March 21, 2022

Rhonda Payne
MT DEQ AQB
1520 E 6th Avenue
Helena, MT 59620-0901
By email: repayne@mt.gov

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

Dear Ms. Payne:

On behalf of the Coalition to Protect America’s National Parks, Montana Environmental Information Center, National Parks Conservation Association, Park County Environmental Council, and Sierra Club (the “Conservation Organizations”), we respectfully submit the following comments and attached expert report¹ regarding Montana Department of Environmental Quality’s (“MDEQ”) Proposed State Implementation Plan Regional Haze Second Planning Period (“Proposed SIP”), dated February 3, 2021. The Conservation Organizations appreciate the extension MDEQ provided to submit comments on the 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 more than 8,200 in Montana. 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 Montana’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

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 Montana Regional Haze Plan for the Second Implementation Period” (March 2022) (“Stamper Report”) (Exhibit A). Ms. Stamper is an independent air quality consultant and engineer with extensive experience in the regional haze program.
practicing and promoting the responsible use of the earth’s ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. The Sierra Club has long participated in Regional Haze rulemaking and litigation across the country in order to advocate for public health and our nation’s national parks.

Park County Environmental Council ("PCEC") is a Montana-based nonprofit organization. PCEC works with Montana communities to safeguard the land, water, wildlife, and people of Yellowstone’s Northern gateway through grassroots organizing and community advocacy.

Montana Environmental Information Center ("MEIC") is a non-profit environmental advocacy organization founded in 1973 by Montanans concerned with protecting and restoring Montana’s natural environment. MEIC plays an active role in Regional Haze rulemaking and advocating for the expansion of responsible, renewable energy and energy efficiency, and supporting policies that reduce pollution in Montana’s iconic national parks and wilderness areas. MEIC has approximately 5,000 members and supporters, many of whom live near, work at, and recreate in the national parks and wilderness areas affected by Montana’s sources.

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.

The Conservation Organizations have serious concerns regarding MDEQ’s Proposed SIP for the second implementation period. As discussed in these comments, the National Park Service’s consultation comments to MDEQ echo many of the concerns raised in this letter. MDEQ’s assertions that no emissions controls are necessary because Montana is under the Uniform Rate of Progress ("URP") are misplaced. The Environmental Protection Agency’s ("EPA") Clarification Memo refuted this assertion and explained that the “URP is a planning metric used to gauge the amount of progress made thus far and the amount left to make.”2 EPA further noted that the URP “is not based on consideration of the four statutory factors and, therefore, cannot answer the question of whether the amount of progress made in any particular implementation period is ‘reasonable progress.’”3

The Proposed SIP will not result in reasonable progress towards improving visibility at Montana’s twelve Class I areas impacted by the state’s sources, including:

3 Id.
• Anaconda-Pintler Wilderness Area;
• Bob Marshall Wilderness Area;
• Cabinet Mountains Wilderness Area;
• Gates of the Mountains Wilderness Area;
• Glacier National Park;
• Medicine Lake Wilderness Area;
• Mission Mountain Wilderness Area;
• Red Rock Lakes Wilderness Area;
• Scapegoat Wilderness Area;
• Selway-Bitterroot Wilderness Area;
• U.L. Bend Wilderness Area; and
• Yellowstone National Park.

We support MDEQ’s decision to request source evaluations of the following sources, which include three power plants and thirteen non-power plant sources:

1. Colstrip Steam Electric Station (Coal Power Plant)
2. Yellowstone Power Plant (Petroleum Coke Power Plant)
3. Rosebud Power Plant (Coal Power Plant)
4. Weyerhaeuser NR-Columbia Falls (Wood Product Manufacturing)
5. Weyerhaeuser NR-Evergreen Facilities (Wood Product Manufacturing)
6. Ash Grove (Cement Manufacturing)
7. GCC Trident (Cement Manufacturing)
8. Roseburg Forest Products Co. (Wood Product Manufacturing)
9. Graymont Western U.S. Inc. (Lime Manufacturing)
10. Montana Sulfur & Chemical Co. (Industrial Gas Manufacturing)
11. ExxonMobil Billings (Petroleum Refinery)
12. CHS Inc. Refinery Laurel (Petroleum Refinery)
13. FH Stoltze Land & Lumber Co. (Wood Product Manufacturing)
14. Sidney Sugars Inc. (Beet Sugar Manufacturing)
15. Phillips 66 Co.-Billings (Petroleum Refinery)
16. Northern Border Pipeline Compressor Station 3 (Oil and Gas Facility)

But none of these sources conducted a complete and accurate statutory Four-Factor Analysis, and MDEQ arbitrarily refused to propose cost-effective emission reductions at any of these facilities to ensure reasonable progress. Despite the thousands of tons of controllable pollution from Montana’s sources including coal-fired power plants, cement kilns, and petroleum refineries, among others, and the many opportunities for cost-effective controls, Montana improperly concludes that no new reductions in pollution are warranted. Thus, MDEQ must revisit these analyses, conduct Four-Factor Analyses for additional sources, and require pollution controls to cut emissions from the polluting sources.

According to NPCA’s analysis of polluting sources in Montana, 72% of visibility impairing pollution comes from Montana’s electricity sector including the following three sources:
• Colstrip Steam Electric Station (Coal Power Plant)
• Yellowstone Power Plant (Petroleum Coke Power Plant)
• Rosebud Power Plant (Coal Power Plant)

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., MDEQ must correct the flaws identified in these comments and in the attached technical report by Victoria R. Stamper. These corrections are:

● Require emission controls for the three power plants the state selected for review in this planning period—the state’s largest sector of visibility-impairing emissions;
● Establish enforceable SIP emission limits for Hardin Generating Station;
● Establish a cost-effectiveness threshold for reasonable progress and one that is in line with other state thresholds;
● Require pollution controls for non-power plants sources the state selected for review;
● Correct the inflated cost of controls calculations; and
● Thoroughly assess environmental justice impacts as EPA recommended in its 2021 Clarification Memo.

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

● Failure to first evaluate whether additional emission reductions from sources are necessary via the Four-Factor Analysis reasonable progress determinations to ensure reasonable progress toward the CAA’s visibility goal;
● Reliance on alleged “on-the-books” emission reductions and emission reductions from other programs absent any enforceable requirement;
● Reliance on flawed modeling data and assumptions that are not secured via enforceable SIP requirements to predict that visibility will continue to improve in 2028;
● Reliance on flawed and incomplete consultations with other states and Regional Planning Organizations (“RPOs”); and
● Failure to adequately respond to comments from the Federal Land Managers (“FLMs”).

The CAA requirements present a significant opportunity to not only improve visibility at Montana’s twelve Class I areas, and other treasured Class I areas across the region, but 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, MDEQ’s Proposed SIP contains fundamental flaws and improperly concludes that no new reductions in pollution are warranted.

Our comments present these issues and offer detailed suggestions to ensure that the SIP Montana submits to EPA will be in line with the CAA’s legal requirements and federal regulations, and address visibility impairing emissions.
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INTRODUCTION

The Conservation Organizations represent thousands of Montanans 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 Montana, Wyoming, the Dakotas, and the Intermountain West. The Clean Air Act imposes a legal obligation on states and EPA to abate haze pollution and its adverse visibility effects in our Class I Areas—large, iconic national parks and wilderness areas. 42 U.S.C. § 7491.

Montana is home to twelve iconic and treasured Class I areas: Anaconda-Pintler Wilderness Area, Bob Marshall Wilderness Area, Cabinet Mountains Wilderness Area, Gates of the Mountains Wilderness Area, Glacier National Park, Medicine Lake Wilderness Area, Mission Mountain Wilderness Area, Red Rock Lakes Wilderness Area, Scapegoat Wilderness Area, Selway-Bitterroot Wilderness Area, U.L. Bend Wilderness Area, and Yellowstone 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 CAA requires the highest level of protection for national parks and wilderness areas.

Emissions of sulfur dioxide (“SO2”) and nitrogen oxide (“NOx”) from Montana sources contribute significantly to visibility impairment in the region’s Class I areas both within Montana 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.5 In addition to impairing visibility, these same pollutants are harmful to human health and the environment.

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4 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 (“NH3”) 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.

MDEQ selected seventeen sources for review of emission-reducing measures in its implementation plan. Despite the many opportunities for cost-effective controls, **MDEQ improperly concludes that no new reductions in pollution are warranted.** MDEQ’s proposal would result 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 Montana are affecting communities that have borne the brunt of anthropogenic-caused pollution. If left unchanged, the state’s plan will not comply with the CAA 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 MDEQ revisit the emission limitations and pollution control requirements for sources in Montana. In order for Montana to fulfill its Regional Haze obligations under the CAA, MDEQ must revise the Proposed SIP to: (1) establish a cost-effectiveness threshold for reasonable progress and one that is in line with other states; (2) correct the inflated cost of controls calculations; (3) require emission controls for the three power plants the state selected for review in this planning period—the state’s largest sector of visibility-impairing emissions; (4) establish appropriate enforceable emissions limits for Hardin Generating Station (a coal power plant); (5) require pollution controls for non-power plant sources the state selected for review; and (6) thoroughly assess environmental justice impacts as EPA recommended in its 2021 Clarification Memo. 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. For the second implementation period, Montana 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 February of 2022, MDEQ made available its draft plan for addressing reasonable progress toward the national visibility goal for Class I areas. MDEQ has proposed to rely on unit closures that have already occurred or that are planned for four units: the J.E. Corette Power Plant, Units 1 and 2 of the Colstrip Power Plant, and Montana Dakota Utilities Lewis & Clark Power Plant. MDEQ also relied on “slight emission decreases projected in 2028” from Colstrip Units 3 and 4 and from the Cenex Harvest States Cooperative (“CHS”) Inc. Laurel Refinery. Several of the plant closures and slight emissions decreases were due to Consent Decrees to resolve Clean Air Act litigation or due to the EPA’s Mercury and Air Toxics Standards (“MATS”).

MDEQ based its selection of sources for review on whether the sum of emissions of NOx and SO2, based on the 2014-2017 average of emissions, exceeded 100 tons per year (“tpy”). For

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6 40 C.F.R. § 51.308(f). Montana’s SIP submission to EPA will be untimely.
8 Proposed SIP at 294, Table 7-2.
9 Id.
10 Id. at 48, 258, 288.
those facilities that met the first cutoff, MDEQ then focused on those facilities with a “Q/d” value greater than or equal to 4. Thus, MDEQ required Four-Factor Analyses of regional haze controls for seventeen facilities. 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.

I. **MONTANA POLLUTANT SOURCES’ IMPACT ON CLASS I AREAS**


Pollutants that cause visibility impairment also harm Montanans’ 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. Similarly, SO2 increases asthma symptoms, leads to increased hospital visits, and can form particulates that aggravate respiratory and heart diseases and cause premature death. PM can penetrate deep into the lungs and cause a host of health problems, such as aggravated asthma, chronic bronchitis, and heart attacks. Emissions reductions from Montana’s sources will ease the impact of pollution related health problems and costs.

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

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11 The Q/d value is the total of NOx + SO2 emissions in tpy divided by distance to nearest Class I area in kilometers.
12 Proposed SIP at 160.
13 Id.
14 40 C.F.R. § 51.308(f)(2)(i).
15 Proposed SIP at Appendix F, PDF page 46.
ecosystem can tolerate. 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. 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.”

In rigorously addressing visibility and, more specifically, visibility-impairing pollutants, Montana 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, 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. This tourism is a critical component of Montana’s economy. For example, in 2018, Yellowstone National Park generated over 4.1 million recreation visits, more than $512 million in local spending, and more than 7,000 jobs.

Despite these benefits, national parks and wilderness areas remain affected by regional haze. The view in western national parks on bad pollution days is 73 miles, versus more than two times that distance naturally. 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. Visitors are also

willing to alter their length of stay based on their perception of air quality.\textsuperscript{27} 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, Montana must limit emissions to enable national parks and wilderness areas affected by Montana sources to achieve reasonable progress towards Congress’ stated visibility goal; likewise, Montana has a duty to take all reasonable measures to adequately temper Montana 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.”\textsuperscript{28} “Manmade air pollution” is defined as “air pollution which results directly or indirectly from human activities.”\textsuperscript{29} 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.\textsuperscript{30} 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”).\textsuperscript{31}

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.”\textsuperscript{32} 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 and a long-term strategy for making reasonable progress toward the national visibility goal.\textsuperscript{33} 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

\textsuperscript{28} 42 U.S.C. § 7491(a)(1).
\textsuperscript{29} Id. § 7491(g)(3).
\textsuperscript{30} Id. § 7491(b)(2).
\textsuperscript{31} 42 U.S.C. § 7410(c)(1).
\textsuperscript{32} 42 U.S.C. § 7491(b)(2).
\textsuperscript{33} Id. § 7491(b)(2)(B); 40 C.F.R. § 51.308(d)(1)(i)(B).
technically achievable controls in the second planning period. 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 Rule requires all states, including Montana, to do their share by reducing pollution in their borders to help restore clean and clear skies at protected national parks and wilderness areas.

Implementing the regional haze requirements promises benefits beyond improving views. Pollutants that cause visibility impairment also harm public health. For example, NO\textsubscript{x} is a precursor to ground-level ozone which is associated with respiratory disease and asthma attacks. NO\textsubscript{x} also reacts with ammonia, moisture, and other compounds to form particulates that can cause and/or worsen respiratory diseases, aggravate heart disease, and lead to premature death. Similarly, SO\textsubscript{2} increases asthma symptoms, leads to increased hospital visits, and can also form particulates. NO\textsubscript{x} and SO\textsubscript{2} emissions also harm terrestrial and aquatic plants and animals through acid rain as well as through deposition of nitrates, which in turn cause ecosystem changes including eutrophication of mountain lakes.

**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.

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. 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. 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. BART must be installed and operated no later than five years after the SIP/FIP approval.

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34 82 Fed. Reg. 3078, 3,083 (Jan. 10, 2017); see also id. at 3,096 (“states must evaluate and reassess all elements required by 40 CFR 51.308(d)").
37 Id. § 7491(g)(7).
38 40 C.F.R. Part 51, Appendix Y.
39 Id. § 51.302(c)(4)(iv).
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, 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.40

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.41 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.42 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.”43 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.44

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.45

40 40 C.F.R. § 51.301; 42 U.S.C. § 7491(g).
41 42 U.S.C. § 7491(b)(2).
42 Id.
43 40 C.F.R. § 51.308(d)(1)(ii).
44 42 U.S.C. § 7491(b)(2); see also 40 C.F.R. § 51.308(d)(3).
45 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”).
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:

(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.46

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.”47 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 first conduct the required Four-Factor Analysis for its sources, and then 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”)];

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• [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
• [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.  

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. 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.

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

50 Id. § 51.308 (f)(2)(ii)(A).
additional technically achievable controls in the second planning period.\textsuperscript{51}

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 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.\textsuperscript{52} The Regional Haze Rule similarly requires each state to include “enforceable emission limitations” as necessary to ensure reasonable progress toward the national visibility goal.\textsuperscript{53} 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.\textsuperscript{54}

In addition, the 2017 Regional Haze Rule revisions further clarified that regional haze SIPs meet certain procedural and consultation requirements.\textsuperscript{55} 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.”\textsuperscript{56}

\textsuperscript{51} 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)

\textsuperscript{52} 42 U.S.C. § 7410(a)(2)(A).

\textsuperscript{53} 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.”).

\textsuperscript{54} 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 “not selecting sources that have an enforceable commitment to be retired or replaced by 2028”); id. at 34 (To the extent a retirement or reduction in operation “is being relied upon for a reasonable progress determination, the measure would need to be included in the SIP and/or be federally enforceable.”) (citing 40 C.F.R. § 51.308(f)(2)); 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.”).

\textsuperscript{55} 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.

\textsuperscript{56} 40 C.F.R. § 51.308(i)(3).
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, MDEQ 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.

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. 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. 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.

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. 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. Ongoing air pollution controls, otherwise improved visibility, and/or air modeling results must not be used to

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57 2021 Clarification Memo at 3.
58 Id. at 2.
59 Id. at 3.
60 Id. at 2.
61 Id. at 13.
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. 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:

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.

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.” 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.” 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 “must be included in the SIP” as enforceable emission reduction measures.

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 MDEQ’s efforts to avoid emission reductions—by asserting, for example, that reductions are not necessary because of anticipated source shutdowns or retirements—are at

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62 Id. at 13.
63 42 U.S.C. § 7491(g)(1); 40 C.F.R. § 51.308(f)(2)(i).
64 2021 Clarification Memo at 7.
65 Id. at 8.
66 Id. at 8-9 (emphasis added).
odds with Montana’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.”67

**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.68 If Montana, 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, MDEQ must conduct such an analysis or provide a demonstration that any emission reductions or controls would be futile to inform its reasonable progress determination.69 For those sources that submit their own Four-Factor Analysis, MDEQ 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.70 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).”71 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

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67 Id. at 13.
68 40 C.F.R. § 51.308(d).
69 2021 Clarification Memo § 2.2.
70 42 U.S.C. §§ 7491(a)(1), (b)(2).
71 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).
make the measures practicably enforceable including averaging times, monitoring requirements, and record keeping and reporting requirements.\textsuperscript{72}

While the SIP is the basis for demonstrating and ensuring state plans meet Regional Haze Rule requirements, state-issued permits must complement the SIP.\textsuperscript{73} 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 \textbf{must} be included as enforceable emission limitations in the SIP itself.\textsuperscript{74} 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.

\textbf{III. REGIONAL HAZE PLANNING IN MONTANA}

Although this is the second implementation period for regional haze planning, the Proposed SIP reflects MDEQ’s first attempt to comply with its regional haze obligations under the Clean Air Act. Montana previously “declined” to prepare a SIP for the first planning period due to a lack of resources, leading EPA in 2012 to finalize a Federal Implementation Plan ("FIP") for the state.\textsuperscript{75} That plan identified minor emissions reductions from a handful of sources subject to BART, namely Colstrip Units 1 and 2, the J.E. Corette coal-fired power plant, the Ash Grove and Trident cement kilns, and Devon Energy’s Blaine County compressor station. The FIP did not identify any emissions reductions from non-BART sources in its long-term strategy, leaving Colstrip Units 3 and 4 and other facilities to continue polluting at existing levels.

Following EPA’s publication of the FIP, numerous factors weakened those emissions reductions requirements. First, as explained in MDEQ’s Proposed SIP, EPA granted a request from the operator of the Trident cement kiln to raise the facility’s NOx limit.\textsuperscript{76} Second, PPL Montana, which at the time operated the Colstrip plant, sued EPA to eliminate NOx and SO2 BART requirements for Colstrip Units 1 and 2. NPCA, Sierra Club, and MEIC also filed suit, arguing that greater emissions reductions were required, including BART-based emissions reductions from Colstrip Units 1 and 2 and reasonable progress measures for Colstrip Units 3 and 4.\textsuperscript{77} The Court’s final order ruled that EPA’s analyses leading to NOx and SO2 emission

\textsuperscript{72} 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)).

\textsuperscript{73} 74 Fed. Reg. at 13,568.

\textsuperscript{74} 42 U.S.C. §§ 7410(a)(2), 7491(b)(2); see also 40 C.F.R. § 51.308(d), (f).


\textsuperscript{76} Proposed SIP at 47.

\textsuperscript{77} See Nat’l Parks Conservation Ass’n v. EPA, 788 F.3d 1134 (9th Cir. 2015).
limits for Colstrip Units 1 and 2 were arbitrary and vacated those limits. The Court declined to require any additional emissions reductions, including for Colstrip Units 3 and 4.

Despite declining to lead regional haze planning in the first planning period, MDEQ submitted the required progress report under the FIP on September 18, 2017.\(^78\) That progress report, approved by EPA on October 4, 2019, concluded that, despite the weakening of the FIP’s emissions reduction requirements, no FIP revisions or additional emissions reductions were necessary to achieve reasonable progress.\(^79\)

At issue in these comments is MDEQ’s latest proposal to allow Montana’s pollution sources to continue emitting NOx and SO2 at current, unnecessarily high, levels.

**DISCUSSION OF MDEQ’S DRAFT PROPOSED SIP**

MDEQ improperly and incorrectly concluded that no new reductions in pollution are warranted for Montana sources of pollution in the second regional haze planning period, including from Montana’s power plants that have never been required to control their emissions 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, Montana’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 Montana to fulfill its Regional Haze obligations under the CAA, MDEQ must revise the Proposed SIP to: (1) establish a cost-effectiveness threshold for reasonable progress and one that is in line with other states; (2) correct the inflated cost of controls calculations; (3) require emission controls for the three power plants the state selected for review in this planning period—the state’s largest sector of visibility-impairing emissions; (4) establish appropriate enforceable emissions limits for Hardin Generating Station; (5) require pollution controls for non-power plant sources the state selected for review; and (6) thoroughly assess environmental justice impacts as EPA recommended. The sections below and the attached Stamper Report provide further detail regarding the changes MDEQ must make to make the Proposed SIP comport with the legal requirements of the CAA and Regional Haze Rule.

**I. MDEQ’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:

> [W]hile states have discretion to reasonably select sources, this analysis

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\(^78\) Proposed SIP at 28.
\(^79\) Id.
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.\textsuperscript{80}

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.\textsuperscript{81} 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.\textsuperscript{82}

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;\textsuperscript{83}
- [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;\textsuperscript{84} and
- [A] threshold that excludes a state’s largest visibility impairing sources from selection is more likely to be unreasonable.\textsuperscript{85}

Contrary to the requirement to meaningfully reduce, which requires that states comprehensively identify sources of human-caused visibility-impairing emissions across source categories, Montana’s SIP fails to analyze controls for numerous units at the sources selected for review. For example, MDEQ only analyzed controls for two units at the Phillips 66 Billings Refinery that only account for approximately 23% of the refinery’s NOx emissions.\textsuperscript{86} For the CHS refinery, MDEQ evaluated NOx controls for combustion sources and emissions units accounting for only 40% of the facility’s NOx emission.\textsuperscript{87} MDEQ also only required Four-Factor Analysis of controls for emission units accounting for 52% of the emissions from the ExxonMobil Billings refinery.\textsuperscript{88} However, to comply with the requirement that states comprehensively identify sources of human-caused visibility-impairing emissions across source

\begin{itemize}
  \item \textsuperscript{80} July 2021 Clarification Memo at 3.
  \item \textsuperscript{81} 40 C.F.R. § 51.308(f)(2).
  \item \textsuperscript{82} 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.”).
  \item \textsuperscript{83} Id. at 19.
  \item \textsuperscript{84} July 2021 Clarification Memo at 3.
  \item \textsuperscript{85} Id.
  \item \textsuperscript{86} Stamper Report at 92.
  \item \textsuperscript{87} Id. at 74.
  \item \textsuperscript{88} Id. at 63.
categories, MDEQ should identify all of the emission units at these facilities, and the units’ actual and allowable emissions.

II. MDEQ FAILED TO REQUIRE APPROPRIATE FOUR-FACTOR ANALYSES FOR SELECTED MONTANA 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 Montana’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.89 MDEQ required four-factor analyses for seventeen sources in its proposed SIP.90

As demonstrated and discussed throughout these comments and the attached Stamper Report, MDEQ 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 haze implementation period.

Accordingly, MDEQ 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.91 Because these sources failed to conduct legally compliant Four-Factor Analyses, MDEQ 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. MDEQ Failed to Follow Four-Factor Analysis Legal Requirements

1. MDEQ failed to secure retirements via enforceable SIP requirements

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89 40 C.F.R. § 51.308(f)(2)(i).
90 Proposed SIP at 179-283.
91 40 C.F.R. § 51.308(d).
The Clean Air Act requires that “[e]ach state implementation plan . . . shall” include “enforceable limitations and other control measures” as necessary to “meet the applicable requirements” of the Act.\(^\text{92}\) The Regional Haze Rule similarly requires each state to include “enforceable emission limitations” as necessary to ensure reasonable progress toward the national visibility goal.\(^\text{93}\) States cannot rely on a source’s remaining useful life to avoid conducting a four-factor analyses unless the source has “an enforceable commitment to be retired or replaced by 2028.”\(^\text{94}\) This is consistent with EPA’s longstanding approach to control determinations under the mandatory BART Guidelines.\(^\text{95}\) Therefore, where a state relies on sources’ plans to permanently cease operations or reduction in utilization to ensure reasonable progress or to avoid any control analysis, the state “must” make those parameters or assumptions into enforceable emission limitations in the SIP itself. MDEQ’s SIP declined to impose emission reduction measures that would satisfy a Four-Factor Analysis—and in other instances, refused to even evaluate controls—based on projected source retirements or reductions in utilization. Including planned retirements as enforceable SIP provisions is not only required under the Clean Air Act and the Regional Haze Rule, but results in significant greenhouse gas emission reductions and other pollution co-benefits.

2. MDEQ’s control cost analyses are legally deficient due to numerous flaws

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 state has a duty to conduct a “robust” analysis of potential reasonable progress controls, and must “document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects.”\(^\text{96}\) Therefore, if a source is unwilling to prepare the analysis, the state must conduct the analysis to inform its reasonable progress determination.

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

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\(^{93}\) 40 C.F.R. § 51.308(d)(3).

\(^{94}\) Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, EPA-457/B-19-003, at 22, 34 (August 2019) (“To the extent such a requirement is being relied upon for a reasonable progress determination, the measure would need to be included in the SIP and/or be federally enforceable. See 40 CFR 51.308(f)(2).”).

\(^{95}\) 70 Fed. Reg. 39167 (July 6, 2005) (“When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.”).

\(^{96}\) 40 C.F.R. § 51.308(f)(2)(iii).
complies with the CAA. As part of its proposed SIP revisions, MDEQ must not only follow the requirements in the Regional Haze Rule, but also the requirements for preparation, adoption and submittal of SIPs. A state must not “rubber stamp” a source’s analysis. 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. 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.

a. MDEQ failed to provide sufficient cost documentation.

MDEQ failed to provide documentation for control costs. 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). MDEQ failed to do so in the Proposed SIP. For example, Phillips 66 Co. Billings Refinery assumed a boiler replacement cost of $20 million per boiler but did not provide any documentation for this assumed cost. As discussed below and in the Stamper Report, MDEQ’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.

97 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).
98 See e.g., 40 C.F.R. §§ 51.100, 51.102, 51.103, 51.104, 51.105, and Appendix V to Part 51.
99 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.
100 40 C.F.R. § 51.308(f)(2)(iii).
101 2019 Guidance at 22.
102 Stamper Report at 29.
103 Id.
b. MDEQ failed to consider control efficiency and performance optimization.

MDEQ 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.” Moreover, MDEQ 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 MDEQ can verify documentation provided by the source. The Stamper Report presents details that show MDEQ failed to consider control upgrades and assumed lower control efficiency. MDEQ must consider control efficiency and performance optimization.

c. MDEQ relied on artificially truncated equipment life for pollution controls and on artificially high interest rates.

MDEQ 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, MDEQ 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.

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

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.

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104 2019 Guidance at 22.
105 Stamper Report at 15.
107 CCM, Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, at 16 (emphasis added).
MDEQ assumed an interest rate of 5.25% when amortizing capital costs of controls in its four-factor analyses.108 But, as the Stamper Report explains, “EPA’s Control Cost Manual recommends the use of the bank prime interest rate for amortizing capital costs.”109 The bank prime rate had been at 3.25% since March 2020 until March 2022,110 which is significantly lower than MDEQ’s assumed 5.25% interest rate.111

As the Stamper Report also explains:

MDEQ also claims that it used a 5.25% interest rate because that was the bank prime rate at the time of the initial four factor analyses from Montana facilities, implying that it would be too time consuming to revise the cost analyses to reflect the current much lower bank prime rate of 3.25%. MDEQ also allowed facilities to use a 20-year amortization period for pollution control cost effectiveness calculations, despite EPA and the Federal Land Managers (FLMs) informing MDEQ that EPA had provided justification for a 30-year life of controls to be assumed. In discussing this issue in its draft regional haze plan, MDEQ provided example annualized capital costs for various interest rates and both 20 and 30 year amortization periods to justify its decision to not revise company’s cost analyses to reflect the current bank prime interest rate and a 30-year life of pollution controls. MDEQ states “[g]iven the four-factor analysis are likely to only estimate capital costs within plus or minus 30 percent, the difference in interest rates and amortization factors does not merit changing four-factor submittals by facilities.” However, MDEQ’s example costs show that use of a 5.25% interest rate that is 2% higher than the current bank prime rate and use of a 20-year life rather than a 30-year life for certain pollution controls like selective catalytic reduction (SCR) and flue gas desulfurization (FGD) will result in annualized capital costs that are 54% higher than the annualized capital cost using the much more appropriate current bank prime interest rate and the 30-year pollution control life that has been justified by EPA and in practice. Specifically, MDEQ shows that, for a pollution control costing $2,000,000, the annualized capital costs assuming a 2% lower interest rate of 3.5% and a 30-year amortization would be $108,743, whereas the annualized capital costs assuming a 5.5% interest rate and a 20-year amortization period would be $167,359 – which is 54% higher. Thus, MDEQ’s claim that its use of an interest rate that is 2% higher than the current bank prime interest rate and an amortization period that is 10 years shorter would not impact costs by more than 30% is incorrect.

108 2022 Draft Montana Regional Haze Plan at 176.
110 At the time the Stamper Report was compiled, the bank prime rate was 3.25%. Since then, the bank prime rate increased by a quarter point to 3.5%. See https://www.federalreserve.gov/releases/h15/. Depending on the capital costs of controls, this one quarter point increase would add somewhere between $50/ton and $200/ton to the cost effectiveness calculations presented.
111 See https://fred.stlouisfed.org/series/DPRIME. As noted, before, these comments and the Stamper Report were compiled prior to the recent change in the bank prime rate on March 17, 2022.
Further, given that other states and facilities have been using the current bank prime interest rate of 3.25% and a 30-year life of controls for SCR and FGD evaluations, MDEQ’s use of a higher interest rate and a shorter pollution control amortization period effectively allows Montana sources a much higher cost effectiveness threshold than similar sources being evaluated in nearby states. MDEQ has not provided any rational justification for its approach.112

Despite requirements and EPA guidance stating that states should use the current bank prime interest rate and a 30-year life of controls for SCR and FGD evaluations, MDEQ accepted the sources’ truncated equipment life assumptions and high interest rates, which artificially raised the cost-effectiveness figures (higher $/ton), resulting in higher costs.113

d. MDEQ improperly used elevated retrofit factors.

Another critical flaw in the Proposed SIP is the use of improper and elevated retrofit factors, which act as a multiplier to increase the costs of installing pollution controls in extraordinary circumstances. The Stamper Report found that MDEQ allowed use of a retrofit factor greater than 1.0.114 A retrofit factor of 1.0 represents the usual situation in which all of the alleged issues identified by the sources are addressed.115 MDEQ’s SIP lacks documentation of why higher retrofit factors were justified for certain sources. Without documentation justifying higher retrofit factors, MDEQ must use a retrofit factor of 1.0.

e. MDEQ erroneously included sale tax.

MDEQ included sales tax in some of its control cost analyses. As noted in the Stamper Report, most states, including Montana, do not charge sale tax on pollution control equipment.116 MDEQ must remove the sales tax costs from all control cost analyses.

f. MDEQ failed to document artificially high normalized stoichiometric ratios.

MDEQ failed to document use of artificially high normalized stoichiometric ratios (“NSR”). The Stamper Report pointed to numerous examples of a higher NSR being used than what is recommended by EPA. Without documentation that justifies a higher value, MDEQ must require that the default NSR be used.117

112 Stamper Report at 9-10 (emphasis added).
113 Id. at 10.
114 Id. at 19.
115 Id. at 19.
B. MDEQ Failed to Require Emissions Reductions from Montana Power Plants

1. MDEQ’s Consideration of Extra-Regulatory Factors to Reject Reasonable Pollution Controls on Montana Power Plants is Unlawful

At the outset, MDEQ’s chief rationale for failing to require emissions reductions from Montana’s coal fleet—namely, that economic headwinds facing the industry make any additional costs unreasonable—is not permitted under the CAA or the Regional Haze Rule. As noted, the Clean Air Act establishes four factors that States must consider in evaluating controls necessary to make reasonable progress: 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 potentially affected major or minor stationary source or group of sources. The Regional Haze Rule identifies five “additional factors” for states to consider as they develop long-term strategies, all addressing circumstances that affect emissions reductions and visibility improvement. None of the statutory or regulatory factors encompasses the economic judgments Montana broadly makes to reject otherwise reasonable controls. Thus, while MDEQ may “believe[] that there are equally significant factors to take into consideration, rather than simply the cost of controls,” such consideration is unlawful.

Moreover, MDEQ’s broad discussion of the economic headwinds facing the coal industry generally could not support rejecting necessary pollution controls on Montana power plants. MDEQ claims that “[a]ny additional costs will hurt the profitability of Montana coal-fired power plants, which would have negative economic impacts to local communities.” Not only does MDEQ fail to provide any analysis to support this concern specifically for Montana coal plants, but also MDEQ fails to explain why the “profitability” of coal-fired power plants is a concern of Montana’s environmental regulator under the federal Clean Air Act.

MDEQ goes on to assert that “[a]dded costs by requiring additional controls at Montana coal-fired [electrical generating units (“EGUs”)] has the potential to create grid instability in the region by driving coal-fired EGUs out of the market before the end of their useful life and prior to having stable replacement generation available.” But again, MDEQ does not provide any analysis to demonstrate that adequately controlling pollution from Montana coal plants would cause such plants to close, or if they did, that the electricity grid would become unstable. Indeed, it is not within MDEQ authority or expertise to ensure grid stability; that is within the authority of the Montana Public Service Commission. Under the Commission’s rules, utilities must plan for upcoming regulatory requirements to ensure they do not impair grid stability. Thus, NorthWestern Energy’s 2019 Resource Procurement Plan discussed the possibility that pollution

118 See Proposed SIP at 173
119 42 U.S.C. § 7491(g)(1).
120 See 40 C.F.R. § 51.308(f)(2)(iv). Even as to these “additional factors,” EPA has clarified that they may not be used “to reject controls that are otherwise reasonable based on the four statutory factors.” 2021 Clarification Memo at 13.
121 Proposed SIP at 173.
122 Id.
123 Id. at 174.
controls on Colstrip Units 3 and 4 would be required under the Regional Haze Rule, and noted that, “should Montana conclude Units 3 and 4 require material upgrades a detailed analysis would be required at that time.” To the extent that MDEQ wishes to accommodate that planning process (which, indeed, should already have taken place for long-standing regional haze requirements), the proper way for MDEQ to do so under the Regional Haze Rule is to establish “compliance schedules,” after considering “the time necessary for compliance.” But MDEQ may not rely on prejudgment about the outcome of that separate regulatory process to evade its regulatory responsibilities under the Regional Haze Rule.

Finally, MDEQ improperly relies on the “significant uncertainty within the market about the future of coal-fired generated electricity and the U.S. … EIA has predicted a steady or declining market for coal-fired generation depending on the price of natural gas and renewables” as a reason for rejecting reasonable pollution controls on Montana coal plants. While MDEQ’s reasoning is opaque, the agency appears to suggest that investments in pollution controls may not be warranted given the potentially short future life of Montana’s coal plants. However, absent an enforceable retirement commitment, it is improper to rely on a shortened “remaining useful life” of a source in evaluating the reasonableness of controls.

2. Talen Montana–Colstrip Units 3 and 4

The Colstrip Power Plant’s Units 3 and 4 are tangentially-fired boilers burning subbituminous coal, and each have generating capacity of 805 megawatts (“MW”). Colstrip Units 3 and 4 are collectively ranked the highest in terms of NOx and SO2 emissions of the sources considered by MDEQ, and these units rank second in terms of Q/d value for sources considered for control by MDEQ. NPCA ranks the Colstrip units as the highest in terms of

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125 40 C.F.R. § 51.308(d)(3).
126 Id. § 51.308(f)(2)(i).
127 Proposed SIP at 174.
128 Id. at 180.
129 Id. at 161.
cumulative Q/d ranking.\textsuperscript{130} MDEQ states that Talen installed Smart Burn\textsuperscript{131} at Colstrip Unit 3 in 2017\textsuperscript{132} and at Colstrip Unit 4 in 2016.\textsuperscript{133}

MDEQ’s four-factor analysis for Colstrip Units 1 and 2 suffers from numerous flaws detailed in the Stamper Report, which include:

- Assumption that the 95\% control level currently being achieved represents the best control measure available for SO2,\textsuperscript{134} even though level of SO2 control of 98\%-99\% is a more justified top level of control for coal-fired boilers equipped with wet scrubbers like those at Colstrip Units 3 and 4;\textsuperscript{135}
- Assumed that SCR could achieve a 0.06 lb/MMBtu controlled NOx emission rate even though 0.04 lb/MMBtu or even lower could be achieved;
- Evaluated SNCR to achieve only 13\% NOx removal with SNCR rather than 20\% NOx removal and a 0.12 lb/MMBtu annual NOx emission rate;
- Used an elevated retrofit factor of 1.3;
- Used a useful life of only 20 years;
- Used an inflated interest rate of 5.5\%; and

\textsuperscript{130} National Parks Conservation Association’s Regional Haze Fact Sheet for Montana (“NPCA Fact Sheet”), https://www.npca.org/reports/regional-haze (last visited Mar. 18, 2022).
\textsuperscript{131} As the Stamper Report explains:
SmartBurn technology is not a very well known NOx control technology. It is notable that MDEQ does not list SmartBurn as an available control in its general list of NOx control technologies that were evaluated in the four-factor analyses for its facilities. Neither MDEQ nor Talen have described the SmartBurn technology and how it works to reduce NOx. According to the SmartBurn\textsuperscript{®} company’s brochure, it appears it is a combustion optimization evaluation:
Using our Applied Computational Modeling (ACM) expertise, we employ millions of partial differential equations to replicate and validate your boilers’ unique combustion properties. ACM allows us to perform root-cause analysis and also provides predictive capability to understand how your boiler will perform under varying conditions, with alternative fuels or potential enhancement modifications.
SmartBurn\textsuperscript{®} Knowledge Makes Power, Brochure, available at https://www.smartburn.com/. While the company’s brochure does indicate lowered NOx emission rates with the technology, it appears to be dependent on site-specific criteria.

\textsuperscript{132} Proposed SIP at 161.
\textsuperscript{133} September 30, 2019, Talen Montana, Regional Haze Progress Analysis–Talen Montana LLC, Colstrip Steam Electric Station (“2019 Talen Colstrip Analysis”), at 4-1.
\textsuperscript{134} Proposed SIP at 181.
• Assumed use of urea when ammonia results in a more cost-effective option.\textsuperscript{136}

The Stamper Report calculated revised cost-effectiveness for Colstrip Units 3 and 4 which is presented in Table 5.\textsuperscript{137}

**Table 5. Revised Cost Effectiveness of Post-Combustion NOx Controls at Colstrip Units 3 and 4, Based on 30-Year Life of Controls and the EPA Control Cost Manual Spreadsheets**\textsuperscript{138}

<table>
<thead>
<tr>
<th>Colstrip Unit</th>
<th>Control</th>
<th>Annual NOx Rate, lb per MMBtu</th>
<th>Capital Cost (2019$)</th>
<th>O&amp;M Costs</th>
<th>Total Annualized Costs (2019 $)</th>
<th>NOx Reduced from 2028 Baseline, tpy</th>
<th>Cost Effectiveness, $/ton</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>SCR</td>
<td>0.04</td>
<td>$266,332,259</td>
<td>$3,525,668</td>
<td>$17,579,986</td>
<td>3,082</td>
<td>$5,704/ton</td>
</tr>
<tr>
<td>3</td>
<td>SNCR</td>
<td>0.12</td>
<td>$14,505,544</td>
<td>$2,809,569</td>
<td>$3,580,538</td>
<td>841</td>
<td>$4,260/ton</td>
</tr>
<tr>
<td>4</td>
<td>SCR</td>
<td>0.04</td>
<td>$265,673,363</td>
<td>$3,525,472</td>
<td>$17,545,027</td>
<td>3,089</td>
<td>$5,680/ton</td>
</tr>
<tr>
<td>4</td>
<td>SNCR</td>
<td>0.12</td>
<td>$14,495,338</td>
<td>$2,815,175</td>
<td>$3,585,602</td>
<td>842</td>
<td>$4,256/ton</td>
</tr>
</tbody>
</table>

MDEQ must ensure that all of these errors are corrected and based on the corrections, include reasonable progress emission limitations in the SIP.

The NPS consultation comments also found errors in the source’s Four-Factor Analysis, like those presented in the Stamper Report.\textsuperscript{139} Additionally, NPS’s calculations determined that cost-effective controls were available to reduce emissions from Colstrip Units 3 and 4:

Our estimated costs for NOx reduction [with SCR or SNCR] for Units 3 and 4 range from $2,121 to $6,521, depending upon the unit, choice of reagent, control technology, and assumed NOx removal efficiency. Other states have set cost-effectiveness thresholds of $5,000/ton (Texas), $7,000/ton (New Mexico), and $10,000/ton (Colorado and Oregon). Our cost estimates are detailed in the following discussion.\textsuperscript{140}

We request that Montana correct errors in the cost estimates and require reasonable controls for NOx reductions from Colstrip Units 1 and 2.

3. **Yellowstone Energy Limited Partnership–Yellowstone Power Plant**

The Yellowstone Energy Limited Partnership (“YELP”) Yellowstone Power Plant consists of two circulating fluidized bed combustion (“CFBC”) boilers which are fired by petroleum coke and coker gas from the nearby Exxon refinery. The YELP facility is in Billings, Montana and is a “qualifying facility” with a contract to sell power to NorthWestern Energy

\textsuperscript{136} Stamper Report at 21.
\textsuperscript{137} Stamper Report at 22-23.
\textsuperscript{138} See SCR and SNCR Cost Manual Spreadsheets for Colstrip Units 3 and 4.
\textsuperscript{139} NPS Consultation Comments, Proposed SIP at Appendix F, PDF pages 56-59.
\textsuperscript{140} Id. at 56.
through 2028. The two CFBC boilers vent to a single baghouse and single stack. The total
design steam production of the facility is 660,000 pounds per hour and the generating capacity is
65 MW.\textsuperscript{141} Although relatively small, the YELP facility is highly polluting. The YELP facility
is ranked the 6th highest in terms of Q/d value for sources considered for control by MDEQ with
a Q/d value of 14.86 based on SO2+NOx emissions.\textsuperscript{142} NPCA ranks the YELP facility as the
second highest in terms of cumulative Q/d ranking.\textsuperscript{143} YELP currently controls SO2 emissions
using limestone injection in the CFBC boilers, and the units share a baghouse.

As explained in the Stamper Report, there are numerous flaws in YELP’s report that must
be corrected:

- Eliminated consideration of circulating dry scrubbers (“CDS”) from review as a
  potential SO2 control measure;
- Relied on YELP’s outdated analysis from the first round of regional haze planning
  and on cost equations from EPA’s 2002 Control Cost Manual when more recent tools
  based on actual retrofit costs of these controls are available;
- Failed to provide sufficient information on the CFBC boilers fuel characteristics, sulfur
  content, and operation data;
- Escalated costs over 8 years (2011 to 2019) and used inflation cost adjustments that
  showed a 15% interest in prices from 2011 to 2019 even though the Chemical
  Engineering Plant Cost Index (“CEPCI”) showed only a 3.7% increase over that same
  timeframe;
- Assumed 80% SO2 removal in its evaluation of spray dryer absorber (“SDA”) as a
  control even though SDA can achieve higher levels of SO2 control, even with the
  CFBC boilers achieving 92% control;
- Included costs for new baghouses for each of the three SO2 control options without
  detailing support that entirely new baghouses would be required with each SO2
  control;
- Assumed a 50% NOx reduction with SNCR using ammonia as the reagent even
  though EPA has indicated that SCNR can achieve 76-80% NOx reduction;
- Used too high of a NSR of 3.0;
- Included sales tax even though Montana has a sales tax exemption for pollution
  control equipment;
- Used inflated interest rate of 5.5%; and
- Truncated equipment life of 20 years.

The Stamper Report corrected these flaws, used default values for undocumented
parameters, and conducted revised cost-effectiveness calculations for SO2 controls and NOx
controls (Tables 7-8).

\textsuperscript{141} Id.
\textsuperscript{142} Proposed SIP at 161.
\textsuperscript{143} NPCA Fact Sheet.
Table 7. Revised Cost Effectiveness of SO2 Controls at YELP’s Yellowstone Power Plant Assuming the Current Bank Prime Rate of 3.25% and a 30-Year Life of Controls (Total for Both Boilers)\textsuperscript{144}

<table>
<thead>
<tr>
<th>SO2 Control</th>
<th>YELP’s Total Capital Investment, 2019$</th>
<th>Annualized Capital Costs, 2019 $/year</th>
<th>Annual Operating and Maintenance Costs, $/year</th>
<th>Total Annualized Costs, $ (2019 $)</th>
<th>SO2 Reduced, tons per year</th>
<th>Cost Effectiveness, $/ton</th>
</tr>
</thead>
<tbody>
<tr>
<td>HAR, Baghouses</td>
<td>$35,816,983</td>
<td>$1,887,555</td>
<td>$2,798,359</td>
<td>$4,685,914</td>
<td>866</td>
<td>$5,411/ton</td>
</tr>
<tr>
<td>SDA, Baghouses</td>
<td>$45,276,409</td>
<td>$2,386,067</td>
<td>$3,719,678</td>
<td>$6,105,744</td>
<td>1,386</td>
<td>$4,405/ton</td>
</tr>
<tr>
<td>DSI, Baghouses</td>
<td>$23,446,964</td>
<td>$1,235,655</td>
<td>$3,099,910</td>
<td>$4,335,565</td>
<td>866</td>
<td>$5,006/ton</td>
</tr>
</tbody>
</table>

Table 8. Revised Cost Effectiveness of NOx Controls at YELP’s Yellowstone Power Plant Assuming the Current Bank Prime Rate of 3.25% and a 30-Year Life of Controls (Total for Both Boilers) and Assuming a Lower NSR for Ammonia in the SNCR Costs\textsuperscript{145}

<table>
<thead>
<tr>
<th>SO2 Control</th>
<th>YELP’s Total Capital Investment, 2019$</th>
<th>Annualized Capital Costs, 2019 $/year</th>
<th>Annual Operating and Maintenance Costs, $/year</th>
<th>Total Annualized Costs, $ (2019 $)</th>
<th>SO2 Reduced, tons per year</th>
<th>Cost Effectiveness, $/ton</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCR</td>
<td>$32,460,400</td>
<td>$1,710,663</td>
<td>$1,436,688</td>
<td>$3,147,351</td>
<td>323</td>
<td>$9,744/ton</td>
</tr>
<tr>
<td>SNCR</td>
<td>$1,020,800</td>
<td>$53,796</td>
<td>$334,838</td>
<td>$388,634</td>
<td>202</td>
<td>$1,658/ton</td>
</tr>
</tbody>
</table>

For SO2 controls, the revised cost-effectiveness analysis resulted in the cost of SDA and new baghouses to be considered reasonable at $4,400/ton as shown above or even at $5,400/ton as calculated by YELP using a higher interest rate and a shorter useful life. Both the revised figures and figures provided by YELP are cost-effective\textsuperscript{146} and MDEQ should require that YELP

\textsuperscript{144} These cost numbers reflect YELP’s costs for these controls as reported in Table 6-19 of the Proposed SIP at 215, but with the annualized costs revised to reflect a 3.25\% interest rate and a 30-year life rather than the 5.5\% interest rate and 20-year life assumed by YELP and MDEQ. Note that the annual operating and maintenance costs were not specifically identified in Table 6-19 of the Proposed SIP. Those costs were calculated based on the difference between the Total Annual Cost and the annualized capital costs assuming YELP’s 5.5\% interest rate and 20-year life.

\textsuperscript{145} These cost numbers reflect YELP’s costs for these controls as reported in Table 6-19 of the Proposed SIP at 215, but with the annualized costs revised to reflect a 3.25\% interest rate and a 30-year life rather than the 5.5\% interest rate and 20-year life assumed by YELP and MDEQ. Note that the annual operating and maintenance costs were not specifically identified in Table 6-19 of the Proposed SIP. Those costs were calculated based on the difference between the Total Annual Cost and the annualized capital costs assuming YELP’s 5.5\% interest rate and 20-year life.

\textsuperscript{146} Stamper Report at 30.
install these controls. If a new baghouse was not required, the costs of SO2 controls would be even more cost effective than shown above.\footnote{Stamper Report at 31.}

For NOx controls, the revised cost-effectiveness analysis resulted in a value of $1,658/ton, which is 44% lower than YELP’s SNCR cost effectiveness calculation. Both the revised figures and figures provided by YELP are cost-effective,\footnote{Stamper Report at 36.} and MDEQ should require that YELP meet emissions limits that reflect installation and operation of these controls. These costs are lower than the cost effectiveness thresholds being established for the second round regional haze plans by several states, including Arizona ($4,000 to $6,500/ton\footnote{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 \url{https://www.azdeq.gov/2021-regional-haze-sip-planning}.}), New Mexico ($7,000 per ton\footnote{See NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, available at \url{https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf}.}, Oregon ($10,000/ton\footnote{See, e.g., September 9, 2020 letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2, available at \url{https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf}.}, Washington ($6,300/ton for Kraft pulp and paper power boilers\footnote{See, e.g., Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, attached to Stamper Report as Ex. 15.}, and Colorado ($10,000/ton).\footnote{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 \url{https://drive.google.com/drive/u/1/folders/1TK41unOYnMKp5uuakhZiDK0-fuziE58y}.} Thus, this analysis demonstrates the reasonableness of requiring NOx emissions reductions from YELP.


The Colstrip Energy Limited Partnership (“CELP”) Rosebud Power Plant burns waste coal from nearby mining operations. Like the YELP facility, the CELP power plant is a “qualifying facility.” It has a power purchase contract with NorthWestern Energy that expires at the end of 2025. The plant uses a CFBC boiler with limestone injection for SO2 control, and the boiler is also equipped with a baghouse for PM control. The capacity of the power plant is 39 MW (net). Also like the YELP facility, the CELP plant “punches above its weight” in terms of the volume of its harmful air pollutants. The CELP facility has a NOx plus SO2 Q/d value of 10.26 based on 2014-2017 average emissions.\footnote{Proposed SIP at 161.} The facility had the fourth highest annual SO2 emissions, and the 5th highest NOx emissions of the sources selected for evaluation by MDEQ.

As explained in the Stamper Report, there are numerous flaws in CELP’s report that must be corrected:
• Eliminated consideration of a CDS from review as a potential SO2 control measure;
• Relyed on CELP’s outdated analysis from the first round of regional haze planning and on cost equations from EPA’s 2002 Control Cost Manual when more recent tools based on actual retrofit costs of these controls are available;
• Failed to provide sufficient information on the CFB boilers fuel characteristics, such as sulfur content and heat value, and operation data;
• Escalated costs over 8 years (2011 to 2019) and used inflation cost adjustments that showed a 15% interest in prices from 2011 to 2019 even though the CEPCI showed only a 3.7% increase over that same timeframe;
• Assumed 80% SO2 removal in its evaluation of SDA even though SDA can achieve higher levels of SO2 control, even with the CFB boilers achieving 90% control;
• Included costs for new baghouses for each of the three SO2 control options without detailing support that entirely new baghouses would be required with each SO2 control;
• Assumed a 50% NOx reduction with SNCR using ammonia as the reagent even though EPA has indicated that SCNR can achieve 76-80% NOx reduction;
• Listed incorrect SCR and SNCR cost and emission reduction information in Table 6-24 (at page 234), as the data does not match CELP’s four-factor analysis (Appendix B at 1);
• Used too high of a NSR of 3.0;
• Including sales tax even though Montana has a sales tax exemption for pollution control equipment;
• Inflated interest rate to 5.5%; and
• Truncated equipment life to 20 years.

The Stamper Report corrected these flaws, used default values for undocumented parameters, and conducted revised cost-effectiveness calculations for SO2 controls and NOx controls (Tables 10-11).
Table 10. Revised Cost Effectiveness of SO2 Controls at CELP’s Rosebud Power Plant
Assuming the Current Bank Prime Rate of 3.25% and a 30-Year Life of Controls

<table>
<thead>
<tr>
<th>SO2 Control</th>
<th>CELP’s Total Capital Investment, 2019$</th>
<th>Annualized Capital Costs, 2019 $/year</th>
<th>Annual Operating and Maintenance Costs, $/year</th>
<th>Total Annualized Costs, $/year (2019 $)</th>
<th>SO2 Reduced, tons per year</th>
<th>Cost Effectiveness, $/ton</th>
</tr>
</thead>
<tbody>
<tr>
<td>HAR, Baghouses</td>
<td>$22,177,580</td>
<td>$1,168,758</td>
<td>$1,812,775</td>
<td>$2,981,533</td>
<td>616</td>
<td>$4,840/ton</td>
</tr>
<tr>
<td>SDA, Baghouses</td>
<td>$28,435,354</td>
<td>$1,498,543</td>
<td>$2,434,370</td>
<td>$3,932,913</td>
<td>985</td>
<td>$3,993/ton</td>
</tr>
<tr>
<td>DSI, Baghouses</td>
<td>$13,994,337</td>
<td>$737,502</td>
<td>$1,677,004</td>
<td>$2,414,506</td>
<td>616</td>
<td>$3,920/ton</td>
</tr>
</tbody>
</table>

Table 11. Revised Cost Effectiveness of NOx Controls at CELP’s Rosebud Power Plant
Assuming the Current Bank Prime Rate of 3.25% and a 30-Year Life of Controls and
Assuming a Lower NSR for Ammonia in the SNCR Costs

<table>
<thead>
<tr>
<th>SO2 Control</th>
<th>CELP’s Total Capital Investment, 2019$</th>
<th>Annualized Capital Costs, 2019 $/year</th>
<th>Annual Operating and Maintenance Costs, $/year</th>
<th>Total Annualized Costs, $/year (2019 $)</th>
<th>NOx Reduced, tons per year</th>
<th>Cost Effectiveness, $/ton</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCR</td>
<td>$15,650,550</td>
<td>$824,784</td>
<td>$959,305</td>
<td>$1,784,089</td>
<td>714</td>
<td>$2,499/ton</td>
</tr>
<tr>
<td>SNCR</td>
<td>$1,020,800</td>
<td>$48,876</td>
<td>$395,571</td>
<td>$444,447</td>
<td>446.2</td>
<td>$887/ton</td>
</tr>
</tbody>
</table>

For SO2 controls, the revised cost-effectiveness analysis resulted in the cost of SDA and new baghouses to be considered reasonable at $3,993/ton as shown above or even at $4,889/ton as calculated by CELP using a higher interest rate and a shorter useful life. Both the revised figures and figures provided by CELP are cost-effective, and MDEQ should require that CELP install SDA baghouse because it removes more SO2 that the other options. If a new baghouse is not required, the costs of SO2 controls would be even more cost effective than shown above.

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155 These cost numbers reflect CELP’s costs for these controls as reported in Table 6-23 of the Proposed SIP at 230, but with the annualized costs revised to reflect a 3.25% interest rate and a 30-year life rather than the 5.5% interest rate and 20-year life assumed by CELP and MDEQ. Note that the annual operating and maintenance costs were not specifically identified in Table 6-23 of the Proposed SIP. Those costs were calculated based on the difference between the Total Annual Cost and the annualized capital costs assuming CELP’s 5.5% interest rate and 20-year life.

156 These cost numbers reflect CELP’s costs for these controls as reported in the 2019 CELP Rosebud Four-Factor Analysis, Appendix B at 1 (pdf page 52 of report), but with the annualized costs revised to reflect a 3.25% interest rate and a 30-year life rather than the 5.5% interest rate and 20-year life assumed by CELP and MDEQ.

157 Stamper Report at 41.
158 Stamper Report at 42.
For NOx controls, the revised cost-effectiveness analysis resulted in a value of SNCR at $887/ton, which is 42% lower than CELP’s SNCR cost effectiveness calculation. Both the revised figures and figures provided by CELP are cost-effective, and MDEQ should require that CELP install these controls. These costs are lower than the cost effectiveness thresholds being established for the second round regional haze plans by several states, including Arizona ($4,000 to $6,500/ton), New Mexico ($7,000 per ton), Oregon ($10,000/ton), Washington ($6,300/ton for Kraft pulp and paper power boilers), and Colorado ($10,000/ton). Thus, like with the YELP analysis discussed above, this analysis demonstrates the reasonableness of emissions reductions, which Montana should require in a revised Proposed SIP.

C. MDEQ 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 Montana power plants to reduce NOx and SO2 emissions, MDEQ must revise its Proposed SIP to appropriately evaluate pollution controls on non-power plant sources, including cement kilns and refineries. The revised SIP must require feasible, cost-effective emissions reductions from these sources to demonstrate reasonable progress.

1. GCC Trident Cement Plant

The GCC Trident Cement Plant is located near Three Forks, Montana. The facility ranks fifth on MDEQ’s list of facilities evaluated for regional haze pollution controls with a Q/d value of 14.86 based on SO2+NOx emissions. NPCA ranks the GCC Trident facility as the fourth highest in terms of cumulative Q/d ranking.

The cement plant operates a long wet kiln, equipped with low NOx burners, SNCR, and a fabric filter baghouse. The NOx BART limit is 7.6 lb/ton of clinker, reflective of 40% control. The SNCR was commissioned in 2017 as required by Montana’s FIP from the first implementation period. Also, indirect coal-firing was commissioned in 2018, which according to GCC’s four-factor report resulted in further reductions in NOx emissions. The cement kiln was also subject to a 1.3 lb/ton of clinker SO2 BART limit in the first round FIP.

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159 Stamper Report at 46.
160 Id. at 42.
161 Proposed SIP at 161.
162 NPCA Fact Sheet.
163 See Montana Air Quality Permit #0982-16, GCC Trident, June 11, 2021, at 13 (states that a new fabric filter baghouse was installed in 2015 and the existing electrostatic precipitator would no longer be used).
165 Stamper Report at 49.
166 Id.
As the Stamper Report explains, due to the lack of detail in GCC Trident’s report, it is unclear what NOx emission rate formed the basis of the assumed 2028 NOx OTB/OTW emission rate of 1,338 tons per year. The report also failed to provide the cement plant’s baseline or 2028 emissions for SO2.

Also, as detailed and discussed in the Stamper Report, the GCC Trident Four-Factor Analysis suffers numerous flaws, including that it:

- Failed to conduct a four-factor analysis of additional controls for SO2;
- Failed to make available for public review the GCC SO2 control analysis that MDEQ referred to in the Proposed SIP;
- Did not provide information on the underlying assumptions for the baseline/2028 OTB/OTW SO2 emissions and what SO2 controls have been implemented even though MDEQ determined that no more SO2 controls for the cement kiln were required;
- Failed to consider ceramic catalytic filtration systems as a control; and
- Incorrectly dismissed SCR as not technically feasible even though SCR is being used at other U.S. and European cement kilns.

MDEQ must ensure that all of these errors are corrected and based on the corrections, include emission limitations in the SIP.

MDEQ must consider use of a ceramic catalytic filtration system in the existing baghouse as a top control technology for NOx and PM and also for SO2 if dry sorbent injection is used. As discussed in detail in the Stamper Report, the use of ceramic catalytic filters in the GCC Trident cement kiln’s existing baghouse would likely be very cost effective, would reduce ammonia slip which GCC Trident claims is an issue with the SNCR required to meet BART, and would allow the cement kiln to improve NOx removal efficiency to 90% for 1,004 tons per year of NOx reduced. As an alternative, MDEQ should more thoroughly evaluate the option of SCR to replace the SNCR to achieve 90% control of NOx, as it has been used at cement kilns in Europe and at two cement kilns in the United States.

2. Ash Grove Cement Plant

The Ash Grove Cement plant is in Montana City, Montana. The facility ranks third on MDEQ’s list of facilities evaluated for regional haze pollution controls with a Q/d value of 40.36 based on SO2+NOx emissions.\textsuperscript{168} NPCA ranks the GCC Trident facility as the fifth highest in terms of cumulative Q/d ranking.\textsuperscript{169}

\textsuperscript{168} Proposed SIP at 161.
\textsuperscript{169} NPCA Fact Sheet.
The cement plant operates a long wet kiln, equipped with a semi-dry scrubber for SO2 removal, low NOx burners, SNCR, and a fabric filter baghouse.170 In 2012, EPA issued a BART determination for the facility, which set NOx limit at 8.0 lb/ton of clinker and reflected installation of low-NOx burners (“LNB”) plus SNCR to reduce NOx emissions by 58%.171 Pursuant to a Consent Decree with EPA, the Ash Grove plant installed semi-dry scrubbing technology to meet an SO2 limit of 2.0 lb/ton of clinker and installed a baghouse to meet a PM limit of 0.07 lb/ton of clinker.172 Pursuant to process optimization requirements in the Consent Decree, Ash Grove demonstrated the ability to achieve a lower NOx limit of 7.5 lb/ton, which has been imposed as an enforceable permit condition.173

The Stamper Report details numerous flaws in the Ash Grove Cement Plant Four-Factor Analysis, which include:

- Failed to consider ceramic catalytic filtration systems as a control;
- Incorrectly dismissed SCR as not technically feasible even though SCR is being used at other U.S. and European cement kilns;
- Failed to provide information to indicate what level of SO2 removal is required by the current limit of 2.0 lb/ton of clinker;
- Incorrectly stated that a semi-dry scrubber was required at Ash Grove to meet BART,174 even though EPA did not require installation of a semi-dry scrubber to meet BART, and EPA’s SO2 BART limit was much higher at 11.5 lb/ton;175 and
- Failed to set an SO2 emission limit or require SO2 controls even though SO2 controls could be optimized and SO2 emissions could be minimized.

MDEQ should consider use of a ceramic catalytic filtration system in the existing baghouse as a top control technology for NOx and PM. As discussed in the Stamper Report, the use of ceramic catalytic filters in the Ash Grove cement kiln’s existing baghouse would likely be very cost effective and would allow the cement kiln to increase NOx reduction efficiency to 90% for 785 tons per year of NOx reduced. MDEQ must also consider strengthening the SO2 limit to reflect the capabilities of the semi-dry scrubbing.

3. **ExxonMobil Billings Refinery**

The ExxonMobil refinery is in Billings, Montana. The facility ranks tenth on MDEQ’s list of facilities evaluated for regional haze pollution controls with a Q/d value of 7.2 based on

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170 Proposed SIP at 201-202. See also Montana Air Quality Permit #2005-16, Ash Grove Cement – Montana City Plant, October 22, 2021, at 4-5 (Conditions B.1, B.3., B.4, and B.5) (requiring operation of a baghouse in the cement kiln exhaust, use of low NOx burner technology, operation of SNCR, and use of semi-dry scrubbing controls).
172 Stamper Report at 56.
173 Proposed SIP at 47.
174 Id. at 202.
SO2+NOx emissions. NPCA ranks the ExxonMobil refinery as the ninth highest in terms of cumulative Q/d ranking. The Billings Refinery is designed to process a variety of crude slates including those containing high sulfur crude oil and does not have a sulfur recovery unit within the refinery. The facility has a capacity of greater than 52,000 barrels per day and is designed to process high sulfur crude oil. In the first implementation period, EPA eliminated the ExxonMobil refinery from consideration for regional haze controls in the FIP based on consent decrees entered into by the owner. Thus, the ExxonMobil refinery has not yet been subject to any regional haze emissions reductions requirements.

MDEQ did not require a four-factor analysis of controls for all emitting units at the ExxonMobil refinery and instead focused on the higher-emitting units which included for NOx: the Coker CO boiler (“KCOB”), F-1 Crude Furnace/F-4012 Vacuum Heater, and the F-551 Hydrogen Plant. ExxonMobil did also include a four-factor analysis for the F-201 Hydrofiner Heater as a “representative, smaller process heater.”

There are numerous flaws in ExxonMobil’s report—detailed in the Stamper Report—that must be corrected:

- Failed to identify all of the emission units at the refinery, and the units’ actual and allowable emissions;
- Did not clarify whether the F-201 Hydrofiner Heater is representative of the smaller process heaters at ExxonMobil refinery, and if so, failed to provide actual and potential emissions data for all heaters at the refinery;
- Failed to provide information on the demonstration period on a desulfurization (“DeSOx”) additive while operating the FCCU in Full Burn Operation, including when it is projected to be completed and when a final SO2 limit required by the Consent Decree are likely to be imposed;
- Failed to evaluate and explain way it did not evaluate SNCR for Unit F1/F401 (Crude Heater/Vacuum Heater), Unit F-551, or Unit F-201; and
- Did not provide documentation for its ultra-low NOx burners (“ULNB”) costs.

The Stamper Report also identified multiple flaws with the cost effectiveness analyses of the NOx controls that were evaluated by ExxonMobil that resulted in higher costs and less cost effectiveness of the controls:

176 Proposed SIP at 161.
177 NPCA Fact Sheet.
178 Regional Haze Four-Factor Analysis, ExxonMobil Billings Refinery, November 2019, at 3 (hereinafter “2019 ExxonMobil Four-Factor Analysis”).
179 Stamper Report at 62.
181 Proposed SIP at 251.
182 Id.
• The company’s cost evaluation for SNCR at Unit KCOB understated the NOx removed with SNCR by inputting a “time that the SNCR operates” of 265 days. ExxonMobil assumed that the SNCR did not operate the other 100 days per year and understated the NOx emissions reduced with SNCR. EPA has issued an updated SNCR spreadsheet on 3/19/21 that now has an entry for number of days SNCR operates and the number of days the boiler operates. ExxonMobil should have assumed that the SNCR operates whenever the boiler operates.

• ExxonMobil used a NSR of 2.0 in the SNCR cost spreadsheet—deviating from the default 1.05 NSR in the EPA SNCR cost spreadsheet—but did not explain how that NSR was derived. Given that the NSR defines how much ammonia or urea reagent is used, MDEQ must require ExxonMobil to document the basis for its assumed NSR rate for SNCR.

• ExxonMobil assumed urea would be the reagent with SNCR to meet 58.5% NOx removal even though the facility already handles ammonia for SCR. Ammonia allows for higher NOx reductions than urea.

• ExxonMobil assumed a life of SNCR of 20 years even though use of a 25-year SNCR lifetime for refinery heaters and boilers is reasonable.

• ExxonMobil inexplicably assumed the SNCR at Unit KCOB would operate 265 days, but the SCR at Unit KCOB would operate 211 days. ExxonMobil must be consistent in its evaluation of SNCR and SCR for Unit KCOB in terms of how many days the control will operate.

• ExxonMobil assumed a life of SCR of 20 years even though a 30-year life of SCR is reasonable based on EPA’s CCM.

• ULNB should have been evaluated at a 30-year life.

• ExxonMobil evaluated ULNB for Unit KCOB and F-201, without providing the basis for these costs or identifying the capital costs and the operating and maintenance costs.

• ExxonMobil used a 5.5% interest rate even though the current interest rate is 3.25%.

As shown in the table below (Table 18), the Stamper Report corrected these flaws, corrected discrepancies, and conducted revised cost-effectiveness calculations for SNCR on Unit KCOB, Unit F-1/F-401, Unit F-551, and Unit F-201.

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184 Stamper Report at 66.
188 EPA, CCM, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 80.
Table 18. Revised Cost Effectiveness of NOx Controls for ExxonMobil Billings Refinery Units KCOB, F-1/F-401, F-551, and F-201\textsuperscript{189}

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>KCOB</td>
<td>SNCR</td>
<td>$1,862,106</td>
<td>$45,891</td>
<td>$156,594</td>
<td>41</td>
<td>$3,785/ton</td>
</tr>
<tr>
<td>KCOB</td>
<td>ULNB</td>
<td>$4,495,882</td>
<td>$66,422</td>
<td>$305,533</td>
<td>67</td>
<td>$4,570/ton</td>
</tr>
<tr>
<td>KCOB</td>
<td>SCR</td>
<td>$6,864,964</td>
<td>$116,017</td>
<td>$480,099</td>
<td>79</td>
<td>$6,095/ton</td>
</tr>
<tr>
<td>F-1/F-401</td>
<td>SCR</td>
<td>$4,771,594</td>
<td>$76,017</td>
<td>$329,645</td>
<td>51</td>
<td>$6,459/ton</td>
</tr>
<tr>
<td>F-551</td>
<td>SCR</td>
<td>$1,809,598</td>
<td>$17,828</td>
<td>$114,671</td>
<td>9</td>
<td>$12,798/ton</td>
</tr>
<tr>
<td>F-201</td>
<td>ULNB</td>
<td>$4,495,882</td>
<td>$66,422</td>
<td>$305,533</td>
<td>67</td>
<td>$4,570/ton</td>
</tr>
</tbody>
</table>

The revised cost-effectiveness analysis shows that SCR should be considered cost effective for Units KCOB, F-1/F-401, and F-551. These costs are within the range that other states are planning to use to determine cost effectiveness of controls in their regional haze plans for the second implementation period. Arizona is using $4,000 to $6,500/ton\textsuperscript{190}. New Mexico is using $7,000 per ton,\textsuperscript{191} and Oregon is using $10,000/ton or possibly even higher.\textsuperscript{192} Oregon has adopted a much higher regional haze control cost threshold of $10,000/ton.\textsuperscript{193} Colorado is also using a reasonableness cost threshold of $10,000/ton.\textsuperscript{194} In addition, the Washington Department of Ecology has found SCR to be cost effective for various heaters and boilers at refineries in its state, relying on a cost-effectiveness threshold of $6,300/ton.\textsuperscript{195} Thus, SCR is cost effective for Units KCOB, F-1/F-401, and F-551.

\textsuperscript{189} The revised costs for SCR and SNCR were based on EPA’s cost spreadsheets. See Stamper Report at 68.
For the reasons provided in the Stamper Report, MDEQ should consider adopting requirements to install SCR at Units KCOB, F-1/F-401, and F-551 as cost-effective measures to make reasonable progress towards the national visibility goal. As shown in Table 18 above, those controls should be considered cost effective with revised costs ranging from $4,500 to $6,500/ton. Such controls would reduce NOx emissions by 95%, which would reduce NOx from the baseline/projected 2028 NOx emissions of the refinery by about 200 tons per year in total across all three units. MDEQ must also more fully evaluate ULNB for the smaller heaters at the ExxonMobil Billings refinery, including obtaining documentation on ExxonMobil’s cost basis for ULNB, and ensuring that the higher emitting small heaters were evaluated for NOx controls.

4. Cenex Harvest States Cooperative Inc. (“CHS”) Inc. Refinery Laurel

CHS Inc. Refinery Laurel is an oil refinery located in Laurel, Montana. The facility ranks eleventh on MDEQ’s list of facilities evaluated for regional haze pollution controls with a Q/d value of 7.2 based on SO2+NOx emissions.196 NPCA ranks the CHS Laurel Refinery in Billings as the fifteenth highest in terms of cumulative Q/d ranking.197

MDEQ states that it determined “it was impractical to perform a four-factor analysis on each individual emitting unit,” due to the many small emitting units in a refinery.198 MDEQ thus focused on the following subset of emitting units at CHS: Main Crude Heater (for NOx), the Platformer Heater (for NOx), Boiler #9 (for NOx), and the Main Refinery Flare (for SO2).

The Stamper Report identified and detailed multiple flaws in the CHS report. Some of the flaws are listed below:

- The report lacks recent data to support the baseline emission rate for the Boiler #9.
- MDEQ appears to rely on the Flare Minimization Plan (“FMP”) in its determination that no SO2 control measures beyond what are already in place at the Main Refinery Flare are needed but fails to include the FMP as a part of the Proposed SIP. The failure to include the FMP that MDEQ relied on in the Proposed SIP, deprives the public of the opportunity to review the specific measures being relied on by MDEQ.
- MDEQ does not clarify what “work practice” measures are and did not cite to relevant permit conditions pertaining to implementing the FMP.
- The report does not detail the basis for the assumed 20% reduction in SO2 emissions from the Main Refinery Flare.
- MDEQ failed to identify all of the emission units at the refinery, and the units’ actual and allowable emissions.
- CHS did not evaluate SCR by itself as a NOx control without explaining why.
- CHS did not evaluate SNCR for any unit.
- CHS did not provide documentation for any of its cost analyses in its four-factor report for the ULNB and ULNB plus SCR analyses.

196 Proposed SIP at 161.
197 NPCA Fact Sheet.
198 Proposed SIP at 258.
The Stamper Report also identified multiple flaws with the cost effectiveness analyses of the NOx controls that were evaluated by CHS that resulted in higher costs and less cost effectiveness of the controls:

- CHS assumed a 7% interest rate instead of the current bank prime interest rate of 3.25%.
- CHS assumed a life of SCR of 20 years even though EPA’s CCM states that the life of SCR at petroleum refineries could be as long as 30 years.\footnote{EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 80.}
- CHS also assumed a life of ULNB of 20 years instead of using a 30-year life.\footnote{80 Fed. Reg. 18944 at 18955 (Apr. 8, 2015).}
- CHS only evaluated SCR to achieve 85% control even though ExxonMobil assumed 95% NOx control in its evaluation of SCR cost effectiveness,\footnote{2019 ExxonMobil Four-Factor Analysis at 28.} and SCRs are typically designed for 90%+ NOx control.\footnote{See, e.g., EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, --- at pdf page 5, available at \url{https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution}.}
- CHS did not evaluate the cost effectiveness of SCR by itself, without the addition of ULNB even though high NOx removal efficiencies can be achieved with SCR alone.

As shown in Table 22 below, the Stamper Report corrected these flaws and conducted revised cost-effectiveness calculations for NOx controls for the Main Crude Heater, Platformer Heater, and Boiler #9.
Table 22. Revised Cost Effectiveness of NOx Controls for CHS Inc. Refinery Laurel Main Crude Heater, Platformer Heater, and Boiler #9

<table>
<thead>
<tr>
<th>Unit</th>
<th>Control</th>
<th>Capital Cost, 2019 $</th>
<th>Operational Costs, $/yr</th>
<th>Total Annualized Costs, 2019 $</th>
<th>NOx reduced, tons per year</th>
<th>Cost Effectiveness, $/ton 2019 $</th>
</tr>
</thead>
<tbody>
<tr>
<td>Main Crude Heater</td>
<td>ULNB</td>
<td>$2,846,617</td>
<td>$71,518</td>
<td>$221,535</td>
<td>21.8</td>
<td>$10,162/ton</td>
</tr>
<tr>
<td>Main Crude Heater</td>
<td>SCR</td>
<td>$4,450,581</td>
<td>$70,641</td>
<td>$308,081</td>
<td>39.7</td>
<td>$7,765/ton</td>
</tr>
<tr>
<td>Platformer Heater</td>
<td>ULNB</td>
<td>$8,549,925</td>
<td>$213,547</td>
<td>$664,128</td>
<td>78.1</td>
<td>$8,504/ton</td>
</tr>
<tr>
<td>Platformer Heater</td>
<td>SCR</td>
<td>$5,385,336</td>
<td>$79,656</td>
<td>$366,414</td>
<td>86.8</td>
<td>$4,220/ton</td>
</tr>
<tr>
<td>Boiler #9</td>
<td>ULNB</td>
<td>$3,272,704</td>
<td>$81,591</td>
<td>$254,062</td>
<td>17.3</td>
<td>$14,686/ton</td>
</tr>
<tr>
<td>Boiler #9</td>
<td>SCR</td>
<td>$3,497,247</td>
<td>$50,644</td>
<td>$237,787</td>
<td>26.6</td>
<td>$8,936/ton</td>
</tr>
</tbody>
</table>

The FLMs’ revised SCR cost numbers are somewhat higher than shown above, at $8,652/ton for SCR at the Main Crude Heater, $4,894/ton for SCR at the Platformer Heater, and $9,865/ton for SCR at the Boiler #9. However, the FLMs’ revised cost numbers reflect a 25-year life of the SCR instead of a 30-year life, and reflect 90% NOx removal across the SCR whereas the cost effectiveness numbers in the above table reflect NOx reductions down to 2.5 ppm or 95% control, whichever is higher. Both FLMs’ revised cost numbers and those in the Stamper Report show that SCR is cost effective for the CHS Platformer Heater. These costs are within the range that other states (Arizona: $4,000 to $6,500/ton, New Mexico: $7,000 per ton; Oregon: $10,000/ton or possibly even higher; Colorado: $10,000/ton) are planning to use to determine cost effectiveness of controls in their regional haze plans for the second implementation period. In addition, the Washington Department of Ecology has found SCR to be cost effective for various heaters and boilers at refineries in its state, relying on a cost-effectiveness threshold of $6,300/ton.

For the reasons discussed above and provided in the Stamper Report, MDEQ should consider adopting a requirement to install SCR at least for the Platformer Heater at the CHS Inc. Refinery Laurel to make reasonable progress towards the national visibility goal. As shown in

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203 The revised costs for SCR were based on EPA’s cost spreadsheets. See SCR cost spreadsheets for the CHS Main Crude Heater at Ex. 39, SCR cost spreadsheet for the CHS platformer heater at Stamper Report Ex. 40, and SCR cost spreadsheet for Boiler #9 at Ex. 41. ULNB costs were revised to reflect 3.25% interest rate and 30-year life but were otherwise based on costs provided by CHS. Costs were revised from the 2018 cost basis used by ExxonMobil to 2019 dollars using the difference in CEPCI indices (607.5/603.1).
204 Proposed SIP, Appendix F, at PDF page 135.
205 Stamper Report at 89-90.
206 Stamper Report at 90.
table above, SCR should be considered cost effective for the platformer heater at $4,200/ton of NOx removed and would remove 86 tons per year of NOx. MDEQ must also consider other emission units at the CHS refinery for NOx controls, as there are several other combustion sources and the emissions units evaluated by CHS only account for 40% of the facility’s NOx emissions. Since MDEQ has also stated that Boiler #9 is planned for replacement, MDEQ must consider adopting a requirement as part of its long-term strategy that the replacement boiler be equipped with state-of-the-art ULNB to ensure that future emissions of the boiler will be minimized as much as possible. Furthermore, given that the assumed 20% reduction in SO2 from the CHS Main Refinery Flare is being taken into account in 2028 emissions projections and setting of RPGs, MDEQ must identify the enforceable requirements and compliance schedules that are part of its long-term strategy, pursuant to 40 C.F.R. §51.308(f)(2).

5. Phillips 66 Co. Billings Refinery

The Phillips 66 Co. Billings Refinery is a petroleum refinery located in Billings, Montana that engages in crude oil distillation, delayed coking, fluid catalytic cracking, hydrotreating, alkylation, and other associated operations.207 The facility ranks fourteenth on MDEQ’s list of facilities evaluated for regional haze pollution controls with a Q/d value of 4.51 based on SO2+NOx emissions.208 NPCA ranks the Phillips 66 refinery in Billings as the sixteenth highest in terms of cumulative Q/d ranking.209

Phillips 66 and MDEQ evaluated SNCR and SCR NOx pollution controls as retrofit controls for Boiler #1 and Boiler #2.

As outlined in the Stamper Report, the information provided by MDEQ is incomplete. For example, MDEQ did not require review of controls to address SO2 emissions from the refinery,210 stating vaguely that “other standards apply from terminated EPA Consent Decree requirements that have largely been incorporated into permit conditions,” as well as referring to NSPS standards and state SIP requirements as further controlling SO2 emissions from the fluidized catalytic cracking unit among other units.211 MDEQ, however, failed to provide more details on the controls and requirements that it is referring to.

The Stamper Report also identified and detailed multiple flaws in the Phillips 66 Co. report, listed below:

- Incomplete list of combustion devices and sources at the refinery as well as pollution controls installed;
- Failure to provide justification as to why other units were not evaluated for pollution controls; and

207 Proposed SIP at 275.
208 Proposed SIP at 161.
209 NPCA Fact Sheet.
210 Proposed SIP at 276-277.
211 Proposed SIP at 276.
Evaluated the cost effectiveness of replacing the boilers outright with new boilers rather than the costs of adding ULNB to Boilers #1 and #2, claiming that retrofit of these controls would be too difficult and too expensive.212

The Stamper Report also identified multiple flaws with the cost effectiveness analyses of the NOx controls that were evaluated by Phillips 66 Co. that resulted in higher costs and less cost effectiveness of the controls. These flaws include:

- Used 2.0 NSR instead of 1.05 default without explaining why;
- Assumed urea would be the reagent with SNCR to meet 58.5% NOx removal even though ammonia allows for higher NOx reductions than urea and is less expensive than urea;213
- Assumed a 20-year life of SNCR even though EPA’s CCM states that the life of SNCR at petroleum refineries could be as long as 25 years;
- Inexplicably assumed the SCR at the boilers would operate 165 days but the SNCR at boilers would operate 365 days;214
- Evaluated SCR to achieve 85.4% control even though ExxonMobil assumed 95% NOx control in its evaluation of SCR cost effectiveness, and SCRs are typically designed for 90%+ NOx control;
- Assumed a life of SCR of 20 years even though EPA’s CCM states that the life of SCR at petroleum refineries could be as long as 30 years;215
- Used 20-year life of ULNB and Flue Gas Recovery System (“FGRS”) even though it is reasonable to assume a 30-year life or longer;216
- Assumed a boiler replacement cost of $20 million per boiler, but did not provide any documentation for this assumed cost;
- Assumed a NOx reduction of 89% with a new boiler equipped with ULNB and FGRS but did not provide any justification; and
- Used a 5.5% interest rate instead of 3.25% current interest rate.

As shown in Table 25 below and detailed in the Stamper Report, the Stamper Report corrected these flaws and conducted revised cost-effectiveness calculations for Boilers #1 and #2 that address some of these issues:

212 Proposed SIP at 28.
215 EPA, CCM, Section 4, Chapter 2 Selective Catalytic Reduction, at PDF page 80.
Table 25. Revised Cost Effectiveness of NOx Controls for Phillips 66 Refinery Boilers # 1 and 2

<table>
<thead>
<tr>
<th>Unit</th>
<th>Control</th>
<th>Capital Cost 2019 $</th>
<th>Operational Costs, $/yr</th>
<th>Total Annualized Costs 2019 $</th>
<th>NOx reduced, tons per year</th>
<th>Cost Effectiveness, $/ton (2019)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boiler #1 or #2</td>
<td>SNCR</td>
<td>$1,749,030</td>
<td>$34,957</td>
<td>$138,937</td>
<td>36</td>
<td>$3,824/ton</td>
</tr>
<tr>
<td>Boiler #1 or #2</td>
<td>ULNB/FGR via Boiler Replacement</td>
<td>$20,145,913</td>
<td>Not provided</td>
<td>$1,054,000</td>
<td>58</td>
<td>$18,890/ton</td>
</tr>
<tr>
<td>Boiler #1 or #2</td>
<td>SCR</td>
<td>$3,963,635</td>
<td>$55,750</td>
<td>$267,499</td>
<td>62</td>
<td>$4,320/ton</td>
</tr>
</tbody>
</table>

As shown in the table above and in the Stamper Report, both SCR and SNCR are cost-effective NOx controls for Boilers #1 and #2. Of the two controls, SCR would achieve more NOx reductions than SNCR at 62 tons per year. These costs are within the range that other states (Arizona: $4,000 to $6,500/ton, New Mexico: $7,000 per ton; Oregon: $10,000/ton or possibly even higher; Colorado: $10,000/ton) are planning to use to determine cost effectiveness of controls in their regional haze plans for the second implementation period. In addition, the Washington Department of Ecology has found SCR to be cost effective for various heaters and boilers at refineries in its state, relying on a cost-effectiveness threshold of $6,300/ton. Thus, for the reasons discussed above and detailed in the Stamper Report, MDEQ should consider adopting requirement to install SCR at Boilers #1 and #2 at the Phillips 66 Billings Refinery as cost-effective measures to make reasonable progress towards the national visibility goal.

As shown above and in Table 25 of the Stamper Report, SCR should be considered cost effective at $4300/ton. Such controls would reduce NOx emissions by 95%, which would reduce NOx from the baseline/projected 2028 NOx emissions of the boilers by a combined 124 tons per year. MDEQ must also more fully evaluate controls for the numerous other combustion sources at the Phillips 66 Billings Refinery, given that it has only analyzed controls for two units that account for approximately 23% of the refinery’s NOx emissions.

6. Northern Border Pipeline Compressor Station No. 3

Northern Border Pipeline Company operates Compressor Station No. 3 in Roosevelt County, Montana. The compressor station ranks sixteenth on Montana’s list of sources evaluated for regional haze controls, with a Q/d value of 4.2 based on the average of 2014-2017 NOx + SO2 emissions. Compressor Station No. 3 consists of a Cooper Rolls 40,350 horsepower turbine that drives a natural gas compressor, as well as an emergency backup generator, a heating

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217 Stamper Report at 89.
218 Stamper Report at 89-90.
219 Stamper Report at 90.
boiler, and an emergency backup engine. MDEQ states in the Proposed SIP that its capacity is lower than stated in its permit at 38,000 hp. The turbine is equipped with a “low NOx lean premixed combustion burner” which MDEQ refers to as “DLE.”

The Stamper Report identified and detailed multiple flaws in Northern Border Pipeline’s evaluation of SCR, listed below:

- Based costs on an outdated and publicly unavailable version of the EPA Control Cost Manual (dated May 2016);
- Based baseline (pre-SCR) NOx emissions on a compliance test from 2003 of 0.117 lb/MMBtu even though the NOx emission rate when the compressor turbine is operating at a lower number of hours per year can be expected to be higher;
- Assumed a 20-year life of SCR instead of a reasonable 30-year life and an interest rate of 5.25% instead of the current 3.25% interest rate; and
- Assumed SCR would achieve 75% NOx reduction, when SCR can achieve in excess of 90% NOx control.

The FLMs raised several other issues with Northern Border Pipeline’s SCR cost analysis, including that too high of a cost of ammonia reagent was used, sales and property taxes were inappropriately included when such taxes do not apply in Montana to pollution control equipment, too high labor costs, excessively high catalyst costs, and reagent stoichiometric ratio that is higher than assumed by EPA in its SCR cost spreadsheet. The FLM recalculated SCR costs based on three operational and emissions scenarios:

1. Full load potential to emit scenario, assuming NOx emissions were at the DLE operational NOx limit of 51.5 lb/hr at 8,760 hours/year;
2. 2017 annual operating hours scenario, which relied on Northern Border Pipeline’s pre-SCR NOx emission rate of 0.117 lb/MMBtu and the operating hours in 2017 as reported in Montana’s Proposed SIP of 6,835 hours per year; and
3. 2017 National Emissions Inventory (“NEI”) Emissions Scenario assuming that the 2017 NOx emissions as reported to the NEI for Compressor No. 3 of 88 tons per year and Northern Border Pipeline’s stated pre-SCR NOx emission rate of 0.117 lb/MMBtu defined the annual heat input, reflecting an estimated 4,788 hours of operation per year.

The FLMs evaluated SCR to achieve 90% NOx control. The results of the FLM’s three SCR cost effectiveness scenarios are shown in the table below (Table 27).

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220 Stamper Report at 92.
221 Proposed SIP at 280.
222 Id.
223 Stamper Report at 92-93.
Table 27: FLM’s Revised SCR Cost Effectiveness for Northern Border Pipeline’s Compressor No. 3 Based on Three Operating Scenarios.\(^{225}\)

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Pre-SCR Uncontrolled NOx Assumed, tpy</th>
<th>Estimated Hours of Operation Assumed, hrs/year</th>
<th>NOx Removed, tpy</th>
<th>Cost Effectiveness, $/ton (2019$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full load PTE</td>
<td>226 tpy</td>
<td>8,760 hours/year</td>
<td>204 tpy</td>
<td>$3,027/ton</td>
</tr>
<tr>
<td>2017 Annual Operating Hours</td>
<td>126 tpy</td>
<td>6,835 hours/year</td>
<td>114 tpy</td>
<td>$5,140/ton</td>
</tr>
<tr>
<td>2017 NEI Emissions</td>
<td>88 tpy</td>
<td>4,788 hours/year</td>
<td>80 tpy</td>
<td>$6,987/ton</td>
</tr>
</tbody>
</table>

Based on the revised SCR cost effectiveness analyses for three operating scenarios shown above, SCR could very likely be cost effective for the analyzed units. These costs are within the range that other states are planning to use to determine cost effectiveness of controls in their regional haze plans for the second implementation period (Arizona: $4,000 to $6,500/ton, New Mexico: $7,000 per ton; Oregon: $10,000/ton or possibly even higher; Colorado: $10,000/ton).\(^{226}\) In addition, the Washington Department of Ecology has found SCR to be cost effective for various heaters and boilers at refineries in its state, relying on a cost-effectiveness threshold of $6,300/ton.\(^{227}\)

The Stamper Report also identified three other options of NOx controls that MDEQ should have evaluated: \(^{228}\)

- Upgrading low NOx burners;
- Replacing the existing combustion turbine with a new turbine with state-of-the-art NOx combustion controls; and
- Restricting the amount of time that the combustion turbine at Compressor No. 3 can operate in non-DLE mode.

For the reasons provided in the Stamper Report and outlined above, MDEQ should adopt a requirement to install SCR at the Northern Border Pipeline Compressor No. 3 to achieve the maximum level of NOx reduction. SCR should be considered cost effective for the Compressor No. 3 turbine, especially at higher operating capacity factors. If it can be adequately documented that future operations of the compressor turbine will be at much lower levels of operating hours and capacity than the unit has been historically operated at, then MDEQ must consider other NOx control options for the compressor turbine. At the minimum, MDEQ should limit the operation of the combustion turbine in non-DLE mode to the maximum extent practicable through increased enforceable restrictions on non-DLE mode operation.

\(^{225}\) Id.
\(^{226}\) Stamper Report at 89-90.
\(^{228}\) Stamper Report at 96-97.
7. Additional Sources Evaluated by the National Park Service

The National Park Service identified a number of other facilities for which technically feasible and cost-effective emissions controls are available and should be required. Those recommendations, which the Conservation Organization’s incorporate by reference in their entirety, are summarized below:

a. Weyerhaeuser Evergreen and Columbia Falls Facilities NOx Analysis

The National Park Service determined that SCR is likely feasible to reduce NOx emissions from Weyerhaeuser’s Columbia Falls Riley Stoker Boiler, and it is cost effective at just $3,306/ton of NOx removed based on Weyerhaeuser’s cost analysis. Moreover, the National Park Service explained that Weyerhaeuser’s reported costs for SCR on the Columbia Falls facility were inflated. As with other facilities considered for control, Weyerhaeuser and MDEQ relied on an unreasonable 5.25% interest rate in lieu of the current interest rate of 3.25%. And they assumed a truncated equipment life of 20 years, rather than the more reasonable 25-30 years for the SCR. The National Park Service further stated that the cost of reheat natural gas of $5.53/MMBTU was used but for the Columbia Falls area a cost of $6.00/MMBTU for industrial scale natural gas was identified. With these adjustments to the Weyerhaeuser SCR cost analysis a cost of $3,113/ton was determined which is well within the range of feasible costs.229

The National Park Service further identified staged combustion combined with low-NOx burners as reasonable NOx controls for the Columbia Falls Line 1 MDF fiber dryers,230 at an estimated cost-effectiveness of $4,751 per ton of NOx removed.231

b. Roseburg Forest Products Co.

As NPS commented, NOx emission reduction opportunities for Roseburg warrant further evaluation. In particular, while there are technically feasible opportunities to control NOx emissions from the ROEMMC burner at Roseburg, MDEQ did not require or itself prepare a full Four-Factor Analysis of these options apparently because of the age of the burner, installed in 1979. The Conservation Organizations concur with NPS that the age of the burner cannot exempt the facility from a full Four-Factor Analysis and may be considered only to the extent there is a federally enforceable retirement date for this emission unit. MDEQ must require a Four-Factor Analysis to evaluate the reasonableness of controlling or replacing the ROEMMC burner.232

c. Graymont Western U.S. Inc.

The Conservation Organizations also agree with National Park Service’s recommendations for the Graymont Indian Creek lime kilns, located near Townsend,

229 Proposed SIP, Appendix F, at PDF page 60.
230 Id. at Appendix F, PDF page 61.
231 Id. at 194.
232 Id. at Appendix F, PDF page 86-88.
While MDEQ proposes no controls, the National Park Service’s review demonstrated that there are technically feasible and cost-effective opportunities available to further control SO2 and NOx emissions from the facility.

With respect to SO2, National Park Service concurred with MDEQ that there are technically feasible control options of semi-wet/dry scrubber and fuel switching to eliminate burning of petroleum coke and burn only coal but did not concur with MDEQ’s cost analysis. Among other things, the National Park Service identified MDEQ’s consistent errors of assuming a 20-year equipment life at 5.5% interest rather than the longer life and lower interest rate recommended by the Control Cost Manual. Correcting for these errors, the annual average cost effectiveness of adding dry scrubbing at Indian Creek would be acceptable and significantly reduce SO2 emissions.

For NOx, the National Park Service corrected for errors in MDEQ’s cost analysis and found that adding SNCR to Indian Creek Kiln 1 and Kiln 2 would be cost-effective at $3,877-$4,252/ton of NOx removed.

MDEQ must correct its four-factor analyses to consider these controls.

d. Montana Sulfur & Chemical Company

For the Montana Sulfur and Chemical Co. facility in Billings, Montana, the National Park Service identified technically feasible and cost-effective opportunities available to further control SO2 emissions from the facility. The cost of control is more economical than estimated when analyses are adjusted in accordance with the EPA Cost Control Manual. Specifically, the National Park Service showed that SCOT emission controls would be cost effective on this facility, particularly when costs are properly adjusted to assume a 3.25% interest rate and 30-year life of controls. MDEQ must correct its four-factor analysis to consider adopting SO2 emissions limits consistent with installation and operation of SCOT.

e. FH Stoltze Land & Lumber Co.

As the National Park Service observed, additional controls appear warranted for the FH Stoltze Land & Lumber Co. sawmill located near Columbia Falls, Montana. As corrected by the National Park Service, among other things to adopt a reasonable control efficiency for SNCR of 50%, the costs of SNCR to control NOx emissions are within the range of reasonableness identified by other states and should be reconsidered as a reasonable progress measure.

f. Sidney Sugars Inc.

Finally, the National Park Service observed that all of the identified NOx control options are technically feasible and cost-effective for Sidney Sugars, which processes sugar beets using

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233 Id. at Appendix F, PDF pages 91-105.
234 Id. at 105-114.
235 Id. at 137-142.
lignite coal in Sidney, Montana. MDEQ’s justification for not requiring such controls was that the costs for such controls may become stranded in the event that Sidney Sugars loses its lignite coal source. This is improper since, as the National Park Service observed, there is no commitment by Sidney Sugars to cease burning coal at any time in the future. Further, MDEQ may simply adopt emissions limits consistent with the operation of SCR (or SNCR if warranted by a proper four-factor analysis), which the facility could meet either by retrofitting its coal-fired boilers or replacing them with natural gas boilers. However, MDEQ cannot simply point to uncertainty about the future of Sidney Sugar’s coal-fired boilers as a reason to defer emissions reductions as necessary to achieve reasonable progress.

III. MDEQ FAILED TO CONSIDER OIL AND GAS AREA SOURCES, DESPITE THEIR SIGNIFICANT NOX 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. States should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. Yet, MDEQ only discussed area sources when describing how its inventories were developed. MDEQ’s own “Figure 3-2. NOx Emissions by Sector” shows that area sources contribute greatly to NOx emissions and that NOx emissions from area sources were higher than point sources from 2002 to 2017. For SO2 emissions trends between 2002 and 2017, area sources appear to increase overall and are second to point sources in emissions. For non-oil and gas area sources, Montana did not consider these sources for additional controls “in part because potential control strategies were focused on reducing NOx and SO2 … [and] VOC is the main visibility impairing pollutant from nonpoint sources in Montana.” For oil and gas area sources, Montana concludes that “[c]ompared to North Dakota, Montana’s proven oil and gas reserves are not as prolific as they are across the border” From this statement, MDEQ appears to conclude that because North Dakota has greater oil and gas production, Montana oil and gas sources were not considered as a part of the long-term strategy. The fact that North Dakota has greater oil and gas production is not a legitimate reason for failing to consider area sources. As EPA has emphasized, and as noted by the FLM comments:

In applying a source selection methodology, states should focus on the in-state contribution to visibility impairment and not decline to select sources based on the fact that there are larger out-of-state contributors.

Given that nonpoint oil and gas sources are significant contributors to Montana’s and out-of-state Class I areas such as Theodore Roosevelt National Park, MDEQ’s Proposed SIP fails to satisfy section 51.308(f)(2)(i). As the FLM comments recommend:

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236 Id. at 142-147.
238 Proposed SIP at 57.
239 Id.
240 Id. at 133.
241 Id. at 136-38.
242 Id. at Appendix F, PDF page 159.
We recommend that NOx emission reductions from upstream oil and gas area sources across the entire Williston Basin, including sources on the Montana side, will be necessary to improve visibility in Theodore Roosevelt National Park … we request that Montana consider state-wide requirements to limit NOx emissions from engines in the SIP.\textsuperscript{243}

As documented in the attached March 2020 technical 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.\textsuperscript{244}

\textsuperscript{243} Id. at Appendix F, PDF page 158-59.

\textsuperscript{244} Vicki Stamper & Megan Williams, Oil and Gas Sector Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration (Mar. 6, 2020) (attached as Exhibit B). See id. at ES-2 (Summary of Cost Effective Control Options for Air Emissions Sources of the Oil and Gas Sector).
Therefore, MDEQ must revise its Proposed SIP to not only consider, but also to require, cost-effective controls on these significant pollution sources.
IV. MDEQ FAILED TO ADEQUATELY RESPOND TO COMMENTS FROM THE FEDERAL LAND MANAGERS

Montana 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.\(^{245}\) 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.\(^{246}\) 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.”\(^{247}\) The “consultation must be early enough for state officials to meaningfully consider the views expressed by the FLMs.”\(^{248}\)

As MDEQ noted, “FLMs have a critical role in protecting air quality in national parks, wilderness and other federally protected areas, and have an affirmative responsibility to protect air quality related values, including visibility, in all Class I areas.”\(^{249}\) For that reason, 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.”\(^{250}\) 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.\(^{251}\) 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, MDEQ failed to adequately respond to comments submitted to the state by the U.S. Forest Service and National Park Service.\(^{252}\) In particular, the National Park Service submitted extensive technical comments, including revised cost analyses, for every source MDEQ

\(^{245}\) 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).

\(^{246}\) 42 U.S.C. § 7491(d); 40 C.F.R. § 51.308(i)(2).

\(^{247}\) 40 C.F.R. § 51.308(i)(2) (emphasis added).


\(^{249}\) Proposed SIP at 42.

\(^{250}\) 40 C.F.R. § 51.308(i)(3); 40 C.F.R. § 51.308(f)(4); July 2021 Clarification Memo at 16-17.

\(^{251}\) 40 C.F.R. § 51.308(i)(2); Regional Haze Rule Revision Response to Comment at 445.

\(^{252}\) Proposed SIP, Appendix F.
considered in the FIP.\textsuperscript{253} Those comments critiqued MDEQ’s proposal to not require any emissions reductions to satisfy reasonable progress requirement and identified a host of feasible, cost-effective technologies for doing so.\textsuperscript{254} While the Proposed SIP includes these comments as an appendix, Montana did not substantively modify its draft Proposed SIP in response to those comments or provide any reasoned justification for not doing so. Thus, MDEQ impermissibly converted the requirement for meaningful coordination into a mere box-checking exercise. MDEQ must revise its Proposed SIP to respond to the FLM’s serious concerns and analysis.

V. MDEQ’S CONSULTATION WITH OTHER STATES AND TRIBES WAS FLAWED AND INCOMPLETE

A. MDEQ Failed to Properly Consult with Other States

MDEQ failed to meet is state-to-state consultation obligations and its Proposed SIP lacks the information, documentation, and necessary enforceable measures. Instead of proper consultation with other states, Montana 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.\textsuperscript{255} 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.\textsuperscript{256} 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.”\textsuperscript{257}

“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).”\textsuperscript{258} 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

\textsuperscript{253} Id., PDF at 44-162. As noted in the Conservation Organizations’ March 10, 2022 letter to MDEQ, the appendices improperly omitted the National Park Service’s cost analysis worksheets underlying their comments. Because this analysis is essential to the public’s informed review and comment on the Proposed SIP, MDEQ should reissue a revised draft for public comment that includes the National Park Service’s complete analysis.

\textsuperscript{254} See id.

\textsuperscript{255} 42 U.S.C. § 7491(b)(2).

\textsuperscript{256} Id., § 7491(a)(1).

\textsuperscript{257} 82 Fed. Reg. at 3,094.

\textsuperscript{258} 82 Fed. Reg. at 3,085.
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.259

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.
(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.260

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.261

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.262

In its 2017 amendments to the Regional Haze Rule, EPA explained that “states must exchange their four-factor analyses and the associated technical information that was developed in the course of devising their long-term strategies. This information includes modeling,

260 40 C.F.R. § 51.308(f)(2); see also, 64 Fed. Reg. 35,765, 35,735 (July 1, 1999) (In conducting the Four-Factor Analysis, EPA explained that “…the State must consult with other States which are anticipated to contribute to visibility impairment in the Class I area under consideration … any such State must consult with other States before submitting its long-term strategy to EPA.”) (emphasis added).
262 40 C.F.R. § 51.308(f)(4).
monitoring and emissions data and cost and feasibility studies.”\textsuperscript{263} 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.”\textsuperscript{264}

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 or groups of sources in the State.”\textsuperscript{265} To that end, the “State must provide a robust demonstration, including documenting the criteria used to determine which sources or groups of 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.”\textsuperscript{266} In any event, “[a]ll substantive interstate consultations must be documented.”\textsuperscript{267}

MDEQ’s purported state-to-state consultation fell short of these obligations. MDEQ’s Proposed SIP explains that it negotiated with seven states and “agreed that with facility shutdowns throughout the region, emissions reductions from ongoing pollution control programs, and the projected improvement in visibility in all Montana Class I areas, that Montana will not request the adoption of controls for any facilities outside of Montana that affect Montana Class I areas.”\textsuperscript{268} In its communications with neighboring states, MDEQ agreed to not request additional controls for sources in other states, such as in Wyoming, impacting Montana Class I areas. MDEQ’s process and results do not follow the legal requirements.\textsuperscript{269}

MDEQ cites a single email correspondence from South Dakota as meeting its state-to-state consultation obligations: “Montana received email correspondence from South Dakota, indicating the state was not planning to install additional controls on its sources for the second implementation period.”\textsuperscript{270} This correspondence is legally insufficient. MDEQ does not discuss whether or how it exchanged its Four-Factor Analyses with South Dakota. Even though South Dakota found that several Montana sources contribute to visibility impairment in South Dakota Class I areas, MDEQ determined it did not need to propose any pollution reductions because South Dakota told MDEQ that it “will not recommend any additional controls for Montana

\begin{footnotes}
\item[263] 82 Fed. Reg. at 3,088 (emphasis added).
\item[264] Id.
\item[266] Id., § 51.308(f)(3)(ii)(B).
\item[267] Id., § 51.308(f)(2)(ii)(C).
\item[268] Proposed SIP at 307.
\item[269] Id.
\item[270] 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. Proposed SIP at 308.
\end{footnotes}
sources for this second implementation period.”

Therefore, despite the impact of Montana’s sources on South Dakota’s Class I areas, MDEQ neither provided the information to South Dakota that it was required to provide, nor does its SIP propose any reductions to improve visibility in South Dakota. Furthermore, there is no information regarding whether those corresponding between states had authority under state law to reach an agreement that “Montana will not request the adoption of controls for any facilities outside of Montana that affect Montana Class I areas”

and “South Dakota will not recommend any additional controls for Montana sources for this second implementation period.” There is not an off-ramp for two states to agree to ask nothing of one another under the CAA or Regional Haze Rule. Rather states must go through the consultation process.

For Wyoming, MDEQ took a similarly sparse “consultation” approach. According to the Proposed SIP, “Montana informed Wyoming via email on November 16, 2020 that the state did not find controls to be reasonable this planning period, due in part to the large emission reductions resulting from EGU shutdowns.” Wyoming and Montana then “met again via phone conference … [and] agreed that the adoption of controls would not be necessary to make reasonable progress in either Montana or Wyoming Class I areas.”

Montana and Wyoming then agreed by email correspondence “that Wyoming will not request the adoption of controls on Montana sources for this second implementation period and that Wyoming agrees that reductions from ongoing pollution control programs and facility closures in Montana will result in improvements in visibility in Wyoming Class I areas.”

The Proposed SIP describes that for both North Dakota and Idaho, Montana has a close working relationship and communicated regularly with the states. For Idaho, the Proposed SIP states that “Because wildfire, prescribed fire and international emissions are large contributors to haze in our Class I areas, both Montana and Idaho agreed that neither state will request additional controls on our sources.” However, Conservation Organizations share similar concerns about the lack of documentation and authority to agree to “ask nothing of one another.” Conservation Organizations also share similar concerns about the consultation with Utah, Oregon, and Washington. Thus, MDEQ must properly consult with other states and document that consultation for public review.

B. MDEQ Failed to Properly Consult with Tribes

MDEQ’s consultation with Tribes was also flawed, and the Proposed SIP does not provide sufficient information regarding the consultation. The Proposed SIP states the following Tribes are in Montana: Blackfeet Tribe of the Blackfeet Reservation, Chippewa Cree Tribe of Rocky Boy’s Reservation, Confederated Salish & Kootenai Tribes of the Flathead Reservation, Crow Tribe of the Crow Reservation, Fort Belknap Tribes of the Fort Belknap Reservation, Fort

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271 Id.
272 Id. at 307.
273 Id. at 308.
274 Id.
275 Id.
276 Id.
Peck Assiniboine & Sioux Tribes of the Fort Peck Reservation, Little Shell Chippewa Tribe and Northern Cheyenne Tribe of the Northern Cheyenne Reservation. MDEQ states that it “shared the draft RH SIP with the tribes on September 27, 2021, the beginning of the 60-day formal FLM consultation period. Montana did not receive any comments on the draft RH SIP.”\textsuperscript{277} MDEQ fails to provide more information regarding its outreach efforts with Tribes or share any details regarding its outreach. MDEQ titles the section in its Proposed SIP “Collaboration with Tribes” yet fails to explain how collaboration occurred when it simply shared the Proposed SIP to Tribes: collaboration requires meaningful and equal engagement. Thus, MDEQ’s claim that it collaborated with Tribes appears to be both incorrect and disingenuous.

The Proposed SIP states that it “did not identify any emission sources on tribal lands that impact a nearby Class I area” and seems to assume that this justifies what appears to be a single outreach effort to Tribes regarding the Proposed SIP.\textsuperscript{278} This is insufficient. As MDEQ itself notes, “[i]n some cases, sources affecting visibility are located on tribal lands and sometimes emissions from other sources may impact tribal air quality.”\textsuperscript{279} For example, the Hardin Generating Station is located near the Crow Agency and Colstrip is located near the Northern Cheyenne Reservation, which is a designated Class I airshed.

Moreover, Montana has a state law that requires consultation with Tribes.\textsuperscript{280} “Recogniz[ing] the fundamental principle and integrity of the government-to-government relationship between the State of Montana and the Indian nations of Montana” and in an effort to “support[] [and] strengthen[] communications and build[] collaborative relationships that will benefit both the Indian nations and the state of Montana” while respecting “tribal sovereignty and self-determination,” the Montana Legislature codified the state’s duty to consult with Tribes on matters that directly impact Tribal nations.\textsuperscript{281}

The Tribal Consultation Law requires that state agencies, including MDEQ, document their consultation with impacted Tribes when “formulating or implementing policies or administrative rules that have direct tribal implications.”\textsuperscript{282} The “guiding principles” underlying the law include “regular and early communication” with Tribes; maintaining “a commitment to cooperation and collaboration”; providing for “a process of accountability for addressing issues”; and “preserv[ing] … the tribal-state relationship.”\textsuperscript{283}

\textsuperscript{277} Id. at 44.
\textsuperscript{278} Id.
\textsuperscript{279} Id.
\textsuperscript{283} Id. at (1)-(5).
Regarding the requirement to engage in “regular and early communication,”284 the Tribal Relations Handbook285 advises state employees “to include Tribes before the pen hits the paper, not when it’s time to sign in ink” and emphasizes that “[t]he goal with tribal governments is to include them early, invite them always, follow-up every time, meet with them regularly and ask them how best to work together.”286 Regarding the principles of cooperation and collaboration,287 the Tribal Relations Handbook stresses the importance of government-to-government collaboration, stating that “[i]ntergovernmental cooperation serves the interests of all Montana citizens while ensuring respect for the sovereign authority of both governments, state and tribal.”288 Regarding the requirement for accountability,289 the Handbook reiterates the importance of initiating discussions with impacted Tribes early.290

MDEQ’s Proposed SIP involved the agency “implementing policies [and] administrative rules that have direct tribal implications.”291 DEQ is the agency charged with drafting the Proposed SIP and is also aware that “sources affecting visibility are located on tribal lands and sometimes emissions from other sources may impact tribal air quality.”292 Thus, MDEQ has a legal duty to consult with the Tribes and failed to do so in violation of the Tribal Consultation Law. MDEQ must rectify its failure and meaningfully consult Tribes prior to finalizing the state’s SIP.

VI. MDEQ’S LONG-TERM STRATEGY IS INCONSISTENT WITH LEGAL REQUIREMENTS

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

286 Tribal Relations Handbook at 12 (emphasis in original).
288 Tribal Relations Handbook at 14.
290 Tribal Relations Handbook at 15 (“[t]he primary means of ensuring accountability is regular state-tribal communication and consultation. The implementation of state-tribal consultation policies and procedures at all levels of state government can help ensure that tribal leadership or their designees are involved early in discussing projects, policy and program changes”) (emphasis added).
292 Proposed SIP at 44.
As drafted, Montana’s reasonable progress goals are based on modeling results, which do not meet the Regional Haze Rule requirement that the RPGs are to be based on enforceable SIP measures. Specifically, Montana’s proposed long-term strategy sets reasonable progress goals based on the WRAP’s modeling results before and in lieu of conducting the required Four-Factor Analysis—it has impermissibly reversed the order of the requirements. The RPGs are not to be developed before the Four-Factor Analyses but as a result of the Four-Factor Analyses.293 MDEQ 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. MDEQ’s Reliance on the “Glide Path” and Its Methodology to Adjust the RPGs for Class I Areas Within Montana Violates the Clean Air Act and Regional Haze Rule

1. MDEQ erroneously relies on the glidepath to avoid emission limitations in the SIP, and the URP is not a safe harbor.

MDEQ attempts to justify deferring any emission reductions by pointing out that projections for Montana’s Class I areas show projections below the area’s glidepath or URP, which it states is sufficient to achieve reasonable progress.294 Suggesting that a historical monitoring emission trend will continue, without enforceable SIP emission limitations to secure reductions, does not ensure the future of emissions. As NPS explained in its comments,

EPA has clarified that the URP is not a “safe harbor.” States should not dismiss otherwise technically feasible, cost-effective controls solely because visibility progress in state’s Class I areas is better than the URP. The URP is a planning tool that allows states to evaluate their overall progress toward the goal, but it is not a standard that indicates whether progress is reasonable. It may be that a state’s Class I areas are not meeting the URP but the state is still making reasonable progress if it finds by applying four-factor analysis to its sources that there are no technically feasible, cost effective controls to implement. Conversely, it may be that a state’s Class I areas are meeting the URP but are still not making reasonable progress if the state rejects technically feasible cost-effective controls because the Class I areas are below the glideslope.295

EPA has made clear that meeting or exceeding the URP does not obviate the need for states to conduct a robust Four-Factor Analysis and make a technical demonstration as to whether additional controls or emission reductions are reasonable. “[A]n evaluation of the four statutory factors is required … regardless of the Class I area’s position on the glidepath … the

293 See e.g., 82 Fed. Reg. at 3090-91.
294 See e.g., Proposed SIP at 310 (“None of the 2028 RPGs selected for Montana Class I areas are above the respective Class I area’s URP; therefore, Montana believes we have demonstrated that all necessary emission reduction measures are included in our LTS.”).
295 Proposed SIP, Appendix F, at PDF page 49.
URP does not establish a ‘safe harbor’ for the state in setting its progress goals.”

Rather, states must “determine what emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors” and must not reject “control measures determined to be reasonable” based on the degree of progress.

MDEQ incorrectly suggests that the Proposed SIP is approvable because the IMPROVE monitoring data is below the glidepath. Reasonable progress is not measured by the glidepath. Furthermore, MDEQ’s suggestion that the RPGs being under the glidepath is a safe harbor inappropriate. In its 2021 Clarification Memo, EPA reiterated that the uniform rate of progress is “not a safe harbor,” and that it is not appropriate to reject cost-effective emission reductions on the basis that visibility in a particular Class I area is on the glidepath. Instead, states are required to “evaluate and determine emission reduction measures that are necessary to make reasonable progress by considering the four statutory factors.”

2. MDEQ must not revise the RPGs based on projected modeling that is not based on enforceable SIP requirements.

MDEQ’s proposed RPGs are inconsistent with the legal requirements for several reasons. First, MDEQ’s Proposed SIP “relies on the data stored in and retrieved from” the WRAP’s modeling to set its RPGs. The emission inventory inputs in WRAP’s modeling are neither

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296 81 Fed. Reg. 66,331, 66,631 (Sept. 27, 2016); see also 81 Fed. Reg. 296, 326 (Jan. 5, 2016) (determining, as part of the reasonable progress federal implementation plan for Texas, “the uniform rate of progress is not a ‘safe harbor’ under the Regional Haze Rule.”); EPA, Responses to Comments at 120, Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan: Best Available Retrofit Technology and Interstate Transport Provisions, EPA Docket No. EPA-R06-OAR-2016-6011 (June 2020) (“EPA has repeatedly and consistently taken the position that meeting a specific reasonable progress goal is not, itself, a ‘safe harbor,’ and does not relieve the state of the obligation to consider additional measures for reasonable progress. If it is reasonable to make more progress than the URP, a state must do so, as EPA explained in the 1999 Regional Haze Rule”) (citing 64 Fed. Reg. at 35732); 81 Fed. Reg. at 66,370 (“EPA’s longstanding interpretation of the Regional Haze Rule is that ‘the URP does not establish a ‘safe harbor’ for the state in setting its progress goals.’”) (quoting 79 Fed. Reg. 74,818, 74,834)).


298 2021 Clarification Memo at 15-16 (emphasis added).

299 Proposed SIP at 33.
enforceable via SIP emissions limitations, nor do they represent recent actual emissions. Second, MDEQ must not propose its RPGs until it first conducts the required Four-Factor Analyses for all the required sources, establishes emission limits in the SIP, and uses those limitations to set the RPGs. Indeed, the Regional Haze Rule explicitly requires Montana to make meaningful reductions to ensure reasonable progress towards the national goal of restoring visibility. As discussed above, commenters conclude that at a minimum there are control measures available that likely satisfy the four factors and therefore should be required at sources both evaluated and excluded by MDEQ. Third, to the extent MDEQ’s Proposed SIP defers controls that satisfy the Four-Factor Analysis to another planning period, simply because Class I areas are on the glidepath, that is contrary to the CAA and the Regional Haze Rule.

MDEQ’s “glidepath” rationale is also misplaced because the agency failed to evaluate and apply the results of the CAA’s reasonable progress analyses in determining whether emission reductions may be necessary to ensure reasonable progress towards natural visibility in each Class I area that Montana’s sources affect, as required by the Regional Haze Rule. Moreover, while MDEQ identified sources in other states that impact its Class I areas, it failed to complete its state-to-state consultation obligations. MDEQ’s decision to not adjust the RPGs based on these issues (i.e., its incomplete state-to-state consultation) is misplaced.

C. MDEQ Must Accurately Disclose Emission Inventory Projections and Identify Measures Needed To Prevent Future Impairment of Visibility.

The Regional Haze program requires states to adopt measures to prevent future visibility impairment as well as to address existing visibility impairment. MDEQ’s Proposed SIP lacks an accurate analysis of 2028 emission inventory projections and future source development, thus the public has no information to assess whether emissions from specific source categories are projected to increase between 2011 and 2028 as seen in other states (e.g., anticipated new

300 See discussion infra Section VI.E. regarding enforceable emission limitations in the SIP.
301 40 C.F.R. § 51.308(f)(2)(iii) (“The State 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. The State may meet this requirement by relying on technical analyses developed by a regional planning process and approved by all State participants. The emissions information must include, but need not be limited to, information on emissions in a year at least as recent as the most recent year for which the State has submitted emission inventory information to the Administrator in compliance with the triennial reporting requirements of subpart A of this part. However, if a State has made a submission for a new inventory year to meet the requirements of subpart A in the period 12 months prior to submission of the SIP, the State may use the inventory year of its prior submission.”).
302 See 40 C.F.R. § 51.308(f)(2) (“Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State that may be affected by emissions from the State.”) (emphasis added); id. § 51.308(f)(3)(ii)(A)-(B).
development in the state, ammonia emissions from nonroad sources, visibility-impairing pollutants from oil and gas and others). MDEQ must analyze future emission inventory projections, explain what these emissions sources are within the state and discuss the programs it has in place to address any potential future increases in emissions. Importantly, MDEQ must evaluate the measures that may be needed to prevent any currently projected future increases in visibility-impairing emissions from these source categories.

Moreover, as MDEQ develops permit modifications for existing sources and permits for new sources, it must take regional haze implications into consideration—these requirements should be discussed and committed to in the state’s SIP. The Regional Haze Rule’s reasonable progress requirements apply and work in conjunction with permitting requirements, and MDEQ must not defer until the next regional haze SIP update or planning period to address permit modifications.

D. MDEQ Must Establish and Provide a Basis for a Cost Effectiveness Threshold.

MDEQ has not clearly defined 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, MDEQ determined that additional controls were not necessary for its long-term strategy—other than the source shutdowns/retirements, or the slight emission decreases already occurring due to other requirements or already planned for by facilities.304 MDEQ 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 MDEQ “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.”305 Absent such an explanation, MDEQ’s reasonable progress analyses are arbitrary.

MDEQ 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, MDEQ 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.

E. MDEQ 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 MDEQ 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. To the extent that a state declines to evaluate additional pollution controls for any source based on that

304 Proposed SIP at 310.
305 Nat’l Parks Conservation Ass’n v. E.P.A., 788 F.3d 1134, 1142–43 (9th Cir. 2015) (citation and quotation omitted).
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. 306 The Regional Haze Rule similarly requires each state to include “enforceable emission limitations” as necessary to ensure reasonable progress toward the national visibility goal. 307 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. 308

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 MDEQ 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, MDEQ is obligated to consider whether there are cost-effective control measures that could be implemented in the meantime. 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.” 309 As mentioned throughout these comments, there are some types of control measures that are likely to be cost-effective even within shorter timeframes.

F. MDEQ’s Anticipated Additional Emissions Reductions from “Ongoing Pollution Control Programs” Are Neither Justified Nor Secured by Enforceable SIP Measures.

MDEQ’s anticipated additional emissions reductions from “Ongoing Pollution Control Programs” are neither justified nor secured by enforceable SIP measures. MDEQ identifies “a number of federal and state control programs aimed at reducing emissions across various sectors that have the co-benefit of reducing haze.” 310 MDEQ fails to provide the details and quantify emission reductions from these ongoing programs, and lacking this required information, MDEQ cannot take credit for “other programs” that are unsupported and not quantified.

307 See generally 40 C.F.R. § 51.308(d)(3).
309 2021 Clarification Memo at 7.
310 Proposed SIP at 285.
G. MDEQ’s Reliance on Outdated and Flawed WRAP Work Products and Adoption of the Sources’ Submittals Suggests It Lacks Adequate Resources To Implement the Clean Air Act’s Reasonable Progress Requirements.

MDEQ’s reliance on outdated and flawed WRAP work products and wholesale adoption of the sources’ submittals suggests it lacks adequate resources to implement the Clean Air Act’s reasonable progress requirements. The contents of MDEQ’s Proposed SIP suggests it lacks the time, personnel, and funding resources to develop a complete regional haze SIP. The Proposed SIP lacks the careful independent review required by the state when it reviewed the sources’ Four-Factor Analyses. MDEQ failed to independently review and identify numerous significant and substantive technical errors made by the sources, which demonstrate the state lacks adequate resources to do its job. At other points in the Proposed SIP, MDEQ chose not to make the required changes necessary—such as updating the interest rate used in its cost calculations—to ensure that the sources’ analyses and the Proposed SIP complied with the CAA, regulations, EPA guidance, and EPA’s clarification memo. This example demonstrates MDEQ’s lack of resources to independently review and correct the sources’ misplaced legal assertions.

Moreover, MDEQ failed to adequately respond to comments made by the NPS and failed to make corrections to numerous errors for the sources the NPS reviewed. Further evidence the state lacks resources to implement the regional haze SIP requirements. MDEQ has thus far failed to do its job, and the Conservation Organizations’ comments via this letter identified many of the same errors identified by the NPS as well as numerous additional technical and legal errors.

The Act and implementing regulations require that states have adequate resources and authority; indeed states are required to certify to EPA in each SIP submission and periodically for infrastructure SIPS that they have such resources and authorities. If MDEQ lacks the resources necessary to develop a complete and approvable SIP, then Montana must do what it has done before and notify EPA that Montana will defer to EPA’s development and implementation of a regional haze FIP.

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312 77 Fed. Reg. 23,988 (April 20, 2012) (EPA’s proposed FIP, explained that “[o]n June 19, 2006, Montana submitted a letter to us signifying that the State would be discontinuing its efforts to revise the visibility control plan that would have incorporated provisions of the Regional Haze Rule. The State acknowledged with this letter that EPA would make a finding of failure to submit and thus promulgate additional federal rules to address the requirements of the Regional Haze Rule, including BART. In response to the State’s decision EPA made a finding of SIP inadequacy on January 15, 2009 (74 FR 2392), determining that Montana failed to submit a SIP that addressed any of the required regional haze SIP elements of 40 CFR 51.308.”); 77 Fed. Reg. 57,864 (Sept. 18, 2012) (EPA’s final FIP).
H. MDEQ’s Proposed SIP Does Not Contain Any Provisions to Ensure Emission Limitations Are Permanent and Enforceable and That Permits Complement 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.\(^{313}\) 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 reasonable progress as determined pursuant to [40 C.F.R. § 51.308](f)(2)(i) through (iv)).”\(^{314}\) 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.\(^{315}\)

There are several issues with MDEQ’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.\(^{316}\) 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.\(^{317}\)

Moreover, the reasonable progress requirements apply to all sources, thus to the extent MDEQ 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

\(^{313}\) 42 U.S.C. §§ 7491(a)(1), (b)(2).
\(^{314}\) 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).
\(^{315}\) 40 C.F.R. § 51.308(f)(3).
\(^{316}\) See, e.g., Stamper Report at 7.
\(^{317}\) 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)).
SIP requirements.\textsuperscript{318} State-issued permits must not frustrate SIP requirements.\textsuperscript{319} 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.\textsuperscript{320}

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 permanent since they may lapse. It is not enough that the Title V permits are reviewable by EPA, Title V permits are not part of the SIP and not approved through EPA’s SIP process. Therefore, to the extent MDEQ 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 MDEQ relies on are Title V permits.

Of significant concern is that MDEQ’s Proposed SIP lacks any of 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, MDEQ’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. MDEQ 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.

I. MDEQ Fails to Consider Increasing Emissions from Cryptocurrency Mining.

1. MDEQ must revise its proposed SIP to require emissions reductions from power plants that may supply electricity for cryptocurrency mining operations.

Montana’s Proposed SIP relies on past reductions from power plant retirements and pollution controls to support its proposal that no future reductions are needed to meet reasonable progress requirements but fails to recognize potentially dramatic future emissions increases associated with growing electricity demand in Montana from, among other things, data-

\textsuperscript{319} 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.
\textsuperscript{320} 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).
processing centers used for cryptocurrency mining. As the Proposed SIP recognizes, “measuring progress under the Regional Haze program relies on a comparison of actual progress to expected/anticipated progress.”

To that end, the Regional Haze Rule requires a SIP to assess “any significant changes in anthropogenic emissions within or outside the State that have occurred over the period since the period addressed in the most recent plan required under paragraph (f) of this section including whether or not these changes in anthropogenic emissions were anticipated in that most recent plan and whether they that have limited or impeded progress in reducing pollutant emissions and improving visibility.”

In addition to emissions increases that already have occurred, Montana must consider reasonably anticipated future emissions increases that could impact the state’s progress toward the national visibility goal.

Proof-of-work cryptocurrency operations, such as Bitcoin, use decentralized computers from anywhere in the world to compete to verify transactions using math problems, with the fastest computer to solve the problem getting a monetary reward. Successful miners use powerful computers that need to be constantly cooled, requiring large amounts of electricity.

Proof-of-work cryptocurrency mining operations already have increased electricity demand in Montana, along with NOx and SO2 emissions associated with such electricity generation. For example, while the Hardin Generating Station in southeastern Montana operated only infrequently between 2015 and 2021 and had been slated to close, bitcoin mining company Marathon signed a deal in 2020 to buy all of the plant’s electricity. Since the last half of 2021, the plant has been operating at or near full capacity and its emissions of NOx and SO2 have increased accordingly. Additionally, it was reported in 2018 that Talen Energy contracted with a bitcoin mining operation for 64 MW of power from the Colstrip Plant, presumably also increasing that facility’s operating time and emissions. And current and planned data-processing centers in Butte, Broadview, Hardin, and Polson may demand up to 500 megawatts of Montana’s electricity generation in the coming years.

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321 Proposed SIP at 62.
322 40 C.F.R. § 51.308(g)(5).
323 See 40 C.F.R. § 51.308(f)(2)(iv)(E) (requiring consideration of “[t]he anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy”).
325 Id.
Considering the potentially significant future emissions increases, Montana must revise its proposed SIP to require emissions reductions both from power plants that may supply electricity for cryptocurrency mining operations and from other sources as necessary to ensure that increases do not thwart Montana’s progress toward the national visibility goal.

2. Power plants and other sources that engage in cryptocurrency mining must be assumed to be operating at 100% capacity, and MDEQ must take into consideration the recently issued Presidential Executive Order

As explained in the Stamper Report, power plants that engage in cryptocurrency mining present a unique problem to the regional haze program.\textsuperscript{330} Conversion of otherwise uncompetitive coal-fired power plants to cryptocurrency mining is a growing trend in the U.S., and reports abound concerning EGUs that are engaging in cryptocurrency mining significantly increasing their capacities. Also, power plants that have announced retirement are being bought and repurposed for providing electricity to cryptocurrency mining operations as seen with the Hardin Generating Station, discussed above.\textsuperscript{331}

Regional Haze SIP modeling must reasonably predict 2028 emissions from all sources, based on historical emissions. Power plant capacity is a direct input to control cost-effectiveness, as the denominator in the familiar \$/ton cost-effectiveness metric is derived from the expected reductions in emissions in comparison to assumed uncontrolled future emissions. If those future emissions increase due to an increased capacity from cryptocurrency mining, then that denominator increases and the cost-effectiveness is improved (lower \$/ton), making the control more attractive.\textsuperscript{332}

MDEQ’s actions on emissions from cryptocurrency mining are further necessary for the state’s actions to comply with the recently issued Executive Order (“EO”). On March 9, 2022, President Biden signed the EO on “Ensuring Responsible Development of Digital Assets.”\textsuperscript{333} This new EO has direct application to MDEQ’s efforts to prepare its Regional Haze SIP. Notably, the EO outlines the “principal policy objectives of the United States with respect to digital assets are as follows”\textsuperscript{334} and explains that the United State “must support technological advances that promote responsible development and use of digital assets.”\textsuperscript{335} The EO acknowledges that “[t]he technological architecture of different digital assets has substantial implications” in numerous areas including “climate change, the ability to exercise human rights, and other national goals.”\textsuperscript{336} Moreover, the EO section on policy objectives further explains that

\textsuperscript{330} Stamper Report at 48.
\textsuperscript{331} Id.
\textsuperscript{332} Id.
\textsuperscript{334} Id. \S 2(f).
\textsuperscript{335} Id.
\textsuperscript{336} Id. (emphasis added).
“[t]he United States has an interest in ensuring that digital asset technologies and the digital payments ecosystem are developed, designed, and implemented in a responsible manner that includes privacy and security in their architecture, integrates features and controls that defend against illicit exploitation, and reduces negative climate impacts and environmental pollution, as may result from some cryptocurrency mining.”

Further evidence of the need for Montana to consider emissions from cryptocurrency mining is seen in Sections 3 and 5 of the EO. For example, Section 3 of the EO specifies the executive branch agencies and appointees that are involved in complying with the EO, and one of the agencies/administrators is EPA’s Administrator. Section 5 contains the measures the agencies are to take to “protect consumers” and others. Specifically, Section 5 requires that the federal agencies (which include EPA) prepare a report that includes “the potential for these technologies to impede or advance efforts to tackle climate change at home and abroad; and the impacts these technologies have on the environment.” Section 5 further requires that the “report should specifically address … potential uses of blockchain that could support monitoring or mitigating technologies to climate impacts, such as exchanging of liabilities for greenhouse gas emissions, water, and other natural or environmental assets.” The references to “environment” and to “other natural or environmental assets” clearly include pollutants that impact visibility.

Thus, when EPA takes final action on Montana’s regional haze SIP, or promulgates a FIP for Montana, it will need to comply with the EO on Digital Assets. MDEQ can assist EPA with its obligations in taking emissions from the cryptocurrency industry into consideration in developing and adopting its SIP.

3. MDEQ must establish appropriate enforceable emissions limits for Hardin Generating Station

As the Stamper Report showed, the Hardin Generating Station “has been increasing operating time and emissions in the past year, as shown in the table below.”

337 Id. § 2(f) (emphasis added).
338 Id. § 3 (coordination).
339 Id. § 5 (b)(vii) (emphasis added).
340 Id. (emphasis added).
341 Stamper Report at 47.
Hardin Generating Station Operational and Emissions Data from 2015 to 2021

<table>
<thead>
<tr>
<th>Year</th>
<th>Operating Time, hours/yr</th>
<th>Gross Load, MW-hrs/year</th>
<th>SO2, tons per year</th>
<th>NOx, tons per year</th>
<th>Heat Input, MMBtu/yr</th>
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“MDEQ did not list Hardin Generating Station in its analysis of sources to consider for controls based on emissions and Q/d, but possibly this was because the plant was projected to close by 2018.”

Given the increase of emissions from Hardin Generating Station, Montana must establish appropriate enforceable emissions limits for the source. MDEQ must also ensure that any EGU known to be considering cryptocurrency mining accepts an enforceable commitment in the SIP that it will not do so or is assessed assuming a 100% future capacity.

J. Montana Must Address a Significant and Growing Source of NOx Emissions in Its Regional Haze Plan—Combustion Sources in Residential and Commercial Buildings

NOx emissions from combustion sources in residential and commercial buildings can be a significant source of emissions. In Montana, NOx emissions from residential natural gas combustion—which includes emissions from private dwellings (including apartments) for heating, cooking, water heating, and other household uses—are over 1,000 tons per year based on EPA and Energy Information Administration (“EIA”). Not only are these residential combustion sources significant, but emissions are growing. In Montana, these emissions rose roughly 10% from 1,010 tons to 1,100 tons from 2017 to 2019. This growth in residential natural gas combustion presents a need for the state to address emissions from this growing source of NOx emissions in Montana.

In addition to residential buildings, NOx emissions from natural gas combustion in commercial buildings in Montana—which includes emissions from nonmanufacturing establishments or agencies primarily engaged in the sale of goods or services such as hotels, restaurants, wholesale, and retail stores, and other service enterprises as well as gas used by local, state, and federal agencies engaged in nonmanufacturing activities—are nearly 2,000 tons per year based on data from EPA, EIA, and using emission factors from California’s South Coast

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342 Data from EPA’s Air Markets Program Database, at https://ampd.epa.gov/ampd/.
343 Stamper Report at 48.
344 March 15, 2022 Memo from M. Williams to G. Smith Re: NOx Emissions from Buildings in Montana.
345 Id.
Air Quality Management District ("SCAQMD").\(^{346}\) Fuel usage in this sector, and therefore emissions, has also risen between 2017 and 2019, by close to 20%.

Combined, NOx emissions from residential and commercial natural gas combustion in Montana are 2,700 tons per year based on 2017 data, making this source category the third largest source of stationary NOx emissions in Montana behind coal-fired power plants and natural gas-fired industrial combustion sources (such as industrial boilers and internal combustion engines) in EPA’s National Emissions Inventory. Further, NOx emissions from residential and commercial natural gas combustion in Montana exceed the reported NOx emissions from statewide oil & gas production in the 2017 National Emissions Inventory. The chart below shows 2017 estimated NOx emissions from residential and commercial buildings\(^{347}\) compared to emissions data in EPA’s 2017 National Emissions Inventory for other stationary and nonpoint industrial sectors.

1. **State and Local Regulations and Incentive Programs Offer Examples for Achieving NOx Emissions Reductions from Natural Gas Combustion Sources in Buildings.**

\(^{346}\) Id. at 3–5
\(^{347}\) NOx emissions from residential and commercial natural gas combustion were based on data from EPA, EIA, and CA-SCAQMD.
State and local air agencies have adopted NOx limits for natural gas-fired combustion sources, including for very small units, many of which have been in place for more than 20 years and many of which have been strengthened over the years. California Air District rules provide several examples of stringent NOx emission limitations for units sized for residential and commercial use in buildings, including the following: (1) South Coast Air Quality Management District (‘‘SCAQMD’’) Rules 1121348 and 1146.2,349 setting NOx limits for manufacturers or at point-of-sale for residential water heaters; (2) San Joaquin Valley Air Pollution Control District (‘‘SJVAPCD’’) Rule 4308,350 adopting point-of-sale NOx limits for water and pool heaters; (3) Sacramento Metropolitan Air Quality Management District (‘‘SMAQMD’’) Rule 414,351 adopting point-of-sale NOx limits for small combustion units; and (4) Feather River Air Quality Management District (‘‘AQMD’’) Rule 3.23,352 with point-of-sale NOx limits for water heaters. Texas also has statewide rules that limit NOx emissions from these sources at 30 TAC 117.3205.353

These state and local rules apply to the smallest of boilers and water heaters at the point-of-sale, including, e.g., tank-type and instantaneous water heaters; pool/spa heaters; heaters used for baking/cooking, etc. These air agencies are requiring NOx emission rates that would reduce emissions up to 80% from uncontrolled emission rates for a wide range of residential and commercial natural gas-fired combustion sources, providing relevant examples for states to consider to help make reasonable progress towards remedying existing visibility impairment.

In addition, many cities and counties have adopted building codes requiring all-electric construction of new residential and commercial buildings. And many local governments and utilities are incentivizing building electrification through rebate programs.

Montana should consider addressing this growing and significant source of NOx emissions through rules and programs similar to those discussed above. Not only could such requirements reduce emissions from a contributing source to regional haze, but such

350 BOILERS, STEAM GENERATORS, AND PROCESS HEATERS – 0.075 MMBtu/hr to less than 2.0 MMBtu/hr, Rule 4308 (Nov. 14, 2013), https://www.valleyair.org/rules/currntrules/03-4308_CleanRule.pdf.
351 WATER HEATERS, BOILERS AND PROCESS HEATERS RATED LESS THAN 1,000,000 BTU PER HOUR, Rule 414 (Oct. 25, 2018), http://www.airquality.org/ProgramCoordination/Documents/rule414.pdf.
requirements could help lessen indoor air pollution from these combustion sources and reduce greenhouse gas emissions.

VII. MDEQ 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

MDEQ has both state and federal obligations to meaningfully consider and advance environmental justice in its regional haze SIP. Unfortunately, the Proposed SIP entirely ignores environmental justice concerns, contrary to EPA guidance.

A. MDEQ Disregarded Communities Impacted by Montana’s Polluting Sources.

Montana’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 MDEQ 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 viewsesh 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. MDEQ 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.354 Ultimately, EPA will review the Final Haze Plan that Montana submits, and EPA will be

354 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 § 110(a)(2).”); Ariz. Pub. Serv. Co. v. EPA, 562 F.3d 1116, 1126 (10th Cir. 2009) (citing Union Elec. Co v. EPA, 427 U.S. 246, 265 (1976)) (“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.
required to ensure that its action on Montana’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.  

On January 27, 2021, the current Administration signed “Executive Order on Tackling the Climate Crisis at Home and Abroad.” 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] … successfully 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.

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

C. MDEQ 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. EPA’s 2019 Regional Haze Guidance for the Second Planning Period specifies, “States may also consider any beneficial non-air quality environmental impacts.” 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:

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.”).

357 Id. § 201.
358 2021 Clarification Memo at 16.
359 2019 Guidance at 49.
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.\textsuperscript{360}

Additionally, a collection of EPA policies, guidance and directives related to the National Environmental Policy Act (“NEPA”) is available at \url{https://www.epa.gov/nepa/national-environmental-policy-act-policies-and-guidance}. One of these policies concerns environmental justice.\textsuperscript{361} MDEQ should consider these sources of information in conducting a meaningful environmental justice analysis.

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

In addition to the NEPA guidance directives referenced above, EPA provides a wealth of additional material.\textsuperscript{362} 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 consistent data to highlight places that may have higher environmental burdens and vulnerable populations.\textsuperscript{363}

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

As occurred in the first planning period, 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’s 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

\textsuperscript{360}2019 Guidance at 33.


plans and actions. Consequently, should EPA promulgate a FIP for Montana 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. MDEQ Must Consider Environmental Justice Under Title VI of the Civil Rights Act.**

As EPA must consider environmental justice, so must MDEQ 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….” MDEQ 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.

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

**G. MDEQ’s Disregard of Environmental Justice Fails To Protect People Living in Communities Affected by Montana’s Sources.**

MDEQ’s Proposed SIP lacks any consideration of environmental justice. MDEQ failed to consider any sources that impact Montana’s vulnerable communities and overburdened areas. MDEQ’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 Montana’s sources, we urge MDEQ to fully and meaningfully consider all sources that impact these communities in environmental areas. In establishing emission limitations in its SIP, MDEQ must reduce impacts at both the Class I areas and overburdened areas affecting vulnerable communities.

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CONCLUSION

When viewed as a whole, the Montana Proposed SIP fails to meet the intent, purpose, and direction of the Clean Air Act. Of the sources MDEQ selected for review, MDEQ did not require any new reductions in pollution for any source. As a result, significant amounts of SO2 and NOx 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 Montana and those pollution controls are cost-effective, Montana 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 MDEQ to reassess its determination not to require new pollution reduction from sources in the Montana 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.

Sincerely,

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

By Victoria R. Stamper

March 17, 2022

Prepared for
National Parks Conservation Association,
Montana Environmental Information Center,
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 February of 2022, the Montana Department of Environmental Quality (MDEQ) made available its plan for addressing reasonable progress toward the national visibility goal for Class I areas.\(^3\) MDEQ has proposed to rely on unit closures that have already occurred or that are planned for four units: the J.E. Corette Power Plant, Units 1 and 2 of the Colstrip Power Plant, and Montana Dakota Utilities (MDU) Lewis & Clark Power Plant.\(^4\) MDEQ also relied on “slight emission decreases projected in 2028” from Colstrip Units 3 and 4 and from the Cenex Harvest States Cooperative (CHS) Inc. Laurel Refinery.\(^5\) Several of the plant closures and slight emissions decreases were due to Consent Decrees to resolve Clean Air Act litigation or due to the EPA’s Mercury and Air Toxics Standards (MATS).\(^6\)

MDEQ selected sources for review based on two criteria: 1) whether the sum of emissions of nitrogen oxides (NOx) and sulfur dioxide (SO2), based on the 2014-2017 average of emissions, exceeded 100 tons per year (tpy), and 2) for those facilities that met the first cutoff, MDEQ then focused on those facilities with a “Q/d” value (i.e., total of NOx + SO2 emissions in tpy divided by distance to nearest Class I area in kilometers) greater than or equal to 4.\(^7\) Using these criteria, MDEQ identified seventeen facilities for which it required four-factor analyses of regional haze controls.\(^8\)

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.\(^9\) 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).


\(^{4}\) 2022 Draft Montana Regional Haze Plan at 294, Table 7-2.

\(^{5}\) Id.

\(^{6}\) 2022 Draft Montana Regional Haze Plan at 48, 258, and 288.

\(^{7}\) Id. at 160.

\(^{8}\) Id. at 161.

\(^{9}\) 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.\textsuperscript{10} 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 controls is generally considered the remaining life of the source.\textsuperscript{11} 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.\textsuperscript{12} 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."\textsuperscript{13}

This report evaluates the four-factor analyses of pollution controls for the following facilities: Colstrip Power Plant, Yellowstone Energy Limited Partnership (YELP) – Yellowstone Power Plant, Colstrip Energy Limited Partnership (CELP) – Rosebud Power Plant, GCC Trident Cement Plant, Ash Grove Cement Plant, ExxonMobil Billings Refinery, CHS Inc. Refinery Laurel, Phillips 66 Co. Billings Refinery, and the Northern Border Pipeline Compressor Station No. 3. This report also addressed another power plant that MDEQ did not evaluate and that has been increasing production as of late – the Hardin Power Plant. In brief, this report finds the following issues with the four-factor analyses for these facilities:

\textsuperscript{11} 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.
\textsuperscript{12} 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 Schaefer 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.
\textsuperscript{13} 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.”).
Talen Montana – Colstrip Units 3 and 4

- MDEQ used an unjustified low 2028 “On the books/On the way” (OTB/OTW) baseline, particularly for NOx emissions.
- MDEQ did not evaluate the top removal efficiencies that could be achieved with SCR or SNCR.
- The SCR analyses assumed urea as reagent, which is more costly than ammonia reagent which is much more commonly used for SCRs installed at electric utility boilers.
- MDEQ used an unjustified retrofit factor, too high of an interest rate, and too short of a life of controls.
- Both SCR and SNCR should be considered as cost effective for Colstrip 3 and 4, with SCR achieving much higher NOx reductions of about 3,100 tons per year per unit.

YELP Yellowstone Power Plant and CELP – Rosebud Power Plant

The issues with the cost effectiveness analyses for these two power plants are largely the same:

- MDEQ used out-of-date EPA Control Cost Manual equations when more recent updates were available.
- MDEQ used difference in inflation factors to escalate costs of control from 2011 dollars, rather than using changes in the Chemical Engineering Plant Cost Index (CEPCI) as recommended by EPA.
- MDEQ did not evaluate a spray dryer absorber (SDA) at the maximum SO2 removal rates it can achieve.
- MDEQ should have evaluated the use of NID™ circulating dry scrubber as a control option, due to its high SO2 removal efficiency, integrated baghouse, low water usage, and compact footprint.
- MDEQ took into account costs to replace baghouse for SO2 controls evaluated, without justifying that the existing baghouse could not work with SO2 controls.
- MDEQ used too high of an interest rate and too short of a useful life of controls.
- MDEQ overestimated the amount of and costs for reagent for the evaluation of SNCR.
- Installation of a spray dryer absorber, even with the cost to replace the baghouse, should be considered cost-effective for the YELP Yellowstone Power Plant and would reduce SO2 emissions by 1,386 tons per year from the facility.
- Installation of a spray dryer absorber, even with the cost to replace the baghouse, should be considered cost-effective for the CELP Rosebud Power Plant and would reduce SO2 emissions by 985 tons per year from the facility.
- Installation of selective noncatalytic reduction (SNCR) should also be considered cost-effective and would reduce NOx by at least 202 tons per year from the Yellowstone Power Plant and by at least 446 tons per year from the Rosebud Power Plant.

GCC Trident Cement Plant

- MDEQ proposes a higher 2028 NOx baseline, claiming that historical emissions are not indicative of what will be achievable for the long term for the plant, even though SNCR has been installed at the plant to meet best available retrofit technology (BART). MDEQ must clarify what formed the basis of the 2028 NOx baseline emissions, particularly if GCC is planning on requesting a relaxation in the NOx BART limit (which was already relaxed once in 2017).
• MDEQ should have evaluated the use of a ceramic catalytic filtration system at the GCC Cement kiln’s existing baghouse, which can achieve 90%+ NOx reductions. A recent evaluation of ceramic catalytic filtration bags as a replacement for bags at an existing baghouse at a cement kiln found the controls to be very cost effective. These controls could reduce NOx by 1,004 tons per year from 2028 projections.
• MDEQ also should not have rejected SCR as technically infeasible, as it has been used at two other cement kilns in the U.S. as a NOx control.

Ash Grove Cement Plant

• MDEQ should have evaluated the use of a ceramic catalytic filtration system at the GCC Cement kiln’s existing baghouse, which can achieve 90%+ NOx reductions. A recent evaluation of ceramic catalytic filtration bags as a replacement for bags at an existing baghouse cement kiln found the controls to be very cost effective. These controls could reduce NOx by 785 tons per year from 2028 projections.
• MDEQ also should not have rejected SCR as technically infeasible, as it has been used at two other cement kilns in the U.S. as a NOx control.
• In addition, MDEQ must evaluate setting a lower SO2 limit for the Ash Grove kiln that reflects the capabilities of semi-dry scrubbing, as MDEQ admits that the facility’s SO2 emissions are well below the currently applicable SO2 limit for the kiln.

Refineries (ExxonMobil, CHS Laurel, and Phillips 66 Billings)

• MDEQ only required evaluation of NOx controls for a few emission units at each refinery. Each of these refineries has many combustion sources that should have been considered for controls. Cost-effective NOx controls are available even for small heaters.
• SNCR was not consistently evaluated as a NOx control option, with no explanation as to why.
• Costs were overstated by flaws such as assuming too much reagent needed, assuming urea as a reagent for SCR when aqueous ammonia is less expensive, assuming too low of an efficiency of SCR, assuming too short of a life of controls, and assuming too high of an interest rate.
• Revised cost effectiveness analyses addressing primarily the interest rate and life of controls show that SCR should be considered cost effective at several units that MDEQ evaluated, including Units KC0B, F-1/F-401, and F-551 at the ExxonMobil Billings Refinery; the platformer heater at the CHS Refinery Laurel; and Boilers No. 1 and 2 at the Phillips 66 Billings Refinery.
• MDEQ must identify and include enforceable requirements and compliance schedules for the assumed 20% reductions in SO2 emissions from the main refinery flare at the CHS Refinery Laurel that it included in its Long Term Strategy.

Northern Border Pipeline Compressor No. 3

MDEQ claims that Compressor No. 3 will operate at much lower operating hours in future years, as compared to historical operation, but MDEQ has not provided any documentation or any indication of an enforceable requirement to support that claim.

Even if the Compressor No. 3 operates far fewer hours, that does not mean a commensurate reduction in NOx emissions, because existing permits allow the unit to operate without its NOx controls (“low NOx lean premixed combustion burner” or “DLE”) up to 750 hours per year and emit NOx at a much higher
rate during those periods. Further, if the unit will be starting up and shutting down more frequently, the DLE controls likely cannot be effectively operated during those periods.

- Several issues with the cost analysis for SCR were identified by the Federal Land Managers (FLMs). The FLMs provided revised SCR cost analyses addressing these issues for three levels of operating capacity factor of the Compressor No. 3 and showed that SCR should be considered cost effective even if the unit operates as few as 4,788 hours/year.
- If it can be adequately documented that future operations of the compressor turbine will be at much lower levels of operating hours and capacity than the unit has been historically operated at, then MDEQ must consider other NOx control options for the compressor turbine.
- At the minimum, MDEQ should limit the operation of the combustion turbine in non-DLE mode to the maximum extent practicable through increased restrictions on non-DLE mode operation.

II. General Comments on Evaluation of Pollution Controls and Cost Effectiveness Analyses

A. MDEQ Has Not Defined a Cost Effectiveness Threshold and Thus Has Not Clearly Defined a Reasoned Basis for Rejecting the Adoption of Additional Regional Haze Controls for the Second Planning Period

MDEQ did not provide a reasonable justification for rejecting effective regional haze controls based on their cost. MDEQ found that additional controls, other than the source shutdowns/retirements or the slight emission decreases” that were already occurring due to other requirements or that were already planned for by facilities, were not necessary for its Long Term Strategy.\textsuperscript{14} MDEQ did not define any cost effectiveness threshold or other objective standard to decide whether the controls evaluated were cost effective. Instead, MDEQ discounted cost-effective controls , without definitively explaining why. For example, for the Weyerhaeuser Columbia Falls’ evaluation of staged combustion to reduce NOx from its Line 1 dryers by 76 tons per year at a cost of $4,751/ton, MDEQ states “[w]hile this cost is not considered excessive, it is above the cost currently used by Montana for the second planning period.”\textsuperscript{15} Yet, MDEQ did not establish what cost is currently being used by MDEQ for the second planning period. Indeed, in its evaluation of SO2 controls for the YELP-Yellowstone Power Plant, which were as low as $5,420/ton to reduce SO2 by 1,386 tons per year, MDEQ refers to the costs as “moderate.”\textsuperscript{16} MDEQ also states that it “did not set a threshold for cost-effectiveness for RH planning,” and it seems to indicate that it is relying on cost-effectiveness benchmarks required for best available control technology (BACT) reviews, stating that “these costs are higher than BACT level cost per ton values at recently permitted units.”\textsuperscript{17} But MDEQ did not identify the cost per ton levels or the recently permitted

\textsuperscript{14} 2022 Draft Montana Regional Haze Plan at 310.
\textsuperscript{15} Id. at 194.
\textsuperscript{16} Id. at 215.
\textsuperscript{17} Id.
units it was referring to. For the same YELP facility, MDEQ dismissed the control of selective non-catalytic reduction (SNCR) that would reduce NOx by 202 tons per year at a cost effectiveness of $2,954/ton, stating that the costs of NOx reductions “are considered moderate” and that “[n]o additional NOx control is required for the second planning period.”18 MDEQ rejected controls at the CELP-Rosebud power plant for similar reasons, and referred to the cost effectiveness of $1,527/ton for SNCR to reduce NOx by 202 tons per year from the Rosebud plant as “moderate.”19 States are required to set forth a reasoned basis for decisions to require or not require controls to make reasonable progress towards the national visibility goal.20 Yet, MDEQ has not clearly stated or explained a reasoned basis for its decisions not to require any additional controls that should be considered cost effective at the sources evaluated for this regional haze plan, other than the source shutdowns and other reductions that were already occurring or planned for.

B. Interest Rate and Amortization Periods

MDEQ has assumed an interest rate of 5.25% in amortizing capital costs of controls in its four-factor analyses, claiming it was the bank prime rate at the time of the initial four-factor analyses.21 EPA’s Control Cost Manual recommends the use of the bank prime interest rate for amortizing capital costs.22 The current bank prime rate is much lower. This report uses an interest rate of 3.25%, which has been the bank prime lending rate since March of 2020.23

MDEQ also allowed facilities to use a 20-year amortization period for pollution control cost effectiveness calculations, despite EPA and the Federal Land Managers (FLMs) informing MDEQ that EPA had provided justification for a 30-year life of controls to be assumed.24 In discussing this issue in its draft regional haze plan, MDEQ provided example annualized capital costs for various interest rates and both 20- and 30-year amortization periods to justify its decision to not revise company’s cost analyses to reflect the current bank prime interest rate and a 30-year life of pollution controls. MDEQ states “[g]iven the four-factor analysis are likely to only estimate capital costs within plus or minus 30 percent, the difference in interest rates and amortization factors does not merit changing four-factor submittals by facilities.”25 However, MDEQ’s example costs show that use of a 5.25% interest rate that is 2% higher than the current bank prime rate and use of a 20-year life rather than a 30-year life for certain pollution controls like selective catalytic reduction (SCR) and flue gas desulfurization (FGD) will result in annualized capital costs that are 54% higher than annualized capital costs using the much more appropriate current bank prime interest rate and the 30-year pollution control life that has been justified by EPA and in practice. Specifically, MDEQ shows that, for a pollution control costing $2,000,000, the annualized capital costs

18 Id. at 221.
19 Id. at 234.
21 2022 Draft Montana Regional Haze Plan at 176.
23 See https://fred.stlouisfed.org/series/DPRIME (last accessed March 17, 2022).
25 Id. at 175.
assuming a 2% lower interest rate of 3.5% and a 30-year amortization would be $108,743, whereas the annualized capital costs assuming a 5.5% interest rate and a 20-year amortization period would be $167,359 – which is 54% higher.\footnote{Id. at 175-176.} Thus, MDEQ’s claim that its use of an interest rate that is 2% higher than the current bank prime interest rate and an amortization period that is 10 years shorter would not impact costs by more than 30% is incorrect.

Further, given that other states and facilities have been using the current bank prime interest rate of 3.25% and a 30-year life of controls for SCR and FGD evaluations, MDEQ’s use of a higher interest rate and a shorter pollution control amortization period effectively allows Montana sources a much higher cost effectiveness threshold than similar sources being evaluated in nearby states. MDEQ has not provided any rational justification for its approach.

It is not difficult to revise cost effectiveness estimates to reflect a lower interest rate. EPA’s Control Cost Manual provides the following equation to calculate the capital recovery factor (CRF), which is used to determine annualized capital costs of a pollution control, based on the assumed interest rate and amortization period (i.e., life of the controls being assumed):

\[
\text{CRF} = \frac{i (1+i)^n}{(1+i)^n - 1}
\]


Revising a company’s cost effectiveness calculations to reflect a lower interest rate simply requires calculating the CRF for the appropriate interest rate and life of pollution controls and multiplying the capital costs of the control by the revised CRF. That revised annualized capital cost is then added to the annual operational and maintenance costs, and the total annual costs are divided by the annual tons of pollutants reduced by the control to get a revised cost effectiveness at a lower interest rate. This report will provide those revised cost effectiveness numbers reflective of the current 3.25% interest rate and appropriate, longer lifetimes of pollution controls.
III. Analysis of Controls for Coal-Fired Power Plants in Montana

A. Talen Montana – Colstrip Units 3 and 4

The Colstrip Power Plant consists of four units. Units 1 and 2 were required to shut down by July 1, 2022 based on a Consent Decree with Sierra Club.\(^{28}\) The units were shut down earlier than the July 2022 date, in January 2020.\(^{29}\) The most recent Title V permit for the Colstrip facility was issued on February 4, 2021, which incorporated the requirements of the Consent Decree including the requirement for Units 1 and 2 to permanently cease operation of Colstrip Units 1 and 2 on or before July 1, 2022.\(^{30}\) MDEQ should incorporate the facility’s Title V Permit requirement to cease operation of Colstrip Units 1 and 2 in the Regional Haze SIP to ensure it is federally enforceable.

Colstrip Units 3 and 4 are tangentially-fired boilers burning subbituminous coal, and each has generating capacity of 805 megawatts (MW).\(^{31}\) MDEQ states that both units “operate at very high rates throughout the year providing baseload power for Montana and the Northwest.”\(^{32}\) Colstrip Units 3 and 4 are collectively ranked the highest in terms of NOx and SO2 emissions of the sources considered by MDEQ in its second round regional haze plan, and these units rank second in terms of “Q/d” value for sources considered for control by MDEQ.\(^{33}\) The National Parks Conservation Association analysis of visibility impairing sources ranks the Colstrip units as the highest in Montana in terms of cumulative Q/d ranking.\(^{34}\)

MDEQ assumed baseline emissions from Colstrip Units 3 and 4 that reflect the average emissions over 2014-2016. MDEQ did not use 2018 emissions because of PM compliance issues and associated downtime and lower capacity factors during the summer of 2018.\(^{35}\) However, for its 2028 “on the books/on the way (OTB/OTW) emissions projections, MDEQ assumed lower emissions for NOx than the 2014-2016 emissions and slightly lower emissions for SO2.\(^{36}\) The lower 2028 emissions apparently reflect Talen’s installation of Smart Burn controls at Unit 3 and at Unit 4.\(^{37}\) MDEQ states that Talen installed Smart Burn at Colstrip Unit 3 in 2017\(^{38}\) and at Colstrip Unit 4 in 2016.\(^{39}\)

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29 Montana Regional Haze Implementation Plan, Second Implementation Period, February 3, 2021, Appendix D.
31 2022 Draft Montana Regional Haze Plan at 180.
32 Id.
33 Id. at 161.
35 2022 Draft Montana Regional Haze Plan at 180.
36 Id. (Table 6-4) and at 184 (Table 6-8).
37 Id. at 181.
38 Id.
A comparison of annual data for Colstrip Unit 3 shows that 2014 was actually the lowest period of MW-hours generated and annual heat input of the past eight years, including 2018. This is demonstrated in the table below.

Table 1. Colstrip Unit 3 and 4 Gross Load, Heat Input, NOx and SO2 Emissions, 2014-2021

<table>
<thead>
<tr>
<th>Year</th>
<th>Annual Gross Load, MW-hr</th>
<th>Annual Heat Input, MMBtu/yr</th>
<th>Annual NOx, tons per year</th>
<th>Annual SO2, tons per year</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Colstrip Unit 3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>5,006,381</td>
<td>50,849,819</td>
<td>4,093</td>
<td>2,207</td>
</tr>
<tr>
<td>2015</td>
<td>6,116,257</td>
<td>60,945,402</td>
<td>5,053</td>
<td>2,903</td>
</tr>
<tr>
<td>2016</td>
<td>5,633,089</td>
<td>56,201,471</td>
<td>4,505</td>
<td>2,603</td>
</tr>
<tr>
<td>2017</td>
<td>5,029,733</td>
<td>49,370,891</td>
<td>3,753</td>
<td>2,280</td>
</tr>
<tr>
<td>2018</td>
<td>5,341,894</td>
<td>52,837,575</td>
<td>4,081</td>
<td>2,291</td>
</tr>
<tr>
<td>2019</td>
<td>5,706,929</td>
<td>55,260,212</td>
<td>4,230</td>
<td>2,549</td>
</tr>
<tr>
<td>2020</td>
<td>5,166,196</td>
<td>49,603,092</td>
<td>3,508</td>
<td>1,927</td>
</tr>
<tr>
<td>2021</td>
<td>5,029,808</td>
<td>49,544,663</td>
<td>3,592</td>
<td>1,972</td>
</tr>
<tr>
<td>Avg 2014-2016</td>
<td>5,585,242</td>
<td>55,998,897</td>
<td>4,550</td>
<td>2,571</td>
</tr>
<tr>
<td>Avg 2019-2021</td>
<td>5,300,978</td>
<td>51,469,322</td>
<td>3,777</td>
<td>2,149</td>
</tr>
<tr>
<td></td>
<td>Colstrip Unit 4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>5,551,215</td>
<td>56,115,654</td>
<td>4,592</td>
<td>2,474</td>
</tr>
<tr>
<td>2015</td>
<td>6,170,099</td>
<td>62,221,139</td>
<td>5,160</td>
<td>2,864</td>
</tr>
<tr>
<td>2016</td>
<td>5,118,577</td>
<td>50,269,533</td>
<td>3,817</td>
<td>2,328</td>
</tr>
<tr>
<td>2017</td>
<td>5,705,121</td>
<td>54,083,267</td>
<td>4,195</td>
<td>2,382</td>
</tr>
<tr>
<td>2018</td>
<td>4,990,676</td>
<td>47,365,590</td>
<td>3,853</td>
<td>2,022</td>
</tr>
<tr>
<td>2019</td>
<td>5,352,510</td>
<td>53,528,688</td>
<td>3,991</td>
<td>2,389</td>
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<tr>
<td>2020</td>
<td>3,698,549</td>
<td>37,194,258</td>
<td>2,758</td>
<td>1,569</td>
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<tr>
<td>2021</td>
<td>5,977,999</td>
<td>55,901,055</td>
<td>4,219</td>
<td>2,431</td>
</tr>
<tr>
<td>Avg 2014-2016</td>
<td>5,613,297</td>
<td>56,202,108</td>
<td>4,523</td>
<td>2,555</td>
</tr>
<tr>
<td>Avg 2019-2021</td>
<td>5,009,686</td>
<td>48,874,667</td>
<td>3,656</td>
<td>2,130</td>
</tr>
</tbody>
</table>

Despite finding that 2014-2016 was a representative baseline period, MDEQ’s projected 2028 emissions of NOx and SO2 were lower than the 2014-2016 average NOx and SO2 emissions at each unit. This is shown in Table 2 below.

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Data from EPA’s Air Markets Program Database, at https://ampd.epa.gov/ampd/
Table 2. Comparison of MDEQ’s Assumed 2028 NOx and SO2 Emissions to its 2014-2016 Baseline Emissions for Colstrip Units 1 and 2.  

<table>
<thead>
<tr>
<th>Colstrip Unit</th>
<th>2014-2016 Average NOx, tons per year</th>
<th>Assumed 2028 NOx, tons per year</th>
<th>2014-2016 Average SO2, tons per year</th>
<th>Assumed 2028 SO2, tons per year</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>4,550</td>
<td>3,833</td>
<td>2,571</td>
<td>2,350</td>
</tr>
<tr>
<td>4</td>
<td>4,523</td>
<td>3,833</td>
<td>2,555</td>
<td>2,350</td>
</tr>
</tbody>
</table>

MDEQ did not provide details as to how the 3,833 tons per year of NOx for projected 2028 emissions was calculated other than to say “[t]he incorporation of SmartBurn technology is the primary reason why the 2028 OTB/OTW NOx estimate is below the 2014-2016 Representative Baseline.” It is assumed that the average annual heat input from the 2014-2016 representative baseline period was used with NOx and SO2 emission factors. Thus, one can calculate the assumed annual average NOx emission rate in lb/MMBtu for the 2028 projected emissions. That analysis shows that MDEQ assumed a NOx emission factor that is lower than has been achieved at Colstrip Units 3 and 4 since the SmartBurn technology was installed in 2017 and 2016, respectively, as shown in the table below.

Table 3. Comparison of Actual Annual NOx Emission Rates at Colstrip Units 3 and 4 after SmartBurn Installation To the 2028 NOx Emission Factor that MDEQ Appears to Have Relyied on for 2028 Emissions

<table>
<thead>
<tr>
<th>Year</th>
<th>Colstrip Unit 3 Annual NOx Rate After SmartBurn Installed, lb/MMBtu</th>
<th>Colstrip Unit 3 NOx Emission Factor that Projected 2028 Emissions Reflects, lb/MMBtu</th>
<th>Colstrip Unit 4 Annual NOx Rate After SmartBurn Installed, lb/MMBtu</th>
<th>Colstrip Unit 4 NOx Emission Factor that Projected 2028 Emissions Reflects, lb/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>------------------------</td>
<td>0.137</td>
<td>0.155</td>
<td>0.136</td>
</tr>
<tr>
<td>2018</td>
<td>0.154</td>
<td>0.149</td>
<td>0.163</td>
<td>0.148</td>
</tr>
<tr>
<td>2019</td>
<td>0.153</td>
<td>0.148</td>
<td>0.151</td>
<td>0.151</td>
</tr>
<tr>
<td>2020</td>
<td>0.141</td>
<td>0.148</td>
<td>0.151</td>
<td>0.151</td>
</tr>
<tr>
<td>2021</td>
<td>0.145</td>
<td>0.148</td>
<td>0.151</td>
<td>0.151</td>
</tr>
</tbody>
</table>

\[ a \] Calculated based on annual NOx emissions in tons per year divided by annual heat input in MMBtu/year, as reported to EPA’s Air Markets Program Database.

\[ b \] Calculated based on projected 2028 NOx emissions of 3,833 tons per year divided by 2014-2017 annual average heat input, MMBtu/year, as reported to EPA’s Air Markets Program Database.

The above table demonstrates that MDEQ assumed a level of NOx control with SmartBurn that has not been demonstrated in practice at either Colstrip Unit 3 or Colstrip Unit 4.

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41 See above table for 2014-2016 average emissions and see Tables 6-4 and 6-8 of 2022 Montana Regional Haze Plan for Assumed 2028 Emissions for Colstrip Units 3 and 4.

42 2022 Montana Regional Haze Plan at 180.
SmartBurn technology is not a very well-known NOx control technology. It is notable that MDEQ does not list SmartBurn as an available control in its general list of NOx control technologies that were evaluated in the four-factor analyses for its facilities.\textsuperscript{43} Neither MDEQ nor Talen have described the SmartBurn technology and how it works to reduce NOx. According to the SmartBurn\textsuperscript{®} company’s brochure, it appears it is a combustion optimization evaluation:

*Using our Applied Computational Modeling (ACM) expertise, we employ millions of partial differential equations to replicate and validate your boilers’ unique combustion properties. ACM allows us to perform root-cause analysis and also provides predictive capability to understand how your boiler will perform under varying conditions, with alternative fuels or potential enhancement modifications.*

SmartBurn\textsuperscript{®} Knowledge Makes Power, Brochure, available at https://www.smartburn.com/. While the company’s brochure does indicate lowered NOx emission rates with the technology, it appears to be dependent on site-specific criteria.

Colstrip Unit 3 and 4’s annual NOx emission rate did appear to decrease after SmartBurn was installed by about 7-10% to levels averaging at 0.147 lb/MMBtu at Colstrip Unit 3 and 0.150 lb/MMBtu at Colstrip Unit 4 on an annual basis. However, the apparent NOx emission factors used by MDEQ to project 2028 NOx emissions reflect an assumed 15-16% reduction in annual average emission rates with SmartBurn, and there is nothing in the record to support such an assumption, particularly considering past performance of this technology at Colstrip.

Moreover, MDEQ’s assumed NOx emissions reductions with SmartBurn are inconsistent with EPA’s 2019 regional haze guidance. That guidance states that, generally, the 2028 projected emissions should be based on emissions over a representative historical period. The guidance identifies narrow circumstances under which it is justified to project 2028 emissions that significantly differ from historical emissions: 1) enforceable requirements, and 2) a documented commitment and verifiable basis for participating in energy efficiency, renewable energy, or similar programs.\textsuperscript{44} To be consistent with EPA’s guidance, MDEQ must identify an enforceable requirement that underlies the assumed NOx emission factor for the 2028 emission projections from Colstrip Units 3 and 4. While the Title V operating permit identifies a “Smartburn\textsuperscript{®} Low NOx combustion system” as among the pollution controls associated with Colstrip Units 3 and 4 (along with Wet Venturi Scrubber, advanced low NOx firing and digital controls for NOx control (Alstom LNCFS III\textsuperscript{®} System),”\textsuperscript{45} the permit does require operation of a Smartburn\textsuperscript{®} Low NOx combustion system. Instead, the permit conditions specifically require operation of “digital controls, low-NOx burners and overfire air” on Units 3 and 4 “sufficient to meet the emission limits in Section III.C.14.”\textsuperscript{46} The lowest NOx emission limits of Section III.C.14. of the permit are: 0.18 lb/MMBtu, 30-day rolling average, weighted average for each hour that either Unit 3 or 4 is operating above 400 gross MW, and 0.30 lb/MMBtu, 30-day rolling average, weighted average for each hour that each unit is

\textsuperscript{43} Montana Regional Haze Plan at 176-178.
\textsuperscript{44} EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 17.
\textsuperscript{45} See Final Title V Operating Permit #OP0513-17, Talen Montana, LLC, Colstrip Steam Electric Station, February 4, 2021, at 2 (Section II), Ex. 1 to this report).
\textsuperscript{46} Id. at 23 (Condition III.C.18 and C.19.).
operating at or below 400 gross MW. These limits are still much higher than the NOx emission factor that appears to have been assumed for 2028 OTB/OTW NOx emissions of 0.136 to 0.137 lb/MMBtu, as shown in Table 3 above. Thus, there are not enforceable requirements that would justify assuming 2028 NOx emission rates as low as DEQ apparently assumed to establish the 2028 OTB/OTW NOx emissions for Colstrip Units 3 and 4.

MDEQ’s 2028 SO2 emission projections for Colstrip Units 3 and 4 also reflect an 8-9% reduction in SO2 emissions from the 2014-2016 representative baseline period, as shown in Table 2 above. As with NOx, MDEQ had not provided any justification for a lower SO2 emission rate at Units 3 and 4 in 2028 than it achieved during the baseline period.

1. Evaluation of Pollution Control Upgrades for Colstrip Units 3 and 4

Colstrip Units 3 and 4 have the following SO2 controls: Digital boiler controls, use of low sulfur coal (<1% sulfur) and wet venturi scrubbers with lime injection and also relying on the alkalinity of the fly ash. The scrubbers have no bypass and are designed to achieve 95% control of SO2.

a) SO2 Control Options for Colstrip Units 3 and 4

MDEQ underestimated potential SO2 emissions reductions achievable through regional haze controls. MDEQ states that the 95% control level currently being achieved represents the best control measure available for SO2. That is not correct. A level of SO2 control of 98% -99% is a more justified top level of control for coal-fired boilers equipped with wet scrubbers like Colstrip Units 3 and 4. Given that Colstrip Units 3 and 4 and their SO2 scrubbers were constructed in 1984 and 1986, the existing scrubbers are 36 to 38 years old. Thus, MDEQ should have considered replacement of the existing scrubbers with higher performing scrubbers as one control option, particularly if the existing scrubbers are near the end of their useful lives. In addition, MDEQ should also have evaluated whether scrubber upgrades could improve SO2 removal efficiency at Units 3 and 4.

b) NOx Control Options for Colstrip Units 3 and 4

MDEQ also underestimated potential NOx emissions reductions achievable through regional haze controls. For NOx control, MDEQ states that Colstrip Units 3 and 4 currently have the following controls: low NOx burners, separate overfire air (SOFA), and SmartBurn®. According to MDEQ, current NOx

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47 Id. at 21 (Condition III.C.14).
49 Id.
50 Id. at 181.
52 2022 Draft Montana Regional Haze Plan at 181.
emission rates being achieved are 0.15 lb/MMBtu, and this presumably includes the effect of SmartBurn®.

MDEQ evaluated SCR and selective noncatalytic reduction (SNCR) as available post-combustion NOx controls at Colstrip Units 3 and 4. MDEQ evaluated SCR to achieve a controlled NOx emission rate of 0.06 lb/MMBtu and SNCR to achieve a controlled NOx emission rate of 0.13 lb/MMBtu. Neither of these NOx emission rates reflect the maximum NOx removal capabilities of SCR and SNCR, although this is most evident for SCR as will be discussed below.

(1) Selective Catalytic Reduction at Colstrip Units 3 and 4

MDEQ understated NOx control achievable with SCR. MDEQ assumed that SCR at Colstrip Units 3 and 4 could achieve a 0.06 lb/MMBtu controlled NOx emission rate. However, a 0.06 lb/MMBtu controlled NOx rate at each Colstrip Unit 3 and 4 only reflects 60% NOx control across the SCR from the 0.15 lb/MMBtu current NOx emission rate at each unit with the combustion controls. Yet, SCR systems are routinely designed to achieve 90% or greater NOx control efficiency. Annual average NOx emission rates with SCR, along with existing low NOx burners and overfire air, can be as low as 0.04 lb/MMBtu or even lower.

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 increases 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.

Given that cost-effectiveness is based on annual average costs, it is most appropriate to evaluate the NOx emission reductions achievable on an annual average basis in determining cost effectiveness. There are several EGUs that have achieved NOx emission rates of 0.04 lb/MMBtu or lower on an annual average basis. A review of the lowest-emitting 2020 annual NOx rates at coal-fired EGUs from EPA’s Air Markets Program Database is provided in the table below.

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53 Id.
54 Id. As demonstrated above, the 2019-2021 actual annual NOx rate with these controls including SmartBurn® are somewhat lower at Colstrip Unit 3, which has achieved 0.147 lb/MMBtu on an annual average basis.
55 Id. at 182.
57 Id.
58 Id. at pdf page 13.
Table 4. Coal-Fired EGUs Equipped with SCR Emitting 0.04 lb/MMBtu on an Annual Average Basis in 2020

<table>
<thead>
<tr>
<th>Power Plant</th>
<th>Unit</th>
<th>2020 Annual NOx Rate, lb/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>Edgewater</td>
<td>5</td>
<td>0.04</td>
</tr>
<tr>
<td>Trimble County</td>
<td>2</td>
<td>0.04</td>
</tr>
<tr>
<td>J K Spruce</td>
<td>**2</td>
<td>0.04</td>
</tr>
<tr>
<td>Dry Fork</td>
<td>1</td>
<td>0.04</td>
</tr>
<tr>
<td>Jeffrey Energy Center</td>
<td>1</td>
<td>0.04</td>
</tr>
<tr>
<td>E W Brown</td>
<td>3</td>
<td>0.04</td>
</tr>
<tr>
<td>Walter Scott Jr.</td>
<td>4</td>
<td>0.04</td>
</tr>
<tr>
<td>Lansing</td>
<td>4</td>
<td>0.04</td>
</tr>
<tr>
<td>John W Turk Jr</td>
<td>S01</td>
<td>0.04</td>
</tr>
<tr>
<td>W A Parish</td>
<td>WAP7</td>
<td>0.04</td>
</tr>
<tr>
<td>Sandy Creek Energy Station</td>
<td>S01</td>
<td>0.04</td>
</tr>
</tbody>
</table>

In its recent 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. However, in its response to comments on its initial NOx BART finding for the San Juan Generating Station, EPA found significant support in actual emissions data for its finding that a 0.05 lb/MMBtu NOx limit was achievable on a 30-boiler operating day average basis, including a study that identified 25 units that are achieving NOx emission rates less than 0.05 lb/MMBtu on an hourly basis. EPA also cited to NOx emission rates at Seminole Units 1 and 2 (achieving 0.04 lb/MMBtu), Morgantown Units 1 and 2 (achieving 0.043 to 0.054 lb/MMBtu), Trimble Unit 1 (achieving 0.032 lb/MMBtu), as well as the Mountaineer plant and Cliffside Unit 5. EPA also analyzed emissions data for the lowest NOx emitting units to calculate rolling 30-day averages (on both a calendar year basis and on a 30-boiler operating day basis). EPA found several units emitting NOx at or below 0.05 lb/MMBtu, including Havana Unit 9, Parish Unit 7, and Parish Unit 8.

All of this long term, actual emissions data for units equipped with SCR shows that those units with unit-specific emission limits that are more closely linked to the capabilities of the unit’s NOx pollution control equipment are achieving substantially lower NOx emission rates.

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59 Based on data reported to EPA’s Air Markets Program Database for 2020.
61 This NOx BART finding was subsequently replaced with a BART alternative, see 79 Fed. Reg. 60,985-60,993 (Oct. 9, 2014).
63 See U.S. EPA, Complete Response to Comments for NM Regional Haze/Visibility Transport FIP, EPA-R06-OAR-2010-0846-0127, at 53-54 (Ex. 2).
64 Id. at 56 -58.
65 Id.
controls consistently have met NOx rates at 0.04 lb/MMBtu on an annual average basis. For an EGU that is already achieving a low NOx rate before the addition of SCR like Colstrip Units 3 and 4, it is possible that annual average rates as low as 0.03 lb/MMBtu could be achieved. That would reflect 80% control across the SCRs at Colstrip Units 3 and 4. Given that cost-effectiveness is based on annual average costs, it is most appropriate to evaluate the NOx emission reductions achievable on an annual average basis in determining cost effectiveness.

For Colstrip Units 3 and 4, an annual controlled NOx rate with SCR of 0.04 lb/MMBtu reflects an annual NOx reduction efficiency across the SCR of 73.3%, which is readily achievable with SCR. As EPA states in its Control Cost Manual, SCR systems are routinely designed to achieve 90% control. Although EPA acknowledges that the design percent reduction may be less than 90% when the SCR is following combustion controls like low NOx burners, that does not mean that high NOx removal efficiencies cannot be achieved by an SCR following combustion controls.

All major SCR catalyst vendors can and have guaranteed at least 90% efficiency for SCRs burning coals with a wide range of properties. Vendor experience lists indicate that SCRs are routinely designed for 90% NOx control, depending on purchaser specifications. Back in 2003, Sargent and Lundy, an engineering firm that designs SCRs, stated:

> [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.

Thus, for all of these reasons discussed above, MDEQ should have evaluated the cost effectiveness of SCR at Colstrip Units 3 and 4 to meet a NOx emission rate of 0.04 lb/MMBtu on an annual basis.

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67 Id.
68 See, e.g., Haldor Topsoe, SCR Experience List, October 2009 (Ex. 5), Hitachi, NOx Removal Coal Plant Supply List, October 17, 2006 (Ex. 6); Argillon Experience List U.S. Coal Plants (Ex. 7); Hitachi, SCR System and NOx Catalyst Experience, Coal, February 2010 (Ex. 8).
Selective Noncatalytic Reduction (SNCR)

While SCR clearly achieves superior NOx control, MDEQ also understated reductions achievable with SNCR. SNCR involves injecting ammonia or an ammonia-type reactant into the furnace of a coal-fired boiler, similar to SCR, but there is no catalyst to enhance NOx removal as with SCR. In SNCR, the ammonia-type reagent mixes with hot flue gases, and the reagent reacts with NOx in the gas stream to convert some of it to nitrogen gas thereby reducing nitrogen oxides.

EPA describes the SNCR system as follows in its Control Cost Manual:

> The mechanical equipment associated with an SNCR system is simple compared to an SCR, semi-dry FGD, or wet scrubber and thereby requires lower capital costs ($/MMBtu/hr basis). Installation of SNCR equipment requires minimum downtime. Although simple in concept, it is challenging in practice to design an SNCR system that is reliable, economical, and simple to control and that meets other technical, environmental, and regulatory criteria. Practical application of SNCR is limited by the boiler design and operating conditions.70

The NOx reduction efficiency of SNCR can vary greatly. According to EPA, “[t]emperature, residence time, type of NOx reducing agent, reagent injection rate, uncontrolled NOx level, distribution of reagent in the flue gas, and [carbon monoxide and oxygen (CO and O2)] concentrations all affect the reduction efficiency of the SNCR.”71 EPA and states, in evaluating the NOx removal efficiency of SNCR in prior analyses under the regional haze program, have assumed NOx control efficiencies with SNCR at coal-fired EGUs in the range of 15% - 40%.72 MDEQ evaluated SNCR at a NOx emission rate of 0.13 lb/MMBtu, which reflects a NOx reduction efficiency of only 13% from the current 0.15 lb/MMBtu NOx rate being achieved with combustion controls. Talen’s justification for that controlled NOx rate with SNCR was based on a similar analysis of SNCR for Entergy’s White Bluff Units 1 and 2 in Arkansas.73 EPA’s Control Cost Manual indicates that the majority of coal-fired boilers are achieving between 20%-40% NOx control with SNCR, and EPA provided a graph indicating a connection between the NOx inlet emission rate and the control efficiency, with higher NOx removal efficiencies achieved with higher inlet NOx emission rates.74 EPA provided a best fit equation to estimate NOx removal efficiency achievable with SNCR based on NOx inlet level. That equation is:

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71 Id. at 1-1. See also Institute of Clean Air Companies White Paper, Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions, February 2008, at 5, attached as Ex. 10.

72 For example, Colorado assumed, 29.5% NOx removal with SNCR for Comanche Unit 1, 15% NOx removal for SNCR at Craig Units 1, 2, and 3, 37% NOx removal with SNCR at Hayden Unit 1 and 43% removal at Hayden Unit 2, 30% NOx removal at Martin Drake Units 5 and 6 and 28% NOx removal at Martin Drake Unit 7 (77 Fed. Reg. 18066, 18068-72, 18087 (3/26/12).

73 2019 Talen Colstrip Analysis at 5-2.

74 EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, 4/25/2019, at 1-3 to 1-4.
NOx Reduction Efficiency, %, = 22.554*Inlet NOx Rate, lb/MMBtu + 16.725.  

Using the 0.15 lb/MMBtu NOx rate that the LNB/SOFA and SmartBurn® are achieving at Colstrip Units 3 and 4, SNCR should be able to achieve a NOx reduction efficiency of 20%, which equates to a controlled annual average NOx rate 0.12 lb/MMBtu. MDEQ should have evaluated SNCR to achieve 20% NOx removal and a 0.12 lb/MMBtu annual NOx emission rate, rather than only assuming 13% NOx removal with SNCR.

Talen and MDEQ’s cost analyses also relied on other flawed assumptions that further overstate the costs of control. Those include the use of an unjustified and high retrofit factor, the use of an unreasonably high interest rate, and only evaluating SCR using urea as the reagent. In addition, although EPA’s Control Cost Manual chapter for SNCR indicates that SCR would have a useful life of 20 years, there is ample justification to assume the same 30-year life for SNCR as there is for SCR.

Talen used the SCR and SNCR cost calculation spreadsheets that EPA made available in 2019 as part of its revised Control Cost Manual chapters on SCR and SNCR. EPA’s cost spreadsheets allow users to input a retrofit factor but states that the user must document why a retrofit factor of greater than 1.0 is justified. Talen applied a retrofit factor to both the SCR and the SNCR costs of 1.3.  

There are several points to keep in mind regarding the use of retrofit factors. First, it must be noted that EPA’s SCR chapter in its Control Cost Manual already provides for a 25% increase in cost 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.  

Second, the methodology of EPA’s SCR and SNCR cost equations is based on the U.S. EPA Clean Air Markets Division’s Integrated Planning Model (IPM), Version 6. The IPM methodology for SCR costs states that the cost algorithms are based on data collected by the Midwest Ozone Group (MOG) and data compiled for the Utility Air Regulatory Group (UARG), and that the data were “significantly augmented by the [Sargent & Lundy] in-house database of recent SCR projects.”

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75 Id. at Figure 1.1c (on page 1-4).
76 2019 Talen Colstrip Analysis at 5-4.
77 Id.
78 EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 66.
79 See “Read Me” section of SCR and SNCR cost spreadsheets.
Importantly, Sargent & Lundy state that the “current industry trend is to retrofit high dust hot-side SCRs.”\textsuperscript{81} That means the cost data that underlie the algorithms of the SCR cost spreadsheet reflect the costs of installing SCR upstream of PM controls and SO2 scrubbers. The fact that Colstrip Units 3 and 4 have existing venturi scrubbers for PM and SO2 control does not make the units unique in retrofit costs from other SCR retrofits, and thus this information does not justify use of an enhanced retrofit factor for SCR systems at Colstrip. MDEQ should not incorporate any retrofit factor greater than 1 for SCR costs at Colstrip Units 3 and 4.

With respect to SNCR, there is no justification for the application of a retrofit factor. EPA’s Control Cost Manual chapter for SNCR states “estimates based on this methodology typically should not include an additional retrofit factor for existing boilers.”\textsuperscript{82} An SNCR system is a fairly simple NOx control, consisting of a reagent storage and injection system and installation of injection points in the boiler for the reagent. This is presumably why EPA does not find a retrofit factor for SNCR to be warranted. Further, as with SCR, the cost algorithms for SNCR are based on actual costs to retrofit SNCR at existing coal-fired EGUs.\textsuperscript{83} Third, EPA’s SNCR provides for a 16% increase in costs for SNCR retrofit above the cost of SCR at a new greenfield coal-fired boiler in its SNCR cost spreadsheet because EPA’s spreadsheet calls for use of a 0.84 retrofit factor for an SNCR installation at a new facility and a “1” retrofit factor for an average SCR retrofit.\textsuperscript{84} Talen has not provided any justification for applying retrofit factors for SNCR installation at Colstrip Units 3 and 4, and for the reasons described herein, MDEQ should not incorporate any retrofit factors for SNCR.

Talen and MDEQ assumed a 5.5% interest rate in amortizing capital costs of SCR and SNCR.\textsuperscript{85} For the reasons described in Section I.B. above, MDEQ should require use of the current bank prime interest rate in determining annualized capital costs of SCR and SNCR.

Further, Talen assumed urea as the SCR reagent instead of ammonia in costing out SCR for Colstrip Units 3 and 4. Yet, EPA has indicated that 80% of SCR installation at electric utilities use anhydrous and/or aqueous ammonia rather than urea in SCR systems, with price being the primary reason for selecting the less expensive ammonia reagent. Thus, Talen and MDEQ should have evaluated the costs of SCR using ammonia as the reagent. For SNCR, urea is the most common reagent used.

Last, while Talen assumed a 20-year life of SNCR, which is what EPA’s Control Cost Manual chapter and spreadsheet also assume,\textsuperscript{86} there is ample support for assuming a 30-year life of SNCR. EPA SNCR Chapter in its Control Cost Manual states: “As mentioned earlier in this chapter, SNCR control systems began to be installed in Japan in the late 1980’s. Based on data EPA collected from electric utility

\textsuperscript{81} Id.
\textsuperscript{82} EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction at I-26.  
\textsuperscript{85} 2019 Talen Colstrip Analysis at 5-3.  
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. 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, it is reasonable to assume a 30-year life of SNCR for application to Colstrip Units 3 and 4, as well as for SCR.

Talen’s assumptions regarding retrofit factor, interest rate, SCR reagent, and life of SNCR resulted in overstated annual costs of these controls. In addition, Talen and MDEQ underestimated the NOx removal efficiencies that could be reliably achieved with SCR and SNCR at Colstrip Units 3 and 4 which resulted in an underestimate of the NOx reduced with each control. These deficiencies would make these controls appear less cost effective than they actually would be for Colstrip Units 3 and 4. In the next section, revised cost analyses are provided which address these deficiencies.

(4) Revised Cost Effectiveness Analysis for SCR and SNCR at Colstrip Units 3 and 4 Demonstrate that these Controls Should Be Considered Cost Effective.

To address these issues for Colstrip Units 3 and 4, EPA’s cost calculation spreadsheets, made available with its Control Cost Manual Chapters for SNCR and for SCR, were used for the cost effectiveness analyses presented herein. The following provides the other relevant inputs made to the cost modules to estimate NOx control costs for Colstrip Units 3 and 4:

a. **Retrofit Difficulty**: I used a retrofit factor of “1” for the SCR and SNCR cost analyses at Colstrip Units 3 and 4 because Talen has not provided any justification for a higher than typical SCR retrofit.

b. **Unit Size**: 805 MW

c. **Higher heating value of the fuel and sulfur content**: Subbituminous coal, 8,451 Btu/lb, 0.95% sulfur, and 10.17% ash content were used, which is what was used in the Talen analyses.

d. **Actual MW-hours**: I used the average of 2014-2016 gross MW-hours reported for each Colstrip Units 3 and 4 to EPA’s Air Markets Program Database.

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87 EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-54.
e. **Net Heat Rate**: This was calculated from the Gross Load (MW-hours) and the heat input (MMBtu/hr) reported to EPA’s Air Markets Program Database over 2014-2016.

f. **Elevation**: 3250 feet.

g. **Number of Days SCR operates**: 365 days.

h. **Inlet and Outlet NOx rates**: I used the 2019-2021 annual average NOx rates at Colstrip Units 3 and 4 of 0.15 lb/MMBtu, which reflects LNB/SOFA, and the recent SmartBurn® installation. I assumed an outlet NOx rate with SCR of 0.04 lb/MMBtu, and an outlet NOx rate with SNCR of 0.12 lb/MMBtu for the reasons stated above.

i. **Interest rate**: I used an interest rate of 3.25%.

j. **Equipment life**: I used 30 years for both SCR and SNCR.

k. **Other inputs**: I used the defaults for the other cost inputs from EPA’s SCR and SNCR spreadsheets for reagent, fuel costs, catalyst, labor, electricity, and water, and assumed use of 29.4% aqueous ammonia as the SCR reagent and urea as the SNCR reagent.

l. **Baseline emissions**: I calculated baseline emissions based on the average annual heat input over 2014-2016 for each unit, which MDEQ stated was the representative baseline period for the units but multiplied that average annual heat input by the NOx emission factor that reflected the LNB/SOFA and SmartBurn® controls of 0.15 lb/MMBtu.

The following table summarizes the cost effectiveness calculations for these NOx controls at Colstrip Units 3 and 4.

**Table 5. Cost Effectiveness of Post-Combustion NOx Controls at Colstrip Units 3 and 4, Based on 30-Year Life of Controls and the EPA Control Cost Manual Spreadsheets**

<table>
<thead>
<tr>
<th>Colstrip Unit</th>
<th>Control</th>
<th>Annual NOx Rate, lb per MMBtu</th>
<th>Capital Cost (2019$)</th>
<th>O&amp;M Costs</th>
<th>Total Annualized Costs (2019 $)</th>
<th>NOx Reduced from 2028 Baseline, tpy</th>
<th>Cost Effectiveness, $/ton</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>SCR</td>
<td>0.04</td>
<td>$266,332,259</td>
<td>$3,525,668</td>
<td>$17,579,986</td>
<td>3,082</td>
<td>$5,704/ton</td>
</tr>
<tr>
<td>3</td>
<td>SNCR</td>
<td>0.12</td>
<td>$14,505,544</td>
<td>$2,809,569</td>
<td>$3,580,538</td>
<td>841</td>
<td>$4,260/ton</td>
</tr>
<tr>
<td>4</td>
<td>SCR</td>
<td>0.04</td>
<td>$265,673,363</td>
<td>$3,525,472</td>
<td>$17,545,027</td>
<td>3,089</td>
<td>$5,680/ton</td>
</tr>
<tr>
<td>4</td>
<td>SNCR</td>
<td>0.12</td>
<td>$14,495,338</td>
<td>$2,815,175</td>
<td>$3,585,602</td>
<td>842</td>
<td>$4,256/ton</td>
</tr>
</tbody>
</table>

As shown above, SCR would reduce NOx emissions by over 3,080 tons per year at each Colstrip unit at a cost effectiveness of approximately $5,700/ton. SNCR would achieve much lower NOx reductions of about 840 tons per year but is more cost effective at approximately $4,260/ton. These revised costs are much more cost effective than the costs calculated by Talen and MDEQ of $12,858/ton for SCR and $10,234/ton for SNCR. But, as stated above, Talen/MDEQ’s costs are inflated due to using an unjustified estimated average annual heat input.

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90 See SCR and SNCR Cost Manual Spreadsheets for Colstrip Units 3 and 4, attached as Exs. 11, 12, 13, and 14.
1.3 retrofit factor, an unreasonably high interest rate, and an underestimate of the NOx removal capabilities of these controls, among other things. While SNCR is more cost effective, SCR would achieve much greater NOx reductions and the costs of SCR at Colstrip Units 3 and 4 are within the range that other states are planning to identify as cost effective in their regional haze plans for the second implementation period. Arizona identified a cost effectiveness range of $4,000 to $6,500/ton.91 New Mexico’s threshold is $7,000 per ton,92 and Oregon is using $10,000/ton or possibly even higher.93 Washington is using $6,300/ton for Kraft pulp and paper power boilers.94 Oregon has adopted a much higher regional haze cost-effectiveness threshold of $10,000/ton.95 Colorado is also using a cost-effectiveness threshold of $10,000/ton.96 SCR at Colstrip Units 3 and 4 would be considered cost effective under all of these state cost thresholds. Thus, MDEQ should find SCR to be cost effective for Colstrip Units 3 and 4.

(5) Consideration of Time Necessary for Compliance, Energy and Non-Air Environmental Factors of SCR and SNCR, and Remaining Useful Life

While the costs of compliance support regional haze controls for Colstrip Units 3 and 4, the other reasonable progress factors are either neutral or further support such controls. MDEQ states that SCR or SNCR could be implemented within a 3 to 5 year time period and could be operational before 2028.97 Thus, the time necessary for compliance with NOx controls should not be an issue.

MDEQ does raise ammonia slip and the formation of particulate species within the exhaust plume as challenges with use of SNCR and SCR. However, these issues can be addressed and minimized through proper design and operation of the SCR and SNCR to minimize ammonia slip. EPA states that SCR systems commonly operate with less than 2 ppm of ammonia slip.98 With an SNCR, higher levels of ammonia slip tend to occur, given that higher amounts of ammonia reagent need to be injected to achieve NOx control without catalyst. EPA states that utilities with SNCR typically have ammonia slip

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94 See, e.g., Washington Department of Ecology, Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, attached as Ex. 15.
97 2022 Draft Montana Regional Haze Plan at 183
limits with SNCR of 5 to 10 ppm. SCR would have much lower levels of ammonia slip, as well as achieving much higher levels of NOx reduction, compared to SNCR.

MDEQ’s other concerns with SCR controls—i.e., the service life of the catalyst due to fouling and plugging, additional waste streams, and downtime including startup and shutdown events that result in higher short term emissions—are unfounded. EPA’s SCR Control Cost Manual describes SCR catalyst plugging as more of an issue for SCR application to cement plants, and EPA does not identify catalyst plugging as an issue for coal-fired utility boilers. EPA’s SCR Control Cost Manual also discusses use of regenerated catalyst, which not only saves costs, causes less waste products, and improves longevity, but can also allow for removal of physical restrictions such as fly ash plugging. There are also online/in situ options for catalyst cleaning, such as soot blowers and sonic horns. These mechanisms can operate frequently, such as every ten minutes, to prevent accumulation of ash. In addition, the type of catalyst and the catalyst pitch can also be designed to “allow easy passage of ash particles without deposition and ease of cleaning with soot blowers or sonic horns.” Thus, there are design options to address the issues raised by MDEQ with catalyst pluggage.

MDEQ indicated that the remaining useful life of the Colstrip units would be at least 20 years, but they also stated that market conditions and policy decisions could impact the viability of future power operations. Given that those conditions are unknown and speculative at this point, and the units are not subject to an enforceable retirement commitment to justify a shortened life of pollution controls, the remaining useful life of Colstrip Units 3 and 4 should not be an impediment to installation of NOx pollution controls.

As shown in Table 5 above, SCR at Colstrip Units 3 and 4 would be cost effective, with SCR achieving greater than 3,000 tons per year of NOx reductions at each unit at costs of roughly $5,700/ton. SNCR could achieve 840 tons per year of NOx reductions at each Colstrip Unit 3 and 4 at costs of roughly $4,260/ton. Based on MDEQ’s criteria for selecting sources to evaluate for controls in its regional haze plan for the second implementation period, the Colstrip facility is the highest emitter of NOx and has the second highest Q/d value. Given that cost-effective 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, MDEQ should

99 EPA, Control Cost Manual, Section 4, Chapter 1 Selective Non-catalytic Reduction, at 1-19.
100 2022 Draft Montana Regional Haze Plan at 183.
102 Id. at pdf page 18.
103 Id. at pdf pages 18 and 29.
104 Id. at pdf page 29.
105 Id. at pdf page 32.
106 2022 Draft Montana Regional Haze Plan at 183.
107 Id. at 161.
reconsider its proposed action to not require any NOx controls at Colstrip Units 3 and 4 as part of its long term strategy for the second implementation period and impose NOx reduction requirements for Colstrip Units 3 and 4.

B. Yellowstone Energy Limited Partnership – Yellowstone Power Plant

The Yellowstone Energy Limited Partnership (YELP) Yellowstone Power Plant consists of two circulating fluidized bed combustion (CFBC) boilers which are fired by petroleum coke and coker gas from the nearby Exxon refinery. According to YELP’s four-factor analysis, the steam produced by the CFBC boilers goes in part to the Exxon Mobil refinery with the remainder going to generating electricity via a steam turbine.108 The YELP facility is located in Billings, Montana. The two CFBC boilers vent to a single baghouse and single stack. The total design steam production of the facility is 660,000 pounds per hour and the generating capacity is 65 MW.109 The YELP facility is ranked the 6th highest in terms of “Q/d” value for sources considered for control by MDEQ with a Q/d value of 14.86 based on SO2+NOx emissions.110 The National Parks Conservation Association ranks the YELP facility as the second-highest in terms of cumulative Q/d ranking.111

YELP currently controls SO2 emissions using limestone injection in the CFBC boilers, and the units share a baghouse. YELP used the average of 2014-2017 emissions as a representative baseline reflective of 2028 emissions.112 Those NOx and SO2 baseline emissions are as follows:

Table 6. YELP Facility 2028 Baseline Emissions (Average of 2014-2017 Annual Emissions)

<table>
<thead>
<tr>
<th>NOx, tons per year</th>
<th>SO2, tons per year</th>
</tr>
</thead>
<tbody>
<tr>
<td>404.3</td>
<td>1,732</td>
</tr>
</tbody>
</table>

MDEQ states that “YELP provided Montana with a justification for the emissions used in their four-factor analysis” and that “Montana concurred this four-year period was reflective of recent normal operation.”113 YELP provided a graphical representation of historical emissions from 2000 to roughly 2019,114 but the specific emissions for each year was not identified. MDEQ should provide such information into the record, so it can be determined that the selected 2014-2017 period is reasonably representative of 2028 operations and emissions. In particular, MDEQ should provide the most recent years of emissions data from the YELP facility.

Based on available information, as described below, cost-effective pollution controls are available and should be required for YELP.

109 Id.
110 2022 Draft Montana Regional Haze Plan at 161.
112 2022 Draft Montana Regional Haze Plan at 212-213.
113 Id. at 212.
114 2019 YELP Four-Factor Analysis at 18.
1. Evaluation of SO2 Pollution Controls for the YELP Facility

The YELP facility is required to achieve 92% SO2 removal in the circulating fluidized bed boilers under their current permit, although MDEQ states this required level of SO2 control depends “on the fuel fired in the boilers and the total heat input.” MDEQ’s Air Quality Permit Analysis for a September 4, 2020 Air Quality Permit issued for YELP indicates that the combined nominal heat input to the boilers is 911 MMBtu/hour but it can be as high as 1,300 MMBtu/hour on a short term basis. According to the 2020 permit, the plant is allowed to emit 2,476 tons of SO2 per rolling 12-month period, 680 pounds of SO2 per hour maximum, and 620 pounds of SO2 per hour on a 30-day average basis. This last limit is indicated as reflecting 0.777 lb/MMBtu. It is not clear if these limits reflect 92% SO2 removal efficiency.

The YELP facility was evaluated for regional haze controls in EPA’s proposed regional haze SIP for Montana that was initially proposed for public comment in April of 2012. EPA issued the Montana Regional Haze plan for the first implementation period because MDEQ discontinued its efforts to adopt a regional haze plan in 2006. EPA did not propose any additional pollution controls for the YELP boilers in its 2012 Montana regional haze plan.

a) MEDQ Failed to Evaluate All Reasonable SO2 Controls for YELP.

MDEQ and YELP only evaluated three SO2 control technologies for the YELP boilers: hydrated ash reinjection (HAR), spray dryer absorber (SDA), and dry sorbent injection (DSI). MDEQ and YELP eliminated the following controls as technically infeasible: circulating dry scrubsers (CDS) and wet flue gas desulfurization (wet FGD).

With respect to CDS systems, MDEQ stated that CDS systems “result in high particulate loading to the unit’s particulate control device,” that the pressure drop across a fabric filter would be unacceptable” and claimed electrostatic precipitators (ESP)s are generally used for particulate control with CDS systems. However, the Alstom Novel Integrated Desulfurization (NID™) CDS has an integrated baghouse. A NID CDS scrubber has been used as a polishing scrubber on at least three circulating fluidized bed boilers: Seward Units 1 and 2 (2 x 285 MW), Gilbert Unit 3 (300 MW), and Spurlock Unit 4

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115 2022 Draft Montana Regional Haze Plan at 213.
116 See Montana Air Quality Permit # 2650-09 for Yellowstone Energy Limited Partnership, attached Montana Air Quality Permit Analysis at 2 (pdf page 28 of permit), issued September 4, 2020, attached as Ex. 16.
117 Id. at 4, Section II.P.1. of Permit (at pdf page 6).
118 Id.
122 2022 Draft Montana Regional Haze Plan at 214.
123 Id. at 213-214.
124 Id. at 213.
125 See Alstom Brochure, NID™ Flue Gas Desulfurization System for the Power Industry at 3 (Ex. 17).
Circulating dry scrubbers have many benefits including low capital investment and maintenance costs, low power consumption, high SO2 removal and high removal efficiencies of SO3 and hazardous air pollutants. Alstom has installed more than 60 NID™ systems worldwide, and is in the process of installing NID™ systems at three coal-fired power plants in the U.S. which include the Brayton Point Unit 3, Indian River Unit 4, and Homer City Unit 3, and for two units at Homer City power plant. CDS systems can achieve up to 98% SO2 removal, and Sargent & Lundy reports the costs are similar to SDA and “has been the technology of choice in the last four years.” As with dry scrubbers, a circulating dry scrubber not only achieves high SO2 removal efficiencies, but it has multipollutant control capability to reduce acid gases, mercury, heavy metals, dioxins and furans, and fine particulate matter. A circulating dry scrubber has low capital costs, low auxiliary power use, low operational and maintenance cost, and low fresh water consumption. Further, circulating dry scrubbers have a smaller footprint than a wet scrubber.

Thus, for these reasons, MDEQ and YELP should not have eliminated consideration of a CDS from review as a potential SO2 control measure for the YELP boilers.

b) YELP’s SO2 Cost Estimates Overstated Annual Costs and Were Not Sufficiently Documented.

YELP’s cost analyses for the SO2 controls that it did evaluate—HAR, SDA, and DSI—were flawed. These analyses were based on YELP’s cost analyses for these same controls that were submitted to EPA for its first regional haze plan (Round 1) for Montana promulgated in 2012. YELP’s prior SO2 cost analysis was estimated based on the EPA example for acid gas removal provided in its 6th edition (i.e., from January 2002) version of the Control Cost Manual. YELP updated the costs by adjusting 2011 prices to 2019 prices due to inflation, and YELP revised the cost effectiveness analyses to reflect a 20-year life of controls, a 5.5% interest rate, and 2014-2017 average SO2 emissions.

There are several problems with YELP’s and MDEQ’s approach to using YELP’s prior analysis from the first round regional haze plan. First, EPA has published new chapters of the Control Cost Manual in April

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126 Black & Veatch, LG&E/KU – Mill Creek Station, Phase II Air Quality Control Study, March 4, 2011, p. 5-16.
127 See Alstom Brochure, NID™ Flue Gas Desulfurization System for the Power Industry at 4.
130 See Babcock & Wilcox, Circulating Dry Scrubber (CDS) Technology, at 1 (Ex. 18).
131 Id.
132 Id.
133 2019 YELP Four-Factor Analysis at 37.
134 Id.
135 2019 YELP Four-Factor Analysis at 37.
2021 and has made available wet and dry scrubber control cost spreadsheets.\textsuperscript{136} Those cost spreadsheets are based on algorithms from the EPA Air Markets Program Database’s Integrated Planning Model (IPM Version 6).\textsuperscript{137} Thus, there are much more recent tools based on actual retrofit costs of these controls that YELP should have used to re-evaluate costs, rather than to rely on cost equations from EPA’s 2002 Control Cost Manual. Because neither YELP nor MDEQ provided sufficient information on the CFB boilers’ fuel, sulfur content, and operation, there is not sufficient information currently in the record to use EPA’s FGD cost spreadsheet to calculate costs of those controls. MDEQ states that YELP did not use the EPA cost spreadsheets for SCR and SNCR, since YELP’s boilers “are not accurately represented within the spreadsheet calculations” because they are “dual purpose and create steam for the ExxonMobil Billings Refinery as well as power generation.”\textsuperscript{138} While it is true that the SO2 and NOx cost spreadsheets are not specifically set up for boilers that operate in this manner, one could very likely use boiler heat input records and known heat rates for electricity production to estimate the total power production for each YELP boiler, which would enable the spreadsheets to be utilized for the YELP units.

EPA’s Control Cost Manual also cautions against escalating costs more than five years from the original cost analysis because it can lead to inaccuracies in price estimation.\textsuperscript{139} YELP escalated costs over 8 years (2011 to 2019) using inflation cost adjustments that showed a 15% increase in prices from 2011 to 2019.\textsuperscript{140} That increase is much higher than the increase in the Chemical Engineering Plant Cost Index (CEPCI) over that same timeframe. Specifically, from 2011 to 2019, the CEPCI increased from 586 to 607.5, an increase of only 3.7%. These differences in cost factors demonstrate why one should not escalate costs to current dollars that are more than five years old.

MDEQ and YELP only assumed 80% SO2 removal in their evaluation of SDA.\textsuperscript{141} Yet, an SDA can achieve higher levels of SO2 control, even with the CFB boilers achieving 92% control.\textsuperscript{142} MDEQ should have at least evaluated SDA to achieve 85% SO2 removal, which would reflect a combined SO2 removal efficiency of 99%. Such a combined high control efficiency has been proposed and required as best available control technology (BACT) for SO2 from CFB boilers. For example, the Spiritwood Generating Station located in North Dakota is a lignite-fired CFB boiler with limestone injection and a spray dryer following, as well as a baghouse, and the SO2 BACT limit for the unit reflects 98.7% SO2 control.\textsuperscript{143}

\textsuperscript{136} Available at \url{https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution}.


\textsuperscript{138} 2022 Montana Regional Haze Plan at 218.


\textsuperscript{140} 2019 YELP Four-Factor Analysis at 37.

\textsuperscript{141} Montana Regional Haze Plan at 215.

\textsuperscript{142} See EPA. Control Cost Manual, Section 5, Chapter 1, Wet and Dry Scrubbers for Acid Gas Control, April 2021, at 1-12.

\textsuperscript{143} See EPA’s RACT/BACT/LAER Clearinghouse, RBLC ID # ND-0024.
YELP’s detailed cost estimates include costs for new baghouses for each of the three SO2 control options.144 The YELP four-factor analysis does not include support that entirely new baghouses would be required with each SO2 control, other than a reference to a discussion with a vendor some time ago who said that the baghouse design “must be matched with the add-on control systems and its resulting particulate loading.”145 However, no documentation was provided to indicate that there would be a mismatch between the SO2 controls being evaluated and the existing baghouses. The regional haze rules require states to document the technical basis, including in 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). Thus, MDEQ must require YELP to provide more support for any assumption that new redesigned baghouses would be needed with each of these SO2 control options. Further, as stated above, a NID™ CDS scrubber has an integrated baghouse and thus does not require installation of a new baghouse, and such a NID™ scrubber should have a similar cost to an SDA. Thus, if MDEQ finds that there truly would be a need for a new baghouse with these SO2 controls, it should evaluate the use of a NID™ circulating dry scrubber.

YELP’s detailed costs also include costs for sales tax. However, it is likely that Montana has a sales tax exemption for pollution control equipment like many states do, and if so, such costs should not be included.

YELP assumed only a 20-year life of SO2 controls and assumed an unreasonably high 5.5% interest rate. As discussed in Section I.B. above, the current bank prime interest rate should be used to determine annualized capital costs of control. In addition, the SO2 pollution controls should be assumed to have a 30-year life, rather than a 20-year life. EPA’s Control Cost Manual provides ample support for a 30-year life of wet and dry scrubbers.146 DSI should also have a life of at least 30 years. EPA has assumed a 30-year life in both FGD and DSI cost effectiveness evaluations in the first round regional haze plans.147

In the table below, we have revised YELP’s cost estimates for HAR, SDA, and DSI to reflect an interest rate of 3.25% and a 30-year life of controls. Just these two changes alone show that the SO2 controls are more cost effective than indicated in the draft Montana Regional Haze plan.

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144 2019 YELP Four-Factor Analysis, Appendix B, at pdf pages 62, 64, 66, and 67-68.
145 Id. at 30.
Table 7. Revised Cost Effectiveness of SO2 Controls at YELP’s Yellowstone Power Plant Assuming an Interest Rate of 3.25% and a 30-Year Life of Controls (Total for Both Boilers)\(^\text{148}\)

<table>
<thead>
<tr>
<th>SO2 Control</th>
<th>YELP’s Total Capital Investment, 2019 $</th>
<th>Annualized Capital Costs, 2019 $/year</th>
<th>Annual Operating and Maintenance Costs, $/year</th>
<th>Total Annualized Costs, $/year (2019 $)</th>
<th>SO2 Reduced, tons per year</th>
<th>Cost Effectiveness, $/ton</th>
</tr>
</thead>
<tbody>
<tr>
<td>HAR, Baghouses</td>
<td>$35,816,983</td>
<td>$1,887,555</td>
<td>$2,798,359</td>
<td>$4,685,914</td>
<td>866</td>
<td>$5,411/ton</td>
</tr>
<tr>
<td>SDA, Baghouses</td>
<td>$45,276,409</td>
<td>$2,386,067</td>
<td>$3,719,678</td>
<td>$6,105,744</td>
<td>1,386</td>
<td>$4,405/ton</td>
</tr>
<tr>
<td>DSI, Baghouses</td>
<td>$23,446,964</td>
<td>$1,235,655</td>
<td>$3,099,910</td>
<td>$4,335,565</td>
<td>866</td>
<td>$5,006/ton</td>
</tr>
</tbody>
</table>

Changing just the current bank prime interest rate to 3.25% and assuming a 30-year life of controls instead of a 20-year life, the cost effectiveness of all of these SO2 control options is reduced by 14-19% from the cost numbers YELP provided. Either way, the cost of SDA and new baghouses should be considered as reasonable at $4,400/ton as shown above or even at $5,400/ton as calculated by YELP using a higher interest rate and a shorter useful life. These costs are lower than the cost effectiveness thresholds being established for the second round regional haze plans by several states, including Arizona ($4,000 to $6,500/ton\(^\text{149}\)) , New Mexico ($7,000 per ton\(^\text{150}\)) , Oregon ($10,000/ton\(^\text{151}\)) , Washington ($6,300/ton for Kraft pulp and paper power boilers\(^\text{152}\)) , and Colorado ($10,000/ton).\(^\text{153}\) If an upgraded or new baghouse is not required, which very well may not be needed, these SO2 controls will be even more cost effective for the YELP facility. The costs of the baghouses increased the annualized costs of SDA by about one-third, the costs of baghouses reflected close to a doubling of annualized costs of DSI, and the costs of baghouses added about 60% to the annualized costs of HAR.\(^\text{154}\) Thus, if a new

\(^\text{148}\) These cost numbers reflect YELP’s costs for these controls as reported in Table 6-19 of the 2022 Montana Regional Haze Plan at 215, but with the annualized costs revised to reflect a 3.25% interest rate and a 30-year life rather than the 5.5% interest rate and 20-year life assumed by YELP and MDEQ. Note that the annual operating and maintenance costs were not specifically identified in Table 6-19 of the 2022 Montana Regional Haze Plan. Those costs were calculated based on the difference between the Total Annual Cost and the annualized capital costs assuming YELP’s 5.5% interest rate and 20-year life.


\(^\text{152}\) See, e.g., Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, attached as Ex. 15.


\(^\text{154}\) 2019 YELP Four-Factor Analysis, Appendix B, at pdf pages 62, 64, and 66.
baghouse was not required, the costs of SO2 controls would be even more cost effective than shown above. MDEQ should collect more data on the design particulate loading of the existing baghouses before it makes a determination of which SO2 control is the most cost effective for the YELP facility. Assuming that a new baghouse would be required to implement an SDA, that combination of SO2 controls would be the most cost effective – and would reduce the greatest amount of SO2 from the YELP facility at 1,390 tons of SO2 reduced per year.

\[c)\] **Consideration of Time Necessary for Compliance, Energy and Non-Air Quality Environmental Impacts, and Remaining Useful Life.**

The other reasonable progress factors do not justify MDEQ’s decision not to require SO2 emissions reductions from YELP. MDEQ and YELP state that the time to retrofit HAR, SDA, or DSI would take the same amount of time, which would be about one year, and they assume that a boiler outage of two to three months per boiler would be necessary to perform the installation.\(^{155}\) The two to three-month boiler outage time seems like an overstatement for SDA installation, even if a new baghouse was also required. There are many examples of complex pollution control installations done at existing coal-fired EGUs in 6 week outages or even less. For example, Asheville Power Station Unit 1 had a wet FGD retrofit that was tied in over a 2-week outage.\(^{156}\) Asheville Unit 2 had a wet FGD and an SCR tied in during a 6-week outage.\(^{157}\) This was accomplished by activities completed while the units were operating or at earlier planned maintenance outages. Specifically, to accomplish the tie-in of the Asheville Unit 1 FGD within a 2 week outage, “modifications to the existing balance-of-plant systems...were made during a 6-week turbine outage” that started in the year before the scrubber was tied in.\(^{158}\) For the Unit 2 pollution control upgrades, construction started on a new chimney and FGD absorber towers a few weeks before the outage.\(^{159}\) This is one example of many regarding how the retrofit of pollution controls can be timed to coincide with planned outages and minimize construction and tie-in time.

In an undated report by the Northeastern States for Coordinated Air Use Management (NESCAUM), a review of SCR installation experience at several coal-fired EGUs found that SCRs were installed in “roughly a four-week timeframe.”\(^{160}\) NESCAUM states “[i]n many cases, outage times can be minimized by constructing the SCR reactor and necessary ductwork adjacent to the boiler without necessitating a shut down and by installing systems during planned maintenance outages (which are scheduled during periods of low demand).”\(^{161}\)

MDEQ/YELP claimed that the changes in ash properties due to increased calcium sulfates or calcium sulfites “could result in the ash being no longer suitable to be sold for beneficial uses” and that the loss

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155 Montana Regional Haze Plan at 215.
157 [Id. at 1-2.](https://www3.epa.gov/region1/npdes/merrimackstation/pdfs/ar/AR-135.pdf).
158 [Id. at 1.](https://www3.epa.gov/region1/npdes/merrimackstation/pdfs/ar/AR-135.pdf).
159 [Id. at 2.](https://www3.epa.gov/region1/npdes/merrimackstation/pdfs/ar/AR-135.pdf).
160 NESCAUM, Power Companies’ Efforts to Comply with the NOx SIP Call and Section 126, at 8, available at [https://www.nescaum.org/documents/noxsip.pdf/](https://www.nescaum.org/documents/noxsip.pdf/).
161 [Id. at 8.](https://www.nescaum.org/documents/noxsip.pdf/)
of this market would cost YELP approximately $2,300,000 per year at the current ash value and production rates. These are costs that can be taken into account in the cost effectiveness analysis, but MDEQ must require that YELP document the technical basis for this claim. As this is currently written, it is not 1) how much ash is currently sold for beneficial use versus sent to the landfill in an average year, and 2) whether YELP has documented that the loss of the ability to sell ash for beneficial use would be a valid concern equally for all three SO2 control options. If additional ash must be landfilled as a result of the controls, that should be taken into account in the cost effectiveness analysis.

MDEQ also states that another potential impact of SO2 controls could be increased mercury due to mercury content in the limestone feed, which apparently contributed to a violation of the federal Mercury Air Toxics Standard. MDEQ must provide documentation of this claim in the regional haze plan. If the limestone in the CFB is a source of mercury emissions, the same effect may not occur with a lime spray dryer (SDA) installed downstream of the boiler or with HAR or DSI injected in the ductwork exiting the boiler. During combustion, mercury in the fuel (and in this case, in the injected limestone in the CFB boiler) is volatilized in the high temperature region of the boiler, and then the mercury often converts to ionic mercury or particulate mercury. Such volatilization of mercury in the limestone is unlikely to occur downstream of the boiler. Further, YELP could look for different sources of limestone for which this might be less of a concern.

Regarding the remaining useful life of the YELP facility, MDEQ reports that the CFB boilers are not planned for retirement at this time. Thus, a 30-year effective life of controls should be assumed in the cost analyses.

\[d] \textit{Summary – There Are Cost-Effective SO2 Control Options for the YELP CFB Boilers that Should Warrant Adoption of Control Measures as Part of MDEQ’s Long Term Strategy for Achieving Reasonable Progress Towards the National Visibility Goal}\]

As shown in Table 7 above, SDA at the YELP boilers would be cost effective, achieving the almost 1,400 tons per year of SO2 reduction at costs of roughly $4,400/ton. Based on MDEQ’s criteria for selecting sources to evaluate for controls in its regional haze plan for the second implementation period, the YELP facility is the second highest emitter of SO2 and has the sixth highest Q/d value. Given that cost-effective controls exist for these units, MDEQ should reconsider its proposed action to not require any SO2 controls at the YELP boilers as part of its long term strategy for the second implementation period.

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163 \textit{id.} at 216.
165 2022 Montana Regional Haze Plan at 216.
166 \textit{id.} at 161.
2. Evaluation of NOx Pollution Controls for the YELP Facility

NOx controls are also justified for the YELP boiler. The YELP facility currently has no specific NOx controls other than using good combustion practices and the CFB boiler design.167 Neither YELP nor MDEQ provided the YELP facility’s actual NOx emission rate in terms of pounds per million British Thermal Unit heat input (lb/MMBtu), but the NOx emission limits applicable to the facility were provided. Those limits are 0.400 lb/MMBtu and 319 pounds per hour.168 MDEQ states that the typical NOx combustion controls of low excess air, flue gas recirculation, overfire air, and low NOx burners cannot be used on CFB boilers, thus only post-combustion NOx controls were evaluated. Specifically, MDEQ and YELP evaluated SNCR and SCR for the YELP boilers.

a) YELP’s NOx Control Cost Estimates Overstated Costs of those Controls

As with the SO2 control cost analyses, YELP’s cost analyses for SNCR and SCR were based on YELP’s cost analyses for these controls submitted to EPA for its first regional haze plan (Round 1) for Montana promulgated in 2012.169 YELP’s prior NOx cost analysis was based on costs estimated with the help of three consulting firms and also based on the 6th edition (i.e., from January 2002) version of the EPA Control Cost Manual.170 YELP updated the costs by adjusting 2011 prices to 2019 prices due to inflation, and YELP revised the cost effectiveness analyses to reflect a 20-year life of controls, a 5.5% interest rate, and 2014-2017 average NOx emissions.171 EPA has published new chapters of the Control Cost Manual on SCR and on SNCR in 2019 and 2021, respectively, and has made available SCR and SNCR control cost spreadsheets.172 MDEQ states that YELP did not use these spreadsheets since YELP’s boilers “are not accurately represented within the spreadsheet calculations” because they are “dual purpose and create steam for the ExxonMobil Billings Refinery as well as power generation.”173 While it is true that the cost spreadsheets are not specifically set up for boilers that operate in this manner, one could very likely use boiler heat input records and known heat rates for electricity production to estimate the total power production for each YELP boiler, which would enable the spreadsheets to be utilized for the YELP units.

There are several problems with YELP’s and MDEQ’s approach to using YELP’s prior analysis from the first round regional haze plan. First, EPA’s Control Cost Manual cautions against escalating costs more than five years from the original cost analysis because it can lead to inaccuracies in price estimation.174 YELP escalated costs over 8 years (2011 to 2019) using inflation cost adjustments that showed a 15% increase.

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167 2019 YELP Four-Factor Analysis at 31.
168 Id.
169 2022 Montana Regional Haze Plan at 219-220.
170 2019 YELP Four-Factor Analysis at 38.
171 Id. at 39.
173 2022 Montana Regional Haze Plan at 218.
interest in prices from 2011 to 2019. That increase is much higher than the increase in the Chemical Engineering Plant Cost Index (CEPCI) over that same timeframe. Specifically, from 2011 to 2019, the CEPCI increased from 586 to 607.5, an increase of only 3.7%. These differences in cost factors demonstrate why one should not escalate costs to current dollars that are more than five years old.

Second, YELP assumed only a 20-year life of NOx controls and assumed an unreasonably high 5.5% interest rate. As discussed in Section I.B. above, the current bank prime interest rate should be used to determine annualized capital costs of control. In addition, the NOx pollution controls should be assumed to have a 30-year life, rather than a 20-year life. EPA’s Control Cost Manual provides ample support for a 30-year life of SCR. SNCR should also have a life of at least 30 years. As discussed above in Section II.A.1.b)(3), while EPA’s Control Cost Manual chapter on SCNR assumes only a 20-year life of SNCR, there is ample support for assuming a 30-year life of SNCR – including in EPA’s Control Cost Manual Chapter on SNCR. 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 as defining SCR equipment life (and thus the injection lances should not define SNCR equipment life). 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, it is reasonable to assume a 30-year life of SNCR for application to the YELP boilers, as well as for SCR.

YELP assumed a 50% NOx reduction with SNCR using ammonia as the reagent. The EPA’s Control Cost Manual provides support for higher NOx removal efficiencies at fluidized bed boilers. Specifically, EPA has indicated that circulating fluidized and bubbling bed boilers can achieve 76-80% NOx reduction with SNCR. As another comparison, the lignite-fired Spiritwood Generating Station located in North Dakota based its NOx BACT limit on use of SNCR to achieve 58% NOx reduction. In addition, EPA states that refinery CO boilers fired with refinery fuel gas (which makes up part of the YELP boilers fuel) can achieve 60% NOx reduction with a urea-based SNCR. YELP has assumed ammonia would be used,

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175 2019 YELP Four-Factor Analysis at 37.
178 Id. at 1-53 to 1-54.
181 See EPA Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, at 1-2.
182 Great River Energy-Spiritwood Station, Application for a Permit to Construct a Combined Heat and Power Plant (CHP), July 2007, Appendix E at 56 (Appendix E attached as Ex. 19).
183 See EPA Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, at 1-2.
and EPA states that NOx removal efficiencies are typically higher with ammonia than urea.\textsuperscript{184} For these reasons, MDEQ should require YELP to evaluate a higher NOx removal efficiency with SNCR than 50%.

YELP’s SNCR cost analysis shows that a normalized stoichiometric ratio (NSR) of 3.0 was assumed for SNCR.\textsuperscript{185} As EPA states, the NSR “defines the amount of reagent needed to achieve the targeted NOx reduction.”\textsuperscript{186} An NSR of 3.0 to achieve only 50% NOx removal seems very high. EPA’s Control Cost Manual lists an NSR of 3.0 at the top end of typical NSR ratios, and states that “[i]ncreasing the quantity of reagent does not significantly increase the NOx reduction for NSR values over 2.0.”\textsuperscript{187} As the YELP Four-Factor analysis makes clear, the bulk of the cost of SNCR is the cost of the ammonia reagent.\textsuperscript{188} Thus, it is imperative that this be accurately determined.

YELP’s four-factor analysis includes a formula used to calculate the NSR, which is the same formula as in EPA’s SNCR chapter of the Control Cost Manual but it is used when urea is the SNCR reagent.\textsuperscript{189} However, YELP’s analysis assumes ammonia will be the reagent which is more effective at reducing NOx than urea.\textsuperscript{190} Further, the NSR calculation in the YELP report assumed a NOx inlet rate (pre-SNCR rate) of 0.094 lb/MMBtu.\textsuperscript{191} There is no support in the draft regional haze SIP for assuming such a low NOx inlet rate. MDEQ states that the YELP boilers must meet NOx emission limits of 0.400 lb/MMBtu.\textsuperscript{192} If a NOx inlet rate of 0.4 lb/MMBtu is input into the NSR formula used by YELP, the NSR at 50% NOx control is 1.875. Use of a NSR of 1.875 rather than an NSR of 3.0 means that the ammonia reagent costs to achieve 50% NOx reduction should be 62.5% of YELP’s projected annual reagent cost of $470,024/year, which equates to $293,000/year.\textsuperscript{193}

In the table below, we have revised YELP’s cost estimates for SNCR and SCR to reflect an interest rate of 3.25% and a 30-year life of controls. We have also revised the SNCR cost estimates to reflect a reduced amount of ammonia reflective of a NSR of 1.875, by reducing the costs of ammonia down from $470,024/year to $293,000/year. Just these changes alone show that the NOx controls are more cost effective than indicated in the draft Montana Regional Haze plan, with SNCR being the most cost effective control.

\begin{table}[h]
\centering
\begin{tabular}{|l|c|c|}
\hline
Control & Initial Cost & Annual Cost \\
\hline
SNCR & $470,024/year & $293,000/year \\
SCR & $500,000/year & $300,000/year \\
\hline
\end{tabular}
\caption{Cost Estimates for NOx Controls}
\end{table}

\textsuperscript{\textup{184}} Id. at 1-1.
\textsuperscript{\textup{185}} 2019 YELP Four-Factor Analysis, Appendix B at 3 (pdf page 57).
\textsuperscript{\textup{186}} See EPA Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, at 1-17.
\textsuperscript{\textup{187}} Id. at 1-18.
\textsuperscript{\textup{188}} 2019 YELP Four-Factor Analysis, Appendix B, METSO, Economic Evaluation of NOx Control, Yellowstone Energy Limited Partnership, Feb 2011, at 6 (pdf page 75).
\textsuperscript{\textup{189}} See EPA Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, at 1-36 to 1-37.
\textsuperscript{\textup{190}} Id. at 1-1.
\textsuperscript{\textup{191}} 2019 YELP Four-Factor Analysis, Appendix B at 3 (pdf page 57).
\textsuperscript{\textup{192}} 2022 Draft Montana Regional Haze Plan at 216.
\textsuperscript{\textup{193}} Based on the ratio of 1.875/3.0, multiplied by YELP’s estimated cost of reagent of $470,024/year (2019 YELP Four-Factor Analysis, Appendix B at 3 (pdf page 57)). See also EPA Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, at 1-38 (Equation 1.18).
Table 8. Revised Cost Effectiveness of NOx Controls at YELP’s Yellowstone Power Plant Assuming an Interest Rate of 3.25% and a 30-Year Life of Controls (Total for Both Boilers) and Assuming a Lower NSR for Ammonia in the SNCR Costs

<table>
<thead>
<tr>
<th>SO2 Control</th>
<th>YELP’s Total Capital Investment, 2019$</th>
<th>Annualized Capital Costs, 2019 $/year</th>
<th>Annual Operating and Maintenance Costs, $/year</th>
<th>Total Annualized Costs, $/year (2019 $)</th>
<th>SO2 Reduced, tons per year</th>
<th>Cost Effectiveness, $/ton</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCR</td>
<td>$32,460,400</td>
<td>$1,710,663</td>
<td>$1,436,688</td>
<td>$3,147,351</td>
<td>323</td>
<td>$9,744/ton</td>
</tr>
<tr>
<td>SNCR</td>
<td>$1,020,800</td>
<td>$53,796</td>
<td>$334,838</td>
<td>$388,634</td>
<td>202</td>
<td>$1,658/ton</td>
</tr>
</tbody>
</table>

Changing just the interest rate to the current bank prime rate of 3.25% and assuming a 30-year life of SCR instead of a 20-year life, the cost effectiveness of SCR is reduced by 24% from the $12,860/ton cost effectiveness provided by YELP. For SNCR, the cost effectiveness with the interest rate and life of controls, along with the lower NSR ratio, shows the cost effectiveness of SNCR is $1,658/ton, which is 44% more cost-effective (i.e., lower cost) than YELP’s SNCR cost calculation. Indeed, even just accounting for the overestimate of the amount of ammonia reagent but keeping YELP’s 5.5% interest rate and 20-year life of SNCR, the cost effectiveness of SNCR would be $2,081/ton. Either way, the cost of SNCR should be considered reasonable for the YELP boilers to reduce NOx by 50%, even at YELP’s very likely overstated cost of $3,000/ton. These costs are lower than the cost effectiveness thresholds being established for the second round regional haze plans by several states, including Arizona ($4,000 to $6,500/ton<sup>195</sup>), New Mexico ($7,000 per ton<sup>196</sup>), Oregon ($10,000/ton<sup>197</sup>), Washington ($6,300/ton for Kraft pulp and paper power boilers<sup>198</sup>), and Colorado ($10,000/ton).<sup>199</sup> In addition, as indicated in the documentation submitted with YELP’s four-factor analysis, CFB boilers allow for “good penetration and mixing of the ammonia [of an SNCR system] with the flue gas” and the “cyclones promote further mixing of the ammonia and the flue gas because of the flue gas cyclonic action, direction change, and

<sup>194</sup> These cost numbers reflect YELP’s costs for these controls as reported in Table 6-19 of the 2022 Montana Regional Haze Plan at 215, but with the annualized costs revised to reflect a 3.25% interest rate and a 30-year life rather than the 5.5% interest rate and 20-year life assumed by YELP and MDEQ. Note that the annual operating and maintenance costs were not specifically identified in Table 6-19 of the 2022 Montana Regional Haze Plan. Those costs were calculated based on the difference between the Total Annual Cost and the annualized capital costs assuming YELP’s 5.5% interest rate and 20-year life.


<sup>198</sup> See, e.g., Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, attached as Ex. 15.

mixing.” These factors allow SNCR to achieve higher NOx reduction rates at CFB boilers than other boiler types, and thus SNCRs have been commonly installed on CFB boilers to achieve NOx control.

b) Consideration of Time Necessary for Compliance, Energy and Non-Air Quality Environmental Impacts, and Remaining Useful Life

The other reasonable progress factors would not impede installation of cost-effective SNCR control at YELP. The Metso report submitted with YELP’s four-factor analysis states the following: Metso has not observed nor is aware of an increased fouling, decreased pressure part life, or other issues associated with the use of SNCRs. Metso also stated that an SNCR could be installed within 16-24 weeks, and that the tie-in could occur during a normal maintenance outage, stating that the “majority of the system can be installed with the boilers online.” As stated above, MDEQ reports that the CFB boilers are not planned for retirement at this time. Thus, a 30-year effective life of controls should be assumed in the cost analyses.

c) Summary – SNCR is Very Cost Effective for the YELP CFB Boilers and MDEQ Should Require this NOx Control Measures as Part of MDEQ’s Long Term Strategy for Achieving Reasonable Progress Towards the National Visibility Goal

For the reasons provided above, MDEQ should require SNCR installation to reduce NOx from the YELP boilers by at least 50%, as it is a very cost effective control to reduce NOx from the YELP CFB boilers.

C. Colstrip Energy Limited Partnership – Rosebud Power Plant

The Colstrip Energy Limited Partnership (CELP) Rosebud Power Plant is an EGU that burns waste coal from mining operations east of Billings. The EGU uses a CFBC boiler with limestone injection for SO2 control, and the boiler is also equipped with a baghouse for PM control. The capacity of the EGU is 39 MW (net). The CELP facility has a NOx plus SO2 Q/d value of 10.26 based on 2014-2017 average emissions. The facility had the 4th highest annual SO2 emissions and the 5th highest NOx emissions of the sources selected for evaluation by MDEQ.

CELP used the average of 2014-2016 emissions as a representative baseline reflective of 2028 emissions. Those NOx and SO2 baseline emissions are as follows:

201 Id.
202 Id. at 6 (pdf page 75).
203 Id.
204 Id.
205 2022 Draft Montana Regional Haze Plan at 216.
206 Id. at 161.
207 Id. at 212-213.
Table 9. CELP Rosebud Power Plant 2028 Baseline Emissions (Average of 2014-2016 Annual Emissions)\(^{208}\)

<table>
<thead>
<tr>
<th>NOx, tons per year</th>
<th>SO2, tons per year</th>
</tr>
</thead>
<tbody>
<tr>
<td>892.6</td>
<td>1,232.6</td>
</tr>
</tbody>
</table>

1. Evaluation of SO2 Controls for the CELP Rosebud Power Plant

As stated above, the Rosebud Power Plant burns waste coal. There is no information in the four-factor analysis or Montana’s draft regional haze plan that identifies how high the sulfur content of the waste coal typically is. MDEQ states that “[d]epending on the fuel fired in the boiler and the total heat input, CELP must control SO2 between a 70% to 90% reduction per Montana Operating Permit #OP2035-04.”\(^{209}\) It is not clear what SO2 emission limit of the operating permit MDEQ is referring to, as the operating permit does not include an SO2 removal efficiency requirement. MDEQ should identify the permit requirements that ensure this range of SO2 control efficiency.

The CELP Rosebud Power Plant facility was evaluated for regional haze controls in EPA’s proposed regional haze SIP for Montana that was initially proposed for public comment in April of 2012.\(^{210}\) EPA did not propose any additional pollution controls for the YELP boilers in its 2012 Montana regional haze plan.\(^{211}\)

MDEQ and CELP only evaluated three SO2 control technologies for the CELP boiler: HAR, SDA, and DSI.\(^{212}\) MDEQ and CELP eliminated the following controls as technically infeasible: circulating dry scrubbers (CDS) and wet FGD.\(^{213}\)

With respect to CDS systems, MDEQ made the same claim that it did with the YELP facility – i.e., that CDS systems “result in high particulate loading to the unit’s particulate control device,” that the pressure drop across a fabric filter would be unacceptable,” and claimed electrostatic precipitators (ESPs) are generally used for particulate control with CDS systems.\(^{214}\) However, as previously discussed, the Alstom NID™ CDS has an integrated baghouse.\(^{215}\) Circulating dry scrubbers have many benefits including: low capital investment and maintenance costs, low power consumption, high SO2 removal and high removal efficiencies of SO3 and hazardous air pollutants.\(^{216}\) CDS systems can achieve up to 98% SO2 removal, and Sargent & Lundy reports the costs are similar to SDA and “has been the technology of choice in the last four years.”\(^{217}\) As with dry scrubbers, a circulating dry scrubber not only

\(^{208}\) Id. at 227-228.
\(^{209}\) Id. at 228.
\(^{211}\) Id.
\(^{212}\) Montana Regional Haze Plan at 229-230.
\(^{213}\) Id. at 229-230.
\(^{214}\) Id. at 228-229.
\(^{215}\) See Alstom Brochure, NID™ Flue Gas Desulfurization System for the Power Industry at 3 (Ex. 17).
\(^{216}\) See Alstom Brochure, NID™ Flue Gas Desulfurization System for the Power Industry at 4.
achieves high SO2 removal efficiencies, but it has multipollutant control capability to reduce acid gases, mercury, heavy metals, dioxins and furans, and fine particulate matter. A circulating dry scrubber has low capital costs, low auxiliary power use, low operational and maintenance cost, and low fresh water consumption. Further, circulating dry scrubbers have a smaller footprint than a wet scrubber.

The multi-pollutant control capability of a NID™ CDS could be very important for the Rosebud Power Plant, as this plant is required to meet a mercury BACT limit of 0.9 lb/TBtu, which reflects about 92%-96% mercury control, and the plant is currently using sorbent injection to meet that limit. The installation of a NID™ scrubber to meet regional haze requirements could improve mercury control and reduce or eliminate the current costs for sorbent injection to achieve the 0.9 lb/TBtu mercury limit applicable to the Rosebud plant.

For all of these reasons, MDEQ and YELP should not have eliminated consideration of a CDS from review as a potential SO2 control measure for the Rosebud plant.

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a) CELP’s SO2 Control Cost Estimates Overstated Annual Costs and Were Not Sufficiently Documented

CELP’s cost analyses for the SO2 controls that it did evaluate, HAR, SDA, and DSI, were based on CELP’s cost analyses for these controls submitted to EPA for its first regional haze plan (Round 1) for Montana promulgated in 2012. CELP’s prior SO2 cost analysis was estimated based on the EPA example for acid gas removal provided in its 6th edition (i.e., from January 2002) version of the Control Cost Manual. CELP updated the costs by adjusting 2011 prices to 2019 prices due to inflation, and CELP revised the cost effectiveness analyses to reflect a 20-year life of controls, a 5.5% interest rate, and 2014-2016 average SO2 emissions.

Similar issues with YELP’s SO2 cost analyses apply to the CELP Rosebud SO2 cost analyses. Specifically, the costs are based on EPA’s 2002 Control Cost Manual for SO2 controls, but EPA published new chapters of the Control Cost Manual in April 2021 and has made available wet and dry scrubber control cost spreadsheets. Thus, there are much more recent tools based on actual retrofit costs of these controls that CELP should have used to re-evaluate costs, rather than to rely on cost equations from EPA’s 2002 Control Cost Manual. Because neither CELP nor MDEQ provided sufficient information on

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See Babcock & Wilcox, Circulating Dry Scrubber (CDS) Technology, at 1 (Ex. 18).
the Rosebud CFB boiler fuel characteristics, including sulfur content and heat value, and operational data for the unit, there is not sufficient information currently in the record to use EPA’s FGD cost spreadsheet to calculate costs of those controls for the Rosebud CFB boiler. MDEQ should request that data and use EPA’s cost spreadsheets to estimate costs for SDA and DSI.

EPA’s Control Cost Manual also cautions against escalating costs more than five years from the original cost analysis because it can lead to inaccuracies in price estimation.226 CELP escalated costs over 8 years (2011 to 2019) used inflation cost adjustments that showed a 15% interest in prices from 2011 to 2019.227 That increase is much higher than the increase in the CEPCI index over that same timeframe. Specifically, over 2011 to 2019, the CEPCI increased from 586 to 607.5, an increase of only 3.7%. These differences in cost factors demonstrate why one should not escalate costs to current dollars that are more than five years old.

MDEQ and CELP only assumed 80% SO2 removal in its evaluation of SDA.228 Yet, an SDA can achieve higher levels of SO2 control, even with the Rosebud CFB boiler potentially achieving 90% control.229 MDEQ should have evaluated SDA to achieve 90% SO2 removal, which would reflect a combined SO2 removal efficiency of 99%. Such a combined high control efficiency has been proposed and required as BACT for SO2 from CFB boilers. For example, the Spiritwood Generating Station located in North Dakota is a lignite-fired CFB boiler with limestone injection and a spray dryer following, as well as a baghouse, and the SO2 BACT limit for the unit reflects 98.7% SO2 control.230

CELP’s detailed cost estimates include costs for new baghouses for each of the three SO2 control options.231 The CELP four-factor analysis does not support an assumption that entirely new baghouses would be required with each SO2 control, other than a reference to a discussion with a vendor some time ago who said that the baghouse design “must be matched with the add-on control systems and its resulting particulate loading.”232 However, no documentation was provided to indicate that there would be a mismatch between the SO2 controls being evaluated and the existing baghouses. The regional haze rules require states to document the technical basis, including in 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). Thus, MDEQ must require CELP to provide more support for any assumption that new, redesigned baghouses would be needed with each of these SO2 control options. Further, as stated above, a NID™ CDS scrubber has an integrated baghouse and thus does not require installation of a new baghouse, and such a NID™ scrubber should have a similar cost to an SDA. Thus, if MDEQ finds that there truly would be a need for a new baghouse with these SO2 controls, that is yet another reason it should evaluate the use of a NID™ circulating dry scrubber.

227 2019 CELP Rosebud Four-Factor Analysis at 32.
228 Montana Regional Haze Plan at 230.
229 See EPA. Control Cost Manual, Section 5, Chapter 1, Wet and Dry Scrubbers for Acid Gas Control, April 2021, at 1-12.
230 See EPA’s RACT/BACT/LAER Clearinghouse, RBLC ID # ND-0024.
232 Id. at 25.
CELP’s detailed costs also include costs for sales tax. However, Montana does not charge sales tax, thus such costs should not be included.

CELP assumed only a 20-year life of SO2 controls and assumed an unreasonably high 5.5% interest rate. As discussed in Section I.B. above, the current bank prime interest rate should be used to determine annualized capital costs of control. In addition, the SO2 pollution controls should be assumed to have a 30-year life, rather than a 20-year life. EPA’s Control Cost Manual provides ample support for a 30-year life of wet and dry scrubbers. DSI should also have a life of at least 30 years. EPA has assumed a 30-year life in both FGD and DSI cost effectiveness evaluations in the first round regional haze plans.

In the table below, we have revised CELP’s cost estimates for HAR, SDA, and DSI to reflect an interest rate of 3.25% and a 30-year life of controls. Just these two changes alone show that the SO2 controls are more cost effective than indicated in the draft Montana Regional Haze plan.

Table 10. Revised Cost Effectiveness of SO2 Controls at CELP’s Rosebud Power Plant Assuming an Interest Rate of 3.25% and a 30-Year Life of Controls

<table>
<thead>
<tr>
<th>SO2 Control</th>
<th>CELP’s Total Capital Investment, 2019 $</th>
<th>Annualized Capital Costs, 2019 $/year</th>
<th>Annual Operating and Maintenance Costs, $/year</th>
<th>Total Annualized Costs, $/year (2019 $)</th>
<th>SO2 Reduced, tons per year</th>
<th>Cost Effectiveness, $/ton</th>
</tr>
</thead>
<tbody>
<tr>
<td>HAR, Baghouses</td>
<td>$22,177,580</td>
<td>$1,168,758</td>
<td>$1,812,775</td>
<td>$2,981,533</td>
<td>616</td>
<td>$4,840/ton</td>
</tr>
<tr>
<td>SDA, Baghouses</td>
<td>$28,435,354</td>
<td>$1,498,543</td>
<td>$2,434,370</td>
<td>$3,932,913</td>
<td>985</td>
<td>$3,993/ton</td>
</tr>
<tr>
<td>DSI, Baghouses</td>
<td>$13,994,337</td>
<td>$737,502</td>
<td>$1,677,004</td>
<td>$2,414,506</td>
<td>616</td>
<td>$3,920/ton</td>
</tr>
</tbody>
</table>

Changing just the interest rate to the current bank prime rate of 3.25% and assuming a 30-year life of controls instead of a 20-year life, the cost effectiveness of all of these SO2 control options is reduced by roughly 28% from the cost numbers CELP provided. Either way, the cost of SDA and new baghouses should be considered as reasonable at $3,993/ton as shown above or even at $4,889/ton as calculated by CELP using a higher interest rate and a shorter useful life. These costs are lower than the cost effectiveness thresholds being established for the second round regional haze plans by several states.

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235 These cost numbers reflect CELP’s costs for these controls as reported in Table 6-23 of the 2022 Montana Regional Haze Plan at 230, but with the annualized costs revised to reflect a 3.25% interest rate and a 30-year life rather than the 5.5% interest rate and 20-year life assumed by CELP and MDEQ. Note that the annual operating and maintenance costs were not specifically identified in Table 6-23 of the 2022 Montana Regional Haze Plan. Those costs were calculated based on the difference between the Total Annual Cost and the annualized capital costs assuming CELP’s 5.5% interest rate and 20-year life.
including Arizona ($4,000 to $6,500/ton236), New Mexico ($7,000 per ton237), Oregon ($10,000/ton238), Washington ($6,300/ton for Kraft pulp and paper power boilers239), and Colorado ($10,000/ton).240 If an upgraded or new baghouse is not required, because it very well may not be needed, these SO2 controls will be even more cost effective for the CELP Rosebud facility. MDEQ should collect more data on the design particulate loading of the existing baghouses before it makes a determination of which SO2 control is the most cost effective for the CELP Rosebud Plant. Assuming that a new baghouse would be required to implement an SDA, that combination of SO2 controls would be cost effective – and would reduce the greatest amount of SO2 from the CELP facility at 985 tons of SO2 reduced per year.

b) Consideration of the Time Necessary for Compliance, Energy and Non-Air Quality Environmental Impacts, and Remaining Useful Life

The other reasonable progress factors would not impede installation of cost-effective SO2 controls at the CELP Rosebud facility. MDEQ and CELP state that the time to retrofit HAR, SDA, or DSI would be roughly the same, which would be about one year, and they assume that a boiler outage of two to three months per boiler would be necessary to perform the installation.241 The two to three-month boiler outage time seems like an overstatement for SDA installation, even if a new baghouse was also required. There are many examples of complex pollution control installations done at existing coal-fired EGUs in 6 week outages or even less. For example, Asheville Power Station Unit 1 had a wet FGD retrofit that was tied in over a 2-week outage.242 Asheville Unit 2 had a wet FGD and an SCR tied in during a 6-week outage.243 This was accomplished by activities completed while the units were operating or at earlier planned maintenance outages. Specifically, to accomplish the tie-in of the Asheville Unit 1 FGD within a 2 week outage, “modifications to the existing balance-of-plant systems...were made during a 6-week turbine outage” that started in the year before the scrubber was tied in.244 For the Unit 2 pollution control upgrades, construction started on a new chimney and FGD absorber towers a few

239 See, e.g., Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, attached as Ex. 15.
241 2022 Draft Montana Regional Haze Plan at 230.
243 Id. at 1-2.
244 Id. at 1.
weeks before the outage.\textsuperscript{245} This is one example of many regarding how the retrofit of pollution controls can be timed to coincide with planned outages and minimize construction and tie in time.

MDEQ stated “[i]f CELP had to dispose of the unsalable ash, the increased cost would be approximately $62,000/year” and that the “total cost from the loss of the beneficial use market and the increase in ash disposal costs would be a total of $1,082,000/year.”\textsuperscript{246} Regarding the “loss of beneficial use market,” it is assumed that MDEQ is referring to if the ash from the Rosebud Power Plant is currently being sold at a profit and could no longer be sold if one of the SO2 controls were installed. However, there is no information in the regional haze plan regarding 1) how much ash is currently sold for beneficial use versus sent to the landfill in an average year, and 2) whether CELP has documented that the loss of the ability to sell ash for beneficial use would be a valid concern equally for all three SO2 control options. If additional ash must be landfilled as a result of the controls, that should be taken into account in the cost effectiveness analysis.

Regarding the remaining useful life of the CELP facility, MDEQ reports that the CFB boiler is not planned for retirement at this time.\textsuperscript{247} Thus, a 30-year effective life of controls should be assumed in the cost analyses.

\begin{itemize}
  \item[c)] \textbf{Summary – There are Cost-Effective SO2 Control Options for the CELP Rosebud Power Plant that Should Warrant Adoption of the Measures as Part of MDEQ’s Long Term Strategy.}
\end{itemize}

As shown in Table 10 above, SDA at the CELP boilers would be cost effective, achieving almost 1,000 tons per year of SO2 reduction at costs of roughly $4,000/ton. DSI has a similar cost effectiveness, but DSI would achieve lower SO2 reduction than SDA. Based on MDEQ’s criteria for selecting sources to evaluate for controls in its regional haze plan for the second implementation period, the CELP Rosebud facility is the fourth highest emitter of SO2 and has the seventh highest Q/d value.\textsuperscript{248} Given that cost-effective controls exist for these units, MDEQ should reconsider its proposed action to not require any SO2 controls at the CELP Rosebud Plant as part of its long term strategy for the second implementation period.

\subsection*{2. Evaluation of NOx Pollution Controls for the CELP Rosebud Power Plant}

NOx pollution controls for the CELP Rosebud Power Plant also are justified. The CELP facility currently has no specific NOx controls other than using good combustion practices and the CFB boiler design.\textsuperscript{249} CELP indicated in its four-factor analysis that the NOx emission rate of the Rosebud boiler was 0.400 lb/MMBtu based on annual emission inventories.\textsuperscript{250} MDEQ states that the typical NOx combustion controls of low excess air, flue gas recirculation, overfire air, and low NOx burners cannot be used on

\begin{flushleft}
\textsuperscript{245} Id. at 2.
\textsuperscript{246} Montana Regional Haze Plan at 231.
\textsuperscript{247} 2022 Draft Montana Regional Haze Plan at 216.
\textsuperscript{248} Id. at 161.
\textsuperscript{249} 2019 CELP Rosebud Four-Factor Analysis at 26.
\textsuperscript{250} Id., Appendix B at 3 (pdf page 54 of report).
\end{flushleft}
CFB boilers, thus only post-combustion NOx controls were evaluated. Specifically, MDEQ and CELP evaluated SNCR and SCR for the CELP Rosebud plant.

a) CELP’s NOx Control Cost Estimates Overstated Costs of those Controls.

As with the SO2 control cost analyses, CELP’s cost analyses for SNCR and SCR were based on CELP’s cost analyses for these controls submitted to EPA for its first regional haze plan (Round 1) for Montana promulgated in 2012. CELP’s prior NOx cost analyses were based on costs estimated with the help of the Metso consulting report and also based on the 6th edition (i.e., from January 2002) version of the EPA Control Cost Manual. CELP updated the costs by adjusting 2011 prices to 2019 prices due to inflation, and YELP revised the cost effectiveness analyses to reflect a 20-year life of controls, a 5.5% interest rate, and 2014-2017 average NOx emissions. EPA has published new chapters of the Control Cost Manual on SCR and on SNCR in 2019 and 2021, respectively, and has made available SCR and SNCR control cost spreadsheets. Because neither CELP nor MDEQ provided sufficient information on the Rosebud CFB boiler fuel characteristics and operational data for the unit, there is not sufficient information currently in the record to use EPA’s SCR and SNCR cost spreadsheet to calculate costs of those controls for the Rosebud CFB boiler. MDEQ should request that data and use EPA’s cost spreadsheets to estimate costs for SCR and SNCR.

There are several problems with CELP’s and MDEQ’s approach to use CELP’s prior analysis from the first round regional haze plan. First, EPA’s Control Cost Manual also cautions against escalating costs more than five years from the original cost analysis because it can lead to inaccuracies in price estimation. YELP escalated costs over 8 years (2011 to 2019) using inflation cost adjustments that showed a 15% increase in prices from 2011 to 2019. That increase is much higher than the increase in the Chemical Engineering Plant Cost Index (CEPCI) over that same timeframe. Specifically, over 2011 to 2019, the CEPCI increased from 586 to 607.5, an increase of only 3.7%. These differences in cost factors demonstrate why one should not escalate costs to current dollars that are more than five years old.

Second, CELP assumed only a 20-year life of NOx controls and assumed an unreasonably high 5.5% interest rate. As discussed in Section I.B. above, the current bank prime interest rate should be used to determine annualized capital costs of control. In addition, the NOx pollution controls should be assumed to have a 30-year life, rather than a 20-year life. EPA’s Control Cost Manual provides ample support for a 30-year life of SCR. SNCR should also have a life of at least 30 years. As discussed above

253. Id. at 33-34.
256. 2019 CELP Rosebud Four-Factor Analysis at 32.
in Section II.A.1.b)(3), while EPA’s Control Cost Manual chapter on SCNR assumes only a 20-year life of SNCR,258 there is ample support for assuming a 30-year life of SNCR – including in EPA’s Control Cost Manual Chapter on SNCR.259 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 as defining SCR equipment life (and thus the injection lances should not define SNCR equipment life). 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,260 it is reasonable to assume a 30-year life of SNCR for application to the YELP boilers, as well as for SCR.

CELP assumed a 50% NOx reduction with SNCR using ammonia as the reagent.261 The EPA’s Control Cost Manual provides support for higher NOx removal efficiencies at fluidized bed boilers. Specifically, EPA has indicated that circulating fluidized and bubbling bed boilers can achieve 76-80% NOx reduction with SNCR.262 As another comparison, the lignite-fired Spiritwood Generating Station located in North Dakota based its NOx BACT limit on use of SNCR to achieve 58% NOx reduction.263 CELP has assumed ammonia would be used as the reagent, and EPA states that NOx removal efficiencies are typically higher with ammonia than urea.264 For these reasons, MDEQ should require CELP to evaluate a higher NOx removal efficiency with SNCR than 50%.

CELP’s SNCR cost analysis shows that a normalized stoichiometric ratio (NSR) of 3.0 was assumed for SNCR.265 As EPA states, the NSR “defines the amount of reagent needed to achieve the targeted NOx reduction.”266 An NSR of 3.0 to achieve only 50% NOx removal seems very high. EPA’s Control Cost Manual lists an NSR of 3.0 at the top end of typical NSR ratios, and states that “[i]ncreasing the quantity of reagent does not significantly increase the NOx reduction for NSR values over 2.0.”267 As the CELP Four-Factor analysis makes clear, the bulk of the cost of SNCR is the cost of the ammonia reagent.268 Thus, it is imperative that this be accurately determined.

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259 Id. at 1-53 to 1-54.
262 See EPA Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, at 1-2.
263 Great River Energy-Spiritwood Station, Application for a Permit to Construct a Combined Heat and Power Plant (CHP), July 2007, Appendix E at 56 (Appendix E attached as Ex. 19).
264 Id. at 1-1.
265 2019 CELP Rosebud Four-Factor Analysis, Appendix B at 3 (pdf page 54).
266 See EPA Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, at 1-17.
267 Id. at 1-18.
CELP’s four-factor analysis includes a formula used to calculate the NSR, which is the same formula as in EPA’s SNCR chapter of the Control Cost Manual when urea is the SNCR reagent. However, CELP’s analysis assumes ammonia will be the reagent which is more effective at reducing NOx than urea. Further, the NSR calculation in the CELP report assumed a NOx inlet rate (pre-SNCR rate) of 0.400 lb/MMBtu. If a NOx inlet rate of 0.400 lb/MMBtu is input into the NSR formula used by CELP, the NSR at 50% NOx control is 1.875, not 3.00 as reflected in the CELP report. Use of a NSR of 1.875 rather than an NSR of 3.0 means that the ammonia reagent costs to achieve 50% NOx reduction should be 62.5% of CELP’s projected annual reagent cost of $554,606/year, which equates to $346,629/year.

In the table below, we have revised CELP’s cost estimates for SNCR and SCR to reflect an interest rate of 3.25% and a 30-year life of controls. We have also revised the SNCR cost estimates to reflect a reduced amount of ammonia reflective of a NSR of 1.875, by reducing the costs of ammonia down from $554,606/year to $346,609/year. Just these changes alone show that the NOx controls are more cost effective than indicated in the draft Montana Regional Haze plan, with SNCR being the most cost effective control.

**Table 11. Revised Cost Effectiveness of NOx Controls at CELP’s Rosebud Power Plant Assuming an Interest of 3.25% and a 30-Year Life of Controls and Assuming a Lower NSR for Ammonia in the SNCR Costs**

<table>
<thead>
<tr>
<th>SO2 Control</th>
<th>CELP’s Total Capital Investment, 2019$</th>
<th>Annualized Capital Costs, 2019 $/year</th>
<th>Annual Operating and Maintenance Costs, $/year</th>
<th>Total Annualized Costs, $/year (2019 $)</th>
<th>NOx Reduced, tons per year</th>
<th>Cost Effectiveness, $/ton</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCR</td>
<td>$15,650,550</td>
<td>$824,784</td>
<td>$959,305</td>
<td>$1,784,089</td>
<td>714</td>
<td>$2,499/ton</td>
</tr>
<tr>
<td>SNCR</td>
<td>$1,020,800</td>
<td>$48,876</td>
<td>$395,571</td>
<td>$444,447</td>
<td>446.2</td>
<td>$887/ton</td>
</tr>
</tbody>
</table>

It must be noted that MDEQ’s Draft Regional Haze Plan appears to list incorrect SCR and SNCR cost and emission reduction information in Table 6-24 (at page 234), as the data does not match with CELP’s four-factor analysis (Appendix B at 1).

Changing just the interest rate to the current bank prime rate of 3.25% and assuming a 30-year life of SCR instead of a 20-year life, the cost effectiveness of SCR is reduced by 21% from the $3,179/ton cost effectiveness provided by CELP. For SNCR, the cost effectiveness with the interest rate and life of

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269 See EPA Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, at 1-36 to 1-37.

270 Id. at 1-1.

271 2019 CELP Rosebud Four-Factor Analysis, Appendix B at 3 (pdf page 54).

272 Based on the ratio of 1.875/3.0, multiplied by CELP’s estimated cost of reagent of $554,606/year (2019 CELP Rosebud Four-Factor Analysis, Appendix B at 4 (pdf page 55)). See also EPA Control Cost Manual, Section 4, Chapter 1 Selective Non-Catalytic Reduction, at 1-38 (Equation 1.18).

273 These cost numbers reflect CELP’s costs for these controls as reported in the 2019 CELP Rosebud Four-Factor Analysis, Appendix B at 1 (pdf page 52 of report), but with the annualized costs revised to reflect a 3.25% interest rate and a 30-year life rather than the 5.5% interest rate and 20-year life assumed by CELP and MDEQ.
controls, along with the lower NSR ratio, shows the cost effectiveness of SNCR is $887/ton, which is 42% less costly than CELP’s SNCR cost effectiveness calculation. Indeed, even just accounting for the overestimate of the amount of ammonia reagent but keeping CELP’s 5.5% interest rate and 20-year life of SNCR, the cost effectiveness of SNCR would be $887/ton – because the operating expenses are the bulk of the costs of SNCR. The cost of SNCR should be considered reasonable for the CELP Rosebud Plant to reduce NOx by 50%, even at CELP’s very likely overstated cost effectiveness of $1,527/ton.

b) Consideration of Time Necessary for Compliance, Energy and Non-Air Quality Environmental Impacts, and Remaining Useful Life.

The Metso report submitted with CELP’s four-factor analysis states the following: Metso has not observed nor is aware of an increased fouling, decreased pressure part life, or other issues associated with the use of SNCRs.”274 Metso also stated that an SNCR could be installed within 16-24 weeks, and that the tie-in could occur during a maximum period of two weeks.275 As stated above, MDEQ reports that the CFB boilers are not planned for retirement at this time.276 Thus, a 30-year effective life of controls should be assumed in the cost analyses.

c) Summary – SNCR is a Very Cost Effective NOx Control for the CELP Rosebud Power Plant and MDEQ Should Require SNCR for the Facility as Part of its Long Term Strategy.

For the reasons provided above, MDEQ should require SNCR installation to reduce NOx from the CELP Rosebud Power Plant by at least 50%, as it is a very cost effective control to reduce NOx from the CFB Boiler.

D. Rocky Mountain Power - Hardin Generating Station

Rocky Mountain Power owns and operates the Hardin Generating Station, located east of Billings. This facility consists of a pulverized coal-fired boiler and steam turbine to produce 116 gross MW of electrical power.277 The Hardin Generating Station was not on MDEQ’s list of sources for which it required four-factor evaluations of controls. However, this facility has been increasing operating time and emissions in the past year, as shown in the table below.

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275 Id. at 5.
276 2022 Montana Regional Haze Plan at 234.
277 Montana Air Quality Permit #3185-07, Rocky Mountain Power LLC – Hardin Generating Station, August 28, 2020, at 1, attached as Ex. 21 to this report.
Table 12. Hardin Generating Station Operational and Emissions Data from 2015 to 2021

<table>
<thead>
<tr>
<th>Year</th>
<th>Operating Time, hours/yr</th>
<th>Gross Load, MW-hrs/year</th>
<th>SO2, tons per year</th>
<th>NOx, tons per year</th>
<th>Heat Input, MMBtu/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>5,424</td>
<td>553,747</td>
<td>297</td>
<td>259</td>
<td>6,412,641</td>
</tr>
<tr>
<td>2016</td>
<td>3,532</td>
<td>392,352</td>
<td>209</td>
<td>185</td>
<td>4,621,073</td>
</tr>
<tr>
<td>2017</td>
<td>1,379</td>
<td>133,348</td>
<td>72</td>
<td>66</td>
<td>1,620,839</td>
</tr>
<tr>
<td>2018</td>
<td>2,011</td>
<td>168,023</td>
<td>109</td>
<td>93</td>
<td>2,182,508</td>
</tr>
<tr>
<td>2019</td>
<td>1,930</td>
<td>155,996</td>
<td>115</td>
<td>78</td>
<td>2,216,507</td>
</tr>
<tr>
<td>2020</td>
<td>828</td>
<td>61,838</td>
<td>50</td>
<td>26</td>
<td>764,994</td>
</tr>
<tr>
<td>2021</td>
<td>7,449</td>
<td>566,445</td>
<td>304</td>
<td>245</td>
<td>7,221,704</td>
</tr>
</tbody>
</table>

According to a recent news article, the Hardin Generating Station had been planned to close in 2018, but then a bitcoin mining company established a data center next to the power plant and “became the sole recipient of the power station's electricity.”

MDEQ did not list Hardin Generating Station in its analysis of sources to consider for controls based on emissions and Q/d, but possibly this was because the plant was projected to close by 2018. However, with the co-located bitcoin operation resulting in increased operation and emissions, MDEQ should evaluate Hardin for regional haze control options.

The Hardin Generating Station is equipped with an SDA and SCR. However, its SO2 and NOx emission limits could be strengthened. Currently, the unit is subject to the following emission limits:

- SO2: 90% reduction, and 0.11 lb/MMBtu (30-day average)
- NOx: 0.09 lb/MMBtu (30-day average).

As previously stated, SDA could achieve 95% SO2 removal. And SCR at coal-fired EGUs has been shown to achieve NOx emission rates as low as 0.04 lb/MMBtu on an annual average. MDEQ should evaluate whether the emission limits for Hardin can be reduced, to ensure that the SO2 and NOx controls are optimized to reduce these pollutants to the maximum extent practicable.

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278 Data from EPA’s Air Markets Program Database, at https://ampd.epa.gov/ampd/.
280 Montana Air Quality Permit #3185-07, Rocky Mountain Power LLC – Hardin Generating Station, August 28, 2020 (Ex. 21).
281 See EPA. Control Cost Manual, Section 5, Chapter 1, Wet and Dry Scrubbers for Acid Gas Control, April 2021, at 1-12.
282 See Table 4 above.
IV. Cement Manufacturing Plants

A. GCC Trident Cement Plant

The GCC Trident Cement Plant is located near Three Forks, Montana, west of Bozeman. The facility ranks fifth on MDEQ’s list of facilities evaluated for regional haze pollution controls with a Q/d value of 14.86 based on SO2+NOx emissions.\(^{283}\) The National Parks Conservation Association ranks the GCC Trident facility as the fourth highest in terms of cumulative Q/d ranking.\(^{284}\)

The Trident Cement Plant began operating in 1972. The cement plant operates a long wet kiln, equipped with low NOx burners, SNCR, and a fabric filter baghouse.\(^{285}\) The Trident plant was acquired by GCC in 2018 and was previously owned by Holcim. In 2012, EPA initially issued a BART determination for the facility in 2012, which set NOx limit at 6.5 lb/ton of clinker and reflected installation SNCR to reduce NOx emissions by 50%.\(^{286}\) That NOx BART limit established by EPA in 2012 was subsequently relaxed in 2017 to 7.6 lb/ton of clinker, reflective of 40% control, due to concerns raised regarding excessive ammonia slip if the lower limit reflective of 50% control was imposed.\(^{287}\) According to GCC’s Four-Factor report, GCC Trident “is currently in the process of determining ideal operating conditions that minimize both NOx emissions and ammonia slip.”\(^{288}\) The SNCR was commissioned in 2017 as required by the FIP.\(^{289}\) Also, indirect coal-firing was commissioned in 2018, which according to GCC’s four-factor report resulted in further reductions in NOx emissions.\(^{290}\)

GCC proposed the following baseline emissions and 2028 OTB/OTW emissions:

Table 13. GCC Proposed Baseline Emissions (2017-2018) and 2028 OTB/OTW Emissions\(^{291}\)

<table>
<thead>
<tr>
<th>Baseline Period</th>
<th>NOx Baseline, tpy</th>
<th>SO2 Baseline, tpy</th>
<th>2028 OTB/OTW NOx, tpy</th>
<th>2028 OTB/OTW SO2, tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017-2018</td>
<td>1204.8</td>
<td>7.5</td>
<td>1338.0</td>
<td>7.5</td>
</tr>
</tbody>
</table>

According to GCC’s Four-Factor report, the reported emission rates for the GCC Trident facility “do not accurately represent baseline emission rates for this facility” because 1) prior to October 18, 2017, the

\(^{283}\) 2022 Draft Montana Regional Haze Plan at 161.


\(^{285}\) See Montana Air Quality Permit 80982-16, GCC Trident, June 11, 2021, attached Montana Air Quality Permit Analysis, at 13, which states that a new fabric filter baghouse was installed in 2015 and the existing electrostatic precipitator would no longer be used.


\(^{288}\) Regional Haze 2nd Implementation Period, Four-Factor Analysis, GCC Trident, Three Forks, MT, September 2019 (hereinafter “Trident Four-Factor Analysis”) at 3-1.

\(^{289}\) Id.

\(^{290}\) Id.

\(^{291}\) 2022 Draft Montana Regional Haze Plan at 210 (Table 6-17).
facility did not have SNCR, and after October 2017, 2) current emissions “are not indicative what will be achievable in the long term for the plant” because the “current permitted [NOx] limit of 7.6 lb/ton of clinker NOx rate is not sustainable due to GCC injecting a “substantial amount of ammonia, resulting in excessive ammonia slip” and 3) “20% to 30% control efficiency is a more realistic efficiency to provide effective NOx control while maintaining desirable ammonia slip.” Given that GCC’s four-factor report was written in 2019, after EPA relaxed its NOx BART limit from 6.5 lb/ton of clinker produced to 7.6 lb/ton of clinker, it appears that GCC may be claiming that it plans to request a second relaxation of its NOx BART limit. If this is the case, MDEQ must make this clear in its regional haze plan for the second implementation period.

GCC’s four-factor analysis states “[g]iven the lack of an accurate baseline emission level for NOx, the reported value provided to MDEQ in the response to a request for future year 2028 on-the-books or on-the-way (OTB/OTW) emissions is assumed to be the baseline rate for the purposes of the four-factor analysis” and GCC cites to a letter from the GCC Trident Plant to MDEQ Air Resources Management Bureau dated August 20, 2019. MDEQ refers to a GCC-provided justification for the emissions used in the four-factor analysis, but that August 20, 2019 GCC submittal is not in the draft regional haze plan record. MDEQ must add that document to the record.

Based on GCC’s four-factor analysis, its 2028 OTB/OTW NOx emissions of 1,338 tons per year reflect the average of 2016-2018 NOx emissions, as shown in the table below. It is thus assumed that GCC’s 2028 OTB/OTW NOx emissions reflect the average annual clinker production over 2016-2018 and the annual NOx rate (which was calculated from the reported annual NOx emissions and annual clinker production). Based on this information, either GCC assumed that the allowable NOx BART limit would increase from 7.6 lb/ton of clinker to 8.7 lb/ton of clinker by 2028, or alternatively, GCC’s 2028 NOx emissions of 1,338 tons per year reflect an increase in annual clinker production to 352,105 tons of clinker.

Table 14. GCC Trident’s Annual Emissions Summary and Presumed Annual NOx Emissions Rates

<table>
<thead>
<tr>
<th>Year</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>Average</th>
<th>Permit Max</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clinker Production (tons)</td>
<td>311,734</td>
<td>291,754</td>
<td>322,383</td>
<td>308,624</td>
<td>425,000</td>
</tr>
<tr>
<td>Reported NOx, tons</td>
<td>1,608</td>
<td>1,328</td>
<td>1,080</td>
<td>1,338</td>
<td>1,615</td>
</tr>
<tr>
<td>Presumed Annual NOx Rate, lb/ton clinker</td>
<td>10.3</td>
<td>9.1</td>
<td>6.7</td>
<td>8.7</td>
<td>7.6</td>
</tr>
</tbody>
</table>

292 Trident Four-Factor Analysis at 4-1.
294 Trident Four-Factor Analysis at 4-1.
295 This was calculated assuming the NOx BART limit of 7.6 lb/ton of clinker still applies in 2028.
296 Trident Four-Factor Analysis at 4-2 (Table 4-1). Presumed Annual NOx Rate was calculated based on Trident’s reported clinker production and reported NOx emissions for each year.
MDEQ must clarify what NOx emission rate formed the basis of the assumed 2028 NOx OTB/OTW emission rate of 1,338 tons per year. Assuming the 1,338 tons per year NOx is based on the average of 2016-2018 emissions and production rate, as shown in the above table, then the assumed NOx emission factor would be 8.7 lb/ton of clinker, which reflects a 14% increase in the current NOx BART emission limit of 7.6 lb/ton of clinker.

Neither GCC Trident nor MDEQ provided the cement plant’s baseline or 2028 emissions for SO2. The cement kiln was subject to a 1.3 lb/ton of clinker SO2 BART limit in the first round regional haze plan.297 Thus, assuming that the 2028 OTB/OTW NOx emissions were based on an annual production rate of 308,624 tons of clinker per year, the 2028 OTB/OTW SO2 emissions would be 201 tons per year. Alternatively, if GCC does not plan on requesting an increase to its NOx BART limit of 7.6 lb/ton of clinker, then its 2028 OTB/OTW NOx emissions reflect an annual production rate of 352,105 tons of clinker. This would equate to 2028 OTB/OTW SO2 emissions of 229 tons per year based on the 1.3 lb/ton SO2 BART limit.

1. Evaluation of Pollutant Control Options for GCC Cement Plant

MDEQ did not conduct a four-factor analysis of additional controls for SO2 at the GCC Trident Plant, referring to the “GCC prepared and submitted four-factor analysis that the current inherent scrubbing continues to provide the best reduction for SO2.”298 However, GCC Trident’s September 2019 four-factor analysis that is posted on MDEQ’s regional haze website did not include a four-factor analysis of additional SO2 control. MDEQ must cite and make available for public review the GCC SO2 control analysis that it is referring to. Based on the annual clinker production calculated for the 2028 OTB/OTW NOx emissions that ranged between 308,624 to 352,105 tons of clinker produced per year, the annual SO2 emissions allowed under the SO2 BART limit of 1.3 lb/ton of clinker reflect a significant increase from the SO2 emissions evaluated in the 2012 BART analysis. Specifically, the 2012 BART analysis assumed a baseline SO2 emission rate of 50.2 tons per year,299 and the 2028 OTB/OTW emissions based on the 1.3 lb/ton SO2 BART limit would be 201 to 229 tons per year. Given that BART did not result in the imposition of any additional controls for SO2 at the GCC Trident cement kiln, the basis of GCC’s claimed baseline and 2028 SO2 emissions of 7.5 tons per year is not clear. MDEQ must provide more information on the underlying assumptions for the baseline/2028 OTB/OTW SO2 emissions and what SO2 controls have been implemented before it can be justified in not evaluating any additional SO2 controls for the cement kiln in a four-factor analysis.

GCC Trident did conduct an analysis of additional NOx controls – specifically of low NOx burners, SNCR and SCR – but GCC Trident found that low NOx burners and SNCR were already installed on the kiln and that SCR was not technically feasible for the GCC Trident cement kiln.300 MDEQ concurred that no additional NOx controls were warranted for the second planning period at GCC Trident.301 Neither MDEQ nor GCC Trident addressed the company’s statements that strongly implied the company would

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298 2022 Draft Montana Regional Haze Plan at 211.
300 Trident Four-Factor Analysis at 5-3 to 5-6.
301 2022 Draft Montana Regional Haze Plan at 21.
be requesting a further relaxation in the current NOx BART limit with SNCR of 7.6 lb/ton, due to its claim of excessive ammonia slip.  

\( a) \quad \text{Use of a Ceramic Catalytic Filtration System} \)

There are additional regional haze control options that MDEQ 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 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. 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.

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. That cost information can be used to estimate the costs of using a ceramic catalytic filtration system at the GCC Trident plant. The GCC Pueblo Plant has a higher cement production rate at 3,750 tons/day compared to the average daily 1,164 tons production rate at the GCC Trident cement plant, thus the capital and operational expenses of ceramic catalytic filters at the GCC Pueblo Plant will presumably be higher than at the GCC Trident Plant. The GCC Pueblo Plant kiln is equipped with SNCR and a fabric filter baghouse, similar to the GCC Trident Plant kiln. Thus, the GCC Trident plant is already equipped with an ammonia storage and injection system, as is the GCC Pueblo Plant. There are a few differences between the two cement plants: the GCC Pueblo Plant kiln is a newer Portland cement plant that has been described as much more energy efficient than earlier wet cement kilns, and the GCC Trident Plant kiln is an older wet kiln. The GCC Pueblo Plant kiln also fires primarily low sulfur coal, while the GCC Trident Plant kiln fires pet coke and low sulfur coal. These differences primarily impact the pollutant emission rate per ton of clinker and should not affect the capabilities of a downstream ceramic catalytic filtration system.

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302 Trident Four-Factor Analysis at 4-1.
306 See GCC Pueblo Four Factor Analysis, Appendix B at 2 (Ex. 24); see also max permitted annual clinker production limit of 425,000 tons per year specified at Trident Four-Factor Analysis at 4-2. Assuming the plant operates 365 days per year, the 425,000 maximum annual tons of clinker production equates to 1,164 tons per day.
307 See GCC Pueblo Four Factor Analysis, Appendix B at 5 (Ex. 24).
308 See GCC Pueblo Four Factor Analysis, Appendix B at 2 (Ex. 24).
310 See GCC Pueblo Four Factor Analysis, Appendix B at 4 (Ex. 24).
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 GCC Trident plant due to the larger size of the Pueblo plant.

There are a few options for using a ceramic catalytic filtration system at the GCC Trident 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. Given that a new baghouse was recently installed at the GCC Pueblo plant, the third option would be the most cost effective option.

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”). 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%). 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 the control system of $1,620,000/year. The capital costs also include the costs to upgrade the existing baghouse if necessary for upgraded structural support and upgraded internals. 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. The use of aqueous ammonia is safer than using anhydrous ammonia, and there is not a federal requirement for an accidental release plan.

The GCC Trident facility has 2028 OTB/OTW NOx emissions of 1,338 tons per year. This reflects some level of NOx removal from the SNCR system, but because GCC Trident did not provide the assumptions that the 2028 OTB/OTW emission projection reflects, it is not clear if this reflects 40% removal as the current NOx limit of 7.6 lb/ton of clinker reflects or a lower level of NOx removal of 20-30% which GCC Trident stated is a “more realistic efficiency to provide effective NOx control while maintaining desirable ammonia slip.” 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 2028 OTB/OTW NOx emissions reflects 40% control. 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 2028 OTB/OTW of 1,004 tons per year of NOx.

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312 See Montana Air Quality Permit #0982-16, GCC Trident, June 11, 2021, attached Montana Air Quality Permit Analysis, at 13 (Ex. 25), which states that a new fabric filter baghouse was installed in 2015 and the existing electrostatic precipitator would no longer be used.
313 GCC Pueblo Four Factor Analysis Appendix F at 5 (Ex. 24).
314 Id. at 5-6 (Ex. 24).
315 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.
316 Id. at 5.
317 Id., Appendix F at 6.
319 Trident Four-Factor Analysis at 4-1.
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), assuming a 3.25% interest rate and a 20-year life of the ceramic filtration system, a ceramic catalytic filtration system could have a cost effectiveness of $2,231/ton of NOx removed. 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 GCC Trident, and the GCC Trident 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 GCC Trident 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.320 Tri-Mer states that “a ceramic filter has no deactivation of the catalyst in a continuous operation for 10 years+.”321 Given GCC Trident’s stated concerns with ammonia slip and that it has implied that it will be requesting a further relaxation in its current NOx BART emission limit due to concerns with excessive ammonia slip, the use of a ceramic catalytic filtration system could address these concerns and provide for a significantly greater reduction in NOx emissions from the cement kiln. With a 90% reduction in NOx from the current NOx limit, the GCC Trident kiln should be able to meet a NOx limit of 0.8 lb/ton. 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.322

The four-factor reasonable progress analysis of use 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.323 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 GCC Trident facility is currently using with SNCR, could pose risk management concerns. However, the four-factor analysis for the GCC Pueblo Cement Plant assumed 19% aqueous ammonia would be used, which may not be subject to EPA’s accidental release requirements, unlike use of aqueous ammonia.324 Further, with use of a ceramic catalytic filtration system instead of SNCR, GCC Trident will likely use less ammonia than it is currently using with SNCR.

For all of these reasons, MDEQ should require GCC Trident to evaluate the installation of ceramic catalytic filtration bags in its existing baghouse because it will significantly and cost-effectively reduce NOx emissions from the cement kiln.

320 GCC Pueblo Four Factor Analysis Appendix F at 7 (Ex. 24).
321 Id.
322 Id., Appendix F at 5.
323 Id. at 13.
324 Id.
Both MDEQ and GCC Trident dismissed SCR as not technically feasible for cement kilns. However, as stated in the Federal Land Managers’ comments in Appendix F of the draft Montana Regional Haze Plan, SCR is being used at two US cement kilns (Lafarge/Holcim in Joppa, IL and Holcim in Midlothian, TX) as well as several in Europe. GCC Trident acknowledges the use of SCR in Europe, but states that “the cement industries between Europe and the U.S. differ significantly due to the increased sulfur content found in the processed raw materials in U.S. cement kiln operations,” and that the pyritic sulfur found in the raw materials used in U.S. cement kilns results in “high-dust levels and rapid catalyst deactivation.” However, given that SCR is being utilized at two cement kilns in the U.S. that are presumably fired with similar fuels to the GCC Trident plant, the SCR systems can be designed to deal with these issues. Further, European deployment of SCR on cement kilns is instructive. For example, a paper describing SCR at the Solnhofen cement plant in Germany explains that the SCR uses honeycomb catalysts with large pitch and describes the most effective catalyst configuration for that cement kiln. The Solnhofen SCR also has a catalyst cleaning system. That paper also discusses where the facility injects ammonia for SCR operation and also where it injects ammonia for SNCR operation. The fact that there is not an “off-the-shelf” SCR that does not require source-specific design and operation should not mean that a pollution control is not technically feasible for the GCC Cement Plant.

MDEQ states “[t]here is not enough information available on the technical success or on the actual costs required for construction and operation” of SCR at cement kilns. Yet, neither MDEQ nor GCC Trident have indicated that they have attempted to gather any available information from the Illinois EPA (for the Lafarge/Holcim cement plant SCR in Joppa, IL) or the Texas Commission on Environmental Quality (for the Holcim cement plant SCR in Midlothian, TX). MDEQ states “[a] more rigorous SCR evaluation is likely in the third planning period, if the technology has advanced and more information is publicly available to perform a proper assessment.” Yet, for the technology to advance, MDEQ should gather available information on the application of SCR to cement kilns now as part of the GCC Trident cement plant four-factor analysis, as well as for the Ash Grove Cement Plant (in Montana City, Montana) four-factor analysis.

Given that GCC Trident has claimed, and appears to continue to claim, that SNCR does not work

325 2022 Draft Montana Regional Haze Plan at 211; Trident Four-Factor Analysis at 5-4 to 5-5.
326 2022 Draft Montana Regional Haze Plan, Appendices at pdf page 65.
327 Trident Four-Factor Analysis at 5-4.
329 Id. at 7-8.
330 Id. at 7.
331 2022 Draft Montana Regional Haze Plan at 211.
332 Id.
effectively at its cement kiln without excessive ammonia slip,\textsuperscript{333} it is incumbent upon MDEQ to fully evaluate other NOx control options for the GCC Trident cement kiln such as SCR.

c) Summary: MDEQ Must Consider Use of Ceramic Catalytic Filters as a Top Control Technology for NOx and PM, and Potentially SO2

For the reasons provided above, MDEQ should consider use of a ceramic catalytic filtration system in the existing baghouse as a top control technology for NOx and PM and also for SO2 if dry sorbent injection is used. As discussed above, the use of ceramic catalytic filters in the GCC Trident cement kiln’s existing baghouse would likely be very cost effective, would reduce ammonia slip with GCC Trident claims is an issue with the SNCR required to meet BART, and would allow the cement kiln to improve NOx removal efficiency to 90% for 1,004 tons per year of NOx reduced.

As an alternative, MDEQ should more thoroughly evaluate the option of SCR to replace the SNCR to achieve 90% control of NOx, as it has been used at cement kilns in Europe and at two cement kilns in the United States.

B. Ash Grove Cement

The Ash Grove Cement plant is located in Montana City, Montana. The facility ranks third on MDEQ’s list of facilities evaluated for regional haze pollution controls with a Q/d value of 40.36 based on SO2+NOx emissions.\textsuperscript{334} The National Parks Conservation Association ranks the GCC Trident facility as the fifth highest in terms of cumulative Q/d ranking.\textsuperscript{335}

The Ash Grove Cement Plant began operating in 1968. The cement plant operates a long wet kiln, equipped with a semi-dry scrubber for SO2 removal, low NOx burners, SNCR, and a fabric filter baghouse.\textsuperscript{336} In 2012, EPA issued a BART determination for the facility in 2012, which set NOx limit at 8.0 lb/ton of clinker and reflected installation of LNB plus SNCR to reduce NOx emissions by 58%.\textsuperscript{337} At the time of EPA’s 2012 BART evaluation, the Ash Grove cement kiln did not have any SO2 controls and the unit had an ESP for PM control. EPA concluded that any additional SO2 or PM controls were not justified to meet BART.\textsuperscript{338} However, pursuant to a Consent Decree with the U.S. EPA, the Ash Grove plant installed semi-dry scrubbing technology to meet an SO2 limit of 2.0 lb/ton of clinker and installed a baghouse to meet a PM limit of 0.07 lb/ton of clinker.\textsuperscript{339} In addition, pursuant to process optimization

\textsuperscript{333} Trident Four-Factor Analysis at 4-1.
\textsuperscript{334} 2022 Draft Montana Regional Haze Plan at 161.
\textsuperscript{335} National Parks Conservation Association’s Regional Haze Fact Sheet for Montana, available at https://www.npca.org/reports/regional-haze.
\textsuperscript{336} 2022 Draft Montana Regional Haze Plan at 201-202. See also Montana Air Quality Permit #2005-16, Ash Grove Cement – Montana City Plant, October 22, 2021, attached Montana Air Quality Permit Analysis, at 4-5 (Conditions B.1, B.3., B.4, and B.5) requiring operation of a baghouse in the cement kiln exhaust, use of low NOx burner technology, operation of SNCR, and use of semi-dry scrubbing controls (Ex. 26).
\textsuperscript{339} As specified in Montana Air Quality Permit #2005-16, Ash Grove Cement – Montana City Plant, October 22, 2021, at 4-5 (Conditions II.B.1. and II.B.5) (Ex. 26).
requirements in the Consent Decree, Ash Grove demonstrated the ability to achieve a lower NOx limit of 7.5 lb/ton, which has been imposed as an enforceable permit condition.\textsuperscript{340}

Ash Grove proposed the following baseline emissions and 2028 OTB/OTW emissions:

**Table 15. Ash Grove Proposed Baseline Emissions (2017-2018) and 2028 OTB/OTW Emissions\textsuperscript{341}**

<table>
<thead>
<tr>
<th>Baseline Period</th>
<th>NOx Baseline, tpy</th>
<th>SO2 Baseline, tpy</th>
<th>2028 OTB/OTW NOx, tpy</th>
<th>2028 OTB/OTW SO2, tpy</th>
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</thead>
<tbody>
<tr>
<td>2017-2018</td>
<td>810.3</td>
<td>101</td>
<td>981.5</td>
<td>120.8</td>
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</table>

1. **Evaluation of Pollutant Controls for Ash Grove Cement Plant**

As stated above, the Ash Grove cement kiln uses low NOx burners and SNCR to meet a NOx limit of 7.5 lb/ton. MDEQ states that Ash Grove operates SNCR to achieve 30-40% NOx reductions.\textsuperscript{342} Given that EPA found that its NOx BART limit of 8.0 lb/ton reflected 58% control, the 7.5 lb/ton NOx limit would reflect 60% control from emissions prior to installation and use of low NOx burners and SNCR.

MDEQ proposed that any additional NOx controls are not justified for the regional haze plan, finding that the current NOx controls provide for the best reduction in NOx emissions.\textsuperscript{343} However, as discussed above in the section on the GCC Trident cement plant, ceramic catalytic filtration systems should have been evaluated as a highly effective NOx control that could also improve reductions in SO2 and PM. Further, MDEQ did not adequately justify not fully evaluating SCR as a NOx control option for the Ash Grove cement kiln.

With respect to SO2, MDEQ states that the current semi-dry scrubbing provides the best reduction for SO2 control, and yet MDEQ has not put forth any information to indicate what level of SO2 removal is required by the current limit 2.0 lb/ton of clinker.

These issues are discussed in more detail below.

a) **Use of a Ceramic Catalytic Filtration System**

MDEQ and Ash Grove should have evaluated the use of a ceramic catalytic filtration system to achieve high levels of NOx control. As discussed in Section III.A.1.a) above, there are several vendors offering ceramic catalytic filter systems for baghouses that can achieve high levels of NOx removal through embedded catalysts in the filter, 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

\textsuperscript{340} 2022 Draft Montana Regional Haze Plan at 47.
\textsuperscript{341} 2022 Draft Montana Regional Haze Plan at 200. See also Regional Haze 2\textsuperscript{nd} Implementation Period Four-Factor Analysis, Ash Grove Cement, Montana City, MT, September 2019, at 1-1, 3-2, and 4-2 (hereinafter “Montana Ash Grove Four-Factor Analysis”).
\textsuperscript{342} 2022 Draft Montana Regional Haze Plan at 203.
\textsuperscript{343} Id.
vendors claim that catalytic filters can achieve 90% or greater NOx removal. Notably, the ceramic catalytic filters have been geared towards cement kilns, among other facilities, to help meet the Portland cement MACT standards.

Recently, a four-factor cost assessment for the use of a ceramic catalytic filtration system was done for the GCC Pueblo Cement Plant. That cost information can be used to estimate the costs of using a ceramic catalytic filtration system at the Montana Ash Grove plant. The GCC Pueblo plant has a rated capacity of 3,750 tons per day, while the Montana Ash Grove cement kiln has a lower daily capacity limit of 2,300 tons of clinker per day which applies on a 12-month rolling average basis. Thus, the cost estimate of the use of a ceramic catalytic filtration system at GCC Pueblo likely is higher than the costs of such a system at the Montana Ash Grove plant due to the larger size of the Pueblo plant.

In terms of pollution controls, the GCC Pueblo Plant kiln is equipped with SNCR and a fabric filter baghouse, which is somewhat similar to the Montana Ash Grove Cement kiln although the Ash Grove is also equipped with a semi-dry scrubber for SO2 control. Due to the installation and use of SNCR at both facilities, they both are already equipped with ammonia storage and injection systems. The GCC Pueblo Plant kiln is a newer Portland cement plant that has been described as much more energy efficient than earlier wet cement kilns, whereas it appears that the Montana Ash Grove plant continues to utilize a long wet kiln that has been in operation since 1963. The GCC Pueblo Plant fires primarily lower sulfur coal, while the Montana Ash Grove plant is fired with coal and pet coke. These differences primarily impact the pollutant emission rate per ton of clinker and should not affect the capabilities of a downstream ceramic catalytic filtration system. The cost estimate of the use of a ceramic catalytic filtration system at GCC Pueblo plant would likely be higher than the costs of such a system at the Montana Ash Grove plant due to the larger size of the Pueblo plant.

There are a few options for using a ceramic catalytic filtration system at the Montana Ash Grove Plant: 1) install a stand-alone ceramic catalytic filtration system that would be used after the existing

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347 See GCC Pueblo Four Factor Analysis, Appendix B at 2 (Ex. 24).
348 Montana Air Quality Permit #2005-16 for Ash Grove Cement at 18 (Condition III.F.9) (Ex. 26).
349 See GCC Pueblo Four Factor Analysis, Appendix B at 5 (Ex. 24).
350 See GCC Pueblo Four Factor Analysis, Appendix B at 2 (Ex. 24).
351 Montana Ash Grove Four-Factor Analysis at 2-1. Note that Ash Grove appears to have received a permit in 2013 to modernize the plant including a conversion from a “wet” process to a “dry” process. It is not clear whether that conversion has been done yet, as MDEQ’s Air Quality Permit Analysis indicates that there have been several permit revisions to extend the construction date for those changes. See Montana Air Quality Permit #2005-16 for Ash Grove Cement, attached Montana Air Quality Permit (MAQP) Analysis, Ash Grove Cement Company, MAQP #2005-16, at 4-6.
352 See GCC Pueblo Four Factor Analysis, Appendix B at 4 (Ex. XX).
353 Montana Ash Grove Four-Factor Analysis at 3-3.
baghouse, 2) replace an existing baghouse with a stand-alone ceramic catalytic filter system, and 3) install catalytic filter bags within the existing baghouse. Given that the Montana Ash Grove plant as a relatively new baghouse, the third option would be the most cost effective option.

Tri-Mer provided a cost estimate for the third option – i.e., 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"). 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%). 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 the control system of $1,620,000/year. The capital costs also include the costs to upgrade the existing baghouse if necessary for upgraded structural support and upgraded internals. 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. The use of aqueous ammonia is safer than using anhydrous ammonia, and there is not a federal requirement for an accidental release plan.

The Ash Grove facility has 2028 OTB/OTW NOx emissions of 981.5 tons per year. This reflects at least 50% NOx removal from the SNCR system with some NOx removal also occurring due to the low NOx burners. Assuming NOx removal efficiency increases from 50% with SNCR to 90% with ceramic catalytic filtration bags which would essentially replace SNCR equates to a reduction from 2028 OTB/OTW of 785.2 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), assuming a 3.25% interest rate and a 20-year life of the ceramic filtration system, a ceramic catalytic filtration system could have a cost effectiveness of $2,852/ton of NOx removed. 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 Ash Grove, and the Montana Ash Grove 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 the Montana Ash Grove plant would likely be even more cost effective than shown here.

354 See Montana Air Quality Permit #2005-16 for Ash Grove Cement, attached Montana Air Quality Permit (MAQP) Analysis at 16.
355 GCC Pueblo Four Factor Analysis Appendix F at 5 (in Ex. 24).
356 Id. at 5-6 (Ex. XX).
357 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.
358 Id. at 5.
359 Id., Appendix F at 6.
360 2022 Draft Montana Regional Haze Plan at 210.
361 See 77 Fed. Reg. 23988 at 24,007 at Table 11 (Apr. 20, 2012). Given that the Ash Grove plant is now subject to a lower NOx limit of 7.5 lb/ton than the 8.0 lb/ton NOx limit that was imposed to meet BART, it is possible that the SNCR is achieving somewhat more than 50% NOx control.
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.\footnote{GCC Pueblo Four Factor Analysis Appendix F at 7 (Ex. 24).} Tri-Mer states that “a ceramic filter has no deactivation of the catalyst in a continuous operation for 10 years+.”\footnote{Id. at 13.} With an increase in NOx removal efficiency from 50% with SNCR to 90% reduction with ceramic catalytic filters, the Montana Ash Grove kiln should be able to meet a NOx limit of approximately 1.6 lb/ton.

The four-factor reasonable progress analysis of use 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.\footnote{Id.} In terms of energy and non-air quality impacts of compliance with the ceramic catalytic filtration system would use electricity, which is taken into account in the cost analysis. The ammonia reagent, which the Montana Ash Grove facility is currently using with SNCR, could pose risk management concerns. However, the four-factor analysis for the GCC Pueblo Cement Plant assumed 19% aqueous ammonia would be used, which may not be subject to EPA’s accidental release requirements, unlike use of aqueous ammonia.\footnote{Id.} Further, with use of a ceramic catalytic filtration system instead of SNCR, the Montana Ash Grove plant will likely use less ammonia than it is currently using with SNCR.

For all of these reasons, MDEQ should require the Ash Grove cement plant to evaluate the installation of ceramic catalytic filtration bags in its existing baghouse which would significantly and cost-effectively reduce NOx emissions from the cement kiln.

\begin{itemize}
\item \textbf{b) Selective Catalytic Reduction}
\end{itemize}

Both MDEQ and Ash Grove dismissed SCR as not technically feasible for cement kilns.\footnote{2022 Draft Montana Regional Haze Plan at 203; Ash Grove Four-Factor Analysis at 4-4 to 4-6.} However, as stated in the Federal Land Managers’ comments in Appendix F of the draft Montana Regional Haze Plan, SCR is being used at two US cement kilns (Lafarge/Holcim in Joppa, IL and Holcim in Midlothian, TX) as well as several in Europe.\footnote{2022 Draft Montana Regional Haze Plan, Appendices at pdf page 65 (in Appendix F).} Ash Grove acknowledges the use of SCR in Europe, but states that “the cement industries between Europe and the U.S. differ significantly due to the increased sulfur content found in the processed raw materials in U.S. cement kiln operations,” and that the pyritic sulfur found in the raw materials used in U.S. cement kilns results in “high-dust levels and rapid catalyst deactivation.”\footnote{Ash Grove Four-Factor Analysis at 4-5.} However, given that SCR is being utilized at two cement kilns in the U.S. that are presumably fired with similar fuels to the GCC Trident plant, the SCR systems can be designed to deal with these issues. Further, SCR deployment in Europe is instructive. A paper regarding SCR at the Solnhofen cement plant in Germany explains that the SCR uses honeycomb catalysts with large pitch and describes the most effective catalyst configuration for the cement kiln.\footnote{See Schreiber, Robert J., Jr., & C.O. Russell, The Experience of SCR at Solnhofen and its Applicability to US Cement Plants, June 6, 2006, at 4-7, available at.} The Solnhofen SCR also...
has a catalyst cleaning system. The paper also discusses where the facility injects ammonia for SCR operation and also where it injects ammonia for SNCR operation. The fact that there is not an “off-the-shelf” SCR that does not require source-specific design and operation should not mean that a pollution control is not technically feasible for the Ash Grove.

MDEQ states “[t]here is not enough information available on the technical success or on the actual costs required for construction and operation” of SCR at cement kilns. Yet, neither MDEQ nor Ash Grove have indicated that they have attempted to gather any available information from the Illinois EPA (for the Lafarge/Holcim cement plant SCR in Joppa, IL) or the Texas Commission on Environmental Quality (for the Holcim cement plant SCR in Midlothian, TX). MDEQ states “[a] more rigorous SCR evaluation is likely in the third planning period, if the technology has advanced and more information is publicly available to perform a proper assessment.” Yet, for the technology to advance, MDEQ should gather available information on the application of SCR to cement kilns now as part of the Ash Grove cement plant four-factor analysis.

c) MDEQ Should Evaluate Strengthening the SO2 Limit on the Ash Grove Cement Kiln

MDEQ states the following regarding SO2 emissions from the Ash Grove cement kiln:

The current SO2 control consists of inherent scrubbing of SO2 by alkali metals including sodium and potassium. In 2012, Ash Grove installed a semi-dry scrubber for SO2 removal. The current permit limit for SO2 is limited to 2.0 lb/ton of clinker. The most recent operation has demonstrated that Ash Grove is currently achieving a rate well below the permitted emission rate.

The basis for the current SO2 limit of 2.0 lb/ton of clinker is not known, as the SO2 emission limit was specified in the Consent Decree with the U.S. EPA. MDEQ states in the draft regional haze plan that the semi-dry scrubber was required at Ash Grove to meet BART, but that is not accurate as EPA did not require installation of a semi-dry scrubber to meet BART and EPA’s SO2 BART limit was much higher at 11.5 lb/ton.

EPA stated in its final Montana regional haze rulemaking in 2012 that the 99th percentile 30-day rolling average rate at the Ash Grove cement plant over 2006-2008 was 11.02 lb/ton of clinker and it imposed a

https://crawler.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Pollutants/transport/Comments/Lehigh_Attachment_Solnhofen.pdf
370 *Id.* at 7-8.
371 *Id.* at 7.
372 2022 Draft Montana Regional Haze Plan at 203.
373 *Id.*
374 *Id.* at 200 [emphasis added].
375 As specified in Montana Air Quality Permit #2005-16, Ash Grove Cement – Montana City Plant, October 22, 2021, at 4-5 (Condition II.B.5) (Ex. 26).
11.5 lb/ton to provide a margin of compliance.\textsuperscript{378} A controlled SO2 limit of 2.0 lb/ton reflects 82% removal from EPA’s SO2 BART limit of 11.5 lb/ton, but semi-dry scrubbing can achieve 90-95% SO2 removal. Given that the Ash Grove cement plant is achieving an SO2 rate “well below” the current limit of 2.0 lb/ton of clinker, it is clear that a higher level of SO2 removal efficiency is achievable with the semi-dry scrubber at the Ash Grove cement kiln. Further, EPA’s regional haze guidance would not justify exclusion from a four-factor control analysis of a source that had a flue gas desulfurization (FGD) system that was achieving less than 90% control efficiency.\textsuperscript{379}

The National Park Service also requested that MDEQ set an SO2 emission limit for the Ash Grove kiln that reflects the capabilities of the SO2 controls.\textsuperscript{380} By imposing a more stringent SO2 limit reflective of the capabilities of the semi-dry scrubbing, MDEQ would ensure that Ash Grove consistently operated the semi-dry scrubber to optimize SO2 reductions. Thus, MDEQ should strengthen the SO2 limit on the Ash Grove cement kiln to ensure the optimization of the SO2 controls and minimize SO2 emissions from the Ash Grove facility to the maximum extent possible.

\textit{d) Summary: MDEQ Must Consider Use of Ceramic Catalytic Filters as a Top Control Technology for NOx at the Ash Grove facility and Must Consider Strengthening the SO2 Limit to Reflect the Capabilities of the Semi-dry Scrubbing.}

For the reasons provided above, MDEQ should consider use of a ceramic catalytic filtration system in the existing baghouse as a top control technology for NOx and PM. As discussed above, the use of ceramic catalytic filters in the Ash Grove cement kiln’s existing baghouse would likely be very cost effective and would allow the cement kiln to increase NOx reduction efficiency to 90% for 785 tons per year of NOx reduced.

\section{Oil Refineries}

\subsection{ExxonMobil Billings Refinery}

The ExxonMobil refinery is located in Billings, Montana. The facility ranks tenth on MDEQ’s list of facilities evaluated for regional haze pollution controls with a Q/d value of 7.2 based on SO2+NOx emissions.\textsuperscript{381} The National Parks Conservation Association ranks the ExxonMobil refinery in Billings as the ninth highest in terms of cumulative Q/d ranking.\textsuperscript{382}

The four-factor submittal for the Billings ExxonMobil refinery describes the facility process as follows:

The Billings Refinery is designed to process a variety of crude slates including those containing high sulfur crude oil. Major process units include: atmospheric and vacuum

\textsuperscript{378} \textit{Id.} at 57878.
\textsuperscript{380} 2022 \textit{Draft Montana Regional Haze Plan}, Appendices at pdf page 61.
\textsuperscript{381} 2022 \textit{Draft Montana Regional Haze Plan} at 161.
\textsuperscript{382} \textit{National Parks Conservation Association’s Regional Haze Fact Sheet for Montana}, available at \texttt{https://www.npca.org/reports/regional-haze}. 
crude distillation towers, a fluidized catalytic cracking unit (FCCU), a hydrocracker and hydrogen plant, a fluid coker, a naphtha fractionator, a catalytic reformer, an alkylation unit, three hydrotreaters for polishing the naphtha and distillate streams, and a catalytic hydrotreating unit (CHUB). The Billings Refinery does not have a sulfur recovery unit within the refinery. Refinery gases high in hydrogen sulfide (H2S) are piped to an off-site sulfur recovery plant owned and operated by the Montana Sulphur and Chemical Company (MSCC). MSCC extracts sulfur from the sour refinery fuel gas (RFG) and returns sweetened fuel gas to the Billings Refinery. The Billings Refinery sends coker process gases to the Yellowstone Energy Limited Partnership (YELP) facility for treatment (combustion) in two boilers, except when YELP is not operating.\textsuperscript{383}

According to the Technical Review Document for the ExxonMobil Title V permit, the facility has a capacity of greater than 52,000 barrels per day and is designed to process high sulfur crude oil.\textsuperscript{384} EPA eliminated the ExxonMobil refinery from consideration for regional haze controls in its regional haze plan for Montana adopted in 2012, based on consent decrees entered into by the owner.\textsuperscript{385} MDEQ refers to an “EPA Refinery Consent Decree,”\textsuperscript{386} but the Consent Decree is not part of the regional haze plan or appendices. MDEQ should at least provide a weblink for the referenced Consent Decree, and a copy should be included in an appendix to the regional haze plan.

MDEQ did not require a four-factor analysis of controls for all emitting units at the ExxonMobil refinery and instead focused on the higher-emitting units which included for NOx: The Coker CO boiler (KCOB), F-1 Crude Furnace/F-4012 Vacuum Heater, and the F-551 Hydrogen Plant.\textsuperscript{387} MDEQ claims that these emission units reflect 52% of the emissions from the refinery.\textsuperscript{388} MDEQ should identify all of the emission units at the refinery, and the units’ actual and allowable emissions. ExxonMobil did also include a four-factor analysis for the F-201 Hydrofiner Heater as a “representative, smaller process heater.”\textsuperscript{389} However, it is not clear whether the F-201 Hydrofiner Heater is representative of the smaller process heaters at ExxonMobil refinery unless MDEQ provides actual and potential emissions data for all heaters at the refinery.

MDEQ states that Exxon selected 2015-2016 as representative of baseline and of 2028 OTB/OTW emissions and that MDEQ concur that this two-year period is representative of recent normal operations.\textsuperscript{390} MDEQ should provide more data to support its finding that the average of 2015-2016 operations and emissions are representative of expected emissions in 2028. The table below shows the plantwide baseline emissions and 2028 OTB/OTW emissions.

\textsuperscript{383} Regional Haze Four-Factor Analysis, ExxonMobil Billings Refinery, November 2019, at 3 (hereinafter “2019 ExxonMobil Four-Factor Analysis”).
\textsuperscript{384} MDEQ, Exxon Mobil Billings Refinery, Operating Permit Technical Review Document, 9/9/2021, at 22, attached as Ex. 27.
\textsuperscript{385} 77 Fed. Reg. 23989 at 24059 (Apr. 20, 2012);
\textsuperscript{386} \textit{See}, e.g., 2022 Draft Montana Regional Haze Plant at 251-2.
\textsuperscript{387} \textit{2022 Draft Montana Regional Haze Plan at 251}.
\textsuperscript{388} \textit{Id}.
\textsuperscript{389} \textit{Id}.
\textsuperscript{390} \textit{Id} at 252.
Table 16. ExxonMobil Plantwide Baseline Emissions and 2028 OTB/OTW Emissions

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<tr>
<th>Baseline Period</th>
<th>NOx Baseline, tons per year</th>
<th>SO2 Baseline, tons per year</th>
<th>2028 NOx OTB/OTW, tons per year</th>
<th>2028 SO2 OTB/OTW, tons per year</th>
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<tr>
<td>2015-2016</td>
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</tbody>
</table>

MDEQ did not require evaluation of any SO2 controls for the emission sources at the ExxonMobil Billings Refinery. MDEQ stated that the FCCU accounts for 75% of the 2015-2016 baseline SO2 emissions, and that the refinery is currently “engaged in an extended demonstration period on a desulfurization (DeSOx) additive while operating the FCCU in Full Burn Operation as required under its EPA Consent Decree....” MDEQ should provide more information on this demonstration period, including when it is projected to be completed and when final SO2 limits required by the Consent Decree are likely to be imposed.

1. Evaluation of NOx Controls for ExxonMobil Billings Refinery

Based on a review of the operating permit for the ExxonMobil Billings refinery, the following is a list of combustion devices and sources at the refinery and the NOx controls that the units have, if any. MDEQ should have included this information in its discussion of NOx controls for the refinery. If any additional NOx controls have been installed that are not reflected in the 11/2/2021 Title V permit issued for the refinery, MDEQ should update this list.

Table 17. ExxonMobil Combustion Sources and NOx Controls/Limits/Emissions

<table>
<thead>
<tr>
<th>Unit ID</th>
<th>Subunit ID and Description</th>
<th>MMBtu/hr (if known)</th>
<th>NOx Pollution Control Devices/Practices</th>
<th>NOx Limit</th>
<th>Estimated Baseline &amp; 2028 NOx (if available), tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>EU00</td>
<td>EU01b: F-3 Heater</td>
<td></td>
<td></td>
<td></td>
<td>6.27 lb/hr &amp; Combined with F201:</td>
</tr>
<tr>
<td></td>
<td>EU02a: F-3x Heater</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>EU02b: F-5 Heater</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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391 Id. at 251-252.
392 Id.
394 Information from 11/2/2021 Final Title V Operating Permit #OP1564-18, ExxonMobil Corporation, Billings Petroleum Refinery (Ex. 29) and from 9/21/2021 Montana Air Quality Permit #1564-35, Exxon Mobil Corporation Billings Refinery, including attached Montana Air Quality Permit Application Analysis (Ex. 30).
395 The unit-specific baseline NOx emissions were estimated from ExxonMobil's stated emission reductions and the stated removal efficiency for the NOx controls it evaluated in the four-factor analyses. See ExxonMobil Four-Factor Analysis at 32 (Table 2). ExxonMobil did not provide a unit-specific baseline emission inventory, and thus NOx emissions for the units not evaluated for controls in the four-factor analysis are not known.
| EU03a: Coker CO Boiler ("KCOB") (also see EU03) | 146 MMBtu/hr | None | 71 tpy |
| EU03b: F-202 Heater | | | |
| EU04a: F-700 Heater | 122 MMBtu/hr | ULNB | None |
| EU05a: F-402 Heater | | | |
| EU07a: F-201 Heater | 36 MMBtu/hr | 4.7 lb/hr | 10 tpy |
| EU09a: FCCU CO Boiler (also see EU09) | SCR | 30 ppmvd (365-day rolling) 80 ppmvd (7-day rolling) |
| EU11a: F651 Heater | | | |
| EU12a: F-551 Heater | 160 MMBtu/hr | 23.35 lb/hr & 75.55 ton/12-month rolling | 54 tpy |
| EU13: B-8 Boiler | 99 MMBtu/hr (limit, rolling 24-hr avg) | ULNB and Flue Gas Recirculation (FGR) | 0.04 lb/MMBtu 3.96 lb/hr 17.3 tons/12-month rolling |
| EU14b: F-10 Heater | | | |
| EU16a: F-1201 Heater | 99 MMBtu/hr | ULNB | 0.060 lb/MMBtu 5.94 lb/hr |
| EU01 EU01a: F-2 Crude/Vacuum Heater (F-1 Crude Furnace/F-401 Vacuum Heater) | 280 MMBtu/hr | None | 83 tpy |
| EU03 EU03a: Coker Unit CO Boiler ("KCOB") | 146 MMBtu/hr | None | 71 tpy |
| EU09 EU09a: CCOB (FCCU CO Boiler) | SCR | 30 ppmvd (365-day rolling) 80 ppmvd (7-day rolling) |

\[396\] *id.*
ExxonMobil only evaluated NOx controls for four units: Unit KCOB (FCCU CO Boiler), Unit F-1/F-401 (Crude/Vacuum Heater), F-551 (Heater), and F-201 (a smaller heater as an example for other small heaters). MDEQ should provide more data on the size and emissions of the other eleven combustion units not evaluated for controls.

ExxonMobil and MDEQ evaluated the following NOx pollution controls for the four units listed above:

- Unit KCOB: ultra-low NOx burners (ULNB), SNCR, and SCR
- Unit F-1/F-401: SCR
- Unit F-551: SCR
- Unit F-201: ULNB, SCR

ExxonMobil did not evaluate SNCR for Unit F1/F401 (Crude Heater/Vacuum Heater), Unit F-551, or Unit F-201. MDEQ must explain why SNCR was not evaluated as a NOx control for these units.

ExxonMobil also did not provide documentation for its ULNB costs, and MDEQ must require documentation of the basis for the ULNB cost estimates. With respect to use of ULNB on smaller heaters and boiler, the California Air Resources Board determined as far back as 1991 that heaters and boilers as small as 5 MMBtu/hour or greater could meet NOx “best available retrofit control technology” (BARCT) limits of 30 ppmv (or about 0.036 lb/MMBtu).\(^\text{397}\) Further, more recently, California’s South Coast Air Quality Management District concluded that even lower NOx limits, as low as 9 ppm, could be met with ULNB at boilers and process heaters as small as 2 MMBtu/hr.\(^\text{398}\) This was based on actual ULNB retrofit experience at boilers and heaters in the San Joaquin Unified Air Pollution Control District.\(^\text{399}\) The Ventura County Air Pollution Control District in California also found that boilers and process heaters as small as 2 MMBtu/hr could meet NOx limits of 9 ppm with ULNB.\(^\text{400}\) For units for which the retrofit of ULNB is not technically feasible and for which SNCR or SCR are not cost effective, MDEQ should evaluate the costs of replacing an existing boiler or heater with a new unit equipped with state-of-the-art ULNBs. If a unit is near the end of its useful life, this could be a very cost effective and readily implementable approach to reducing NOx emissions.

A review of the cost effectiveness analyses of the NOx controls that were evaluated shows the following deficiencies in ExxonMobil’s cost calculations that would tend to overstate costs and understate cost effectiveness of the controls:

1) While not shown in the printed out spreadsheet in ExxonMobil’s four-factor report, the company’s cost evaluation for SNCR at Unit KCOB understated the NOx removed with SNCR by inputting a “time that the SNCR operates” of 265 days.\(^\text{401}\) The version of the EPA cost spreadsheet that ExxonMobil used assumed that the SNCR did not operate the other 100 days per year and understated the NOx emissions reduced with SNCR. EPA has issued an updated SNCR spreadsheet on 3/19/21 that now has an entry for the number of days SNCR operates and

\(^{397}\) As discussed in Stamper, V. & 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 120 (attached as Ex. 31).

\(^{398}\) Id. at 121.

\(^{399}\) Id.

\(^{400}\) Id. at 121-122.

\(^{401}\) 2019 ExxonMobil Four-Factor Analysis, Appendix B, at pdf page 55 of document.
the number of days the boiler operates.\textsuperscript{402} ExxonMobil should have assumed that the SNCR operates whenever the boiler operates, which can either be assumed by inputting into the spreadsheet that the SNCR operates 365 days per year or by keeping the number of days the boiler operates to be the same as the number of days the SNCR operates, if using EPA’s updated SNCR cost spreadsheet.

2) ExxonMobil used a normalized stoichiometric ratio (NSR) of 2.0 in the SNCR cost spreadsheet but did not explain how that NSR was derived. The default NSR in the EPA SNCR cost spreadsheet is 1.05. Given that the NSR defines how much ammonia or urea reagent is used, MDEQ must require ExxonMobil to document the basis for its assumed NSR rate for SNCR.

3) ExxonMobil assumed urea would be the reagent with SNCR to meet 58.5\% NOx removal. Ammonia allows for higher NOx reductions than urea and is less expensive than urea.\textsuperscript{403} Given that the facility is already handling ammonia for the SCR that has been installed on the FCCU pursuant to the Consent Decree,\textsuperscript{404} ExxonMobil should have assumed ammonia as the reagent.

4) ExxonMobil assumed a life of SNCR of 20 years. However, EPA’s SNCR chapter of its Control Cost Manual states that the life of SNCR at petroleum refineries could be as long as 25 years. For the reasons discussed in Section II.A.1.b.2) above, it is reasonable to assume a longer life for SNCR than the example lifetime EPA assumed in the Control Cost Manual. MDEQ should require use of SNCR lifetime for refinery heaters and boilers of at least 25 years.

5) ExxonMobil inexplicably assumed the SNCR at Unit KCOB would operate 265 days, but the SCR at Unit KCOB would operate 211 days.\textsuperscript{405} The length of time that the SCR operates does affect the cost calculations, and ExxonMobil should have been consistent in its evaluation of SNCR and SCR for Unit KCOB in terms of how many days the control will operate – which should be the same as the typical number of days the unit operates in a year.

6) ExxonMobil assumed a life of SCR of 20 years. However, EPA’s SCR chapter of its Control Cost Manual states that the life of SCR at petroleum refineries could be as long as 30 years.\textsuperscript{406} MDEQ should have evaluated SCR at a 30-year life.

7) ULNB should have been evaluated at a 30-year life. For example, in its proposed regional haze review for controls at a fuel oil and natural gas-fired boiler at the AECC Carl E. Bailey Generating Station in Arkansas, EPA assumed a 30-year life of combustion controls (including LNB).\textsuperscript{407}

8) ExxonMobil evaluated ultra-low NOx burners for Unit KCOB and F-201. However, the company did not provide the basis for these costs, nor did it identify the capital costs and the operating and maintenance costs. Instead, it just provided the cost effectiveness of the control. MDEQ must include the basis for these cost estimates and the details of the cost estimates. Further,

\textsuperscript{402} Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.


\textsuperscript{404} Consent Decree, Third Amendment, U.S.A. v. ExxonMobil Corporation, filed 12/17/2008, at page 7, paragraph 17 (Ex. 28).

\textsuperscript{405} 2019 ExxonMobil Four-Factor Analysis, Appendix B, at pdf pages 55 and 63 of document.

\textsuperscript{406} EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 80.

\textsuperscript{407} 80 Fed. Reg. 18944 at 18955 (Apr. 8, 2015).
ExxonMobil must document the basis for the assumed NOx removal/controlled emission rate with ultra-low NOx burners.

9) ExxonMobil used a 5.5% interest rate, but the current interest rate is 3.25%. MDEQ must require use of the current bank prime interest rate.

In the table below, revised cost effectiveness analyses are provided for Unit KCOB, Unit F-1/F-401, Unit F-551, and Unit F-201 that address some of these issues. Specifically, the costs reflect a 3.25% interest rate, a 25-year life for SNCR, a 30-year life for SCR, and the SNCR cost calculations correct the discrepancies in item 1 above regarding ensuring that the SNCR cost effectiveness is based on the SNCR operating every day the boiler is operated. With respect to the ULNB costs for which the specific capital and operational expenses were not provided by ExxonMobil, an estimate of revised cost effectiveness at a 3.25% interest rate and a 30-year life was done by multiplying the cost effectiveness numbers by the ratio in the capital recovery factor for ExxonMobil’s assumed 5.5% interest rate and 20-year life (i.e., 0.0837) and the capital recovery factor for 3.25% interest rate and a 30-year life.

Table 18. Revised Cost Effectiveness of NOx Controls for ExxonMobil Billings Refinery Units KCOB, F-1/F-401, F-551, and F-201

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>KCOB</td>
<td>SNCR</td>
<td>$1,862,106</td>
<td>$45,891</td>
<td>$156,594</td>
<td>41</td>
<td>$3,785/ton</td>
</tr>
<tr>
<td>KCOB</td>
<td>ULNB</td>
<td></td>
<td></td>
<td></td>
<td>62</td>
<td>$3,678/ton</td>
</tr>
<tr>
<td>KCOB</td>
<td>SCR</td>
<td>$4,495,882</td>
<td>$66,422</td>
<td>$305,533</td>
<td>67</td>
<td>$4,570/ton</td>
</tr>
<tr>
<td>F-1/F-401</td>
<td>SCR</td>
<td>$6,864,964</td>
<td>$116,017</td>
<td>$480,099</td>
<td>79</td>
<td>$6,095/ton</td>
</tr>
<tr>
<td>F-551</td>
<td>SCR</td>
<td>$4,771,594</td>
<td>$76,017</td>
<td>$329,645</td>
<td>51</td>
<td>$6,459/ton</td>
</tr>
<tr>
<td>F-201</td>
<td>ULNB</td>
<td></td>
<td></td>
<td></td>
<td>7</td>
<td>$19,724/ton</td>
</tr>
<tr>
<td>F-201</td>
<td>SCR</td>
<td>$1,809,598</td>
<td>$17,828</td>
<td>$114,671</td>
<td>9</td>
<td>$12,798/ton</td>
</tr>
</tbody>
</table>

As the above table demonstrates, there are cost-effective NOx controls for Units KCOB, Unit F01/F-401, and Unit F-551. SCR should be considered cost effective for Units KCOB, F-1/F-401, and F-551. These costs are within the range that other states are planning to use to determine cost effectiveness of controls in their regional haze plans for the second implementation period: Arizona is using $4,000 to $6,500/ton. New Mexico is using $7,000 per ton, and Oregon is using $10,000/ton or possibly even

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408 The revised costs for SCR and SNCR were based on EPA’s cost spreadsheets. See SNCR and SCR cost spreadsheets for Unit KCOB at Exs. 32 and 33, SCR cost spreadsheet for Unit F-1/F-401 at Ex. 34, SCR cost spreadsheet for Unit F-551 at Ex. 35, and SCR cost spreadsheet for Unit F-201 at Ex. 36. ULNB costs were revised to reflect a 3.25% interest rate and 30-year life but were otherwise based on costs provided by ExxonMobil. Costs were revised from the 2018 cost basis used by ExxonMobil to 2019 dollars using the difference in CEPCI indices (607.5/603.1).


higher.\textsuperscript{411} Oregon has adopted a much higher regional haze control cost threshold of $10,000/ton.\textsuperscript{412} Colorado is also using a reasonableness cost threshold of $10,000/ton.\textsuperscript{413} In addition, the Washington Department of Ecology has found SCR to be cost effective for various heaters and boilers at refineries in its state, relying on a cost-effectiveness threshold of $6,300/ton.\textsuperscript{414}

SCR systems have been retrofitted to many refinery emission units over the years, including at fluid catalytic cracking units (FCCUs). A paper from 2002 discusses the success of SCR retrofit at an FCCU at the BP Whiting Refinery and refers to SCR installations at FCCUs dating back to 1986.\textsuperscript{415} SCR has also been used on refinery boilers and heaters, including at some Washington refineries\textsuperscript{416} and can achieve in excess of 95% NOx control from the NOx emitted from the heaters.\textsuperscript{417} Experience using SCRs in the refinery industry shows the controls are reliable and have low operational and maintenance costs.\textsuperscript{418}

Thus, MDEQ should find that SCR is a cost effective control for Units KCOB, F-1/F-401, and F-551.

2. Consideration of Time Necessary for Compliance, Energy and Non-Air Quality Environmental Impacts, and Remaining Useful Life

Consideration of the remaining reasonable progress factors does not reveal any impediment to the installation and operation of SCR. MDEQ states that ExxonMobil estimates that it would take 3-5 years for installation of SCR.\textsuperscript{419} MDEQ states that the SCRs would likely be tail-end installations,\textsuperscript{420} which would make installation of SCR less complicated than a high-dust SCR installation.

\textsuperscript{416} For example, BP Cherry Point has installed SCR on its #2 hydrogen plant SMR furnace, its #6 and #7 boilers, according to its August 26, 2014 Air Operating Permit #015R1M1, available at https://nwcleanairwa.gov/?wpdmdl=981.
\textsuperscript{418} Id.
\textsuperscript{419} Id. at 256.
\textsuperscript{420} Id.
MDEQ also states:

Any major control installation at affected units would have to wait until either the estimated 2026 Hydrogen Plant/Hydrocracker turnaround (affecting the F-551 Heater) or the estimated 2025 FCCU/Alkylation Unit turnaround. The retrofit of smaller process heaters (such as the F-201 Hydrofiner Heater) may allow for implementation outside of major turnarounds, but such efforts would require a similar level of planning as the major units because of the interdependence of refinery systems.421

If MDEQ requires SCR installation now as part of its regional haze plan for the second implementation period, it could very likely be installed during the 2025 or 2026 turnaround events. But in any event, the precise turnaround outage when SCR could be installed at the refinery units is not properly considered a limiting factor under the four-factor analysis. The time necessary for compliance does not provide the same type of barrier to consideration of a control to meet reasonable progress as the other three factors do, because the time perspective of the regional haze program is long. EPA states in its 2019 regional haze guidance that “[i]n 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 must not consider this fact in determining whether the measure is necessary to make reasonable progress (40 CFR 51.308(f)(2)(i)).”422

With respect to the energy and non-air quality impacts of compliance with SCR or SNCR, those should not be considered an impediment to implementation of the controls. The energy costs are taken into account in the cost analyses done with EPA’s SCR and SNCR cost spreadsheets. The non-air quality impacts mainly are due to the handling of ammonia. The ExxonMobil Billings refinery has installed SCR on the FCCU CO boiler, and thus it presumably has staff trained in the safe handling of ammonia.

MDEQ also states that the facility operator may need to dispose of the spent catalyst in a hazardous waste landfill.423 However, EPA’s Control Cost Manual states that “most catalyst formations are not considered hazardous waste.”424 In its four-factor analysis of NOx controls for the CHS Inc. Refinery Laurel, MDEQ acknowledges this, stating that the spent catalyst “is comprised of metals that are not considered toxic.”425 EPA also states that “[m]ost SCR manufacturers offer a disposal service, in which either the catalyst is reactivated (i.e., rejuvenated or regenerated) for reuse or its components are recycled for other uses.”426

421 2022 Draft Montana Regional Haze Plan at 256.
423 2022 Draft Montana Regional Haze Plan at 257.
425 2022 Draft Montana Regional Haze Plan at 266.
3. Summary – MDEQ Must Consider SCR as a NOx Control for the Units KCOB, F-1/F-401, and F-551 as Reasonable Progress Measures, and MDEQ Must More Fully Evaluate ULNB Controls for the Smaller Heaters at the ExxonMobil Billings Refinery

For the reasons provided above, MDEQ should consider adopting requirements to install SCR at Units KCOB, F-1/F-401, and F-551 as cost-effective measures to make reasonable progress towards the national visibility goal. As shown in Table XX above, those controls should be considered cost effective with revised costs ranging from $4,500 to $6,500/ton. Such controls would reduce NOx emissions by 95%, which would reduce NOx from the baseline/projected 2028 NOx emissions of the refinery by about 200 tons per year in total across all three units.

MDEQ must also more fully evaluate ULNB for the smaller heaters at the ExxonMobil Billings refinery, including obtaining documentation on ExxonMobil’s cost basis for ULNB, and ensuring that the higher emitting small heaters were evaluated for NOx controls.

B. Cenex Harvest States Cooperative Inc. (CHS) Inc. Refinery Laurel

CHS Inc. Refinery Laurel is an oil refinery located in Laurel, Montana, southwest of Billings. The facility ranks eleventh on MDEQ’s list of facilities evaluated for regional haze pollution controls with a Q/d value of 7.2 based on SO2+NOx emissions.427 The National Parks Conservation Association ranks the CHS Laurel refinery in Billings as the fifteenth highest in terms of cumulative Q/d ranking.428

MDEQ states that it determined “it was impractical to perform a four-factor analysis on each individual emitting unit,” due to the many small emitting units in a refinery.429 MDEQ thus focused on the following subset of emitting units at CHS: Main Crude Heater (for NOx), the Platformer Heater (for NOx), Boiler #9 (for NOx), and the Main Refinery Flare (for SO2).

MDEQ states that CHS selected 2017-2018 as representative of baseline, and CHS selective a future year 2028 OTB/OTW emissions scenario that was used to calculate cost effectiveness.430 MDEQ should provide more data to support its finding that the average of 2015-2016 operations and emissions are representative of expected emissions in 2028. The table below shows the plantwide baseline emissions and 2028 OTB/OTW emissions.

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427 2022 Draft Montana Regional Haze Plan at 161.
429 2022 Draft Montana Regional Haze Plan at 258.
430 Id.
MDEQ states that the 2028 OTB/OTW considers reductions from the electrification of the Platformer Recycle Compressor that was done in 2018, additions from stationary emergency engines that were added to the refinery in 2018, and the following two future expected emission reductions:

1) The #2 RFG-fueled Crude Unit Vacuum Heater is expected to be replaced prior to 2028 with a heater that includes ultra-low NOx burners, and
2) SO2 emissions from the main refinery flare are expected to decrease by 20% from the 2017-2018 baseline by 2028 “as a result of ongoing air pollution control programs, including optimization and increased utilization of the [flare gas recovery system (FGRS)] and the ongoing work practices required by applicable regulations.”

EPA states in its 2019 regional haze guidance that, generally, the 2028 emissions are based on emissions over a representative historical period, but that there may be circumstances under which it is justified to project 2028 emissions that significantly differ from historical emissions: 1) enforceable requirements, and 2) a documented commitment and verifiable basis for participating in energy efficiency, renewable energy, or similar programs.

To be consistent with EPA’s guidance, MDEQ must identify the enforceable requirements that ensure replacement of the #2 RFG-fueled Crude Unit Vacuum Heater with a new heater equipped with ultra-low NOx burners, as well as the requirements to use and optimize a flue gas recovery system to reduce SO2 emissions from flaring.

CHS Inc. included specific 2017-2018 baseline emissions for four units for which it evaluated controls, which are shown in the table below.

### Table 19. CHS Inc. Refinery Laurel – Baseline Emissions by Emitting Unit for Which Four-Factor Analyses of Controls were Done

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>Pollutant</th>
<th>2017-2018 Baseline, tpy</th>
<th>Baseline NOx, lb/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>Main Crude Heater</td>
<td>NOx</td>
<td>43.6</td>
<td>0.1</td>
</tr>
<tr>
<td>Platformer Heater</td>
<td>NOx</td>
<td>91.4</td>
<td>0.275</td>
</tr>
<tr>
<td>#9 Boiler</td>
<td>NOx</td>
<td>29.3</td>
<td>0.098</td>
</tr>
<tr>
<td>Main Refinery Flare</td>
<td>SO2</td>
<td>181.6</td>
<td>Not Given</td>
</tr>
</tbody>
</table>
With respect to the baseline lb/MMBtu NOx emission rates, there does not appear to be any recent data to support the baseline emission rate emission rate for the Boiler #9. MDEQ should document the basis of the assumed lb/MMBtu NOx rate for Boiler #9.

1. Evaluation of SO2 Controls for the CHS Inc. Refinery Laurel

According to the 2017-2018 baseline SO2 inventory for the CHS Inc. Refinery Laurel, SO2 emissions from flaring account for 72% of total SO2 emissions from the facility and averaged 181.6 tons per year over 2017-2018. MDEQ and CHS’s four-factor analysis includes discussion of its Flare Gas Recovery System (FGRS) that has been in operation since November 2015, stating the FGRS “was identified as one element of BACT for the Main Refinery Flare during a 2014 minor modification permit action.” MDEQ and CHS cite to requirements in Subpart Ja of the New Source Performance Standards (NSPS) (at 40 C.F.R. §60.103a(a)) and in Subpart CC of the National Emission Standards for Hazardous Air Pollutants (NESHAPs) (at 40 C.F.R. §63.670(o)(1)) as requiring the development of a written flare management plan (FMP). MDEQ lists the following information as specifically required to be included in or referenced in the FMP:

- Listing of all process units, ancillary equipment, and fuel gas systems that are connected to the flare header system;
- A flare minimization assessment;
- Description of all flare components and design parameters;
- Specifications for all required monitoring instrumentation;
- A baseline flow evaluation;
- A description of procedures to reduce flaring during planned startups and shutdowns, during imbalances of the fuel gas system, and during outages of a FGRS; and
- A completion of a root cause/corrective action analysis when the 24-hour total SO2 from the flare exceeds 500 pounds and/or when the 24-hour total flare flow is greater than 0.5 MMSCF above the baseline.

With respect to SO2 controls for the Main Refinery Flare, MDEQ states:

No control measures beyond what are already in place were identified. Each of the work practices identified above together function as a means of minimizing SO2 emissions. However, additional SO2 reductions at the Main Refinery Flare are anticipated as part of ongoing air pollution control programs.

However, it is not clear what the “work practice” measures are, because MDEQ has not included as part of its regional haze plan the Flare Minimization Plan developed by CHP. MDEQ also has not identified any conditions of the CHS refinery’s Title V operating permit that contain work practice or other measures/limitations that are part of the Flare Minimization Plan. MDEQ should have included the Flare Minimization Plan in the regional haze plan and also cited to relevant permit conditions pertaining to

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435 2022 Draft Montana Regional Haze Plan at 260.
436 Id.
437 Id.
438 Id. at 261.
implementing the Flare Minimization Plan in the draft regional haze plan, so the public would be able to review the specific measures being relied on by MDEQ to address SO2 emissions from the CHS Main Refinery Flare.

MDEQ also states CHS’ belief “that SO2 emissions from the Main Refinery Flare will decrease by at least 20% from the 2017-2018 baseline by 2028 as a result of ongoing programs and work practices.” 439 MDEQ and CHS gave two examples of recently identified opportunities, which included:

- Using additional online analyzers, which have been installed, to better identify flare gases that may be compatible with the RFG system; and
- A piping modification, which CHS states “is being implemented,” to allow for recovery and amine treatment of certain flare gases that aren’t currently being recovered because they don’t meet RFG specifications. Those additional gases will still be flared, but (presumably) after treatment by the amine unit. 440

MDEQ must make clear whether the above two examples are the basis of its assumed 20% reduction in SO2 emissions from the Main Refinery Flare that it is taking into account for its 2028 emission projections. More specifically, MDEQ must make clear when the additional online analyzers were installed, what additional flare gases CHS determined were determined to be compatible with the RFG system (including whether that means the gases will first be treated with the amine unit before being used as RFG), what additional flare gases are now being treated through the amine unit before flaring, and – if this work of identifying additional flare gases to route through the amine unit and/or avoid flaring is continuing - the planned schedule for completion of this analysis. The Long Term Strategy section of Montana’s Draft Regional Haze Plan clearly identifies the 20% reduction in SO2 emissions from flaring in the 2028 SO2 emission inventories that were used to set the 2028 Reasonable Progress Goals (RPGs). 441 Given that the assumed 20% reduction in SO2 from the CHS Main Refinery Flare is being taken into account in 2028 emissions projections and setting of RPGs, MDEQ must identify the enforceable requirements and compliance schedules that are part of the Long Term Strategy, pursuant to 40 C.F.R. §51.308(f)(2).

2. Evaluation of NOx Controls for the CHS Inc. Refinery Laurel

As shown in Table 19 above, CHS and MDEQ only evaluated NOx controls for three units: the main crude heater, the platformer heater, and the #9 boiler. The 2017-2018 NOx emissions of those three units total 164.3 tons per year, and that only reflects 40% of the 408.6 tons per year emitted by the CHS Inc. Refinery Laurel. MDEQ should identify all of the emission units at the refinery, and the units’ actual and allowable emissions.

Based on a review of the 2021 operating permit for the CHS Refinery Laurel and of a 2022 Montana Air Quality Permit and its attached Montana Air Quality Permit Analysis which has historical information, the following is a list of combustion devices and sources at the refinery and the NOx controls that the units have, if any. Note that, for determining the MMBtu/hr capacity, this information was mostly

439 Id.
440 Id. at 261-262. See also CHS 2019 Four-Factor Analysis at 3-17.
441 2022 Draft Montana Regional Haze Plan at 294 (Table 7-2).
obtained from narrative in the Montana Air Quality Permit (MAQP) Analysis of Permit #1821-44, issued February 23, 2022. The heat input capacities should be considered approximate, because several of the unit’s heat input appear to have been modified over time and it was difficult to ensure the current heat input capacity was reflected. Further, there are several units for which the capacity could not be ascertained in the permit documents.

MDEQ should have included this information in its discussion of NOx controls for the refinery. If any additional NOx controls have been installed that are not reflected in the 6/8/2021 Title V permit issued for the refinery, MDEQ should update this list.

Table 20. CHS Inc. Refinery Laurel Combustion Sources and NOx Controls/Limits/Emissions

<table>
<thead>
<tr>
<th>Unit ID</th>
<th>Subunit ID and Description</th>
<th>MMBtu/hr (if known)</th>
<th>NOx Pollution Control Devices/Practices</th>
<th>NOx Limit Baseline/2028 NOx (if available), tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>EU002</td>
<td>CV-HTR-1: #1 Crude Unit Preheater</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>CV-HTR-2: #1 Crude Unit Main Heater</td>
<td>142 MMBtu/hr</td>
<td>LNB</td>
<td>43.6</td>
</tr>
<tr>
<td></td>
<td>CV-HTR-4: #1 Crude Unit Vacuum Heater</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>C-401: Low Pressure Vapor Recovery Compressor</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU003</td>
<td>2CV-HTR-1: #2 Crude Unit Main Heater</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>2CV-HTR-2: #2 Crude Unit Vacuum Heater</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU005</td>
<td>H-8301: Naphtha Hydrotreating Unit (NHT) Charge Heater</td>
<td></td>
<td>Low NOx Technology</td>
<td></td>
</tr>
<tr>
<td></td>
<td>H-8302: NHT Reboiler Heater</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>H-8303: NHT Reboiler Heater #2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>H-8304: NHT Splitter Reboiler Heater</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>C-8302A: Makeup Hydrogen Compressor</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>C-8302B: Recycle Hydrogen Compressor</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU007</td>
<td>P-HTR-1: Platformer</td>
<td>190.4</td>
<td></td>
<td>91.4</td>
</tr>
</tbody>
</table>

*Information from 6/8/2021 Final Title V Operating Permit #OP1821-19, CHS Laurel Petroleum Refinery, attached as Ex. 37, and from 2/23/2022 Montana Air Quality Permit #1821-44, CHS Laurel Refinery, attached as Ex. 38.*
<table>
<thead>
<tr>
<th>Location</th>
<th>Equipment</th>
<th>MMBtu/hr</th>
<th>NOx Technology</th>
<th>Emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>EU008</td>
<td>FCC-Htr-1: FCC Charge Heater</td>
<td>66 MMBtu/hr</td>
<td>Low NOx Technology-ULNB</td>
<td>2.6 lb/hr, 24-hr rolling avg, 10.1 tons per 12 months</td>
</tr>
<tr>
<td>EU009</td>
<td>ALKY-HTR-1: Alkylation Unit Hot Oil Belt Heater</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU010</td>
<td>H-101: Reformer Heater</td>
<td>135.5 MMBtu/hr</td>
<td>Low NOx Technology</td>
<td></td>
</tr>
<tr>
<td>H-102: Reformer Heater</td>
<td></td>
<td></td>
<td>Low NOx Technology (ULNB)</td>
<td>3.02 lb/hr, 24-hr rolling avg, 11.3 tons per 12 months</td>
</tr>
<tr>
<td>H-201: Reactor Charge Heater</td>
<td>41.5 MMBtu/hr</td>
<td>Low NOx Technology</td>
<td></td>
<td></td>
</tr>
<tr>
<td>H-202: Fractionator Feed Heater</td>
<td>29.9 MMBtu/hr</td>
<td>Low NOx Technology</td>
<td></td>
<td></td>
</tr>
<tr>
<td>C-203: Recycle Hydrogen Compressor</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C-204A/B: Makeup Hydrogen Compressor</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU011</td>
<td>INC-401: Tail Gas Incinerator</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU012</td>
<td>SRU-AUX-4: Tail Gas Incinerator</td>
<td>10.85 MMBtu/hr</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU013</td>
<td>Boiler #9</td>
<td>98 MMBtu/hr</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Boiler #10</td>
<td>&gt;100 MMBtu/hr</td>
<td>Low NOx Technology</td>
<td>0.03 lb/MMBtu</td>
<td></td>
</tr>
<tr>
<td>Unit</td>
<td>Description</td>
<td>NOx Emissions</td>
<td>Technology</td>
<td>Remarks</td>
</tr>
<tr>
<td>------------</td>
<td>---------------------------------------</td>
<td>---------------</td>
<td>--------------------------------</td>
<td>--------------------------------</td>
</tr>
<tr>
<td>EU017</td>
<td>FL-7202: Main Refinery Flare</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU021</td>
<td>FL-7201: Zone E Coker Flare</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU021</td>
<td>H-901: Reactor Charge Heater</td>
<td>32.60 MMBtu/hr</td>
<td>Low NOx Technology – ULNB</td>
<td></td>
</tr>
<tr>
<td>EU021</td>
<td>H-902: Fractionator Reboiler</td>
<td>65.10 MMBtu/hr</td>
<td>ULNB?</td>
<td></td>
</tr>
<tr>
<td>EU021</td>
<td>H-1001: Refomer Heater</td>
<td>161.56</td>
<td>Low NOx Technology (ULNB)</td>
<td></td>
</tr>
<tr>
<td>EU022</td>
<td>C-901A/B Compressor</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU022</td>
<td>C-902A/B Compressor</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU022</td>
<td>H-7501: Coker Charger Heater</td>
<td>160.9 MMBtu/hr</td>
<td>Low NOx Technology</td>
<td></td>
</tr>
<tr>
<td>EU023</td>
<td>Tail Gas Incinerator (TGI)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU024</td>
<td>Ammonia Combustor</td>
<td></td>
<td>SCR</td>
<td>1.85 lb/hr, 24-hr avg</td>
</tr>
<tr>
<td>EU025</td>
<td>067HT0001: Hydrogen</td>
<td>562</td>
<td>SCR</td>
<td>5.62 lb/hr</td>
</tr>
<tr>
<td></td>
<td>MMBtu/hr</td>
<td>365-day rolling avg, 25.16 ton/12-months rolling</td>
<td></td>
<td></td>
</tr>
<tr>
<td>----------------</td>
<td>----------</td>
<td>--------------------------------------------------</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU026</td>
<td>Several Emergency Generators, Diesel Fire Water Pump Engines, and Emergency Plant Air Compressors</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

CHS Inc. only evaluated NOx controls for three units: Unit CV-HTR-2 (#1 Crude Unit Main Heater), Unit P-HTR-1 (Platformer Heater), and Boiler #9. MDEQ should provide more data on the size and emissions of the several other combustion units not evaluated for controls and provide further justification as to why the other units were not evaluated for controls.

For example, cost-effective controls are available for smaller heaters. As previously stated in Section IV.A.1. of this report, the California Air Resources Board determined as far back as 1991 that heaters and boilers as small as 5 MMBtu/hour or greater could meet NOx “best available retrofit control technology” limits of 30 ppmv (or about 0.036 lb/MMBtu). Further, more recently, California’s South Coast Air Quality Management District concluded that even lower NOx limits, as low as 9 ppm, could be met with ULNB at boilers and process heaters as small as 2 MMBtu/hr. This was based on actual ULNB retrofit experience at boilers and heaters in the San Joaquin Unified Air Pollution Control District. The Ventura County Air Pollution Control District in California also found that boilers and process heaters as small as 2 MMBtu/hr could meet NOx limits of 9 ppm with ULNB. For units for which the retrofit of ULNB is not technically feasible and for which SNCR or SCR are not cost effective, MDEQ should evaluate the costs of replacing an existing boiler or heater with a new unit equipped with state-of-the-art ULNBs. If a unit is near the end of its useful life, this could be a very cost effective and readily implementable approach to reducing NOx emissions.

In addition, NOx controls are available for rich burn internal combustion engines that are very cost effective. If any of the compressors at the refinery identified in the above table are powered by rich burn internal combustion engines, then NSCR should be evaluated as a very cost effective control to achieve high levels of NOx reduction from such engines.

443 As discussed in Stamper, V. & 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 Ex. 31.
444 Id. at 121.
445 Id.
446 Id. at 121-122.
447 See V. & 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 15-27 (Ex. 31).
CHS and MDEQ evaluated two NOx pollution controls for the three units listed above: ULNB and ULNB+SCR. \(^{448}\) CHS did not evaluate SCR by itself, without explaining why. Given that SCR is a highly effective NOx control, MDEQ must consider it as a reasonable progress control by itself as another control option.

CHS also did not evaluate SNCR for any unit. CHS states “[b]ecause SNCR’s ability to achieve NOx reductions requires operation of the combustion source within specific ranges, it has previously only been applied to the control of NOx emissions from sources that operate within well-defined operating ranges and that do not rapidly vary across ranges such as base-loaded boilers and FCCUs.”\(^{449}\) MDEQ should evaluate if there are other emission units at the CHS Inc. Refinery Laurel that meet these criteria for which SNCR would be a NOx control technology appropriate to consider.

With respect to the controls that CHS did evaluate, ULNB and ULNB plus SCR, CHS did not provide documentation for any of its cost analyses in its four-factor report. MDEQ must require documentation of the basis for the ULNB and the ULNB/SCR cost estimates. The regional haze rules require states to document the technical basis, including in 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).

Based on the limited information provided about the cost effectiveness analyses of ULNB and SCR, the following deficiencies in CHS’s analysis would overstate costs and understate cost effectiveness of the controls:

- CHS assumed a 7% interest rate. For the reasons stated in Section I.B. above, MDEQ must require use of the current bank prime interest rate of 3.25%.
- CHS assumed a life of SCR of 20 years. However, EPA’s SCR chapter of its Control Cost Manual states that the life of SCR at petroleum refineries could be as long as 30 years.\(^{450}\) MDEQ should have evaluated SCR at a 30-year life.
- CHS also assumed a life of ULNB of 20 years. However, it should have evaluated ULNB at a 30-year life. For example, in its proposed regional haze review for controls at a fuel oil and natural gas-fired boiler at the AECC Carl E. Bailey Generating Station in Arkansas, EPA assumed a 30-year life of combustion controls (including LNB).\(^{451}\)
- CHS only evaluated SCR to achieve 85% control. ExxonMobil assumed 95% NOx control in its evaluation of SCR cost effectiveness.\(^{452}\) SCRs are typically designed for 90%+ NOx control.\(^{453}\) Several air districts in California have set RACT/BARCT NOx limits for industrial heaters and
boilers reflective of SCR with NOx emission limits in the range of 2.5 – 5 ppm.\textsuperscript{454} A NOx limit of 2.5 ppm at a natural gas-fired heater or boiler would equate to 0.009 lb/MMBtu.\textsuperscript{455} Using the baseline NOx emission rates identified by CHS, SCR should be able to achieve the following removal efficiencies to achieve a controlled NOx rate of 0.009 lb/MMBtu:

Table 21. NOx Removal Efficiency Pertaining to Compliance with a 2.5 ppm NOx rate with SCR at the CHS Units Evaluated for NOx Controls.

<table>
<thead>
<tr>
<th>Emission Unit</th>
<th>Baseline NOx, lb/MMBtu</th>
<th>Controlled NOx, lb/MMBtu</th>
<th>NOx Removal Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Main Crude Heater</td>
<td>0.1</td>
<td>0.009</td>
<td>91%</td>
</tr>
<tr>
<td>Platformer Heater</td>
<td>0.275</td>
<td>0.009</td>
<td>96%</td>
</tr>
<tr>
<td>Boiler #9</td>
<td>0.098</td>
<td>0.009</td>
<td>91%</td>
</tr>
</tbody>
</table>

Based on the lowest NOx rates that have been required with SCR, it is reasonable to assume a NOx control efficiency of greater than 90% for SCR at the three CHS units evaluated for controls.

- CHS did not evaluate the cost effectiveness of SCR by itself, without the addition of ULNB. Given the high NOx removal efficiencies that can be achieved with SCR alone, CHS should have evaluated the cost effectiveness of the control by itself.

The Federal Land Managers (FLMs) addressed some of the issues described above. The FLMs used EPA’s SCR cost spreadsheet made available with its updated SCR chapter of its Control Cost Manual.\textsuperscript{456} The FLMs calculated revised cost effectiveness of SCR at 90% NOx control, assuming the current bank prime interest rate of 3.25%, and assuming a useful life of 25 years of SCR.\textsuperscript{457} The FLMs also revised CHS’s ULNB cost effectiveness analyses to reflect an interest rate of 3.25% and a life of controls of 25 years. However, because the FLMs did not take into account a 30-year life of controls and the maximum NOx removal capabilities, revised cost effectiveness analyses are provided here.

In the table below, revised cost effectiveness analyses are provided for Main Crude Heater, Platformer Heater, and Boiler #9 to reflect a 30-year life of controls, a 3.25% interest rate, NOx control down to an annual NOx emission rate of 0.009 lb/MMBtu (~2.5 ppm) for the Main Crude Heater and Boiler #9 (reflective of 91% NOx removal) and a NOx removal rate at the Platformer Heater of 95% control (consistent with the NOx removal efficiency evaluated by ExxonMobil). Updated cost effectiveness analyses for ULNB at a 30-year life and a 3.25% interest rate are also provided, based on the capital costs and operational costs are those identified by CHS.

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\textsuperscript{454} As discussed in Stamper, V. & 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 133-136 (attached as Ex. 10).


\textsuperscript{456} Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

\textsuperscript{457} 2022 Draft Montana Regional Haze Plan, Appendices at pdf pages pdf 131-135 (in Appendix F of plan).
### Table 22. Revised Cost Effectiveness of NOx Controls for CHS Inc. Refinery Laurel Main Crude Heater, Platformer Heater, and Boiler #9

<table>
<thead>
<tr>
<th>Unit</th>
<th>Control</th>
<th>Capital Cost, 2019 $</th>
<th>Operational Costs, $/yr</th>
<th>Total Annualized Costs, 2019 $</th>
<th>NOx reduced, tons per year</th>
<th>Cost Effectiveness, $/ton 2019 $</th>
</tr>
</thead>
<tbody>
<tr>
<td>Main Crude Heater</td>
<td>ULNB</td>
<td>$2,846,617</td>
<td>$71,518</td>
<td>$221,535</td>
<td>21.8</td>
<td>$10,162/ton</td>
</tr>
<tr>
<td>Main Crude Heater</td>
<td>SCR</td>
<td>$4,450,581</td>
<td>$70,641</td>
<td>$308,081</td>
<td>39.7</td>
<td>$7,765/ton</td>
</tr>
<tr>
<td>Platformer Heater</td>
<td>ULNB</td>
<td>$8,549,925</td>
<td>$213,547</td>
<td>$664,128</td>
<td>78.1</td>
<td>$8,504/ton</td>
</tr>
<tr>
<td>Platformer Heater</td>
<td>SCR</td>
<td>$5,385,336</td>
<td>$79,656</td>
<td>$366,414</td>
<td>86.8</td>
<td>$4,220/ton</td>
</tr>
<tr>
<td>Boiler #9</td>
<td>ULNB</td>
<td>$3,272,704</td>
<td>$81,591</td>
<td>$254,062</td>
<td>17.3</td>
<td>$14,686/ton</td>
</tr>
<tr>
<td>Boiler #9</td>
<td>SCR</td>
<td>$3,497,247</td>
<td>$50,644</td>
<td>$237,787</td>
<td>26.6</td>
<td>$8,936/ton</td>
</tr>
</tbody>
</table>

The FLMs’ revised SCR cost numbers are somewhat higher than shown above, at $8,652/ton for SCR at the Main Crude Heater, $4,894/ton for SCR at the Platformer Heater, and $9,865/ton for SCR at the Boiler #9. However, as stated above, the FLMs’ revised cost numbers reflect a 25-year life of the SCR instead of a 30-year life, and reflect 90% NOx removal across the SCR whereas the cost effectiveness numbers in the above table reflect NOx reductions down to 2.5 ppm or 95% control, whichever is higher. The revised cost numbers presented above and the FLMs’ revised cost numbers, which are both based on EPA’s SCR cost spreadsheet made available with its Control Cost Manual, show that SCR is clearly cost effective for the CHS Platformer Heater. These costs are within the range that other states are planning to use to determine cost effectiveness of controls in their regional haze plans for the second implementation period: Arizona is using $4,000 to $6,500/ton. New Mexico is using $7,000 per ton. In addition, the Washington Department of Ecology has found SCR to be cost effective for various heaters and boilers at refineries in its state, relying on a cost-effectiveness threshold of $6,300/ton. The costs of SCR at the Main Crude Heater and at the Boiler #9 are also within the range that Oregon and Colorado have found to be cost effective, as Oregon has adopted a regional haze control cost.

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458 The revised costs for SCR were based on EPA’s cost spreadsheets. See SCR cost spreadsheets for the CHS Main Crude Heater at Ex. 39, SCR cost spreadsheet for the CHS platformer heater at Ex. 40, and SCR cost spreadsheet for Boiler #9 at Ex. 41. ULNB costs were revised to reflect a 3.25% interest rate and 30-year life but were otherwise based on costs provided by CHS. Costs were revised from the 2018 cost basis used by ExxonMobil to 2019 dollars using the difference in CEPCI indices (607.5/603.1).


threshold of $10,000/ton. And Colorado is also using a reasonableness cost threshold of $10,000/ton. SCR systems have been retrofitted to many refinery emission units over the years, including at FCCUs. A paper from 2002 discusses the success of SCR retrofit at an FCCU at the BP Whiting Refinery and refers to SCR installations at FCCUs dating back to 1986. SCR has also been used on refinery boilers and heaters, including at some Washington refineries, and can achieve in excess of 95% NOx control from the NOx emitted from the heaters. Experience using SCRs in the refinery industry shows the controls are reliable and have low operational and maintenance costs. At the minimum, MDEQ should find that SCR is a cost effective control for the Platformer Heater.

3. Consideration of the Time Necessary for Compliance, Energy and Non-Air Quality Environmental Impacts, and Remaining Useful Life

Consideration of the remaining reasonable progress factors does not demonstrate any impediment to requiring cost effective pollution controls. CHS did not identify any energy or non-air quality related issues regarding the flue gas recovery system for controlling SO2 from the main refinery flare. CHS also indicated that it is expected that the FGRS installed in 2015 has a remaining useful life of greater than 20 years. Neither CHS nor MDEQ identified the time necessary for compliance to achieve the 20% reduction in SO2 emissions from the Main Refinery Flare, other than to project that the emission reductions would occur by 2028. Given that MDEQ is clearly relying on the Flare Minimization Plan and FGRS in its Long Term Strategy to result in 20% SO2 reductions from 2017-2018 baseline emissions by 2028 and that its RPGs reflect this reduction in SO2 emissions, MDEQ is required to identify the enforceable measure including the compliance schedules to achieve the 20% reduction in SO2 from the Main Refinery Flare pursuant to 40 C.F.R. §51.308(f)(2).

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466 For example, BP Cherry Point has installed SCR on its #2 hydrogen plant SMR furnace, its #6 and #7 boilers, according to its August 26, 2014 Air Operating Permit #015R1M1 on the Northwest Clean Air Agency’s (NWCAA’s) website at https://nwcleanairwa.gov/?wpdmdl=981.
468 Id.
469 CHS 2019 Four-Factor Analysis at 3-17.
470 Id.
With respect to the NOx controls evaluated, CHS did not identify a restriction on the remaining useful life of the three units evaluated for NOx controls. However, MDEQ did refer to the “planned replacement of Boiler #9” in its draft regional haze plan. This implies that Boiler #9 is somewhat near the end of its useful life, although CHS assumed the remaining useful life of the facility as “greater than 20 years.” MDEQ should provide more detail on its statement that a replacement is planned for Boiler #9. However, without an enforceable requirement to shut down or replace the unit, the remaining useful life of the pollution control should not be a limiting factor in the four-factor analysis of NOx controls.

MDEQ and CHS raised the issue of energy impacts from SCR operation, but those energy impacts are taken into account as costs to operate the SCR in the cost effectiveness analysis. MDEQ and CHS also raise concerns with ammonia slip and the additional fine particulate matter that could be emitted from SCR. EPA states that SCR systems commonly operate with less than 2 ppm of ammonia slip. Thus, these issues can be addressed and minimized through proper design and operation of the SCR to minimize ammonia slip.

4. Summary - MDEQ Must Consider SCR as a NOx Control at Least for the Platformer Heater, and MDEQ Must Also Identify the Enforceable Requirements and Compliance Schedule for the 20% Reduction in Refinery Flare SO2 Emissions that Are Reflected in MDEQ’s Reasonable Progress Goals and Long Term Strategy.

For the reasons provided above, MDEQ should consider adopting a requirement to install SCR at least for the Platformer Heater at the CHS Inc. Refinery Laurel to make reasonable progress towards the national visibility goal. As shown in Table 22 above, SCR should be considered cost effective for the platformer heater at $4,200/ton of NOx removed and would remove 86 tons per year of NOx. MDEQ must also consider other emission units at the CHS refinery for NOx controls, as there are several other combustion sources and the emissions units evaluated by CHS only account for 40% of the facility’s NOx emissions. Further, since MDEQ has stated that Boiler #9 is planned for replacement, MDEQ must consider adopting a requirement as part of its long term strategy that the replacement boiler be equipped with state-of-the-art ULNB to ensure that future emissions of the boiler will be minimized to the maximum extent.

In addition, given that the assumed 20% reduction in SO2 from the CHS Main Refinery Flare is being taken into account in 2028 emissions projections and setting of RPGs, MDEQ must identify the enforceable requirements and compliance schedules that are part of the Long Term Strategy, pursuant to 40 C.F.R. §51.308(f)(2).

C. Phillips 66 Co. Billings Refinery

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471 2022 Draft Montana Regional Haze Plan at 266.
472 CHS 2019 Four-Factor Analysis at 3-14.
The Phillips 66 Co. Billings Refinery is a petroleum refinery located in Billings, Montana that includes the following operations: crude oil distillation, delayed coking, fluid catalytic cracking, hydrotreating, alkylation, and other associated operations, including the adjacent Jupiter Sulphur LLC sulfur recovery plant.\textsuperscript{475} The facility ranks fourteenth on MDEQ’s list of facilities evaluated for regional haze pollution controls with a Q/d value of 4.51 based on SO2+NOx emissions.\textsuperscript{476} The National Parks Conservation Association ranks the Phillips 66 refinery in Billings as the sixteenth highest in terms of cumulative Q/d ranking.\textsuperscript{477}

MDEQ states that it determined “it was impractical to perform a four-factor analysis on each individual emitting unit,” due to the many small emitting units in a refinery.\textsuperscript{478} MDEQ thus focused on the following subset of emitting units at the Phillips 66 Billings Refinery: Boiler #1 and Boiler #2. According to MDEQ, these two units are responsible for 22% of the refinery’s NOx emissions in 2018.\textsuperscript{479}

MDEQ states that Phillips 66 selected 2017-2018 as representative of baseline and proposed 2017-2018 emissions as reflective of 2028 OTB/OTW emissions that were used to calculate cost effectiveness.\textsuperscript{480} MDEQ should provide more data to support its finding that the average of 2017-2018 operations and emissions are representative of expected emissions in 2028. The table below shows the plantwide baseline emissions and 2028 OTB/OTW emissions.

**Table 23. Phillips 66 Billings Refinery Plantwide Baseline Emissions and 2028 OTB/OTW Emissions**\textsuperscript{481}

<table>
<thead>
<tr>
<th>Baseline Period</th>
<th>NOx Baseline, tons per year</th>
<th>SO2 Baseline, tons per year</th>
<th>2028 NOx OTB/OTW, tons per year</th>
<th>2028 SO2 OTB/OTW, tons per year</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017-2018</td>
<td>563.5</td>
<td>100.7</td>
<td>563.5</td>
<td>100.7</td>
</tr>
</tbody>
</table>

MDEQ did not require review of controls to address SO2 emissions from the refinery.\textsuperscript{482} MDEQ vaguely referred to “other standards apply from terminated EPA Consent Decree requirements (that have largely been incorporated into permit conditions),” as well as referring to NSPS standards and state SIP requirements as further controlling SO2 emissions from the fluidized catalytic cracking unit among other units.\textsuperscript{483} MDEQ should provide more details on the controls and requirements that it is referring to for the FCCU.

\textsuperscript{475} 2022 Draft Montana Regional Haze Plan at 275.
\textsuperscript{476} 2022 Draft Montana Regional Haze Plan at 161.
\textsuperscript{477} National Parks Conservation Association’s Regional Haze Fact Sheet for Montana, available at https://www.npca.org/reports/regional-haze.
\textsuperscript{478} 2022 Draft Montana Regional Haze Plan at 275.
\textsuperscript{479} Id. at 276.
\textsuperscript{480} Id.
\textsuperscript{481} Id. at 276 (Table 6-41).
\textsuperscript{482} Id. at 276-277.
\textsuperscript{483} Id. at 276.
1. Evaluation of NOx Controls for the Phillips 66 Billings Refinery

Based on a review of the operating permit for the Phillips 66 Billings refinery, the following is a list of combustion devices and sources at the refinery and the NOx controls that the units have, if any. MDEQ should have included this information in its discussion of NOx controls for the refinery. If any additional NOx controls have been installed that are not reflected in the 2020 Title V permit issued for the refinery, MDEQ should update this list.

Table 24. Phillips 66 Billings Refinery Combustion Sources and NOx Controls/Limits/Emissions

<table>
<thead>
<tr>
<th>Unit ID</th>
<th>Subunit ID and Description</th>
<th>MMBtu/hr (if known)</th>
<th>NOx Pollution Control Devices/Practices</th>
<th>NOx Limit</th>
<th>Estimated Baseline/2028 NOx (if available), tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>EU001</td>
<td>B-1 Boiler (share a common stack)</td>
<td>120</td>
<td></td>
<td>65</td>
<td></td>
</tr>
<tr>
<td></td>
<td>B-2 Boiler</td>
<td>120</td>
<td></td>
<td>65</td>
<td></td>
</tr>
<tr>
<td></td>
<td>B-5-Boiler</td>
<td>183</td>
<td>ULNB</td>
<td>0.03 lb/MMBtu, rolling 365 days; 24.05 tpy, rolling 365-day</td>
<td></td>
</tr>
<tr>
<td></td>
<td>B-6 Boiler</td>
<td>183</td>
<td>ULNB</td>
<td>Operated no more than 8 weeks per 12-months</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Temporary Boiler</td>
<td>51</td>
<td></td>
<td>Operated no more than 8 weeks per 12-months</td>
<td></td>
</tr>
<tr>
<td>EU002</td>
<td>FCCU</td>
<td></td>
<td></td>
<td>49.2 ppmvd @ 0% O2, 365-day rolling avg; 69.5 ppmvd at 0% O2, 7-day rolling avg</td>
<td></td>
</tr>
<tr>
<td>EU003</td>
<td>H-1 (Small Crude Unit)</td>
<td>55.92</td>
<td>Some have LNB, but Permit does not indicate which units</td>
<td>0.03 lb/MMBtu</td>
<td></td>
</tr>
</tbody>
</table>

484 Information from 7/1/2020 Final Title V Operating Permit #OP2619-16, Phillips 66 Company, Billings Refinery, attached as Ex. 42, and from 1/31/2022 Montana Air Quality Permit #2619-42 and associated Montana Air Quality Permit Analysis, attached as Ex. 43.
<p>| | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>H-2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>H-3</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>H-4</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>H-5</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>H-10 (No. 2 HDS)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>H-11 (No. 2 HDS Debutanizer Reboiler)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>H-12 (No. 2 HDS Main Frac. Reboiler)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>H-13 (Catalytic Reforming Unit #2)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>H-14 (Catalytic Reforming Unit #2)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>H-15</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>H-16 (Saturated Gas Stabilizer Reboiler)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>H-17 (New Vacuum Furnace)</td>
<td>75</td>
<td></td>
<td>0.030 lb/MMBtu</td>
</tr>
<tr>
<td>H-18 (FCCU Preheater)</td>
<td>77</td>
<td></td>
<td></td>
</tr>
<tr>
<td>H-19</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>H-20</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>H-21</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>H-23 (Catalytic Reforming Unit #2)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>H-24 (Large Crude Unit)</td>
<td>108.36</td>
<td>ULNB</td>
<td>0.040 lb/MMBtu</td>
</tr>
<tr>
<td>H-3901 (Coker Heater)</td>
<td></td>
<td>LNB</td>
<td>0.08 lb/MMBtu, 7.38 lb/hr</td>
</tr>
<tr>
<td>H-8401 (Recycle Hydrogen Heater)</td>
<td>31.20</td>
<td>ULNB</td>
<td>0.03 lb/MMBtu</td>
</tr>
<tr>
<td>H-8402 (Fractionator Heater)</td>
<td>31.70</td>
<td>ULNB</td>
<td>0.03 lb/MMBtu</td>
</tr>
<tr>
<td>H-9401 (No. 1 H2 Reformer Heater)</td>
<td>179.20 (PSA Gas), 76.80 (Nat Gas, Cryo Gas)</td>
<td>LNB and FGR</td>
<td>0.042 lb/MMBtu</td>
</tr>
<tr>
<td>H-9501</td>
<td>25.0</td>
<td>ULNB</td>
<td>0.03 lb/MMBtu per rolling 12-month</td>
</tr>
<tr>
<td>H-9502</td>
<td>49.0</td>
<td>ULNB</td>
<td>0.03 lb/MMBtu per rolling 12-month</td>
</tr>
<tr>
<td>H-9701 (No. 2 H2 Reformer Heater)</td>
<td>111.35 (PSA Gas), 79.65</td>
<td>ULNB</td>
<td>0.03 lb/MMBtu</td>
</tr>
<tr>
<td>EU007</td>
<td>Jupiter SRU Incinerator F-304</td>
<td>(Nat Gas, Cryo Gas)</td>
<td>LNB</td>
</tr>
<tr>
<td>-------</td>
<td>--------------------------------</td>
<td>---------------------</td>
<td>-----</td>
</tr>
<tr>
<td>EU013</td>
<td>Catalytic Reforming Unit 1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EU014</td>
<td>Backup Coke Crusher Reciprocating Internal Combustion Engine (RICE)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cryo Backup Air Compressor RICE</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Boiler House RICE</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td>Storm Water to Holding Pond RICE</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Boiler House Backup RICE</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Backup Fire Pump RICE</td>
<td>665 hp</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Backup HDS Flare Drum Pump Engine</td>
<td>300 hp</td>
<td></td>
</tr>
</tbody>
</table>

Phillips 66 only evaluated NOx controls for two units: Boiler #1 and Boiler #2. MDEQ should provide more data on the size and emissions of the several other combustion units not evaluated for controls and provide further justification as to why the other units were not evaluated for controls.

For example, cost-effective controls are available for smaller heaters. As previously stated in Section IV.A.1. of this report, the California Air Resources Board (CARB) determined as far back as 1991 that heaters and boilers as small as 5 MMBtu/hour or greater could meet NOx “best available retrofit control technology” (BARCT) limits of 30 ppmv (or about 0.036 lb/MMBtu). 485 Further, more recently, California’s South Coast Air Quality Management District (AQMD) concluded that even lower NOx limits, as low as 9 ppm, could be met with ULNB at boilers and process heaters as small as 2 MMBtu/hr. 486 This was based on actual ULNB retrofit experience at boilers and heaters in the San Joaquin Unified Air Pollution Control District (SJVAPCD). 487 The Ventura County Air Pollution Control District in California also found that boilers and process heaters as small as 2 MMBtu/hr could meet NOx limits of 9 ppm with ULNB. 488 For units for which the retrofit of ULNB is not technically feasible and for which SNCR or SCR are not cost effective, MDEQ should evaluate the costs of replacing an existing boiler or heater with a

485 As discussed in Stamper, V. & 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 120 (attached as Ex. 31).
486 Id. at 121.
487 Id.
488 Id. at 121-122.
new unit equipped with state-of-the-art ULNBs. If a unit is near the end of its useful life, this could be a very cost effective and readily implementable approach to reducing NOx emissions.

In addition, NOx controls are available for rich burn reciprocating internal combustion engines (RICE) that are very cost effective. If any of the compressors at the refinery identified in the above table are powered by rich burn internal combustion engines, then NSCR should be evaluated as a very cost effective control to achieve high levels of NOx reduction from such engines.

Phillips 66 and MDEQ evaluated two NOx pollution controls as retrofit controls for two emission units: Boiler #1 and Boiler #2: SNCR and SCR. For the SNCR and SCR cost estimates, Phillips 66 used EPA’s SNCR and SCR cost spreadsheets.

Rather than evaluate the costs of adding ULNB to Boilers #1 and #2, Phillips 66 evaluated the cost effectiveness of replacing the boilers outright with new boilers equipped with ULNB and flue gas recirculation (FGR), because they claimed retrofitting these controls to the existing boilers would be too difficult and too expensive.

A review of the cost effectiveness analyses of the NOx controls that were evaluated shows the following deficiencies in Phillips 66’s cost calculations that would tend to overstate costs and understate cost effectiveness of the controls:

1) Phillips 66 used a normalized stoichiometric ratio (NSR) of 2.0 in the SNCR cost spreadsheet but did not explain how that NSR was derived. The default NSR in the EPA SNCR cost spreadsheet is 1.05. Given that the NSR defines how much ammonia or urea reagent is used, MDEQ must require Phillips 66 to document the basis for its assumed NSR rate for SNCR.

2) Phillips 66 assumed urea would be the reagent with SNCR to meet 58.5% NOx removal. Ammonia allows for higher NOx reductions than urea and is less expensive than urea. Phillips 66 should have assumed ammonia as the reagent.

3) Phillips 66 assumed a life of SNCR of 20 years. However, EPA’s SNCR chapter of its Control Cost Manual states that the life of SNCR at petroleum refineries could be as long as 25 years. For the reasons discussed in Section II.A.1.b.2) above, it is reasonable to assume a longer life for SNCR than the example lifetime EPA assumed in the Control Cost Manual. MDEQ should require use of SNCR lifetime for refinery heaters and boilers of at least 25 years.

4) Phillips 66 inexplicably assumed the SCR at the boilers would operate 165 days but the SNCR at boilers would operate 365 days. Phillips 66 should have been consistent in its evaluation of SNCR and SCR for the boilers of how many days the control will operate – which should be the

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489 See V. & 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 15-27 (Ex. 31 to this report).


491 Id. at 29-30 and at Appendix B.

492 Id. at 28.


same as the typical number of days the unit operates in a year. It is assumed that Phillips 66 meant to use 365 days of boiler operation in both SNCR and SCR cost calculations.

5) Phillips 66 only evaluated SCR to achieve 85.4% control. ExxonMobil assumed 95% NOx control in its evaluation of SCR cost effectiveness. SCRs are typically designed for 90%+ NOx control. Several air districts in California have set RACT/BARCT NOx limits for industrial heaters and boilers reflective of SCR with NOx emission limits in the range of 2.5 – 5 ppm. A NOx limit of 2.5 ppm at a natural gas-fired heater or boiler would equate to 0.009 lb/MMBtu.495 At least 95% NOx reduction should have been evaluated across the SCR, similar to what was evaluated by ExxonMobil. Using the baseline NOx emission rate identified by Phillips 66 for Boiler #1 and #2 of 0.2748 lb/MMBtu, 95% control equates to an annual NOx rate of SCR 0.014 lb/MMBtu.

6) Phillips 66 assumed a life of SCR of 20 years. However, EPA’s SCR chapter of its Control Cost Manual states that the life of SCR at petroleum refineries could be as long as 30 years.496 MDEQ should have evaluated SCR at a 30-year life.

7) Replacement of the boilers to enable use of ULNB and FGR should have been evaluated at a longer lifetime than 20 years. Just for ULNBs, there is support for a longer life than 20 years. For example, in its proposed regional haze review for controls at a fuel oil and natural gas-fired boiler at the AECC Carl E. Bailey Generating Station in Arkansas, EPA assumed a 30-year life of combustion controls (including LNB).497 However, with Phillips 66 taking into account the entire replacement of the boilers as a NOx control, the life of the new boilers including the ULNB and FGR could very well be even greater than 30 years. Phillips 66 has indicated that the existing Boilers #1 and #2 have been operating for 70 years each.498 Thus, it seems reasonable to assume even longer than a 30-year life of replacement boilers, consistent with the expected life of the refinery.

8) Phillips 66 assumed a boiler replacement cost of $20 million per boiler, but the company did not provide any documentation for this assumed cost. Further, Phillips 66 assumed a NOx reduction of 89% with a new boiler equipped with ULNB and FGR but did not provide any justification for this assumption. The regional haze rules require states to document the technical basis, including in 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). Thus, MDEQ must require documentation for these assumptions.

9) Phillips 66 used a 5.5% interest rate, but the current interest rate is 3.25%. MDEQ must require use of the current bank prime interest rate.

In the table below, revised cost effectiveness analyses are provided for Boilers #1 and 2 that address some of these issues. Specifically, the costs reflect a 3.25% interest rate, a 25-year life for SNCR and a 30-year life for SCR, and 95% control across the SCR. With respect to the boiler replacement cost estimates to enable use of ULNB and FGR, an estimate of revised cost effectiveness at a 3.25% interest

496 EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 80.
rate and a 30-year life was done by multiplying the cost effectiveness numbers by the ratio in the capital recovery factor for Phillips 66’s assumed 5.5% interest rate and 20-year life (i.e., 0.0837) and the capital recovery factor for 3.25% interest rate and a 30-year life (0.0527).

Table 25. Revised Cost Effectiveness of NOx Controls for Phillips 66 Refinery Boilers #1 and #2

<table>
<thead>
<tr>
<th>Unit</th>
<th>Control</th>
<th>Capital Cost 2019 $</th>
<th>Operational Costs, $/yr</th>
<th>Total Annualized Costs 2019 $</th>
<th>NOx reduced, tons per year</th>
<th>Cost Effectiveness, $/ton (2019)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boiler #1</td>
<td>SNCR</td>
<td>$1,749,030</td>
<td>$34,957</td>
<td>$138,937</td>
<td>36</td>
<td>$3,824/ton</td>
</tr>
<tr>
<td>or #2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Boiler #1</td>
<td>ULNB/FGR via Boiler Replacement</td>
<td>$20,145,913</td>
<td>Not provided</td>
<td>$1,054,000</td>
<td>58</td>
<td>$18,890/ton</td>
</tr>
<tr>
<td>or #2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Boiler #1</td>
<td>SCR</td>
<td>$3,963,635</td>
<td>$55,750</td>
<td>$267,499</td>
<td>62</td>
<td>$4,320/ton</td>
</tr>
<tr>
<td>or #2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

As the above table demonstrates, both SCR and SNCR are cost-effective NOx controls for Boilers #1 and #2. Of the two controls, SCR would achieve more NOx reductions than SNCR at 62 tons per year. These costs are within the range that other states are planning to use to determine cost effectiveness of controls in their regional haze plans for the second implementation period: Arizona is using $4,000 to $6,500/ton. New Mexico is using $7,000 per ton. Oregon has adopted a much higher regional haze control cost threshold of $10,000/ton. Colorado is also using a reasonableness cost threshold of $10,000/ton. In addition, the Washington Department of Ecology has found SCR to be cost effective for various heaters and boilers at refineries in its state, relying on a cost-effectiveness threshold of $6,300/ton.

SCR systems have been retrofitted to many refinery emission units over the years. A paper from 2002 discusses the success of SCR retrofit at an FCCU at the BP Whiting Refinery and refers to SCR

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499 Revised costs for SNCR and SCR based on EPA cost spreadsheets. See attached spreadsheets with revised cost calculations at Exs. 44 and 45. Phillips 66’s costs for control of ULNB/FGR via boiler replacement were amortized using a 3.25% interest rate and a 30 year life. Costs were revised from the 2018 cost basis used by ExxonMobil to 2019 dollars using the difference in CEPCI indices (607.5/603.1).


installations at FCCUs dating back to 1986. SCR has also been used on refinery boilers and heaters, including at some Washington refineries, and can achieve in excess of 95% NOx control from the NOx emitted from the heaters. Experience using SCRs in the refinery industry shows the controls are reliable and have low operational and maintenance costs.

Thus, MDEQ should find that SCR is a cost effective control for Boilers #1 and 2.

2. Consideration of the Time Necessary for Compliance, Energy and Non-Air Quality Environmental Impacts, and Remaining Useful Life

None of the other reasonable progress factors provides a reason for not requiring NOx controls. MDEQ did not identify any issues with the time necessary for compliance, stating “[i]f any controls are identified, the Department has concluded based on the submitted four-factor analysis that those controls could be operational by 2028.”

In terms of non-air environmental impacts of compliance, MDEQ and Phillips 66 raise concerns with ammonia slip and the additional fine particulate matter that could be emitted from SCR. EPA states that SCR systems commonly operate with less than 2 ppm of ammonia slip. Thus, these issues can be addressed and minimized through proper design and operation of the SCR to minimize ammonia slip. With SNCR operation, a more-refined balance is needed between NOx removal efficiency and acceptable levels of ammonia slip, but this is not an issue of significant concern with SCR.

MDEQ also states that the facility operator may need to dispose of the spent SCR catalyst in a hazardous waste landfill. However, EPA’s Control Cost Manual states that “most catalyst formations are not considered hazardous waste.” In its four-factor analysis of NOx controls for the CHS Inc. Refinery Laurel, MDEQ acknowledges this, stating that the spent catalyst “is comprised of metals that are not

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506 For example, BP Cherry Point has installed SCR on its #2 hydrogen plant SMR furnace, its #6 and #7 boilers, according to its August 26, 2014 Air Operating Permit #015R1M1 on the Northwest Clean Air Agency’s (NWCAA’s) website at https://nwcleanairwa.gov/?wpdmdl=981.


508 Id.

509 2022 Draft Montana Regional Haze Plan at 229.


511 EPA, Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, April 2019, at 1-19-1-20.

512 2022 Draft Montana Regional Haze Plan at 280.

considered toxic." EPA also states that “[m]ost SCR manufacturers offer a disposal service, in which either the catalyst is reactivated (i.e., rejuvenated or regenerated) for reuse or its components are recycled for other uses.”

Although MDEQ did not raise any energy and non-air quality related issues regarding replacing the boilers with new boilers equipped with ULNB and FGR, it must be noted that new boilers will most likely be more energy efficient than the existing 70-year old boilers, which will not only save on fuel costs, but will also result in decreased emissions of other air pollutants, including greenhouse gas emissions, compared to the existing boilers. Given that a new boiler with ULNB and FGR can achieve as low NOx rates as SCR, MDEQ should evaluate whether the existing boilers that are 70 years old are simply at the end of their useful life and up for replacement soon, in which case boiler replacement with new ULNB and FGR may make the most sense overall as a regional haze control measure. However, it must be noted that, with respect to the NOx controls evaluated, neither MDEQ nor Phillips 66 identified a restriction on the remaining useful life of the boilers, despite their advanced age.

3. Summary – MDEQ Must Consider Requiring SCR to Achieve Reasonable Further Progress and, if it Can be Adequately Documented that Future Operations Will Be at Much Lower Levels of Operating Hours and Capacity, MDEQ Must More Fully Evaluate NOx Control Options for the No. 3 Compressor.

For the reasons provided above, MDEQ should consider adopting requirement to install SCR at Boilers #1 and #2 at the Phillips 66 Billings Refinery as cost-effective measures to make reasonable progress towards the national visibility goal. As shown in Table 25 above, SCR should be considered cost effective at $4300/ton. Such controls would reduce NOx emissions by 95%, which would reduce NOx from the baseline/projected 2028 NOx emissions of the boilers by a combined 124 tons per year.

MDEQ must also more fully evaluate controls for the numerous other combustion sources at the Phillips 66 Billings Refinery, given that it has only analyzed controls for two units that account for approximately 23% of the refinery’s NOx emissions.

VI. Northern Border Pipeline Compressor Station No. 3

Northern Border Pipeline Company operates Compressor Station No. 3 in Roosevelt County, Montana. The compressor station ranks 16th on Montana’s list of sources evaluated for regional haze controls, with a Q/d value of 4.2 based on the average of 2014-2017 NOx + SO2 emissions.

Northern Border Pipeline’s Compressor Station No. 3 consists of a Cooper Rolls 40,350 horsepower (hp) turbine that drives a natural gas compressor, as well as an emergency backup generator, a heating boiler, and an emergency backup engine. MDEQ states in the draft regional haze plan that its

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514 2022 Draft Montana Regional Haze Plan at 266.
516 See July 30, 2019 Montana Air Quality Permit #2974-04, Northern Border Pipeline Company, Compressor Station No. 3, at 2 (Ex. 46).
capacity is lower than stated in its permit at 38,000 hp. The turbine is equipped with a “low NOx lean premixed combustion burner” which MDEQ refers to as “DLE.”

MDEQ indicates that the baseline and 2028 OTB/OTW emissions for the compressor station are based on average emissions over the period of 2017-2018. Yet, Table 6-44 of the draft Montana Regional Haze plan indicates that baseline and 2028 emissions are based on a 2014-2017 baseline period. Table 6-44 appears to be in error referring to 2014-2017 as the baseline period, as MDEQ’s list of source emissions for its Q/d analysis identifies the 2014-2017 average emissions from the Compressor Station No. 3 as much higher than reflected in MDEQ’s Table 6-44, which is shown in the table below.


<table>
<thead>
<tr>
<th>Timeframe</th>
<th>Avg NOx, tpy</th>
<th>Avg SO2, tpy</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014-2017</td>
<td>92</td>
<td>4</td>
</tr>
<tr>
<td>2017-2018</td>
<td>56.0</td>
<td>2.6</td>
</tr>
</tbody>
</table>

MDEQ claimed that the lower period of emissions from 2017-2018 was used as a projection of 2028 OTB/OTW emissions. However, Northern Border Pipeline did not adequately justify its decision to use the lower 2017-2018 emissions as baseline and 2028 OTB/OTW emissions, other than to say that “[r]elatively low operations similar to 2018 and 2019 are expected in the future...” and that the compressor operated 2,113 hours in 2019 and 181 hours “through May” in 2019. The company identified the 2016 operating hours as much higher at 6,835 hours. Thus, Northern Border Pipeline appears to be projecting a significant decrease in the operating hours of Compressor Station No. 3 for future years.

EPA’s regional haze guidance states that, while it may be reasonable to project that 2028 emissions are expected to differ significantly from historical emissions, there generally should be a documented basis for the change such as enforceable requirements, energy efficiency, renewable energy, or other such programs where there is a documented commitment/verifiable basis to quantify future changes in emissions. Thus, MDEQ must require more documentation from Northern Border Pipeline to support its claim of much more limited operation of the Compressor Station No. 3 in 2028 and beyond.

In addition, if the Compressor No. 3 turbine is going to be operated in the range of 181 to 2,113 hours in the future, as compared to the 6,835 hours the turbine operated in 2017, this lower level of operation could actually mean NOx emissions increase — especially over short term periods. That is because the turbine is allowed to operate without operating the DLE NOx controls and is allowed a much higher NOx emission rate during “non-DLE” hours of 78.0 lb/hr, as compared to the 51.5 lb/hr NOx limit that applies

517 2022 Draft Montana Regional Haze Plan at 280.
518 Id.
519 Id. at 281 (Table 6-44).
520 Emissions data from 2022 Draft Montana Regional Haze Plan at 161 and at 281.
522 Northern Border Pipeline Compressor No. 3 Four-Factor Submittal at 3.
523 Id.
when the turbine is operating with DLE.\textsuperscript{525} Moreover, the compressor turbine is allowed to emit at this higher NO\textsubscript{x} rate for up to 750 hours per 12-month period.\textsuperscript{526} The Montana Air Quality Permit Analysis for a 2019 Air Quality Permit issued for Compressor Station No. 3 states that the reasons for non-DLE operation included periods of start-up and shutdown, when operation is required during downstream maintenance requirements, and operation during low ambient temperatures at the site.\textsuperscript{527} However, the air permit allows up to 750 hours per 12-month period, with no restriction that the non-DLE operation be limited to those hours.\textsuperscript{528}

In addition, while emissions testing is required to be conducted semi-annually, there is no permit requirement that sets the conditions for testing or requires testing of emissions during non-DLE operation. Thus, while a higher NO\textsubscript{x} emission limit applies during non-DLE operation, it is not known if the turbine meets that limit or not, as the permit primarily relies on limiting and tracking hours of operation in non-DLE mode.\textsuperscript{529} Moreover, a review of the permit shows that there are no permit provisions that require any set test method to test NO\textsubscript{x} emissions, as the permit simply allows NO\textsubscript{x} to be tested “with a portable analyzer.”\textsuperscript{530} These issues are important to determining the proper 2028 OTB/OTW baseline for a four-factor analysis. If operating hours are going to decrease to 2,100 or less hours per year, the compressor turbine could very well be operating in non-DLE mode for a much higher percentage of the time, especially if the DLE NO\textsubscript{x} controls do not work during startup and shutdown which would presumably occur more frequently if the compressor turbine operates at a lower capacity factor each year. Given that the permit does not clearly require NO\textsubscript{x} emissions testing during non-DLE mode, it is not clear what the NO\textsubscript{x} emissions from that period of operation would be, as it is not known if the compressor turbine complies with the 78.0 lb/hr NO\textsubscript{x} limit that applies during non-DLE operation. Further, a paper regarding NO\textsubscript{x} emissions from gas turbine engines employed in natural gas compressor stations found that the NO\textsubscript{x} emissions from non-DLE mode (at low loads) were higher than the NO\textsubscript{x} emissions from a non-DLE engine at the same load and ambient conditions.\textsuperscript{531}

For these reasons, MDEQ must provide more information on the historical operation and emissions of the Northern Border Pipeline Compressor No. 3, the historical period of time operating in non-DLE mode, more justification as to why future operation is expected to be at much lower hours of operation per year, and an explanation of how this would affect operation in non-DLE mode. It is very important to understand how NO\textsubscript{x} emissions and emission rates will change if the compressor station will truly be operated at lower hours of operation per year.

\textsuperscript{525} See July 30, 2019 Montana Air Quality Permit #2974-04, Northern Border Pipeline Company, Compressor Station No. 3, at 2, Condition II.A.2. (Ex. 46).
\textsuperscript{526} Id. at 2 (Condition II.A.2.).
\textsuperscript{527} Id. at attached Montana Air Quality Permit Analysis, MAQP #2974-04, at 1.
\textsuperscript{528} Id. at 2 (Condition II.A.2.). See also August 12, 2021 Final Title V Operating Permit #OP2974-14, Northern Border Pipeline Co. Compressor No. 3, at 8 (Ex. 47).
\textsuperscript{529} Id. at 10 (Condition B.20).
\textsuperscript{530} August 12, 2021 Final Title V Operating Permit #OP2974-14, Northern Border Pipeline Co. Compressor No. 3, at 9 (Conditions B.11 and B.17). (Ex. 47).
1. Evaluation of NOx Controls for Northern Border Pipeline Compressor No. 3

MDEQ and Northern Border Pipeline only evaluated one control – SCR – to reduce NOx emissions from the Compressor No. 3 turbine.\(^{532}\) While SCR is a top NOx control strategy to consider, three other NOx control strategies should also be evaluated: 1) whether the low NOx burners can be upgraded, 2) if the NOx controls cannot be upgraded, consider replacing the turbine (which currently is about 26 years old) with a turbine designed with state of the art dry low NOx combustors, and 3) requiring operation of DLE at all times of operation or, at the minimum, limiting the periods of time that DLE does not have to be operated to startup and shutdown times of limited duration. As stated above, the permit for the Compressor No. 3 currently allows up to 750 hours per year of operation in non-DLE mode, without any other restrictions.

With respect to evaluation of SCR, there are several deficiencies in Northern Border Pipeline’s analysis, as follows:

1) Costs were based on an older and seemingly unavailable version of the EPA Control Cost Manual (dated May 2016), using changes in Consumer Price Index (a factor of 1.5) to escalate costs to 2018 dollars.\(^{533}\) EPA has an updated version of its SCR chapter of its Control Cost Manual dated June 12, 2019, and EPA has made available an associated SCR cost calculation spreadsheet.\(^{534}\) Further, EPA recommends escalating costs to current costs using the Chemical Engineering Plant Cost Index (CEPCI).\(^{535}\) EPA states that “the CPI is not recommended because the price change of interest is among consumer goods and services which have little relevance to capital project spending or industrial intermediate goods such as raw materials such as reagents.”\(^{536}\) It is not clear what the cost basis of the May 2016 version of the SCR cost analysis is that Northern Border Pipeline refers to, but assuming it is 2016, the ratio of 2018 CEPCI to 2016 CEPCI is 1.10 (603.1/547.7).

2) Baseline (pre-SCR) NOx emissions were based on a compliance test from 2003 of 0.117 lb/MMBtu, which the company states has been used for annual emissions estimates.\(^{537}\) For the reasons previously described, the NOx emission rate when the compressor turbine is operating at a lower number of hours per year can be expected to be higher, given that the permit allows for 750 hours per year in non-DLE mode and so it could constitute a much higher proportion of total operating hours and the unit is allowed to operate at a much higher NOx emission rate during non-DLE mode operation. Northern Border Pipeline indicates the NOx emission rate

532 2022 Draft Montana Regional Haze Plan at 282-283.
533 Northern Border Pipeline Compressor No. 3 Four-Factor Submittal at 3.
536 Id.
537 Northern Border Pipeline Compressor No. 3 Four-Factor Submittal at 3.
prior to SCR controls is 22.5 lb/hr. As stated above, the permit allows NOx emissions to be as high as 78 lb/hr.\textsuperscript{538}

3) The company assumed a 20-year life of SCR and an interest rate of 5.25%.\textsuperscript{539} An SCR at a combustion turbine should have a life of up to 30 years.\textsuperscript{540} Also, for the reasons stated in Section I.B. above, MDEQ must require use of the current bank prime interest rate of 3.25%.

4) Northern Border Pipeline only assumed SCR would achieve 75% NOx reduction, when SCR can achieve in excess of 90% NOx control.\textsuperscript{541} Thus, the NOx reductions with SCR were understated.

The FLMs comments raised several other issues with Northern Border Pipeline’s SCR cost analysis, including that too high of a cost of ammonia reagent was used, sales and property taxes were inappropriately included when such taxes don’t apply in Montana to pollution control equipment, labor costs seem high, catalyst costs seem excessively high, and the reagent stoichiometric ratio used (which defines how much ammonia is used) was higher than assumed by EPA in its SCR cost spreadsheet.\textsuperscript{542} The FLM recalculated SCR costs based on three operational and emissions scenarios:

- Full load potential to emit scenario, assuming NOx emissions were at the DLE operational NOx limit of 51.5 lb/hr at 8,760 hours/year;
- 2017 annual operating hours scenario, which relied on Northern Border Pipeline’s pre-SCR NOx emission rate of 0.117 lb/MMBtu and the operating hours in 2017 as reported in Montana’s draft plan of 6,835 hours per year; and
- 2017 National Emissions Inventory (NEI) Emissions Scenario assuming that the 2017 NOx emissions as reported to the NEI for Compressor No. 3 of 88 tons per year and Northern Border Pipeline’s stated pre-SCR NOx emission rate of 0.117 lb/MMBtu defined the annual heat input. The FLM stated that this reflected an estimated 4,788 hours of operation per year.\textsuperscript{543} The FLMs evaluated SCR to achieve 90% NOx control. The results of the FLM’s three SCR cost effectiveness scenarios are reiterated in the table below.

\textsuperscript{538} See July 30, 2019 Montana Air Quality Permit #2974-04, Northern Border Pipeline Company, Compressor Station No. 3, at 2, Condition II.A.2. (Ex. 46).

\textsuperscript{539} Northern Border Pipeline Compressor No. 3 Four-Factor Submittal at 3.


\textsuperscript{541} Id. at pdf page 5.

\textsuperscript{542} 2022 Draft Montana Regional Haze Plan, Appendices at pdf pages 156-157 (Appendix F).

\textsuperscript{543} Id. at pdf pages 157-158.
Table 27 FLM’s Revised SCR Cost Effectiveness for Northern Border Pipeline’s Compressor No. 3 Based on Three Operating Scenarios.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Pre-SCR Uncontrolled NOx Assumed, tpy</th>
<th>Estimated Hours of Operation Assumed, hrs/year</th>
<th>NOx Removed, tpy</th>
<th>Cost Effectiveness, $/ton (2019$)</th>
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<tbody>
<tr>
<td>Full load PTE</td>
<td>226 tpy</td>
<td>8,760 hours/year</td>
<td>204 tpy</td>
<td>$3,027/ton</td>
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<tr>
<td>2017 Annual Operating Hours</td>
<td>126 tpy</td>
<td>6,835 hours/year</td>
<td>114 tpy</td>
<td>$5,140/ton</td>
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<tr>
<td>2017 NEI Emissions</td>
<td>88 tpy</td>
<td>4,788 hours/year</td>
<td>80 tpy</td>
<td>$6,987/ton</td>
</tr>
</tbody>
</table>

Based on the revised SCR cost effectiveness analyses for three operating scenarios for the Northern Border Pipeline Compressor No. 3, SCR could very likely be cost effective for the facility. These costs are within the range that other states are planning to use to determine cost effectiveness of controls in their regional haze plans for the second implementation period: Arizona is using $4,000 to $6,500/ton. New Mexico is using $7,000 per ton. Oregon has adopted a much higher regional haze control cost threshold of $10,000/ton. Colorado is also using a reasonableness cost threshold of $10,000/ton. In addition, the Washington Department of Ecology has found SCR to be cost effective for various heaters and boilers at refineries in its state, relying on a cost-effectiveness threshold of $6,300/ton.

There are three other options of NOx controls that MDEQ should have evaluated. One of those options is upgrading the low NOx burners. The air quality permit for Compressor Station No. 3 imposes a NOx limit of 40 parts per million, with the DLE in operation. MDEQ refers to this as a BACT limit for this turbine, which was initially permitted in approximately 1997. This is a very high emission rate for natural gas-fired combustion turbines with dry low NOx controls. Even at the time of construction of the Compressor No. 3, there were several turbine models with DLE that emitted NOx at rates between 9 ppm to 15 ppm. GE is now offering a gas combustion turbine with NOx emissions as low as 5 ppm.

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544 Id.
550 See July 30, 2019 Montana Air Quality Permit #2974-04, Northern Border Pipeline Company, Compressor Station No. 3, at 1, Condition II.A.1. (Ex. 46).
551 Id. at attached Montana Air Quality Permit Analysis at 1 and 10.
A second option is the replacement of the existing combustion turbine with a new turbine with state-of-the-art NOx combustion controls. The existing Cooper-Rolls turbine at Compressor No. 3 is currently about 26 years old. Given that there are much lower NOx-emitting turbines currently available, this option for significant NOx reductions should be considered.

A third option that MDEQ must consider, at the very minimum, is restricting the amount of time that the combustion turbine at Compressor No. 3 can operate in non-DLE mode. As stated above, the permit for the compressor station currently allows up to 750 hours per year in non-DLE mode, and there is no requirement limiting non-DLE operation to startups or shutdowns. MDEQ must evaluate whether non-DLE operation can be much more limited and impose specific conditions in the permit to require operation in DLE mode to the maximum extent practicable.

2. Consideration of the Time Necessary for Compliance, Energy and Non-Air Quality Environmental Impacts, and Remaining Useful Life

MDEQ did not identify any issues with the time necessary for compliance, stating “any required controls could be implemented by 2028.”

In terms of non-air environmental impacts of compliance, MDEQ and Northern Border Pipeline raise concerns with the fuel penalty of SCR and the required use of electricity to drive ammonia reagent pumps. Those issues are addressed in the EPA’s SCR cost spreadsheet and taken into account as increased operational costs. MDEQ also states concerns with ammonia slip. EPA states that SCR systems commonly operate with less than 2 ppm of ammonia slip. Thus, these issues can be addressed and minimized through proper design and operation of the SCR to minimize ammonia slip.

MDEQ states that remaining useful life of the turbine is much longer than the 20 year life that Northern Border Pipeline assumed in evaluating SCR and that remaining useful life is “not limited if standard maintenance requirements are followed.”

3. Summary – MDEQ Must Consider Requiring SCR to Achieve Reasonable Further Progress and, if it Can be Adequately Documented that Future Operations Will Be at Much Lower Levels of Operating Hours and Capacity, MDEQ Must More Fully Evaluate Other NOx Control Options for the No. 3 Compressor.

For the reasons provided above, MDEQ should consider adopting a requirement to install SCR at the Northern Border Pipeline Compressor No. 3 to achieve the maximum level of NOx reduction. SCR should be considered cost effective for the Compressor No. 3 turbine, especially at higher operating

554 2022 Draft Montana Regional Haze Plan at 283.
555 2022Draft Montana Regional Haze Plan at 283.
557 2022 Draft Montana Regional Haze Plan at 283.
capacity factors. If it can be adequately documented that future operations of the compressor turbine will be at much lower levels of operating hours and capacity than the unit has been historically operated at, then MDEQ must consider other NOx control options for the compressor turbine. At the minimum, MDEQ should limit the operation of the combustion turbine in non-DLE mode to the maximum extent practicable through increased enforceable restrictions on non-DLE mode operation.
## List of Exhibits

<table>
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<tr>
<th>Exhibit Number</th>
<th>Description</th>
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<tbody>
<tr>
<td>1</td>
<td>Final Title V Operating Permit #OP0513-17, Talen Montana, LLC, Colstrip Steam Electric Station, February 4, 2021</td>
</tr>
<tr>
<td>2</td>
<td>U.S. EPA, Complete Response to Comments for NM Regional Haze/Visibility Transport FIP, 8/5/11 (Docket EPA-R06-OAR-2010-0846)</td>
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<tr>
<td>3</td>
<td>LG&amp;E Energy, Selective Catalytic Reduction: From Planning to Operation, Competitive Power College, December 2005</td>
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<td>5</td>
<td>Haldor Topsoe, SCR Experience List, October 2009</td>
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<td>6</td>
<td>Hitachi, NOx Removal Coal Plant Supply List, October 17, 2006</td>
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<td>7</td>
<td>Argillon Experience List U.S. Coal Plants</td>
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<td>8</td>
<td>Hitachi, SCR System and NOx Catalyst Experience, Coal, February 2010</td>
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<td>9</td>
<td>Kurtides, T., Sargent and Lundy, Lessons Learned from SCR Reactor Retrofit, COAL-GEN, Columbus, OH, August 6-8, 2003</td>
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<tr>
<td>10</td>
<td>Institute of Clean Air Companies White Paper, Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions, February 2008</td>
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<tr>
<td>11</td>
<td>Colstrip Unit 3 SCR Cost Spreadsheet</td>
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<td>12</td>
<td>Colstrip Unit 3 SNCR Cost Spreadsheet</td>
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<td>13</td>
<td>Colstrip Unit 4 SCR Cost Spreadsheet</td>
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<td>14</td>
<td>Colstrip Unit 4 SNCR Cost Spreadsheet</td>
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<td>15</td>
<td>Washington Department of Ecology, Responses to Comments for Chemical Pulp and Paper Mills</td>
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<td>16</td>
<td>Montana Air Quality Permit # 2650-09 for Yellowstone Energy Limited Partnership</td>
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<td>Alstom Brochure, NID™ Flue Gas Desulfurization System for the Power Industry</td>
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<td>18</td>
<td>Babcock &amp; Wilcox, Circulating Dry Scrubber Technology</td>
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<td>19</td>
<td>Great River Energy-Spiritwood Station, Application for a Permit to Construct a Combined Heat and Power Plant (CHP), July 2007</td>
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<td>Montana Air Quality Permit #2035-07, Colstrip Energy Limited Partnership-Rosebud Power Plant, August 31, 2019</td>
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<td>21</td>
<td>Montana Air Quality Permit #3185-07, Rocky Mountain Power LLC – Hardin Generating Station, August 28, 2020</td>
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<td>22</td>
<td>Haldor Topsoe CataFlex™ brochure</td>
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<td>23</td>
<td>Air &amp; 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</td>
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<td>25</td>
<td>Montana Air Quality Permit #0982-16, GCC Trident, June 11, 2021</td>
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<td>26</td>
<td>Montana Air Quality Permit #2005-16, Ash Grove Cement – Montana City Plant, October 22, 2021</td>
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<td>27</td>
<td>MDEQ, ExxonMobil Billings Refinery, Operating Permit Technical Review Document, 9/9/2021</td>
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<tr>
<td></td>
<td>Description</td>
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<td>Consent Decree, Third Amendment, U.S.A. v. ExxonMobil Corporation, filed 12/17/2008</td>
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<td>29</td>
<td>11/2/2021 Final Title V Operating Permit #OP1564-18, ExxonMobil Corporation, Billings Petroleum Refinery</td>
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<td>30</td>
<td>9/21/2021 Montana Air Quality Permit #1564-35, Exxon Mobil Corporation Billings Refinery</td>
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<td>31</td>
<td>Stamper, V. &amp; 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</td>
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<tr>
<td>32</td>
<td>SNCR Cost Spreadsheet for ExxonMobil Billings Refinery Unit KCOB</td>
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<td>SCR Cost Spreadsheet for ExxonMobil Billings Refinery Unit KCOB</td>
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<td>34</td>
<td>SCR Cost Spreadsheet for ExxonMobil Billings Refinery Unit F-1/F-401</td>
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<td>SCR Cost Spreadsheet for ExxonMobil Billings Refinery Unit F-551</td>
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<td>SCR Cost Spreadsheet for ExxonMobil Billings Refinery Unit F-201</td>
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<td>6/8/2021 Final Title V Operating Permit #OP1821-19, CHS Laurel Petroleum Refinery</td>
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<td>2/23/2022 Montana Air Quality Permit #1821-44, CHS Laurel Refinery</td>
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<td>SCR cost spreadsheets for the CHS Main Crude Heater</td>
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<td>SCR cost spreadsheets for the CHS Boiler #9</td>
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<td>7/1/2020 Final Title V Operating Permit #OP2619-16, Phillips 66 Company, Billings Refinery</td>
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<td>1/31/2022 Montana Air Quality Permit #2619-42, Phillips 66 Billings Refinery</td>
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<td>SNCR Cost Spreadsheet for Phillips 66 Boiler 1 or 2</td>
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<td>SCR Cost Spreadsheet for Phillips 66 Boiler 1 or 2</td>
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<tr>
<td>46</td>
<td>July 30, 2019 Montana Air Quality Permit #2974-04, Northern Border Pipeline Company, Compressor Station No. 3</td>
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<tr>
<td>47</td>
<td>August 12, 2021 Final Title V Operating Permit #OP2974-14, Northern Border Pipeline Co. Compressor No. 3</td>
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Exhibit B
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

Prepared for National Parks Conservation Association
by Vicki Stamper & Megan Williams

March 6, 2020
EXECUTIVE SUMMARY

States are required to revise and submit revisions to their regional haze state implementation plans to make reasonable progress toward the national visibility goal, with the next revision due to the U.S. Environmental Protection Agency by July 31, 2021. In this second round of regional haze plans, each state needs to look broadly at the sources of visibility-impairing emissions within its state and determine the sources or source categories for which to conduct a four-factor analysis of emission reducing measures. Oil and gas development is a significant source of visibility-impairing emissions in many states, including emissions of nitrogen oxides (NOx), volatile organic compounds (VOCs), sulfur dioxide (SO2), and particulate matter (PM).

This report conducts a four-factor analysis of reasonable progress controls for five air emission 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. This report includes a compilation of information on available pollution control options for visibility-impairing pollutants, provides cost of controls (where available) and documents the cost effectiveness of controls for various size units and a range of operating levels. The report also provides information for specific pollution controls regarding the three other reasonable progress factors: the time necessary for compliance to install the controls, the energy and non-air quality environmental impacts of the controls, and the remaining useful life of both the source category and the pollution control in question, if it differs from that of the source category.

With respect to the cost of controls, the authors used control cost data that were relied upon by federal, state, and local air agencies. Also, capital costs of control were amortized based on the expected useful life of the unit unless a shorter useful life of the specific pollution control was expected, all of which is documented in the report. The authors did not escalate costs to current dollars, because in many cases, the cost information was more than five years old, and EPA’s Control Cost Manual cautions against attempting to escalate costs more than five years from the original cost analysis. Last, the authors compiled 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 to the source category. 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. Looking to state regional haze plans, the authors note that determinations of cost effectiveness for a particular source category should be based on the costs that similar sources have had to incur to meet Clean Air Act requirements.

Although the authors attempted to identify the pollution control methods that were both cost effective and the most effective at reducing visibility-impairing emissions and evaluated varying levels of operation, it is recognized that air pollution control determinations to retrofit existing sources cannot always be implemented via a “one-size-fits-all” approach. Thus, in some cases, a few different options for retrofit pollution controls are recommended for a source category, with the primary reasons for differentiating recommended pollution controls being based on size of the unit and/or operating capacity factor. Below the authors summarize the pollution controls that are presumed to be the best control options for each source category, with a focus on NOx pollution controls.
## Summary of Cost Effective Control Options for Air Emissions Sources of the Oil and Gas Sector

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

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.
As shown in the table above, there are technically feasible and cost effective options to control NOx, VOCs, PM, and SO2 from these four source categories of combustion-related emissions from the oil and gas sector and, in most cases, there are many examples of state and local air agency rules that require these or similar levels of control for existing sources. While many of these state and local rules were adopted to address the National Ambient Air Quality Standards (NAAQS), cost effectiveness of controls is generally part of the rulemaking process under reasonably available control technology (RACT) and best available retrofit control technology (BARCT – which applies in California) determinations. Given that state and local air agencies have found the costs of these controls to be reasonable for imposition of various pollution control requirements, these costs should be considered reasonable to impose to meet other Clean Air Act requirements including under the Regional Haze Program.

For flaring of waste gases, the following control options are recommended:

- 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
- 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.
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<th>Description</th>
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<tr>
<td>2SLB</td>
<td>Two-stroke lean-burn</td>
</tr>
<tr>
<td>4SLB</td>
<td>Four-stroke lean-burn</td>
</tr>
<tr>
<td>4SRB</td>
<td>Four-stroke rich-burn</td>
</tr>
<tr>
<td>A/F</td>
<td>Air-to-fuel ratio</td>
</tr>
<tr>
<td>ACT</td>
<td>Alternative control techniques</td>
</tr>
<tr>
<td>AFRC</td>
<td>Air/fuel ratio controller</td>
</tr>
<tr>
<td>APCD</td>
<td>Air pollution control district</td>
</tr>
<tr>
<td>AQMD</td>
<td>Air Quality Management District</td>
</tr>
<tr>
<td>BACT</td>
<td>Best Available Control Technology</td>
</tr>
<tr>
<td>BARCT</td>
<td>Best Available Retrofit Control Technology</td>
</tr>
<tr>
<td>BART</td>
<td>Best Available Retrofit Technology</td>
</tr>
<tr>
<td>BAT</td>
<td>Best Available Technology</td>
</tr>
<tr>
<td>BSFC</td>
<td>Brake-specific fuel consumption</td>
</tr>
<tr>
<td>BLM</td>
<td>U.S. Bureau of Land Management</td>
</tr>
<tr>
<td>CARB</td>
<td>California Air Resources Board</td>
</tr>
<tr>
<td>CEPCI</td>
<td>Chemical Engineering Plant Cost Index</td>
</tr>
<tr>
<td>CAA</td>
<td>Clean Air Act</td>
</tr>
<tr>
<td>CDPF</td>
<td>Catalyzed diesel particulate filter</td>
</tr>
<tr>
<td>CDPHE</td>
<td>Colorado Department of Public Health and Environment</td>
</tr>
<tr>
<td>CI</td>
<td>Compression ignition</td>
</tr>
<tr>
<td>CEMS</td>
<td>Continuous emissions monitoring system</td>
</tr>
<tr>
<td>CO</td>
<td>Carbon monoxide</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon dioxide</td>
</tr>
<tr>
<td>CSAPR</td>
<td>Cross-State Air Pollution Rule</td>
</tr>
<tr>
<td>DRE</td>
<td>Destruction and removal efficiency</td>
</tr>
<tr>
<td>DPF</td>
<td>Diesel particulate filter</td>
</tr>
<tr>
<td>DOE</td>
<td>U.S. Department of Energy</td>
</tr>
<tr>
<td>DLNC</td>
<td>Dry low NOx combustors</td>
</tr>
<tr>
<td>EIA</td>
<td>U.S. Energy Information Administration</td>
</tr>
<tr>
<td>EPA</td>
<td>U.S. Environmental Protection Agency</td>
</tr>
<tr>
<td>FGR</td>
<td>Flue gas recirculation</td>
</tr>
<tr>
<td>4CAQTF</td>
<td>Four Corners Air Quality Task Force</td>
</tr>
<tr>
<td>GPU</td>
<td>Gas production unit</td>
</tr>
<tr>
<td>Gen Set</td>
<td>Generator-Set Engine</td>
</tr>
<tr>
<td>g/bhp-hr</td>
<td>Grams per brake horsepower-hour</td>
</tr>
<tr>
<td>g/hp-hr</td>
<td>Grams per horsepower-hour</td>
</tr>
<tr>
<td>HAP</td>
<td>Hazardous air pollutant</td>
</tr>
</tbody>
</table>
LIST OF TERMS

HC hydrocarbon
H₂S Hydrogen sulfide
hp horsepower
kW Kilowatt
INGAA Interstate Natural Gas Association of America
IR Ignition timing retard
LB Lean-burn
LEC Low emission combustion
LNB Low NOx burners
MCF Thousand cubic feet
MW Megawatt
MMBtu Million British Thermal Unit (heat input)
MMscf Million standard cubic feet
NAAQS National Ambient Air Quality Standards
NESCAUM Northeast States for Coordinated Air Use Management
NESHAP National Emission Standards for Hazardous Air Pollutants
NPS National Park Service
NSPS New Source Performance Standards
NOx Nitrogen oxides
NMHC Non-methane hydrocarbons
NSCR Nonselective catalytic reduction
NSPS New Source Performance Standards
OTC Ozone Transport Commission
PEMS Parametric emissions monitoring system
PM Particulate matter
PM₂.₅ Particulate matter with an aerodynamic diameter equal to or less than 2.5 microns
ppm Parts per million
ppmv Parts per million by volume
ppmvd Parts per million dry volume
PSC Prestratified charge
PSD Prevention of Significant Deterioration
psig Pounds per square inch gauge
RACT Reasonably Available Control Technology
RECLAIM Regional Clean Air Incentives Market
RHR Regional Haze Rule
RB Rich-burn
RICE Reciprocating internal combustion engine(s)
**LIST OF TERMS**

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>SMAQMD</td>
<td>Sacramento Metropolitan Air Quality Management District</td>
</tr>
<tr>
<td>SCAQMD</td>
<td>South Coast Air Quality Management District</td>
</tr>
<tr>
<td>SCR</td>
<td>Selective catalytic reduction</td>
</tr>
<tr>
<td>SI</td>
<td>Spark ignition</td>
</tr>
<tr>
<td>SJVAPCD</td>
<td>San Joaquin Valley Air Pollution Control District</td>
</tr>
<tr>
<td>SNCR</td>
<td>Selective noncatalytic reduction</td>
</tr>
<tr>
<td>SO(_2)</td>
<td>Sulfur dioxide</td>
</tr>
<tr>
<td>SO(_x)</td>
<td>Sulfur oxides</td>
</tr>
<tr>
<td>TCEQ</td>
<td>Texas Commission on Environmental Quality</td>
</tr>
<tr>
<td>TSD</td>
<td>Technical support document</td>
</tr>
<tr>
<td>THC</td>
<td>Total hydrocarbons</td>
</tr>
<tr>
<td>ULSD</td>
<td>Ultra-low sulfur diesel</td>
</tr>
<tr>
<td>ULNB</td>
<td>Ultra-low NO(_x) burners</td>
</tr>
<tr>
<td>VCAPCD</td>
<td>Ventura County Air Pollution Control District</td>
</tr>
<tr>
<td>VOC</td>
<td>Volatile organic compound</td>
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</tbody>
</table>
I. BASIS FOR REASONABLE PROGRESS CONTROLS

Under the Regional Haze Rule (RHR), states are required to revise and submit periodic comprehensive revisions to their regional haze plans, with the next revision due to be submitted to the U.S. Environmental Protection Agency (EPA) by July 31, 2021.\(^1\) This next round of regional haze plans is referred to as the regional haze plan for the second implementation period. States’ regional haze plans address regional haze in all Class I areas within the state and in all Class I areas located outside the state that may be affected by emissions from within the state.\(^2\) Each state’s plan and plan revision must include, among other things, a long term strategy which is to be determined as follows:

Each State must submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State that may be affected by emissions from the State. The long-term strategy must include 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). In establishing its long-term strategy for regional haze, the State must meet the following requirements:

(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.

\[\text{40 C.F.R. § 51.308(f)(2)(i).}\]

The requirement for evaluation of emission reduction measures quoted above is generally referred to as a “four-factor analysis” or a “reasonable progress analyses” of controls. To reiterate, the four factors that must be considered when evaluating reasonable progress controls for a source are (1) cost of compliance, (2) time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and (4) the remaining useful life of the source. In the first round of regional haze plans, States were required to evaluate and impose emission limitations that reflect “best available

\[^{1}\text{40 C.F.R. § 51.308(f).}\]
\[^{2}\text{Id.}\]
retrofit technology” (BART) at all BART-subject sources (which were clearly defined by regulation). States also were required to identify sources to control in order to make reasonable progress towards the national visibility goal; for these sources states tended to focus on the larger single sources of emissions, as was also the focus of BART controls. In the second round of regional haze plans, each state needs to look more broadly at the sources of visibility-impairing emissions within its state and determine the sources or source categories for which to conduct a four-factor analysis of controls. Each state must adopt emission-reduction measures in its regional haze plan developed for the second implementation period to make reasonable progress towards the national visibility goal. The Clean Air Act (CAA) mandated that regional haze plans must address sources of “emissions from which may reasonably be anticipated to cause or contribute to any impairment of visibility” (emphasis added)).

Air emissions from oil and gas development, production, treatment, and transmission represent a significant quantity of regional haze-impairing emissions in many states. Air emissions from oil and gas development that can impact visibility include nitrogen oxides (NOx), sulfur dioxide (SO2), directly emitted particulate matter (PM), volatile organic compounds (VOCs), and ammonia. NOx, SO2, VOCs, and ammonia, initially emitted as gases, often convert into fine (i.e., less than 2.5 micrometers in diameter) particulate matter (PM2.5) in the atmosphere, which can travel far and which are very efficient in scattering light and impacting visibility. Oil and gas development often occurs on federal, state, and/or private lands near or even adjacent to Class I areas. Oil and/or gas development tends to be clustered in certain areas where such fossil fuels are found. Many of the air emissions sources associated with gas and/or oil production are minor sources, not large enough in emissions to trigger new source review permitting. However, such sources collectively are often significant contributors to visibility impairment in Class I areas due to sheer numbers of emission sources or proximity to Class I areas, or both.

In the United States, oil and gas production has been increasing and is projected to continue to increase in the future. States with significant increases in oil production since 2013 include Colorado with almost a tripling of production since 2013, New Mexico with more than a doubling of production since 2013, Texas with a 73% increase in production since 2013, and North Dakota with a 48% increase since 2013. States with significant increases in gas production include, among others, Ohio with annual gas production in 2018 that is more than 14 times higher than it was in 2013, West Virginia with a 143% increase in gas production since 2013, North Dakota with a doubling of production in 2018 compared to 2013, Pennsylvania with a 91% increase in gas production since 2013, and New Mexico with a 27% increase in gas production since 2013. The U.S. Energy Information Administration (EIA) currently projects crude oil production in the United States to be 25% higher in 2021 than it was in 2018 and marketed gas production in the United States to be 13% higher in 2021 than it was in 2018. In many areas of the country, these increases in production are projected to continue well into the future. For

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3 42 U.S.C. § 7491(b)(2).
example, the New Mexico Oil and Gas Association recently presented a report to state lawmakers indicating that there will be “solid growth for the next decade or so” in the Permian Basin.\(^8\)

There are several combustion-related sources of visibility-impairing emissions associated with oil and gas development. Various engines, typically fired by natural gas or diesel, are used in the drilling and completion phase, in the processing of natural gas, and at compressor stations. On-site power sources are often used, in the form of natural gas-fired engines, diesel generators, and/or combustion turbines. Natural gas-fired boilers and heaters are also used throughout the oil and gas production and process segments of the industry, to generate power, and to create steam and process heat. Those engines and combustion turbines emit significant quantities of NOx and VOCs and also of SO\(_2\) and PM for diesel-fired engines. Flaring of excess and waste gas can be a significant source of SO\(_2\) and NOx emissions.

This report presents a four-factor analysis of reasonable progress controls for NOx and VOCs, and SO\(_2\) and PM as appropriate, for five significant air emissions source categories associated with oil and gas development: natural gas-fired reciprocating internal combustion engines (RICE), natural gas-fired combustion turbines, diesel-fired RICE, natural gas-fired boilers and heaters, and flaring/incineration of waste or excess gas. This report (1) proposes pollution controls and/or measures for such sources considering the control technology available and the most effective controls; (2) compiles cost data with a focus on data relied upon by federal, state, and local air agencies in regulatory decisions; (3) evaluates non-air quality environmental and energy impacts of controls; and (4) considers the remaining useful life of the equipment.

It is important to note that, while New Source Performance Standards (NSPS) exist for these source categories, the existence of an NSPS does not negate the need for a four-factor analysis of controls to achieve reasonable progress towards the national visibility goal for several reasons. First, it has been many years since the NSPS standards for RICE units, gas turbines, and small boilers have been re-evaluated. Although EPA correctly states in its 2019 Regional Haze guidance that “[t]he [CAA] requires EPA to review, and if necessary, revise NSPS every 8 years,”\(^9\) EPA has not always updated the NSPS emission standards for a source category in accordance with this timetable. Second, the NSPS emission standards only apply to a facility if it is constructed, modified, or reconstructed after the applicability date.\(^{10}\) The applicability date of an NSPS (or of a revised NSPS emission standard) is set as either the date of publication of any proposed or of any final rulemaking establishing the standard. Third, when EPA adopts or revises NSPS for a source category, EPA is establishing an emission standard applicable to all of the source types and variable fuels, operating conditions, etc. that exist for that source category. Thus, the NSPS are generally applicable emission standards and not a source-specific evaluation of controls.

Further, while EPA’s Regional Haze guidance states that, if a new or modified unit is subject to and complying with an NSPS promulgated or reviewed since July 31, 2013, it is unlikely that new or existing controls are available or more effective, no such assumption should be made without considering the

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\(^{9}\) EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 23, note 44.

\(^{10}\) See 40 C.F.R. § 60.1(a); see also definitions in § 60.2 and regulations on “modification” and “reconstruction” in §§ 60.14 and 60.15.
specific emission and operational characteristics of the source in question. EPA’s statements are problematic and need clarification. One cannot simply determine the last time the NSPS for a source category was amended and assume that if the amendments occurred within the last eight years, the NSPS is up to date. Section 111(b)(1)(B) of the CAA requires EPA to review and revise each NSPS at least every eight years, to essentially determine if the NSPS currently reflect the “degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.” EPA amends its NSPS for various reasons (e.g., changes in test methods or protocols, clarifications), but thorough reviews and revisions generally occur much less frequently — in many cases less frequently than every eight years as required by the CAA. Table 1 below shows the NSPS applicable to RICE units, turbines, and small boilers and provides the most recent date of EPA’s comprehensive review and revision. The NSPS rules applicable to RICE units and gas turbines were last subject to a comprehensive revision to reflect the best-demonstrated technology well before July 31, 2013.

Table 1. NSPS Categories that Address RICE, Natural Gas Turbines, and Small Boilers

<table>
<thead>
<tr>
<th>NSPS Subpart in 40 C.F.R. Part 60</th>
<th>Emission Source(s)</th>
<th>Date of Promulgation of Most Recent Revisions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dc</td>
<td>Smaller Industrial-Commercial-Institutional Steam Generating Units</td>
<td>2/27/06 (reflects most recent review of the emission standards)</td>
</tr>
<tr>
<td>GG</td>
<td>Stationary Gas Turbines</td>
<td>9/20/79 (first promulgation of NSPS for gas turbines and revised standards promulgated at Subpart KKKK)</td>
</tr>
<tr>
<td>IIII</td>
<td>Stationary Compression Ignition Internal Combustion Engines</td>
<td>6/28/11 (reflects most recent adoption of emission standards for this source category)</td>
</tr>
<tr>
<td>JJJJ</td>
<td>Stationary Spark Ignition Internal Combustion Engines</td>
<td>1/18/08 (NSPS for source category first promulgated, and reflects most recent review of emission standards)</td>
</tr>
<tr>
<td>KKKK</td>
<td>Stationary Combustion Turbines constructed, reconstructed or modified after 2/18/05</td>
<td>7/6/2006 (first promulgation of NSPS Subpart KKKK, and reflects most recent review of emission standards)</td>
</tr>
<tr>
<td>OOOO</td>
<td>Crude Oil and Natural Gas Production, Transmission, and Distribution for which Construction, Modification, or Reconstruction Commenced after 8/23/11 and on or before 9/15/15</td>
<td>6/3/2016 (reflects most recent review the emission standards)</td>
</tr>
<tr>
<td>OOOOa</td>
<td>Crude Oil and Natural Gas Production, Transmission, and Distribution from which Construction, Modification, or Reconstruction Commenced after 9/18/15</td>
<td>6/3/2016 (NSPS Subpart first promulgated)</td>
</tr>
</tbody>
</table>

Thus, while the NSPS may be a place to start in evaluating pollution controls for air emissions sources associated with the oil and gas industry, it is also necessary to evaluate if more stringent requirements and pollution controls have been required in state rules or local air rules, air permits, or other requirements. Review of state regulations and state implementation plans, particularly to address national ambient air quality standards (NAAQS) which requires reductions in emissions from existing sources, is necessary to fully evaluate controls for emission sources associated with oil and gas development to achieve reasonable progress towards the national visibility goal.

The information provided below reflects a comprehensive review of the pollution controls and techniques and associated emissions levels applicable to each of the source categories, along with data on cost of controls where available, non-air quality environmental and energy impacts, and the reasonable useful life of the emission source being evaluated.

II. CONTROL OF NO\textsubscript{x} EMISSIONS FROM NATURAL GAS-FIRED RECIPROCATING INTERNAL COMBUSTION ENGINES

Reciprocating internal combustion engines (RICE) are used in a variety of applications, including gas compression, pumping, and power generation. RICE can either be: (1) spark-ignited and fueled by natural gas, propane, or gasoline; or (2) compression-ignited and fueled by diesel. Spark-ignition engines fueled by natural gas, propane, and gasoline can operate lean (i.e., with a higher air-to-fuel ratio) or rich (i.e., with a lower air-to-fuel ratio). Compression-ignition diesel-fueled engines operate lean. A rich-burn engine operates with excess fuel during combustion, whereas a lean-burn engine operates with excess air.

Natural gas-fired RICE are the focus of this section and are used throughout the oil and gas industry, as described by EPA:

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Most natural gas-fired reciprocating engines are used in the natural gas industry at pipeline compressor and storage stations and at gas processing plants. These engines are used to provide mechanical shaft power for compressors and pumps. At pipeline compressor stations, engines are used to help move natural gas from station to station. At storage facilities, they are used to help inject the natural gas into high pressure natural gas storage fields. At processing plants, these engines are used to transmit fuel within a facility and for process compression needs (e.g., refrigeration cycles). The size of these engines ranges from 50 brake horsepower (bhp) to 11,000 bhp. In addition, some engines in service are 50–60 years old and consequently have significant differences in design compared to newer engines, resulting in differences in emissions and the ability to be retrofitted with new parts or controls.

At pipeline compressor stations, reciprocating engines are used to power reciprocating compressors that move compressed natural gas (500–2000 [pounds per square inch gauge (psig)]) in a pipeline. These stations are spaced approximately 50 to 100 miles apart along a pipeline that stretches from a gas supply area to the market area. The reciprocating compressors raise the discharge pressure of the gas in the pipeline to overcome the effect of frictional losses in the pipeline upstream of the station, in order to maintain the required
suction pressure at the next station downstream or at various downstream delivery points. The volume of gas flowing and the amount of subsequent frictional losses in a pipeline are heavily dependent on the market conditions that vary with weather and industrial activity, causing wide pressure variations. The number of engines operating at a station, the speed of an individual engine, and the amount of individual engine horsepower (load) needed to compress the natural gas is dependent on the pressure of the compressed gas received by the station, the desired discharge pressure of the gas, and the amount of gas flowing in the pipeline. Reciprocating compressors have a wider operating bandwidth than centrifugal compressors, providing increased flexibility in varying flow conditions. Centrifugal compressors powered by natural gas turbines are also used in some stations and are discussed in another section of this document.¹²

Natural gas-fired reciprocating engines are also used at well sites across the oil and gas industry in various applications including, e.g., reciprocating compressors and pump engines used to lift oil out of a well.

Natural gas-fired RICE can be classified as two-stroke or four-stroke engines. In a two-stroke engine, the power cycle occurs in a single crankshaft revolution and two strokes: an intake/compression stroke; and a power/exhaust stroke. In a four-stroke engine, the power cycle is completed with two crankshaft revolutions and four strokes: an intake stroke; compression stroke; power stroke; and exhaust stroke. Natural gas-fired RICE units encompass three engine types or classes:

1. Two-stroke lean-burn (2SLB)
2. Four-stroke lean-burn (4SLB)
3. Four-stroke rich-burn (4SRB)

NOx emissions from RICE are highly dependent on combustion temperature, with higher temperatures resulting in more NOx emissions. Rich-burn engines operate with an air-to-fuel ratio (A/F) that is rich with fuel resulting in higher fuel use, increased combustion temperatures, increased engine power, and decreased engine efficiency relative to a lean-burn engine. Lean-burn engines operate with an A/F that is lean with fuel resulting in less fuel use, decreased combustion temperatures, decreased engine power, and increased engine efficiency relative to a rich burn engine.

**UNITS**

NOx emissions from RICE are generally expressed as emission rates in grams per brake horsepower hour (g/bhp-hr) or as a concentration in parts per million by volume (ppmv or ppmvd). All concentrations expressed in ppmv are on a dry basis and corrected to 15% oxygen. Emission rates expressed in g/bhp-hr and grams per horsepower-hour (g/hp-hr) are assumed to be roughly equivalent for the RICE applications in this section. The following conversion factors from EPA’s Updated Information on NOx Emissions and Control Techniques document* are used in this section:

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Uncontrolled rich-burn Spark-Ignition (SI) engines and rich-burn engines controlled with nonselective catalytic reduction (NSCR)........................................67 ppmv = 1 g/bhp-hr

Uncontrolled lean-burn engines, lean-burn engines controlled with selective catalytic reduction (SCR), and rich-burn engines controlled with prestratified charge™ (PSC) technology........................................73 ppmv = 1 g/bhp-hr

Lean-burn engines controlled with Low Emission Combustion (LEC) Technology...............................................................75 ppmv = 1 g/bhp-hr

* EPA, Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques, September 2000 (EPA-457/R-00-001)

A. RICH-BURN RICE: COMBUSTION CONTROLS

Emission control technologies for RICE depend on the A/F and therefore different controls apply to different engine types. NOx emissions reductions from these engines can be achieved through combustion controls or through post-combustion (add-on) controls. The following retrofit combustion control technologies for rich-burn RICE are described by EPA in its Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines, and EPA’s descriptions are reprinted below.¹³

Rich-Burn A/F Adjustments

Adjusting the A/F toward fuel-rich operation reduces the oxygen available to combine with nitrogen, thereby inhibiting NOx formation. The low-oxygen environment also contributes to incomplete combustion, which results in lower combustion temperatures and, therefore, lower NOx formation rates. The incomplete combustion also increases [carbon monoxide (CO)] emissions and, to a lesser extent, [hydrocarbons (HC)] emissions. Combustion efficiency is also reduced, which increases brake-specific fuel consumption (BSFC). Excessively rich A/F’s may result in combustion instability and unacceptable increases in CO emissions.

The A/F can be adjusted on all new or existing rich-burn engines. Sustained NOx reduction with changes in ambient conditions and engine load, however, is best accomplished with an automatic A/F control system.

The achievable NOx emission reduction ranges from approximately 10 to 40 percent from uncontrolled levels. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 9.5 to 14.0 g/hp-hr (640 ppmv).

to 940 ppmv). Available data show that the achievable NOx reduction using A/F varies for each engine model and even among engines of the same model, which suggests that engine design and manufacturing tolerances influence the effect of A/F on NOx emission reductions.\textsuperscript{14}

\textbf{NOx Removal Efficiency:} 10-40\%
\textbf{Controlled NOx Emission Rates:} 9.5 to 14.0 g/hp-hr
640 to 940 ppmv

**Rich-Burn Ignition Timing Retard (IR)**

Ignition timing retard delays initiation of combustion to later in the power cycle, which increases the volume of the combustion chamber and reduces the residence time of the combustion products. This increased volume and reduced residence time offer the potential for reduced NOx formation. . . .

Ignition timing can be adjusted on all new or existing rich-burn engines. Sustained NOx reduction with changes in ambient conditions and engine load, however, is best accomplished using an electronic ignition control system.

The achievable NOx emission reduction ranges from virtually no reduction to as high as 40 percent. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 9.5 to 15.8 g/hp-hr (640 to 1,060 ppmv). Available data and information provided by engine manufacturers show that, like AF, the achievable NOx reductions using IR are engine-specific.\textsuperscript{15}

\textbf{NOx Removal Efficiency:} 0-40\%
\textbf{Controlled NOx Emission Rates:} 9.5 to 15.8 g/hp-hr
640 to 1,060 ppmv

A/F adjustment and IR can be employed together to reduce NOx emissions from rich-burn RICE. According to EPA, the achievable emissions reductions are similar to that for A/F adjustments (i.e., 10-40%) but may offer the potential to minimize some of the adverse impacts of other operating parameters (e.g., CO emissions, engine response, fuel consumption).\textsuperscript{16}

Limited cost data indicate that combustion controls for rich-burn RICE costs between $400 to $1,000 per ton of NOx reduced for engines greater than 500 horsepower (hp).\textsuperscript{17}

\textsuperscript{14} Id. at 2-5.
\textsuperscript{15} Id. at 2-5 and 2-9.
\textsuperscript{16} Id. at 2-9.
\textsuperscript{17} Id. at 2-30. See also California Air Resources Board (CARB) Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-Ignited Internal Combustion Engines, November 2001, Table V-2 at V-3, available at: https://ww3.arb.ca.gov/ractbarc/rb-iceall.pdf [hereinafter referred to as “CARB 2001 Guidance”]. The CARB cost effectiveness analysis assumes the engines are run at 100% load for 2,000 hours per year, annualized costs are figured based on an interest rate of 10% over a 10-year life.
B. RICH-BURN RICE: PRESTRATIFIED CHARGE (PSC)

Prestratified charge (PSC) is a combustion modification that converts rich-burn engines to lean-burn engines by retrofitting the air injectors to make a leaner A/F ratio. PSC is described by EPA in its Alternative Control Techniques Document for RICE, as follows:

This add-on control technique facilitates combustion of a leaner A/F. The increased air content acts as a heat sink, reducing combustion temperatures, thereby reducing NOx formation rates. Because this control technique is installed upstream of the combustion process, PSC® is often used with engines fueled by sulfur-bearing gases or other gases (e.g. sewage or landfill gases) that may adversely affect some catalyst materials.

Prestratified charge applies only to four-cycle, carbureted engines. Pre-engineered, “off-the-shelf” kits are available for most new or existing candidate engines, regardless of age or size. According to the vendor, PSC® to date has been installed on engines ranging in size up to approximately 2,000 hp.

The vendor offers guaranteed controlled NOx emission levels of 2 g/hp-hr (140 ppmv), and available test data show numerous controlled levels of 1 to 2 g/hp-hr (70 to 140 ppmv). The extent to which NOx emissions can be reduced is determined by the extent to which the air content of the stratified charge can be increased without excessively compromising other operating parameters such as power output and CO and HC emissions. The leaner A/F effectively displaces a portion of the fuel with air, which may reduce power output from the engine. For naturally aspirated engines, the power reduction can be as high as 20 percent, according to the vendor. This power reduction can be at least partially offset by modifying an existing turbocharger or installing a turbocharger on naturally aspirated engines. In general, CO and HC emission levels increase with PSC®, but the degree of the increase is engine-specific. The effect on BSFC is a decrease for moderate controlled NOx emission levels (4 to 7 g/hp-hr, or 290 to 500 ppmv), but an increase for controlled NOx emission levels of 2 g/hp-hr (140 ppmv) or less.18

PSC NOx Removal Efficiency: 87% (85-90%, EPA 2000)19
Controlled NOx Emission Rates: 2 g/hp-hr
140 ppmv

PSC NOx reduction efficiency depends on how much the air content can be increased without adversely affecting the performance of the engine; achieving lower NOx rates with PSC will result in sacrifices in engine power output. PSC, generally, can only achieve a NOx emission rate as low as 2 g/bhp-hr. EPA re-affirmed the limitations of PSC in its 2000 Updated Information on NOx Emissions and Control Techniques for RICE, stating:

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19 EPA-457/R-00-001 Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques, September 2000, available at: https://nepis.epa.gov/Exe/ZyPDF.cgi/P100V343.PDF?Dockey=P100V343.PDF [hereinafter referred to as “EPA 2000 Updated Information on NOx Emissions and Control Techniques”].
The 1993 ACT document found that the achievable NOX emission level for PSC is 2.0 g/bhp-hr, based on the vendor’s guarantees. This value is generally consistent with the information gathered for this project and is a representative value for the NOX emission level that can be achieved using PSC control technology.²⁰

Limited cost data indicate that PSC achieving 80% NOx reduction efficiency costs between $200 to $800 per ton of NOx reduced for engines ranging in size from 50–1,500 hp.²¹

Even the best-case NOx emissions reductions for PSC are generally lower than the emissions reductions that can be accomplished with the nonselective catalytic reduction (NSCR) technologies discussed below. And NSCR also generally costs less, with capital and annual costs less than PSC for almost all engine sizes, according to data from EPA.²² However, for fuels with higher sulfur content (e.g., waste gases), PSC technology can be effective at achieving NOx emissions reductions where higher sulfur fuels would adversely impact catalyst material used in post-combustion control technologies such as NSCR.

C. RICH-BURN RICE: NONSELECTIVE CATALYTIC REDUCTION (NSCR)

The use of NSCR technology began in the 1970s with the application of 3-way catalysts to gasoline-fueled motor vehicles in order to simultaneously control carbon monoxide, VOCs, and NOx emissions. In automobiles, the technology is known as a “catalytic convertor.” Since then, NSCR has been widely applied to stationary engines. NSCR is usually also accompanied by an air/fuel ratio controller (AFRC), which is used to adjust the combustion parameters across the operating range of the engine in order to maintain the conditions needed for the efficient operation of the NSCR system (e.g., sufficient excess oxygen in the exhaust gas).

NSCR is described by EPA in its Alternative Control Techniques Document for RICE, as follows:

Nonselective catalytic reduction is essentially the same catalytic reduction technique used in automobile applications and is also referred to as a three-way catalyst system because the catalyst reactor simultaneously reduces NOx, CO, and HC to water (H₂O), carbon dioxide (CO₂), and diatomic nitrogen (N₂). The chemical stoichiometry requires that O₂ concentration levels be kept at or below approximately 0.5 percent, and most NSCR system require that the engine be operated at fuel-rich A/F’s . . . .

Nonselective catalytic reduction applies only to carbureted rich-burn engines and can be retrofit to existing installations. Sustained NOx reductions are achieved with changes in ambient conditions and operating loads only with an automatic A/F control system . . . .

²⁰ Id. at 4-21.
²¹ See CARB 2001 Guidance at Table V-2 at V-3. The CARB cost effectiveness analysis assumes the engines are run at 100% load for 2,000 hours per year, annualized costs are figured based on an interest rate of 10% over a 10-year life.
²² See EPA’s 1993 Alternative Control Techniques Document for RICE Table 2-12 at 2-30.
Catalyst vendors quote NOx emission reduction efficiencies of 90 to 98 percent. Based on an average uncontrolled NOx emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NOx emissions is from 0.3 to 1.6 g/hp-hr (20 to 110 ppmv). . . .

The predominant catalyst material used in NSCR applications is a platinum-based metal catalyst. The spent catalyst material is not considered hazardous, and most catalyst vendors accept return of the material, often with a salvage value that can be credited toward purchase of replacement catalyst.23

| NSCR NOx Removal Efficiency: | 90-98% |
| Controlled NOx Emission Rates: | 0.3 to 1.6 g/hp-hr |
| | 20 to 110 ppmv |

According to EPA, when California air district standards were tightened to 96% NOx reduction and emission limits of 25 ppmv (0.37 g/bhp-hr), facilities shifted from PSC to NSCR to meet the standard.24 This level of NOx control can be met with an NSCR retrofit to an existing unit. For example, retrofit installations of NSCR on five Caterpillar rich burn engines in Texas achieved a NOx reduction of 96% or greater on all of the engines.25 On two of those engines, testing conducted after more than 4,000 hours of operation with NSCR indicated the NSCR controls were still achieving a 95% NOx reduction.26 Employing NSCR to reduce NOx emissions from EPA’s uncontrolled emission rate of 15.8 g/bhp-hr to 1.0 g/bhp-hr corresponds to a NOx emission reduction efficiency of 94%. Unless otherwise noted, the analyses provided further below in this section assume a 94% NOx reduction efficiency to meet a 1 g/bhp-hr emission rate. Lower NOx emission limits have been required by some states and local agencies that reflect a higher NOx removal efficiency (see Section II.G., below).

NSCR can effectively reduce CO, HC, VOCs (include formaldehyde), as well as NOx emissions, if properly optimized for control of all these pollutants. Such systems must control the A/F carefully to provide enough oxygen to ensure that CO and VOCs are oxidized but also limit oxygen enough to ensure the NOx is effectively reduced. The oxygen content of the exhaust gas needs to be within a narrow window to ensure effective control of all three pollutants, and thus an AFRC is necessary along with an oxygen sensor to provide feedback to the AFRC to ensure the proper fuel-rich operation.

HOURS OF OPERATION FOR RICE

Stationary RICE are used in a variety of applications throughout the oil and gas sector, from providing on-site power, driving pumps or compressors, and drilling operations at well sites to driving pipeline compressor stations to powering pumps, compressors, and refrigeration at gas processing plants. Because of the varying uses for RICE units, RICE units used in the oil and gas sector cover the full

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24 EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-19.
25 OTC Technical Information Oil and Gas Sector Significant Stationary Sources of NOx Emissions October 17, 2012, available at:
26 Id.
range of operating schedules. In providing cost estimates herein, this report presents cost
effectiveness analyses to reflect operating as few as 2,000 hours per year and as high as 8,000 hours
per year. For example, compressor stations typically operate continuously, although not all
compressor engines at a compressor station operate continuously. On the other hand, RICE units
used for backup onsite electrical generation may not operate much at all in a year. Thus, a low-end
operating capacity factor and a high-end capacity factor were assumed to reflect a range of costs
across varying levels of operation.

A cost effectiveness analysis of NSCR was performed in 2010 for EPA, to help determine national
impacts associated with EPA’s final rule for Reciprocating Internal Combustion Engine National Emission
Standards for Hazardous Air Pollutants (RICE NESHAP).27 The analysis, performed by E\textsuperscript{C}/R Incorporated,
was based on 2009 cost data for retrofitting NSCR on existing 4SLB engines from industry groups,
vendors, and manufacturers of RICE control technology. E\textsuperscript{C}/R Incorporated performed a linear
regression analysis\textsuperscript{28} on the data set to determine the following linear equation for annual cost, which
includes annual operating and maintenance costs plus annualized capital costs based on a 7% interest
rate and 10-year life of controls:

\[
\text{NSCR Annual Cost} = 4.77 \times (\text{hp}) + 5,697 \text{ (2009$)}
\]

The capital cost equation for retrofitting an AFRC and NSCR on a 4SRB engine was determined by E\textsuperscript{C}/R
Incorporated to be, as follows:

\[
\text{NSCR Capital Cost} = 24.9 \times (\text{hp}) + 13,118 \text{ (2009$)}
\]

These relationships are derived from a data set that includes engines ranging in size from 50–3,000 hp.

The E\textsuperscript{C}/R document does not explain why it assumed a 10-year life of controls for estimating the
annualized capital costs. The life of a RICE unit is generally much longer than ten years, and is often at
least thirty years.\textsuperscript{29} The assumed 10-year life was not based on the catalyst replacement timeframe,
because the E\textsuperscript{C}/R operating costs took into account the cost for replacing the catalyst every three years,
as well as replacing the thermocouple every 7.5 years, the crankcase filters every three months, the
oxygen sensor on a quarterly basis, and rotating the catalyst for cleaning annually.\textsuperscript{30} Thus, the assumed
10-year life of an NSCR system seems arbitrary. In cost analyses done in 2000 for EPA, an equipment life
of NSCR of fifteen years was assumed.\textsuperscript{31} The state of Colorado also recently assumed a 15-year life of

\begin{footnotesize}
\begin{itemize}
    \item \textsuperscript{27} Memo from E\textsuperscript{C}/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), available at: https://www.epa.gov/sites/production/files/2014-02/documents/5_2011_ctrlcostmemo_exist_si.pdf.
    \item \textsuperscript{28} Id. The report notes that the linear equation has a correlation coefficient (R) of 0.7987, concluding that it “shows an acceptable representation of cost data.”
    \item \textsuperscript{29} See, e.g., EPRI, 20 Power Companies Examine the Role of Reciprocating Internal Combustion Engines for the Grid, available at: https://eprijournal.com/start-your-engines/. The authors also note that, in reviewing permits for gas processing facilities and compressor stations in New Mexico, it is not uncommon to have engines that were constructed from the 1950’s to 1970’s still operating at such facilities.
    \item \textsuperscript{30} Memo from E\textsuperscript{C}/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), at 4 and at 11, 13, and 15.
\end{itemize}
\end{footnotesize}
NSCR for RICE units. Given that EPA assumed a selective catalytic reduction (SCR) system at an industrial fossil fuel-fired boiler has a life of 20-25 years, it seems very likely that NSCR would have a useful life of at least fifteen years if not longer. For the purpose of the NSCR cost analyses presented herein, a 15-year life of the NSCR system was assumed.

In addition, a lower interest rate than 7% is assumed in determining annualized costs of controls for this report, to be consistent with EPA’s Control Cost Manual which recommends the use of the bank prime interest rate. The bank prime rate fluctuates over time, and the highest it has been in the past five years is 5.5%. In its cost calculation spreadsheet for SCR provided with its Control Cost Manual, EPA also used an interest rate of 5.5%. Thus, a 5.5% interest rate has been used for the revised cost calculations presented herein.

Table 2 shows the cost effectiveness of NSCR and an AFRC achieving 94% NOx reduction efficiency and operating at 2,000 hours per year and 8,000 hours per year, based on these cost equations from EPA’s 2010 RICE NESHAP, adjusted to reflect a 5.5% interest rate and 15-year life of controls.

Note that lower NOx emission limits have been required by some states and local agencies that reflect a higher NOx removal efficiency than the 94% assumed in the table below (see Section II.G.) and the costs of employing NSCR to meet these lower limits will be even more cost effective than what is shown here.

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35 See, e.g., https://fred.stlouisfed.org/series/DPRIME.
36 Available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
Table 2. Cost Effectiveness to Reduce NOx Emissions from Rich-Burn RICE with NSCR and an AFRC, Based on EPA RICE NESHAP Cost Equations for Existing Stationary Spark-Ignition (SI) Engines

<table>
<thead>
<tr>
<th>ENGINE TYPE</th>
<th>SIZE, hp</th>
<th>ANNUALIZED COSTS OF NSCR AND AFRC, 2009$</th>
<th>COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2009$</th>
<th>COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2009$</th>
</tr>
</thead>
<tbody>
<tr>
<td>RICH-BURN</td>
<td>50</td>
<td>$5,303</td>
<td>$3,251/ton</td>
<td>$813/ton</td>
</tr>
<tr>
<td></td>
<td>200</td>
<td>$5,859</td>
<td>$898/ton</td>
<td>$224/ton</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>$6,971</td>
<td>$427/ton</td>
<td>$107/ton</td>
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<tr>
<td></td>
<td>1,000</td>
<td>$8,824</td>
<td>$270/ton</td>
<td>$68/ton</td>
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<tr>
<td></td>
<td>2,500</td>
<td>$14,382</td>
<td>$176/ton</td>
<td>$44/ton</td>
</tr>
</tbody>
</table>

**TABLE NOTES:**
- Cost data are assumed to be in 2009$, based on E\(^2\)/R Incorporated analysis of vendor and industry group data for engines ranging from 50–3,000 hp (EPA RICE NESHAP, 2010).
- Recalculated for 15-year life of controls and 5.5% interest rate.
- Assumes 94% NOx removal efficiency.

Colorado requires emissions from rich-burn RICE greater than 500 hp be controlled using NSCR with an AFCR. This requirement applies statewide to engines for which control costs are below $5,000 per ton of NOx reduced.\(^38\) In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the RICE Stationary Source Category, including a NOx emission 4-Factor analysis for reasonable progress toward the national visibility goal.\(^39\) In its evaluation, Colorado reported that, “[f]ew of the statewide rich burn RICE demonstrated control costs exceeding the $5,000 cost off-ramp. Consequently, the state concluded that such NSCR controls are installed on the majority of rich burn RICE over 500 HP statewide.”\(^40\) Colorado further reports that “[n]one of the operators of rich burn RICE outside the [Denver] metro-area ozone non-attainment area submitted information demonstrating control costs in excess of $5,000 per ton cost threshold, consequently, the majority of natural-gas fired RB RICE over 500 HP must operate an NSCR with an AFR controller.”\(^41\)

Colorado’s Reasonable Progress Evaluation for RICE listed the capital and annual operating costs for retrofitting existing engines with NSCR and an AFCR, which are reiterated in Table 3.

\(^37\) See Memo from E\(^2\)/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010). Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA’s 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and a 94% NOx removal efficiency.

\(^38\) Colorado Regulation Number 7, see Section XVII.E.3.a.

\(^39\) CDPHE RP for RICE.

\(^40\) Id. at 4.

\(^41\) Id. at 8.
Table 3. Capital and Operating Costs of NSCR with AFCR

<table>
<thead>
<tr>
<th>SOURCE CATEGORY</th>
<th>CAPITAL COSTS, 2003$*</th>
<th>ANNUAL OPERATING AND MAINTENANCE COSTS, 2003$*</th>
</tr>
</thead>
<tbody>
<tr>
<td>RICH-BURN RICE &gt; 500 hp</td>
<td>$35,000</td>
<td>$6,000</td>
</tr>
</tbody>
</table>

TABLE NOTES:
*Colorado’s cost estimates are from its “Denver Early Action Compact Analysis of Stationary Sources,” dated 2003. Colorado does not specify, but it is assumed the cost data are from the 2003 timeframe.

Colorado determined the annualized costs of control assuming a 15-year life of controls and indicating that, “[g]enerally the operational life of a catalyst is approximately 5 to 15 years, depending on factors such as how it is maintained and the particular duty cycle of the engine.” 43 Colorado’s use of a 15-year life of controls is also consistent with previous EPA analysis. 44 The annualized capital cost in Colorado’s analysis of $4,851 appears to assume roughly a 10% interest rate, with total annualized costs – i.e., annualized capital costs plus annual operating and maintenance costs – of $10,851. 45 To be consistent with EPA’s Control Cost Manual, which recommends the use of the bank prime interest rate, a lower interest rate than 10% is assumed in determining annualized costs of controls for this report. 46 As previously discussed, it is more appropriate to use a lower interest rate of 5.5%. 47 Thus, the cost data were revised to be consistent with the EPA’s Control Cost Manual in assuming a 5.5% interest rate in amortizing the capital costs. 48

Colorado presented the cost effectiveness of retrofitting RICE greater than or equal to 500 hp with NSCR and an AFCR based on 2008 NOx emissions reductions for 305 RICE units located outside the nonattainment area of the state. However, the more generalized approach used in this report of assuming 94% control effectiveness is consistent with Colorado’s requirement that these engines – controlled with NSCR and an AFCR – meet an emission limit of 1 g/hp-hr. 49 Again, using EPA’s uncontrolled emission rate of 15.8 g/bhp-hr, the NOx emissions reduction efficiency of meeting a 1 g/hp-hr NOx limit for these engines is approximately 94%. 50

The following table shows the cost effectiveness of a 500 hp RICE unit operating at 2,000 hours per year and at 8,000 hours per year and employing NSCR and an AFRC to meet a 1 g/hp-hr NOx limit, based on a 15-year life and 5.5% interest rate.

42 Id.
43 Id. at 10.
44 EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).
45 CDPHE RP for RICE at 8.
46 EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.
47 See, e.g., https://fred.stlouisfed.org/series/DPRIME.
48 See, e.g., https://fred.stlouisfed.org/series/DPRIME.
49 See Colorado Regulation Number 7, see Section XVII.E.2.b.
50 EPA 1993 Alternative Control Techniques Document for RICE.
Table 4. Cost Effectiveness to Reduce NOx Emissions from Rich-Burn RICE with NSCR and an AFRC To Meet a 1 g/hp-hr NOx Limit

<table>
<thead>
<tr>
<th>ENGINE TYPE</th>
<th>SIZE, hp</th>
<th>ANNUALIZED COSTS OF NSCR AND AFRC, 2003$</th>
<th>COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2003$</th>
<th>COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2003$</th>
</tr>
</thead>
<tbody>
<tr>
<td>RICH-BURN</td>
<td>500</td>
<td>$9,487</td>
<td>$582/ton</td>
<td>$145/ton</td>
</tr>
</tbody>
</table>

TABLE NOTES:
- Cost data are assumed to be in 2003$, based on Colorado’s Reasonable Progress Evaluation for the RICE Source Category.
- Analysis assumes 15-year life of controls and 5.5% interest rate.
- Analysis assumes 94% NOx removal efficiency.

NSCR for Smaller Rich-Burn RICE and Cyclically-Loaded RICE (< 500 hp)

California Air Districts have long been regulating NOx emissions from RICE, including engines smaller than 500 hp, and the California Air Resources Board (CARB) issued guidance to Air Districts in 2001 on the best available retrofit technologies for controlling NOx emissions from a broad range of stationary RICE.

In the 1990s, when EPA first issued its Alternative Control Techniques document for stationary RICE, over 90% of all natural gas-fueled RICE were well pumps with an average size of 15 hp operating, on average, 3,500 hours per year. Today, these smaller well pump engines likely make up a smaller share of nationwide RICE applications across the oil and gas industry, with continued growth in gas production and associated compression and processing applications. However, NOx emissions from these smaller pumping engines, on a regional scale, can be significant. For example, NOx emissions from artificial lifts (e.g., beam pumping used to push oil to the surface) in the New Mexico counties of the Permian Basin make up 13% of all NOx emissions. The average rated horsepower of these engines is 21 hp and the magnitude of these NOx emissions – inventoried in 2014 – was close to 4,000 tons.

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51 See CDPHE RP for RICE. Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA’s 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and a 94% NOx removal efficiency.
52 CARB 2001 Guidance.
53 EPA 1993 Alternative Control Techniques Document for RICE Table 3-1 at 3-14.
CARB’s 2001 guidance discusses RICE units derated\textsuperscript{55} to less than 50 hp, indicating that, “[o]ne of the largest categories of the derated engines are cyclically-loaded units used to drive reciprocating oil pumps.”\textsuperscript{56}

Two specific concerns with respect to the applicability of NSCR to certain types of smaller pump engines used in the oil and gas sector include: (1) the impact that moisture and sulfur in the fuel have on the catalyst; and (2) the impact that variable engine loading has on maintaining sufficient temperatures. Some fuel gases contain high amounts of moisture and sulfur which can result in damage to (deactivation of) the catalyst. The sulfur content of pipeline-quality natural gas is low but some oil field gases can contain high sulfur concentrations. And in applications where engines are periodically idle or where the load is cyclical, it can be more difficult to maintain an adequate exhaust gas temperature. For example, for an oil well pump, the engine may operate at load for a time-period lasting from several seconds to around 20 seconds, followed by an equal amount of time idle. These limitations can generally be minimized through design and maintenance activities, e.g., by treating the field gas to reduce the moisture and sulfur content, heating the catalyst to avoid deactivation, thermally insulating the exhaust pipe and catalyst to maintain a proper temperature, etc.\textsuperscript{57}

CARB recognized that these characteristics (e.g., cyclic loads and variable fuel composition) would, “tend to discourage the use of catalysts with air-to-fuel controllers.” But CARB specifically noted that, “a review of source test data in [CARB’s 2001 Guidance] indicates that there have been instances where these engines have been successfully controlled in the past by cleaning up the field gas, and ‘leaning-out’ the engine or installing a catalyst in some cases.”\textsuperscript{58}

Specifically, cyclic engines that drive certain oil pumps (e.g., beam- or crank-balanced pumping engines) fueled by oil field gas operate in a way that may adversely impact the effectiveness of NSCR control. Following are specific pump engine types, as defined in Santa Barbara County Air Pollution Control District (APCD) Rule 333 Control of Emissions from Reciprocating Internal Combustion Engines:\textsuperscript{59}

“Air-balanced pumping engine” means a noncyclically-loaded engine powering a well pump, with the pump using compressed air in a cylinder under the front of the walking beam to offset the weight of the column of rods and fluid in the well, eliminating the need for counterweights.

\textsuperscript{55} CARB describes a derated engine as, “one in which the manufacturer’s brake horsepower rating has been reduced through some device which restricts the engine’s output.” CARB 2001 Guidance at IV-1.
\textsuperscript{56} See CARB 2001 Guidance at IV-1.
\textsuperscript{58} See CARB 2011 Guidance at IV-1.
“Beam-balanced pumping engine” means a cyclically-loaded engine powering a well pump, with the pump counterweight on the back end of the walking beam. The counterweight is moved mechanically without a cylinder supplying air pressure.

“Crank-balanced pumping engine” means a cyclically-loaded engine powering a well pump, with the pump counterweight attached to a gearbox which is attached to the walking beam with a pitman arm. The counterweight is moved mechanically, in a circular motion, without a cylinder supplying air pressure.

“Cyclically-loaded engine” means an engine that under normal operating conditions has an external load that varies by 40 percent or more of rated brake horsepower during any load cycle or is used to power a well reciprocating pump including beam-balanced or crank-balanced pumps. Engines powering air-balanced pumps are noncyclically-loaded engines.

In Santa Barbara County APCD, cyclic rich-burn engines (beam- and crank-balanced pump engines) greater than 50 hp are expected to meet a NOx limit of 300 ppmv, corrected to 15% oxygen, by adjusting the A/F mixture (to operate lean) and properly tuning and maintaining the engines; these engines are not required to install add-on NSCR control. However, according to CARB’s guidance, cyclic rich-burn engines have met emission limits as low as 50 ppmv (< 1 g/bhp-hr) by “using NSCR or by leaning the air/fuel mixture in conjunction with treating the field gas to reduce moisture and sulfur content.” Specifically, the following engine test data demonstrate emission rates under 50 ppmv (corrected to 15% oxygen) for pump engines:

Table 5. Pump Engine Test Data

<table>
<thead>
<tr>
<th>CA AIR DISTRICT</th>
<th>ENGINE TYPE</th>
<th>ENGINE SIZE</th>
<th>CONTROL TECHNOLOGY</th>
<th># OF TESTS</th>
<th>NOx EMISSIONS [ppmv corrected to 15% oxygen]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Santa Barbara</td>
<td>Air-balanced oil pumps</td>
<td>195 hp</td>
<td>NSCR</td>
<td>18</td>
<td>2-14</td>
</tr>
<tr>
<td>Santa Barbara</td>
<td>Beam- and crank-balanced oil pumps</td>
<td>131 hp</td>
<td>Leaning of A/F mixture</td>
<td>4</td>
<td>12-35</td>
</tr>
<tr>
<td>Santa Barbara</td>
<td>Beam- and crank-balanced oil pumps</td>
<td>39-46 hp</td>
<td>Leaning of A/F mixture</td>
<td>16</td>
<td>8-28</td>
</tr>
<tr>
<td>Santa Barbara</td>
<td>Beam- and crank-balanced oil pumps</td>
<td>39-49 hp</td>
<td>Leaning of A/F mixture</td>
<td>18</td>
<td>7-33</td>
</tr>
<tr>
<td>Ventura</td>
<td>Beam- and air-balanced oil pumps</td>
<td>Not specified</td>
<td>NSCR</td>
<td>5</td>
<td>50</td>
</tr>
</tbody>
</table>

60 See CARB 2001 Guidance at IV-5.
61 Id. at IV-5 to IV-6.
62 Oil pump engines, sometimes derated, are typically less than 50 hp, however there do appear to be some engines used for oil pumping applications that are larger, as shown in this table. And in addition, the underlying source test data in CARB’s 2001 Guidance from Santa Barbara County and Ventura County also include a few data points for rich-burn engines less than 50 hp with NSCR, e.g., four 48 hp engines in Santa Barbara County with NSCR, and a 48 hp engine and 25 hp engine in Ventura County with catalyst control. See CARB 2001 Guidance Tables D-2 and D-3.
CARB concluded that, “[b]ecause of the demonstrated success of meeting the 50 ppmv NOx limit for cyclic rich-burn engines fueled by low-sulfur or treated field gas, we recommend that the districts consider the cost effectiveness of field gas treatment and emission controls in setting limits for these engines on a site-specific basis.” Essentially, CARB guidance proposed considering in its cost effectiveness analysis, the additional cost of field gas treatment including the material and labor costs of piping the treated fuel from the gas processing unit to the engine.

As of January 1, 2017, the San Joaquin Valley Air Pollution Control District (SJVAPCD) requires emissions from rich-burn RICE meet the following NOx limits:

Table 6. NOx Emission Limits for All Rich-Burn Non-Agricultural Operations Engines Rated at > 50 bhp

<table>
<thead>
<tr>
<th>ENGINE TYPE</th>
<th>NOx LIMIT [ppmv corrected to 15% O2]</th>
<th>EQUIVALENT NOx LIMIT Converted to g/bhp-hr</th>
</tr>
</thead>
<tbody>
<tr>
<td>4SRB</td>
<td>Cyclic Loaded, Field Gas Fueled</td>
<td>50</td>
</tr>
<tr>
<td></td>
<td>Limited Use</td>
<td>25</td>
</tr>
<tr>
<td></td>
<td>All other</td>
<td>11</td>
</tr>
</tbody>
</table>

TABLE NOTES:
Conversions to g/bhp-hr limits are based on:
67 ppmv = 1 g/bhp-hr (per EPA’s 1993 Alternative Control Techniques Document, page 4-11)

SJVAPCD completed a cost effectiveness analysis for the second phase of its internal combustion engine rule (Rule 4702) in 2003. The District analyzed a broad array of control scenarios to meet these NOx limits including installing NSCR on both cyclic and non-cyclic rich-burn RICE of wide-ranging power output and capacity utilization.

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63 See CARB 2001 Guidance at IV-6.
66 Id.
SJVAPCD found that the costs to install and operate NSCR at cyclically-loaded RICE units to meet the limit in Table 6 above were cost effective, with costs ranging from $394/ton to $20,272/ton (1999$), which reflected costs of NSCR assuming a 10-year life and a 10% interest rate.\textsuperscript{67}

To use more current data on NSCR costs applied to cyclically-loaded units, the $E^c/R$ cost equations provided in Section II.C. above were used to estimate cost effectiveness for cyclically-loaded RICE units. As previously stated, the $E^c/R$ cost equations take into account the addition of an AFRC as well as the costs of the NSCR. It was assumed that the NSCR system would achieve 90% control of NOx at cyclically-loaded engines as is required by the Santa Barbara emission limit.\textsuperscript{68} To reflect varying levels of operation, emission reductions were based on operating 2,000 hours per year, 4,500 hours per year, and 8,000 hours per year. Texas Commission on Environmental Quality (TCEQ) data for artificial lifts operating in the Permian Basin indicates that such units operate 4,380 hours per year, although a much higher annual hours of operation of 7,106 has been assumed for artificial lift engines in the Greater San Juan Basin.\textsuperscript{69} Thus, to give a range of cost effectiveness of NSCR at cyclically-loaded units, cost effectiveness of NSCR was determined for a low, medium, and high number of operating hours per year. As with other NSCR cost effectiveness analyses, a 15-year life and a 5.5% interest rate were assumed. The results of this cost effectiveness analyses are presented in Table 7.

\textsuperscript{67} Id. at B-2 and at Table 3.
\textsuperscript{68} Santa Barbara County APCD Rule 333 CONTROL OF EMISSIONS FROM RECIPROCATING INTERNAL COMBUSTION ENGINES, 333.C at 333-2.
Table 7. Cost Effectiveness to Reduce NOx Emissions from Rich-Burn Cyclically-Loaded RICE Units with NSCR and AFRC, Based on EPA RICE NESHAP Cost Equations for NSCR

<table>
<thead>
<tr>
<th>ENGINE TYPE</th>
<th>SIZE (hp)</th>
<th>ANNUALIZED COSTS OF NSCR, 2009$</th>
<th>COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2009$</th>
<th>COST EFFECTIVENESS OF NSCR AND AFRC AT 4,500 HR/YR, 2009$</th>
<th>COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2009$</th>
</tr>
</thead>
<tbody>
<tr>
<td>RICH-BURN</td>
<td>50</td>
<td>$5,303</td>
<td>$3,383/ton</td>
<td>$1,504/ton</td>
<td>$846/ton</td>
</tr>
<tr>
<td></td>
<td>75</td>
<td>$5,396</td>
<td>$2,295/ton</td>
<td>$1,020/ton</td>
<td>$574/ton</td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>$5,489</td>
<td>$1,751/ton</td>
<td>$778/ton</td>
<td>$438/ton</td>
</tr>
<tr>
<td></td>
<td>250</td>
<td>$6,045</td>
<td>$771/ton</td>
<td>$343/ton</td>
<td>$193/ton</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>$6,971</td>
<td>$445/ton</td>
<td>$198/ton</td>
<td>$111/ton</td>
</tr>
</tbody>
</table>

TABLE NOTES:
- Cost data are assumed to be in 2009$, based on E$^{5}$/R Incorporated analysis of vendor and industry group data (EPA RICE NESHAP, 2010).
- Recalculated for 15-year life of controls and 5.5% interest rate.
- Assumes 90% NOx removal efficiency.

CARB’s 2001 Guidance and the cost effectiveness analysis in this section for RICE units smaller than 500 hp show that application of NSCR to engines less than 500 hp can be cost effective. For RICE units used in oil pumping applications CARB describes situations where NSCR has been applied to cyclic rich-burn RICE to meet limits as low as 50 ppmv, citing certain types of “grasshopper” oil well pumps in Santa Barbara County. And for oil pumping RICE units less than 50 hp CARB identified electrification (discussed in Section II.F, below), in addition to A/F adjustments and catalytic control, as technically feasible approaches to reducing NOx emissions from engines of this size.

Further, SJVAPCD Rule 4702 for Internal Combustion Engines has a provision for RICE units at least 25 bhp, up to, and including 50 bhp that requires units that are sold after July 2012 to meet the applicable requirements and emission limits of EPA’s NSPS for spark-ignition internal combustion engines in 40 CFR Subpart Part 60, JJJ, for the year in which the ownership of the engine changes. In the response to comments on its NSPS Subpart JJJ rulemaking, EPA provides many examples of the successful application of NSCR on small rich-burn engines and variable-load engines (noted as pumpjack engines or

70 Id. Annualized costs of control were calculated using a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA’s 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and control efficiency of 90%.
71 CARB 2001 Guidance at IV-5. “Source tests of NSCR-equipped cyclic engines in Santa Barbara County have shown that these engines can be effectively controlled with or without air/fuel controllers provided the oil well pumps are air-balanced units.”
72 CARB 2001 Guidance at II-1.
73 SJVAPCD Rule 4702 Internal Combustion Engines Section 5.1
compressor engines) that justify its standards as achievable and demonstrated for very small rich-burn RICE.  

**Application of NSCR to rich-burn RICE is cost effective for a wide range of engine sizes and types.**

While the cost estimates and cost algorithms in this section are of a cost basis that is from the 1999–2009 timeframe, it is important to note that, from at least 2001, several state and local air agencies have found that the costs of control to achieve NOx emission limits of 1 g/bhp-hr (67 ppmvd) and even lower NOx emission limits were cost effective to require such a level of control on existing rich-burn RICE. This will be discussed further in Section II.G. below. It is not possible to accurately escalate these costs to 2019 dollars. The Chemical Engineering Plant Cost Index (CEPCI) has been used extensively by EPA for escalating costs, but EPA states that using the CEPCI indices to escalate costs over a period longer than five years can lead to inaccuracies in price estimation. Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. As an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.

The environmental and energy impacts of NSCR for rich-burn RICE include the following:

- 0 to 5% increase in fuel consumption resulting in increased CO₂ emissions
- 1 to 2% reduction in power output
- Increased solid waste disposal from spent catalysts.

The impacts on increased fuel consumption and increased solid waste disposal are taken into account in the cost effectiveness analysis. Further, NSCR has been installed extensively on RICE units in the United States, and these non-air quality environmental and energy impacts are not generally considered to be impediments to implementing the control.

NSCR can be installed fairly quickly. The Institute of Clean Air Companies indicates that “off-the-shelf” NSCR converters can be installed in six to eight weeks. For NSCR installations that are more site-specific, NSCR can be installed in approximately fourteen weeks.

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77 See EPA 1993 Alternative Control Techniques Document for RICE Table 3-1 at 3-14.

78 Id. Table 2-4 at 2-8.


D. LEAN-BURN RICE: LOW EMISSION COMBUSTION (LEC)

Low emission combustion (LEC) retrofit kits are designed to achieve extremely lean A/F in order to minimize NOx emissions. The various retrofit technologies can include:

- Redesign of cylinder head and pistons to improve mixing (on smaller engines)
- Precombustion chamber (on larger engines)
- Turbocharger
- High energy ignition system
- Aftercooler
- AFRC

According to EPA, “[n]ew spark-ignition engines equipped with LEC technology are, by definition, lean-burn engines.” A wide range of emission rates are achievable with LEC technology, with emissions generally no higher than 2 g/hp-hr and often significantly lower. EPA’s updated information on stationary RICE NOx emissions and control technologies concludes, for lean-burn engines, an emission rate of 2.0 g/bhp-hr is achievable for “new engines and most engines retrofitted with LEC technology.”

LEC is described by EPA in its Alternative Control Techniques Document, as follows:

Low-emission combustion designs are available from engine manufacturers for most new SI engines, and retrofit kits are available for some existing engine models. For existing engines, the modifications required for retrofit are similar to a major engine overhaul, and include a turbocharger addition or upgrade and new intake manifolds, cylinder heads, pistons, and ignition system. The intake air and exhaust systems must also be modified or replaced due to the increased air flow requirements.

Controlled NOx emission levels reported by manufacturers for [LEC] are generally in the 2 g/hp-hr (140 ppm) range, although lower levels may be quoted on a case-by-case basis. Emission test reports show controlled emission levels ranging from 1.0 to 2.0 g/hp-hr (70 to 140 ppmv). Information provided by manufacturers shows that, in general, BSFC decreases slightly for [LEC] compared to rich-burn designs, although in some engines the BSFC increases. An engine’s response to increases in load is adversely affected by [LEC], which may make this control technique unsuitable for some installations, such as stand-alone power generation applications. The effect on CO and HC emissions is a slight increase in most engine designs.

**LEC NOx Removal Efficiency:** 87%

**Controlled NOx Emission Rates:**
- 1-2 g/hp-hr
- 70 to 140 ppmv

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82 EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-3.
83 Id. at 4-12.
84 EPA 1993 Alternative Control Techniques Document for RICE.
In its Updated Information on NOx Emissions and Control Techniques Document for RICE, EPA states the following test data for LEC:

In all, the sources of NOx emission test data include the results of 476 individual tests conducted on 58 engines. (This count does not include the aggregated data in some of the sources discussed, such as the May 2000 EPA memo and the AP-42 sections.) In these tests, NOx emissions ranged from 0.1 g/bhp-hr to 4.8 g/bhp-hr. Ninety-seven percent of these tests (460) found emissions less than or equal to 2 g/bhp-hr. Almost 75 percent (356) of the tests found emissions less than or equal to 1 g/bhp-hr, and 25 percent (120) found emissions of less than or equal to 0.5 g/bhp-hr. Only two tests measured NOx emissions greater than or equal to 4 g/bhp-hr.85

EPA also indicates that, “LEC is expected to be the most common control method for meeting the [1991 CARB Best Available Retrofit Control Technology (BARCT) for Stationary IC Engines], although SCR may be used as an alternative if LEC is unsuitable for a particular model engine.”86

And according to the Interstate Natural Gas Association of America (INGAA), “LEC is the preferred approach to reduce lean-burn engine NOx emissions, but EPA or states may consider additional controls such as selective catalytic reduction (SCR).”87

EPA further states in its Updated Information on NOx Emissions and Control Techniques for RICE:

Low-emission combustion retrofit equipment and services are generally available, particularly for the most plentiful engine models. Cooper Energy Services, maker of Cooper-Bessemer, Ajax, Superior, and Delaval engines provides CleanBurn™ retrofits for all of its larger models and offers these services for engines manufactured by other companies, as well. Dresser-Rand, manufacturer of Ingersoll-Rand, Clark, and Worthington engines also offers retrofit services for its lean-burn engines. The Waukesha Engine Division of Dresser Industries manufactures two engine families that are available either in rich-burn or LEC configurations. The company offers LEC retrofit services for those engines originally sold in the rich-burn configuration. At least three third-party vendors (Diesel Supply Company; Enginuity, Inc.; and Emissions Plus, Inc.) offer retrofit services for a wide variety of engine makes and models. These vendors will work with any model engine, although economies of scale can reduce capital costs for plentiful engines. For other engines, customized precombustion chambers can result in somewhat higher costs.88

85 EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-9.
86 Id. at 4-11.
88 EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-4.
California Air Districts have long been regulating NOx emissions from RICE, including lean-burn RICE. CARB issued guidance to Air Districts in 2001 on the reasonably available control technologies (RACT) and the best available retrofit control technologies (BARCT) for controlling NOx emissions from a broad range of stationary RICE.\textsuperscript{89} In its analysis, CARB determined that LEC was a RACT level of control, and CARB set a NOx RACT limit of 125 ppmv.\textsuperscript{90} CARB established a BARCT NOx limit for two- and four-stroke lean-burn engines rated at or higher than 100 hp of 65 ppmv or 90% reduction in NOx emissions.\textsuperscript{91} CARB indicated that this lower NOx BARCT limit could also be met with LEC for many engines, although some engines might require some supplemental measures such as ignition system modifications and engine derating and others might require SCR to meet the BARCT NOx limit.\textsuperscript{92} LEC can achieve 80 to 90% NOx reductions or even higher.\textsuperscript{93}

The only exemptions CARB proposed from the NOx BARCT limit were for lean-burn engines rated less than 100 hp. With respect to these smaller engines, CARB determined that there are a relatively small number of such two-stroke lean-burn engines that cannot cost effectively install LEC or other NOx controls necessary to meet the NOx limits set for lean-burn RICE (both RACT and BARCT limits).\textsuperscript{94} CARB described these engines as “located in gas fields statewide and [] used to drive compressors at gas wells.”\textsuperscript{95} CARB determined that, “the only cost effective way to control emissions from the[se] small two-stroke engines is by properly maintaining and tuning these engines which includes replacing oil-bath air filters with dry units and periodically cleaning the air/fuel mixer and muffler.”\textsuperscript{96} CARB ultimately recommend that the air districts, “require the replacement of these engines at the end of the two-stroke engine’s useful life with prime movers having lower NOx emissions.”\textsuperscript{97}

CARB conducted cost effectiveness analyses for LEC on lean-burn RICE at a wide variety of engine power output ratings. CARB’s analyses of capital and annual operating costs for retrofitting existing engines with LEC (and other NOx controls) were based on, “a mixture of quotes and extrapolations of cost from information provided by industry sources, associations, local governments, and the U. S. EPA.”\textsuperscript{98} CARB’s cost data for LEC are presented in the table below.

\begin{table}
\centering
\begin{tabular}{|c|c|}
\hline
Engine Type & NOx Reduction \%
\hline
Two-Stroke & 80 - 90
\hline
Four-Stroke & 90
\hline
\end{tabular}
\end{table}

\textsuperscript{89} CARB 2001 Guidance.
\textsuperscript{90} Id. at IV-6.
\textsuperscript{91} Id. at IV-9.
\textsuperscript{92} Id. at II-2, IV-10.
\textsuperscript{93} EPA has said NOx reductions with LEC could be as high as 93%. See EPA’s 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) at 5-67.
\textsuperscript{94} Id. at II-2.
\textsuperscript{95} Id. at IV-7.
\textsuperscript{96} Id.
\textsuperscript{97} Id.
\textsuperscript{98} Id. at V-2.
Table 8. Capital Costs of LEC, 2001$\textsuperscript{99}

<table>
<thead>
<tr>
<th>POWER OUTPUT (hp)</th>
<th>LEC CAPITAL COSTS</th>
</tr>
</thead>
<tbody>
<tr>
<td>50-150</td>
<td>$14,000</td>
</tr>
<tr>
<td>151-300</td>
<td>$24,000</td>
</tr>
<tr>
<td>301-500</td>
<td>$42,000</td>
</tr>
<tr>
<td>501-1,000</td>
<td>$63,000</td>
</tr>
<tr>
<td>1,001-1,500</td>
<td>$148,000</td>
</tr>
</tbody>
</table>

CARB calculated cost effectiveness for LEC assuming 80% NOx control, a 10-year life of the controls, and a 10% interest rate.\textsuperscript{100} As previously discussed, to be consistent with EPA’s Control Cost Manual which recommends the use of the bank prime interest rate, it is more appropriate to use a lower interest rate of 5.5%.\textsuperscript{101} Thus, the CARB LEC cost data were revised to be consistent with the EPA’s Control Cost Manual in assuming a 5.5% interest rate in amortizing the capital costs. It must be noted that CARB’s assumed 10-year life of LEC controls seems unreasonably short, as EPA has assumed a 15-year life of all controls for stationary internal combustion engines in other cost analyses.\textsuperscript{102} Thus, the CARB LEC cost data were revised to assume a 15-year life of LEC controls.

CARB’s cost analysis also assumed that the engines are run at rated power (100% load) for only 2,000 hours annually, which is equivalent to a capacity factor of roughly 25%. To reflect the cost effectiveness values for a range of operating hours, CARB’s cost analysis was revised to reflect costs at 91% capacity factor, or 8,000 operating hours per year.

Last, CARB’s cost effectiveness analysis only assumed an 80% NOx removal efficiency with LEC. As discussed above, an 80% NOx control efficiency is the low-end of NOx removal rates that can be achieved with LEC at lean-burn engines. CARB’s BARCT limit is based on 90% NOx reduction. Thus, CARB’s cost analyses were also revised to include cost effectiveness for 90% NOx control as well as 80% NOx control. These revised cost effectiveness calculations—assuming a 5.5% interest rate, 15-year life of LEC, capacity factors of 2,000 operating hours and of 8,000 operating hours, and both 80% NOx control and 90% NOx control—are presented in Table 9 below.

\textsuperscript{99} Id. Note that the cost basis is not identified, and it is assumed to be 2001 dollars based on the date of the analysis. Also note that for engines with power output of 1,001-1,500 hp, a mid-range cost of $148,000 was assumed, similar to the assumption made by EPA when using CARB’s cost data in its 2016 CSAPR TSD.

\textsuperscript{100} CARB 2001 Guidance at V-4.

\textsuperscript{101} See, e.g., https://fred.stlouisfed.org/series/DPRIME.

\textsuperscript{102} EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).
Table 9. Cost Effectiveness to Reduce NOx Emissions by 80%–90% from Lean-Burn RICE with LEC Operating at 2,000 and 8,000 Hours per Year\textsuperscript{103}

<table>
<thead>
<tr>
<th>ENGINE TYPE</th>
<th>SIZE, hp</th>
<th>ANNUALIZED COSTS OF LEC, 2001$</th>
<th>COST EFFECTIVENESS OF LEC TO REDUCE NOx BY 80%–90%, 2,000 HOURS/YEAR, 2001$</th>
<th>COST EFFECTIVENESS OF LEC TO REDUCE NOx BY 80%–90%, 8,000 HOURS/YEAR, 2001$</th>
</tr>
</thead>
<tbody>
<tr>
<td>LEAN-BURN</td>
<td>50</td>
<td>$1,857$</td>
<td>$941/ton-$837/ton</td>
<td>$235/ton-$209/ton</td>
</tr>
<tr>
<td></td>
<td>200</td>
<td>$3,184$</td>
<td>$403/ton-$359/ton</td>
<td>$101/ton-$90/ton</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>$5,572$</td>
<td>$282/ton-$251/ton</td>
<td>$71/ton-$63/ton</td>
</tr>
<tr>
<td></td>
<td>1,000</td>
<td>$8,358$</td>
<td>$212/ton-$188/ton</td>
<td>$53/ton-$47/ton</td>
</tr>
<tr>
<td></td>
<td>1,500</td>
<td>$19,635$</td>
<td>$332/ton-$295/ton</td>
<td>$83/ton-$74/ton</td>
</tr>
</tbody>
</table>

The above analyses demonstrate that, with the exception of lean-burn engines rated at 50 hp that only operated 2,000 hours per year, the cost effectiveness of LEC at lean-burn engines is essentially between $80–$400/ton for a wide range of engine sizes and a wide range of operating hours.

In its Technical Support Document for Non-EGU NOx emissions for the CSAPR rule, EPA presented an equation for estimating the capital cost of LEC on natural gas lean-burn engines, based on cost calculations for engines of varying size and annual capacity factor from CARB’s 2001 Guidance:\textsuperscript{104}

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

Thus, the above equation can be used to estimate capital costs for LEC based on the hp rating of the unit. CARB did not identify any operating expenses with LEC, and thus the appropriate capital recovery factor can be multiplied by the results of the equation above for any size lean-burn engine to estimate annual costs of control with LEC.

CARB’s cost estimates for LEC are relatively consistent with EPA’s prior cost analyses of LEC lean-burn engines. For example, EPA’s 1993 Control Techniques Document for RICE found the cost effectiveness for medium-speed engines operating at a 91% capacity factor was in the range of $310–$590/ton (1993$, assuming a 7% interest rate and a 15-year life).\textsuperscript{105} EPA subsequently updated the cost information on LEC technology for lean-burn SI engines because “developments in LEC technology have brought retrofit costs down in recent years.”\textsuperscript{106} Specifically, in EPA’s Updated Information on NOx

\textsuperscript{103} Cost information for LEC from CARB 2001 Guidance at Tables V-1 and V-2. Annualized cost of control assumed a capital recovery factor of 0.099626 (assuming a 15-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA’s 1993 Alternative Control Techniques for RICE (EPA-453/R-93-032).

\textsuperscript{104} 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 5-5. Note that the CSAPR TSD also presented an equation for annual costs, but it reflected annualized capital costs assuming a 7% interest rate and a 10-year life. Thus, the annualized cost equation is not provided here because it is not reflective of the current recommended interest rate for cost calculations of 5.5% or a 15-year life of controls.

\textsuperscript{105} See EPA 1993 Alternative Control Techniques Document for RICE, Table 2-13 at 2-36.

\textsuperscript{106} EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-33.
Emissions and Control Techniques for RICE, its analysis of LEC retrofit for lean-burn SI engines showed, “cost effectiveness below $500 per ton of NOx reduced [in 1997] for all engines larger than 2,000 bhp,” which reflected an 80% capacity factor, 88% control, and a 7% interest rate.\(^{107}\)

The 2001 CARB cost analyses for LEC is the most current comprehensive analyses for the costs of LEC available. It is recommended that the CARB cost data, as reflected in the equation given above (from EPA’s CSAPR TSD), be used to calculate capital costs based on horsepower rating of an engine, assuming a 15-year life, 5.5% interest rate, and 90% NOx control. CARB’s BARCT NOx limit of 125 ppmv should be considered as an achievable NOx emission limit with LEC at a lean-burn engine.

Application of LEC to lean-burn RICE is cost effective for a wide range of engine sizes and types.

While the cost estimates and cost algorithms in this section are of a cost basis that is close to twenty years old, it is important to note that, from at least 2001, several state and local air agencies have found that the costs of control to achieve NOx emission rates reflective of LEC at lean-burn engines (<2 g/bhp-hr (150 ppmv)) have been considered as cost effective to require such a level of control on existing lean-burn RICE over 100 hp. This will be discussed further in Section II.G. below. For the reasons previously discussed in this report, it is not possible to accurately escalate these costs from 2001 to a current dollar basis. Nonetheless, the fact that numerous state and local agencies have imposed NOx limits that reflect the application of LEC demonstrates that it is a control that has been extensively retrofitted to existing lean-burn engines.

The environmental and energy impacts of LEC for lean-burn RICE are minimal and include the following:

- A decrease in fuel consumption of 0 to 5% resulting in decreased CO\(_2\) emissions, as well as a corresponding decrease in emissions of other air pollutants\(^{108}\)
- No effect on power output.\(^{109}\)

E. LEAN-BURN RICE: SELECTIVE CATALYTIC REDUCTION (SCR)

Selective catalytic reduction (SCR) is an add-on (post combustion) NOx reduction technology that has been in use as early as the 1970s and has been applied to numerous source categories including stationary RICE units. In its 1993 Alternative Control Techniques Document for Stationary RICE, EPA described SCR systems as follows:

Selective catalytic reduction is an add-on control technique that injects ammonia (NH\(_3\)) into the exhaust, which reacts with NO\(_x\) to form N\(_2\) and H\(_2\)O in the catalyst reactor. The two primary catalyst formulations are base-metal (usually vanadium pentoxide) and zeolite. Spent catalysts containing vanadium pentoxide may be considered a hazardous material in some areas, requiring special disposal considerations. Zeolite catalyst formulations do not contain hazardous materials.

\(^{107}\) Id. at 5-9.
\(^{108}\) See EPA 1993 Alternative Control Techniques Document for RICE, Table 2-7 at 2-15.
\(^{109}\) Id.
Selective catalytic reduction applies to all lean-burn SI engines and can be retrofit to existing installations except where physical space constraints may exist. There is limited operating experience to date, however, with these engines. A total of 23 SCR installations with lean-burn SI engines were identified in the United States from information provided by catalyst vendors, in addition to over 40 overseas installations. To date [1993] there is also little experience with SCR in variable load applications due to ammonia injection control limitations. Several vendors cite the availability of injection systems, however, designed to operate in variable load applications. Injection systems are available for either anhydrous or aqueous ammonia. As is the case for NSCR catalysts, fuels other than pipeline-quality natural gas may contain contaminants that mask or poison the catalyst, which can render the catalyst ineffective in reducing NOx emissions. Catalyst vendors typically guarantee a 90 percent NOx reduction efficiency for natural gas-fired applications, with an ammonia slip level of 10 ppm or less. One vendor offers a NOx reduction guarantee of 95 percent for gas-fired installations. Based on an average uncontrolled NOx emission level of 16.8 g/hp-hr (1,230 ppmv), the expected controlled NOx emission level is 1.7 g/hp-hr (125 ppmv). Emission test data show NOx reduction efficiencies of approximately 65 to 95 percent for existing installations. Ammonia slip levels were available only for a limited number of installations for manually adjusted ammonia injection control systems and ranged from 20 to 30 ppmv. Carbon monoxide and HC emission levels are not affected by implementing SCR. The engine BSFC increases slightly due to the backpressure on the engine caused by the catalyst reactor.\footnote{EPA 1993 Alternative Control Techniques Document for RICE.}

There have been many advances in SCR systems and catalysts since EPA’s 1993 Alternative Control Techniques Document. In 2012, the Ozone Transport Commission (OTC) issued a Technical Information Document on significant stationary sources of NOx emissions in the Oil and Gas Sector (hereinafter referred to as the “2012 OTC Report”).\footnote{See Ozone Transport Commission, Technical Information, Oil and Gas Sector, Significant Stationary Sources of NOx Emissions, Final, October 17, 2012, available at: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20Gas%20Sector%20TSD%2010-17-12.pdf.} The OTC is a multi-state organization created under the CAA to address ozone problems in the Northeast and Mid-Atlantic U.S.\footnote{See https://otcair.org/about.asp.} According to the 2012 OTC Report, many of the issues with variable load operation have been addressed by catalysts that have been designed to operate over a wide range of exhaust temperatures and for combustion devices with variable loads.\footnote{See 2012 OTC Report at 25-26.} For example, in the 2012 OTC Report,\footnote{Id. at 26-27.} several vendors were listed that could provide such SCR systems and catalysts effective for the NOx control issues of lean-burn engines, such as Johnson Matthey,\footnote{See https://matthey.com/en/products-and-services/emission-control-technologies/mobile-emissions-control/selective-catalytic-reaction.} Miratech Corporation which offers an SCR system for lean-burn engines used in natural gas compression,\footnote{See https://www.miratechcorp.com/products/cbl/.} CleanAir Systems which offers a lean-burn SCR called “E-Pod SCR” that is advertised to achieve up to 95% NOx reduction and reduce particulates, HC, and CO\footnote{See http://intermountainelectronics.com/uploads/media/Media_633929646982817973.pdf.}, and Caterpillar...
which offers SCR systems for several of its engines. Although EPA’s 1993 Alternative Control Techniques Document indicates achievable NOx emission rates of 1.7 g/hp-hr, the OTC identified NOx rates achievable with SCR at lean-burn engines of 0.2 to 1.0 g/bhp-hr, with the lower NOx rates achievable at four-stroke lean-burn engines and/or engines that also have some combustion control upgrades. Moreover, two air districts in California—South Coast Air Quality Management District (SCAQMD) and SJVAPCD—have adopted NOx emission limits of 11 ppmv, which equates to 0.15 g/hp-hr, for lean-burn engines. Based on this more recent information, the NOx reduction efficiency and achievable NOx emission rates are:

- **NOx Removal Efficiency:** 90-95+%
- **Controlled NOx Emission Rates:** 0.15 to 1.0 g/hp-hr (11 to 73 ppmv)

SCR can be applied to lean-burn spark-ignition engines, diesel compression-ignition engines, and dual-fuel compression-ignition engines. And while diesel engines are the most prevalent applications of SCR at RICE units, SCR has also been applied at lean-burn spark-ignition engines fired with natural gas, including at natural gas pipeline compressor stations. Outside of the U.S., EPA stated in its 2000 update that “there are over 700 IC engines controlled with SCR systems in Europe and Japan, including approximately 80 to 100 2-stroke engines.” Thus, for those engines for which effective LEC retrofits are not available, SCR is available to achieve high levels of NOx control.

As previously stated, CARB issued guidance to California Air Districts in 2001 on the best available retrofit technologies for controlling NOx emissions from a broad range of stationary RICE. For two- and four-stroke lean-burn engines greater than 100 hp, CARB set a BARCT limit 65 ppmv or 90% reduction in NOx emissions. CARB indicated that “it is expected that the most common control method used to meet the BARCT emission limit [] will be the retrofit of low-emission combustion controls. Other techniques may also be used to supplement these retrofits, such as ignition system modifications and engine derating. For engines that do not have low-emission combustion modification

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120 See SCAQMD Rule 1110.2, Table I and SJVAPCD Rule 4702, Table 2. The SCAQMD 11 ppmv limit applies to engines at facilities that are not in the Regional Clean Air Incentives Market (RECLAIM) as of January 5, 2018, and SCAQMD has indicated there are 18 engines currently meeting the 11 ppmv limit. See http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/par1110-2-wg2-final.pdf?sfvrsn=6 at Slide 32. The SJVAPCD 11 ppmv limit does not apply to lean-burn engines used for gas compression, or those engines of limited use operation (less than 4,000 hours per year), or those engines that are waste gas-fuel—a higher limit of 65 ppmv applies to these engines.  
121 See, e.g., EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-13.  
122 Id. at 4-13 (EPA notes, “[f]rom the context, we believe that the source of this last data meant 2-stroke lean-burn SI engines fired with natural gas, although it is not explicit in the reference.”).  
123 See CARB 2001 Guidance.  
124 Id.
kits available, SCR may be used as an alternative to achieve the BARCT emission limits.” Thus, CARB envisioned that some RICE units would need to install SCR.

The SJVAPCD requires that emissions from lean-burn RICE meet the following NOx limits:

**Table 10. SJVAPCD NOx Emission Limits for All Lean-Burn Non-Agricultural Operations Engines**

<table>
<thead>
<tr>
<th>ENGINE TYPE</th>
<th>NOx LIMIT [ppmv corrected to 15% O2]</th>
<th>EQUIVALENT NOx LIMIT [g/bhp-hr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>2SLB</td>
<td>Gaseous Fueled; &gt;50 hp and &lt;100 hp</td>
<td>75</td>
</tr>
<tr>
<td>4SLB</td>
<td>Limited Use</td>
<td>65</td>
</tr>
<tr>
<td></td>
<td>Used for gas compression</td>
<td>65 or 93% reduction</td>
</tr>
<tr>
<td></td>
<td>All other</td>
<td>11</td>
</tr>
</tbody>
</table>

**TABLE NOTES:**
- Conversions to g/bhp-hr limits are based on EPA’s Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques (September 2000), where the conversion for uncontrolled lean-burn engines and lean-burn engines controlled with SCR is: 73 ppmv = 1 g/bhp-hr

The 11 ppmv limit is clearly more stringent than CARB’s recommended BARCT limit and thus presumably requires SCR to achieve at lean-burn RICE, possibly along with combustion modifications. SCAQMD adopted an 11 ppmv NOx limit for all RICE units unless located at a Regional Clean Air Incentives Market (RECLAIM) Facility, and thus SCAQMD has applied this lower NOx limit more broadly than the SJVAPCD.

The SJVAPCD completed a cost effectiveness analysis for the emission limits in the above table in 2003. The District analyzed a broad array of control scenarios including installing SCR on lean-burn RICE of wide-ranging power output and capacity utilization and multiple applications (e.g., limited use, gas compression, etc.). SJVAPCD’s report indicated that “[d]istrict staff feels that the annual compliance costs are reasonable for [all] five cases analyzed [including installation of a SCR system for a lean-burn engine].” The report further concluded that “[a]lthough a few of the results indicated a high cost effectiveness, such results are due to the low emission reductions and not from high annual costs.”

SJVAPCD used the capital and annual operating costs for retrofitting existing engines with SCR based on CARB’s 2001 guidance—which are based on installation of the more advanced parametric emissions

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125 Id.
128 Id. at B-2.
129 Id.
monitoring systems (PEMS) feedforward system controls, the use of urea as the reducing agent, and a catalyst sized to achieve 96% reduction in NOx emissions—as presented in the table below.

Table 11. Capital and Operating Costs of SCR\textsuperscript{130}

<table>
<thead>
<tr>
<th>POWER OUTPUT (hp)</th>
<th>INSTALLED SCR CAPITAL COSTS, 1999$</th>
<th>ANNUAL OPERATING AND MAINTENANCE COSTS, 1999$</th>
</tr>
</thead>
<tbody>
<tr>
<td>50</td>
<td>$45,000</td>
<td>$20,102</td>
</tr>
<tr>
<td>200</td>
<td>$45,000</td>
<td>$26,102</td>
</tr>
<tr>
<td>500</td>
<td>$60,000</td>
<td>$35,102</td>
</tr>
<tr>
<td>1,000</td>
<td>$149,000</td>
<td>$78,102</td>
</tr>
<tr>
<td>1,500</td>
<td>$185,000</td>
<td>$117,102</td>
</tr>
</tbody>
</table>

TABLE NOTES:
- The cost for the SCR is based on urea injection, with PEMS, and catalyst sized for 96% NOx conversion.

SJVAPCD determined the annualized costs of control assuming a 10-year life of controls and a 10% interest rate.\textsuperscript{131} As previously discussed, to be consistent with EPA’s Control Cost Manual, a lower interest rate of 5.5% should be used for current cost effectiveness calculations.\textsuperscript{132} With respect to the SCR equipment life, SCR systems can likely last much longer than 15 years. EPA states that SCRs at boilers, refineries, industrial boilers, etc. have a useful life of 20-30 years.\textsuperscript{133} To be consistent with EPA’s statements on SCR, this report will assume a 20-year life for SCRs at lean-burn engines. Thus, a 5.5% interest rate and 20-year life of controls has been used for the revised SCR cost calculations presented herein.

SJVAPCD presented the cost effectiveness of retrofitting RICE with SCR based on reducing NOx emissions from a NOx rate of 740 ppmv to the proposed (and ultimately adopted) emission limit of 65 ppmv, which reflects a 91% control efficiency across the SCR. For RICE not already meeting NOx limits of 740 ppmv, employing SCR to reduce NOx emissions from what EPA considers to be the uncontrolled NOx emission rate of 1,230 ppmv (16.8 g/bhp-hr) to 65 ppmv corresponds to a NOx emissions reduction efficiency of 95%.\textsuperscript{134} Such removal rates are achievable with SCR at lean-burn RICE, as discussed above.\textsuperscript{135} However, the lower NOx rate of 11 ppmv that SJVAPCD has adopted for lean-burn engines not

\textsuperscript{130} Id. Table 5.
\textsuperscript{131} Id. Table 2 and 3.
\textsuperscript{132} EPA’s Control Cost Manual recommends the prime lending rate be used to amortize capital costs, and the highest the bank prime rate has been in the past five years is 5.5%. See, e.g., https://fred.stlouisfed.org/series/DPRIME.
\textsuperscript{133} See EPA’s Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80.
\textsuperscript{134} EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.
\textsuperscript{135} See, e.g., 2012 OTC Rep at 19.
used for compression and not operated at limited use (less than 4,000 hours per year) would also be achievable with SCR alone or with combustion controls plus SCR. A NOx limit of 11 ppmv reflects 99% control from uncontrolled levels.

SJVAPCD claimed to present cost effectiveness data for two different operating capacity factors: 25% and 75%. However, SJVAPCD also cited to CARB’s cost analyses as the basis for SJVAPCD’s assumed costs. In the underlying cost effectiveness analysis, CARB assumed that the engines are run at rated power (100% load) for 2,000 hours annually, which is equivalent to a capacity factor of roughly 23%. It does not appear that SJVAPCD accounted for increased operating costs in its evaluation of costs at the higher capacity factor. Operating expenses at higher operating capacity factors would increase approximately by the ratio of the higher capacity factor (or operating hours) to the originally assumed capacity factor (or operating hours) in the original cost analysis. The following table shows the cost effectiveness of retrofitting SCR to an uncontrolled lean-burn RICE operating at 2,000 hours per year and at 8,000 hours per year and meeting a 65 ppmv NOx limit, based on a 20-year life and 5.5% interest rate. For the cost analyses shown in Table 12, SJVAPCD’s operational costs were increased by a factor of four to more accurately reflect operational expenses at an operating capacity of 8,000 hours per year.

Table 12. Cost Effectiveness to Reduce NOx Emissions by 95% from 4SLB RICE with SCR Operating at 2,000 and 8,000 Hours per Year

<table>
<thead>
<tr>
<th>ENGINE TYPE</th>
<th>SIZE, hp</th>
<th>ANNUALIZED COSTS OF SCR, 1999$</th>
<th>COST EFFECTIVENESS OF SCR, 2,000 HOURS PER YEAR, 1999$</th>
<th>COST EFFECTIVENESS OF SCR, 8,000 HOURS PER YEAR, 1999$</th>
</tr>
</thead>
<tbody>
<tr>
<td>4SLB</td>
<td>50</td>
<td>$24,585</td>
<td>$13,567/ton</td>
<td>$3,392/ton</td>
</tr>
<tr>
<td></td>
<td>200</td>
<td>$30,585</td>
<td>$5,244/ton</td>
<td>$1,061/ton</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>$41,080</td>
<td>$2,281/ton</td>
<td>$570/ton</td>
</tr>
<tr>
<td></td>
<td>1,000</td>
<td>$92,946</td>
<td>$2,574/ton</td>
<td>$644/ton</td>
</tr>
<tr>
<td></td>
<td>1,500</td>
<td>$135,533</td>
<td>$2,512/ton</td>
<td>$628/ton</td>
</tr>
</tbody>
</table>

As previously stated, the cost effectiveness presented in Table 12 above reflects compliance with the 65 ppmv NOx emission limit with SCR, which corresponds to a NOx emissions reduction efficiency of

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136 See SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), Table 5, notes F and H.
137 This is based on an analysis of varying hours of operation in EPA’s SCR Cost Calculation Spreadsheet (06/2019) available on its Control Cost Manual website at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution. While this spreadsheet is designed to estimate costs of SCR for fossil fuel-fired boilers, it can be used to estimate the increased in operational costs with increases in operating hours for any SCR system given that the SCR components are the same whether for a gas-fired boiler or a gas-fired RICE unit.
138 See SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), Table 5. Annualized costs of control were calculated using a capital recovery factor of 0.083679 (assuming a 20-year life of controls and a 5.5% interest rate). NOx emission reductions are based on SJVAPCD’s assumed 91% removal efficiency. Uncontrolled NOx emissions are based on EPA’s 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032).
95%. However, the lower NOx rate of 11 ppmv that SJVAPCD has adopted for lean-burn engines not used for compression and not operated at limited use (less than 4,000 hours per year) would also be achievable with SCR alone or with combustion controls plus SCR. A NOx limit of 11 ppmv reflects 99% control from uncontrolled levels.

More recently, EPA’s 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls developed the following cost equations for SCR on natural gas four-stroke lean-burn engines, based on cost calculations for engines of varying size and annual capacity factor from SJVAPCD’s 2003 cost effectiveness analysis:

\[
\text{Capital cost} = 107.1 \times \text{(hp)} + 27,186 \\
\text{Annual cost} = 83.64 \times \text{(hp)} + 14,718
\]

The annual cost equation given above includes capital costs amortized assuming a 7% interest, which as discussed above is too high, and a 10-year equipment life, which should be 20 years as discussed above. In the table below, the cost effectiveness of SCR based on these cost equations from EPA’s 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls but revising the annual costs to reflect a 5.5% interest rate and a 20-year life of SCR and reflecting operations at 2,000 hours per year and at 8,000 hours per year. EPA’s cost equations given above are based on an assumed 90% NOx reduction across the SCR, so the same level of NOx control was assumed in the revised cost calculations presented in Table 13. Higher levels of NOx reduction and lower emission limits can be met with SCR alone or in combination with combustion controls. However, because higher levels of NOx reduction could also increase the operational expenses of SCR (unless some of the NOx reductions were achieved with combustion controls), the same 90% level of NOx control was assumed in the revised cost effectiveness analyses presented below to be consistent with the basis of EPA’s cost equations.

\[\text{Footnotes:}\]
\[\text{139 EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.}\]
\[\text{140 See 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 5-11 to 5-12.}\]
\[\text{141 Id.}\]
Table 13. Cost Effectiveness to Reduce NOx by 90% from 4SLB RICE with SCR Operating at 23% and 91% Capacity Factors, Based on EPA’s 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls

<table>
<thead>
<tr>
<th>ENGINE TYPE</th>
<th>SIZE, hp</th>
<th>ANNUALIZED COSTS OF SCR, 2001$</th>
<th>COST EFFECTIVENESS OF SCR, 2,000 HOURS PER YEAR, 2001$</th>
<th>COST EFFECTIVENESS OF SCR, 8,000 HOURS PER YEAR, 2001$</th>
</tr>
</thead>
<tbody>
<tr>
<td>4SLB</td>
<td>50</td>
<td>$17,509</td>
<td>$10,194/ton</td>
<td>$2,548/ton</td>
</tr>
<tr>
<td></td>
<td>200</td>
<td>$29,368</td>
<td>$4,289/ton</td>
<td>$1,072/ton</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>$53,086</td>
<td>$3,108/ton</td>
<td>$777/ton</td>
</tr>
<tr>
<td></td>
<td>1,000</td>
<td>$92,617</td>
<td>$2,714/ton</td>
<td>$679/ton</td>
</tr>
<tr>
<td></td>
<td>1,500</td>
<td>$132,148</td>
<td>$2,583/ton</td>
<td>$646/ton</td>
</tr>
</tbody>
</table>

Application of SCR to lean-burn RICE is cost effective for a wide range of engine sizes and types.

While the cost estimates and cost algorithms are of a cost basis that is twenty years old, the cost data have been relied on extensively. And, from at least 2001, it is important to note that several state and local air agencies have found that the costs of control to achieve NOx emission limits of 1 g/bhp-hr (65 ppmvd) and even lower (as low as 11 ppmvd as required by SJVAPCD and SCAQMD) were cost effective to require such a level of control on existing lean-burn RICE rated greater than 100 hp. This will be discussed further in Section II.G. below. It is not possible to accurately escalate these costs to 2019 dollars. The CEPCI has been used extensively by EPA for escalating costs, but EPA states that using the CEPCI indices to escalate costs over a period longer than five years can lead to inaccuracies in price estimation. Further, the prices of air pollution control do not always rise at the same level as price inflation rates. As air pollution control is required to be implemented more frequently over time, the costs of air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.

The environmental and energy impacts of SCR for lean-burn RICE include the following:

- 0.5% increase in fuel consumption resulting in increased CO₂ emissions
- 1 to 2% reduction in power output

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142 See 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 5-12. Note that EPA assumes the cost basis is 2001$. Annualized costs of control were calculated using a capital recovery factor of 0.083679 (assuming a 20-year life of controls and a 5.5% interest rate). Uncontrolled NOx emissions are based on EPA’s 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032).

143 EPA relied on the 2003 SJVAPCD Cost Effectiveness Analysis for Rule 4702 (which, in turn, relied on the 2001 CARB Guidance for Stationary SI Engines) in its 2016 EPA CSAPR TSD for Non-EGU NOx Emission Controls (Appendix A at 5-10 through 5-12).


145 See EPA 1993 Alternative Control Techniques Document for RICE, Table 2-7 at 2-15.
• Increased solid waste disposal from spent catalysts\textsuperscript{146}
• If ammonia is used instead of urea (which is assumed to be the reagent used in the SCR cost analyses presented above), there would be an increased need for risk management and implementation and associated costs.\textsuperscript{147} If urea or aqueous ammonia is used as the reagent, the hazards from the use of pressurized anhydrous ammonia do not apply.

Regardless of these impacts, SCR technology is widely used at many industrial sources. 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.

In terms of length of time to install SCR at a lean-burn RICE unit, EPA has estimated that it takes 28–52 weeks to install SCR at a diesel-fired RICE unit.\textsuperscript{148} It is reasonable to assume a similar time for the installation of SCR at a lean-burn natural gas-fired RICE unit.

\textbf{F. RICE ELECTRIFICATION}

Replacement of RICE with an electric motor is another pollution control option. In its 2001 guidance to California Air Districts, CARB indicated that electrification would be a NOx control option for RICE, with the potential to significantly reduce NOx emissions.\textsuperscript{149} \textit{Replacement of on-site engines with electric motors will reduce on-site NOx and other pollutant emissions by 100%}. Depending on the power source used for providing electricity to the site, air emissions may increase from the power generating site (i.e., if the power generating source is fueled by fossil fuels, rather than renewable energy such as wind or solar). However, even if the power is produced by a fossil fuel-fired power plant, it is likely more cost effective to a fossil fuel-fired power plant than it is to apply air pollution controls to individual engines.

CARB indicated in its 2001 guidance that “the majority of beam-balanced and crank-balanced oil pumps in California are driven by electric motors.”\textsuperscript{150} Thus, it stands to reason that electrification of such oil pumps is cost effective, given the widespread implementation.

CARB also found that electrification of RICE that fall within a size range from 50 to 500 hp would be a cost effective NOx control, but CARB stated that beyond the range of 50 to 500 hp, “modification and installation costs may become so extensive that this approach may not be cost effective.”\textsuperscript{151} However, on a cost per ton of NOx removed basis, CARB found that the electrification of engines in the 500 to 1,000 hp size range was as cost effective as the electrification of engines in the 50–150 hp size range.

\textsuperscript{146} See CDPHE RP for RICE at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6\textsuperscript{th} ed., EPA/452/B-02-001, EPA, Office of Air Quality Planning and Standards, RTP).
\textsuperscript{147} Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. See EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.
\textsuperscript{148} 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls at 15.
\textsuperscript{149} CARB 2001 Guidance at I-7.
\textsuperscript{150} Id. at IV-2.
\textsuperscript{151} Id. at V-2.
that is, $1,100/ton in 1999 dollars.\textsuperscript{152} For engines in the size range of 150 to 500 hp, electrification of engines was somewhat more cost effective at $900/ton in 1999 dollars.\textsuperscript{153} CARB indicated that Air Districts in California should consider the replacement of engines with electric motors as a control option “whenever it is feasible in order to maximize emission reductions.”\textsuperscript{154}

It is important to note that CARB’s cost effectiveness calculations were based the assumption of only 2,000 hours per year operation, and CARB assumed capital costs would be amortized over a 10-year period and at a 10% interest rate.\textsuperscript{155} There is no basis for assuming such a short lifespan for an electric internal combustion engine. As discussed further above, gas-fired RICE units have a useful life of at least 30 years, and many have been in operation much longer than 30 years.\textsuperscript{156} Had CARB assumed a 30-year life of controls, the annualized cost of a new electric compressor over 30 years would be significantly lower than CARB’s assessment of those costs over 10 years. Further, for an engine that operates more than 2,000 hours per year, replacement with an electric engine will reduce more NOx emissions, which would also make the replacement of an engine with an electric engine more cost effective.

More recently, EPA’s Natural Gas STAR Program issued a Fact Sheet which evaluated the methane-reduction benefits of replacing gas-fired reciprocating compressors with electric compressors.\textsuperscript{157} According to EPA, “[t]he EPA’s Natural Gas STAR Program provides a framework for Partner companies within U.S. oil and gas operations to implement methane reducing technologies and practices and document their voluntary emission reduction activities.”\textsuperscript{158}

The Fact Sheet documents the costs of replacing five existing gas-fired reciprocating compressors with four electric compressors.\textsuperscript{159} This Fact Sheet was made available in 2011, and thus the cost basis is assumed to be either from 2010 or 2011. Specifically, the Fact Sheet indicates that a partner replaced two 2,650 hp reciprocating compressors, two 4,684 reciprocating compressors, and one 893 hp reciprocating compressor with four 1,750 hp electric compressors.\textsuperscript{160} The Fact Sheet states that the total cost of the replacement was $6,050,000, including the cost of the motor and compressor.\textsuperscript{161} The Fact Sheet calculated the cost of electricity as the primary operating expense, and the electricity costs assuming continual operation of the compressors throughout the year were estimated to be $6,800,000

\begin{footnotes}
\footnotetext{152}{Id. at V-3.}
\footnotetext{153}{Id.}
\footnotetext{154}{Id. at VII-2.}
\footnotetext{155}{Id. at V-4 to V-4.}
\footnotetext{156}{See, e.g., EPRI, 20 Power Companies Examine the Role of Reciprocating Internal Combustion Engines for the Grid, available at: https://eprijournal.com/start-your-engines/. The authors also note that, in reviewing permits for gas processing facilities and compressor stations in New Mexico, it is not uncommon to have engines that were constructed from the 1950s to 1970s still operating at such facilities.}
\footnotetext{157}{See EPA, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, PRO Fact Sheet No. 103 Install Electric Compressors, 2011, available at: https://www.epa.gov/sites/production/files/2016-06/documents/installelectriccompressors.pdf.}
\footnotetext{158}{See https://www.epa.gov/natural-gas-star-program/natural-gas-star-program.}
\footnotetext{159}{See EPA, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, PRO Fact Sheet No. 103 Install Electric Compressors, 2011.}
\footnotetext{160}{Id. at 2.}
\footnotetext{161}{Id.}
\end{footnotes}
For electric compressors that operated less than every hour of the year, these operating costs can be scaled back by multiplying the projected electricity cost for continual operation by the ratio of the number of hours operated per year to 8,760 hours per year. Maintenance costs were assumed to be approximately 10% of the capital costs, and the maintenance costs would be lower than apply to gas-fired engines. The Fact Sheet also presents the fuel gas savings for not having to pay for the natural gas to fire the reciprocating compressors based on three prices for natural gas ($3.00 per thousand cubic feet (MCF) of gas, $5.00 per MCF, and $7.00 per MCF). The amount of natural gas saved by changing to electric compressors was estimated to be 1,700,000 MCF, assuming continual (8,760 hours) operation throughout the year and 20% efficiency of the gas-fired reciprocating compressors. Because this analysis was focused on reducing methane emissions, no calculations of cost effectiveness of this control was done for NOx or any other pollutant.

With these data, the cost effectiveness of replacing similar-sized existing reciprocating compressor engines with similar-sized electric compressor engines as a NOx control measure can be calculated. For these calculations, it is assumed that the existing gas-fired reciprocating compressor engines are uncontrolled for NOx and thus emitting NOx at 16.8 g/bhp-hr. To reflect compressor engines operating at varying hours per year, cost effectiveness calculations were done for replacing compressor engines operating at 2,000 hours, 4,000 hours, and 8,000 hours per year. The capital costs of the new electric compressors were amortized over a 30-year expected life of the new electric compressor engines, assuming a 5.5% interest rate consistent with EPA’s Control Cost Manual methodology. The results of this analysis are provided in Table 14 below.

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162 Id. This assumed that the four 1,750 hp compressor engines had 50% efficiency, operated 8,760 hours per year, and electricity cost $0.075/kW-hr.
163 Id.
164 Id.
165 Id. A heating value of natural gas of 1,020 British Thermal Units (BTU) per standard cubic feet (SCF) of gas was also assumed.
166 See EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.
Table 14. NOx Cost Effectiveness to Replace Natural Gas-Fired RICE Units with Electric Compressor Engines

<table>
<thead>
<tr>
<th>Costs at Operating Hours per Year (2011 $)</th>
<th>2,000 hours/yr</th>
<th>4,000 hrs/yr</th>
<th>8,000 hrs/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annualized Capital Costs of New Electric Engines</td>
<td>$506,385</td>
<td>$506,385</td>
<td>$506,385</td>
</tr>
<tr>
<td>Annual Operating Costs of New Engines and Excluding Costs of Gas for Replaced Engines</td>
<td>$992,940</td>
<td>$1,380,880</td>
<td>$2,156,761</td>
</tr>
<tr>
<td>Total Annual Costs</td>
<td>$1,887,265</td>
<td>$1,887,265</td>
<td>$2,663,146</td>
</tr>
<tr>
<td>NOx Removed, tpy</td>
<td>542 tpy</td>
<td>1,084 tpy</td>
<td>2,168 tpy</td>
</tr>
<tr>
<td>NOx Cost Effectiveness at Stated Hours/Year</td>
<td>$2,766/ton</td>
<td>$1,741/ton</td>
<td>$1,228/ton</td>
</tr>
</tbody>
</table>

Assumptions
- Existing Gas-Fired Reciprocating Compressor Engines: 2–2,650 hp, 2–4,684 hp, 1–893 hp
- Replacement Electric Compressor Engines: 4–1,750 hp
- Efficiency of Existing Gas-Fired Engines: 20%
- Efficiency of Electric Engines: 50%
- 30 Year Life of Electric Engines, 5.5% Interest Rate
- Cost of Electricity: $0.075 per kilowatt-hour; Cost of Natural Gas: $3.00/MCF
- Annual Maintenance Costs: 10% of Capital Costs of New Electric Engines

The above cost effectiveness analysis does not take into account the increased emissions that may occur from the electric power generation that will power the new electric compressor engines, which will depend on the source of that power for the new electric engines. If the energy is provided by renewable sources, there will be no NOx, greenhouse gas, or other air pollution increase associated with the energy production. To take into account the increase in NOx from a fossil fuel-fired power plant providing the electricity to the electric compressor engines, a high-end estimate of the increase in NOx from fossil-fuel fired power plant would mean that the switch to electric engines would result in an overall NOx emission reduction of about 97% of the NOx emitted by the gas-fired reciprocating compressor engines (i.e., a power plant providing the electricity for the new electric compressor engines might increase NOx by 15 to 59 tons per year depending on the hours of operation of the new electric compressor engines).

167 The basis for the capital and operating costs are from EPA’s PRO Fact Sheet No. 103 Install Electric Compressors.
168 The $3.00/MSCF estimated cost of natural gas may overestimate natural gas prices. The EIA reported the Henry Hub Spot Price for 2019 to be $2.66/MCF and has projected the cost to stay similar or decrease slightly in 2020-2021. However, the Henry Hub spot price was higher ($3.27/MCF) in 2018. Further, the EIA lists the 2019 Industrial Sector price of natural gas to be $3.90. It is not clear which of these two prices would apply, and thus the assumed $3.00/MCF price of natural gas is a middle ground between these two prices. See https://www.eia.gov/outlooks/steo/report/natgas.php.
From the perspective of cost effectiveness, the potential increase in NOx emissions from the power generating source would not significantly impact cost effectiveness of replacing gas-fired engines with electric engines.

The costs in Table 14 assume that the engines are located relatively close to the power grid and thus do not take into account any costs to bring electricity to the site. For a site that is not relatively close to the power grid, CARB estimated it could cost $5,000 to $10,000 (in 1999 dollars) to set up the site for electric motor operation and states that some utilities may waive or refund those costs if monthly energy usage matches the cost to connect to the grid.\textsuperscript{170}

There are many benefits associated with replacing gas-fired reciprocating compressor engines with electric compressor engines. Those benefits include:\textsuperscript{171}

- Reduced maintenance requirements and costs.
- Electric engines are more efficient than gas-fired engines.
- Lower noise levels with electric motors compared to gas-fired engines.
- No on-site emissions of other air pollutants.

An additional benefit of replacing gas-fired engines with electric engines is the greenhouse gas reductions that would be achieved. With renewable energy accounting for a larger share of electricity production over time, there could be significant reductions in greenhouse gases by using electrified engines powered by renewable energy. In the EPA’s Natural Gas STAR Program Fact Sheet for electric compressors, the gas savings by electrifying the compressors is stated to be 32,800 MCF per year.\textsuperscript{172} With that amount of gas not being combusted in the compressor engines and the power for the compressor engines being supplied by renewable energy, there would be a decrease in greenhouse gas emissions of almost 2,000 tons per year.\textsuperscript{173} With electric compression engines used, there also will be less methane released from compressor blowdowns. Compressors must be taken offline at times due to emergency upsets and due to maintenance. As previously stated, the maintenance requirements with an electric compressor engine are significantly less with electric compressor engines.\textsuperscript{174} It also seems likely that an electric engine would be less prone to upsets that cause the engine to go offline, compared to a gas-fired reciprocating engine. Moreover, with no gas used in the compressor engine, fugitive emission leaks due to fuel gas are also eliminated. EPA’s Natural Gas STAR Program Fact Sheet provided an estimate that methane emissions savings from replacing the five gas-fired compressor engines with electric engines could be as high as 16,000 MCF per year, based on a methane emission factor of 2.11

\textsuperscript{169} A NOx rate of 1.4 pounds per megawatt-hour was assumed for these calculations to represent a high-end estimate of the increase in NOx emissions if a fossil fuel-fired power plant provided the electricity for the electric engines. This reflects a NOx limit of 0.15 lb/MMBtu for a coal-fired power plant, which reflects a plant burning subbituminous coal with combustion controls. A natural gas-fired power plant would likely have a lower NOx rate, particularly if equipped with SCR.

\textsuperscript{170} CARB 2001 Guidance at V-2.

\textsuperscript{171} See EPA, PRO Fact Sheet No. 103 Install Electric Compressors at 2.

\textsuperscript{172} Id. at 1.

\textsuperscript{173} Calculated based on EPA’s greenhouse gas emission factors for natural gas combustion in Table C-1 of Subpart C of 40 C.F.R. Part 98.

\textsuperscript{174} See EPA, PRO Fact Sheet No. 103 Install Electric Compressors at 2.
MCF per horsepower.\textsuperscript{175} Using the 100-year global warming potential identified by EPA,\textsuperscript{176} that equates to roughly 10,000 tons per year of CO\textsubscript{2} equivalent emissions that would be avoided with no natural gas releases due to blowdowns with electric compressor engines. Thus, the total CO\textsubscript{2} equivalent emissions that could be reduced by replacing the five gas-fired engines with electric compressors powered with renewable energy would be about 12,000 tons per year.

There are several examples of electric engines being used in the oil and gas industry for compression, both at the wellhead and in compressor stations,\textsuperscript{177} for drill rigs,\textsuperscript{178} and in oil pumps.\textsuperscript{179} Ambient air quality concerns have typically been the driver for electrification of engines in the past. Electrification of RICE units can be a very cost effective way to eliminate NOx and other air emissions, including greenhouse gas emissions, for the oil and gas industry and thus should be given serious consideration as an effective pollution control to address regional haze.

G. NOx EMISSION LIMITS THAT HAVE BEEN REQUIRED FOR EXISTING NATURAL GAS-FIRED STATIONARY RICE UNITS

The NSPS standards applicable to stationary spark ignition gas-fired RICE units were last reviewed and revised in 2008.\textsuperscript{180} The most stringent NOx limit of those standards currently in effect for new and modified spark ignition RICE units is 1.0 g/hp-hr for rich burn engines greater than 100 hp and for lean-burn engines between 100 hp and 1,350 hp.\textsuperscript{181} In considering reasonable progress controls for gas-fired spark-ignition RICE units, the applicable NSPS standards should be considered the “floor” of potential NOx controls to consider for an existing RICE unit.

Numerous states and local air agencies have adopted similar or more stringent NOx limits for existing spark-ignition gas-fired RICE units to meet, many of which have been in place for 10–20 years. In Table 15 below, we summarize those state and local air pollution requirements. Some of this information was initially obtained from EPA’s 2016 CSAPR TSD,\textsuperscript{182} which provided a summary of state NOx regulations for gas engines.\textsuperscript{183} The current state/local requirements for those CSAPR states were confirmed by a review of the state and local rules. The CSAPR TSD focused on the rules applicable in the CSAPR states. A review of California Air District rules was also done for this report, because several of those air districts have adopted the most stringent NOx emission limitations for existing gas-fired engines. We reviewed many of the remaining states’ regulations to determine whether there were NOx limitations for existing natural gas-fired stationary RICE units.

\textsuperscript{175} Id. at 1.
\textsuperscript{176} See https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#Learn%20why.
\textsuperscript{178} Id. at 18.
\textsuperscript{179} CARB 2001 Guidance at IV-2.
\textsuperscript{180} See 40 C.F.R. Part 60, §60.4230(a)(5) and Subpart JJJ. 73 Fed. Reg. 3568 (1/18/08).
\textsuperscript{181} 40 C.F.R. Part 60, Subpart JJJ, Table 1.
\textsuperscript{182} See 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix B at 14-15.
\textsuperscript{183} Id.
Table 15 is a summary of the NOx emission limits required of existing gas-fired stationary RICE units in states and local air districts across the United States. It is important to note that these are limits that, unless otherwise noted, currently apply to existing RICE. Unlike the NSPS standards of 40 C.F.R. Part 60, Subpart JJJJ, the RICE did not have to be modified to trigger applicability to these emission limits. Instead, these emission limits apply to existing natural gas-fired stationary RICE units and generally required an air pollution control retrofit. These state and local NOx limits were most likely adopted to address nonattainment issues with the ozone NAAQS and possibly also the PM$_{2.5}$ NAAQS. However, Colorado adopted a NOx limit for lean-burn RICE of 1 g/hp-hr as part of its initial regional haze plan to achieve reasonable progress towards the national visibility goal.\textsuperscript{184} Regardless of the reason for adopting the NOx emission limits, what becomes clear in this analysis is that numerous states and local governments have adopted NOx limitations that require NSCR at rich burn RICE units and either LEC or SCR at lean-burn RICE units. The lowest, most broadly applicable NOx limits are those recently adopted by SCAQMD which require gas-fired RICE units greater than 50 hp in size to meet a 11 ppmvd (equivalent to 0.15 g/hp-hr) NOx limit.

These limits were adopted generally to meet reasonably available control technology (RACT) and best available retrofit control technology (BARCT — applies in California), and costs are taken into account in making these RACT and BARCT determinations. However, RACT is not necessarily as stringent as BARCT. RACT is generally defined as: “devices, systems, process modifications, or other apparatus or techniques that are reasonably available taking into account: (1) The necessity of imposing such controls in order to attain and maintain a national ambient air quality standard; (2) The social, environmental, and economic impact of such controls.”\textsuperscript{185} BARCT, on the other hand, is defined as “an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source.”\textsuperscript{186} BARCT is like a best available control technology (BACT) determination under the federal prevention of significant deterioration (PSD) program, but it evaluates controls to be retrofit to existing sources, rather than applying to new or modified sources.

### Table 15. State/Local Air Agency RICE Rules for Natural Gas-fired Stationary RICE Units\textsuperscript{187}

<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Rich-Burn (RB) or Lean-Burn (LB) or Both</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent g/hp-hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA-Antelope Valley AQMD\textsuperscript{188}</td>
<td>Rule 1110.2</td>
<td>Both</td>
<td>50–500 hp</td>
<td>45 ppmvd (0.67 g/hp-hr (RB) or 0.62 g/hp-hr (LB))</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>&gt;500</td>
<td>36 ppmvd (0.54 g/hp-hr (RB) or 0.49 g/hp-hr (LB))</td>
</tr>
</tbody>
</table>

\textsuperscript{184} See CDPHE RP for RICE at 10.

\textsuperscript{185} 40 C.F.R. § 51.100(o).

\textsuperscript{186} HSC Code § 40406 (California Code), available at: https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=40406.&lawCode=HSC.

\textsuperscript{187} This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to RICE units, and in case of any errors in this table.

\textsuperscript{188} https://ww3.arb.ca.gov/drdb/av/curhtml/r1110-2.pdf.
<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Rich-Burn (RB) or Lean-Burn (LB) or Both</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent g/hp-hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA-Bay Area AQMD&lt;sup&gt;189&lt;/sup&gt;</td>
<td>Reg. 9, Rule 8</td>
<td>RB</td>
<td>&gt;50 bhp &amp;/or not Low Usage (&lt;100 hrs/yr) &amp;/or not registered as portable</td>
<td>25 ppmv (0.37 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>LB</td>
<td>&gt;50 bhp &amp;/or not Low Usage (&lt;100 hrs/yr) &amp;/or not registered as portable</td>
<td>65 ppmv (0.89 g/hp-hr)</td>
</tr>
<tr>
<td>CA-Mojave Desert APCD&lt;sup&gt;190&lt;/sup&gt;</td>
<td>Rule 1160&lt;sup&gt;191&lt;/sup&gt;</td>
<td>RB</td>
<td>&gt;500 bhp &amp;/or &gt;100 hours/4 quarters, and only if located in the Federal Ozone Nonattainment area</td>
<td>50 ppmv (0.75 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>LB</td>
<td></td>
<td>140 ppmv (1.92 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>RB</td>
<td>Ozone Nonattainment area</td>
<td>50 ppmv (0.75 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>LB</td>
<td></td>
<td>125 ppmv (1.71 g/hp-hr)</td>
</tr>
<tr>
<td>CA-Sacramento AQMD&lt;sup&gt;192&lt;/sup&gt;</td>
<td>Rule 412</td>
<td>RB</td>
<td>&gt;50 bhp &amp; exemptions for 50-525 hp if low op hours (200-40 hrs)</td>
<td>25 ppmv (0.37 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>LB</td>
<td>&gt;50 bhp</td>
<td>65 ppmv (0.89 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Alt Limit: 90% NOx reduction</td>
</tr>
<tr>
<td>CA-Santa Barbara AQMD&lt;sup&gt;193&lt;/sup&gt;</td>
<td>Rule 333</td>
<td>RB</td>
<td>&gt;50 bhp Noncyclically-loaded&lt;sup&gt;194&lt;/sup&gt;</td>
<td>50 ppmv (0.75 g/hp-hr) or 90% NOx reduction</td>
</tr>
<tr>
<td></td>
<td></td>
<td>RB</td>
<td>&gt;50 bhp</td>
<td>300 ppmvd (4.48 g/hp-hr)</td>
</tr>
</tbody>
</table>


<sup>192</sup> [http://www.airquality.org/ProgramCoordination/Documents/rule412.pdf](http://www.airquality.org/ProgramCoordination/Documents/rule412.pdf).

<sup>193</sup> [https://ww3.arb.ca.gov/drdb/sb/curhtml/r333.pdf](https://ww3.arb.ca.gov/drdb/sb/curhtml/r333.pdf).

<sup>194</sup> Noncyclically loaded means an engine that is not cyclically loaded. See Santa Barbara AQMD Rule 333.C.
<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Rich-Burn (RB) or Lean-Burn (LB) or Both</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent g/hp-hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA – San Diego AQMD&lt;sup&gt;196&lt;/sup&gt;</td>
<td>Rule 69.4.1</td>
<td>LB</td>
<td>&gt;50 bhp &amp; &lt;100 bhp</td>
<td>200 ppmvd (2.74 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>LB</td>
<td>≥100 bhp</td>
<td>125 ppmvd (1.71 g/hp-hr) or 80% NOx reduction</td>
</tr>
<tr>
<td>CA-San Joaquin Valley APCD&lt;sup&gt;197&lt;/sup&gt;</td>
<td>Rule 4702</td>
<td>RB</td>
<td>&gt;50 bhp &amp; &gt;200 hrs/yr</td>
<td>25 ppmvd (0.37 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>LB</td>
<td>&gt;50 bhp &amp; &gt;200 hrs/yr</td>
<td>65 ppmvd (0.89 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>RB</td>
<td>&gt;50 bhp, Cyclic loaded, Field Gas Fueled</td>
<td>50 ppmvd (0.75 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>RB</td>
<td>&gt;50 bhp &amp; &lt;4,000 hrs/yr</td>
<td>25 ppmvd (0.37 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>RB</td>
<td>&gt;50 bhp and all others (engines not waste gas-fueled or cyclic loaded or limited hours)</td>
<td>11 ppmvd (0.16 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2SLB</td>
<td>&gt;50 bhp &amp; &lt;100 bhp</td>
<td>75 ppmvd (1.03 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>LB</td>
<td>&gt;50 bhp &amp; &lt;4,000 hrs/yr</td>
<td>65 ppmvd (0.89 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>LB</td>
<td>&gt;50 bhp and used for gas compression</td>
<td>65 ppmvd (0.89 g/hp-hr) or 93% NOx reduction</td>
</tr>
<tr>
<td></td>
<td></td>
<td>LB</td>
<td>&gt;100 hp and not limited use (&lt;4,000 hrs), not used for gas compression, or not waste-gas fueled</td>
<td>11 ppmvd (0.15 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td>Rule 431</td>
<td>RB</td>
<td>&gt;50 bhp &amp; &gt;200 hrs/yr</td>
<td>50 ppmvd (0.75 g/hp-hr)</td>
</tr>
</tbody>
</table>

<sup>195</sup> “Cyclically-loaded” means “an engine that under normal operating conditions has an external load that varies by 40% or more of rated brake horsepower during any load cycle or is used to power a well reciprocating pump including beam-balanced or crank-balanced pumps. Engines powering air-balanced pumps are noncyclically-loaded engines.” See Santa Barbara AQMD Rule 333.C.

<sup>196</sup> [https://www.sandiegocounty.gov/content/dam/sdc/apcd/PDF/Rules_and_Regulations/Prohibitions/APCD_R69-4-1.pdf](https://www.sandiegocounty.gov/content/dam/sdc/apcd/PDF/Rules_and_Regulations/Prohibitions/APCD_R69-4-1.pdf).

<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Rich-Burn (RB) or Lean-Burn (LB) or Both</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent g/hp-hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA- San Luis Obispo APCD&lt;sup&gt;198&lt;/sup&gt;</td>
<td>LB</td>
<td>&gt;50 bhp &amp; &gt;200 hrs/yr</td>
<td>or 90% NOx Reduction</td>
<td></td>
</tr>
<tr>
<td>CA - SCAQMD&lt;sup&gt;199&lt;/sup&gt;</td>
<td>RB &amp; LB</td>
<td>&gt;50 bhp</td>
<td>11 ppmvd (0.16 g/hp-hr (RB)</td>
<td></td>
</tr>
<tr>
<td>CA- Ventura County AQMD&lt;sup&gt;200&lt;/sup&gt;</td>
<td>RB</td>
<td>&gt;50 bhp &amp; &gt;200 hrs/yr</td>
<td>25 ppmvd (0.37 g/hp-hr)</td>
<td></td>
</tr>
<tr>
<td>CA- Ventura County AQMD&lt;sup&gt;200&lt;/sup&gt;</td>
<td>LB</td>
<td>&gt;50 bhp &amp; &gt;200 hrs/yr</td>
<td>45 ppmvd (0.62 g/hp-hr)</td>
<td></td>
</tr>
<tr>
<td>TX- Houston-Galveston-Brazoria Area&lt;sup&gt;201&lt;/sup&gt;</td>
<td>RB &amp; LB</td>
<td>&gt;50 hp</td>
<td>0.50 g/hp-hr (33 ppmvd (RB)</td>
<td>36 ppm vd (LB))</td>
</tr>
<tr>
<td>TX- Dallas - Ft. Worth Area&lt;sup&gt;202&lt;/sup&gt;</td>
<td>RB</td>
<td>&gt;50 hp</td>
<td>0.50 g/hp-hr</td>
<td></td>
</tr>
<tr>
<td>TX- Dallas - Ft. Worth Area&lt;sup&gt;202&lt;/sup&gt;</td>
<td>LB</td>
<td>In service before 6/1/07</td>
<td>0.70 g/hp-hr</td>
<td></td>
</tr>
<tr>
<td>TX- Dallas - Ft. Worth Area&lt;sup&gt;202&lt;/sup&gt;</td>
<td>LB</td>
<td>Placed into service, modified, reconstructed, or relocated after 6/1/07</td>
<td>0.50 g/hp-hr</td>
<td></td>
</tr>
<tr>
<td>NJ&lt;sup&gt;203&lt;/sup&gt;</td>
<td>RB</td>
<td>&gt;500 bhp</td>
<td>1.5 g/bhp-hr</td>
<td></td>
</tr>
<tr>
<td>NJ&lt;sup&gt;203&lt;/sup&gt;</td>
<td>LB</td>
<td>&gt;500 bhp</td>
<td>2.5 g/bhp-hr</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Rich-Burn (RB) or Lean-Burn (LB) or Both</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent g/hp-hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>LB &amp; used for generating electricity</td>
<td>≥148 kW</td>
<td>1.5 g/bhp-hr or 80% NOx reduction</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2SLB</td>
<td>≥200 bhp &amp; &lt;500 bhp</td>
<td>3.0 g/bhp-hr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>4SLB</td>
<td>≥200 bhp &amp; &lt;500 bhp</td>
<td>2.0 g/bhp-hr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>RB&amp;LB</td>
<td>Constructed or modified after 3/7/07, engines used to generate electricity with output ≥37 kW</td>
<td>0.90 g/bhp-hr or 90% NOx reductions (for modified units)</td>
</tr>
<tr>
<td>NY204</td>
<td>6 CCR-NY 227-2.4 (f)</td>
<td>RB &amp; LB</td>
<td>&gt;200 bhp</td>
<td>1.5 g/bhp-hr</td>
</tr>
<tr>
<td>MA205</td>
<td>310 CMR 7.19:(8)(c)</td>
<td>RB</td>
<td>&gt;3 MMBtu/hr and &gt;1,000 hrs</td>
<td>1.5 g/bhp-hr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>LB</td>
<td>&gt;3 MMBtu/hr and &gt;1,000 hrs</td>
<td>3.0 g/bhp-hr</td>
</tr>
<tr>
<td>MD206</td>
<td>COMAR 26.11.29.02.C.</td>
<td>RB</td>
<td>RICE used to compress nat gas ≥2400 hp</td>
<td>110 ppmv (1.64 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>LB</td>
<td>RICE used to compress nat gas ≥2,400 hp</td>
<td>125 ppmv (1.71 g/hp-hr)</td>
</tr>
<tr>
<td>CT207</td>
<td>22a-174-22e(d)(6a)</td>
<td>RB</td>
<td>&gt;3 MMBtu/hr, until 5/31/23 Beginning 6/1/23</td>
<td>2.5 g/bhp-hr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>LB</td>
<td>&gt;3 MMBtu/hr, until 5/31/23 Beginning 6/1/23</td>
<td>2.5 g/bhp-hr</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>IL (Chicago area and Metro East area)208</td>
<td>Title 35 Part 217, § 217.388a(1)</td>
<td>RB</td>
<td>Applies to specific engines listed in App G and those &gt;500 bhp</td>
<td>150 ppmv (2.24 g/hp-hr)</td>
</tr>
</tbody>
</table>

204 https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData={sc.Default}.  
<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Rich-Burn (RB) or Lean-Burn (LB) or Both</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent g/hp-hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>LB except Worthington engines not listed in App G</td>
<td>LB</td>
<td>&gt;500 bhp &amp; &gt;8 MMbhp-hrs</td>
<td>365 ppmv (5.0 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td>WL Worthington engines not listed in App G</td>
<td>WL</td>
<td>&gt;500 bhp &amp; &gt;8 MMbhp-hrs</td>
<td>210 ppmv (2.88 g/hp-hr)</td>
</tr>
<tr>
<td>GA (45 county area – ozone)</td>
<td>Rule 391-3-1-.02.(2)(mmm)</td>
<td>RB &amp; LB</td>
<td>≥100kW&amp;≤25 MW, in operation &lt;4/1/00</td>
<td>160 ppmv (2.19–2.39 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td>Applies only to engines used to generate electricity</td>
<td>RB &amp; LB</td>
<td>≥100kW≤25 MW, in operation &gt;4/1/00</td>
<td>80 ppmv (1.10–1.19 g/hp-hr)</td>
</tr>
<tr>
<td>MI</td>
<td>R 336.1818</td>
<td>RB</td>
<td>&gt;1 ton/day NOx engines per avg ozone control period day in 1995</td>
<td>1.5 g/bhp-hr</td>
</tr>
<tr>
<td></td>
<td>LB</td>
<td>LB</td>
<td></td>
<td>3.0 g/bhp-hr</td>
</tr>
<tr>
<td>CO</td>
<td>Reg. No 7, Sections XVIII.E. 2 and 3</td>
<td>RB</td>
<td>&gt;500 hp constructed before 2/1/09</td>
<td>Install and operate both a NSCR and an AFRC by 7/1/2010</td>
</tr>
<tr>
<td></td>
<td>RB or LB constructed or relocated to Colorado ≥1/1/11</td>
<td>RB or LB</td>
<td>≥100 hp &amp; ≤500 hp</td>
<td>1.0 g/hp-hr</td>
</tr>
<tr>
<td></td>
<td>RB or LB constructed or relocated ≥7/1/10</td>
<td>RB or LB</td>
<td>≥500 hp</td>
<td>1.0 g/hp-hr</td>
</tr>
<tr>
<td>MT</td>
<td>ARM 17.8.1603</td>
<td>RB engines at “oil and gas well facilities” (which does not include Compressor engines) which completed or modified</td>
<td>&gt;85 bhp</td>
<td>Install and operate NSCR or its equivalent to control air emissions</td>
</tr>
</tbody>
</table>

209 [http://rules.sos.ga.gov/GAC/391-3-1-.02](http://rules.sos.ga.gov/GAC/391-3-1-.02).
In addition to the state and local air agency rules requiring NOx emission limits that clearly reflect highly effective NOx controls, some states have BACT or similar requirements that are required of new or modified sources regardless of whether or not such sources or modifications are major and subject to the major source PSD permitting programs. In some cases, states have issued guidelines on what is essentially considered BACT for these non-PSD new and modified sources, in the form of guidance and/or general permit or permit by rule requirements for RICE units. Table 16 below summarizes some of these state requirements which, when imposed in a permit would become binding emission limits.

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**Table 16: State/Local Regulations and NOx Limit Requirements**

<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Rich-Burn (RB) or Lean-Burn (LB) or Both</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent g/hp-hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>UT²¹³</td>
<td>R307-510</td>
<td>Gas-fired engine at a well site that began operations, installed new engines or made modifications to existing engines after 1/1/16</td>
<td>≥100 hp</td>
<td>1.0 g/hp-hr</td>
</tr>
</tbody>
</table>

---

**Most stringent NOx Limit of State/Local Rules:**

11 ppmvd (0.15–0.16 g/hp-hr) applicable to either rich-burn or lean-burn RICE units greater than 50 bhp

---

Table 16. Other NOx Limits Applicable to Natural Gas-fired Stationary RICE Units

<table>
<thead>
<tr>
<th>State</th>
<th>Determination</th>
<th>Applicability [hp]</th>
<th>NOx Limits and Engine Type Applicability [RB, LB or BOTH]</th>
</tr>
</thead>
<tbody>
<tr>
<td>NEW JERSEY&lt;sup&gt;214&lt;/sup&gt;</td>
<td>State of the Art (SOTA) Emission Performance Levels</td>
<td>NO SIZE SPECIFIED</td>
<td>0.15 g/hp-hr (BOTH)&lt;sup&gt;215&lt;/sup&gt;</td>
</tr>
<tr>
<td>PENNSYLVANIA 216</td>
<td>Best Available Technology (BAT) Emission Limits for new SI RICE permitted on or after 8/8/18</td>
<td>≤100</td>
<td>1.0 g/hp-hr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;100 TO ≤500</td>
<td>0.7 g/hp-hr (LB) 0.25 g/hp-hr (RB)&lt;sup&gt;217&lt;/sup&gt;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;500</td>
<td>0.5 g/hp-hr (LB) 0.2 g/hp-hr (RB)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>≥2,370</td>
<td>0.3 g/hp-hr uncontrolled (LB) or 0.05 g/hp-hr with control (LB)&lt;sup&gt;218&lt;/sup&gt;</td>
</tr>
<tr>
<td>PENNSYLVANIA 219</td>
<td>Best Available Technology (BAT) Emission Limits for existing SI RICE permitted on or after</td>
<td>≤100</td>
<td>2.0 g/hp-hr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;100 TO ≤500</td>
<td>1.0 g/hp-hr (LB)</td>
</tr>
</tbody>
</table>


<sup>215</sup> Generally applied controls to meet State of the Art Emission Performance Levels:
- Rich-burn: NSCR
- Lean-burn: SCR or LEC

Basis: “In determining SOTA performance levels for RICE engines, permitting agencies, industry associations, manufacturers of RICE and manufacturers of emissions control equipment were contacted to obtain updated information on emissions and control technologies. Databases for recent permitted and tested engines from New Jersey, California and USEPA were reviewed.” Id. at 8.


<sup>217</sup> PA DEP determined that NSCR is required for all rich burn engines rated greater than or equal to 100 bhp. PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. See Appendix C at 75, available at: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

<sup>218</sup> Lean-burn engines greater than or equal to 2,370 hp have a dual BAT: (1) engines with a NOx emission rate of 0.30 g/bhp-hr do not require SCR based on economic feasibility; and (2) engines with a NOx emission rate of 0.050 g/bhp-hr require SCR.

<sup>219</sup> Id.
<table>
<thead>
<tr>
<th>State</th>
<th>Determination</th>
<th>Applicability [hp]</th>
<th>NOx Limits and Engine Type Applicability [RB, LB or BOTH]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2/2/13 but prior to 8/8/18</td>
<td></td>
<td>0.25 g/hp-hr (RB)</td>
</tr>
<tr>
<td></td>
<td>&gt;500</td>
<td></td>
<td>0.50 g/hp-hr (LB) 0.20 g/hp-hr RB)</td>
</tr>
<tr>
<td>PENNSYLVANIA</td>
<td>Best Available Technology (BAT) Emission limits for existing SI RICE permitted prior to 2/2/13</td>
<td>&lt;1,500</td>
<td>2.0 g/hp-hr</td>
</tr>
<tr>
<td>WYOMING</td>
<td>Oil and Gas Production Facilities Permitting Guidance Applicable to Natural Gas-Fired Pumping Units</td>
<td>≤50 hp AND MEETS BACT</td>
<td>2.0 g/hp-hr</td>
</tr>
<tr>
<td>TEXAS</td>
<td>Oil and Gas Handling and Production Facilities Standard Permit RB engines manufactured on or after 1/1/2011; LB engines manufactured on or after 7/1/2010</td>
<td>≥100 bhp (RB) ≥500 bhp (LB)</td>
<td>1 g/bhp-hr</td>
</tr>
</tbody>
</table>

And in addition to the state guidance and/or general permit or permit by rule requirements for RICE units listed in Table 16, BACT analyses completed for PSD permits also demonstrate the feasibility of controls. As an example, in Missouri, BACT for lean-burn RICE at the Mid-Kansas Electric Company, LLC’s

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220 PA DEP determined that NSCR is required for all rich burn engines rated greater than or equal to 100 bhp. PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. See Appendix C at 75, available at: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

221 Id.


Rubart Station was determined to be SCR with a NOx BACT limit equivalent to 0.07 g/hp-hr for loads of 50% or higher.\textsuperscript{224}

As Table 15 shows, twenty-three state and local air pollution control agencies have adopted NOx emission limits for existing gas-fired stationary RICE units that reflect the application of NSCR to rich-burn natural gas-fired RICE units greater than 50 hp and LEC and/or SCR for lean-burn natural gas-fired RICE units greater than 50 hp. These air agencies have thus found that the levels of NOx control listed in Table 15, including NOx limits as low as 11 ppmvd, are cost effective for existing natural gas-fired RICE units, providing relevant examples of one measure for states to consider in their second round haze plans to help make reasonable progress towards remedying existing visibility impairment. Further, several states have adopted essentially presumptive BACT NOx limits for new or modified RICE engines that are at least as stringent as the most stringent NSPS limit and/or apply to smaller units than the NSPS. The fact that these limits could apply to modified units means that the states consider retrofit controls to meet the emission limits in Table 15 above to be cost effective. Table 16 above also provides relevant examples of one measure for states to consider to prevent future impairment of visibility due to oil and gas development.

H. SUMMARY — NOx CONTROLS FOR EXISTING RICH-BURN AND LEAN-BURN NATURAL GAS-FIRED RICE

The above analyses and state/local rule data demonstrate that numerous state and local air agencies have found that NSCR is a cost effective NOx control for rich-burn natural gas-fired RICE units with costs ranging from $44/ton to $3,383/ton (2009$). NSCR not only reduces NOx, but can also be optimized with the use of an AFRC and an oxygen sensor to effectively reduce CO and HC and VOCs.

Further, numerous state and local air agencies have found that LEC is cost effective for lean-burn natural gas-fired RICE units with costs ranging from $74/ton to $941/ton (2001$). For the lowest NOx limit of 11 ppmvd applicable to lean-burn engines under rules adopted by SCAQMD and SJVAPCD, SCR was presumably necessary to meet these limits with costs ranging from $650 to $3,500 per ton of NOx removed or even higher for engines that operate 2,000 hours per year.

As states evaluate regulation of NOx emissions from natural gas-fired RICE units, there are several factors to consider, such as how the units are loaded (cyclically or not), operating capacity factor, and size. Nonetheless, given the numerous state and local NOx limits in Table 15 above that reflect operation of NSCR at rich-burn units and LEC or SCR at lean-burn units, these controls for rich-burn and lean-burn units rated at 50 hp or greater should generally be considered as cost effective measures available to make reasonable progress from natural gas-fired RICE units, given that similar sources have assumed similar costs of control to meet Clean Air Act requirements. NSCR has the added visibility benefit of reducing VOCs, as well as NOx.

\textsuperscript{224} Prevention of Significant Deterioration Air Construction Permit Application for Mid-Kansas Electric Company, LLC Rubart Station (July 2012), available at: \url{http://www.kdheks.gov/bar/midkanec/Mid-Kansas_Rubart_Station_PSD_Air_Permit_App_12_19_12.pdf}.\hspace{1cm}
It also must be recognized that it may be as or more cost effective for NOx control, and more beneficial for regional haze, to replace gas-fired RICE units with electric engines rather than install NOx pollution controls. Moreover, electric engines have numerous benefits that should be considered with regard to the energy and non-air impacts factor of a reasonable progress analysis. These additional benefits include reducing on-site emissions of all pollutants, reduced noise levels, more efficient operation and maintenance requirements (including less frequent maintenance required), and decreased methane emissions due to blowdowns because the electric engines do not require as frequent maintenance and do not have as many upsets. In addition, if the power for the electric engines can be derived from renewable energy sources, the greenhouse gas reductions can be very significant. Indeed, with renewable energy becoming an increasingly greater proportion of electricity generation and with coal-fired electricity generation being phased out, these added benefits of replacing gas-fired RICE units with electric engines should be considered in the four-factor analysis of controls. Electrification of engines may be less cost effective than some of the NOx controls evaluated above such as NSCR and LEC, but the potential added benefits with electric motors will likely weigh in favor of electrification as the most effective reasonable progress control for RICE.

III. CONTROL OF VOC EMISSIONS FROM NATURAL GAS-FIRED RICE

VOC emissions from natural gas-fired RICE units result from incomplete combustion. The same is true for CO emissions. The combustion conditions that favor lower NOx emission rates, such as lower temperature combustion, tend to result in less complete combustion and thus higher VOC as well as CO emission rates. In general, the emissions of VOCs from uncontrolled gas-fired RICE are of a lower magnitude compared to NOx emissions. A discussion of the pollution controls to reduce VOC emissions from these engines is provided below.

EPA’s AP-42 Emission Factor documentation indicates that the uncontrolled VOC emission factors for natural gas-fired RICE in the range of 0.03 to 0.12 lb/MBtu,\(^{225}\) although it must be noted that EPA gives these emission factors a “C” rating. EPA’s emission factor ratings indicate the reliability of the emissions factor, and a “C” rating reflects that “[t]ests are based on unproven or new methodology, or are lacking a significant amount of background information.”\(^{226}\) EPA also states that “actual emissions may vary considerably from the published emission factors due to variations in engine operating conditions.”\(^{227}\) That said, EPA’s emission factors for uncontrolled VOCs are an order of magnitude lower than uncontrolled NOx emissions from RICE units. For that reason, this report focuses extensively on NOx emission controls for RICE units. However, there are emission controls feasible and implemented for VOCs from RICE units.

225 EPA, AP-42, Section 3.2, Tables 3.2-1, 3.2-2, and 3.2-3, available at: https://www3.epa.gov/ttn/chief/ap42/ch03final/c03s02.pdf.


227 EPA, AP-42, Section 3.2 at 3.2-3.
VOC Controls for Lean-Burn RICE

For lean-burn natural gas-fired RICE, as well as natural gas-fired combustion turbines, the primary method available for reducing VOC emissions is the use of an oxidation catalyst. For rich-burn RICE, NSCR is the pollution control of choice to address VOCs, as its three-way catalyst generally reduces NOx, CO, and VOCs with proper operation, although an oxidation catalyst can be installed downstream of the NSCR to improve VOC control.

A 2015 report issued by the Manufacturers of Emission Controls Association on emission controls for stationary internal combustion engines states as follows regarding oxidation catalyst for lean-burn engines:

Oxidation catalysts (or two-way catalytic converters) are widely used on diesel engines and lean-burn gas engines to reduce hydrocarbon and carbon monoxide emissions. Specifically, oxidation catalysts are effective for the control of CO, NMHCs, VOCs, and formaldehyde and other [hazardous air pollutants (HAPs)] from diesel and lean-burn gas engines. Oxidation catalysts consist of a substrate made up of thousands of small channels. Each channel is coated with a highly porous layer containing precious metal catalysts, such as platinum or palladium. As exhaust gas travels down the channel, hydrocarbons and carbon monoxide react with oxygen within the porous catalyst layer to form carbon dioxide and water vapor. The resulting gases then exit the channels and flow through the rest of the exhaust system.

An oxidation catalyst has two simultaneous reactions:

Oxidation of carbon monoxide to carbon dioxide:

\[ 2\text{CO} + \text{O}_2 \rightarrow 2\text{CO}_2 \]

Oxidation of hydrocarbons (unburnt and partially burnt fuel) to carbon dioxide and water:

\[ \text{C}_x\text{H}_{2x+2} + [(3x+1)/2]\text{O}_2 \rightarrow x\text{CO}_2 + (x+1)\text{H}_2\text{O} \]

This 2015 report states that oxidation catalysts can reduce VOC emissions by 60–99%, as well as reduce CO emissions by 70–99%, non-methane HC by 40–90%, and formaldehyde and other hazardous air pollutants by 60–99%.\footnote{229} If a lean-burn engine is equipped with SCR for NOx control, an oxidation catalyst can be added to the SCR design.\footnote{230}

Cost information of oxidation catalyst was provided to EPA in 2010 to help determine national impacts associated with EPA’s RICE NESHAP.\footnote{231} The analysis, performed by EC/R Incorporated, was based on 2009 cost data for oxidation catalyst from industry groups, vendors, and manufacturers of RICE control.

\footnote{228}{See Manufacturers of Emission Controls Association, Emission Control Technology for Stationary Internal Combustion Engines, Revised May 2015, at page 8, Section 1.2.1, available at: \url{http://www.meca.org/resources/MECA_stationary_IC_engine_report_0515_final.pdf}.}
\footnote{229}{Id.}
\footnote{230}{Id. at 7.}
\footnote{231}{Memo from EC/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010).}
technology. EC/R Incorporated performed a linear regression analysis on the oxidation catalyst cost data set for 2-stroke lean-burn engines and for 4-stroke lean-burn engines to establish an equation for each type of engine to estimate total annual cost and total capital costs as follows:

\[
\begin{align*}
\text{2SLB Oxidation Catalyst Total Annual Cost} &= 11.4 \times \text{HP} + 13,928 \\
\text{2SLB Oxidation Catalyst Total Capital Cost} &= 47.1 \times \text{HP} + 41,603 \\
\text{4SLB Oxidation Catalyst Total Annual Cost} &= 1.81 \times \text{HP} + 3,442 \\
\text{4SLB Oxidation Catalyst Total Capital Cost} &= 1.81 \times \text{HP} + 3,442 \\
\end{align*}
\]

Where HP equals the engine size in horsepower.

EC/R Incorporated developed equations to reflect total annual costs oxidation catalyst assuming a 7% interest rate and a 10-year life for amortizing the capital costs of control and adding in the annual operation and maintenance costs. For the same reasons discussed regarding NSCR in Section II.C. above, it is reasonable to assume a 15-year life of oxidation catalyst controls at lean-burn RICE. Further, a lower interest rate of 5.5% is the appropriate interest rate to currently apply pursuant to the recommendations of EPA’s Control Cost Manual for determining annualized capital costs of oxidation catalyst. Table 17 below provides the capital costs for oxidation catalysts at various size gas-fired lean-burn RICE and the total annualized cost of the control, assuming a 5.5% interest rate and a 15-year life.

Table 17. Capital and Annual Costs of Oxidation Catalyst at Lean-Burn RICE.

<table>
<thead>
<tr>
<th>ENGINE TYPE</th>
<th>HORSEPOWER</th>
<th>TOTAL CAPITAL COSTS</th>
<th>TOTAL ANNUALIZED COSTS</th>
</tr>
</thead>
<tbody>
<tr>
<td>2SLB</td>
<td>50</td>
<td>$43,958</td>
<td>$12,619</td>
</tr>
<tr>
<td></td>
<td>75</td>
<td>$45,136</td>
<td>$12,853</td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>$46,313</td>
<td>$13,088</td>
</tr>
<tr>
<td></td>
<td>250</td>
<td>$53,378</td>
<td>$14,496</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>$65,153</td>
<td>$16,843</td>
</tr>
<tr>
<td></td>
<td>1000</td>
<td>$88,703</td>
<td>$21,536</td>
</tr>
<tr>
<td></td>
<td>1500</td>
<td>$112,253</td>
<td>$26,229</td>
</tr>
<tr>
<td>4SLB</td>
<td>50</td>
<td>$3,533</td>
<td>$3,381</td>
</tr>
<tr>
<td></td>
<td>75</td>
<td>$3,578</td>
<td>$3,425</td>
</tr>
<tr>
<td></td>
<td>100</td>
<td>$3,623</td>
<td>$3,468</td>
</tr>
<tr>
<td></td>
<td>250</td>
<td>$3,895</td>
<td>$3,727</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>$4,347</td>
<td>$4,160</td>
</tr>
<tr>
<td></td>
<td>1000</td>
<td>$5,252</td>
<td>$5,025</td>
</tr>
<tr>
<td></td>
<td>1500</td>
<td>$6,157</td>
<td>$5,890</td>
</tr>
</tbody>
</table>

\[^{232}\text{Id. at 5-6.}\]
\[^{233}\text{Id. at 5-6 and Appendix A.}\]
\[^{234}\text{Cost calculations based on EC/R equations from above, but assuming a 15-year life and a 5.5% interest rate.}\]
A 2019 report by SCAQMD indicates that 500 stationary lean-burn engines have been fitted with oxidation catalyst.\textsuperscript{235} In Colorado, sixty lean-burn RICE of sizes greater than 500 hp were required to install oxidation catalyst under the 2004 Denver Early Action Compact rulemaking.\textsuperscript{236} As of July 1, 2010, Colorado requires all existing lean-burn RICE greater than 500 hp in the state’s ozone action areas to install and operate an oxidation catalyst with an emission performance standard of 0.7 g/hp-hr.\textsuperscript{237} Colorado only exempted lean-burn engines in the Denver area from the requirement to install oxidation catalyst if the cost was greater than $5,000/ton.\textsuperscript{238} There are also several examples of oxidation catalyst being required as BACT for VOCs for lean-burn RICE. For example, in Missouri, BACT for lean-burn RICE at the Mid-Kansas Electric Company, LLC’s Rubart Station was based on good combustion practices and an oxidation catalyst with a VOC BACT limit equivalent to 0.2 g/hp-hr for loads of 50% or higher.\textsuperscript{239} In another example, BACT for RICE at the Irving Generating Station in Arizona was based on use of an oxidation catalyst with a VOC BACT limit (less formaldehyde) of 0.7 g/hp-hr.\textsuperscript{240} In the BACT analysis for the Irving Generating Station several other recent examples were presented demonstrating consistent VOC BACT limits for natural gas-fired RICE, including limits as low as 0.3 g/hp-hr.\textsuperscript{241}

In summary, oxidation catalyst is an available control technology that should be considered as a reasonable progress control option to reduce VOC emissions for lean-burn gas-fired RICE.

**VOC Controls for Rich-Burn RICE**

As discussed in Section II.C. above, NSCR is a three-way catalyst applicable to rich-burn RICE units, which not only removes NOx emissions, but also reduces CO and VOC emissions. In addition to the NSCR catalyst and housing, NSCR requires installation of an oxygen sensor and an AFRC ensure optimum air-to-fuel ratios to ensure conditions are NSCR is the primary VOC control that is implemented for rich-burn gas-fired RICE. Colorado has indicated that an “oxidation catalyst using additional air can be installed downstream of the NSCR catalyst for additional CO and VOC control.”\textsuperscript{242} The costs for NSCR have been detailed above in Section II.C. NSCR’s cost effectiveness for NOx control and its widespread required use, as shown in the state and local air agency rules detailed in Table 15 above, indicates that NSCR must be considered as a reasonable progress control option to reduce VOC emissions from rich-burn RICE.


\textsuperscript{236} See CDPHE RP for RICE at 3. See also Colorado Regulation No. 7, Part E, Section I.B., available at: \url{https://drive.google.com/file/d/16qTQLSTX1T49DfyWp3voXRNI4_g-vbhQT/view}.

\textsuperscript{237} Colorado Regulation 7 (5 CCR 1001-9) Part E 1. Control of Emissions from Engines.

\textsuperscript{238} Id. at Section I.C.4. of Part E.

\textsuperscript{239} Prevention of Significant Deterioration Air Construction Permit Application for Mid-Kansas Electric Company, LLC Rubart Station (July 2012), available at: \url{http://www.kdheks.gov/bar/midkanec/Mid-Kansas_Rubart_Station_PSD_Air_Permit_App_12_19_12.pdf}.


\textsuperscript{241} Id. Table 5-3 at 5-10. Showing sources from Texas, Oregon, Kansas, and Hawaii receiving permits between 2013 and 2016.

\textsuperscript{242} CDPHE RP for RICE at 6.
IV. CONTROL OF NOx EMISSIONS FROM NATURAL GAS-FIRED COMBUSTION TURBINES

Natural gas-fired combustion turbines are used in the oil and gas development industry generally for two purposes: (1) power generation and (2) compression. Combustion turbines are sometimes used to provide on-site power to gas processing facilities, or combustion turbines are used to drive compressors. There are several points in the oil and gas production process where compression of the natural gas is required to move the gas in the pipeline. When a combustion turbine is used for gas compression, the turbine drives the compressor, which is typically a centrifugal compressor.

Gas turbines have been used for power generation since the late 1930s and are available in sizes as low as 500 kilowatts (kW) to over 300 Megawatts (MW). Gas turbines produce a high-heat exhaust that can be recovered in a combined heat and power to produce steam to power a generator. This process is referred to as combined cycle power generation. However, in the oil and gas production industry, gas turbines are generally operated in simple cycle mode. Gas turbines can be used in remote locations such as oil and gas wellfields to provide distributed generation and portable power generation. In some cases, combustion turbines are used at power plants developed for the purpose of providing power to oil and/or gas development but which are also selling electricity to the grid. If a power generating source is constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale, then it is considered an electric utility.

Although this specific analysis of controls will focus on the gas turbines used for gas compression or used for on-site power (i.e., “distributed generation”) at oil and/or gas production and processing facilities, the available air pollution controls are the same for simple cycle turbines regardless of whether or not such turbines are part of an electric utility.

When combustion turbines are used to drive a compressor, there is no electrical generator (although there could be some heat recovery which could be used to generate electricity through a steam turbine). Instead, the turbine shaft power is used as mechanical power to drive a compressor. Regardless of the purpose of the gas-fired combustion turbines, the air pollution controls for the associated visibility-impairing pollutants are the same.

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245 Id. at 3-2.
246 40 C.F.R. § 60.331(q).
The 2012 Ozone Transport Commission Report refers to a report on costs of NOx controls at gas turbines prepared for the U.S. Department of Energy (DOE) in 1999. That DOE Report, “Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines” dated November 5, 1999 (hereinafter “1999 DOE Report”) is cited in several EPA and state documents on the cost of NOx controls at gas turbines, including in a Northeast States for Coordinated Air Use Management (NESCAUM) 2000 Status Report on NOx Controls for gas turbines and other sources, which, in turn, serves as EPA’s primary reference for the cost of SCR in its recently revised SCR chapter in its Control Cost Manual. The NESCAUM 2000 Status Report on NOx controls also has other cost information for NOx controls for gas turbines. While these reports are twenty years old, the cost analyses have been relied on extensively by EPA and states. In addition, more recent analyses of the costs of NOx controls for gas turbines have been summarized as supporting information for state and local air agency adoption of NOx emission limitations for gas turbines, but those cost analyses are generally not as detailed as the 1999 DOE report. In the discussion below of the NOx pollution control options for gas turbines, we provide information on all of these various cost analyses.

Note that in the following discussion, NOx emission rates are often referred to as parts per million or “ppm.” It should be assumed that such concentration rates are in parts per million by volume or “ppmv” measured on a dry basis and corrected to 15% oxygen unless stated otherwise.

A. WATER OR STEAM (DILUENT) INJECTION

Water or steam injection has been used for decades to reduce NOx emissions from gas turbines. EPA describes the control in its “AP-42” emission factor documentation for gas turbines as follows:

Water or steam injection is a technology that has been demonstrated to effectively suppress NOx emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Depending on the initial NOx levels, such rates of injection may reduce NOx by 60 percent or higher. Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The increased power output results from the increased mass flow required

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252 EPA relied on the cost analyses in the 1999 DOE Report for the Cross-State Air Pollution Rule. See 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-10 through 3-18.
to maintain turbine inlet temperature at manufacturer’s specifications. Both CO and VOC emissions are increased by water injection, with the level of CO and VOC increases dependent on the amount of water injection.253

The 1999 DOE Report on NOx pollution controls for gas turbines indicates that water or steam injection can achieve a NOx rate of 42 ppm.254 In a more recent document, EPA states that water or steam injection enables a gas turbine to achieve NOx levels of 25 ppm at 15% oxygen.255 General Electric also indicates that water injection can reduce NOx emissions to 25 ppm for gas-fired turbines.256 The achievable NOx rate with water or steam injection likely depends on the uncontrolled NOx rate before water or steam injection, which can vary by turbine size and manufacturer.

Water injection has been a commonly applied retrofit NOx control technology for gas turbines for several decades. Water injection is available to most turbines; however, with advances in dry low NOx combustion techniques (discussed in the next section), it is not necessarily the first NOx control of choice given the lower cost and more effective options being available, depending on the turbine type. The turbine modifications necessary to accommodate water or steam injection could range from replacement of fuel nozzles with nozzles capable of supplying both fuel and water or steam, to replacement of the combustors with combustors designed to operate with water or steam injection, depending on the make and model of the combustion turbine.257 There would also be other required equipment such as appropriate combustion turbine controls, an onsite water plant to demineralize water with storage or a storage tank for delivered demineralized water, a water injection pump, and a water or steam flow metering station.258

The 1999 DOE Report listed the capital and annual operating costs for water injection installed at specific makes/models of combustion turbines, which are reiterated in the table below.

**Table 18. Capital and Operating Costs of Water or Steam Injection for Select Combustion Turbines**259

<table>
<thead>
<tr>
<th>Turbine Make/Model</th>
<th>Size, MW</th>
<th>Size, hp</th>
<th>Capital Costs of Water/Steam Injection 1999$</th>
<th>Annual Costs (Excluding Capital Recovery), 1999$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar Centaur 50</td>
<td>4.2 MW</td>
<td>5,632 hp</td>
<td>$405,500</td>
<td>$79,000</td>
</tr>
<tr>
<td>Allison 501-KB5</td>
<td>4.0 MW</td>
<td>5,364 hp</td>
<td>$291,000</td>
<td>$100,000</td>
</tr>
<tr>
<td>GE LM2500</td>
<td>22.7 MW</td>
<td>30,441 hp</td>
<td>$1,083,175</td>
<td>$294,000</td>
</tr>
<tr>
<td>GE MS7001F</td>
<td>161 MW</td>
<td>215,904 hp</td>
<td>$4,834,770</td>
<td>$1,325,000</td>
</tr>
</tbody>
</table>

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253 EPA, Compilation of Air Pollutant Emission Factors (AP-42), Section 3.1 Gas Turbines, April 2000, at 3.1-6.
254 1999 DOE Report, Appendix A at A-5 (Table A-4).
258 Id.
259 See 1999 DOE Report, Appendix A at A-5 (Table A-4).
The 1999 DOE report determined the annualized costs of control assuming only a 15-year life of controls and a 10% interest rate. The DOE report provides no discussion as to why it assumed a 15-year life of controls, other than to state that EPA used the same 15-year life in a 1993 NOx control document. There is no documented justification for assuming a 15-year life of water or steam injection controls for a combustion turbine. Instead, it is reasonable to assume that the design life of a combustion control like water or steam injection at a gas-fired combustion turbine is equal to the design life of the combustion turbine. A literature review indicates that 25 to 30 years is the design life of a gas combustion turbine. Indeed, a review of permitted compressor stations and gas processing facilities in the state of New Mexico shows several combustion turbines operating today that were installed more than 30 years ago. For the purpose of determining the annualized cost of controls, an assumption of a 25-year life of a water or steam injection system is more than reasonable and justified. Thus, to determine annualized costs based on the capital and operational expenses for water/steam injection presented in Table 18 above, a 25-year life of controls was assumed. Further, to be consistent with EPA’s Control Cost Manual, which recommends the use of the bank prime interest rate, a lower interest rate of 5.5% was assumed. In its 2019 cost calculation spreadsheet for SCR provided with its Control Cost Manual, EPA used an interest rate of 5.5%. The annualized costs of controls are presented for the four turbine types in Table 19 below.

The 1999 DOE Report calculated cost effectiveness of water or steam injection for the four turbine models listed in Table 18 above based on achieving a NOx rate of 42 ppm. EPA relied on these cost estimates in its 2016 Technical Support Document for the Cross-State Air Pollution Rule regarding non-EGU NOx emissions controls, stating that the “generally accepted threshold” NOx emission rates that can be achieved with water injection was 42 ppmvd. In its 2016 TSD for the CSAPR rule, EPA did not escalate the costs of controls from 1999 dollars. As discussed above, lower NOx rates with water or steam injection of 25 ppm are generally achievable. Thus, in Table 19 below, the cost effectiveness of

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260 Id. at 3-1. See also EPA’s January 1993 Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (EPA-453/R-93-007) at 6-222 [hereinafter referred to as “1993 ACT for Stationary Gas Turbines”].

261 In the 1993 NOx control document, EPA also assumed a 15-year life for SCR, when now EPA assumes a 20 to 30-year life of SCR systems, depending on the application. See, EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 80.


263 See Title V air operating permits for Chaco Gas Plant, Pecos River Compressor, and Kutz Canyon Gas Plant, among others, available on the New Mexico Environment Department’s website.

264 See e.g., https://fred.stlouisfed.org/series/DPRIME.


266 Id. at A-3

267 2016 EPA CSAPR TSD for Non-EGU Emissions Controls, November 2015, Appendix A at 3-10 through 3-12.

268 Id.
water/steam injection is calculated both to comply with a 42 ppm limit and a 25 ppm limit, based on a 25-year life and a 5.5% interest rate.

Table 19. Cost Effectiveness to Reduce NOx Emissions by Water or Steam Injection for Select Combustion Turbines Operating at 91% Capacity Factor

<table>
<thead>
<tr>
<th>Turbine Make/Model</th>
<th>Size, MW</th>
<th>Annualized Costs of Water/Steam Injection 1999$</th>
<th>Cost Effectiveness of Water/Steam Injection to Meet 42 ppm NOx Rate (1999$)</th>
<th>Cost Effectiveness of Water/Steam Injection to Meet 25 ppm NOx Rate (1999$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar Centaur 50</td>
<td>4.2</td>
<td>$109,230</td>
<td>$1,496/ton</td>
<td>$1,265/ton</td>
</tr>
<tr>
<td>Allison 501-KB5</td>
<td>4.0</td>
<td>$121,694</td>
<td>$1,323/ton</td>
<td>$1,153/ton</td>
</tr>
<tr>
<td>GE LM2500</td>
<td>22.7</td>
<td>$374,750</td>
<td>$846/ton</td>
<td>$752/ton</td>
</tr>
<tr>
<td>GE MS7001F</td>
<td>161</td>
<td>$1,685,429</td>
<td>$409/ton</td>
<td>$373/ton</td>
</tr>
</tbody>
</table>

In sum, the cost effectiveness of water or steam injection at a gas-fired turbine is in the range of $1,150-$1,500/ton for the smaller turbines, $750 to $850/ton for a mid-sized turbine, and $375 to $410 for a large turbine. It must be noted that this cost effectiveness analysis is based on an assumed 8,000 hours of operation per year. A 2012 document of technical information on the oil and gas sector available on the Ozone Transport Commission’s website indicates that “on average a compressor unit will tend to experience an annual average capacity factor of approximately 40%.” This is presumably an average across all compressor engines used in the oil and gas sector, and there are very likely some compressors that do operate at 90% capacity factors. Indeed, the Ozone Transport Commission document indicates that “[f]or many mainline natural gas compressor stations, industry data indicated that the gas compressor stations have compressors in operation 24 hrs/day and 365 days/year, although not all compressors may be operating or may not be operating at high capacity.” Given that a compressor station typically is composed of multiple compressors either in parallel or in series powered either by combustion turbines or by reciprocating engines, it seems very likely that one or more of the compressors at a compressor station would operate at a high capacity factor while others would be operated at lower capacity factors, depending on the volume of gas that is being moved through the pipeline at the time. To provide a complete analysis of the range of costs of water or steam injection at a gas-fired combustion turbine, the cost effectiveness analysis of the 1999 DOE Report was revised to reflect a 40% capacity factor. Specifically, the fuel penalty cost (due to the reduction in turbine efficiency with water injection) and all costs dependent on the gallons of water used per year (i.e., the

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270 See 1999 DOE Report, Appendix A at A-5 (Table A-4). Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in Appendix A of EPA’s 1993 ACT for Stationary Gas Turbines and a 91% operating capacity factor was assumed, reflective of the assumed 8,000 hours of operation per year in the November 1999 DOE Cost Analysis report.

271 Id., Appendix A at A-5.


273 Id.
water costs, water treatment costs, associated labor costs, and water disposal costs) in the annual costs of the 1999 DOE Report were reduced by 56% to reflect the reduction in operating hours when the units operate at a 40% capacity factor compared to a 91% operating factor. Also, the tons of NOx reduced per year were revised to reflect operations at a 40% capacity factor.

Table 20. Cost Effectiveness to Reduce NOx Emissions by Water or Steam Injection for Select Combustion Turbines Operating at 40% Annual Capacity Factor

<table>
<thead>
<tr>
<th>Turbine Make/Model</th>
<th>Size, MW</th>
<th>Size, hp</th>
<th>Annualized Costs of Water/Steam Injection 1999$</th>
<th>Cost Effectiveness of Water/Steam Injection to Meet 42 ppm NOx Rate (1999$)</th>
<th>Cost Effectiveness of Water/Steam Injection to Meet 25 ppm NOx Rate (1999$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar Centaur 50</td>
<td>4.2</td>
<td>5,632</td>
<td>$85,649</td>
<td>$2,675/ton</td>
<td>$2,257/ton</td>
</tr>
<tr>
<td>Allison 501-KB5</td>
<td>4.0</td>
<td>5,364</td>
<td>$90,021</td>
<td>$2,232/ton</td>
<td>$1,940/ton</td>
</tr>
<tr>
<td>GE LM2500</td>
<td>22.7</td>
<td>30,441</td>
<td>$255,506</td>
<td>$1,316/ton</td>
<td>$1,166/ton</td>
</tr>
<tr>
<td>GE MS7001F</td>
<td>161</td>
<td>215,904</td>
<td>$1,060,507</td>
<td>$587/ton</td>
<td>$533/ton</td>
</tr>
</tbody>
</table>

EPA’s 2016 TSD for the CSAPR rule provided algorithms for estimating the total capital investment and the total annual costs of water injection based on the hourly heat input of the combustion turbine. These equations were based on a 1993 EPA Control Technique guideline as well as the 1999 DOE Report, and the total annual cost algorithms assumed a 15-year equipment life and a lower interest rate of 7%, but still high compared to today’s interest rates. The cost algorithms of EPA’s 2016 TSD for the CSAPR Rule are reprinted below.

Water Injection/Gas Turbines:

Total Capital Investment (1999 dollars) = 27665 x (MMBtu/hr)^0.69

Total Annual Costs (1999 dollars) = 3700.2 x (MMBtu/hr)^0.95

Steam Injection/Gas Turbines:

Total Capital Investment (1999 dollars) = 43092 x (MMBtu/hr)^0.82

Total Annual Costs (1999 dollars) = 7282 x (MMBtu/hr)^0.76

274 It is possible that other items in the annual costs should also be reduced to reflect a 40% capacity factor, but it was not clear how to adjust those other costs.

275 See 1999 DOE Report, Appendix A at A-5 (Table A-4). Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA’s 1993 ACT for Stationary Gas Turbines and a 40% operating capacity factor was assumed. The annual costs due to the fuel penalty, water use, water treatment, associated labor, and water disposal were decreased by 56% to reflect a 40% operating capacity factor as opposed to a 91% capacity factor.

276 See 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-11 to 12 and Appendix B at B-2.

277 Id., Appendix A at 3-12.
While the cost estimates and cost algorithms are of a cost basis that is from 1999, it is important to note that beginning in the mid- to late-1990s, EPA and several state and local air agencies have found that the costs of control to achieve NOx emission limits of 42 ppmv or even lower were cost effective to require such a level of control on existing gas turbines. This will be discussed further in Section IV.D. below. It is not possible to accurately escalate these costs in 1999 dollars to 2019 dollars. The CEPCI has been used extensively by EPA for escalating costs, but EPA states that using the indices to escalate costs over a period longer than five years can lead to inaccuracies in price estimation. Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. Moreover, as an air pollution control is required to be implemented more frequently over time, the costs of the air pollution control often decrease due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. Thus, the costs for water or steam injection are presented on a 1999 dollar cost basis in this report, but in any event, Table 29 in Section IV.D. of this report shows that numerous state and local air agencies found that water or steam injection was cost effective to require as a retrofit NOx pollution control at numerous gas turbines.

The environmental and energy impacts of the use of water or steam injection include the following:

- Requires the use of water, likely including a water treatment system, and disposal of wastewater
- Energy penalty due to decreased combustion turbine efficiency, but also increased power output
- May increase turbine maintenance requirements, depending on turbine type
- Can increase carbon monoxide and HC/VOC emissions

Water use and water availability may be a significant environmental impact for this control technology, especially for locations in the arid West that already have water shortage issues. The 1999 DOE Report included information on expected water usage of water injection at the four turbines evaluated for the cost effectiveness analysis, which can be projected into annual water use for water injection at these turbine types. The projected annual water use is provided in the table below, for both operating at a 91% capacity factor and at a 40% capacity factor. The amount of water needed for water injection is directly related to the operating capacity factor of the unit, with more water being needed for units operating at higher capacity factors.

**Table 21. Projected Water Use of Water/Steam Injection at Gas-Fired Combustion Turbines**

<table>
<thead>
<tr>
<th>Turbine Model</th>
<th>Size, MW</th>
<th>Annual Water Use at 91% Capacity Factor</th>
<th>Annual Water Use at 40% Capacity Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar Centaur 50</td>
<td>4.2</td>
<td>1,401,407</td>
<td>616,003</td>
</tr>
<tr>
<td>Allison 501-KB5</td>
<td>4.0</td>
<td>1,889,269</td>
<td>830,448</td>
</tr>
<tr>
<td>GE LM2500</td>
<td>22.7</td>
<td>7,093,130</td>
<td>3,117,859</td>
</tr>
<tr>
<td>GE MS7001F</td>
<td>161</td>
<td>95,166,555</td>
<td>41,831,453</td>
</tr>
</tbody>
</table>

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279 See, e.g., EPA’s 1993 ACT for Stationary Gas Turbines at 2-41.
281 Id.
As shown by the above table, water use with water/steam injection significantly increases with larger turbines and with units operated at higher capacity factors.

In addition to water availability, according to EPA, “[w]ater purity is essential for wet injection systems in order to prevent erosion and/or the formation of deposits in the hot sections of the gas turbine.” Water quality may be more of an issue for remote sites, especially if surface water or well water is used for the water supply. The costs for the water use, treatment, and disposal, as well as the energy penalty costs, were taken into account in the annual costs of controls used in the NOx cost effectiveness analyses presented in Tables 19 and 20 above.

Notwithstanding the high water usage, water or steam injection is a well-proven and cost effective control for NOx emissions from gas combustion turbines of all sizes. As is discussed in Section IV.D. below, NOx limits reflective of water or steam injection have been required by EPA and numerous state and local air agencies, and water or steam injection is used to control NOx at combustion turbines extensively throughout the U.S. However, for turbines constructed in the early 1990s or later, dry low NOx combustion controls were much more commonly used at gas-fired combustion turbines than water or steam injection, due to lower costs of control, improved NOx control, and the fact that there would be no need for use and treatment of water. Dry low NOx combustors are also available for retrofit for several turbine makes and models. This technology to control NOx is discussed in the next section of this report.

B. DRY LOW NOx COMBUSTION

In the late 1980s, dry low NOx burners (DLNBs) became available on larger turbines and, currently, such controls are available on all new turbines. As described by EPA, “[l]ean premixed combustion . . . pre-mixes the gaseous fuel and compressed air so that there are no local zones of high temperatures, or ‘hot spots,’ where high levels of NOx would form. Lean premixed combustion requires specially designed mixing chambers and mixture inlet zones to avoid flashback of the flame.” Many DLNBs can achieve reduced NOx rates across the full load range of a gas turbine. DLNBs are also available to retrofit to several types of combustion turbines. General Electric has dry low NOx burner retrofit

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282 Id. at 7-10.
283 Id.
284 1999 DOE Report, Appendix A at A-5 (Table A-4).
285 Dry low NOx combustors were first developed by GE in the early 1990s. See CARB, Report to Legislature, Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts, May 2004, at 19, available at: https://ww3.arb.ca.gov/research/apr/reports/l2069.pdf.
286 Id. at 2-8.
287 As discussed in Chapter 7, Controlling NOx Formation in Gas Turbines, by Brian W Doyle, September 2009, at 7-1, which is part of Chapter 10 of the EPA’s Air Pollution Training Institute Class APTI 418, available at: https://www.apti-learn.net/lms/register/display_document.aspx?dID=39.
289 As discussed in 2012 OTC Report at 62.
options for many of its turbine makes and models, and Solar Turbines has an extensive line of retrofit kits including Solar Turbines’ SoLoNOx™ technology. To retrofit such DLNBs, the turbines’ combustors must be replaced and there may be changes necessary to associated piping and turbine combustion controls.

Based on the range of NOx emission rates that have been reported as achievable with DLNBs, these combustion controls can achieve in the range of 80% to 95% control of NOx emissions. For the turbines for which DLNBs are available, NOx rates have generally ranged from 9–15 ppm. The 1999 DOE Report assumed only a 25 ppmv NOx rate would be achieved at most of the combustion turbines with DLN combustion which reflects approximately 84% NOx reduction, although the DOE report also calculated costs for a larger turbine to meet a 9 ppmv NOx rate which reflects approximately 95% NOx reduction. The 1999 DOE Report indicates that the operation and maintenance costs increase with the lower NOx rate being achieved. The ability to achieve 9 ppmv NOx rates with dry low NOx combustors is not limited to large turbines, such as the GE Frame 7FA turbine (169.9 MW) for which the 1999 DOE Report calculated costs to achieve a 9 ppm NOx rate. Solar Turbines makes several turbines that are guaranteed to achieve 9 ppmvNOx with Solar Turbines’ SoLoNOx™ burners, including the Solar Centaur 50L which is rated at 6,276 horsepower (< 5 MW). However, the ability to achieve 9 ppm NOx rates through dry low NOx combustor retrofits to existing turbines is likely more limited. Solar Turbines indicates that SoLoNOx™ retrofits are available for the Solar Taurus 70 gas turbine (11,110 horsepower). GE recently announced NOx upgrades completed at 9 GE 9E Gas Turbines (132 145 MW) at a facility in China with its DLN1.0+ with Ultra Low NOx combustors to achieve about 7.5 ppm NOx rates.

In its 2016 CSAPR TSD for Non-EGU NOx Emissions Controls, EPA relied on the cost analyses for DLNBs presented in the November 1999 DOE Report. However, EPA acknowledged that, except for the costs for a 169 MW unit, the costs reported in the 1999 DOE Report are “incremental [costs] relative to the costs of a conventional combustor.” Table 22 below reflects the cost effectiveness calculations presented in the 1999 DOE report, but with changes made to the interest rate to reflect a 5.5% interest rate consistent with the EPA’s Control Cost Manual and to change and life of the controls to the expected life of a combustion turbine of twenty-five years, as was done for the water/steam injection cost analyses. DLN combustors should be expected to last the life of a natural gas-fired combustion

290 Id. at 66.
291 Id.
292 See, e.g., 2015 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12, which indicates that 84% control can be met with DLNB achieving a NOx emission rate of 25 ppmv.
293 See 1999 DOE Report at 2-10.
294 Id. at 2-10 and at Appendix A at A-3.
295 Id. at 2-9 to 2-10.
299 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12.
300 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12. See also 1999 DOE Report at 3-3 and Appendix A at A-3.
turbine, which is at least twenty-five years as discussed above. Indeed, there are likely several examples
of gas turbines with dry low NOx combustor retrofits that have operated for twenty-five years. The
Tennessee Gas Pipeline Company’s Compressor Station in Lockport, New York has four Solar Centaur
Turbines that were retrofitted with dry low NOx combustion systems in 1995\(^{301}\) (two of which continue
to operate today, twenty-five years later, while the other two were replaced between 2012–2019 with
turbines rated at a higher horsepower).\(^{302}\)

<table>
<thead>
<tr>
<th>Turbine Make/Model</th>
<th>Size, MW</th>
<th>Size, hp</th>
<th>Annualized Costs of DLN Combustion 1999$</th>
<th>Cost Effectiveness of Dry Low NOx Combustion to meet 25 ppm NOx Rate</th>
<th>Cost Effectiveness of Dry Low NOx Combustion to Meet 9 ppm NOx Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Allison 501-KB7</td>
<td>4.9</td>
<td>6,571</td>
<td>$33,491</td>
<td>$259/ton</td>
<td></td>
</tr>
<tr>
<td>Solar Centaur 50</td>
<td>4.0</td>
<td>5,364</td>
<td>$14,164</td>
<td>$164/ton</td>
<td></td>
</tr>
<tr>
<td>Solar Centaur 60</td>
<td>5.2</td>
<td>6,973</td>
<td>$14,164</td>
<td>$128/ton</td>
<td></td>
</tr>
<tr>
<td>GE LM2500</td>
<td>22.7</td>
<td>30,441</td>
<td>$179,639</td>
<td>$360/ton</td>
<td></td>
</tr>
<tr>
<td>GE Frame 7FA</td>
<td>169.9</td>
<td>227,839</td>
<td>$455,472 (25 ppmv) $474,109 (9 ppmv)</td>
<td>$96/ton</td>
<td>$92/ton</td>
</tr>
</tbody>
</table>

In Table 23 below, the cost effectiveness of dry low NOx combustors is calculated to reflect operation at
a 40% capacity factor. Operating at a lower capacity factor should not change the operating or capital
costs of the dry low NOx combustion system, given that there is no energy penalty requiring additional
fuel use.

\(^{301}\) NESCAUM 2000 Status Report at IV-36.
\(^{302}\) See New York State Department of Environmental Conservation (NYDEC), Permit 9-2920-00008/00015, Mod 3
Effective 12/2/2014, Issued for the Tennessee Gas Pipeline Co Compressor Station 230-C, available at:
https://www.dec.ny.gov/dardata/boss/afs/permits/929200000800015_r2_3.pdf. See also NYDEC Title V
Operating Permit 9-2920-00008/00015 issued 10/23/2018 for the Tennessee Gas Pipeline Co Compressor Station
\(^{303}\) See 1999 DOE Report, Appendix A at A-3. Capital costs in 1999 dollars were updated from 1999 to 2018 dollars
based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of
0.074549 (assuming a twenty-five -year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx
emissions were calculated based on procedures outlined in outlined in Appendix A of EPA’s 1993 ACT for
Stationary Gas Turbines and a 91% operating capacity factor was assumed.
Table 23. Summary of Cost Effectiveness for DLN Combustion (1999$) at 40% Annual Capacity Factor

<table>
<thead>
<tr>
<th>Turbine Make/Model</th>
<th>Size, MW</th>
<th>Size, hp</th>
<th>Cost Effectiveness of Dry Low NOx Combustion to meet 25 ppm NOx Rate</th>
<th>Cost Effectiveness of Dry Low NOx Combustion to Meet 9 ppm NOx Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Allison 501-KB7</td>
<td>4.9</td>
<td>6,571</td>
<td>$590/ton</td>
<td></td>
</tr>
<tr>
<td>Solar Centaur 50</td>
<td>4.0</td>
<td>5,364</td>
<td>$373/ton</td>
<td></td>
</tr>
<tr>
<td>Solar Centaur 60</td>
<td>5.2</td>
<td>6,973</td>
<td>$292/ton</td>
<td></td>
</tr>
<tr>
<td>GE LM2500</td>
<td>22.7</td>
<td>30,441</td>
<td>$820/ton</td>
<td></td>
</tr>
<tr>
<td>GE Frame 7FA</td>
<td>169.9</td>
<td>227,839</td>
<td>$218/ton</td>
<td>$208/ton</td>
</tr>
</tbody>
</table>

EPA’s 2016 TSD for the CSAPR rule provided algorithms for estimating the total capital investment and the total annual costs of DLN combustion based on the hourly heat input of the combustion turbine. These equations were based on a 1993 EPA Control Technique guideline as well as the 1999 DOE Report, and the total annual cost algorithms assumed a 15-year equipment life and a lower interest rate of 7%, which is still high compared to today’s interest rates. The cost algorithms of EPA’s 2016 TSD for the CSAPR Rule for DLN combustion are reprinted below.

\[
\text{Total Capital Investment (1999 dollars) } = 2860.6 \times (\text{MMBtu/hr}) + 25427 \\
\text{Total Annual Costs (1999 dollars) } = 584.5 \times (\text{MMBtu/hr})^{0.96}
\]

In its 2000 Status Report, NESCAUM provided information on the capital and operational expenses for two dry low NOx combustor upgrades to a Solar Centaur turbine (4,700 hp) and a Solar Mars turbine (13,000 hp). Given that it appears the cost data in the 1999 DOE Report may not necessarily reflect retrofit costs (in that, with the exception of the costs for the GE Frame 7FA, the costs were identified in the 1999 DOE Report as “incremental” costs relative to the cost of a conventional combustor), the NESCAUM cost information for retrofit DLNC is also presented here. NESCAUM used a shorter useful life of controls than twenty-five years and a higher interest rate than the 5.5% interest rate used by EPA in its cost spreadsheets provided with its 2018 updates to the Control Cost Manual. NESCAUM also assumed that DLNCs could only reduce NOx to 50 ppm, whereas such combustors should be able to reduce NOx to at least 25 ppm. Thus, in Table 24 below, the cost effectiveness of the DLNC retrofit projects discussed in the NESCAUM report are revised to reflect amortized capital costs assuming a 25-year life and a 5.5% interest rate and to reflect reducing NOx to both 50 ppm and to 25 ppm.

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304 See 1999 DOE Report, Appendix A at A-3. Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a twenty-five-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA’s 1993 ACT for Stationary Gas Turbines and a 40% operating capacity factor was assumed.

305 See 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-11-12, Appendix B at B-2.

306 See id., Appendix A at 3-13.


308 Id.
Table 24. Summary of Cost Effectiveness for Retrofit DLN Combustion at 40% and 91% Annual Capacity Factors Based on Retrofit Costs Provided in 2000 NESCAUM Report

<table>
<thead>
<tr>
<th>Turbine Make/Model</th>
<th>Size, hp</th>
<th>Capacity Factor</th>
<th>Cost Effectiveness of Retrofit DLN Combustion to meet 50 ppm NOx Rate</th>
<th>Cost Effectiveness of Retrofit DLN Combustion to Meet 25 ppm NOx Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar Centaur</td>
<td>4,700</td>
<td>91%</td>
<td>$1,217/ton</td>
<td>$940/ton</td>
</tr>
<tr>
<td>Solar Centaur</td>
<td>4,700</td>
<td>40%</td>
<td>$2,769/ton</td>
<td>$2,140/ton</td>
</tr>
<tr>
<td>Solar Mars</td>
<td>13,000</td>
<td>91%</td>
<td>$359/ton</td>
<td>$296/ton</td>
</tr>
<tr>
<td>Solar Mars</td>
<td>13,000</td>
<td>40%</td>
<td>$816/ton</td>
<td>$673/ton</td>
</tr>
</tbody>
</table>

The NESCAUM 2000 Status Report notes that the capital costs reported for these two turbine types were the “total project costs the owners attributed to the project, which may include project management or other charges associated with the project beyond the equipment and installation.” Thus, the costs reflected in Table 24 may be higher than what would typically be reported for DLNC controls in a cost effectiveness analysis consistent with EPA’s Control Cost Manual, because EPA does not generally allow such owner’s costs to be considered in a cost effectiveness analysis.

In terms of non-air environmental or energy impacts with the use of DLNCs, there are relatively few impacts. There is not an energy penalty associated with the operation of the DLNCs, nor is there any waste product that requires proper disposal. However, there can be increased maintenance required with DLNCs, and those additional maintenance costs are often proprietary. In fact, the increased maintenance costs are not reflected in the cost analyses for the Solar Centaur 50 and Solar Centaur 60 turbines in Tables 22 and 23 above, due to the information being considered proprietary. A non-air quality environmental impact is that DLNBs “tend to create harmonics in the combustor that result in significant vibration and acoustic noise.”

EPA has indicated that the length of time to install DLNBs is 6–12 months.

As previously discussed, while the cost estimates and cost algorithms for DLN combustion are of a cost basis that is from 1999-2000, it is important to note that, beginning in the late-1990s, EPA and numerous several state and local air agencies have found that the costs of control to achieve NOx emission limits of 25 ppmv or even lower were cost effective to require such a level of control on existing gas turbines. This will be discussed further in Section IV.D. below.

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309 Id. at III-16. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in outlined in Appendix A of EPA’s 1993 ACT for Stationary Gas Turbines and both a 91% and a 40% operating capacity factor were assumed.
310 Id.
311 See EPA Control Cost Manual, Section 1, Chapter 2 at 9.
312 Id. at 2-9 and 3-10.
313 Id., Appendix A at A-3.
314 Id. at 2-9 and Appendix A at A-3.
315 See 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls at 18.
Given the lower costs compared to water or steam injection, along with lower operational costs and no need to have water nearby, it is clear why DLNC has been preferable to water or steam injection since such dry low NOx combustion systems have been available. However, as stated above, these DLNC systems are not available for retrofit for all gas-fired turbines and thus, for many turbines, water or steam injection would be the available combustion control. As Tables 22 through 24 show, DLNC is more cost effective than water or steam injection and can achieve lower NOx rates. Thus, low NOx combustion is a preferable combustion-related retrofit option for gas turbines, if a low NOx combustion retrofit option is available for the turbine make and model.

C. SELECTIVE CATALYTIC REDUCTION

SCR is a post-combustion NOx reduction control that is commonly applied to gas-fired combustion turbines used for power generation. SCR technology can reduce NOx emissions by 80–90% or more and, when used along with water injection or DLNC, it can achieve NOx emission rates in the range of 1.5 to 5 ppm. The 1999 DOE Report stated that SCR was the “primary post-combustion NOx control method in use” as of 1999.

An SCR system consists of a reagent injection system (typically ammonia or urea) and a catalyst. The ammonia or urea (which converts to ammonia in the flue gas) is injected into the exhaust stream and the flue gas then passes over a catalyst reduced NOx to N₂, H₂O, and CO₂. The catalyst selected depends on the temperature range of the flue gas and the size of the catalyst depends on the level of NOx reduction to be achieved. SCR technology requires a reagent injection system, including a storage tank and reagent injectors and controls to regulate the quantity of reagent, and the SCR catalyst. According to the 1999 DOE Report, the cost of conventional SCR had dropped significantly by 1999 with innovations in catalysts allowing for a significant reduction in catalyst volume with no change in NOx removal performance. Catalysts are also available for SCR to work at a variety of flue gas temperatures, from as low as 300 degrees Fahrenheit to as high as 1,100 degrees Fahrenheit. For simple cycle turbines, which are more commonly used in the oil and gas sector, the reactor chamber with the catalyst is in place directly at the turbine exhaust, which may require the use of high temperature catalyst such as zeolite. Several options for SCR catalyst exist for simple cycle turbines. For example, BASF makes several SCR catalysts that it claims can achieve up to 97% NOx reduction. The NOxCat ETZ catalyst is specifically designed for simple-cycle power generating turbines and other high temperature turbine applications. The NOxCat VNX and ZNX catalysts can achieve up to 99%

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317 1999 DOE Report at 1-5.
318 Id.
319 Id.
NOx reduction and are most effective at a temperature range of 550 to 800 degrees Fahrenheit. A related catalyst called NOxCat VNX-HT is designed for use in aeroderivative simple-cycle turbines that can achieve 99% NOx removal and can reach optimal performance at 800 to 850 degrees Fahrenheit.

Conventional SCR systems can be used with simple cycle turbines if the gas stream is cooled to the optimal temperatures for conventional SCR catalysts, through air dilution or tempering. Further, aeroderivative turbines typically have somewhat lower exhaust gas temperatures which can work better with conventional SCR systems than frame-type turbines. The optimal temperature of the flue gas to both minimize the amount of catalyst needed and ensure the highest NOx removal (> 90%) is 700 to 750 degrees Fahrenheit for conventional SCR catalysts. Conventional catalysts can achieve 80% or greater NOx removal over a wide temperature range of approximately 625 to 900 degrees Fahrenheit. SCR vendors have experience installing SCR to achieve low NOx emission rates on numerous simple cycle turbines of all types and sizes.

In its Control Cost Manual chapter on SCR, which was updated in 2019, EPA cites capital costs of SCR for simple cycle gas turbines that range from $237/kilowatt for a 2 MW gas turbine down to $50/kilowatt for a larger gas turbine, all in 1999 dollars cost basis. For these cost ranges, EPA cites to the NESCAUM 2000 Status Report. That NESCAUM report in turn relies on the 1999 DOE Report, as well as a 1991 report by the Electric Power Research Institute and some personal communications. The NESCAUM 2000 Status report provides a range of cost effectiveness data based on these reports for the application of high temperature SCR to gas turbines of varying operating capacity factors, sizes, and baseline NOx emission rates. Table 25 below presents that data for turbines with year-round high temperature SCR operation.

324 Id.
328 Id. at pdf page 20.
331 Id. at pdf page 98 (see Reference 19).
332 NESCAUM 2000 Status Report at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15).
Table 25. Cost Effectiveness for High Temperature SCR Retrofit on Simple Cycle Gas Turbines.\textsuperscript{333}

<table>
<thead>
<tr>
<th>Turbine Size, MW</th>
<th>Turbine Size, hp</th>
<th>Uncontrolled NOx, ppm</th>
<th>Controlled NOx, ppm</th>
<th>Cost Effectiveness of SCR, $/ton (2000$), at listed capacity factor</th>
<th>Capacity Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>75</td>
<td>100,590</td>
<td>154</td>
<td>15</td>
<td>$849</td>
<td>45%</td>
</tr>
<tr>
<td>75</td>
<td>100,590</td>
<td>154</td>
<td>15</td>
<td>$664</td>
<td>65%</td>
</tr>
<tr>
<td>75</td>
<td>100,590</td>
<td>42</td>
<td>7</td>
<td>$2,980</td>
<td>45%</td>
</tr>
<tr>
<td>75</td>
<td>100,590</td>
<td>42</td>
<td>7</td>
<td>$2,247</td>
<td>65%</td>
</tr>
<tr>
<td>75</td>
<td>100,590</td>
<td>15</td>
<td>3</td>
<td>$8,441</td>
<td>45%</td>
</tr>
<tr>
<td>75</td>
<td>100,590</td>
<td>15</td>
<td>3</td>
<td>$6,303</td>
<td>65%</td>
</tr>
<tr>
<td>75</td>
<td>100,590</td>
<td>15</td>
<td>3</td>
<td>$5,171</td>
<td>85%</td>
</tr>
<tr>
<td>5</td>
<td>7,000</td>
<td>142</td>
<td>15</td>
<td>$3,395</td>
<td>45%</td>
</tr>
<tr>
<td>5</td>
<td>7,000</td>
<td>142</td>
<td>15</td>
<td>$2,523</td>
<td>65%</td>
</tr>
<tr>
<td>5</td>
<td>7,000</td>
<td>42</td>
<td>5</td>
<td>$11,335</td>
<td>45%</td>
</tr>
<tr>
<td>5</td>
<td>7,000</td>
<td>42</td>
<td>5</td>
<td>$8,341</td>
<td>65%</td>
</tr>
<tr>
<td>5</td>
<td>7,000</td>
<td>42</td>
<td>5</td>
<td>$6,756</td>
<td>85%</td>
</tr>
</tbody>
</table>

The different shading in the table reflects different levels of NOx combustion controls of the existing turbine:

- Gray shading reflects the cost effectiveness of SCR applied to gas turbines with no water injection or dry low NOx combustion controls, in which case the SCR was assumed to achieve about 90% NOx reductions.
- Blue shading reflects the cost effectiveness of SCR applied to gas turbines with, presumably, water injection which can achieve 42 ppm or lower NOx emission rates, in which case the SCR was assumed to achieve about 83–88% removal.
- Green shading reflects the cost effectiveness of SCR applied to gas turbines with, presumably, low NOx combustion controls that can achieve 15 ppm NOx, in which case the SCR was assumed to achieve 80% removal.

\textsuperscript{333} Id. at III-24.
The NESCAUM cost effectiveness numbers in Table 25 above reflect a 15-year equipment life and an interest rate of 7.5%. The NESCAUM cost effectiveness numbers were also primarily based on the 1999 DOE report. However, EPA has indicated that a 25-year life is a more appropriate life of an SCR system at a gas turbine used in an industrial setting like a compressor station. Further, as stated above, EPA currently uses a 5.5% interest rate in its cost effectiveness calculations. Tables 26 and 27 below present the cost effectiveness for conventional and high-temperature SCR added to a gas-fired combustion turbine meeting an uncontrolled rate of 42 ppmv, reflective of water or steam injection, to achieve a controlled NOx rate of 9 ppmv, which reflects a 79% reduction in NOx emissions. These cost effectiveness analyses are based on the costs of the 1999 DOE Report, but with the capital cost amortized to reflect a 25-year equipment life and a 5.5% interest rate. The 1999 DOE cost analyses were based on operating 8,000 hours per year, or a 91% capacity factor. Given information previously cited that, on average, a compressor unit may operate at a 40% annual capacity factor, revisions to the cost data and emissions reduced were made to reflect a 40% capacity factor. Specifically, the electricity costs (due to the parasitic load of the SCR system) and the ammonia costs in the direct annual costs of the 1999 DOE Report were reduced by 56% to reflect the reduction in SCR operating hours when the units operate at a 40% capacity factor compared to a 91% operating factor.

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334 Id. at IV-22.
335 Id. at III-21 through III-24 (see cites to Reference 11, which is the 1999 DOE report).
336 See EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.
337 1999 DOE Report at 3-9 to 3-10, Appendix A at A-6 to A-7.
339 It is possible that other items in the direct annual costs should also be reduced to reflect a 40% capacity factor, but it was not clear how to adjust those other costs.
Table 26. Cost Effectiveness to Reduce NOx Emissions by Conventional SCR for Select Combustion Turbines with Existing Water or Steam Injection, Operating at Either a 91% or 40% Annual Capacity Factor

<table>
<thead>
<tr>
<th>Turbine Model</th>
<th>Size, MW</th>
<th>Size, hp</th>
<th>Uncontrolled NOx, ppm at 15% O2</th>
<th>Controlled NOx with SCR, ppm at 15% O2</th>
<th>Annualized Costs of SCR, 1999$</th>
<th>Cost Effectiveness of Conventional SCR at Stated Capacity Factor, 1999$</th>
<th>Capacity Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar Centaur 50</td>
<td>4.2</td>
<td>5,632</td>
<td>42</td>
<td>9</td>
<td>$135,475</td>
<td>$11,794/ton</td>
<td>40%</td>
</tr>
<tr>
<td>Solar Centaur 50</td>
<td>4.2</td>
<td>5,632</td>
<td>42</td>
<td>9</td>
<td>$143,368</td>
<td>$5,486/ton</td>
<td>91%</td>
</tr>
<tr>
<td>GE LM2500</td>
<td>22.7</td>
<td>30,441</td>
<td>42</td>
<td>9</td>
<td>$295,872</td>
<td>$6,098/ton</td>
<td>40%</td>
</tr>
<tr>
<td>GE LM2500</td>
<td>22.7</td>
<td>30,441</td>
<td>42</td>
<td>9</td>
<td>$317,134</td>
<td>$3,049/ton</td>
<td>91%</td>
</tr>
<tr>
<td>GE Frame 7FA</td>
<td>161</td>
<td>215,904</td>
<td>42</td>
<td>9</td>
<td>$1,426,883</td>
<td>$3,050/ton</td>
<td>40%</td>
</tr>
<tr>
<td>GE Frame 7FA</td>
<td>161</td>
<td>215,904</td>
<td>42</td>
<td>9</td>
<td>$1,317,285</td>
<td>$1,679/ton</td>
<td>91%</td>
</tr>
</tbody>
</table>

---

340 1999 DOE Report, Appendix A at A-6 (Table A-5). Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). To reflect a 40% capacity factor, the annual operating costs due to the fuel penalty and ammonia use were decreased by 56%, to reflect a 40% capacity factor rather than a 91% capacity factor. Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in Appendix A of EPA’s 1993 ACT for Stationary Gas Turbines.
Table 27. Cost Effectiveness to Reduce NOx Emissions by High Temperature SCR for Select Combustion Turbines with Existing Water or Steam Injection, Operating at Either a 91% or 40% Annual Capacity Factor\textsuperscript{341}

<table>
<thead>
<tr>
<th>Turbine Model</th>
<th>Size, MW</th>
<th>Size, hp</th>
<th>Uncontrolled NOx, ppm at 15% O2</th>
<th>Controlled NOx with SCR, ppm at 15% O2</th>
<th>Annualized Costs of SCR, 1999$</th>
<th>Cost Effectiveness of High Temperature SCR at Stated Capacity Factor, 1999$</th>
<th>Capacity Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar Taurus 60</td>
<td>5.2</td>
<td>6,973</td>
<td>42</td>
<td>9</td>
<td>$179,385</td>
<td>$13,238/ton</td>
<td>40%</td>
</tr>
<tr>
<td>Solar Taurus 60</td>
<td>5.2</td>
<td>6,973</td>
<td>42</td>
<td>9</td>
<td>$188,760</td>
<td>$6,123/ton</td>
<td>91%</td>
</tr>
<tr>
<td>GE LM2500</td>
<td>22.7</td>
<td>30,441</td>
<td>42</td>
<td>9</td>
<td>$324,122</td>
<td>$6,680/ton</td>
<td>40%</td>
</tr>
<tr>
<td>GE LM2500</td>
<td>22.7</td>
<td>30,441</td>
<td>42</td>
<td>9</td>
<td>$364,879</td>
<td>$3,305/ton</td>
<td>91%</td>
</tr>
<tr>
<td>GE Frame 7FA</td>
<td>161</td>
<td>215,904</td>
<td>42</td>
<td>9</td>
<td>$1,379,722</td>
<td>$3,695/ton</td>
<td>40%</td>
</tr>
<tr>
<td>GE Frame 7FA</td>
<td>161</td>
<td>215,904</td>
<td>42</td>
<td>9</td>
<td>$1,680,250</td>
<td>$1,978/ton</td>
<td>91%</td>
</tr>
</tbody>
</table>

Although the above costs reflect a 1999-2000 dollar cost basis, EPA has indicated that the costs of conventional SCR “have dropped significantly over time – catalyst innovations have been a principal driver, resulting in a 20% in catalyst volume and cost with no change in performance.”\textsuperscript{342} Moreover, high temperature SCR catalysts are not necessarily required for turbines operated in simple cycle mode, as was assumed in the NESCAUM 2000 report, because air tempering can be used to lower the cost of the exhaust gas stream, as discussed above. Thus, it is likely that costs for SCR at gas-fired turbines are lower than the cost estimates in the 1999 DOE report and the NESCAUM 2000 Status Report. Indeed, in 2015, the SCAQMD in California collected SCR cost information from vendors for 20 non-refinery, non-power plant gas turbines including turbines used in gas compression, and total installed costs ranged from $1,200,000 to $3,500,000.

\textsuperscript{341} 1999 DOE Report, Appendix A at A-7 (Table A-6). Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). The annual costs due to the fuel penalty and ammonia use were decreased by 56% to reflect a 40% capacity factor, rather than the 91% capacity factor. Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in Appendix A of EPA’s 1993 ACT for Stationary Gas Turbines.

from $1.5 million to $2.9 million with the annual costs ranging from $63,000 to $727,000. These costs reflected SCR achieving 95% control for those turbines with NOx rates of 40 ppm or higher and achieving 2 ppm for those turbines with NOx rates lower than 40 ppm. The cost basis of these costs is not identified, but presumably the costs are from the 2010-2015 timeframe. In 2019, SCAQMD ultimately determined it was cost effective to require SCR retrofits as BARCT for non-refinery, non-power plant combustion turbines. SCAQMD required gas turbines of capacities 0.3 MW and larger that power compressor stations to install retrofit NOx controls to meet a NOx limit of 3.5 ppmv at 15% oxygen and required other gas turbines, such as those used for power generation, to meet a NOx limit of 2.5 ppmv. These limits are required to be met by 2024. Other California air districts have adopted NOx limits for existing simple cycle gas turbines that reflect installation of SCR with NOx limits ranging from 2.5 to 9 ppm. While several of these air districts limits were based on SCR applied to turbines of 10 MW capacity or greater, the SJVAPCD in California adopted NOx limits in the range of 5 to 9 ppmv for gas turbines in 2007 that were based on the installation of SCR, with the higher limits for turbines with capacities between 0.3 MW and 10 MW.

The use of SCR presents several non-air quality and energy impacts, most of which are accounted for in the annual operating costs. Those impacts include the following:

- Parasitic load of operating an SCR system, which requires additional energy (fuel use and electricity) to maintain the same steam output at the boiler.
- 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. The use of regenerated catalyst can reduce the amount of spent catalyst that needs to be disposed of.

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344 Id. at 182.
347 Id.
348 These other California air districts that adopted NOx limits for gas-fired combustion turbines in the 2.5 to 9 ppm range include Sacramento AQMD, Bay Area AQMD, San Joaquin AQMD, Ventura County AQMD, and Yolo Solano AQMD. Further, it must be noted that while a 9 ppmv NOx limit can be met with ultra-low NOx combustors at some turbines, SCR may be required at other units to meet such a NOx limit.
351 Id. at pdf 18.
352 Id. at pdf 18-19.
If anhydrous ammonia is used, there would be an increased need for risk management and implementation and associated costs for receiving and storing the anhydrous ammonia. If urea or aqueous ammonia is used as the reagent, the hazards from use of pressurized anhydrous ammonia do not apply. Excess ammonia can pass through the SCR (called “ammonia slip”), which then can react with sulfate or nitrate in the ambient air to form ammonium bisulfate or ammonium nitrate (i.e., fine particulate matter). Typically, permitting authorities limit the amount of ammonia slip that may occur with SCR to limit the formation of ammonium bisulfate or ammonium nitrate.

There are typically not overarching non-air quality or energy concerns with this technology, and SCR technology is widely used at natural gas-fired combustion turbines. Most of the impacts mentioned above are considered as additional costs of using SCR and are taken into account in the SCR cost effectiveness analysis.

In terms of length of time to install SCR at gas-fired combustion turbines, a report prepared for the SCAQMD found that the typical installation time is about twenty-four months after an engineering firm begins the engineering design for the SCR, or a total of about 27–30 months. These costs should all be included in the annual operating costs.

There are numerous examples of natural gas-fired combustion turbines with SCR installed for NOx control. Just in the electric utility industry, there are at least 310 gas-fired combustion turbines operating with SCR. Clearly, SCR has been considered to be a cost effective NOx reduction technology for combustion turbines, including smaller compressor engines and those that power compressor stations, since at least 2007. Further, SCR is often combined with a combustion control like water injection or dry low NOx combustors, which optimizes the NOx emissions reductions and costs of control.

D. NOx EMISSION LIMITS THAT HAVE BEEN REQUIRED FOR EXISTING NATURAL GAS-FIRED COMBUSTION TURBINES

In 2005, EPA proposed a new NSPS for gas turbines, which was eventually promulgated at 40 C.F.R. Part 60, Subpart KKKK in 2006. In promulgating Subpart KKKK, EPA updated the NSPS for gas turbines, which had last been reviewed for EPA’s initial promulgation of NSPS for gas turbines in 1979. As a starting point for considering the level of control that EPA considered to be cost effective as a retrofit control for existing gas turbines, it is instructive to review what EPA required in the NSPS Subpart KKKK.

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353 Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. See EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.
355 See ETS, Inc., NOx RECLAIM BARCT INDEPENDENT EVALUATION OF COST ANALYSIS PERFORMED BY SCAQMD STAFF FOR BARCT IN THE NON-REFINERY SECTOR, FINAL REPORT, NOVEMBER 26, 2014, at 17.
356 Based on a search on EPA’s Air Markets Program Database, available at: https://ampd.epa.gov/ampd/.
358 44 Fed. Reg. 52,798.
for existing gas turbines that were modified on or after February 18, 2005. These standards are summarized in the table below. It is important to note that these standards were adopted for gas turbines that generate electricity or that are used for mechanical drive such as at a gas compressor station.

Table 28. NSPS Subpart KKKK NOx Control Requirements for Modifications to Existing Gas Turbines Occurring on or after February 18, 2005.\(^{359}\)

<table>
<thead>
<tr>
<th>Turbine Size/Range</th>
<th>Approximate Turbine size range, hp(^{360})</th>
<th>Subpart KKKK NOx limits for modified sources after 2/2005, ppmv</th>
<th>Control that NOx limit reflects</th>
</tr>
</thead>
<tbody>
<tr>
<td>≤50 MMBtu/hr</td>
<td>≤6,850 hp</td>
<td>150</td>
<td>Probably none</td>
</tr>
<tr>
<td>&gt;50 MMBtu/hr and ≤850 MMBtu/hr</td>
<td>&gt;6,850 hp and ≤116,456 hp</td>
<td>42</td>
<td>Water/Steam Injection</td>
</tr>
<tr>
<td>&gt;850 MMBtu/hr</td>
<td>&gt;116,456 hp</td>
<td>15</td>
<td>DLNC</td>
</tr>
</tbody>
</table>

Thus, in 2005, EPA found that the cost of water or steam injection or dry low NOx combustion was cost effective for gas-fired turbines with capacity greater than 50 MMBtu/hr (or 116,500 hp, ~86 MW). In considering reasonable progress controls for gas-fired combustion turbines in the oil and gas industry in 2020, the EPA’s NSPS NOx limits for sources modified in 2005 or later should be considered the “floor” of potential NOx controls to consider for an existing gas turbine meaning that, at the very minimum, this level of control should be considered cost effective for NOx reductions at gas turbines. However, installation of SCR, with or without water/steam injection or DLNC, would be the much more effective pollution control that should be evaluated in an analysis of controls to achieve reasonable progress, as it has been found to be a cost effective control for gas-fired combustion turbines.

Numerous states and local air agencies have adopted similar or more stringent NOx limits for existing gas turbines to meet, many of which have been in place for 10–20 years. In Table 29 below, we summarize those state and local air pollution requirements. Some of this information was initially obtained from EPA’s 2016 CSAPR TSD,\(^{361}\) which provided a summary of state NOx regulations for gas turbines and other NOx sources as of September 2014.\(^{362}\) The current state/local requirements for those CSAPR states were confirmed by a review of the state and local rules. The CSAPR TSD focused on the rules applicable in the CSAPR states. EPA found that 9 CSAPR states did not have regulations limiting NOx emissions from existing gas turbines: Alabama, Arkansas, Indiana, Kentucky, Michigan, Mississippi, Oklahoma, South Carolina, and West Virginia.\(^{363}\) We also reviewed California Air District rules, because several of those air districts have adopted the most stringent NOx emission limitations for existing gas turbines. Indeed, several air districts in California have adopted rules necessitating installation of SCR at

\(^{359}\) See 40 C.F.R. Part 60m Subpart KKKK, Appendix, Table 1.

\(^{360}\) Converted MMBtu/hr to hp based on following assumptions/conversion factors: Typical heat rate of simple cycle turbine of 9,788 Btu/kWh (per https://www.eia.gov/todayinenergy/detail.php?id=32572), and 0.7457 kW= 1 hp.

\(^{361}\) See 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix B at 11-13.

\(^{362}\) Id.

\(^{363}\) Id. at 13.
virtually all simple cycle turbines. We reviewed some of the remaining states’ regulations to determine whether there were NOx limitations for existing gas turbines. Specifically, we reviewed air regulations in New Mexico, Colorado, Utah, Montana, North Dakota, South Dakota, and Washington. It appears there are no NOx emission limits required for existing gas turbines in those states aside from what applies to modified gas turbines under the NSPS Subpart KKKK.

Table 29 is a summary of the NOx emission limits required of existing simple cycle gas-fired combustion turbines in state and local air districts across the United States. It is important to note that these are limits that, unless otherwise noted, currently apply to existing gas turbines. Unlike the NSPS standards of 40 C.F.R. Part 60, Subpart KKKK, gas turbines did not have to be modified to trigger applicability to these emission limits. Instead, these emission limits apply to existing gas turbines and generally require an air pollution control retrofit or an outright replacement of the gas turbine with a new turbine with integrated dry low NOx combustors. These state and local NOx limits were most likely adopted to address nonattainment issues with the ozone NAAQS and possibly also the PM$_{2.5}$ NAAQS. Nonetheless, what becomes clear in this analysis is that numerous states and local governments have adopted NOx regulations that require, at the very least, water or steam injection at existing gas turbines (or DLNC if available) to meet NOx limits of 42 ppmv, and several state/local air agencies have adopted NOx limits in the range of 9–25 ppmv which require dry low NOx combustors or, if unavailable as a retrofit for the turbine type, SCR. Moreover, four California air districts and Georgia have adopted NOx limits for gas turbines that clearly require SCR, probably along with water injection or DLNC, to comply with NOx limits in the range of 2–5 ppmv. The lowest NOx limits are those recently adopted by the SCAQMD which require, by January 1, 2024, gas-fired combustion turbines of 0.3 MW or greater size to meet a 2.5 ppmv limit and compressor gas turbines to meet a 3.5 ppmv limit.

These limits were adopted generally to meet RACT and California BARCT requirements, and costs of controls are considered in making these RACT and BARCT determinations. However, RACT is not necessarily as stringent as BARCT. RACT is generally defined as: “devices, systems, process modifications, or other apparatus or techniques that are reasonably available taking into account: (1) The necessity of imposing such controls in order to attain and maintain a national ambient air quality standard; (2) The social, environmental, and economic impact of such controls.” BARCT, on the other hand, is defined as “an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source.” BARCT is similar to a BACT determination under the federal PSD program, but it evaluates controls to be retrofit to existing sources, rather than applying to new or modified sources.

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364 Even some of the NOx limits in Table 29 that are higher than 42 ppmv may require water or steam injection to meet the limit.
365 40 C.F.R. § 51.100(o).
366 HSC Code § 40406 (California Code), available at: https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=40406.&lawCode=HSC.
<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Applicability (Size/Operating Hours if Given)</th>
<th>NOx Limit, ppmv at 15% Oxygen, unless otherwise stated</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CA – Sacramento Metro AQMD</strong>&lt;sup&gt;368&lt;/sup&gt;</td>
<td>Rule 413.301.3</td>
<td>&gt;0.3 MW or 3 MMBtu/hr (RACT)</td>
<td>42</td>
</tr>
<tr>
<td></td>
<td>Rule 413.302.1</td>
<td>&lt;2.9 MW or &gt;2.9 MW but &lt;877 hrs/yr (BARCT)&lt;sup&gt;369&lt;/sup&gt;)</td>
<td>42</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;877 hrs/yr &amp; 2.9-10 MW (BARCT)</td>
<td>25</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;877 hrs/yr or &gt;10 MW without SCR (BARCT)</td>
<td>15</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;877 hrs/yr or &gt;10 MW with SCR (BARCT)</td>
<td>9</td>
</tr>
<tr>
<td><strong>CA – Bay Area AQMD</strong>&lt;sup&gt;370&lt;/sup&gt;</td>
<td>Regulation 9-9-301 Effective 1/1/2010:</td>
<td>5-50 MMBtu</td>
<td>42 ppmv or 2.12 lb/MWhr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;50-150 MMBtu/hr &amp; no retrofit available</td>
<td>42 ppmv or 1.97 lb/MWhr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;5-150 MMBtu/hr &amp; Water/Steam Injection Enhancement available</td>
<td>35 ppmv or 1.64 lb/MWhr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;50 150 MMBtu/hr &amp; DLNC available</td>
<td>25 ppmv or 1.17 lb/MWhr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;150- 250 MMBtu/hr</td>
<td>15 ppmv or 0.70 lb/MWhr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;250-500 MMBtu/hr</td>
<td>9 ppmv or 0.43 lb/MWhr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;500 MMBtu/hr</td>
<td>5 ppmv or 0.15 lb/MWhr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&lt;877 hrs/yr &amp; 50-250 MMBtu/hr</td>
<td>25 ppmv or 1.97 lb/MWhr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>250-500+ MMBtu/yr</td>
<td>25 ppmv or 1.17-0.72 lb/MWhr</td>
</tr>
</tbody>
</table>

<sup>367</sup> This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to RICE units, and in case of any errors in this table.

<sup>368</sup> [http://www.airquality.org/ProgramCoordination/Documents/rule413.pdf](http://www.airquality.org/ProgramCoordination/Documents/rule413.pdf).

<sup>369</sup> Best Available Retrofit Control Technology (BARCT) was to be met by May 31, 1997.

<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Applicability (Size/Operating Hours if Given)</th>
<th>NOx Limit, ppmv at 15% Oxygen, unless otherwise stated</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA-SCAQMD</td>
<td>Rule 1134</td>
<td>&gt;0.3-2.9 MW</td>
<td>25 (reference limit) x EFF/25%</td>
</tr>
<tr>
<td></td>
<td>Effective 12/31/95:</td>
<td>2.9-10.0 MW</td>
<td>9 (reference limit) x EFF/25%</td>
</tr>
<tr>
<td></td>
<td>CA-SCAQMD</td>
<td>2.9-10.0 MW (no SCR)</td>
<td>15 (reference limit) x EFF/25%</td>
</tr>
<tr>
<td></td>
<td>By 1/1/24:</td>
<td>&gt;10.0 MW</td>
<td>9 (reference limit) x EFF/25%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;10.0 MW and no SCR</td>
<td>12 (reference limit) x EFF/25%</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;0.3 MW</td>
<td>2.5</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Compressor gas turbine</td>
<td>3.5</td>
</tr>
<tr>
<td>CA – SJVAPCD</td>
<td>Rule 4703</td>
<td>&gt;0.3 MW to &lt;3 MW</td>
<td>9</td>
</tr>
<tr>
<td></td>
<td>Tier 3 limits</td>
<td>3-10 MW pipeline gas turbine</td>
<td>8 (steady state) and 12 (non-steady state)</td>
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<tr>
<td></td>
<td></td>
<td>&gt;3-10 MW &amp; &lt;877 hrs/yr</td>
<td>9</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;10 MW &amp; &lt;200 hrs/yr</td>
<td>25</td>
</tr>
<tr>
<td></td>
<td></td>
<td>3-10 MW &amp; &gt;877 hrs/yr</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td></td>
<td>and</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;10 MW and 200-877 hrs/yr</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;10 MMW</td>
<td>3-5</td>
</tr>
<tr>
<td></td>
<td>Rule 74.23</td>
<td>0.3-2.9 MW</td>
<td>42</td>
</tr>
</tbody>
</table>

372 EFF = gas turbine efficiency, which can never be less than 25%. In other words, this multiplier allows a higher ppm limit than the reference limit if a turbine is more efficient than 25%.
374 Note that NOx limits reflective of water/steam injection, DLNC, and/or SCR have been in effect in San Joaquin Valley since 2000. Compliance with the Tier 3 limits was required between 2009-2012.
375 Tier 2 limits, that were to be complied with in 2005, require turbines greater than 10 MW and greater than 877 hours per year to meet NOx limits in the range of 3-5 ppmv. See Table 5-2 of San Joaquin AQMD Rule 4703. Tier 3 limit is 5 ppmv for turbines>10 MW but with operations between 200 hr/yr - 877 hrs/yr. See Table 5-3 of San Joaquin AQMD Rule 4703.
<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Applicability (Size/Operating Hours if Given)</th>
<th>NOx Limit, ppmv at 15% Oxygen, unless otherwise stated</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA – Ventura County APCD</td>
<td>Currently proposed revisions: By 1/1/24:</td>
<td>2.9-10.0 MW &amp; &gt;10.0 MW w/SCR &amp; &gt;10.0 MW w/o SCR &amp; &gt;4.0 MW &amp; &lt;877 hrs/yr &amp; All turbines</td>
<td>25 x EFF/25 &amp; 9 x EFF/24 &amp; 15 x EFF/25 &amp; 42 &amp; 2.5</td>
</tr>
<tr>
<td>CA – San Diego APCD</td>
<td>Rule 69.3.1</td>
<td>≥1.0 &amp; &lt;2.9 MW &amp; ≥2.9 &amp; &lt;10.0 MW &amp; ≥10.0 MW w/o installed post combustion air pollution controls &amp; ≥10.0 with installed post-combustion air pollution controls</td>
<td>42 &amp; 25 x EFF/25 &amp; 15 x EFF/25 &amp; 9 x EFF/25</td>
</tr>
<tr>
<td>CA-Yolo Solano AQMD</td>
<td>Rule 2.34</td>
<td>0.3-2.9 MW &amp; &gt;877 hrs/yr AND &gt;4 MW &amp; less than 877 hrs/yr &amp; 2.9-10 MW &amp; &gt;10.0 MW</td>
<td>42 &amp; 25 &amp; 9</td>
</tr>
<tr>
<td>CA-Imperial County APCD</td>
<td>Rule 400.1</td>
<td>&gt;1 MW &amp; &gt;400 hr/yr</td>
<td>42</td>
</tr>
<tr>
<td>CA-Mojave Desert AQMD</td>
<td>Rule 1159</td>
<td>&gt;4 MW &amp; &gt;877 hrs/yr</td>
<td>42</td>
</tr>
<tr>
<td>CA – Placer County APCD</td>
<td>Rule 250</td>
<td>&gt;0.3-2.9 MW &amp; &gt;877 hrs/yr</td>
<td>42</td>
</tr>
</tbody>
</table>

376 http://vcapcd.org/Rulebook/Reg4/RULE%2074.23.pdf
377 https://ww3.arb.ca.gov/drdb/sd/crhtml/r69-3-1.pdf
378 https://ww3.arb.ca.gov/drdb/ys/crhtml/r2-34.pdf
379 https://ww3.arb.ca.gov/drdb/imp/crhtml/r400-1.pdf
380 https://ww3.arb.ca.gov/drdb/moj/crhtml/r1159.htm
381 https://ww3.arb.ca.gov/drdb/pla/crhtml/r250.pdf
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<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Applicability (Size/Operating Hours if Given)</th>
<th>NOx Limit, ppmv at 15% Oxygen, unless otherwise stated</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA – Tehama County APCD</td>
<td>Rule 4: 37</td>
<td>&gt;0.3 MW (exempt if &lt;4 MW &amp; &lt;877 hrs/yr)</td>
<td>42</td>
</tr>
<tr>
<td>TX/Houston Galveston Brazoria Ozone NAA</td>
<td>30 TAC 117.310(a)(11)</td>
<td>Emission specs for mass emission cap and trade &gt;10.0 MW</td>
<td>0.032 lb/MBtu (9 ppmv)</td>
</tr>
<tr>
<td>TX/Dallas</td>
<td>30 TAC 117.410(a)(5)</td>
<td>Emission Specs for 8 hr ozone Demo &gt;10.0 MW</td>
<td>0.032 lb/MBtu (9 ppmv)</td>
</tr>
<tr>
<td>TX/Beaumont Port Arthur</td>
<td>30 TAC 117.105 (c)</td>
<td>RACT &gt;10.0 kW</td>
<td>42</td>
</tr>
<tr>
<td>GA (45 county area – ozone)</td>
<td>Rule 391-3-1-.02.(2) (nnn)1.(i)</td>
<td>&gt;25 MW, permitted after 4/1/00</td>
<td>30</td>
</tr>
<tr>
<td></td>
<td>Rule 391-3-1-.02.(2)(nnn)1.(iii)</td>
<td>&gt;25 MW, permitted after 4/1/00</td>
<td>6</td>
</tr>
<tr>
<td>WI (Milwaukee 7 county area)</td>
<td>NR 428.22(1)(g)</td>
<td>&gt;50 MW</td>
<td>25</td>
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</table>

385 This appears to be a new source requirement because compliance was required upon startup. [https://docs.legis.wisconsin.gov/code/admin_code/nr/400/428/IV/22](https://docs.legis.wisconsin.gov/code/admin_code/nr/400/428/IV/22).
<table>
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<tr>
<th>State/Local</th>
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<th>NOx Limit, ppmv at 15% Oxygen, unless otherwise stated</th>
</tr>
</thead>
<tbody>
<tr>
<td>NJ²⁸⁷</td>
<td>7:27-19.5(d)</td>
<td>&gt;25 MMBtu/hr (case by case exemptions allowed for limits on water supply or no commercially available DLNCs)</td>
<td>2.2 lb/MWhr</td>
</tr>
<tr>
<td></td>
<td>7:27-19.5(g)1 (Table 7)</td>
<td>HEDD Simple Cycle Gas Turbine (Power Generators) &gt;15 MW</td>
<td>1.00 lb/MWhr</td>
</tr>
<tr>
<td>DE²⁸⁸</td>
<td>Title 7, §1112.3.5 (Table 3-2)</td>
<td>Gas turbines &gt;15 MMBtu/hr</td>
<td>42</td>
</tr>
<tr>
<td>IL (Chicago area and Metro East area)²⁸⁹</td>
<td>Title 35 Part 217, §217.388a.1.E.</td>
<td>Gas turbines &gt;2.5 MW (4,694 bhp)</td>
<td>42</td>
</tr>
<tr>
<td>PA²⁹⁰</td>
<td>Ch. 129.97(g)(2)(iv)</td>
<td>Gas turbines &gt; 6,000bhp</td>
<td>42</td>
</tr>
<tr>
<td>MD (certain counties)²⁹¹</td>
<td>COMAR 26.11.09.08G(2)</td>
<td>Turbines with Capacity Factor &gt;15%</td>
<td>42</td>
</tr>
<tr>
<td>VA (northern VA)²⁹²</td>
<td>9VAC5-40-7430 (9VAC5-40-7410 requires compliance with RACT)</td>
<td>Turbines &gt;10 MMBtu/hr RACT Limit</td>
<td>42</td>
</tr>
<tr>
<td>OH (Cleveland 8 county area)²⁹³</td>
<td>3745-110-03(E)(1)</td>
<td>&gt;3.5 MW</td>
<td>42</td>
</tr>
<tr>
<td>CT²⁹⁴</td>
<td>22a-174-22e</td>
<td>Simple Cycle combustion turbines&gt;5 MMBtu/hr</td>
<td>55</td>
</tr>
</tbody>
</table>

²⁹¹ http://mdrules.elaws.us/comar/26.11.09.08.
<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Applicability (Size/Operating Hours if Given)</th>
<th>NOx Limit, ppmv at 15% Oxygen, unless otherwise stated</th>
</tr>
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<tr>
<td>MA</td>
<td>310 CMR 7.19:(7)(a)1</td>
<td>Phase I limits (2018-2023) Ozone Season</td>
<td>50</td>
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<tr>
<td>NY</td>
<td>6CRR-NY 227-2-4(e)</td>
<td>&gt;25 MMBtu/hr</td>
<td>65</td>
</tr>
<tr>
<td>LA (Baton Rouge 5 Counties &amp; Region of Influence)</td>
<td>LAC 33.03, Chapter 22, §2201.D.1 (Table D-1A)</td>
<td>≥5-10 MW</td>
<td>0.24 lb/MMBtu (65 ppmv)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>≥10 &lt;MW</td>
<td>0.16 lb/MMBtu (43 ppmv)</td>
</tr>
<tr>
<td>MO (St Louis Area)</td>
<td>10 CSR 10-5.510(3)(C)1</td>
<td>&gt;10 MMBtu/hr</td>
<td>75</td>
</tr>
<tr>
<td>NC (Charlotte 6 County Area)</td>
<td>15A NCAC 02D.1408</td>
<td>&gt;100 and ≤ 250 MMBtu/hr</td>
<td>75</td>
</tr>
</tbody>
</table>

As the above table shows, eleven state and local air pollution control agencies have adopted NOx emission limits for existing gas-fired simple cycle combustion turbines that reflect operation of SCR or possibly dry low NOx combustors (i.e., NOx emission limits in the range of 2.5 to 9 ppmv). SJVAPCD’s NOx limits for pipeline gas compressor stations of 8 ppm (steady state) and 12 ppmv (non-steady state),

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396 [https://govt.westlaw.com/nycrr/Document/l4e978e48cd1711dda432a117e6e0f345?viewType=FullText&origina
tionContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default)](https://govt.westlaw.com/nycrr/Document/l4e978e48cd1711dda432a117e6e0f345?viewType=FullText&origina
tionContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default)).
397 [https://www.dec.ny.gov/regulations/116185.html](https://www.dec.ny.gov/regulations/116185.html).
399 These are emission factors, used in setting facility emission caps.
which were adopted in 2007, also reflect application of SCR.\textsuperscript{402} The state of Georgia has stringent NOx limits for larger turbines in its 45-county ozone nonattainment area that also likely require SCR to comply with the NOx emission limits. These air agencies have thus found that the levels of NOx control listed in Table 29, including NOx limits as low as the 2.5–5 ppmv range of NOx emissions, are cost effective for existing simple cycle natural gas-fired combustion turbines.

**NOx Limits Required for New Gas Turbines Used in the Oil and Gas Sector**

Recently, there have been some examples of SCR being required in draft or final air construction permits for proposed new installations of compressor stations powered by gas-fired combustion turbines. Specifically, SCR was proposed to meet BACT requirements for the proposed Buckingham Compressor Station to be located in Virginia, with all four combustion turbines ranging from 6,276 to 15,900 hp to be subject to a NOx BACT emission limit of 3.75 ppmv at 15% oxygen.\textsuperscript{403} In addition, SCR was proposed to be installed at the Charles Compressor Station to be located in Maryland,\textsuperscript{404} the Northampton Compressor Station to be located in North Carolina,\textsuperscript{405} and the Marts Compressor Station to be located in West Virginia.\textsuperscript{406} These draft and final permits provide additional evidence of states and companies finding SCR to not be a cost prohibitive control for a compressor station.

E. SUMMARY – NOx CONTROLS FOR EXISTING NATURAL GAS-FIRED COMBUSTION TURBINES

The above analyses and state/local rule data demonstrates 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


\textsuperscript{403} See January 9, 2019 Registration No. 21599, available at: \url{https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permits.pdf}. Note that this permit was recently vacated by the Courts, see \url{https://www.cbs19news.com/story/41533113/permit-for-buckingham-county-compressor-station-vacated}.

\textsuperscript{404} See Draft Permit for Dominion Energy Cove Point – Charles Station, available at: \url{https://mde.maryland.gov/programs/Permits/AirManagementPermits/Documents/Dominion%20Charles%20Station%20Draft%20Ptc%20Conditions%20for%20Compressor%20Station%202018.pdf}. It is not clear whether the final air permit has been issued yet for this facility.

\textsuperscript{405} See Air Permit No. 10466R00, issued February 27, 2018, available at: \url{https://edocs.deq.virginia.gov/WaterResources/PDF/bf820b89-33eb-4cf9-bf89-2d6fb31b7418/Final%20Pmt%20Northampton%20Compressor%20Station%202018.pdf}.

meet NOx limits ranging from 42 ppmv down to 2.5 ppmv. Further, it is notable that, in the rules summarized above in Table 29, the primary exemptions or higher allowable NOx limits for low use turbines are those that operate at 10% or lower annual capacity factors (i.e., less than 877 hours/year), although there are several California districts with no exemptions for low capacity factor turbines. In addition, 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. 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.

As states evaluate the level of NOx control to require at gas-fired combustion turbines associated with the oil and gas industry to make reasonable progress towards the national visibility goal, costs of NOx control should not be a significant consideration in the decision of what NOx emission limits to require existing natural gas-fired combustion turbines to meet, as there are ample examples of existing gas-fired combustion turbines being required to incur similar costs of control. Indeed, 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. 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. If DLNCs are not available for retrofit to the turbine model, water or steam injection should be considered for NOx control, which should enable the combustion turbine to meet NOx limits in the range of 25 to 42 ppmv. 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.

V. CONTROL OF VOC EMISSIONS FROM NATURAL GAS-FIRED COMBUSTION TURBINES

VOC emissions from natural gas-fired combustion turbines result from incomplete combustion. The same is true for CO emissions. The combustion conditions that favor lower NOx emission rates, such as lower temperature combustion, tend to result in less complete combustion and thus higher VOC as well as CO emission rates.

Similar to RICE units, NOx is emitted at much higher rates from uncontrolled natural gas-fired combustion turbines compared to VOC emissions, with uncontrolled VOC emissions about two orders of magnitude lower than NOx emissions according to EPA’s AP-42 emission factor documentation. On the basis of pounds of VOC emission per heat input, EPA’s AP-42 emission factors indicate that natural
gas-fired combustion turbines emit VOCs at a much lower rate than natural gas-fired RICE.\textsuperscript{408} However, it must be noted that EPA’s uncontrolled VOC emission factor has an emission factor rating of “D,” which means tests are based on a generally unaccepted method and/or from a small number of facilities.\textsuperscript{409} Regardless, the same control for VOC emissions from lean-burn RICE units – oxidation catalyst – applies to control of VOC emissions from natural gas-fired combustion turbines.

According to EPA, oxidation catalyst is typically used on combustion turbines to control CO emissions as well as HAP emissions – primarily formaldehyde.\textsuperscript{410} Removal of VOCs is a co-benefit of oxidation catalyst at natural gas-fired combustion turbines. Data collected by CARB of emission test results at combustion turbines used for power generation that were equipped with oxidation catalysts, among other air pollution controls, showed VOC emission rates generally in the range of 1 to 3 ppmv at 15% oxygen.\textsuperscript{411}

It is not clear that oxidation catalyst has been widely implemented at existing natural gas-fired combustion turbines. According to documentation for EPA’s 2019 Risk and Technology Review for its Stationary Combustion Turbine NESHAP, a review of air permits for 719 turbines found 50 units using oxidation catalyst.\textsuperscript{412} That said, the data collected by CARB in 2004 indicated 31 natural gas-fired combustion turbines using oxidation catalyst.\textsuperscript{413}

In addition, oxidation catalyst has been recently proposed and required for new natural gas-fired combustion turbines used in the oil and gas industry. For example, in its permit application for the Weymouth Compressor Station to be located in Massachusetts, oxidation catalyst was proposed to be installed on a combustion turbine-driven compressor unit to reduce VOCs as well as to reduce CO and HAP to meet BACT. Oxidation catalyst has been proposed to be installed along with SCR at the proposed Buckingham Compressor Station to be located in Virginia,\textsuperscript{414} the Charles Compressor Station to be located in Maryland,\textsuperscript{415} the Northampton Compressor Station to be located in North Carolina,\textsuperscript{416} and the

\begin{footnotesize}
\begin{enumerate}
\item Compare VOC emission factors from EPA’s AP-42, Section 3.1, Tables 3.1-1 and 3.1-2 to EPA’s AP-42, Section 3.2, Tables 3.2-1, 3.2-2, and 3.2-3.
\item EPA AP-42, Introduction at 8-10.
\item EPA, AP-42, Section 3.1, at 3.1-7.
\item See CARB, Report to the Legislature, Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts, May 2004, Appendix A.
\item See January 9, 2019 Registration No. 21599, available at: https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599_Signed_Permit.pdf. Note that this permit was recently vacated by the Courts, see https://www.cbs19news.com/story/41533113/permit-for-buckingham-county-compressor-station-vacated.
\item See Draft Permit for Dominion Energy Cove Point – Charles Station, available at: https://mde.maryland.gov/programs/Permits/AirManagementPermits/Documents/Dominion%20Charles%20Station%20draft%20ptc%20conditions%20for%20compressor%20station2018.pdf. It is not clear whether the final air permit has been issued yet for this facility.
\item See Air Permit No. 10466R00, issued February 27, 2018, available at: https://edocs.deq.nc.gov/WaterResources/PDF/bf820b89-33eb-4cf9-bf89-2d6fb31b7418/Final%20Permit%20Northampton%20Compressor%20Station.pdf.
\end{enumerate}
\end{footnotesize}
Marts Compressor Station to be located in West Virginia. These draft and final permits provide evidence of states and companies finding oxidation catalyst to be a cost effective control for a combustion turbine-powered compressor stations.

In summary, oxidation catalyst is an available air pollution control to reduce VOC emissions, as well as to reduce CO and HAP emissions, from natural gas-fired combustion turbines used in the oil and gas industry. States should consider oxidation catalyst when evaluating reasonable progress controls for natural gas-fired combustion turbines used in the oil and gas industry.

VI. CONTROL OF EMISSIONS FROM DIESEL-FIRED RICE

Compression-ignited (i.e., diesel-fired) RICE units are used in oil and gas exploration, production, and transmission sectors. These types of engines 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. According to EPA’s Alternative Control Techniques Document for Stationary Diesel Engines (2010), many of the “stationary” diesel RICE (meaning engines that are not mobile) are designated for continuous power use or used in standby power applications. Company data suggests that those engines used as standby or emergency generators are generally less than 300 horsepower (hp), and diesel engines used for onsite power generation are typically greater than 300 hp although this is not a firm cutoff for standby diesel generator capacities. The size of diesel engines for drilling rigs are likely much larger. A 2014 drilling rig emission inventory prepared for the state of Texas found that the mechanical drill rig engine sizes ranged from 430 hp for vertical wells less than 7,000 feet deep to 1,094 hp for vertical wells greater than 7,000 feet deep. The study also found that, in Texas, mechanical rigs (diesel engines) were used for 96% of shallow vertical wells (< 7,000 feet) and 80% of deep vertical wells (> 7,000 feet), whereas 86% of horizontal wells are drilled by electric rigs. According to the Texas drilling rig report, the trend in new drilling rigs is mostly electric rigs especially for larger drilling rigs, meaning that diesel-fired electrical generating sets are used to power the drilling engines (rather than diesel engines driving the drilling engines). The electrical rigs typically have three large identical diesel generators, with one of the three units designated for standby use.

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419 Id.


421 Id. at 4-1.

422 Id. at 3-1.
capacity.\textsuperscript{423} The Texas inventory report indicates that the typical size of electric generators to power the electric rigs is 1,338 hp.\textsuperscript{424} This report was specific to Texas, and other states may have a different mix of size engines used for different types and depth wells. Diesel engine pumps are also used in hydraulic fracturing (“fracking”). In 2016, fracking accounted for 69 percent of all new oil and gas wells, according to the Energy and Information Administration.\textsuperscript{425} Diesel engines used to power hydraulic fracturing pumps are generally in the range of 1,000–1,500 hp, with 8 to 12 pumps necessary per well site (total of 20,000+ hp per well site).\textsuperscript{426}

A. CONTROL OPTIONS FOR DIESEL-FIRED RICE

Uncontrolled diesel RICE emit several pollutants that can contribute to regional haze, including NOx, particulate matter (PM), SO2, and VOCs. In some cases, the pollutant controls used for one pollutant can negatively or positively affect control of another pollutant. For example, combustion modifications employed to reduce NOx emissions will tend to increase PM emissions and VOC emissions, and vice versa. Controlling SO2, which is achieved by use of ultra-low sulfur diesel (ULSD) fuel, will reduce PM emissions as well. Thus, it can be important to evaluate pollution controls for diesel RICE holistically.

In its 1993 Alternative Control Techniques Document for Stationary RICE, EPA described NOx controls for diesel RICE, including combustion modifications (injection timing retard) and add-on controls (SCR), as follows:

- Ignition timing retard delays initiation of combustion to later in the power cycle, which increases the volume of the combustion chamber and reduces the residence time of the combustion products. This increased volume and reduced residence time offers the potential for reduced NOx formation. ... Achievable NOx reductions using IR is engine-specific but generally ranges from 20 to 30 percent. Based on an average uncontrolled NOx emission level for diesel engines of 12.0 g/hp-hr (875 ppmv), the expected range of controlled NOx emissions is from 8.4 to 9.6 g/hp-hr (610 to 700 ppmv).\textsuperscript{427}

- Selective catalytic reduction applies to all CI engines and can be retrofit to existing installations except where physical space constraints may exist. ... Based on an average uncontrolled NOx emission level of 12.0 g/hp-hr (875 ppmv) for diesel engines, the expected range of controlled NOx emissions is from 1.2 to 2.4 g/hp-hr (90 to 175 ppmv). ... Limited emission test data show NOx reduction efficiencies of approximately 88 to 95 percent for existing installations, with ammonia slip levels ranging from 5 to 30 ppmv.\textsuperscript{428}

\textsuperscript{423} Id.
\textsuperscript{424} Id. at 5-4.
\textsuperscript{425} \url{https://www.eia.gov/todayinenergy/detail.php?id=34732}.
\textsuperscript{426} See, e.g., Solar Turbines, Turbomachinery Considerations in Drilling and Fracturing, Gas Electric Partnership 2013, at 7-8, \url{available at: http://www.gaselectricpartnership.com/hReinerKurzTurboMachinery.pdf}.
\textsuperscript{427} EPA 1993 Alternative Control Techniques Document for RICE at 2-5 and 2-22.
\textsuperscript{428} Id.
Compression-ignition diesel-fueled engines operate lean, meaning there is excess air during combustion. And while the application of similar control techniques can differ for spark-ignition (gas-fired) and compression-ignition (diesel-fired) engines, according to EPA’s 1993 Alternative Control Techniques Document for RICE, the: (1) process; (2) application considerations; (3) performance factors; and (4) potential NOx emissions reductions for SCR applications with diesel engines are similar to those for natural gas applications.429

In its 2010 Alternative Control Techniques Document for Stationary Diesel RICE, EPA discusses combining SCR with a particulate filter to reduce both NOx and PM emissions.430 EPA describes diesel particulate filters (DPF) and catalyzed diesel particulate filters (CDPF) as follows:

[DPF and CDPF] emission control technologies are designed to remove PM from the diesel engine exhaust stream using a wall flow filter material in which the exhaust gas must pass through a ceramic wall. In addition to PM, the catalyst in the CDPF also reduces emissions of [Total Hydrocarbons (THC)] and CO. ... CARB reports PM emission reductions of 85 to 97 percent for various types of verified DPF or CDPFs. The EPA has verified DPF and CDPF systems that achieve up to 90 percent reduction. In addition to the PM reductions, the CDPF filter also reduces emissions of CO and THC by 90 percent but requires sufficient exhaust temperatures to facilitate regeneration by the catalyst. These reductions have been verified by both the CARB and EPA diesel control technology verification programs.431

CDPFs are thus a control device for PM and also for VOCs (THC) and CO.

Stationary diesel engine exhaust emissions include SO₂ due to sulfur in fuel, although a smaller percentage of the sulfur in fuel is converted to sulfates (particulate matter). At high temperatures, SO₂ can oxidize to form sulfates, contributing to further increases in PM emissions from engine exhaust. The use of ULSD fuel is essential in conjunction with exhaust treatment control technologies for reducing NOx and PM and is also, by itself, an effective and commonly applied way to reduce SO₂ emissions. Manufacturers require diesel engines equipped with CDPF to use ULSD fuel. EPA, in its 2010 Alternative Control Techniques Document for Stationary Diesel RICE, describes the use of ULSD as follows:

EPA [] finalized NSPS for stationary CI engines that require all new stationary diesel engines to use ULSD in 2010. This ULSD fuel enables the use of aftertreatment technologies for new and existing diesel engines and can also by itself reduce emissions of criteria pollutants. The use of ULSD reduces the formation of sulfur oxides and particulate sulfates from the diesel engine exhaust. The reductions in PM are expected to be approximately 5 to 30 percent depending on the sulfur content of the fuel that is replaced. ... It should be noted that ULSD is prevalent in the fuel pool today, including in some nonroad fuels that may not be labeled as such, and therefore may already be used in many stationary diesel engines.432

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431 Id. at 32 and 34.
432 Id. at 47 and 48.
In summary, while any one of these pollution controls can be used at a diesel RICE to control one pollutant, the co-benefits of using all of these controls together (ULSD, CDPF, and SCR) ensure the most effective control of NOx, PM, SO2, as well as CO and hazardous air pollutants.

B. EXISTING FEDERAL AIR REGULATIONS FOR DIESEL-FIRED RICE

The diesel engines that power and/or drive drill rigs and wellsite pumping operations may be considered to be nonroad engines (as opposed to stationary engines), if they meet the regulatory criteria to be considered a nonroad engine. 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).\(^{433}\) EPA distinguishes between nonroad diesel engines and stationary diesel engines because the Clean Air Act directs EPA to set emission standards for new nonroad engines and 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.\(^{434}\)

EPA has established emission limitations to decrease air emissions from nonroad diesel engines using a tiered approach, with the most stringent Tier 4 standards currently in effect for engine manufacturers. See 40 C.F.R. §§89.112, 1039.101, 1039.102. These are emission standards that the manufacturers must meet in their production and sale of diesel engines and for which they demonstrate compliance on a fleetwide basis. There have been four tiers of emission standards applicable to diesel RICE, with Tier 1 standards applying to engines constructed beginning in 1996-1998, Tier 2 standards applying in 2000-2004, Tier 3 standards applying in 2006-2008, and Tier 4 standards applying in approximately 2014 and beyond.\(^{435}\) The emission standards do not specify any one pollution control technology that needs to be installed to meet the emission limitations. Instead, the standards set limitations on emissions. Generally, the Tier 1, 2, and 3 emission standards were met with advanced engine design, while the Tier 4 emission standards reflect application of CDPF and SCR.\(^{436}\) These controls reduce PM and NOx emissions by over 90% from diesel RICE. In addition, the Tier 4 standards mandate that ULSD be used in Tier 4 engines.\(^{437}\) This requirement also ensures reduced SO2 emissions from diesel engines.

EPA has also established NSPS for stationary diesel engines (i.e., those diesel RICE not considered to be nonroad engines) in 40 C.F.R. Part 60, Subpart IIII. Those emission standards generally require engine manufacturers to meet the same emission standards applicable to nonroad diesel engines for the size and model year, beginning in model year 2007, for non-emergency engines of displacement below 10

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\(^{433}\) See EPA’s “Understanding the Stationary Engines Rules,” at https://www.epa.gov/stationary-engines/understanding-stationary-engines-rules. See also 40 C.F.R. §89.2.

\(^{434}\) Section 209(e)(2) of the Clean Air Act.


\(^{437}\) 40 C.F.R. §1037.501(d)(2)
liters per cylinder. Non-emergency engines of displacement higher than 10 liters per cylinder must generally meet the applicable emission standards for marine engines in 40 C.F.R. §94.8 which vary based on year of manufacturer and cylinder displacement. Emergency engines that operate in emergency situations (like standby generators) do not have to meet the Tier 4 standards and instead must meet less stringent standards.

The NSPS have separate requirements for owners or operators of stationary diesel engines that are generally not as stringent either in date of applicability or emission limits as the limits applicable to engine manufacturers. As summarized by an industry website, owners or operators of engines of pre-2007 model year must meet Tier 1 nonroad engine standards for engines less than 10 liters per cylinder and must meet Tier 1 marine standards for engines greater than or equal to 10 but less than 30 liters per cylinder. For engines of 2007 model year or later, owners or operators of engines less than 30 liters per cylinder must buy engines that are certified to meet the NSPS standards applicable to manufacturers. Owners or operators of 2007 model or later year engines greater than or equal to 30 liters per cylinder displacement must meet emission standards that vary depending on the year the engine was installed, with installations after January 1, 2016 having to meet emission limits reflective of application of DPF and SCR.

Significantly, the NSPS do not apply to owners or operators of stationary diesel RICE that have been modified or reconstructed, nor do they apply to engines that were removed from one location and reinstalled at a new location. Further, while the NSPS required by October 1, 2010 the use of ULSD fuel for those engines subject to the NSPS that are below 30 liters per cylinder displacement, engines with greater than or equal to 30 liters displacement that are subject to the NSPS are allowed to use 1,000 ppm sulfur content fuel.

EPA has also adopted a National Emission Standard for Hazardous Air Pollutants for Stationary RICE (RICE NESHAP) that requires emission limits on CO that effectively also limit hazardous air pollutants and VOCs.

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438 40 C.F.R. §60.4201. Exceptions existing for engines operated in remote areas of Alaska and in marine offshore installations. 40 C.F.R. §60.4201(f).
439 See 40 C.F.R. §60.4201.
440 See 40 C.F.R. §60.4202.
441 See https://dieselnet.com/standards/us/stationary_nsps_ci.php. See also 40 C.F.R. §60.4204(a).
442 40 C.F.R. §60.4204(b).
443 40 C.F.R. §60.4204(c).
444 40 C.F.R. §60.4208(i).
445 40 C.F.R. §60.4207.
446 40 C.F.R. Part 63, Subpart ZZZZ.
C. POLLUTION CONTROL UPGRADES OR RETROFITS FOR DIESEL-FIRED RICE

1. REPLACEMENT OF EXISTING DIESEL-FIRED RICE WITH TIER 4 ENGINES

Given that manufacturers are currently producing diesel RICE with integrated SCR and DPF to meet EPA’s Tier 4 emission standards, it is likely the more cost effective option to consider the replacement of existing engines with new Tier 4 engines rather than requiring retrofitting of pollution controls. The emission reduction benefits from replacing existing diesel RICE with Tier 4 diesel RICE can be quite significant. It is difficult to directly compare the regulatory emission standards for Tiers 1–3 to the Tier 4 emission standards because the Tier 2 and 3 emission standards for NOx were based on the total of non-methane hydrocarbons (NMHC) plus NOx. EPA’s 2010 Alternative Control Techniques Document for Stationary Diesel Engines summarized the NOx and PM emission rates for various size ranges and for the Tiers 1, 2, and 3, based on EPA’s Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling – Compression Ignition (EPA 420-P-04-009), April 2004. In the table below, we compare “Tier 0” (pre-1998) and EPA’s Tier 1, 2, and 3 emission factors to the emission standards of the Tier 4 standards promulgated by EPA for specific size engines that fall within the various size ranges of applicability for EPA’s nonroad emission standards. The table below shows the NOx and PM emission rates expected for each of the four Tiers of diesel RICE rules, as well as NOx and PM emissions from diesel RICE manufactured before the EPA emission standards applied (i.e., pre-1998 or “Tier 0”).

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447 See EPA’s Alternative Control Techniques Guideline Stationary Diesel Engines, March 5, 2010 at 58 and 61 (Tables 5-2 and 5-3).
448 See May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1, available at: https://nepis.epa.gov/Exe/ZyPDF.cgi/P10001RN.PDF?Dockey=P10001RN.PDF.
Table 30. Comparison of NOx and PM Emission Rates for Various Engine Sizes and Tier Engines.  

<table>
<thead>
<tr>
<th>ENGINE SIZE, HP</th>
<th>TIER ENGINE</th>
<th>NOX EMISSIONS, G/HP-HR</th>
<th>PM EMISSIONS, G/HP-HR</th>
</tr>
</thead>
<tbody>
<tr>
<td>75</td>
<td>0</td>
<td>6.89</td>
<td>0.72</td>
</tr>
<tr>
<td></td>
<td>1</td>
<td>5.58</td>
<td>0.47</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>4.72</td>
<td>0.24</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>3.00</td>
<td>0.30</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>3.50&lt;sup&gt;450&lt;/sup&gt;</td>
<td>0.02</td>
</tr>
<tr>
<td>174</td>
<td>0</td>
<td>8.39</td>
<td>0.40</td>
</tr>
<tr>
<td></td>
<td>1</td>
<td>5.58</td>
<td>0.25</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>4.00</td>
<td>0.13</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>2.50</td>
<td>0.15</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>0.30</td>
<td>0.01</td>
</tr>
<tr>
<td>600</td>
<td>0</td>
<td>8.39</td>
<td>0.40</td>
</tr>
<tr>
<td></td>
<td>1</td>
<td>5.58</td>
<td>0.22</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>4.10</td>
<td>0.13</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>2.50</td>
<td>0.15</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>0.30</td>
<td>0.01</td>
</tr>
<tr>
<td>750</td>
<td>0</td>
<td>8.39</td>
<td>0.40</td>
</tr>
<tr>
<td></td>
<td>1</td>
<td>5.58</td>
<td>0.22</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>4.10</td>
<td>0.13</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>2.60</td>
<td>0.15</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>2.60</td>
<td>0.075</td>
</tr>
<tr>
<td>1500 GEN SET&lt;sup&gt;451&lt;/sup&gt;</td>
<td>0</td>
<td>8.9</td>
<td>0.40</td>
</tr>
<tr>
<td></td>
<td>1</td>
<td>5.58</td>
<td>0.22</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>4.10</td>
<td>0.13</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>2.50</td>
<td>0.15</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>0.5</td>
<td>0.02</td>
</tr>
</tbody>
</table>

As shown in the above table, the Tier 4 NOx limits reflect significant NOx reductions from each prior Tier engine for some engine sizes, except the smallest engines and the non-electrical generating set engines that are greater than 750 hp in size for which there is no different between Tier 3 and Tier 4 NOx emissions. The PM emissions, on the other hand, get increasingly more stringent with each Tier engine.

To determine the cost effectiveness of replacing an existing engine with a Tier 4 engine, one needs to know the costs of a Tier 4 engine. A 2010 analysis done by CARB collected cost data from equipment manufacturers for Tier 4 compliant Generator-Set Engines (or “Gen Sets”) and determined the average cost per horsepower for a Tier 4 engine equipped with DPF and SCR.  

<sup>449</sup> 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.

<sup>450</sup> This limit applies to NMHC plus NOx. See https://nepis.epa.gov/Exe/ZyPDF.cgi/P10001RN.PDF?Dockey=P10001RN.PDF.

<sup>451</sup> Generator-set engines or “Gen Sets.” These engines are used to operate an electrical generator or an alternator to produce electric power for other applications.

for emergency standby engines, the cost data can provide a reasonable estimate of the capital costs to purchase diesel RICE meeting Tier 4 standards. This data was collected in 2010, and thus presumably reflects a 2010 $ cost basis.\textsuperscript{453} CARB provided an average cost per horsepower of Tier 4 engines installed with DPF and SCR as follows:

**Table 31. Average Cost Per Horsepower for Diesel RICE Meeting Tier 4 Final Requirements\textsuperscript{454}**

<table>
<thead>
<tr>
<th>HP RANGE</th>
<th>$/HP FOR NEW ENGINES MEETING TIER 4 FINAL STANDARDS (2010 $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>50-174</td>
<td>$250</td>
</tr>
<tr>
<td>175-749</td>
<td>$184</td>
</tr>
<tr>
<td>750-1,206</td>
<td>$160</td>
</tr>
<tr>
<td>1,207-2,000</td>
<td>$155</td>
</tr>
<tr>
<td>&gt;2,000</td>
<td>$125</td>
</tr>
</tbody>
</table>

With this average cost per horsepower data, the average cost effectiveness of replacing an older engine with a Tier 4-compliance diesel engine can be estimated. For the purpose of this cost effectiveness analysis, a 10-year useful life was assumed. The useful life for the emissions warranty guarantee period required in EPA’s nonroad diesel engine rules is only 10 years.\textsuperscript{455} While we contend that it is likely a RICE unit including such an engine with SCR installed, can have a useful life of 20 years or more, it is not as clear that the diesel particulate filter would have a life of more than 10 years.\textsuperscript{456} Thus, for the purpose of this cost effectiveness analysis, a 10 year life of the new Tier 4 engines was assumed. A 5.5% interest rate was also assumed to be consistent with EPA’s Control Cost Manual which recommends use of the bank prime interest rate.\textsuperscript{457} The bank prime rate fluctuates over time, and the highest it has been in the past 5 years is 5.5%.\textsuperscript{458} Reductions in NOx and PM emissions with the replacement of existing diesel RICE with Tier 4 engines were based on the emission factors reflected in Table 30 above. Given that the Tier 4 engines have significantly lower emissions of both NOx and PM, the total of NOx plus PM emissions reduced were considered in calculating cost effectiveness. The table below provides the cost effectiveness of replacing either a pre-1998 or a Tier 1, 2, or 3 engine with a Tier 4 engine. Calculations were done assuming that the engines operate at two different levels: 1,000 hours per year and 4,000 hours per year. EPA assumed 1,000 hours per year in cost analyses done for stationary diesel engines in its 2010 Control Techniques Document for Stationary Diesel Engines.\textsuperscript{459} However, EPA also presented information from other sources indicating the average operating hours of diesel RICE are as high as 3,790 hours per year.\textsuperscript{460} Thus, a 4,000 hour operating level was assumed to capture the upper end capacity factor of diesel RICE.

\textsuperscript{453} Id. at B-11 and B-20.
\textsuperscript{454} Id., Table B-6.
\textsuperscript{455} See 40 CFR 89.014.
\textsuperscript{457} U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.
\textsuperscript{458} See, e.g., https://fred.stlouisfed.org/series/DPRIME.
\textsuperscript{459} See EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 56.
\textsuperscript{460} Id. at 56 (Table 5-1).
Table 32. COST EFFECTIVENESS OF REPLACING EXISTING DIESEL RICE WITH TIER 4-COMPLIANT DIESEL RICE (2010$).

<table>
<thead>
<tr>
<th>ENGINE SIZE, HP</th>
<th>ANNUALIZED COST OF NEW ENGINE461</th>
<th>ENGINE REPLACED WITH TIER 4</th>
<th>COST EFFECTIVENESS OF REPLACEMENT, 1,000 OPERATING HOURS/YR, $/TON of NOx+PM REMOVED (2010$)</th>
<th>COST EFFECTIVENESS OF REPLACEMENT, 4,000 OPERATING HOURS/YR, $/TON of NOx+PM REMOVED (2010$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>75</td>
<td>$2,488</td>
<td>Tier 0</td>
<td>$6,544/TON</td>
<td>$1,636/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 1</td>
<td>$9,921/TON</td>
<td>$2,480/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 2</td>
<td>$15,517/TON</td>
<td>$3,879/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 3</td>
<td>$107,526/TON</td>
<td>$26,882/TON</td>
</tr>
<tr>
<td>174</td>
<td>$4,247</td>
<td>Tier 0</td>
<td>$2,610/TON</td>
<td>$653/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 1</td>
<td>$4,011/TON</td>
<td>$1,003/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 2</td>
<td>$5,794/TON</td>
<td>$1,448/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 3</td>
<td>$9,466/TON</td>
<td>$2,367/TON</td>
</tr>
<tr>
<td>600</td>
<td>$14,647</td>
<td>Tier 0</td>
<td>$2,610/TON</td>
<td>$653/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 1</td>
<td>$4,034/TON</td>
<td>$1,009/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 2</td>
<td>$5,646/TON</td>
<td>$1,412/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 3</td>
<td>$9,466/TON</td>
<td>$2,367/TON</td>
</tr>
<tr>
<td>750</td>
<td>$15,920</td>
<td>Tier 0</td>
<td>$3,147/TON</td>
<td>$787/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 1</td>
<td>$6,164/TON</td>
<td>$1,541/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 2</td>
<td>$12,368/TON</td>
<td>$3,092/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 3</td>
<td>$256,280/TON</td>
<td>$64,070/TON</td>
</tr>
<tr>
<td>1500 GEN SETS462</td>
<td>$30,845</td>
<td>Tier 0</td>
<td>$2,255/TON</td>
<td>$564/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 1</td>
<td>$3,534/TON</td>
<td>$883/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 2</td>
<td>$5,026/TON</td>
<td>$1,256/TON</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tier 3</td>
<td>$8,760/TON</td>
<td>$2,190/TON</td>
</tr>
</tbody>
</table>

Because the NOx emission rates of the various Tier 1–4 standards did not always decrease to the same extent for the smallest and the mid-size to large (non-Gen Set) engines, the cost effectiveness of replacing an existing engine with a Tier 4 engine of 75 hp and of 750 hp increases significantly between installing a Tier 4 engine to replace a Tier 0, 1, or 2 engine as compared to a Tier 3 engine. Also, as would be expected, it is generally more cost effective to replace an engine that operates 4,000 hours per year compared to one that operates 1,000 hours per year. In any event, as Table 32 demonstrates, it should at least be considered cost effective to replace a Tier 0 or Tier 1 engine with a Tier 4 engine of any size or operating hours. For engines in the range of 174 hp to less than 750 hp that operate 4,000 hours or more per year, it is also clearly cost effective to replace any tier engine with a Tier 4 engine, as it also is cost effective for large generator set engines.

461 Based on the costs per horsepower given in Table 31 above and a capital recovery factor based on a 10-year life and a 5.5% interest rate of 0.132668.

462 Generator sets > 1,200 hp have more stringent Tier 4 emission standards than other engines that are greater than 750 hp. See May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1.
Although the above review focused on the cost effectiveness for the combined reductions of NOx plus PM, it is important to note that the EPA nonroad engine requirements also set emission limits on THC. Specifically, the Tier 4 standards set a THC emission limit that reflects an 87% reduction in THC compared to pre-1998 (Tier 0 levels). Further, only ULSD is to be used on Tier 4 engines. That is not only a legal requirement but, as discussed above, it is technically required by the manufacturer to ensure that the CDPF works effectively. The use of ULSD which is 15 ppm sulfur, compared to diesel fuel which may be 500 ppm sulfur, reflects a 97% reduction in SO2 emissions from diesel RICE. The increased costs for using ULSD are estimated to be $0.07 more per gallon, but the costs would be reduced to $0.04 per gallon due to anticipated savings because of decreased RICE maintenance with the use of low sulfur fuel. 463 Some states may already mandate the use of ULSD or it could be that ULSD is the only fuel available in some areas, so installation of a Tier 4 engine may not necessarily reduce SO2 emissions for all sources.

In terms of the non-air quality environmental and energy impacts associated with the replacement of an older engine with a Tier 4 engine, the impacts associated with the pollution controls could include increased fuel consumption due to reduced efficiency/parasitic load of SCR and CDPF and/or result in reduced power output. However, improvements in combustion efficiency that have been required and engineered into these newer engines also mean fuel savings that will make up for any parasitic loads, particularly for Tier 0 or Tier 1 engines replaced with Tier 4 engines. Other environmental impacts include solid waste disposal issues from spent catalysts. Further, the Tier 4 engines will require operator training and may result in increased maintenance, although the switch from higher sulfur diesel to ULSD which is mandated for use in Tier 4 engines will result in decreased maintenance. One likely benefit regarding maintenance associated with these controls when purchasing an engine with the NOx and PM controls built into the design as one package (as compared to retrofitting an existing engine) is that the manufacturers will have a standard set of operating and maintenance procedures for each engine, whereas for a retrofit of SCR and/or CDPF to an existing diesel RICE, the operating and maintenance procedures will presumably need to be tailored to the specific make, model, and condition of the existing engine.

There are also other environmental benefits of replacing existing diesel engines with Tier 4 engines, particularly due to effects that increased engine efficiency and the use of a CDPF will have on reducing black carbon emissions from diesel RICE. Black carbon is very effective at absorbing solar energy. The black carbon particles in the atmosphere absorb solar energy and thus can warm the planet, although black carbon is considered a short-lived climate change pollutant. 464 And when the black carbon particles precipitate to surfaces of snow and ice, it reduces the reflecting power of the snow or ice which results in increased melting of snow and ice. The increased melting of the snow and ice results in a feedback loop with more land exposed to absorb, rather than reflect, solar energy, melting more snow and ice as well as permafrost that releases carbon trapped in the soils which further adds to climate change pollution. 465 Thus, the reduction in black carbon emissions by switching older diesel RICE with Tier 4 engines could have climate change benefits as well as visibility benefits.

465 Id. See also https://scied.ucar.edu/shortcontent/melting-ice-and-climate-change.
Given that manufactures were required to exclusively produce Tier 4 nonroad diesel engines by January 1, 2015, the Tier 4 engines should be readily available for purchase and installation, or be available in fairly short order. Thus, the replacement of an existing diesel RICE with a Tier 4 diesel RICE should presumably be able to be completed within six months to one year.

When EPA adopted the nonroad diesel engine emission standards, EPA envisioned that the nonroad diesel engine fleet would be comprised entirely of Tier 4 engines by 2030. It is not clear whether the diesel RICE used in the oil and gas industry are on track to be operating on Tier 4 engines by 2030. As part of the process of evaluating controls to achieve reasonable progress towards the national visibility goal, States should evaluate the age and EPA emission compliance status (i.e., Tier) of existing diesel RICE operating within the oil and gas industry in the state. If states do not already collect such information, states should gather this information through required source inventory and/or source registration or licensure requirements.

It is clear that requiring replacement of existing diesel RICE with Tier 4 RICE engines is a cost effective control to reduce NOx and PM along with VOCs and SO2 for many size engines in a range of operating hours. Requiring the replacement of existing diesel RICE with new Tier 4 engines along with requiring the use of ULSD fuel is the most readily implementable approach to reducing visibility-impairing emissions from diesel RICE.

It would be most effective to require use of Tier 4-compliant generator sets in conjunction with electric motors for all drilling operations, because large Gen Sets (which would be necessary to power electric drill rigs) are subject to much more stringent NOx limits than large diesel RICE (i.e., 0.5 g/hp-hr is the NOx limit for Tier 4 engines, compared to the 2.60 g/hp-hr NOx limit for large diesel RICE, as shown in Table 30 above). Indeed, the Superintendent of Carlsbad National Park has requested this approach as a mitigation measure for the Chevron U.S.A. Hayhurst Master Development Plan for which the western boundary of the project area was to be located only 17 kilometers from Carlsbad National Park in New Mexico. Specifically, the National Park Service stated that “[i]f this option were implemented, engines would meet the 0.5 g NOx/hp-hr [limit] and would reduce drilling and completion emissions by 90%.”

In summary, for stationary diesel RICE units, states should require the replacement of older existing engines with Tier 4 engines. For those diesel RICE that are considered nonroad engines, states should consider adopting emission requirements for diesel nonroad engines if California has adopted emission standards that have been approved by EPA under Section 209(e)(2) of the Clean Air Act, where the state adopts the same standards. Alternatively, a state can incentivize the replacement of existing nonroad engines with Tier 4 engines. Further, the state should otherwise encourage use of electric engines for drill rigs and the use of Tier 4 Gen Sets to power those electric engines, as that will result in the greatest reduction in NOx due to the lower emission limits that apply to Tier 4 Generator Set engines. States should evaluate all available options to, at the minimum, encourage replacement of older existing nonroad engines with Tier 4 engines.

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2. REPLACEMENT OF EXISTING DIESEL-FIRED RICE WITH NATURAL GAS-FIRED RICE

A second option for reducing emissions from diesel RICE is to replace the engines with natural gas-fired or dual-fuel RICE. This was another mitigation measure recommended by the National Park Service to the Bureau of Land Management for the Chevron U.S.A. Hayhurst Master Development Plan. Specifically, the National Park Service stated: “[b]oth natural gas-fired and dual-fuel engines have proven to be feasible, cost effective options for drilling operations in various basins throughout the United States and Canada [fn omitted].”

The National Park Service gave numerous examples of companies employing natural gas-fired or dual-fuel drill rig engines, including “EQT, Apache Corporation, Chesapeake Energy, Statoil, Encana Corporation, Cabot Oil and Gas, Antero Resources, CONSOL Energy and Seneca Resources.” The National Park Service specifically highlighted Chesapeake Energy’s move to “transition all of its hydraulic fracturing equipment to [liquefied natural gas].”

The Four Corners Air Quality Task Force (4CAQTF) also evaluated this option of using natural gas-fired engines on the drill rigs in the Four Corners region. The 4CAQTF found that this switch from diesel RICE to lean burn RICE engines 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, but this was based on an assumed NOx emission rate from lean burn natural gas-fired RICE of 2 to 3 g/hp-hr.

As discussed in Section II.D. and E. of this report, use of LEC or SCR at lean burn engines is cost effective for lean-burn RICE and could achieve NOx emission rates of no higher than 2 g/hp-hr and more likely 1 g/hp-hr or even lower. Use of natural gas-fired RICE instead of diesel RICE would also significantly reduce SO₂ and PM emissions. The 4CAQTF report found that use of natural gas-fired RICE may be less expensive than diesel RICE if natural gas is located within close proximity and able to be piped to the natural gas-fired RICE.

Diesel fuel generally needs to be hauled to the drill rig, thus replacement of diesel RICE with natural gas-fired RICE would also reduce mobile source tailpipe and fugitive emissions associated with transporting the diesel fuel. The 4CAQTF report gave one example of a natural gas-fired drill rig being utilized in the Jonah Field in Wyoming to indicate that the use of natural gas-fired drill rigs is a technically feasible option, which is clearly the case given the number of companies cited by the National Park Service that are employing natural gas-fired or dual-fuel drill rig engines. The 4CAQTF indicated a capital cost of up to $1.2 million dollars per rig for the retrofit. Some of the negative impacts included that the use of natural gas-fired RICE would increase carbon monoxide emissions by

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468 Id. at 7.
469 Id.
470 Id.
472 Id.
473 Id.
474 Id. at 62.
476 Id.
approximately 175%, and also that there could be increased land disturbance regarding the installation of natural gas pipelines for delivery of fuel.\footnote{Id. at 61-62.}

In summary, replacement of diesel RICE with natural gas-fired RICE is a viable control option for addressing the visibility-impairing emissions from diesel RICE that states should consider in evaluating reasonable progress measures for diesel RICE units.

3. RETROFIT OF DIESEL-FIRED RICE WITH AIR POLLUTION CONTROLS

Another option to control emissions from stationary diesel RICE is to require retrofits of specific pollution controls. Provided below are cost effectiveness analyses for SCR retrofits and for DPF retrofits to diesel RICE.

\textit{a) RETROFITTING SCR TO EXISTING DIESEL-FIRED RICE TO REDUCE NOx}

EPA’s 2010 Alternative Control Techniques Document for Stationary Diesel RICE presented control costs for SCR and for CDPF retrofits at diesel RICE units. For SCR, EPA estimated capital costs at $98 per hp, based on industry data, and this included costs for the catalyst, reactor housing and ductwork, ammonia injection system, controls, and engineering and installation of the equipment.\footnote{EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 57.} EPA estimated annualized costs for SCR at $40 per hp, based on annualized capital costs and costs for operating/supervisory labor, maintenance, ammonia, steam diluent, and fuel penalty calculated using the EPA Control Cost Manual and based on 1,000 hours of operation per year.\footnote{Id.}

EPA’s cost data for the 2010 Alternative Control Techniques document for Stationary Diesel RICE assume 90 percent reduction of NOx emissions from SCR, which should be readily achievable.\footnote{Id.} EPA estimates uncontrolled NOx emissions based on emission factors from modeling for the different tiers of EPA’s exhaust emission standards for nonroad engines: (1) Tier 0 Standards (pre-1998); (2) Tier 1 Standards (1998-2003); (3) Tier 2 Standards (2004-2007); and Tier 3 Standards (2006-2010). As discussed above, the Tier 4 standards reflect the NOx control levels achievable with SCR, and thus it would not make sense for EPA to evaluate SCR retrofits for a Tier 4 engine.

The following table shows the cost effectiveness, based on EPA’s cost data, of retrofitting SCR to an uncontrolled stationary diesel RICE and to a Tier 1, 2, or 3 diesel RICE operating 1,000 hours per year and 4,000 hours per year using EPA uncontrolled NO\textsubscript{x} emissions estimates. EPA assumed 1,000 hours per year in cost analyses done for stationary diesel engines in its 2010 Control Techniques Document for Stationary Diesel Engines.\footnote{See EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 56.} However, EPA also presented information from other sources indicating the average operating hours of diesel RICE as high as 3,790 hours per year.\footnote{Id. at 56 (Table 5-1).} Thus, a 4,000 hour operating level was assumed to capture the upper end capacity factor of diesel RICE. To estimate operating costs for operating at 4,000 hours per year, EPA’s annual cost estimates for an engine
operating 1,000 hours per year were multiplied by a factor of four to estimate potential annual costs reflective of engines operating closer to 4,000 hours per year. For the cost effectiveness analysis presented herein, the SCR system was assumed to have a life of 20 years. EPA states that SCRs at boilers, refineries, industrial boilers, etc. have a useful life of 20-30 years.\textsuperscript{483} To be consistent with EPA’s statements on SCR and also considering the useful life of diesel RICE, this analysis will assume a 20-year life of the SCR. A 5.5% interest rate was used to be consistent with EPA’s Control Cost Manual which recommends use of the bank prime interest rate.\textsuperscript{484}

Table 33. Cost Effectiveness to Reduce NOx Emissions by 90% from Stationary Diesel RICE with SCR Operating 1,000 Hours per Year and 4,000 Hours per Year\textsuperscript{485}

<table>
<thead>
<tr>
<th>ENGINE SIZE, hp</th>
<th>ANNUALIZED COSTS OF SCR, 2005$</th>
<th>EMISSIONS STANDARD</th>
<th>COST EFFECTIVENESS OF SCR, 1,000 HOURS PER YEAR, 2005$</th>
<th>COST EFFECTIVENESS OF SCR, 4,000 HOURS PER YEAR, 2005$</th>
</tr>
</thead>
<tbody>
<tr>
<td>75</td>
<td>$2,808</td>
<td>TIER 0</td>
<td>$5,474/ton</td>
<td>$4,575/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 1</td>
<td>$6,739/ton</td>
<td>$5,632/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 2</td>
<td>$8,021/ton</td>
<td>$6,703/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 3</td>
<td>$12,581/ton</td>
<td>$10,514/ton</td>
</tr>
<tr>
<td>238</td>
<td>$8,911</td>
<td>TIER 0</td>
<td>$4,500/ton</td>
<td>$3,761/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 1</td>
<td>$6,781/ton</td>
<td>$5,667/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 2</td>
<td>$9,430/ton</td>
<td>$7,881/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 3</td>
<td>$15,093/ton</td>
<td>$12,614/ton</td>
</tr>
<tr>
<td>675</td>
<td>$25,272</td>
<td>TIER 0</td>
<td>$4,500/ton</td>
<td>$3,761/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 1</td>
<td>$6,485/ton</td>
<td>$5,420/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 2</td>
<td>$9,207/ton</td>
<td>$7,694/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 3</td>
<td>$15,097/ton</td>
<td>$12,617/ton</td>
</tr>
<tr>
<td>1,000</td>
<td>$37,441</td>
<td>TIER 0</td>
<td>$4,497/ton</td>
<td>$3,759/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 1</td>
<td>$6,500/ton</td>
<td>$5,432/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 2</td>
<td>$9,204/ton</td>
<td>$7,692/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 3</td>
<td>$15,073/ton</td>
<td>$12,597/ton</td>
</tr>
</tbody>
</table>

\textsuperscript{483} See EPA’s Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80.
\textsuperscript{484} U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.
\textsuperscript{485} See EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 58, Table 5-2. Annualized costs of control were based on a 20-year life and a 5.5% interest rate. NOx emission reductions are based on 90% NOx removal efficiency, with uncontrolled emissions based on EPA estimates (EPA-420/P-04-09, 2004).
Lower cost data were reported by EPA in its 2000 Updated Information on NOx Emissions and Control Techniques for what it referred to then as ‘modern SCR’: “The vendor carried out a similar analysis for a 1,000 bhp diesel engine. For an engine operating 200 hours per year, the cost effectiveness was calculated at almost $4,000 per ton. For an engine operating 2,000 hours per year, the cost effectiveness dropped to less than $900 per ton.”

In its 1993 Alternative Control Techniques Document for RICE, EPA included a cost effectiveness analysis for diesel-fueled RICE with SCR operating 8,000 hours per year with costs as low as $690/ton for the largest engine sizes (4,000-8,000 hp). EPA noted costs of $1,000/ton or less for engines larger than 3,200 hp and costs of $3,000/ton or less for engines larger than 750 hp.

It is clearly cost effective to retrofit SCR to diesel RICE units that emit NOx at levels similar to the older tier nonroad engines (e.g., Tiers 0 or 1) even at low levels of operating hours per year. And, diesel RICE used in the oil and gas industry have been retrofitted with SCR to reduce NOx. For example, the state of Wyoming and the Bureau of Land Management coordinated with companies drilling in the Pinedale Anticline in western Wyoming to reduce NOx emissions from all drill rigs and, as a result, Shell Exploration and Production Company retrofitted 21 drill rigs with SCRs that have achieved 91-99% reduction in NOx emissions with low levels of ammonia slip (averaging 2-3 ppm). There are several examples of successful SCR retrofits to diesel RICE, including for stationary diesel electrical generating sets and backup generators.

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487 See EPA’s 1993 Alternative Control Techniques Document for RICE at 2-38 and Table 2-14 at 2-42.


489 See Manufacturers of Emission Controls Association, Case Studies of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 14, 5-7 and 12.
The environmental and energy impacts of SCR systems for diesel RICE include the following:

- 0.5 percent increase in fuel consumption for SCR and associated air emissions increases
- 1 to 2 percent reduction in power output for SCR
- Increased solid waste disposal from spent catalysts
- If ammonia is used instead of urea (which is assumed to be the reagent used in the SCR cost analyses presented above), there would be an increased need for risk management and implementation and associated costs. If urea or aqueous ammonia is used as the reagent, the hazards from the use of pressurized anhydrous ammonia do not apply. It is likely that urea is the most common reagent used in SCR for diesel RICE.

SCR technology is widely used at many industrial sources. 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.

In terms of length of time to install SCR, EPA has estimated that it takes 28-58 weeks to install SCR at a diesel-fired (lean-burn) RICE unit.

b) RETROFITTING CDPF TO DIESEL-FIRED RICE TO REDUCE PM AND VOCS

For CDPF, EPA estimated capital and annual costs in its 2010 Alternative Control Techniques Document for Stationary Diesel RICE based on cost equations developed for the RICE NESHAP. EPA’s analysis was based on 2008 cost data from stationary diesel RICE retrofits. The following linear equation for annual cost includes annual operating and maintenance costs plus annualized capital costs based on a 7% interest rate and 10-year life of controls:

\[
\text{CDPF Annual Cost} = 11.6 \times \text{ENGINE HP} + 1,414 \ (2008\$)
\]

The capital cost equation for retrofitting a CDPF on a diesel engine was determined by EPA to be:

\[
\text{CDPF Capital Cost} = 63.4 \times \text{ENGINE HP} + 5,699 \ (2008\$)
\]

These relationships are derived from a data set that includes engines ranging from 40–1,400 hp. EPA’s cost estimates are based on 1,000 hours of operation per year.

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490 See EPA 1993 Alternative Control Techniques Document for RICE, 2-23 (Table 2-11).
491 Id. at 2-23 (Table 2-11).
493 Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. See EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.
494 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls at 15.
EPA’s cost data for the 2010 Alternative Control Techniques document for Stationary Diesel RICE assume 90 percent reduction of PM emissions from CDPF. EPA estimates uncontrolled PM emissions based on emission factors from nonroad engine modeling for the different tiers of EPA’s exhaust emission standards for nonroad engines: (1) Tier 0 Standards (pre-1998); (2) Tier 1 Standards (1998-2003); (3) Tier 2 Standards (2004-2007); and Tier 3 Standards (2006-2010). In 2004, EPA adopted Tier 4 Standards, which were to be phased-in from 2008 to 2015. The Tier 4 Standards require 90 percent reduction of PM and NOx emissions. According to EPA, “[t]hese emission reductions can be achieved through the use of control technologies, including advanced exhaust gas aftertreatment, similar to those required by the 2007-2010 standards for highway engines.”

The following table shows the results of a cost analysis, based on EPA’s cost data, of retrofitting CDPF to an uncontrolled stationary diesel RICE operating 1,000 hours per year and 4,000 hours per year using EPA uncontrolled PM emissions estimates. For this cost analysis of CDPF, a 10-year life and 5.5% interest rate. As discussed above, while we contend that it is likely a RICE unit can have a useful life of 20 years, it is not as clear that the diesel particulate filter would have a life of more than 10 years. Therefore, a useful life of a CDPF retrofit was assumed to be 10 years in determining annualized costs of CDPF. A 5.5% interest rate was also assumed to be consistent with EPA’s Control Cost Manual which recommends use of the bank prime interest rate. To estimate annual operating costs for operation of CDPF at 4,000 hours per year, EPA’s annual cost estimates which were based on 1,000 operating hours per year were multiplied by a factor of four.

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497 Id.


<table>
<thead>
<tr>
<th>ENGINE SIZE, hp</th>
<th>ANNUALIZED COSTS OF CDPF, 2008$</th>
<th>EMISSIONS STANDARD</th>
<th>COST EFFECTIVENESS OF CDPF, 1,000 HOURS PER YEAR, 2008$</th>
<th>COST EFFECTIVENESS OF CDPF, 4,000 HOURS PER YEAR, 2008$</th>
</tr>
</thead>
<tbody>
<tr>
<td>75</td>
<td>$1,670</td>
<td>TIER 0</td>
<td>$31,088/ton</td>
<td>$10,155/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 1</td>
<td>$47,467/ton</td>
<td>$15,505/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 2</td>
<td>$93,735/ton</td>
<td>$30,619/ton</td>
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<td></td>
<td>TIER 3</td>
<td>$74,837/ton</td>
<td>$24,445/ton</td>
</tr>
<tr>
<td>238</td>
<td>$2,955</td>
<td>TIER 0</td>
<td>$31,265/ton</td>
<td>$10,510/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 1</td>
<td>$49,665/ton</td>
<td>$16,696/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 2</td>
<td>$95,155/ton</td>
<td>$31,988/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 3</td>
<td>$83,321/ton</td>
<td>$28,010/ton</td>
</tr>
<tr>
<td>675</td>
<td>$6,397</td>
<td>TIER 0</td>
<td>$23,774/ton</td>
<td>$8,150/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 1</td>
<td>$43,343/ton</td>
<td>$14,860/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 2</td>
<td>$72,608/ton</td>
<td>$24,892/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 3</td>
<td>$63,467/ton</td>
<td>$21,759/ton</td>
</tr>
<tr>
<td>1,000</td>
<td>$8,958</td>
<td>TIER 0</td>
<td>$22,468/ton</td>
<td>$7,740/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 1</td>
<td>$40,960/ton</td>
<td>$14,110/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 2</td>
<td>$68,644/ton</td>
<td>$23,646/ton</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TIER 3</td>
<td>$59,960/ton</td>
<td>$20,654/ton</td>
</tr>
</tbody>
</table>

It must be noted that the higher cost effectiveness values for CDPF in comparison to SCR cost effectiveness values are due to the magnitude of PM emissions from diesel RICE being much lower than the NOx emissions from diesel RICE. The capital costs of CDPF range from $10,000 to $70,000, which is somewhat lower than the range of capital costs for SCR (which range from $7,300 to $100,000), and the annual operating costs of CDPF are significantly lower than the operating costs of SCR ($800-$3,200 per

See EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 58, Table 5-2. Annualized costs of control were calculated assuming a 10-year life of controls and a 5.5% interest rate. NOx emission reductions are based on EPA’s assumed 90% removal efficiency. Uncontrolled NOx emissions are based on EPA estimates (EPA-420/P-04-09, 2004).
year for CDPF compared to $2,200 to $29,000 per year for SCR). Although CDPF can achieve greater than 90% reduction of PM, overall the tons of PM reduced with CDPF is an order of magnitude lower than the NOx emissions reduced with SCR, and thus the cost effectiveness of CDPF is much higher than the cost effectiveness of SCR.

To truly understand whether this control is considered cost effective, one has to evaluate whether similar sources have been required to install the control at similar costs. Indeed, there are several examples of diesel particulate filter systems being retrofitted to diesel RICE. As previously stated, the use of a CDPF requires the use of ULSD fuel. It should be noted that ULSD is prevalent in the fuel pool today, including in some nonroad fuels that may not be labeled as such, and therefore may already be used in many stationary diesel engines. The use of ULSD which is 15 ppm sulfur, compared to higher sulfur diesel fuel which may be of 500 ppm sulfur content, reflects a 97% reduction in SO2 emissions from diesel RICE. The increased costs for using ULSD are estimated to be $0.07 more per gallon, but the costs would be reduced to $0.04 per gallon due to anticipated savings because of decreased RICE maintenance with the use of low sulfur fuel. EPA’s 2010 Alternative Control Techniques Document for Stationary Diesel RICE estimated that using ULSD fuel would increase fuel costs by only $0.03 to $0.05 per gallon.

The environmental and energy impacts of controls for stationary diesel RICE include the following:

- 1 to 2 percent fuel penalty for CDPF
- Increased solid waste disposal from spent catalysts

The CDPF will have an added benefit of reducing VOCs and associated air toxics. EPA has found that CDPF can reduce THC by 90 percent. Thus, CDPF can be considered a top control technology for both PM and VOCs.

CDPF can be installed fairly quickly. EPA has indicated that diesel particulate filters can be installed in less than a day, although this claim likely pertains to onroad diesel engines (i.e., trucks). Nonetheless, it is the same technology whether applied to a mobile source or a larger generating diesel RICE. It can be assumed that even taking into account time for engineering, design, ordering of parts, etc., the time to install a CDPF is likely under a year.

502 These costs reflect the range of capital and operating costs for the engine sizes evaluated in Tables 33 and 34, using EPA’s SCR and CDPF cost calculations from its 2010 Alternative Control Techniques Document for Stationary Diesel RICE.
509 EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 32 and 34.
States and local air agencies have adopted NOx limits for diesel RICE, some of which have been in place for over 20 years. In Table 35 below, we summarize some of the stronger state and local air pollution requirements. Note that this is not a comprehensive list of state and local air regulations for diesel RICE.

California has adopted fleet-wide emission requirements for existing diesel “off-road” (i.e., non-road) diesel-fueled engines of 25 hp or greater (see Title 13 California Code of Regulations Sections 2449 through 2449.2), and EPA has authorized those rules under Section 209(e) of the Clean Air Act. The goal of this program is to turnover nonroad diesel RICE to Tier 4 engines. The rule established in-use statewide emission performance standards that apply to any person owning and operating a nonroad diesel engine in California of 25 hp or greater. The fleet requirements phase in over time and require that fleets either meet fleet average emission targets or meet best available control technology (BACT). States may be able to adopt requirements like this for nonroad diesel RICE, pursuant to Section 209(e)(2) of the Clean Air Act.

Table 35 is a summary of the stronger NOx emission limits required of diesel RICE in states and local air districts across the United States. It is important to note that these are limits that generally do not apply to portable or nonroad engines, unless clearly stated otherwise. The most broadly applicable NOx limit required is approximately 1.10 g/hp-hr which applies in several air districts in California, although SCAQMD has adopted a more stringent NOx limit of 0.15 g/hp-hr. Those limits all likely reflect application of SCR to diesel RICE. These limits were adopted generally to meet RACT and BARCT (in California) and, as previously discussed, costs are taken into account in making these RACT and BARCT determinations. Thus, the fact that state and local air agencies have adopted emission limits reflective of SCR indicate that these agencies have found SCR to be a cost effective control to retrofit to existing stationary diesel RICE.

Table 35. State/Local Air Agency Diesel RICE Rules for NOx Emissions

<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent g/hp-hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA-Bay Area AQMD</td>
<td>Reg. 9, Rule 8</td>
<td>51 to 275 bhp</td>
<td>180 ppmvd (2.47 g/hp-hr)</td>
</tr>
<tr>
<td></td>
<td>Effective 1/1/2012:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>&gt;50 bhp &amp;/or not Low Usage (&lt;100 hrs/yr)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>&amp;/or not registered as portable:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>&gt;175 bhp</td>
<td></td>
<td>110 ppmvd (1.51 g/hp-hr)</td>
</tr>
</tbody>
</table>

512 This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to different units, and in case of any errors in this table.
513 Emission limits that are in ppmvd are at @ 15% oxygen.
<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Applicability</th>
<th>NOx Limit and units(^{513}) (equivalent g/hp-hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA-Mojave Desert APCD(^{515})</td>
<td>Rule 1160 (Amended 1/22/18)</td>
<td>&gt;50 bhp &amp;/or &gt;100 hours/4 quarters, not portable, not subject to Airborne Toxic Control Measure, and only if located in the Federal Ozone Nonattainment area</td>
<td>80 ppmv (1.09 g/hp-hr)</td>
</tr>
</tbody>
</table>
| CA-Sacramento AQMD\(^{516}\) | Rule 412 | >50 bhp with exemptions if portable, or if operated less than certain # of hours which vary based on rating of engine | 80 ppmv (1.10 g/hp-hr)  
Alt Limit: 90% NOx reduction |
| CA-San Joaquin Valley APCD\(^{517}\) | Rule 4702  
Exemptions for <50 bhp, portable, or low use engines  
Non-EPA certified Compression Ignition Engines installed on or before 6/1/06.  
--------------  
Applicable to EPA-certified CI Engines |  
>50 & ≤ 500 bhp | EPA Tier 3 or Tier 4 by 1/1/2010  
>500 & ≤750 bhp and < 1000 hrs/yr | EPA Tier 3 by 1/1/2010  
>750 bhp & < 1000 hrs/yr | EPA Tier 4 by 7/1/2011  
>500 bhp & ≥1000 hrs/yr | EPA Tier 1 or 2 engine  
EPA Tier 4 by 1/1/2015 or 12 years after install date, but no later than 6/1/2018.  
EPA Tier 3 or Tier 4 engine | Meet certified CI engine standard at time of installation |
| SCAQMD\(^{518}\) | Rule 1110.2  
As amended 11/1/2019 | >50 bhp and not nonroad engines or portable (except portable generators that provide primary or supplemental power to a building, facility, | 11 ppmvd (0.15 g/hp-hr) |

\(^{516}\) [http://www.airquality.org/ProgramCoordination/Documents/rule412.pdf](http://www.airquality.org/ProgramCoordination/Documents/rule412.pdf).  
<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent g/hp-hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA- Ventura County AQMD</td>
<td>Rule 74.9</td>
<td>&gt;50 bhp &amp; &gt; 200 hrs/yr Does not apply to diesel engines with permitted capacity factor ≤ 15%</td>
<td>80 ppmvd (1.10 g/hp-hr) or 90% NOx reduction</td>
</tr>
<tr>
<td>TX- Houston- Galveston-Brazoria Area</td>
<td>30 TAC 117.2010(c)(2) Emission Specs for 8hr ozone demo</td>
<td>≥50hp &amp; &lt;100 hp, on or after 10/1/2007</td>
<td>3.3 g/hp-hr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>≥100 hp &amp; &lt;750 hp, On or after 10/1/2006</td>
<td>2.8 g/hp-hr</td>
</tr>
<tr>
<td></td>
<td></td>
<td>≥750 hp, On or after 10/1/2005</td>
<td>4.5 g/hp-hr</td>
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<tr>
<td></td>
<td></td>
<td>≥300 hp &amp; &lt; 600 hp, On or after 10/1/2005</td>
<td>2.8 g/hp-hr</td>
</tr>
<tr>
<td>TX- Dallas - Ft. Worth Area</td>
<td>30 TAC 117.2110(3) Emission Specs for 8hr ozone demo</td>
<td>≥50hp &amp; &lt;100 hp, on or after 3/1/2009</td>
<td>3.3 g/hp-hr</td>
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<tr>
<td></td>
<td></td>
<td>≥100 hp &amp; &lt;750 hp, On or after 3/1/2009</td>
<td>2.8 g/hp-hr</td>
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<td></td>
<td>≥750 hp, On or after 3/1/2009</td>
<td>4.5 g/hp-hr</td>
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<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Applicability</th>
<th>NOx Limit and units(^{513}) (equivalent g/hp-hr)</th>
</tr>
</thead>
</table>
| MI\(^{522}\) | R 336.1818  
Applies to stationary engines | >1 ton/day NOx engines per avg ozone control period day in 1995 | 2.3 g/bhp-hr |
| NY\(^{523}\) | 6 CCR-NY 227-2.4 (f)(3)  
Applies to stationary engines | ≥ 200 bhp in a severe ozone nonattainment area or ≥400 bhp outside a severe NAA | 2.3 g/bhp-hr |
| WI\(^{524}\) | NR 428.22(1)(i)  
Exemptions for low operating unit engines or for engines certified to meet federal nonroad emission standards. | ≥500 hp | 2.0 g/bhp-hr |
| MO\(^{525}\) | 10 CSR 10-5.510(3)(D)3.B.  
Applies in St. Louis ozone nonattainment area, to installations with potential to emit ≥100 tpy that operate more than 750 hours annually or more than 400 hours during ozone season | ≥1800 hp | 2.5 g/hp-hr |
| OH\(^{526}\) | OAC Chapter 3745-110-03(F)(3)  
Applies in counties around Cleveland ozone nonattainment | ≥2,000 hp | 3.0 g/hp-hr |

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\(^{524}\) [http://docs.legis.wisconsin.gov/code/admin_code/nr/400/428.pdf](http://docs.legis.wisconsin.gov/code/admin_code/nr/400/428.pdf)

\(^{525}\) [https://www.sos.mo.gov/cmsimages/adrules/csr/current/10csr/10c10-5.pdf](https://www.sos.mo.gov/cmsimages/adrules/csr/current/10csr/10c10-5.pdf)

\(^{526}\) [https://www.epa.ohio.gov/portals/27/regs/3745-110/3745-110-02_Final.pdf](https://www.epa.ohio.gov/portals/27/regs/3745-110/3745-110-02_Final.pdf)
Based on all of the analysis provided above, there are several options for reducing visibility-impairing emissions from diesel-fired RICE units. These options are as follows, in order of most beneficial for reducing visibility-impairing pollutants from this source category:

1) Replace existing older diesel-fired engines with Tier 4 engines.

Replacement of existing older diesel-fired RICE with Tier 4 engines is cost effective as shown in Table 32 above, and has the benefit of reducing NOx by 49% to 96% and PM by 81% to 97.5% (with the percentage reduction based on the emission rates the existing engines is complying with). Replacement of older diesel RICE with Tier 4 engines will also result in a reduction in VOC emissions, due to the VOC emission limits required of Tier 4 engines, and it will also reduce \( \text{SO}_2 \) emissions because ULSD fuel is required for Tier 4 engines.

The cost effectiveness of replacing existing diesel-fired RICE varies based on the size of the engine being replaced (smaller engines and larger engines that are not electrical generating sets have less stringent Tier 4 emission limits, which impacts cost effectiveness for those engines, and also the annual operating hours impact cost effectiveness). In general, as demonstrated in Table 32 above, it is cost effective to replace a Tier 0 or Tier 1 engine with a Tier 4 engine for any size engine including for those engines operating on the lower end of annual operating hours.

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 (as shown in Table 30 above). 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.

2) Replace existing diesel-fired RICE with natural gas-fired RICE equipped with LEC or SCR.

Replacing existing older diesel-fired RICE with natural gas-fired RICE, particularly those equipped with LEC or SCR, is also a very effective method for reducing NOx emissions by 85% to 95% and also significantly reducing if not eliminating \( \text{SO}_2 \) and PM emissions. While we did not calculate
the cost effectiveness of this control option, it is significant to note that the National Park Service has highlighted several companies that employ natural gas-fired or dual fuel drill rig engines,\footnote{See August 29, 2016 Memorandum from Doug Neighbor, Superintendent, Carlsbad Caverns National Park, to Paul Murphy, Project Lead, Bureau of Land Management, Carlsbad Field Office, at 7.} and such engines are also being used in the Jonah Field in Wyoming.\footnote{See Four Corners Air Quality Task Force, Report of Mitigation Options, November 1, 2007, at 62.}

3) As a third option, existing diesel RICE can be retrofit with SCR and/or with CDPF. As demonstrated in Table 33, it is most cost effective to retrofit SCR to an existing Tier 0 or Tier 1 engine, and SCR can result in NOx emission reductions of 90% or more. And, as shown in Table 35, several California air districts have adopted NOx emission limitations that would require retrofitting of SCR to diesel RICE.

In addition, CDPF can be retrofit to existing diesel RICE and achieve greater than 90% reduction of PM as well as reductions in VOC emissions. It must be noted that, overall, the tons of PM reduced with CDPF is an order of magnitude lower than the NOx emissions reduced with SCR, and thus the cost effectiveness of CDPF is much higher than the cost effectiveness of SCR- but that does not mean it is has not been considered a cost effective control. There are several examples of diesel particulate filter systems being retrofitted to diesel RICE.\footnote{See Manufacturers of Emission Controls Association, Case Study of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 6-14.}

Existing diesel-fired RICE should also be required to use ULSD fuel. EPA estimated that use of ULSD fuel would increase fuel costs by only $0.03 to $0.05 per gallon.\footnote{EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 71.} ULSD fuel is prevalent in the available fuels today and may already be required to be used in some areas/states. It is also required by the CDPF manufacturer to use ULSD fuel.

Thus, there are several options to cost effectively reduce emissions from diesel-fired engines used in the oil and gas industry. States must evaluate all available options for addressing this significant source of NOx, SO$_2$, PM and VOC emissions as part of their reasonable progress analysis. The most preferable options are those that address all of the visibility-impairing pollutants from this source category, with replacement of older diesel-fired engines with Tier 4 engines or replacing diesel-fired engines with natural gas-fired RICE equipped with LEC or SCR as the most effective emission limiting options.


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),\textsuperscript{531} to maintain temperatures within pipes / connectors (e.g., line heaters),\textsuperscript{532} to maintain storage tank temperatures (e.g., tank heaters), and as regenerators / reboilers (e.g., glycol dehydrators, desiccant dehydrators).\textsuperscript{533,534} These smaller integrated units are generally rated at less than about 2.5 million Btu per hour (MMBtu/hr) heat input.\textsuperscript{535} Larger units can be found at gas processing plants, including steam boilers, hot oil heaters, fractionation column heaters, and other process heaters that range in size from a few MMBtu/hr to 100 MMBtu/hr heat input, or more.\textsuperscript{536}

There are two basic ways of supplying combustion air to these types of external combustion units (i.e., two draft types): (1) natural draft (i.e., atmospheric units); and (2) mechanical or forced draft. In atmospheric units, the pressure difference between the hot stack gases and the cooler ambient air creates a draft, drawing supply air into the burners. These units are open to the atmosphere (i.e., non-sealed units). Mechanical draft units use a fan to introduce combustion air into the burners. Draft type can affect the level of excess air in the combustion chamber, and the resulting emissions from the unit (e.g., NOx emissions are generally lower in mechanical draft units by operating with lower excess air and improved flame characteristics).

\textsuperscript{531} Heater-treaters consist of a heater, free-water knockout, and oil/condensate and gas separator. GPUs consist of a heater and a separator to remove liquid from gas prior to further processing. Heated flash separators are equipped with small boilers to facilitate condensate removal through flashing.

\textsuperscript{532} In-line heaters are used to maintain temperatures as pressure decreases, in order to prevent formation of hydrates. Note, in-line heaters can also be used to heat gas transmission lines further downstream in the oil and gas industry.

\textsuperscript{533} Glycol dehydrators use glycol to remove water from the gas stream in order to prevent corrosion and freezing; small reboilers are used to regenerate the glycol. Dehydrators can be located at well pads, as well as at centrally-located gathering stations and processing facilities. Solid-desiccant dehydrators are generally used for large volumes of gas, e.g., downstream of a compressor station and use a heater to regenerate the desiccant.

\textsuperscript{534} Dehydrator use varies depending on the moisture content of the gas; dry gas requires little dehydration. For example, according to the \textit{Four Corners Air Quality Task Force Report of Mitigations} (Oil and Gas Section), “[i]n the [coal bed methane] areas of Colorado the gas is predominantly methane and the gas is relatively dry gas and requires little dehydration. . . Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required.” See p. 90.

\textsuperscript{535} See Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for Heater-Treater Source Category, completed for the 1\textsuperscript{st} round RH plans [hereinafter referred to as “CDPHE RP for Heater-Treaters”], available at: https://www.colorado.gov/pacific/sites/default/files/AP_PO_Heater-Treaters_1.pdf; also see PA DEP PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) and the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. See p.52, available at: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

\textsuperscript{536} Hot oil heaters, or thermal fluid heaters, are used in the oil and gas industry in combination with a heat exchanger to warm up a secondary fluid (gas or liquid). This can be useful in situations with certain temperature limitations (e.g., amine used to remove H\textsubscript{2}S can degrade at high temperatures) or to prevent corrosive fluids from degrading heating coils. Fractionation column heaters are used at natural gas processing plants to separate out natural gas liquids for further use and can be larger than 10 MMBtu/hr.
Natural gas-fired external combustion units are sources of NOx, CO, VOC, and particulate matter emissions, with NOx the primary pollutant and the focus of this section. SO₂ emissions may also occur if the field-gas used to fire the heaters contains H₂S, which converts to SO₂ during combustion. While emissions from natural gas-fired heaters (e.g., heater-treaters, line heaters, tank heaters, and reboilers) may be relatively small on a unit level, compared to other combustion sources at oil and gas production and processing sites, these units may operate continuously throughout the year. And cumulative emissions from all of the heaters in use at an oil and gas production site or processing facility can be significant.

In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the Heater-Treater Source Category, including a NOx emission 4-Factor analysis for reasonable progress toward the national visibility goal. In its evaluation, Colorado reported that, “the multitude of gas wells in Colorado (~26,000 by 2018) result in cumulative heater-treater NOx emissions that are projected to be the largest single area source category in Colorado by 2018.” Colorado projected NOx emissions in 2018 would reach close to 23,000 tons per year.

Federal standards, in the form of NSPS and NESHAP, exist for industrial boilers and process heaters. The NSPS for industrial-commercial-institutional steam generating units are outlined in 40 C.F.R. Part 60, Subparts Db and Dc, and apply to boilers that are capable of combusting over 10 MMBtu/hr of fuel (burning coal, oil, natural gas, or wood). Subpart Db covers industrial-commercial-institutional steam generating units with heat inputs greater than 100 MMBtu/hr and that commenced construction after September 18, 1978. Subpart Dc covers smaller industrial-commercial-institutional steam generating units that commenced constructed after June 9, 1989. These NSPS include emission standards for sulfur oxides (SOx) and PM from burning fuels other than natural gas. In addition, there are no performance testing standards for boilers burning only natural gas. EPA also regulates VOC emissions from boilers and process heaters that are used as combustion control devices under Subpart OOOO and OOOOa through VOC emission reduction requirements, operating requirements, performance testing and monitoring requirements. The NESHAP for industrial boilers, commercial and institutional boilers, and process heaters is outlined in 40 C.F.R. Part 63 Subpart DDDDD and controls mercury, hydrogen chloride, particulate matter (as a surrogate for non-mercury metals), and CO (as a surrogate for organic hazardous emissions) from coal-fired, biomass-fired, and liquid-fired major source boilers based on the maximum achievable control technology. However, these requirements will not address NOx emissions. In addition, all major source boilers and process heaters are subject to a work practice standard to periodically conduct tune-ups of the boiler or process heater.

When EPA adopts or revises Federal standards for a source category, EPA is establishing an emission standard applicable to all of the source types and variable fuels, operating conditions, etc. that exist for that source category. Thus, the NSPS are generally-applicable emission standards and not a source-specific evaluation of controls. It is necessary to evaluate if more broadly applicable and more stringent requirements and pollution controls are available to achieve reasonable progress towards the national

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537 See CDPHE RP for Heater-Treaters.
538 Id. at 1.
539 Id.
540 See, e.g., 40 C.F.R. Part 60 Subpart OOOOa §§ 60.5412, 60.5412a, 60.5413a, 60.5417a.
visibility goal, especially because the NSPS and NESHAP standards have not been re-evaluated in at least 8 years. Review of state regulations, particularly to address the NAAQS which require reductions in emissions from existing sources, is also necessary to fully evaluate controls for emission sources associated with oil and gas development to achieve reasonable progress towards the national visibility goal.

The information provided in this section for heaters and boilers reflects a review of the available pollution controls and techniques and associated emissions levels applicable to these source categories, along with data on cost of controls where available, non-air quality environmental and energy impacts, and the useful life of the emission source being evaluated.

### Uncontrolled Emission Factors from Natural Gas-Fired External Combustion Units

NOx emissions from natural gas-fired heaters and boilers are generally expressed as emission rates in pounds per million Btu heat input (lb/MMBtu) or pounds per million standard cubic feet of gas (lb/MMscf) or as a concentration in parts per million by dry volume (ppmv or ppmvd). All concentrations expressed in ppmv are on a dry basis and corrected to 3% oxygen. The following emission factors are used in this section:

**EPA Emission Factor**

AP-42 Natural Gas Combustion (Section 1.4, last revised 1998)

Small Boilers <100 MMBtu/hr (Uncontrolled)..........................100 lb/MMscf (0.098 lb/MMBtu)

Converted to lb/MMBtu based on fuel heating value of 1,020 Btu/scf

**SCAQMD Emission Factor**

Units ≤2 MMBtu/hr .................................................................110 ppmv (0.136 lb/MMBtu)

SCAQMD derived an average emission rate to calculate baseline emissions for this size category in its implementation studies for Rule 1146.2 Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters. This factor accounts for units that are considerably older and also for ones that have not had continual maintenance and upkeep.541

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A. COMBUSTION MODIFICATIONS

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. The following is EPA’s description of these combustion control techniques:

Staging techniques are usually used by LNB and ULNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNB’s create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNB’s create a lean primary combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures. The secondary combustion zone is fuel-rich. Ultra-low-NOx burners use staging techniques similar to staged-fuel LNB in addition to internal flue gas recirculation. Flue gas recirculation returns a portion of the flue gas to the combustion zone through ducting external to the firebox that reduces flame temperature and dilutes the combustion air supply with relatively inert flue gas.  

Retrofitting natural gas-fired heaters and boilers with LNB was identified by EPA in 1998 as one of the two most prevalent control techniques in its AP-42 Emission Factor documentation, along with FGR. EPA states that, “NOx emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NOx burners.” And EPA further states that, “When low NOx burners and FGR are used in combination, these techniques are capable of reducing NOx emissions by 60 to 90 percent.”

CARB, in its 1991 RACT and BARCT determinations for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, also identified LNB as one of four control methods (along with FGR, SCR, and selective noncatalytic reduction (SNCR)). CARB concluded that, for units ≥5 MMBtu/hr (and ≥90,000 therms annual heat input) a BARCT NOx limit of 30 ppmv (0.036 lbs/MMBtu) could be achieved by installing new burners with FGR, noting that some units would “need to install selective noncatalytic reduction or other emission control technology instead of flue gas recirculation due to particular unit design problems.” However, these determinations were from 1991, and the NOx removal capabilities of low NOx burners and similar combustion controls for NOx has greatly improved over time.

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543 EPA, AP-42, Section 1.4.4 (last revised 1998), available at: https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf.
544 Id.
For example, in 2018, California’s SCAQMD concluded the following with regard to ULNB technology and its ability to meet very low NOx emission limits across a wide range of unit sizes:

It was noted in the 2008 Rule 1146 and 1146.1 staff reports that there was clear evidence that these types of [ultra-low NOx] burners had been successfully retrofitted on boilers and heaters in the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) in their Rule 4306. Source tests that were conducted in conjunction with Rule 4306 showed a 98% compliance rate with a 9 ppm NOx limits using ultra-low NOx burners. In 2010, staff published a technology assessment report discussing the implementation assessment of ultra-low NOx burners subject to Rules 1146 and 1146.1. The report concluded that the 9 ppm NOx limit can be achieved by ultra-low NOx burner systems for boilers and process heaters greater than 2 MMBtu/hour. There were ultra-low NOx burners from 16 different manufacturers that could achieve the 9 ppm NOx compliance limit.\(^{547}\)

In 2010, California’s Sacramento Metropolitan AQMD (SMAQMD) determined, based on SCAQMD’s rules for similar size sources and models being sold that meet SCAQMD limits, that ULNB technology was available to meet emissions limits for very small units, less than 1 MMBtu/hr.\(^{548}\) Specifically, SMAQMD found that very small units less than 1 MMBtu/hr could meet a NOx limit equivalent to 20 ppmv:

The proposed standards are technically feasible. The low NOx technology is commercially available and widely used. Additionally, these standards have already been adopted by the South Coast AQMD and the Bay Area AQMD, and except for the limits proposed for 2013 (which take effect for the SCAQMD in 2012), are already in effect in SCAQMD. As documented in the SCAQMD staff report for Rule 1146.2, as of 2006, 18% of the certification tests for units between 75,000–400,000 Btu/hr and 44% of the certification tests for units between 400,000 and 2,000,000 Btu/hr were already meeting the 14 ng/J (20 ppmv) standard. SCAQMD currently keeps a list of well over 100 certified models that are complaint with the standards in Rules 1146.2 and 1121.\(^{549}\)

SMAQMD concluded that, “[t]he proposed emission limits are readily achievable through the use of low NOx burners.”\(^{550}\)


\(^{549}\) Id. at 16.

\(^{550}\) Id. at 13.
In 2015, a Ventura County Air Pollution Control District (VCAPCD) analysis for amendments to its rules for boilers, steam generators, and process heaters ≥2 and <5 MMBtu/hr found:

Ultra-low NOx burner systems can achieve less than 9 ppm NOx for boilers, steam generators, or process heaters without the use of Flue Gas Recirculation (FGR) systems. Source tests performed by the San Joaquin Unified Air Pollution Control District showed a 95 percent compliance rate with 9 ppm limits using ultra-low NOx burners. The average NOx concentration measured was 7 ppm.\textsuperscript{551}

And as recently as April 2019, Santa Barbara County APCD concluded the following about the ability of ULNB technology to achieve lower NOx limits of between 9 and 12 ppm for units between 2–5 MMBtu/hr:

The focus of this rule amendment is to lower the emission limits for new and modified natural gas and field gas units from 30 ppm to the 9-12 ppm NOx emission limits, beginning on January 1, 2020. To meet these lower standards, most boilers will have to be equipped with ultra-low NOx burners. Ultra-low NOx burners are designed to achieve low emissions while maintaining good flame stability and heat transfer characteristics. Furthermore, these burners may increase thermal efficiencies by reducing the amount of excess air needed for combustion. This has the added benefit of reducing fuel usage, which results in energy savings.

For most systems, a blower will be required to mix the fuel and air prior to combustion. Even atmospheric boilers, where the burners are not totally enclosed, may still need a blower to premix the fuel and air. Due to the design criteria of these atmospheric boilers, it is only feasible to have them reach the 12 ppm NOx limit, as opposed to the 9 ppm limit for non-atmospheric boilers. It is possible to reach both the 9 and 12 ppm NOx limits without the use of Flue Gas Recirculation (FGR), yet some operators may still choose to use this technology.\textsuperscript{552}

Thus, in rulemakings enacted in California air districts from 2015 to 2019, it was essentially deemed reasonable to impose a NOx emission limit of 9 ppm for natural gas-fired heaters and boilers with heat input capacities greater than or equal to 2 ppm. However, as will be discussed in Sections B. and F., even lower NOx limits have been required for heaters and boilers in some California Air Districts.


\textsuperscript{552} Santa Barbara County APCD Draft Staff Report for Amended Rule 361. Boilers, Steam Generators, and Process Heaters (Between 2–5 MMBtu/hr); Amended Rule 342. Boilers, Steam Generators, and Process Heaters (5 MMBtu/hr and greater), April 22, 2019, p. 5, available at: https://www.ourair.org/wp-content/uploads/2019-05cac-r361-r342-att1.pdf [hereinafter referred to as “Santa Barbara County APCD 2019 Draft Staff Report”].
There are several emerging combustion technologies that demonstrate the potential for even lower levels of NOx without the use of post-combustion controls, such as SCR:

- **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.” It can be retrofit to existing units and fits traditional ULNB footprints.

- **ClearSign Ultra Low NOx Technology** is designed to achieve sub 5 ppm NOx. 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. This technology has been installed on several units in SJVAPCD with more testing / demonstration needed:
  - Installation at two refinery heaters (burning natural gas, not refinery gas):
    - 15 MMBtu/hr heater
    - 8 MMBtu/hr heater
  - Installation at two natural gas-fired 62.5 MMBtu/hr oil field steam generators
  - Installation at six enclosed flares (thermal oxidizers)

- **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. This technology is being developed as an alternative to SCR for meeting NOx limits as low as 5 ppm for smaller units (e.g., in response to SCAQMD’s consideration of a 5 ppm NOx limit for units ≥2 MMBtu/hr).

1. **COST EFFECTIVENESS EVALUATIONS FOR COMBUSTION MODIFICATION RETROPTS, REPLACEMENTS, AND UPGRADES**

California Air Districts have long been regulating NOx emissions from boilers and process heaters, with CARB issuing RACT / BARCT guidance to Air Districts in 1991. In its 1991 guidance CARB determined the cost effectiveness of LNB (in 1986$) for units as small as 3.5 MMBtu/hr and as large as 150 MMBtu/hr, as follows: (1) $500–$6,400/ton for units operating at a 50% capacity factor; and (2) $300–$4,000/ton for units operating at a 90% capacity factor.

More recent and more detailed cost data are available from California Air Districts that have adopted, and continue to update, regulations for these sources. Based on a review of the various California Air

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554 *Id.*
557 *Id.*
559 CARB 1991 Guidance Table 4. Note, CARB does not identify the underlying assumptions for annualized costs, life of controls, etc.
District rules and in researching vendor information, the source category of boilers and heaters should be subcategorized into three categories for assessing cost effectiveness and achievable NOx emission rates with combustion modifications: (1) Units > 20 MMBtu/hr (achieving NOx levels as low as 6 ppm); (2) Units >5 MMBtu/hr and ≤20 MMBtu/hr (achieving NOx levels as low as 6 ppm); and (3) Units ≤5 MMBtu/hr (achieving NOx levels of 9–20 ppm). Below, we evaluate cost effectiveness of combustion controls for each of these categories of boilers and heaters, based on cost analyses that local air agencies have relied on for regulating these units.

a) Units >20 MMBtu/hr

SJVAPCD is in the process of reviewing its rules for boilers and process heaters >5 MMBtu/hr and is proposing updates as part of its 2018 PM2.5 Attainment Plan commitments to reduce NOx emissions. SJVAPCD is considering lowering NOx limits for units >5 MMBtu/hr to levels ranging from 2–3.5 ppm. As part of its control measure analysis, SJVAPCD analyzed the cost effectiveness of retrofitting units of varying sizes with ULNB to achieve a NOx level of 6 ppm, based on vendor cost data. We assume these data are in 2018$.

The SJVAPCD cost data for retrofitting existing units with ULNB includes detailed direct and indirect capital and operating costs for two unit size categories: (1) units >5 and ≤20 MMBtu/hr; and (2) units >20 MMBtu/hr. For the larger size units (>20 MMBtu/hr), SJVAPCD notes that the retrofit may involve “upgrades to various systems such as fuel train to comply with up to date codes, and may involve upgrades to air intake fans, as these units require more air for the burner to operate at its optimum level.”

Table 36 below summarizes the total costs for retrofitting existing units >20 MMBtu/hr with ULNB, based on SJVAPCD vendor data, along with calculated annualized costs of the control, assuming a 5.5% interest rate and a 25-year life. Low NOx technologies should last the life of the emission unit. SCAQMD is currently assuming a 25-year life for refinery heaters and boilers. And a review of the emission units in New Mexico permitted oil and gas sources such as gas processing plants show average ages of boilers and heaters of 30-35 years. Thus, we used a 25-year life as a minimum life for a heater or boiler controls in the cost effectiveness analysis, which seems more than justified. Table 36 presents the cost effectiveness of applying these low NOx technologies to existing units to reduce NOx emissions from uncontrolled levels to 6 ppm. Uncontrolled emissions are based on the EPA AP-42 uncontrolled

562 SJVAPCD 2018 PM2.5 Attainment Plan pp. C-80–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.
563 SJVAPCD 2018 PM2.5 Attainment Plan at C-81.
emission rate for small boilers <100 MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting an emission limit of 6 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art ultra-low NOx burner technology of 93%. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

Table 36. Cost Effectiveness of Retrofitting Existing Units with ULNB to Achieve a NOx Level of 6 ppm at Boilers and Heaters >20 MMBtu/hr Operating at a 50% and 90% Capacity Factor.\textsuperscript{565}

<table>
<thead>
<tr>
<th>UNIT SIZE (MMBtu/hr)</th>
<th>TOTAL CAPITAL COSTS (2018$)</th>
<th>TOTAL ANNUALIZED COSTS (2018$)</th>
<th>COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR</th>
<th>COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR</th>
</tr>
</thead>
<tbody>
<tr>
<td>30</td>
<td>$261,813</td>
<td>$19,518</td>
<td>$3,270</td>
<td>$1,817</td>
</tr>
<tr>
<td>40</td>
<td></td>
<td></td>
<td>$2,452</td>
<td>$1,362</td>
</tr>
<tr>
<td>50</td>
<td></td>
<td></td>
<td>$1,962</td>
<td>$1,090</td>
</tr>
<tr>
<td>60</td>
<td></td>
<td></td>
<td>$1,635</td>
<td>$908</td>
</tr>
<tr>
<td>70</td>
<td></td>
<td></td>
<td>$1,401</td>
<td>$779</td>
</tr>
<tr>
<td>80</td>
<td></td>
<td></td>
<td>$1,226</td>
<td>$681</td>
</tr>
<tr>
<td>90</td>
<td></td>
<td></td>
<td>$1,090</td>
<td>$606</td>
</tr>
<tr>
<td>100</td>
<td></td>
<td></td>
<td>$981</td>
<td>$545</td>
</tr>
</tbody>
</table>

Based on this analysis of SJVAPCD cost data, it can be cost effective to apply ULNB to existing units >20 MMBtu/hr to reduce NOx emissions to a level of 6 ppm.

SJVAPCD provides separate cost data for oilfield steam generators, noting that most of these units would be 62.5 MMBtu/hr.\textsuperscript{566} The SJVAPCD analysis notes that, “[a]s many steam generators are one off built units, they may have different firebox configurations that may not accept the new burner without varying degrees of modification.”\textsuperscript{567} However, SJVAPCD analyzed retrofitting these units with new burner technology to achieve a NOx level as low as 5 ppm, based on vendor data. Using this same vendor cost data, the cost effectiveness of retrofitting a 62.5 MMBtu/hr unit to reduce NOx levels to 5 ppm ranges from $1,664/ton to $6,656/ton, depending on the extent of the modifications or upgrades that are needed.\textsuperscript{568}

\textsuperscript{565} Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.

\textsuperscript{566} SJVAPCD 2018 PM\textsubscript{2.5} Attainment Plan at C-83.

\textsuperscript{567} Id.

\textsuperscript{568} This range of cost effectiveness is based on retrofit cost data of $450,000–$1,800,000 and assumes an 80% capacity factor from SJVAPCD’s analysis. Annualized costs are calculated assuming a 25-year life and a 5.5% interest rate.
We also completed a cost effectiveness analysis of retrofitting existing units >5 and ≤20 MMBtu/hr with ULNB based on SJVAPCD vendor cost data for units of this size. Table 37 presents the cost effectiveness of retrofitting existing units >5 and ≤20 MMBtu/hr with ULNB to reduce NOx emissions to 6 ppm from uncontrolled levels based on the EPA AP-42 uncontrolled emission rate for small boilers <100 MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting an emission limit of 6 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art ultra-low NOx burner technology of 93%. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

Table 37. Cost Effectiveness of Retrofitting Existing Units with ULNB to Achieve a NOx Level of 6 ppm at Boilers and Heaters >5 and ≤20 MMBtu/hr Operating at a 50% and 90% Capacity Factor.

<table>
<thead>
<tr>
<th>UNIT SIZE (MMBtu/hr)</th>
<th>TOTAL CAPITAL COSTS (2018$)</th>
<th>TOTAL ANNUALIZED COSTS (2018$)</th>
<th>COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR</th>
<th>COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>$69,816</td>
<td>$5,205</td>
<td>$5,232</td>
<td>$2,906</td>
</tr>
<tr>
<td>10</td>
<td>$2,616</td>
<td></td>
<td>$2,616</td>
<td>$1,453</td>
</tr>
<tr>
<td>15</td>
<td>$1,744</td>
<td></td>
<td>$1,744</td>
<td>$969</td>
</tr>
<tr>
<td>20</td>
<td>$1,308</td>
<td></td>
<td>$1,308</td>
<td>$727</td>
</tr>
</tbody>
</table>

Based on this analysis using SJVAPCD cost data, it can be cost effective to apply ULNB to existing units >5 and ≤20 MMBtu/hr to reduce NOx emissions to a level of 6 ppm.

c) Units ≤5 MMBtu/hr

SMAQMD, in a cost effectiveness analysis for its most recent revision of its rules (in 2005) for boilers and heaters ≥1 MMBtu/hr, noted that, for units ≥1 MMBtu/hr and <5 MMBtu/hr, “[s]ome of these units may not be retrofitted because of equipment age and design and will have to be replaced with new units.”

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569 SJVAPCD 2018 PM2.5 Attainment Plan pp. C-81–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.

570 Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.

The SMAQMD cost data included the costs for replacing existing units with new units equipped with “low NOx technologies” in order to meet the District’s emission limits, including costs for equipment, installation, permitting, and source testing for unit sizes ranging from 1–100 MMBtu/hr. Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. Thus, it is assumed that it is more cost effective to replace units that are of a size less than or equal to 5 MMBtu/hr with new units equipped with state-of-the-art combustion controls for NOx.

Table 38 below summarizes cost data for replacing units ≤5 MMBtu/hr with new units with “low NOx technologies.” The costs include costs for equipment, installation, permitting, and source testing, along with calculated annualized costs of the control, and assume a 5.5% interest rate and a 30-year life of the new unit. These low NOx technologies should last the life of the emission unit, and Colorado assumed a 30–40 year life for heater-treater units of this size based on manufacturer data. We used a 30-year life as a minimum useful life for replacement heater or boiler controls in the cost effectiveness analysis, which is justified.

Table 38. Total and Annualized Costs of Replacement of Boilers and Heaters ≤5 MMBtu/hr with New Units with Low NOx Technologies.

<table>
<thead>
<tr>
<th>UNIT SIZE (MMBtu/hr)</th>
<th>TOTAL CAPITAL COSTS (2005$)</th>
<th>TOTAL ANNUALIZED COSTS (2005$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>$36,284</td>
<td>$2,551</td>
</tr>
<tr>
<td>2</td>
<td>$52,284</td>
<td>$3,652</td>
</tr>
<tr>
<td>3</td>
<td>$72,284</td>
<td>$5,028</td>
</tr>
<tr>
<td>4</td>
<td>$80,284</td>
<td>$5,579</td>
</tr>
<tr>
<td>5</td>
<td>$135,567</td>
<td>$9,328</td>
</tr>
</tbody>
</table>

For the units of 5 MMBtu/hr and lower, SMAQMD’s Rule 411 establishes a NOx limit of 30 ppm, but there have been improvements in low NOx technologies demonstrating that units in this size range can meet NOx limits of 20 ppm and even as low as 9 ppm for some applications, based on a review of vendor information. Several California Air Districts require units >2 and <5 to meet a limit of 7–12 MMBtu/hr and units ≤2 MMBtu/hr to meet a limit of 20 ppm. For example, SCAQMD Rule 1146.1 requires units >2 and <5 MMBtu/hr meet limits between 7–12 ppm, depending on the type of unit. And SJVAPCD Rule 4307 requires units >2 and ≤5 MMBtu/hr meet limits of 9 ppm (non-atmospheric units) and 12 ppm.

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572 SMAQMD 2005 Rule 411 Staff Report Attachment D-1.
573 SMAQMD 2005 Rule 411 Staff Report Attachment D-2.
574 CDPHE RP for Heater-Treaters at 5.
575 Cost data provided by boiler manufacturers to SMAQMD, annualized costs calculated assuming a 30-year life and a 5.5% interest rate.
576 See, e.g., Parker Industrial Boiler, offering units <5 MMBtu/hr with Low NOx Power Burners for NOx levels to 9 ppm. Available at: https://www.parkerboiler.com/products/.
SCAQMD Rule 1146.2 requires units ≤2 MMBtu/hr be manufactured to meet a NOx limit of 20 ppm and SCAQMD provides a list of numerous units that are pre-certified to meet this limit. SJVAPCD also requires point-of-sale NOx limits for units ≤2 MMBtu/hr of 20 ppm. And VCAPCD’s Rule 74.15.1 currently requires new and replacement units ≥1 and ≤2 MMBtu/hr to also meet a 20 ppm NOx limit. See Table 42 for a complete and more detailed list of state and local rules, including many with limits for units in this size range of 9–20 ppm.

While the costs of NOx combustion control technologies to meet NOx limits as low as 9 ppm may be higher than what SMAQMD assumed in its 2005 cost analysis, it is also likely that the costs of low NOx combustion controls have not changed much since then. This is because as air pollution controls are required to be implemented more frequently over time, the cost of the air pollution control often decreases due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. For example, SCAQMD concluded from its 2008 cost analysis that, “[t]he capital cost for retrofitting a unit has decreased by about 70%....” Therefore, we calculated the cost effectiveness of retrofitting these size units with low NOx technologies using these cost data based on two emission control scenarios: (1) meeting the SMAQMD limit of 30 ppm; and (2) meeting limits achievable today with low NOx combustion technology.

Table 39 below summarizes the cost effectiveness of replacing existing units ≤5 MMBtu/hr with new units with low NOx technologies, based on SCAQMD cost data shown above in Table 38. Table 39 below presents the cost effectiveness of replacement units with low NOx technologies to reduce NOx emissions from the uncontrolled emission rate based on EPA for units >2 MMBtu/hr and the SCAQMD-derived average unit emission rate of 110 ppmv (0.136 lb/MMBtu/hr) for units ≤2 MMBtu/hr. The SCAQMD-average unit emission rate was, “derived by the SCAQMD to calculate the baseline emissions for this [size] category.” This rate, “accounts for units that are considerably older and also for ones that have not had continual maintenance and upkeep.” Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. For the second scenario, the analysis assumes units >2 and ≤5 MMBtu/hr meet a NOx limit of 9 ppm and units ≤2 MMBtu/hr meet a NOx limit of 20 ppm. Meeting emission limits of 9 ppm and 20 ppm from the estimated uncontrolled levels reflect a control efficiency of 89% and 82%, respectively. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

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579 VCAPCD Rule 74.15.1. Available at: http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.15.1.pdf.
580 SCAQMD 2018 Draft Staff Report at 4-3. Note, while SCAQMD’s analysis specifically applies to retrofitting units ≥20 and <75 MMBtu/hr with ULNB it’s also possible that these changes in cost would apply to units of other sizes, as well.
581 SJVAPCD 2009 Final Draft Staff Report for Rule 4308.
582 Id.
Table 39. Cost Effectiveness of Replacing Existing Boilers and Heaters ≤5 MMBtu/hr with New Units with Low NOx Technologies Operating at a 50% and 90% Capacity Factor.\(^{583}\)

<table>
<thead>
<tr>
<th>UNIT SIZE (MMBtu/hr)</th>
<th>COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR NOx RATE: 30 ppm</th>
<th>COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR NOx RATE: 30 ppm</th>
<th>COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR NOx RATES: 20 ppm (≤2 MMBtu/hr) 9 ppm (&gt;2 MMBtu/hr)</th>
<th>COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR NOx RATES: 20 ppm (≤2 MMBtu/hr) 9 ppm (&gt;2 MMBtu/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>$12,160</td>
<td>$6,756</td>
<td>$10,809</td>
<td>$6,005</td>
</tr>
<tr>
<td>2</td>
<td>$8,703</td>
<td>$4,835</td>
<td>$7,736</td>
<td>$4,298</td>
</tr>
<tr>
<td>3</td>
<td>$12,322</td>
<td>$6,846</td>
<td>$8,771</td>
<td>$4,873</td>
</tr>
<tr>
<td>4</td>
<td>$10,254</td>
<td>$5,696</td>
<td>$7,298</td>
<td>$4,055</td>
</tr>
<tr>
<td>5</td>
<td>$13,715</td>
<td>$7,619</td>
<td>$9,762</td>
<td>$5,423</td>
</tr>
</tbody>
</table>

For the smallest units, San Joaquin Valley APCD (SJVAPCD) analyzed the cost of reducing NOx emissions for its point-of-sale rule for boilers and process heaters sized 0.075 to less than 2 MMBtu/hr. Table 40 below shows the differential capital costs (i.e., the difference in cost between a compliant and non-compliant unit), the annualized costs recalculated using a 5.5% interest rate (in place of the 10% interest rate assumed by SJVAPCD), and the cost of NOx reduction based on a current unit average emission rate of 110 ppmv meeting a limit of 20 ppmv. For units ≤2 MMBtu/hr uncontrolled emissions are estimated based on the SCAQMD-derived average unit emission rate of 110 ppmv (0.136 lb/MMBtu/hr). Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. Cost data were provided to SJVAPCD by stakeholders, retailers, and manufacturers. And again, we used a 30-year life as a minimum life for replacing unit controls with low NOx technologies in the cost effectiveness analysis, as previously discussed. SJVAPCD used a 22% capacity factor in its analysis based on survey data collected by SCAQMD and Bay Area AQMD for “typical usages for these units,” which presumably reflect a wide range of application and do not necessarily reflect how these size units are used in oil and gas applications, where heaters can operate continuously.

\(^{583}\) Cost data provided by boiler manufacturers to SMAQMD (2005$), annualized costs calculated assuming a 30-year life and a 5.5% interest rate.
Table 40. Cost Effectiveness Based on Differential Costs to Reduce NOx Emissions from Replacing Units with Units with Low-NOx Burner Technology to Meet a NOx Limit of 20 ppm, Operating at 22% Capacity

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>0.75</td>
<td>$100</td>
<td>$8</td>
<td>$883/ton</td>
</tr>
<tr>
<td>0.4</td>
<td>$750</td>
<td>$63</td>
<td>$1,242/ton</td>
</tr>
<tr>
<td>2.0</td>
<td>$3,000</td>
<td>$251</td>
<td>$994/ton</td>
</tr>
</tbody>
</table>

For units operating at a higher capacity factor, as would likely be the case for many of the units used in the oil and gas production and processing segments, the cost per ton of NOx removal of choosing to replace a unit with a new unit with low NOx technologies over a higher-emitting unit would be even less than what is shown in Table 40. For these type of smaller units, SCAQMD Rule 1146.2 requires units with rated capacities between 400,000 and 2,000,000 Btu/hr (i.e., 0.04 and 2 MMBtu/hr) and more than 15 years old, depending on the original manufacturer date, to meet the same emission standards as new units. Meeting these standards, according to SCAQMD, requires the retrofit, or more likely, replacement of the older units.

In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the heater-treater source category, including a NOx emission 4-Factor analysis for reasonable progress toward the national visibility goal. In its evaluation, Colorado reported that:

The Four Corners Air Quality Task Force considered low NOx burners as a mitigation option for the Four Corners area and had the following finding: “Application not appropriate for the San Juan Basin, because most burners commonly used in the Four Corners Area are smaller than the technology is capable of providing emission reduction.” It appears likely that this technology would also be technically infeasible for the Denver-Julesburg (DJ) Basin considering that low-NOx burners are not commercially available for very small combustion sources such as heater-treaters.

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584 See SJVAPCD 2009 Final Draft Staff Report for Rule 4308. Annualized costs of control were calculated using a capital recovery factor of 0.068805 (assuming a 30-year life of controls and a 5.5% interest rate). NOx emission reductions are based on SJVAPCD’s assumed unit average emission rate of 110 ppmv meeting an emission limit of 20 ppmv.


586 See SMAQMD 2010 Rule 414 Staff Report at 13 (describing SCAQMD rules).

587 CDPHE RP for Heater-Treaters.

588 Id. at 3.
The Four Corners Air Quality Task Force report was from 2007 and there have been great improvements since then in low NOx technologies. As shown throughout this section on combustion modifications, however, units around 2 MMBtu/hr, and even smaller, are available with low NOx technologies that can meet very low NOx emission limits and can even, in some cases, be retrofitted with these technologies to achieve emissions reductions from existing units. Note, Colorado’s RP for Heater-Treaters indicates that a typical heater-treater design rate is about half of the 5 MMBtu/hr threshold for exemptions from Colorado’s permitting requirements. And beyond these very small units, low NOx technologies are widely available and generally cost effective for units ≥5 MMBtu/hr.

2. LOWERING COMBUSTION TEMPERATURES TO REDUCE NOx EMISSIONS

Colorado also considered lowering heater-treater temperatures to reduce NOx emissions and described this combustion modification approach, as follows:

This technology (lowering the heater-treater temperature) was identified by EPA Natural GasSTAR in PRO Fact Sheet No. 906. The fact sheet was written with reduction of methane in mind, although this technology would also reduce combustion emissions because it would reduce fuel use. The following is from the fact sheet: “...heater-treater temperatures at remote sites may be higher than necessary, resulting in increased methane emissions. Commonly, the reason for this is that operators need to reduce the chance of having a high water content in the produced oil and manpower limitations do not allow for constant monitoring at remote sites. Field personnel, consequently, are inclined to operate the equipment at levels that cause the least problems, but also result in higher than necessary emissions.”

Estimates for NOx emission reductions from lowering heater-treater temperatures were not provided in EPA’s Gas STAR analysis and were not assessed by Colorado. Capital costs were estimated at $1,000–$10,000 and annual operating and maintenance costs were estimated to range from $100–$1,000. Colorado anticipated that there would be no additional time needed for achieving compliance with this technology, that the lowered heater-treater temperature would reduce fuel use, and that there would be no non-air quality impacts. Further, Colorado concluded that this control technology would not affect the service life of the heater-treater, noting that the typical life of a heater-treater is 30 to 40 years.

There are few energy and non-air environmental impacts of combustion modifications for heaters and boilers. Generally, the combustion practices used to reduce NOx emissions also increase thermal efficiencies by reducing the amount of excess air needed for combustion, which has the added benefit

589 Id. at 5.
590 Id. at 2.
591 See EPA Partner Reported Opportunities (PRO) Fact Sheet No. 906 (last updated September 2004), available at: https://www.globalmethane.org/documents/m2mtool/docs/lowheaterattrevertemp.pdf and CDPHE RP for Heater-Treaters at 3.
592 CDPHE RP for Heater-Treaters at 4.
of reducing fuel usage and increasing energy savings. According to EPA, “[r]eductions in NOx formation achieved by reducing flame temperature and oxygen levels can increase CO and HC emissions if NOx reductions by combustion controls are taken to extremes.”\textsuperscript{593} And systems where blowers or fans are used, e.g., for LNB plus FGR, will require additional electric energy.

According to EPA, the length of time to install ULNB is 6–8 months (excluding permitting, reporting preparation, and programmatic and administrative considerations).\textsuperscript{594}

While the cost estimates in this section on combustion modification are of a cost basis that spans a timeframe from 1986–2018, it is important to note that, beginning in 2006, several state and local air agencies adopted rules to lower NOx emission limits of 30 ppmv to as low as 5–12 ppm for larger units and found it was cost effective to require such a level of control on existing boilers and heating units. This will be discussed further in Section F. below. It is not possible to accurately escalate the older costs to more current dollars. EPA cautions against escalating costs over a period longer than five years because it can lead to inaccuracies in price estimation.\textsuperscript{595} Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. In some cases, the cost of the air pollution control decreases over time due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.\textsuperscript{596} In any event, the fact that air agencies have found low NOx combustion technologies to be cost effective to meet NOx emission limits in the range of 5 to 30 ppm indicates that similar sources have had to incur the costs reflected in Tables 36-40 to meet reduced NOx emission limits, and thus the costs of low NOx combustion technology should be considered reasonable for most heaters and boilers.

\section*{B. POST-COMBUSTION CONTROLS: SCR AND SNCR}

Post-combustion controls, such as SCR and SNCR, reduce NOx formation in the flue gas. The following is EPA’s description of these add-on control techniques:

These techniques control NOx by using a reactant that reduces NOx to nitrogen (N\textsubscript{2}) and water. The reactant, ammonia (NH\textsubscript{3}) or urea for SNCR, and NH\textsubscript{3} for SCR, is injected into the flue gas stream. Temperature and residence time are the primary factors that influence the reduction reaction. Selective catalytic reduction uses a catalyst to facilitate the reaction.\textsuperscript{597}

\begin{flushright}
\textsuperscript{593} EPA 1993 ACT for Process Heaters Section 2.4.
\textsuperscript{594} 2016 EPA CSAPR TSD for Non-EGU Emissions Controls at 15.
\textsuperscript{595} EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
\textsuperscript{596} For example, SCAQMD concluded from its 2008 cost analysis that, “[t]he capital cost for retrofitting a unit has decreased by about 70%....” (SCAQMD 2018 Draft Staff Report at 4-3).
\textsuperscript{597} EPA 1993 ACT for Process Heaters at 2-6.
\end{flushright}
SCR systems on natural gas-fired boilers and heaters should be able to achieve NOx removal efficiencies in the range of 80 to 90+%. SNCR systems on natural gas-fired industrial boilers and heaters can achieve NOx reductions in the range of 30-75%.

As early as 1991, CARB, in its 1991 RACT / BARCT determination for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, identified SCR and SNCR as two of four control methods (along with FGR and LNB). CARB concluded that, for units ≥5 MMBtu/hr (and ≥90,000 therms annual heat input), a BARCT NOx limit of 30 ppmv (0.036 lbs/MMBtu) could be achieved by installing new burners with FGR, noting that some units would “need to install selective noncatalytic reduction or other emission control technology instead of flue gas recirculation due to particular unit design problems.”

EPA provided cost effectiveness data for SNCR at model heaters in its 1993 Alternative Control Techniques document. Specifically, cost effectiveness of SNCR for heaters, at the time, ranged from: (1) $3,200–$6,700/ton for a 77 MMBtu/hr heater; (2) $2,700–$5,700/ton for a 121 MMBtu/hr heater; and (3) $2,300–$4,900/ton for 186 MMBtu/hr heater.

California Air Districts have long been regulating NOx emissions from boilers and process heaters, with CARB issuing RACT / BARCT guidance to Air Districts in 1991. In its 1991 guidance, CARB determined the cost effectiveness of SNCR (in 1986$) for units as small as 50 MMBtu/hr and as large as 375 MMBtu/hr, as follows: (1) $1,500–$6,000/ton for units operating at a 50% capacity factor; and (2) $1,300–$3,800/ton for units operating at a 90% capacity factor.

More recent and more detailed cost data are available from California Air Districts that have adopted, and continue to update, regulations for these sources. A recent analysis by California’s SCAQMD for revisions to its series of rules for boilers and process heaters (i.e., Rules 1146, 1146.1, and 1146.2) concluded that, “[u]pon reviewing the type of pollution control technologies available to control NOx emissions applicable to the boilers, steam generators and process heaters subject to Rule 1146 and 1146.1, SCR and ultra-low NOx burners are still the main technologies that can achieve the NOx concentration limits specified in these rules.” SCAQMD further determined that, “[b]ased on the 2008 staff reports for Rule 1146 and 1146.1, SCR as applied to Rule 1146 boilers can achieve NOx

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600 CARB 1991 Guidance at 8.
602 EPA 1993 ACT for Process Heaters Table 2-4. EPA calculates an annualized cost of control assuming a capital recovery factor of 0.131474 (i.e., assuming a 15-year life of controls and a 10% interest rate).
603 CARB 1991 Guidance.
604 CARB 1991 Guidance Table 4. Note, CARB does not identify the underlying assumptions for annualized costs, life of controls, etc.
605 SCAQMD 2018 Draft Staff Report at 2-4.
concentrations from 5 to 6 ppm for units greater than or equal to 75 MMBtu/hr.” \(^{606}\) SCAQMD’s revisions to Rule 1146 for Boilers, steam generators, and process heaters ≥5 MMBtu/hr allow facilities until January 1, 2022 to retrofit all existing units and until January 1, 2023 to replace any existing units to meet a NOx emission limit of 5 ppm for units ≥75 MMBtu/hr burning natural gas. \(^{607}\) SCAQMD determined that the 1146 rule series are cost effective, including for units ≥75 MMBtu/hr retrofitted with SCR to meet an emission limit of 5 ppm. \(^{608}\)

In the SJVAPCD, the District described the following approach to achieving lower NOx limits, acknowledging certain technical and cost feasibility considerations with SCR for certain units:

The amendment of Rule 4306 in October 2008 was initially proposed to lower the NOx emission limit from 9 ppmv to 6 ppmv for units greater than 20 MMBtu/hr. It was determined that the proposed NOx limits could be accomplished by using selective catalytic reduction (SCR) or a combination of SCR and ultra-low NOx burners (ULNBs), thus making the lower limits technologically feasible. However, through the public workshop process and additional research it was also determined that most of the units subject to Rule 4306 have undergone several generations of NOx controls, and consequently, certain applications of SCR may not be cost effective and/or technologically infeasible because of physical limitations. Therefore, the lower NOx limits were included in new Rule 4320 and an option was provided in the rule that allows for the payment of an annual emissions fee based on total actual emissions, rather than installation of additional NOx controls. These fees are used by the District to achieve cost effective NOx reductions through District incentive programs, the District’s Technology Advancement Program, and other routes. \(^{609}\)

SJVAPCD is in the process of reviewing its rules for boilers and process heaters >5 MMBtu/hr and is proposing updates as part of its 2018 PM\(_{2.5}\) Attainment Plan commitments to reduce NOx emissions. \(^{610}\) SJVAPCD is considering lowering NOx limits for units >5 MMBtu/hr to levels ranging from 2–3.5 ppm. \(^{611}\) As part of its control measure analysis, SJVAPCD analyzed the cost effectiveness of retrofitting units of varying sizes with SCR to achieve these NOx levels, based on information from SCR vendors. We assume these data are in 2018$.

The SJVAPCD cost data for retrofitting existing units with SCR includes detailed direct and indirect capital, installation, and operating and maintenance costs for two unit size categories: (1) units >5 and ≤20 MMBtu/hr; and (2) units >20 MMBtu/hr. \(^{612}\)

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606 Id. at 2-2.  
607 Id. at 1-2.  
608 Id. at 4-6.  
610 SJVAPCD Rules 4306 and 4320. See: https://www.valleyair.org/Workshops/public_workshops_idx.htm#12-05-19_ICE.  
611 SJVAPCD 2018 PM\(_{2.5}\) Attainment Plan pp. C-84–C-87.  
612 SJVAPCD 2018 PM\(_{2.5}\) Attainment Plan pp. C-80–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.
Table 41 below summarizes the total costs for retrofitting existing units ≥5 MMBtu/hr with SCR, based on SJCAPCD-obtained vendor data, along with calculated annualized costs of the control, assuming a 5.5% interest rate and a 25-year life for SCR. SCAQMD is currently assuming a 25-year life for refinery heaters and boilers.\textsuperscript{613} Table 41 also presents the cost effectiveness of applying SCR existing units to reduce NOx emissions from uncontrolled levels to levels of: (1) 2.5 ppm for units >20 MMBtu/hr; and (2) 3.5 ppm for units >5 and ≤20 MMBtu/hr.\textsuperscript{614} Uncontrolled emissions are based on the EPA AP-42 uncontrolled emission rate for small boilers <100 MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting emission limits of 2.5 ppm and 3.5 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art SCR technology of 96% and 97%, respectively. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

**Table 41. Cost Effectiveness of Retrofitting Existing Units with SCR to Achieve NOx Levels of 2.5 ppm for Units >20 MMBtu/hr and 3.5 ppm for Units >5 and ≤20 MMBtu/hr Operating at a 50% and 90% Capacity Factor.**\textsuperscript{615}

<table>
<thead>
<tr>
<th>UNIT SIZE (MMBtu/hr)</th>
<th>TOTAL CAPITAL COSTS (2018$)</th>
<th>TOTAL ANNUALIZED COSTS (2018$)</th>
<th>COST EFFECTIVENESS ($/TON) 50% CAPACITY FACTOR</th>
<th>COST EFFECTIVENESS ($/TON) 90% CAPACITY FACTOR</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>$261,728</td>
<td>$26,055</td>
<td>$25,354</td>
<td>$14,086</td>
</tr>
<tr>
<td>10</td>
<td>$12,677</td>
<td>$7,043</td>
<td>$12,677</td>
<td>$7,043</td>
</tr>
<tr>
<td>15</td>
<td>$8,451</td>
<td>$4,695</td>
<td>$8,451</td>
<td>$4,695</td>
</tr>
<tr>
<td>20</td>
<td>$6,339</td>
<td>$3,521</td>
<td>$6,339</td>
<td>$3,521</td>
</tr>
<tr>
<td>30</td>
<td>$385,705</td>
<td>$38,397</td>
<td>$38,397</td>
<td>$21,217</td>
</tr>
<tr>
<td>40</td>
<td>$6,149</td>
<td>$3,416</td>
<td>$6,149</td>
<td>$3,416</td>
</tr>
<tr>
<td>50</td>
<td>$4,612</td>
<td>$2,562</td>
<td>$4,612</td>
<td>$2,562</td>
</tr>
<tr>
<td>60</td>
<td>$3,689</td>
<td>$2,050</td>
<td>$3,689</td>
<td>$2,050</td>
</tr>
<tr>
<td>70</td>
<td>$3,074</td>
<td>$1,708</td>
<td>$3,074</td>
<td>$1,708</td>
</tr>
<tr>
<td>80</td>
<td>$2,635</td>
<td>$1,464</td>
<td>$2,635</td>
<td>$1,464</td>
</tr>
<tr>
<td>90</td>
<td>$2,306</td>
<td>$1,281</td>
<td>$2,306</td>
<td>$1,281</td>
</tr>
<tr>
<td>100</td>
<td>$2,050</td>
<td>$1,139</td>
<td>$2,050</td>
<td>$1,139</td>
</tr>
</tbody>
</table>


\textsuperscript{614} See SJVAPCD 2018 PM\textsubscript{2.5} Attainment Plan at C-85 and C-87, stating: “Source test results of various units with SCR systems indicate that an SCR can potentially achieve 3.5 ppmv NOx @ 3% O2 for units rated between 5 to 20 MMBtu/hr.” and “Source test results of various units with SCR system indicate that an SCR can reliably achieve 2.5 ppmv NOx @ 3% O2 (or less) emissions for units greater than 20 MMBtu/hr.”

\textsuperscript{615} Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.
SJVAPCD based its cost analysis on vendor data for the SCR systems and largely on EPA’s Air Pollution Control Cost Manual (6th Edition) for installation, operating and maintenance costs, etc., for these systems.

This analysis indicates that it is cost effective to retrofit units, especially those >20 MMBtu/hr, with SCR to achieve NOx levels as low as 2.5–3.5 ppm.

The energy and non-air environmental impacts of post-combustion control techniques include:

- Parasitic load of operating an SCR system, which requires additional energy (fuel use and electricity) in order to maintain output across the catalyst;
- Solid waste disposal of spent SCR catalyst;
- Ammonia, CO, and nitrous oxide emissions with the use of SNCR;
- Ammonia and sulfite emissions with the use of SCR; and
- Ammonia handling and storage with SNCR and SCR.616

According to EPA, the length of time to install SCR is 28–58 weeks (excluding permitting, reporting preparation, and programmatic and administrative considerations).617 The Institute of Clean Air Companies has stated that SCRs for smaller units (less than 20,000 standard cubic feet per minute gas throughput) are often available in ready-to-install SCR skid packages, and thus SCR for smaller units would take closer to 28 weeks to install.618 An SNCR would take much less time to install. The Institute of Clean Air Companies states that it takes about 10-13 months to install SNCR, which covers the time from bid evaluations to startup of the SNCR.619

C. NOx CONTROLS FOR SEPARATORS

Colorado’s Reasonable Progress Evaluation for the heater-treater source category evaluated the installation of insulation on the separator to reduce fuel usage, and resulting combustion emissions (including NOx).620 Installation of insulation on separators was also included in the Four Corners Air Quality Task Force Report of Mitigation Options for the oil and gas industry and determined to be a technically feasible technique for reducing NOx emissions.621 Estimates for NOx emission reductions from insulating separators were not provided in the Four Corners Air Quality Task Force report and were not assessed by Colorado. The cost effectiveness of this control will depend on the remaining life of the

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616 EPA 1993 ACT for Process Heaters Section 2.4.
617 2016 EPA CSAPR TSD for Non-EGU Emissions Controls at 15.
619 Id. at 7-8.
620 CDPHE RP for Heater-Treaters.
621 Four Corners Air Quality Task Force Report of Mitigation Options (November 1, 2007) at 89.
equipment to which it is applied. Colorado anticipated that there would be no additional time needed for achieving compliance with this technology and that there would be no non-air quality impacts.

**D. NOx CONTROLS FOR DEHYDRATORS**

Use of a zero emission dehydrator can significantly reduce fuel requirements for a reboiler and therefore reduce combustion emissions (including NOx). The Four Corners Air Quality Task Force report identified this type of dehydrator as a mitigation option and described this type of unit and its emissions, as follows:

The zero emissions dehydrator combines several technologies that lower emissions. These technologies eliminate emissions from glycol circulation pumps, gas strippers and the majority of the still column effluent. . . . Benefits of this technology include: . . . Reduces emissions of particulate matter, sulfur dioxide, NOx or CO emissions . . . Significantly reduces fuel requirements for glycol reboiler. Natural gas that was used for this purpose can now be sent to market.  

The Four Corners Air Quality Task Force report describes how existing dehydrators can be retrofitted to zero emissions dehydrators, “by modifying the gas stream piping and using a 5 kW engine-generator for electricity needs.” The Four Corners Air Quality Task Force reports that operating and maintenance costs are lower than for conventional glycol dehydrators and further reports that EPA estimates the payback for installing a zero emission dehydrator in place of a conventional glycol dehydrator to occur in less than a year.

**E. CENTRAL GATHERING FACILITIES TO REDUCE NOx EMISSIONS FROM WELLHEAD SEPARATION SOURCES**

Centralization of gas well gathering facilities can be employed to reduce and consolidate wellsite sources, including heaters and separators. Colorado’s Reasonable Progress Evaluation for the heater-treater source category evaluated central gathering facilities to remove wellhead separation. With centralization, emissions from heater-treaters would be reduced because fewer heater-treaters would be needed. Colorado described the effectiveness of this restructuring, as follows:

Removing individual heater-treaters and replacing them with a central gathering facility would eliminate emissions from the heater-treaters. The central gathering facility would be a new source of emissions; however, overall emissions will be reduced. Not only would combustion emissions from the multiple heater-treaters be eliminated, VOC emissions from condensate  

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622 Id. at 92.
623 Id. at 93. The report further notes that the electricity needs require a “fuel or power source, for which associated emissions need to be quantified.”
624 Id. at 93.
625 CDPHE RP for Heater-Treaters.
tanks (which would also be removed from wellheads if this technology was implemented) would be eliminated. If a vapor recovery unit (VRU) were used at the central gathering facility, VOCs could be compressed back into the gas stream.\

Colorado acknowledges that it would be most cost effective to implement a centralized gathering facility on a new field but indicates that retrofitting a field already set up with infrastructure for wellhead separation would be site-specific and depends on several considerations, including the number of heater-treaters being removed, topography, gas composition, mineral rights, etc. Additional benefits of a centralized gathering facility include reduced truck traffic to wellheads (which can be significant sources of fugitive PM emissions) and a reduction in condensate and water tanks (and their associated fugitive emissions). States should consider requiring or otherwise advocating for centralized gathering facilities for new oil and gas development as a measure to prevent future visibility impairment.

Estimates for NOx emission reductions from the centralization of gas well gathering facilities were not assessed by Colorado other than saying that overall emissions will be reduced. Colorado anticipated that additional time needed for achieving centralization would be site-specific, e.g., depending on gas well density and topographical barriers. Finally, Colorado notes that central gathering facilities would be more efficient to operate, reducing overall energy impacts.

F. NOx EMISSION LIMITS THAT HAVE BEEN REQUIRED FOR HEATERS AND BOILERS

States and local air agencies have adopted NOx limits for existing boilers and heaters, many of which have been in place for more than 20 years and many of which have been strengthened over the years. In Table 42 below, we summarize some of those state and local air pollution requirements. Primarily, a review of California Air District rules was done for this report, because several of those air districts have adopted the most stringent NOx emission limitations.

Table 42 is a summary of the NOx emission limits required of existing boilers and heaters in states and local air districts across the United States. It is important to note that these are limits that, unless otherwise noted, currently apply to existing units and generally required an air pollution control retrofit. These NOx limits were most likely adopted to address nonattainment issues with the ozone and PM$_{2.5}$ NAAQS. Regardless of the reason for adopting the NOx emission limits, what becomes clear in this analysis is that governments have adopted NOx limitations that require low NOx technologies at boilers and heaters as small as 0.4 MMBtu/hr and SCR for units $\geq$75 MMBtu/hr. The lowest, most broadly applicable NOx limits are those recently adopted by SCAQMD and SJVAPCD. SJVAPCD has a more stringent limit than SCAQMD rules for units between 20 and 75 MMBtu/hr (7 ppm in SJVUAPCD Rule 4320 vs. 9 ppm in SCAQMD Rule 1146), however, it is important to note that for SJVUAPCD’s Rules 4306 and 4320, the owner or operator has the option of paying into an annual emissions fee in lieu of

\[^{626}\text{Id. at 3.}\]
complying with these limits. For units ≥ 75 MMBtu/hr, the emission limit in SCAQMD Rule 1146 of 5 ppm is more stringent than SJVAPCD’s limit of 7 ppm.

Table 42. State/Local Air Agency Natural Gas-Fired Boiler and Heater Rules

<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent lb/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA–SCAQMD</td>
<td>Rule 1146.628</td>
<td>≥5 MMBtu/hr</td>
<td>30 ppm (0.036 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td>Adopted 9/9/98 Last revised 12/7/18</td>
<td>Effective 9/5/08</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>≥5 MMBtu/hr</td>
<td>12 ppm (0.015 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Effective 1/14</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Atmospheric units</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>≥75 MMBtu/hr</td>
<td>5 ppm (0.0062 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Effective 1/1/13</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Excluding thermal fluid heaters</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>≥20 and &lt;75 MMBtu/hr</td>
<td>5 ppm (0.0062 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Effective 12/7/18</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Excluding thermal fluid heaters, certain fire-tube boilers, and units with a previous NOx limit ≤12 and &gt;5 ppm prior to 12/7/18</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>≥5 and &lt;20 MMBtu/hr</td>
<td>9 ppm (0.011 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Effective 1/1/15 (or later for units with a previous NOx limit ≤12 ppm prior to 9/5/08)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Excluding atmospheric units and thermal fluid heaters</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>≥5 and &lt;20 MMBtu/hr</td>
<td>7 ppm (0.0085 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Effective 12/7/18 (or later for units with a previous NOx limit ≤9 ppm prior to 12/7/18)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Fire-tube boilers excluding units with a previous NOx limit ≤12 and &gt;9 ppm prior to 12/7/18</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>≥5 MMBtu/hr</td>
<td>12 ppm (0.015 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Effective 12/7/18 (or later for certain units at non-RECLAIM facilities)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Thermal fluid heaters</td>
<td></td>
</tr>
</tbody>
</table>

627 This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules applicable to the types of units found in the oil and gas industry, but the authors recommend that readers check each specific rule for the details of how the rule applies to different units, and in case of any errors in this table.

<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent lb/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA–SCAQMD</td>
<td>Rule 1146.1⁶²⁹</td>
<td>&gt;2 and &lt;5 MMBtu/hr Effective 9/5/08</td>
<td>30 ppm (0.036 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;2 and &lt;5 MMBtu/hr Effective 1/1/14 Atmospheric units</td>
<td>12 ppm (0.015 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;2 and &lt;5 MMBtu/hr Effective 1/1/14 (or later for units with a previous NOx limit ≤12 and &gt;9 ppm prior to 9/5/08) Excluding atmospheric units, thermal fluid heaters, and certain fire-tube boilers</td>
<td>9 ppm (0.011 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;2 and &lt;5 MMBtu/hr Effective 12/7/18 (or later for units with a previous NOx limit ≤9 ppm prior to 12/7/18) Fire-tube boilers excluding units with ≤12 and &gt;9 ppm prior to 12/7/18</td>
<td>7 ppm (0.0085 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;2 and &lt;5 MMBtu/hr Effective 12/7/18 (or later for certain units at non-RECLAIM facilities) Thermal fluid heaters</td>
<td>12 ppm (0.015 lb/MMBtu)</td>
</tr>
<tr>
<td>CA–SCAQMD</td>
<td>Rule 1146.2⁶³⁰</td>
<td>&gt;0.4 and ≤2 MMBtu/hr Effective 1/1/10 Units manufactured or offered for sale</td>
<td>20 ppm (0.024 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;1 and ≤2 MMBtu/hr Effective 1/1/06 Units more than 15 years old manufactured on or after 1/1/92, except for units at a RECLAIM or former RECLAIM facility</td>
<td>30 ppm (0.037 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;0.4 and ≤1 MMBtu/hr Effective 1/1/06 Units more than 15 years old manufactured prior to 1/1/00, except for units at a</td>
<td>30 ppm (0.037 lb/MMBtu)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent lb/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA–SJVAPCD</td>
<td>Rule 4320[^631]</td>
<td>RECLAIM or former RECLAIM facility</td>
<td>NOx Limit and units (equivalent lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td>Adopted 10/16/08</td>
<td>&gt;5 and ≤20 MMBtu/hr Effective 1/1/14 Except for certain other units[^632]</td>
<td>6 ppmv (0.007 lb/MMBtu)^[633]</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;20 MMBtu/hr Effective 1/1/14[^634] Except for refinery units[^635] and certain other units[^636]</td>
<td>5 ppmv (0.0062 lb/MMBtu)^[637]</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;5 MMBtu/hr Effective at the next unit replacement but no later than 1/1/14 Certain units[^638]</td>
<td>9 ppmv (0.011 lb/MBtu)</td>
</tr>
<tr>
<td>CA–SJVAPCD</td>
<td>Rule 4306 (Phase 3)[^639]</td>
<td>&gt;5 and ≤20 MMBtu/hr</td>
<td>9 ppmv (0.011 lb/MBtu)</td>
</tr>
</tbody>
</table>


[^632]: These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

[^633]: Note, the owner or operator has the option of paying into an annual emissions fee based on total actual emissions, rather than installation of additional NOx controls. These fees are used by the District to achieve cost effective NOx reductions through incentives programs, etc.

[^634]: The rule allows for a “Staged Enhanced Schedule” for oil field steam generators and refinery units as follows: (1) Initial Limit of 9 ppmv (0.011 lb/MBtu), effective 7/1/12; and (2) Final Limit of 5 ppmv (0.0062 lb/MBtu), effective 1/1/14.

[^635]: Note, refinery unit requirements are the same except that these units have a Standard Schedule limit of 6 ppm, effective 7/1/11.

[^636]: These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

[^637]: Note, the owner or operator has the option of paying into an annual emissions fee based on total actual emissions, rather than installation of additional NOx controls. These fees are used by the District to achieve cost effective NOx reductions through incentives programs, etc.

[^638]: These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

[^639]: [https://ww3.arb.ca.gov/drdb/sju/curhtml/r4306.pdf](https://ww3.arb.ca.gov/drdb/sju/curhtml/r4306.pdf)
<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent lb/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Adopted 9/18/03 Last revised 10/16/08</td>
<td>Effective 12/1/08 Except for oil field steam generators, refinery units, and certain other units&lt;sup&gt;640&lt;/sup&gt;</td>
<td>&gt;20 MMBtu/hr Effective 1/1/14 Except for oil field steam generators, refinery units, and certain other units&lt;sup&gt;641&lt;/sup&gt; 6 ppmv (0.007 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;5 MMBtu/hr Effective 6/1/07 Oilfield steam generators Load-following units&lt;sup&gt;642&lt;/sup&gt; 15 ppm (0.036 lb/MMBtu)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>&gt;5 MMBtu/hr Effective 6/1/07 Certain other units&lt;sup&gt;643&lt;/sup&gt; 30 ppm (0.036 lb/MMBtu)</td>
<td></td>
</tr>
<tr>
<td>CA–SJVAPCD</td>
<td>Rule 4307&lt;sup&gt;644&lt;/sup&gt;</td>
<td>&gt;2 and ≤5 MMBtu/hr Existing units</td>
<td>30 ppm (0.036 lb/MMBtu)</td>
</tr>
<tr>
<td></td>
<td>Adopted 12/15/05 Last revised 4/21/16</td>
<td>&gt;2 and ≤5 MMBtu/hr New or replacement units Effective 1/1/16 Atmospheric units Non-atmospheric units</td>
<td>12 ppm (0.014 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)</td>
</tr>
<tr>
<td>CA–SJVAPCD</td>
<td>Rule 4308&lt;sup&gt;645&lt;/sup&gt;</td>
<td>&gt;0.4 and &lt;2 MMBtu/hr Effective 1/1/15 Point-of-sale&lt;sup&gt;646&lt;/sup&gt; PUC gas Non-PUC gas</td>
<td>20 ppm (0.024 lb/MMBtu) 30 ppm (0.036 lb/MMBtu)</td>
</tr>
<tr>
<td>CA–SMAQMD</td>
<td>Rule 411&lt;sup&gt;647&lt;/sup&gt;</td>
<td>Effective 10/27/09</td>
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</tr>
</tbody>
</table>

<sup>640</sup> These certain other units include: (1) load-following units; (2) units limited by a Permit to Operate to an annual heat input 9–30 billion Btu/yr; and (3) units in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is > 5 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

<sup>641</sup> *Id.*

<sup>642</sup> Load-following units must meet a limit of 9 ppm under the Enhanced Schedule, with a compliance date of 12/1/08.

<sup>643</sup> These certain other units include: (1) refinery units >5 and ≤65 MMBtu/hr (note that units >65 and ≤110 MMBtu/hr are required to meet a limit of 25 ppm (0.031 lb/MMBtu and units >110 MMBtu/hr are required to meet a limit of 5 ppm); (2) units limited by a Permit to Operate to an annual heat input 9–30 billion Btu/yr; and (3) units in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is > 5 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.


<sup>646</sup> This point-of-sale rule covers units supplied, sold, offered for sale, installed, or solicited for installation.

<sup>647</sup> [http://www.airquality.org/ProgramCoordination/Documents/rule411.pdf](http://www.airquality.org/ProgramCoordination/Documents/rule411.pdf).
<table>
<thead>
<tr>
<th>State/Local</th>
<th>Regulation</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent lb/MMBtu)</th>
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</thead>
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<tr>
<td>CA–SMAQMD</td>
<td>Rule 414&lt;sup&gt;648&lt;/sup&gt;</td>
<td>New and existing units ≥1 and &lt;5 MMBtu/hr ≥5 and ≤20 MMBtu/hr &gt;20 MMBtu/hr</td>
<td>30 ppm (0.036 lb/MMBtu) 15 ppm (0.036 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)</td>
</tr>
<tr>
<td>CA–VCAPCD</td>
<td>Rule 74.15.1&lt;sup&gt;650&lt;/sup&gt;</td>
<td>≥1 and &lt;5 MMBtu/hr &lt;1 MMBtu/hr &gt;0.4 and &lt;1 MMBtu/hr Effective 10/25/18 (date of last revision) Point-of-sale&lt;sup&gt;649&lt;/sup&gt;</td>
<td>20 ppm (0.024 lb/MMBtu)</td>
</tr>
<tr>
<td>CA–Santa Barbara County APCD</td>
<td>Rule 361&lt;sup&gt;651&lt;/sup&gt;</td>
<td>≥2 and ≤5 MMBtu/hr Existing units Installed and modified (after 1/1/20): Atmospheric units Non-atmospheric Units</td>
<td>30 ppm (0.036 lb/MMBtu) 12 ppm (0.014 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)</td>
</tr>
<tr>
<td>CA–Santa Barbara County APCD</td>
<td>Rule 342&lt;sup&gt;652&lt;/sup&gt;</td>
<td>≥5 MMBtu/hr Existing units Installed and modified (after 1/1/20): ≥5 and ≥20 MMBtu/hr &gt;20 MMBtu/hr</td>
<td>30 ppm (0.036 lb/MMBtu) 9 ppm (0.011 lb/MMBtu) 7 ppm (0.0085 lb/MMBtu)</td>
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<tr>
<td>CA–Feather River AQMD</td>
<td>Rule 3.23&lt;sup&gt;653&lt;/sup&gt;</td>
<td>&gt;0.4 and ≤1 MMBtu/hr Effective 1/1/15</td>
<td>20 ppm (0.024 lb/MMBtu)</td>
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<tr>
<td>CA–Bay Area AQMD</td>
<td>Regulation 9 Rule 7&lt;sup&gt;655&lt;/sup&gt;</td>
<td>&gt;2 and ≤5 MMBtu/hr Effective 1/1/15</td>
<td>30 ppm (0.036 lb/MMBtu)</td>
</tr>
</tbody>
</table>

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<sup>648</sup> [http://www.airquality.org/ProgramCoordination/Documents/rule414.pdf](http://www.airquality.org/ProgramCoordination/Documents/rule414.pdf).

<sup>649</sup> This point-of-sale rule covers units manufactured, distributed, offered for sale, sold, or installed.


<sup>654</sup> This point-of-sale rule covers units offered for sale, sold, or installed.

<table>
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<th>State/Local</th>
<th>Regulation</th>
<th>Applicability</th>
<th>NOx Limit and units (equivalent lb/MMBtu)</th>
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</thead>
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<tr>
<td>TX- Houston-Galveston-Brazoria Area</td>
<td>30 TAC 117.2010(c)(1)</td>
<td>Emission specs for 8hr ozone demo 656</td>
<td>0.036 lb/MMBtu (or, alternatively 30 ppm @ 3% O2)</td>
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<tr>
<td>TX</td>
<td>30 TAC 117.3205(a)</td>
<td>Statewide Point-of-sale 658</td>
<td>30 ppm or 0.037 lb/MMBtu</td>
</tr>
<tr>
<td>MA</td>
<td>310 CMR 7.26(30)</td>
<td>&gt;0.4 and ≤2 MMBtu/hr Effective 7/1/02</td>
<td>0.0350 lb/MMBtu</td>
</tr>
<tr>
<td>NY</td>
<td>6 CRR-NY 227-2.4</td>
<td>&gt;25 and ≤100 MMBtu/hr</td>
<td>0.05 lb/MMBtu</td>
</tr>
<tr>
<td>GA</td>
<td>Rule 391-3-1-.02.(2)(III)1</td>
<td>Effective 5/1/00 Fuel-burning equipment 45 county area - ozone May 1 – September 30 each year</td>
<td>30 ppm</td>
</tr>
</tbody>
</table>

658 Applies to units sold, distributed, installed, or offered for sale.
660 RACT for major sources of NOx:
[https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a432a117e6e0f345?viewType=FullText&originatContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default)](https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a432a117e6e0f345?viewType=FullText&originatContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default)).
As Table 42 shows, several state and local air pollution control agencies have adopted NOx emission limits for boilers and heaters that reflect the application of low NOx burner technologies, and reflect SCR for units ≥75 MMBtu/hr. These air agencies have thus found that the levels of NOx control listed in Table 42, including NOx limits as low as 5 ppm for larger units, in the range of 5–12 ppm for smaller units, and as low as 20 ppm for very small units, providing relevant examples for states to consider in their second round haze plans to help make reasonable progress towards remedying existing visibility impairment. The fact that these limits could apply to modified units >2 MMBtu/hr means that the states consider retrofit controls to meet the emission limits in Table 42 above to be cost effective, and should also consider the cost effectiveness of retrofitting units >5 MMBtu/hr to meet NOx limits as low as 2–3.5 ppm based on the work being done in the SJVAPCD.

G. SUMMARY – NOx CONTROLS FOR NATURAL GAS-FIRED HEATERS AND BOILERS

The above analyses and rule data demonstrate that 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. 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. 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. For most units, including atmospheric units, a blower may be required to mix the fuel and air prior to combustion. It is possible to reach NOx levels of 9 ppm for non-atmospheric units and 12 ppm for atmospheric units without the use of FGR.662

Further, SJVAPCD 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. For the lowest NOx limit of 5–6 ppm currently applicable to units under rules adopted by SCAQMD and SJVAPCD, SCR is presumably necessary to meet these limits.

As states evaluate regulation of NOx emissions from boilers and heaters, there are several factors to consider, such as draft type (i.e., atmospheric vs. non-atmospheric), operating capacity factor, and size. Nonetheless, given the numerous local NOx limits in Table 42 above that reflect operation of low NOx burner technology, and SCR for larger units, these controls for units of all sizes should generally be considered as cost effective measures available to make reasonable progress from boilers, reboilers, and

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662 See, e.g., Santa Barbara County APCD 2019 Draft Staff Report.
heaters, given that similar sources have assumed similar costs of control to meet Clean Air Act requirements.

VIII. ADDRESSING VISIBILITY-IMPAIRING EMISSIONS FROM FLARING AND THERMAL INCINERATION OF EXCESS GAS AND WASTE GAS

Gas flaring is a process to combust excess or waste gases from oil wells, gas processing plants, or oil refineries. Flaring is intended as a means of disposal of excess gas as a safety measure and is also done to relieve pressure in gas pipelines. Combustion of excess or waste gas can also be accomplished with thermal incinicators rather than flaring. Combustion of excess gas whether done through flaring or thermal incineration is also a VOC control device, as the combustion of the gas destroys most of the VOCs. However, the extent to which VOC emissions are effectively destroyed depends on the design and operation of the combustion device.

There are several processes associated with oil and gas development in which excess gas is flared or combusted, including the following: during testing of a new oil or gas well, when natural gas co-occurs with a new oil well, at gas pipeline headers and at gas processing plants when needed to relieve pressure, at gas compressor stations to combust vapors captured by a dehydrator unit, at gas processing plants and at oil refineries when an upset occurs or to allow maintenance of equipment, and at gas sweetening plants.

A flare system is a thermal oxidation process using an open flame. It consists of an elevated flare stack through which the waste or excess gas stream flows, where it is combusted at the tip of the stack producing a flame. This is sometimes referred to as a “candlestick” flare. A thermal incinerator, which is also called a direct flame incinerator, thermal oxidizer, or an afterburner, is a thermal oxidation process that occurs in an enclosed combustion chamber. The temperature of the waste gas is raised in the combustion chamber in the presence of oxygen above its autoignition point by passing the gas through a flame which is maintained by the waste gas and auxiliary fuel, and combustion of the waste gas occurs. More specific descriptions of these control devices are provided below. The purpose of both a flare and a thermal incinerator is to combust the excess or waste gas and reduce VOC emissions.

A. FLARING SYSTEM

EPA describes a flare system as follows:

Flaring is a high-temperature oxidation process used to burn waste gases containing combustible components such as volatile organic compounds (VOCs), natural gas (or

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methane), carbon monoxide (CO), and hydrogen (H₂). The waste gases are piped to a remote, usually elevated location, and burned in an open flame in ambient air using a specially designed burner tip, auxiliary fuel, and, in some cases, assist gases like steam or air to promote mixing for nearly complete (e.g., ≥ 98%) destruction of the combustible components in the waste gas. Note that destruction efficiency is the percentage of a specific pollutant in the flare vent gas that is converted to a different compound (such as carbon dioxide [CO₂], carbon monoxide, or another hydrocarbon intermediate), while combustion efficiency is the percentage of hydrocarbon in the flare vent gas that is completely converted to CO₂ and water vapor.

Combustion requires three ingredients: fuel, an oxidizing agent (typically oxygen in the air), and heat (or ignition source). Flares typically operate with pilot flames to provide the ignition sources, and they use ambient air as the oxidizing agent. The waste gases to be flared typically provide the fuel necessary for combustion. Combustible gases generally have an upper and lower flammability limit. The upper flammability limit (UFL) is the highest concentration of a gas in air that is capable of burning. Above this flammability limit, the fuel is too rich to burn. The lower flammability limit (LFL) is the lowest concentration of the gas in air that is capable of burning. Below the LFL, the fuel is too lean to burn. Between the UFL and the LFL, combustion can occur. Completeness of combustion in a flare is governed by flame temperature, residence time and flammability of the gas in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and available oxygen for free radical formation. Combustion is complete if all hydrocarbons and CO are converted to CO₂ and water. Incomplete combustion results in some hydrocarbons or CO discharged to the flare being unaltered or converted to other organic compounds such as aldehydes or acids.

Flares, if operated in a manner to provide for complete combustion, are intended to destroy hydrocarbons and VOCs. Flaring also converts methane to CO₂. Both are greenhouse gases, but methane is a more powerful greenhouse gas. EPA indicates that properly operated flares should achieve 98% destruction efficiency of VOCs. However, according to EPA studies, flares “can operate at a wide range of Destruction and Removal Efficiency (DRE).” 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,” 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.

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666 See https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#Learn%20why
Flaring is also a significant cause of \text{SO}_2 emissions when sour gas or acid gas is flared. Although the sulfur content for gas to be considered sour gas can vary by state, gas with a hydrogen sulfide (H\textsubscript{2}S) content of 5.7 milligrams per cubic meter of gas (about 4 ppm) is generally considered to be sour gas. Among other places in the United States, sour gas exists in areas of New Mexico, Texas, Wyoming, and North Dakota.

In terms of air pollution control measures to apply directly to flare design and operation, controls and techniques to ensure or improve DRE are the primary pollution control for natural gas flares. These are discussed further below in Section E.

**B. THERMAL INCINERATION**

Thermal incineration of gases is generally able to result in more complete combustion due to the greatly improved ability to control fuel and air flow, temperature, turbulence, and residence time. Thus, incineration of excess gases may result in greater destruction of hydrocarbons and lower VOC emissions than if the same amount of gas was flared. As with flaring, while thermal incineration is a VOC control technology, the incineration of waste gas does result in emissions of NOx and some particulate matter as a result of incomplete combustion, along with CO\textsubscript{2}. Further, when sour gas or acid gas is combusted in a thermal incinerator, SO\textsubscript{2} will be emitted. In the absence of SO\textsubscript{2} pollution controls, incineration of waste or excess gases may not be the best choice compared to flaring for gas with sulfur compounds, because the elevated height of the flare can allow for greater dispersion of the SO\textsubscript{2} emissions. On the other hand, use of a thermal incinerator to combust excess or waste gas allows for the addition of an acid gas scrubber to remove SO\textsubscript{2} and also could allow for use of the thermal heat produced by the waste gas combustion, whereas those opportunities for SO\textsubscript{2} control and for getting some energy benefit from the combustion of waste gases do not exist with a flare. Further, low NOx combustion controls exist for thermal incinerators. The pollution controls to apply directly to thermal incinerators are discussed further below in Section F.

The best method to reduce/eliminate air emissions from flaring or incineration of excess or waste gas is to avoid the need for combustion of the gases altogether. The options for doing so are discussed further below in Section D.

**C. \text{SO}_2 EMISSIONS FROM THE DESTRUCTION OF SOUR GAS WASTE STREAMS**

For sour gas, the sulfur compounds must be removed to produce pipeline quality natural gas. H\textsubscript{2}S is the sulfur compound of most concern in sour gas because the majority of sulfur compounds in sour gas are in the form of H\textsubscript{2}S and because it is it is very poisonous, explosive and corrosive. According to the Occupational Safety and Health Administration (OSHA), exposure to H\textsubscript{2}S can cause significant eye and respiratory irritation and exposure to high concentrations of H\textsubscript{2}S can cause shock, convulsions, inability

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669 http://naturalgas.org/naturalgas/processing-ng/.
to breathe, extremely rapid unconsciousness, coma and death.”  It is also very corrosive to gas pipelines and can be explosive. Thus, H₂S has to be removed from sour gas streams before the gas can be sent into gas pipelines to consumers. H₂S is removed from the gas in gas sweetening plants, usually via an amine process which separates the H₂S and also CO₂ from the natural gas. Since 1985, the EPA’s NSPS have required gas sweetening plants with a capacity of more than 2 long tons per day of H₂S in the acid gas to either 1) completely reinject the acid gas stream into oil- or gas-bearing geologic strata or 2) to use a sulfur reduction and removal technology to reduce SO₂ emissions from the acid gas before it is flared or combusted. Sweetening plants that aren’t subject to such requirements may be allowed to flare the acid gas stream or incinerate the gas stream, either of which could release very significant quantities of SO₂ emissions, although it is not clear that any such plants continue to operate. However, even for gas sweetening plants required to control the H₂S by reinjecting into the geologic strata or by using a sulfur recovery unit or other control method, SO₂ emissions from flaring or from thermal incineration is of significant concern. For those plants, flaring episodes occur due to malfunctions or due to maintenance or possibly for other reasons. When flared or combusted, the H₂S in the acid gas stream converts to SO₂, which is a significant visibility-impairing pollutant. EPA states that “100 tons or more of SO₂ can be released in [a flaring episode] within a 24-hour period.” In the case of flaring of acid gas streams, the only methods to reduce SO₂ emissions directly from flaring acid gas streams at gas sweetening plants are to reduce or eliminate flaring episodes. Methods to reduce such flaring episodes are discussed in the next section.

D. CONTROL MEASURES, TECHNIQUES, AND OPERATING PRACTICES TO PREVENT FLARING OR INCINERATION OF EXCESS OR WASTE GAS

Prevention of flaring/incineration of excess or waste gases is the best method to reduce the air emissions from this source category. It will also prevent NOx, particulate matter, air toxic emissions including formaldehyde, and CO₂ emissions, as well as any VOCs and methane that are not destroyed in the combustion process. Available methods and techniques to reduce flaring or thermal combustion of excess or waste gas are discussed below.

1. REDUCING FLARING AT THE WELL SITE

In 2016, the U.S. Bureau of Land Management (BLM) issued a rule intended “to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production on onshore Federal and Indian (other than Osage Tribe) leases.” This rule is often referred to as the “BLM Waste Prevention Rule.”

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674 See 40 C.F.R. Subparts LLL and OOOO.
676 Id.
The fact sheet issued by EPA at the time of the rulemaking stated that the rule would phase in, over several years, a flaring limit per development oil well that ratcheted down over time.\textsuperscript{678} There were several options for complying with the flaring limits, including: “expanding gas-capture infrastructure (e.g., installing compressors to increase pipeline capacity, or connecting wells to existing infrastructure through gathering lines); adopting alternative on-site capture technologies (e.g., compressing the natural gas or stripping out natural gas liquids and trucking the product to a gas processing plant); or temporarily slowing production at a well to minimize losses until capture infrastructure is installed.”\textsuperscript{679} The rule also required operators to evaluate opportunities for gas capture before drilling a development oil well, which were to be submitted with an Application for a Permit to Drill and which were to be shared with midstream gas capture companies “to facilitate timely pipeline development. . . .”\textsuperscript{680} In 2018, the BLM rescinded the gas capture requirements of the 2016 rule “in favor of an approach that relies on State and tribal regulations and reinstates the NTL-4A standard for flaring in the absence of State or tribal regulations.”\textsuperscript{681} The 2018 BLM rulemaking describes the NTL-4A standard as the BLM’s existing policy from before the 2016 BLM Waste Prevention Rule, which was published in the Federal Register in 1979 (44 Fed. Reg. 76600, Dec. 27, 1979)\textsuperscript{682} and “governed venting and flaring from BLM-administered leases for more than 35 years.”\textsuperscript{683} The BLM has clearly indicated that states could regulate flaring. Indeed, development of the BLM Waste Prevention Rule considered “analogous state requirements related to waste of oil and gas resources,” and the BLM “reviewed requirements from Alaska, California, Colorado, Montana, North Dakota, Ohio, Pennsylvania, Utah, and Wyoming.”\textsuperscript{684} Further, EPA has been requiring the capture and collection of excess gas from the drilling of natural gas wells under the NSPS since 2012.\textsuperscript{685} Thus, there are example state and federal rules\textsuperscript{686} and methods that states should adopt, if not already in place, to reduce flaring of gas associated with oil wells, that would not only reduce visibility-impairing pollution from flaring, but that would also reduce air toxics and greenhouse gases emissions as well as ensure that the natural gas produced along with oil at oil wells is utilized as an energy source rather than just flared or combusted to destroy the VOCs.

\textsuperscript{680} Id.
\textsuperscript{681} 83 Fed. Reg. 49,184 at 49,188 (Sept. 28, 2018).
\textsuperscript{682} 83 Fed. Reg. 49,184 at 49,185 (Sept. 28, 2018).
\textsuperscript{683} 83 Fed. Reg. 49,189 at 49,185 (Sept. 28, 2018).
\textsuperscript{684} 81 Fed. Reg. 83,008 at 83,019 (Nov. 18, 2016).
\textsuperscript{685} 40 C.F.R. Part 60, Subpart OOOO, §§60.5375.
2. REDUCING FLARING AT COMPRESSOR STATIONS, GAS PROCESSING PLANTS, AND GAS SWEETENING PLANTS

As discussed above, flaring at compressor stations and gas processing plants including gas sweetening plants, is often due primarily to plant upsets and maintenance. Flaring of sour gas or acid gas streams at gas sweetening plants can be a significant source of visibility-impairing SO$_2$, and thus reducing flaring emissions at gas sweetening plants could be an effective reasonable progress measure to address regional haze. Reducing flaring will also reduce the NOx, PM, VOCs, and CO$_2$ emitted from the flares.

EPA listed the following measure to prevent excess flaring at refineries, and this same approach can be used to identify methods and techniques to reduce flaring at natural gas compressor stations and at gas processing facilities:

Conduct a root-cause analysis of each flaring incident to identify if any equipment and/or operational changes are necessary to eliminate or minimize that cause so as to reduce or avoid future flaring events. As appropriate, corrective measures should be taken and implemented. If the analysis shows that the same cause has happened before, the incident should not be considered a malfunction and corrective measures should be taken to prevent future occurrences....

In addition, it is imperative to ensure that there is adequate gas handling capacity at the various processing points in a compressor station, gas processing or gas sweetening plant. EPA states that “[r]edundant units can prevent flaring by allowing one unit to operate if the other needs to be shut down for maintenance or an upset. . . .” Thus, adding excess capacity and/or backup units could be very important in reducing the amount of flaring due to upsets.

As part of their evaluation of measures to provide for reasonable progress towards the national visibility goal, states should evaluate the flaring episodes at the compressor station and at gas processing plants, including the collection of data on the length of time of each flaring episode, frequency, and causes. For plants that have more frequent flaring episodes, and especially for those plants flaring sour gas or acid gas streams from a gas sweetening plant, states should evaluate the root causes of upsets that cause flaring episodes to determine if measures, such as improved maintenance or duplicative parts or processing units, can be employed to reduce flaring episodes.

E. POLLUTION CONTROL TECHNIQUES FOR FLARES

EPA has described the control techniques for flares, based on the federal requirements in EPA’s New Source Performance Standards (NSPS) (at 40 C.F.R. §60.8) and EPA’s National Emission Standards for Hazardous Air Pollutants (NESHAPs) (at 40 C.F.R. §63.11) as follows:

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688 Id.
At a minimum, these [NSPS and NESHAP] rules require flares to be:

- Designed and operated with no visible emissions using EPA [test] Method 22 (except for periods not to exceed 5 minutes in 2 hours);
- Operated with a flame present at all times, confirmed by the use of a thermocouple or equivalent device;
- Used only when the net heating value of the gas to be combusted is 300 BTU per standard cubic foot (BTU/scf) or greater (if the flare is steam- or air-assisted), or 200 BTU/scf or greater (if the flare is nonassisted); and
- Designed for and operated with an exit velocity less than 60 feet per second (f/sec). An exit velocity of greater than 60 ft/sec but less than 400 ft/sec may be used if the net heating value of the gas being combusted is sufficiently high.  

Other requirements that must be met include that the flare must be operated at all times in a manner consistent with good air pollution control practices for minimizing emissions, and that flaring operations must be monitored to ensure they are operated and maintained according to their design. EPA has listed several other more detailed guidelines to ensure flares are properly operated. Proper training of employees is also an important part of ensuring the flares are properly operated. States must require documentation of each flaring episode to ensure that the flaring regulations of the NSPS and NESHAPs have been complied with, as well as to ensure that adequate records of the amount of gas flared and causes of flaring are maintained and reported.

The above operating standards are required for all flaring. Alternatives to flaring include 1) gas capture to decrease or eliminate flaring as discussed above, or 2) combusting the gas in a thermal incinerator which can provide for greater destruction of VOC emissions. Also, additional air pollution controls can be used at an incinerator, as is discussed below.

**F. POLLUTION CONTROL TECHNIQUES FOR THERMAL INCINERATION OF EXCESS OR WASTE GAS**

As discussed above, waste gases or excess gas can be disposed of via thermal incineration rather than a flare. EPA describes a thermal incinerator, or a thermal oxidizer, as follows:

Incineration, or thermal oxidation is the process of oxidizing combustible materials by raising the temperature of the material above its auto-ignition point in the presence of oxygen, and maintaining it at high temperature for sufficient time to complete combustion to carbon dioxide and water. Time, temperature, turbulence (for mixing), and the availability of oxygen all affect the rate and efficiency of the combustion process. These factors provide the basic design parameters for VOC oxidation systems (ICAC, 1999).

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690 Id. at 2; see also 40 C.F.R. §63.172(e) and 60.482-10.
691 See, e.g., EPA, Enforcement Alert, EPA Enforcement Targets Flaring Efficiency Violations, August 2012, at 3.
A straight thermal incinerator is comprised of a combustion chamber and does not include any heat recovery of exhaust air by a heat exchanger (this type of incinerator is referred to as a recuperative incinerator).

The heart of the thermal incinerator is a nozzle-stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. Upon passing through the flame, the waste gas is heated from its preheated inlet temperature to its ignition temperature. The required level of VOC control of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. The nominal residence time of the reacting waste gas in the combustion chamber is defined as the combustion chamber volume divided by the volumetric flow rate of the gas.

EPA indicates that thermal incinerators can achieve 98% to 99.9999% destruction of VOCs. However, thermal incinerators typically require auxiliary fuel to preheat the waste gas and sustain the heat necessary for destruction of VOCs. The high temperature reaction necessary in an incinerator to destroy the VOC and air toxic emissions can result in increased NOx emissions. To limit NOx emissions, low NOx burners or other low NOx processes are available control measures to integrate into the thermal incinerator to limit NOx emissions. Thus, for any thermal incinerators or thermal oxidizers, low NOx burners or other low NOx emission systems should be installed to minimize NOx emissions from the thermal incinerator.

It is important to note that thermal incinerators can be used at gas sweetening plants along with acid gas scrubbers to remove the SO\(_2\) that is formed from combusting the H\(_2\)S in the acid gas. Such a system could potentially be used as an SO\(_2\) control, or it could be used as a backup system for a sulfur recovery unit when it is down due to malfunction, maintenance, or during startup or shutdown. This method of control could greatly reduce if not eliminate the SO\(_2\) emissions that occur at gas sweetening.

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693 Id. at 5.
facilities when the gas injection well or sulfur recovery unit is not in operation due to malfunctions or maintenance.

In many respects, combusting of waste gases and/or excess gas in a thermal incinerator seems more preferable from an air pollutant perspective than flaring, because thermal incineration will likely result in a greater destruction efficiency of VOCs and because control options exist for limiting emissions of NOx and of SO₂ (to the extent that sour gas or an acid gas stream is what was being flared). Further, there could be an option of gathering and routing excess gas emission from multiple points to a centralized thermal incinerator. Moreover, continuous emission monitoring systems (CEMS) could be installed in the thermal oxidizer stack to provide valuable actual emissions data due to the combustion of waste or excess gases, including information to ensure that optimal VOC destruction efficiency is achieved.

However, the need for auxiliary fuel in thermal combustion means more CO₂ will be emitted than if the gas stream was flared. Yet, there are options for thermal incinerators that recover the waste heat, which are called recuperative oxidizers or regenerative oxidizers. The recovered waste heat can be used to preheat the incoming air which would reduce the amount of supplemental fuel required.

To sum up, use of a recuperative or regenerative thermal incinerator (thermal oxidizer) with low NOx combustion controls, CEMs, and an acid gas scrubber if necessary, seems to be a preferable alternative to flaring of waste gas streams. Such a system would provide better control of VOCs, reduce NOx emissions from combustion of the waste gas via the use of low NOx combustion controls, and provide the ability to add an acid gas scrubber to remove SO₂ (which is a control option that does not exist for flares).

G. SUMMARY – BEST OPTIONS FOR CONTROLLING EMISSIONS DUE TO FLARING OR INCINERATION OF EXCESS OR WASTE GAS

Based on the above analysis, it seems evident that prevention of flaring through the collection of excess gas is the most beneficial option for reducing emissions from flaring. Capturing and using the natural gas that is produced at oil wells would ensure that the energy value of the gas is not wasted by being combusted in a flare or in an incinerator, and it is very likely that the end user of the gas would at least be using some level of NOx and VOC control.

Thermal incineration should be considered in lieu of flaring for waste gases due to the pollution controls for NOx and SO₂ that are available and because of the improved operation and VOC destruction. Moreover, use of a thermal incinerator provides the opportunity to monitor and accurately track emissions from the combustion of waste or excess gases with the use of CEMS.

At gas processing facilities including gas sweetening plants, it is important that the causes of flaring episodes be documented and assessed to determine any changes in operations, training, and/or in equipment that may be needed to reduce plant upsets and maintenance during which flaring occurs due

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698 EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022, at 5.
699 Id.
to the unavailability of plant equipment to process the gas stream. As stated above, adding excess capacity and/or backup units could be very effective in reducing the amount of flaring due to upsets. Proper maintenance of equipment is also key, as is appropriate training of staff to minimize flaring episodes due to maintenance and upsets.

In general, states should ensure that their rules require companies to document all flaring episodes, including the cause, duration of the flaring, flue gas flow, actions taken to stop the flaring, and emission estimates, and to submit such documentation to the state or local air agency in a timely manner. This data will best enable states to develop appropriate rules and procedures to limit the various causes of flaring emissions within its state.

Overall, the goal of state programs to address flaring emissions should be to minimize flaring to the maximum extent possible. However, for those situations when flaring does occur, it is imperative that the flares be operated in accordance with NSPS and NESHAP requirements, and that the flares are operated and maintained in accordance with their design. Moreover, to ensure these requirements are being met and to ensure that flaring is minimized to the maximum extent possible, the state or local air agencies must conduct thorough oversight into the causes of flaring episodes, to ensure that the facility is being maintained and operated in a manner to minimize all flaring episodes to the extent possible.