controls at 146-155 (Ex. 24).

- Thermal incineration should be considered in lieu of flaring due to ability for improved VOC destruction and available NOx and SO2 controls (if sour/acid gas is being combusted)

The ultimate goal to reduce VOC, NOx, PM, and SO2 emissions from excessive flaring should be to eliminate or minimize flaring to the maximum extent possible and to use, and not waste, excess gas produced.

F. Summary – There Are Several Control Options that UDAQ Should Evaluate for the Oil and Gas Sources Within its State.

As discussed in the attached 2020 Four-Factor Analysis of Controls for the Oil and Gas Sector (Ex. 24 to this report), there are several cost-effective control options to reduce NOx and other regional haze-impairing emissions from oil and gas production. Given that emissions from this sector are a significant source of regional haze pollutants in the state of Utah, UDAQ must evaluate and consider NOx controls for the various sources associated with the oil and gas industry to achieve reasonable further progress towards the national visibility goal.

List of Exhibits

Exhibit Number	Description
1	Washington Department of Ecology, Responses to Comments for Chemical Pulp and Paper Mills
2	EPA, Response to Technical Comments for Sections E. through H. of the Federal Register Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan, Docket No. EPA-R06-OAR-2010-0190
3	Modified spreadsheet from EPA's "SCR Actual Annual Emissions by Range.xlsx" (from Docket ID EPA-R08-OAR-2015-0463-1157)
4	Kurtides, T., Sargent and Lundy, Lessons Learned from SCR Reactor Retrofit, COAL-GEN, Columbus, OH, August 6-8, 2003
5	May 2009, White Paper, Selective Catalytic Reduction (SCR) Control of NOx Emissions from Fossil Fuel-Fired Electric Power Plants, Institute of Clean Air Companies
6	SCR System Performance at LG&E's Trimble County Generating Station, Babcock Power Inc. Technical Publication, presented at EPRI Workshop on Selective Catalytic Reduction, October 22-23, 2002
7	Energy Information Administration, Coal Data Browser information for the coal received at the Hunter Power Plant
8	Energy Information Administration, Coal Data Browser information for the coal received at the Huntington Power Plant
9	August 2021, Air Construction Permit Application – Technical Support Document, IPP Renewal Project, Intermountain Generating Station, at pdf page
10	UDAQ, Intent to Approve, Modification to Approval Order DAQE-AN103270026-14 for the IPP Renewal Project, Project Number: N103270029, April 29, 2022
11	Energy Information Administration, Coal Data Browser, Shipments to Sunnyside Cogen
12	Cost Effectiveness Workbook for CDS without baghouse for Sunnyside Cogen
13	Utah Statement of Basis, Ground Water Quality Discharge Permit UGW570002, April 2020
14	DSI with Lime Cost Effectiveness Spreadsheet Sunnyside Cogen
15	February 8, 2012 Direct Testimony of Christian T. Beam on behalf of Southwestern Electric Power Company, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding that Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Before the Arkansas Public Utilities Commission, Docket 12-008-U
16	SNCR Cost Effectiveness Spreadsheet Sunnyside Cogen
17	SCR Cost Effectiveness Spreadsheet Sunnyside Cogen
18	Approval Order DAQE-AN105720040-20, Kennecott Utah Copper, February 4, 2020
19	Illinois Environmental Protection Agency, September 2015, Responsiveness Summary for the Public Comment Period on the Issuance of a Construction Permit/PSD Approval for Mississippi Lime Company to Construct a Lime Plant in Prairie du Rocher, Illinois
20	Haldor Topsoe CataFlex™ Brochure

21	Haldor Topsoe Cataflex Brochure, "Single-step dust, NOx, Sox, and NH3 removal in lime kilns"
22	May 25, 2018 Permit Application for Atlantic Coast Pipeline LLC, Buckingham Compressor Station
23	Buzanowski, Mark A. and Sean P. McMenamin, Peerless Mfg. Co., Automated Exhaust Temperature Control for Simple Cycle Power Plants
24	Stamper, V. and M. Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration, March 6, 2020
25	SCR Cost Effectiveness Spreadsheet US Magnesium Rowley Plant Riley Boiler
26	Air & Waste Management Association, The Magazine for Environmental Managers, Sponsored Content, "Catalytic Filter Technology Provides Important Flexibility for Controlling PM, NOx, SOx, O-HAPS
27	Klafka, Steve, Wingra Engineering, GCC Rio Grande – Pueblo Cement Plant, Four-Factor Reasonable Progress Analysis, September 23, 2021
28	National Parks Conservation Association Regional Haze Fact Sheet, Utah
29	Approval Order DAQE AN100070031-22, Holcim (US) Incorporated - Devil's Slide Plant, March 10, 2022
30	Title V Operating Permit Number 2900001004, Holcim (US) Inc. – Devil's Slide Plant, revised March 25, 2022
31	National Parks Conservation Association, "Controlling Regional Haze Pollution from the Oil and Gas Sector" March 2019