From:	Stinson, Colleen (ECY)
To:	Guilfoil, Elena (ECY)
Subject:	e-comments
Date:	Thursday, February 18, 2021 8:06:28 AM
Attachments:	NPCAetalCmmtLtrWARP_Ex2-11-02162021.pdf
Importance:	High

2nd e-mail

From: sara@laumannlegal.com <sara@laumannlegal.com>
Sent: Tuesday, February 16, 2021 4:43 PM
To: Gent, Philip (ECY) <pgen461@ECY.WA.GOV>
Cc: Stephanie Kodish <skodish@npca.org>; Joshua Jenkins <jjenkins@npca.org>; katelyn@pugetsoundkeeper.org; adrienne@duwamishcleanup.org; gwingard@earthlink.net; joshua.smith@sierraclub.org; Viswanathan.krishna@Epa.gov; Berkey, Jacob (ECY) <berj461@ECY.WA.GOV>; Hanlon-Meyer, Christopher (ECY) <chrh461@ECY.WA.GOV>; Huitsing, Gary (ECY) <ghui461@ECY.WA.GOV>; Inloes, Scott (ECY) <SINL461@ECY.WA.GOV>; Taylor, Kathy (ECY) <ktay461@ECY.WA.GOV>; Stinson, Colleen (ECY) <csti461@ECY.WA.GOV>; Vicki Stamper <stamper.vr@gmail.com>; Steven Klafka <sklafka@wingraengineering.com>
Subject: Conservation Organizations' Comments (Exhibits 2-11) on Ecology's Informal Comment Period on the RH RP Reports

Dear Mr. Gent,

As referenced in my prior email, attached are Exhibits 2-11.

Best,
Sara Laumann

Sara L. Laumann
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Exhibit 2

December 3, 2020

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Olympia, WA 98504-7600

Judy Schwieters
Department of Ecology
Industrial Section
P.O. Box 47600
Olympia, WA 98504-7600

Submitted via online public comment forms at:
http://aq.ecology.commentinput.com/?id=Wh9Km (Intalco draft order)
http://aq.ecology.commentinput.com/?id=Yg439 (Alcoa Wenatchee draft order)

Re: NPCA Comments on Draft Air Quality Agreed Orders for Alcoa Wenatchee Agreed Order 18100 (Chelan County), Intalco Agreed Order 18216 (Whatcom County)

Dear Mr. Nguyen and Ms. Schwieters:

On behalf of the National Parks Conservation Association (NPCA), Laumann Legal, LLC. respectfully submits the following comments regarding the Washington Department of Ecology's ("Ecology") proposed source-specific amendments to its Regional Haze State Implementation Plan ("Haze Plan") for two facilities: Alcoa Wenatchee ("Wenatchee") and Alcoa Intalco ("Intalco").

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. NPCA has over 340,000 members nationwide with its main office in Washington, D.C. and 24 regional and field offices. NPCA's regional Northwest office is located in Seattle working on a variety of issues affecting Northwest national parks such as North Cascades, Olympic, and Mt. Rainier National Parks. NPCA is an active nation-wide in advocating for strong air quality requirements in our parks, including submission of petitions and comments relating to visibility issues, regional haze State Implementation Plans, global warming and mercury impacts on parks, and emissions from individual power plants and other sources of pollution affecting National Parks. NPCA's members live near, work at, and recreate in all the national parks of the Northwest, including those directly affected by the Alcoa Intalco Works near Ferndale, Washington and the Alcoa Wenatchee Works in Malaga, Washington. Ecology's proposed source-specific Regional Haze SIP fails to meet the legal requirements of the Clean Air Act and federal regulations and fails to address emissions that cause haze pollutions.

As detailed below, NPCA respectfully requests that the proposed Haze Plan be revised to adequately ensure pollutants from these facilities are enforceably limited.

INTRODUCTION AND BACKGROUND

Washington is home to three national parks, Mount Rainier, Olympic, and North Cascades National Parks, and five wilderness areas, Alpine Lakes, Glacier Peak, Goat Rocks, Mount Adams, and Pasayten Wilderness Areas. Our national parks and wilderness areas are iconic, treasured landscapes and Washington is rich in national parks and natural areas.

Congress set aside these national parks and wilderness areas to protect our natural heritage for generations. Washington's protected areas also generate millions of dollars in tourism revenue, provide habitat for a range of species, and provide year-round recreational opportunities for residents. These special places are designated "Class I areas" under the Clean Air Act ("CAA") and as such, their air quality is entitled to the highest level of protection. Unfortunately, that requirement and promise is unfulfilled because the air in most Class I areas, including in Washington's most treasured natural areas, remains polluted by industrial sources, including the two sources covered by this proposal.

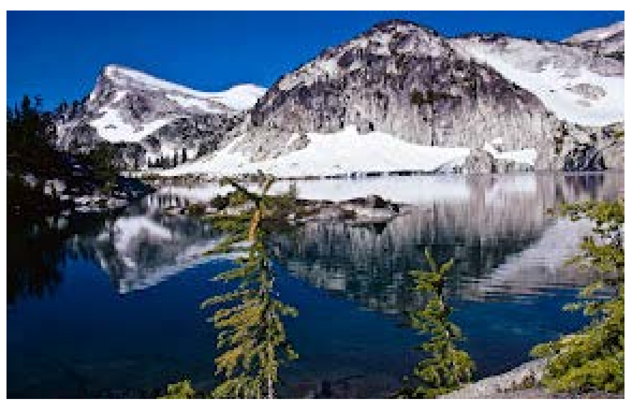
Figure 1. Alpine Lakes Wilderness. (U.S. Forest Service)

Alcoa Wenatchee. Emissions from the Wenatchee facility located at Malaga/Alcoa Highway, Washington, adversely affect visibility at the Alpine Lakes Wilderness Area, located approximately 28 miles west of the facility, at the crest of the Cascade Mountain Range.[1] The Alpine Lakes Wilderness encompasses approximately 394,000 acres in the Central Cascades Region within Washington.[2] The area is accessed by 47 trailheads and 615 miles of trails, including 67 miles of the Pacific Crest National Scenic Trail (PCT).[3] The Enchantment Lakes area contains the Cashmere Crags, which rate among the best rock-climbing

[1] 78 Fed. Reg. 79344, 79348-79349. (Dec. 30, 2013).
[2] U.S. Department of Agriculture, Forest Service, Alpine Lakes Wilderness, https://www.fs.usda.gov/recarea/okawen/recarea/?recid=79432 (Nov. 26, 2020).
[3] *Id.*

sites in the western United States. There are more than 700 lakes and mountain ponds in Alpine Lakes, which dot the glacier-carved terrain of this wilderness.[4]

According to NPCA's analysis, emissions from Wenatchee rank the facility third on the list of worst sources of regional haze pollution in the State,[5] with emissions potentially impacting 34 Class I areas, including North Cascades National Park to the northwest and Mount Rainier National Park to the southwest.

The Wenatchee facility consists of a carbon anode production plant, four prebake aluminum potlines, and an ingot casting facility.[6] It initially opened in 1952 with four potlines.[7] In 1967, a fifth potline was added along with increased anode production capability and materials handling operations. In 2018, Line 3, one of the original potlines that had not operated since 2001, was permanently closed, resulting in four remaining potlines.[8] Another line was permanently closed in 2004.[9] At that time, the permanently closed portions were to be evaluated for potential redevelopment.[10] EPA's FIP set new emission limits for specific emission points and a plant-wide limit on the sulfur content of the petroleum coke, representing what the facility emitted, and did not result in any actual emission reductions. The Wenatchee facility has been closed since December 18, 2015, with its reopening uncertain.[11]

Alcoa Intalco. Notably, the Intalco facility is the single worst haze polluter at North Cascades National Park, and potentially affects impacts 41 additional Class I areas.

North Cascades has numerous scenic vistas, including its most iconic: Diablo Lake and the intense turquoise hue of its waters,

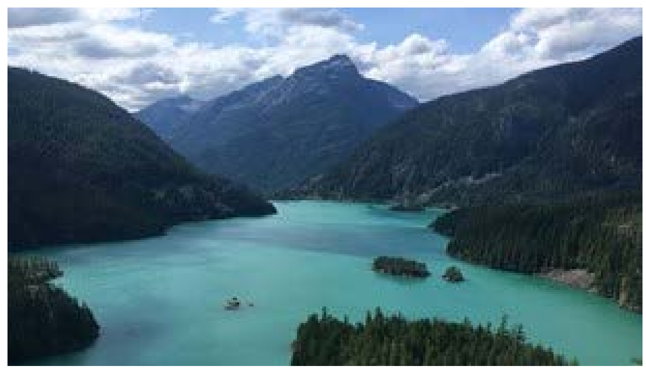

Figure 2. North Cascades National Park, Diablo Lake. (NPS)

[4] *Id.*
[5] These emissions refer to EPA's 2014 National Emissions Inventory.
[6] 78 Fed. Reg. 79344, 79348-79349. (Dec. 30, 2013).
[7] *Id.* These four potlines and associated processes were constructed prior to the BART window and were not BART-eligible.
[8] *Id.*
[9] "Alcoa Announces Permanent Closure of Wenatchee Works' Line 3 Potline, Aluminum Insider, https://aluminiuminsider.com/alcoa-announces-permanent-closure-of-wenatchee-works-line-3-potline/ (June 20, 2018). Alcoa Corporation, 2018 Annual Report, U.S. SEC Form 10-k, at 13, 46 (In June 2018, one of the four potlines was permanently closed, it had not operated since 2001), http://d18rn0p25nwr6d.cloudfront.net/CIK-0001675149/555ce5d4-26f7-4a23-b242-92bdbfbbfbe2.pdf.
[10] Alcoa News Release, "Alcoa Corporation Provides Update Regarding Wenatchee Smelter in Washington State," (June 18, 2018), "https://investors.alcoa.com/news-releases/news-release-details/2018/Alcoa-Corporation-Provides-Update-Regarding-Wenatchee-Smelter-in-Washington-State/default.aspx.

[11] "Hope dims for Alcoa Wenatchee Works restart," Yakima Herald, https://www.yakimaherald.com/news/business/regional/hope-dims-for-alcoa-wenatchee-works-restart/article_172bbf02-73d5-11e8-90b6-b3ca3455b194.html (June 19, 2018).

created by the glacier-ground rock powder that is carried to the lake via creeks.

The visibility-impairing pollutants are PM, SO_2, and NO_X, which significantly and adversely affect the air quality in Olympic National Park, as well as five other Washington Class I areas (Alpine Lakes, Glacier Peak, Mount Rainer and North Cascades).[12] The major sources of these pollutants at the Intalco facility are the potlines and to a lesser extent, the anode bake furnace. According to NPCA analysis, emissions from Intalco rank the facility second on the list of worst sources of regional haze pollution in the State.[13] Washington's 5-year regional haze progress report acknowledged that the SO2 emissions from Intalco, and to a lesser extent the Wenatchee facility, create a challenge to additional visibility improvement in North Cascades and Olympic National Park.[14]

EPA finalized a limited approval and limited disapproval of the State's SO_2 BART determination and promulgated a Federal BART alternative for the potlines, the only units at the Intalco facility subject to BART.[15] EPA took no action on the remaining units, which, in addition to the BART units, are covered by the reasonable progress requirements.[16] The State's draft Order indicates that Alcoa 'curtailed" production at the Intalco facility in August 2020.[17] Prior to the closure, emissions had increased due to fluctuations in the market price of aluminum and the corporate decision in 2007 to ramp up production to nearly full capacity.[18]

Therefore, both Alcoa Wenatchee and Alcoa Intalco are closed and neither facility produces aluminum. While different terms are used to describe the facility status (e.g., closed, curtailed, fully curtailed idle, temporarily closed, fully shut down),[19] for consistency our comments use "closed" to describe the current status of both facilities.

To improve air quality in our most treasured landscapes, Congress passed the visibility protection provisions of the Clean Air Act in 1977, establishing "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in the

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[12] 77 Fed. Reg. at 76,174, 76,191 (Dec. 26, 2012).
[13] The facility was originally constructed in 1965, began operation in 1966.
[14] Department of Ecology, State of Washington, "Washington State Regional Haze 5-Year Progress Report," at 213, (Sept. 2017), https://www.regulations.gov/document?D=EPA-R10-OAR-2018-0001-0004. (Progress Report)
[15] 79 Fed. Reg. 33438 (June 11, 2014); 40 C.F.R. § 52.250 (Best available retrofit technology requirements for the Intalco Aluminum Corporation (Intalco Works) primary aluminum plant—Better than BART Alternative, limiting the SO2 emissions from the plant and establishing monitoring and reporting requirements). EPA took no action on the remaining units, which, in addition to the BART units, are covered by the reasonable progress requirements.
[16] Progress Report at 15.
[17] "Alcoa to shut Ferndale smelter, putting 700 out of work," Wenatchee World, https://www.wenatcheeworld.com/business/alcoa-to-shut-ferndale-smelter-putting-700-out-of-work/article_e98689d6-c7c1-57fd-96e7-34992a5785dd.html (April 23, 2020)(The direct effect of Alcoa's decision was the loss of 700 jobs as the facility.)
[18] Washington State Regional Haze 5-Year Progress Report, at 15-16 (Sept. 2017), https://www.regulations.gov/document?D=EPA-R10-OAR-2018-0001-0004.
[19] Alco Annoucement, "Alcoa Corporation Announces Full Curtailment of Intalco Works," (April 22, 2020)(Attachment 3). *See also* "Looming closure of Alcoa aluminum plant in Ferndale threatens to leave hundreds jobless, King5, https://www.king5.com/article/money/economy/alcoa-workers-rally-to-save-ferndale-plant/281-dd42e1da-39fe-4494-8584-e2e85fac4e81 (April 23, 2020)("Earlier in the week the company announced it is shutting the plant down, putting some 700 people out of work. … The company plans to shutter the plant by the end of July."); "Intalco's closure brings pain for now — what may the future bring?")

mandatory class I Federal areas which impairment results from manmade air pollution."[20] "Manmade air pollution" is defined as "air pollution which results directly or indirectly from human activities."[21] In order to protect Class I areas' "intrinsic beauty and historical and archeological treasures," the 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 SIP designed to make reasonable progress toward achieving natural visibility conditions.[22]

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."[23] 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.[24] The haze requirements in the Clean Air Act present an unparalleled opportunity to protect and restore regional air quality by curbing visibility-impairing emissions from some of the nation's oldest and most polluting facilities.

Implementing the regional haze requirements promises benefits beyond improving views. Pollutants that cause visibility impairment also harm public health. For example, oxides of nitrogen ("NO_X") are a precursor to ground-level ozone which is associated with respiratory disease and asthma attacks. NO_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, sulfur dioxide ("SO_2") increases asthma symptoms, leads to increased hospital visits, and can also form particulates.[25] NO_X and SO_2 emissions also harm terrestrial and aquatic plants and animals through acid rain as well as through deposition of nitrates (which in turn cause ecosystem changes including eutrophication of mountain lakes).

Unfortunately, instead of acting on Congress's direction, the states and EPA have repeatedly dragged their feet in implementing the visibility protection provisions, which is true in Washington. After failing to control visibility impairing pollutants for these two sources during the first planning period, the Department of Ecology yet again proposes SIP provisions that delay the required reasonable progress analysis and lack enforceable and permanent emission reducing measures. The State's proposals fail to meet the Act's requirements because it would allow both sources to restart, allowing emissions from these sources to impact the Class I areas, leaving them dirty for years to come. Ecology's proposal must be revised to adequately control emissions and contain enforceable and permanent measures in this planning period to ensure the Clean Air Act's regional haze SIP requirements are met from these sources. As discussed in our comments, these measures must be in place before either source restarts.

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[20] 42 U.S.C. § 7491(a)(1).
[21] *Id.* § 7491(g)(3).
[22] *Id.* § 7491(b)(2).
[23] 42 U.S.C. § 7491(b)(2).
[24] *Id.* § 7491(b)(2)(A); 40 C.F.R. § 51.308(d)(1)(i)(B).
[25] Emissions from Intalco not only impact Class I areas, but as explained in the State's notice for the Intalco Draft Order, EPA is in the process of making a determination whether to designate part of Whatcom County near the smelter to be in non-attainment for the 2010 1-hour SO2 NAAQS.

I. Washington's Proposed State Implementation Plan Revisions Do Not Meet the Regional Haze Reasonable Progress Requirements

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.[26] A state should consider "major and minor stationary sources, mobile sources and area sources."[27] At a minimum, a state must consider the following elements:

> (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.

40 C.F.R. § 51.308(d)(3)(v)(A)-(G). Additionally, a state "must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated."[28] In developing its plan, the State must 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.[29] A state's reasonable progress analysis must consider the factors identified in the Clean Air Act and regulations. *See* CAA 169A(g)(1); 40 C.F.R. 51.308(d)(1)(i)(A)("Consider 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 sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.") Finally, the state's SIP revisions must meet certain consultation and procedural requirements (e.g., the state must provide the Federal Land Manager(s) with an opportunity to consult and comment, and there is no information indicating that consultation occurred for these proposed SIP revisions; [30] and the state must provide for public hearing, which has also not been provided.[31])

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[26] 40 C.F.R. § 51.308(d).
[27] *Id.*
[28] 40 C.F.R. § 51.308(f)(2)(i).
[29] 40 C.F.R. § 51.308(d)(3)(iii).
[30] 40 C.F.R. § 51.308(i).
[31] 40 C.F.R. § § 51.104, 51.102.

A. The Intalco and Alcoa Facilities Are Subject to the Reasonable Progress Requirements

The State's proposed SIP revisions cover two major stationary sources, the Intalco and Wenatchee facilities. The draft Orders for the sources explain that based on the facilities' 2014 emission inventories, "Ecology has determined that it is appropriate to include the facility as a source to be evaluated for regional haze impacts."[32] The draft Order for Intalco, further explains that:

> Per 40 C.F.R. § 51.308, Ecology conducted a screening of major facilities by summing the Regional Haze producing emissions (NOx, PM2.5, SO2, and H2SO4) for each facility (Q) and dividing by the distance to the closest Class I Area (d). Ecology selected facilities with Q/d values greater than 6.7 as well as facilities that contributed more than 80 percent of the total summed Q/d for a Four-Factor Analysis.[33]

Similarly, the draft Order for Wenatchee, explains that:

> Per 40 C.F.R. § 51.308, Ecology conducted a screening of major facilities by summing the Regional Haze producing emissions (NOx, PM2.5, SO2, and H2SO4) for each facility (Q) and dividing by the distance to the closest Class I Area (d). Ecology selected facilities with Q/d values greater than 6.7 as well as facilities that contributed more than 80 percent of the total summed Q/d for a Four-Factor Analysis.[34]

Based on the emissions and Class I area impacts, Ecology determined both facilities are subject to the reasonable progress analysis. Rather than conduct its own reasonable progress analysis, Ecology sent letters notifying Intalco and Alcoa that the respective facilities (Intalco Aluminum facility and Alcoa Wenatchee Works) were selected as facilities requiring a Four-Factor Analysis based on the 2014 emission inventory data.[35]

B. Washington's Proposed SIP Revisions Fail to Include the Required Four-Factor Analysis

Washington's proposed SIP revisions merely include draft Orders. The proposals fail to include the required reasonable progress Four-Factor Analysis or an enforceable requirement that the facility is shutdown and must apply for new air permits and associated reasonable progress

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[32] Draft Intalco Aluminum LLC, Regional Haze Agreed Order No. 18216, at 2 (undated)("Intalco Order"); Draft Alcoa Wenatchee Works, Regional Haze AO No. 18100, at 2 (undated)("Alcoa Order").

[33] *Id.* Although the State explains it conducted a screening of all facilities, this proposal only includes some of the information for two of those facilities. Since this proposal fails to provide for emission limitations, the State is unable to explain how what it proposes for these facilities are adequate to meet the overall reasonable progress requirements statewide.

[34] *Id.*

[35] *Id.* The supporting analysis and information is missing, should be made available, and is foundational to public knowledge of the facilities' past and potential projected impacts. (e.g., Ecology's proposal does not provide a citation for how and where the emission inventory was obtained; the SIP proposal does not include copies of the letters sent to the sources, nor does it include the responses from the sources; there's no basis for the screening method; no basis for the cut off level used for screening).

and other analyses should it endeavor to come back online. As detailed in these comments, while we have concerns about Ecology's efforts thus far, Ecology has only done part of its job. Thus far, Ecology:

- Evaluated the emissions from these sources and impacts to the Class I area, calculated a Q/d value, and

- Based on the Q/d values, determined that a Four-Factor Analysis is required for the Intalco and Wenatchee facilities.

Ecology cannot stop here. As clearly laid out in EPA's regulations, the duty to ensure the reasonable progress requirements are met for purposes of the SIP rests with the state, not the sources. If the companies are unwilling to respond to Ecology's May 31, 2019, letters, which asked the companies to conduct a Four-Factor Analysis, Ecology must conduct the analyses to inform its reasonable progress determination. While a state may certainly ask that a source conduct and submit a Four-Factor analysis, a state can't ignore the rule requirements if it fails to receive the analysis from a source.[36]

Ecology appears to suggest that its proposed Orders are justified because the Alcoa "facility has been curtailed since December 18, 2015" and the Intalco "facility fully curtailed its operations at the end of August 2020." Neither the Clean Air Act nor the regional haze regulations include provisions that allow a state to take a pass on emission control requirements because a facility is closed. Indeed, Ecology's Orders provides no authority for such a deferral.

Ecology has two options in this SIP revision: (1) conduct the required four-factor analysis for these two sources, and issue requirements for emission limitations and other measures; or (2) revise the SIP to void the current permits and include requirements for the sources to obtain new construction and operating permits prior to restarting operation.

II. If Washington Proceeds without the Required Reasonable Progress Analysis, the SIP Must Contain Provisions to Ensure Permits *Complement* the 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.[37] 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 [51.308](f)(2)(i) through (iv)."[38] The State's proposal is merely a commitment to do something in the future: it lacks the required Four-Factor

[36] Under the Act's cooperative federalism structure, when a state fails to meet these requirements, EPA is required to step in and promulgate a FIP (which EPA was forced to do in the first round of regional haze for the State for these two facilities).
[37] 42 U.S.C. § 7491(a)(1), (b)(2).
[38] 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).

Analysis, emission limitations and other requirements necessary. Furthermore, EPA's Guidance further explains these requirements:

> This provision requires SIPs to include enforceable emission limitations and/or other measures to address regional haze, deadlines for their implementation, and provisions to make the measures practicably enforceable including averaging times, monitoring requirements, and record keeping and reporting requirements.[39]

Washington's proposed SIP revisions do not include emissions limitations with practicably enforceable provisions. Rather, they contain provisions for potential future action, requiring the sources to "install or otherwise implement all reasonable emission reduction measures that are identified in the Four-Factor Analysis and subsequently approved by Ecology."[40] Moreover, EPA's recent Guidance recognizes EPA's long-standing position that while the SIP is the basis for demonstrating and ensuring state plans meet the regional haze requirements, state-issued permits must complement the SIP and SIP requirements.[41] State-issued permits must not frustrate SIP requirements.[42] For example, sources with PSD permits under Title I must not hold permits that allow emissions that conflict with SIP requirements.[43] 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. And sources with Title V permits must not hold such permits if they contain permit terms and conditions that conflict with the SIP and Clean Air Act SIP requirements.

The proposed SIP revisions for these two sources lack the required "enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress" and thus would allow both companies to restart and operate without first meeting the regional haze requirements. The draft Orders allow the currently closed sources to restart with emissions at levels that impact the Class I areas for many years without first meeting reasonable progress emission limitation and other necessary requirements.[44] Contrary to the requirement to ensure permits complement the SIP, Washington's proposed SIP revisions do

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[39] "EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," at 42-43 (August 20, 2019), https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf. (While NPCA filed a Petition for Reconsideration regarding EPA's issuance of the 2019 Guidance (Attachment 2), 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 Clean Air Act Amendments of 1990, 74 Fed. Reg. 13498 (April 16, 1992)..

[40] Intalco Draft Order at 1, Wenatchee Draft Order at 1.

[41] 74 Fed. Reg. 13498, 13568 (April 16, 1992).

[42] Furthermore, to the extent stationary source are granted permits by rule or other mechanisms, these other categories that allow construction and operation must also complement SIP requirements.

[43] 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).

[44] The draft Orders find that for Alcoa and Intalco, the facility's Q/d value was "greater than 6.7" and it "contributed more than 80 percent of the total summed Q/d for a Four-Factor Analysis" Alcoa Order at 2; and Intalco Order at 2. Furthermore, the draft Orders fail to include Ecology's review of the future Four-Factor Analysis, its proposed determinations, and public notice and comment on the proposed SIP, Furthermore, the draft Orders do not disclose that once the State adopts the SIP provisions, they must be submitted to EPA for review and approval. Therefore, given the time necessary for the State's and EPA's rulemaking process, if Ecology were to adopt SIP provisions, it would be many more years before such provisions were enforceable as a matter of federal law.

nothing to address the PSD permits issued to Wenatchee[45] and Intalco.[46] The revised SIPs must make clear that reactivation of either facility means it will be treated as operation of a new source for purposes of PSD. Attachment 1 to these comments contains 13 additional concerns with the draft Orders.

Ecology issued Title V permits to both sources, which Ecology suggests are still effective.[47, 48] Based on the information referenced in the proposal, the Title V permits expired and the sources do not have valid Title V permits.[49] Washington has no information on its website to indicate either facility submitted a timely and complete application to renew its Title V permit and demonstrate an intent to reopen. Therefore, the revised SIP must include provisions that make enforceable the retirement of these facilities as part of this action and also require that the sources each obtain a new Title V permit compliant with the regional haze program should the intend to restart.[50]

Washington cannot cover its eyes and act as if emissions from these sources cannot exist or that it is relieved of its obligation to address visibility impairing emissions from sources. Therefore it must revise the SIP to ensure that the reasonable progress measures and Clean Air Act permits properly support the requirements that must be in the SIP.[51]

Finally, it appears the proposed SIP revisions were negotiated between the State and the company, other stakeholders were not invited to participate. In the future, as EPA does, we urge Washington to invite stakeholders to the table when its rule is negotiated.[52]

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[45] Furthermore, Wenatchee shutdown in 2015. Thus, under EPA's well-established PSD Reactivation Policy it is shutdown of greater than two years and is presumed permanent. *See In the Matter of Monroe Electric Generating Plant Entergy Louisiana, Inc., Proposed Operating Permit*, Petition No 6-99-2 (June 11, 1999), https://www.epa.gov/sites/production/files/2015-07/documents/ccaw_ord.pdf

[46] Ecology's website includes the Alcoa Intalco Ferndale PSD permit issued 10/17/1984 (No. PSD-2). However, while the Title V Operating Permit for Wenatchee (No. 000068-0) references PSD-X82 04, at 28, the PSD permit information for the Alcoa Wenatchee plant incorrectly links to the 10/17/1984 Intalco permit. No other construction permits or information was found on Ecology's website for the facilities.

[47] The Intalco Air Operating Permit No. 000295-1 expired on December 31, 2019. The Wenatchee Air Operating Permit No. 000068-0 expired on April 1, 2015 (cites PSD-X82 04).

[48] While Ecology's proposed Orders refer to some existing permits, the Orders fail to include provisions revising the permits so that the permits support the SIP. The draft Order's merely require the following: "Nothing in this Order shall in any way relieve Alcoa of its obligations to comply with the requirements of its Air Operating Permit No. 000068-0 or any other requirements of the law. Nor shall anything in this Order limit Ecology's authority to enforce the provisions of the aforementioned Permit or the CAA"[48] Alcoa Order at 2; and "Nothing in this Order shall in any way relieve Intalco of its obligations to comply with the requirements of its Air Operating Permit No. 000295-0 or any other requirements of the law. Nor shall anything in this Order limit Ecology's authority to enforce the provisions of the aforementioned Permit or the CAA." Intalco Order at 2.

[49] The Title V Operating Permits for these sources have expired: Alcoa Intalco Ferndale Title V operating permit, expired on 12/31/2019 and the Alcoa Wenatchee Title V operating permit, expired on 4/1/2015.

[50] Appears expired without timely renewal application.

[51] 74 Fed. Reg. 13498, 13568 (April 16, 1992).

[52] Federal Advisory Committee Act (FACA) of 1972 (Public Law 92-463).

CONCLUSION

NPCA urges Ecology not to finalize the Washington haze SIP revisions as proposed. Ecology has inappropriately excused and delayed Intalco and Alcoa from meeting the reasonable progress requirements, which is inconsistent with the statutory command to require reasonable progress. Ecology's proposal fails to include the required Four-Factor Analysis or establish measures for these sources that make retirement of these sources enforceable in the regional haze SIP. Furthermore, the proposed SIP revisions fail to include provisions necessary to ensure that should either facility restart, new Ecology-issued permits be required and complement – rather than thwart – SIP requirements. Ecology's proposals for these facilities are inadequately supported and not in keeping with the requirements of the law. NPCA strongly encourages the State of Washington to go back to the drawing board and prepare a reasonable progress SIP for these sources that is consistent with the Act and regulatory requirements, including consideration of retiring the current permits.

Please feel free to contact the undersigned should you have any questions regarding these comments.

Sincerely,

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Attachments

Attachment 1

The Draft Orders Fail to Comply with the Act's Requirements

The draft Orders are arbitrary, capricious and contrary to the requirements of the Act and regulations for numerous other reasons.

1. The draft Orders indicate they are effective on signature, recommend clarification that they must be submitted to EPA for review and final action (approval/disapproval).
2. The draft Orders allow the State to revise the Orders without going through the SIP public notice and comment process, and EPA submittal and action.
3. There are no deadlines requirements for Ecology to make a final decision regarding the Four-Factor Analyses. Ecology could take months or years to act on the submissions from the companies. The Orders must include deadlines for Ecology to act.
4. The draft Orders fail to contemplate a situation where the companies fail to provide the additional information Ecology requests. The Orders must recognize that Ecology retains responsibility to conduct the Four-Factor Analysis.
5. Section V of the draft Orders allows Ecology to change the conditions of the Order, without first providing for public notice and comment, and submittal to EPA for approval
6. In conducting the Four-Factor Analysis, the draft Orders allow the sources to take credit for emissions that have not occurred ("The analysis will be based on the facility's permitted emission limits…"[53]), which is prohibited. Emission measures must reflect quantifiable emission reductions and be real. Reductions from permitted levels, unless they represent real emissions, do not meet this requirement. Furthermore, if permit limits exceed CAA requirements, emissions in violation of those requirements cannot be counted as reductions.
7. There are no control measures and reasonable progress emission limits in the draft Orders. Therefore, there are no measures to enforce.
8. The draft Orders lacks recordkeeping, monitoring and recording requirements.
9. The draft Orders merely cover restart of the potlines, which is contrary to Ecology's determination that emissions from the entire facilities are subject to reasonable progress.
10. The draft Orders do not require that the facilities do anything now. Rather, they have until at least 180 days prior to restarting any of the facilities potlines, at which point they must prepare and submit a Four-Factor analysis to Ecology.
11. The draft Orders require the sources to install or otherwise implement and begin operating all emission control measures identified in the final Four-Factor Analysis within three years of Ecology's approval. The draft Order fails to disclose that the Analysis will be subject to EPA's review and final action (approval/disapproval). Thus, if the sources install and implement requirements prior to EPA's review, they assume the risk that EPA may

[53] Alcoa Order at 2, Intalco Order at 2.

disapprove the State's proposal and that they will need to install and implement other requirements.

12. The draft Orders allow the companies to not comply with the Order, as long as they receive approval from the State. SIPs cannot contain variance provisions that allow the sources to violate the Order.

13. The draft Orders contains language that allows them to terminate. As SIP provisions must be permanent, it is unclear how an Order that allows for termination meets those requirements.

Attachment 2

May 8, 2020

Via Federal Express and Email

Administrator Andrew Wheeler
Office of the Administrator
United States Environmental Protection Agency
William Jefferson Clinton Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460
Wheeler.andrew@epa.gov

Re: Petition for Reconsideration of Guidance on Regional Haze State Implementation Plans for the Second Implementation Period

Dear Administrator Wheeler:

I. Introduction

National Parks Conservation Association, Sierra Club, Natural Resources Defense Council, Western Environmental Law Center, Appalachian Mountain Club, Coalition to Protect America's National Parks, and Earthjustice (hereinafter "Conservation Organizations") hereby petition[1] the Administrator of the United States Environmental Protection Agency ("EPA") to reconsider the entitled "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" (hereinafter "Final Guidance" or "Guidance")[2] and replace it with

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[1] This Petition is filed pursuant to section 4(d) of the Administrative Procedure Act ("APA"), 5 U.S.C. § 553(e), and, to the extent it may be applicable and relevant, section 307(d)(7)(B) of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B).

[2] EPA issued the Final Guidance on August 20, 2019 via Memorandum from Peter Tsirigotis, Director at EPA Office of Air Quality Planning and Standards to EPA Air Division Directors.

guidance that comports with the Clean Air Act ("CAA") and the Regional Haze Rule, and aids states in making progress towards achieving the national goal of natural visibility conditions at all Class I areas.[3] The Final Guidance is a significant departure from the Draft Guidance[4] issued in 2016 for the second planning period and contains provisions that are expressly at odds with the Clean Air Act and Regional Haze Rule. The table below summarizes how key provisions of the Final Guidance should be revised to comply with the requirements of the applicable statutes and regulations.

The Guidance unlawfully directs states on how they may exclude certain emission sources from four-factor consideration and delay or altogether avoid reducing emissions necessary to meet Congress's mandate that the states make reasonable progress towards the national goal of restoring natural visibility to Class I area national parks and wilderness areas. 42 U.S.C. § 7491(b)(2). The Guidance not only conflicts with the text and purpose of the Clean Air Act and the Regional Haze Rule itself, but it conflicts with EPA's 2016 Draft Guidance by arbitrarily constraining EPA review authority, diminishing the science of regional haze, and recasting technical and analytical requirements for State Implementation Plans ("SIPs"). Implementation of the Final Guidance will result in inconsistencies between SIPs, create arbitrary exceptions allowing states to avoid controlling emission sources, impede progress toward the national goal of a restoring natural visibility, and may actually degrade visibility at some Class I areas.

Section of the Petition	Summary of Issue	Applicable Regional Haze Rule or other Regulations[5]
III.A.	States must comprehensively identify sources of human-caused visibility-impairing emissions across source categories and cannot arbitrarily defer some sources to another implementation period.	Section 51.308(f)(3)(ii) of the Regional Haze Rule and Clean Air Act section 169A(b)
III.B.	States have only limited discretion to decide which sources they consider for reasonable progress. SIPs will be found deficient where they fail to require emission reductions that collectively make reasonable progress towards natural visibility at all Class I areas in each planning period; no backsliding is permitted.	82 Fed. Reg. at 3,088 and sections 51.308(f)(2)(i), 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)(B)
III.C.	States cannot arbitrarily circumvent a four-factor analysis for sources that intend to retire.	Sections 51.308(f)(2)(i), 51.308(f)(2)(iv)(C)

[3] 42 U.S.C. §§ 7491, 7492; 82 Fed. Reg. 3078 (Jan. 10, 2017); 71 Fed. Reg. 60,612 (Oct.13, 2006); 70 Fed. Reg. 39,104 (July 6, 2005); 64 Fed. Reg. 35,714 (July 1, 1999).

[4] Draft Guidance on Progress Tracking Metrics, Long-term strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, (hereinafter "Draft Guidance") 81 Fed. Reg. 44,608 (July 8, 2016).

[5] Clean Air Act section 110(k)(5) provides EPA the authority to review a SIP and assess the adequacy of that SIP. Therefore any aspect of this guidance that interferes with that authority is in conflict.

III.D.	States cannot consider being under the uniform rate of progress ("URP") when selecting sources for a four-factor analysis. The glidepath is not a safe harbor; rather a state must take measures necessary to make progress towards natural visibility at any Class I areas its emissions affect.	82 Fed. Reg. at 3,093
III.E.	Previous installation of certain types of controls does not excuse a state from considering more stringent levels of control.	Section 51.308(f)(2)(iv)(D)
III.G.	States must include both "dominant" and "non-dominant" pollutants in their analyses of controls.	82 Fed. Reg. at 3,088 and sections 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)((B), 51.308(f)(2)(i)
III.H.	States cannot eliminate volatile organic compounds ("VOCs") and ammonia emissions from consideration.	82 Fed. Reg. at 3,088 and sections 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)(B), 51.308(f)(2)(i)
IV.A.	States must use methods permitted by statute and regulation to identify its sources that potentially affect visibility at Class I areas in other states, not merely any "reasonable method."	82 Fed. Reg. at 3,094 and sections 51.308(f)(2)(i), 51.308(d)(3)(iv)
IV.B.	States must consider cumulative impacts of sources or groups of sources to all affected Class I areas.	Section 51.308(f)(2)(i)
V.A.	States must prioritize emissions within their borders to achieve reasonable progress.	Sections 51.308(f)(1)(vi)(B), 51.308(f)(2)(iv)(D), and Clean Air Act section 169A(b)
VI.B.	States must adhere to the accounting principles of the Control Cost Manual and should compile and make publicly available the documentation for generic cost estimates.	Section 51.308(f)(2)(i)
VII.A.	States cannot allow sources to discontinue the use of currently operating controls.	Section 51.308(f)(2) and Clean Air Act section 169A(b)(2)
VIII	States should use regional scale modeling to support their regional haze SIPs.	Section 51.308(f)(3)(ii)(A), Appendix W to Part 51
IX.A.	If a state's reasonable progress goal ("RPG") is above the URP, the state's "robust demonstration" must include a consideration of specific items identified by EPA.	Section 51.308(f)(3)(ii)
X.A.	States must submit to EPA the emission inventory used in a regional haze SIP.	Section 51.308(f)(2)(iii), Clean Air Act section

		110(k)(5), and EPA's Emission Inventory Guidance[6]
X.B.	States must ensure that Federal Land Managers' ("FLMs") opinions and concerns are made transparent to the public, considered by the state and addressed in the SIP.	Sections 51.308(i), 51.308(f)(4) and Clean Air Act sections 169A(a) and (d)
XI.B.	Decisions on which controls to require as part of the long-term strategy cannot merely ratify past determinations.	Section 51.308(f)(2)(i)
XI.C.	EPA must ensure that long-term strategies include appropriate measures to prevent future as well as remedy existing impairment of visibility.	Clean Air Act section 169A(a)

This Petition seeks reconsideration and substantial revision of the Final Guidance so that the Guidance will direct states to deliver on the statutory objective of preventing future and remedying existing Class I area visibility impairment that results from human-caused pollution. As issued, the Final Guidance conflicts with this statutory objective, previous rulemaking and guidance; misdirects states as to how they can go about complying with their legal obligations to make reasonable progress towards restoring natural visibility to protected public lands; and otherwise fails to set expectations that comport with legal requirements for the second planning period.

In addition to the provisions noted in the table above, the Conservation Organizations incorporate several recommendations from their Comments on EPA's Draft Guidance[7] and request that EPA reconsider and revise the Final Guidance to direct states with regard to the following issues:

- States should ensure that modeled emissions are tied to enforceable limits for sources with appropriate averaging times that reflect year-round abilities of existing controls or operation.
- Light extinction thresholds should be tailored to Class I areas and low enough to bring in most sources of visibility-impairing pollution.
- States should include all visibility-impairing pollutants when calculating a source's annual emissions.
- States should identify and consider the best available emission control measures in the four-factor reasonable progress analysis.

[6] EPA, Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations (May 2017), https://www.epa.gov/sites/production/files/2017-07/documents/ei_guidance_may_2017_final_rev.pdf.
[7] Conservation Organizations incorporate by reference their full Comments on the 2016 proposed Draft Guidance.

- States should analyze the climate and environmental justice impacts of measures to achieve reasonable progress.

The gains made in the first regional haze planning period established a critical, if delayed, foundation for our national parks and wilderness areas to make progress towards the natural visibility which they and their visitors and neighboring communities are due. The Final Guidance not only hinders future gains but in some cases actually jeopardizes the gains made in the first planning period. Conservation Organizations urge EPA to reconsider its Final Guidance and instead issue a revised guidance that directs states to fulfill regulatory requirements for reasonable progress in the second planning period to help attain clearer skies at America's prized national parks and wildernesses.

II. SIP development steps

As EPA states in the Final Guidance, the key steps to developing a regional haze SIP start with identifying the twenty percent most anthropogenically impaired days and the twenty percent clearest days and determining baseline, current, and natural visibility conditions for each Class I area within the state, and then determining which Class I area(s) in other states may be affected by the state's own emissions.[8] States must then screen sources and conduct a four-factor analysis of which controls are required before establishing reasonable progress goals.[9] Once a state has determined the reasonable progress measures to require at specific sources, the state must quantify the "reasonable progress goal"—i.e., the visibility improvement that will result from implementing the controls merited by a four-factor analysis.[10] Additional steps include regional scale modeling of the long-term strategy to set the RPGs for 2028 and progress, degradation, and URP glidepath checks.[11]

Some of the most problematic provisions of the Final Guidance, which are contrary to several requirements of the Regional Haze Rule and Clean Air Act, involve the selection of sources for analysis. After discussing these provisions, this Petition discusses the determination of affected Class I areas in other states, ambient data analysis, the characterization of factors for emission control measures, decisions on what control measures are necessary to make reasonable progress, regional scale modeling of the long-term strategy to set the RPGs for 2028, progress, degradation, and URP glidepath checks, and additional requirements for regional haze SIPs. After addressing how these various provisions of the Guidance are contrary to the regulatory requirements, the Petition provides several overarching recommendations that EPA should consider when revising the Guidance, including advising states that in order for a SIP to be approvable it must result in measures to reduce visibility impairing pollution beyond those required from the past planning period and reflective of an adequate reasonable progress analysis.

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[8] Final Guidance at 5.
[9] *Id.*
[10] *Id*.
[11] *Id.* at 5-6.

III. Selection of sources for analysis

A. Selection of sources under section 51.308(f)(3)(ii)(A).

In the Final Guidance, EPA presents a statement at the beginning of the section II.B.3 that is in conflict with the Regional Haze Rule's requirements:

> A key flexibility of the regional haze program is that a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures. . . . Accordingly, it is reasonable and permissible for a state to distribute its own analytical work, and the compliance expenditures of source owners, over time by addressing some sources in the second implementation period and other sources in later periods.[12]

This statement by EPA is contrary to the requirements in section 51.308(f)(3)(ii) of the Regional Haze Rule and section 169A(b) of the Clean Air Act.

In a footnote, EPA indicates that "analysis of control measures" refers to an analysis of what emission control measures for a particular source are necessary in order to make reasonable progress and must include consideration of the four statutory factors and consideration of the five additional factors listed in 40 C.F.R. § 51.308(f)(2)(iv).[13] This important requirement of how sources should be selected by states for analyses is presented as if it were a secondary consideration. In other words, EPA's Guidance now advises states that they can arbitrarily delay the selection of sources for evaluation, or exclude certain sources as noted *infra*, and thereby "distribute [their] analytical work" and the "compliance expenditures of source owners" as if it is a stand-alone, top-level decision that states can make, divorced of the need to apply the four statutory factors and the five additional factors to actually make reasonable progress.

If a state were to arbitrarily "distribute its own analytical work, and the compliance expenditures of source owners, over time"[14] as the guidance provides, it would not be able to address section 51.308(f)(3)(ii)(B), which requires:

> If a State contains sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another State for which a demonstration by the other State is required under (f)(3)(ii)(A), the State must demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to

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[12] *Id.* at 9.
[13] *Id.* at 9 n.22.
[14] *Id.* at 9.

> include in its own long-term strategy. The State must provide a robust demonstration, including documenting the criteria used to determine which sources or groups or sources were evaluated and how the four factors required by paragraph (f)(2)(i) were taken into consideration in selecting the measures for inclusion in its long-term strategy.

A state that arbitrarily excludes sources from consideration cannot determine if it actually has "sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area." To satisfy that requirement, a state must first have a reasonable understanding of the emissions from all of its sources and it must have a reasoned methodology for excluding sources from a four-factor analysis (e.g., those sources are inconsequential or do not have cost-effective control options). Similarly, if a state, which arbitrarily excludes sources from evaluation, has a RPG that is above the URP, it cannot satisfy section 51.308(f)(3)(ii)(A)[15], which requires that it demonstrate "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the long-term strategy." In contrast, not only was this advice absent from EPA's Draft Guidance, the Draft Guidance provided detailed, valid information on source selection.[16]

Additionally, as mentioned *infra* section IV.A, the Final Guidance also arbitrarily allows states to decide whether they contribute to out-of-state Class I areas by claiming states can use any reasonable method for quantifying the impacts of its own emissions on out-of-state Class I areas.[17] The Final Guidance also allows a state to disregard its impacts on an out-of-state Class I area that a neighboring state may identify as being affected by emissions from the state developing the long-term strategy.[18] By allowing states to arbitrarily make these determinations, EPA is attempting to slice the program into inconsequential bits and pieces that set the

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[15] EPA noted in the 2017 Regional Haze Rule revision:

[I]n a situation where the RPG for the most impaired days is set above the glidepath, a contributing state must make the same demonstration with respect to its own long-term strategy that is required of the state containing the Class I area, namely that there are no other measures needed to provide for reasonable progress. The intent of this proposal was to ensure that states perform rigorous analyses, and adopt measures necessary for reasonable progress, with respect to Class I areas that their sources contribute to, regardless of whether such areas are located within their borders.

82 Fed. Reg. at 3099. *See also* 81 Fed. Reg. 66,331, 66,631 (Sept. 27, 2016) ("[A]n evaluation of the four statutory factors is required . . . regardless of the Class I area's position on the glidepath. . . . [T]he URP does not establish a 'safe harbor' for the state in setting its progress goals."); 81 Fed. Reg. 295, 326 (Jan. 5, 2016) ("[T]he uniform rate of progress is not a 'safe harbor' under the Regional Haze Rule"); EPA, Guidance for Setting Reasonable Progress Goals under the Regional Haze Program (hereinafter "RPGs Guidance") (June 2007) 4–1, https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/20070601_wehrum_reasonable_progress_goals_reghaze.pdf.

[16] Draft Guidance at 57-83.

[17] Final Guidance at 8.

[18] *Id.* at 9.

provisions of the Final Guidance against fulfilling the requirements of the Clean Air Act and Regional Haze Rule that compel a comprehensive "regional" approach to restoring visibility. EPA should strike the above-mentioned language discussing selection of sources under section 51.308(f)(3)(ii)(A) from the Final Guidance and restore the language from the Draft Guidance.

B. States have only limited discretion to decide which sources they consider for reasonable progress.

In Section II.B.3.d of the Final Guidance, EPA states, "[t]he source-selection step is intended to add flexibility and discretion to the state planning process – ultimately, the state decides which sources to consider for reasonable progress."[19] This blanket statement, written as if a state has unbounded discretion to determine which sources it evaluates under reasonable progress, is incorrect. A state cannot arbitrarily determine which sources it evaluates under the Regional Haze Rule's reasonable progress requirements. Ultimately, a state's source selection criteria is a part of its long-term strategy. As EPA indicated in the Regional Haze Rule revision, a state does not have discretion to arbitrarily exclude sources from a four-factor analysis. Specifically, EPA stated:

> [W]e expect states to exercise reasoned judgment when choosing which sources, groups of sources or source categories to analyze. Consistent with CAA section 169A(g)(1) and our action on the Texas SIP, a state's reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by arbitrarily including costly controls at sources that do not meaningfully impact visibility or failing to include cost-effective controls at sources with significant visibility impacts, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a [Federal Implementation Plans ("FIPs")]. [20]

A state with a RPG below the URP that followed this guidance and arbitrarily excluded sources from a four-factor analysis runs afoul of section 51.308(f)(3)(ii)(A), which requires a "robust demonstration" that "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the long-term strategy." If a state that followed this guidance had emission sources that potentially affect visibility at a Class I area in another state, it would similarly be unable to satisfy the same requirement found in section 51.308(f)(3)(ii)(B). EPA should reconsider this provision, and delete it from the Final Guidance.

C. States cannot arbitrarily circumvent a four-factor analysis for sources that intend to retire.

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[19] Final Guidance at 20.
[20] 82 Fed. Reg. at 3088.

In Section II.B.3.d of the Final Guidance, EPA also states "[i]f a source is expected to close by December 31, 2028, under an enforceable requirement, a state may consider that to be sufficient reason to not select the source at the source selection step."[21] EPA goes on to extend this deadline by adding an indeterminate grace period: "The year 2028 is not a bright line for these considerations, so a state may be able to justify not selecting a source for analysis of control measures because there is an enforceable requirement for the source to cease operation by a date after 2028."[22] EPA further advises states that consideration of source retirement and replacement schedules required by Section 51.308(f)(2)(iv)(C) are automatically considered if a state decides to not subject sources which will retire by 2028 to a four-factor analysis.[23]

This is a departure from EPA's long-standing requirement in the regional haze program and is in conflict with basic requirements of the Regional Haze Rule. Remaining useful life is one of the four statutory factors that a state must consider when selecting the sources for which it will determine what control measures are necessary to make reasonable progress.[24]

The Clean Air Act does not define the phrase "remaining useful life." However, EPA, in regulations and guidance, has clarified the meaning of the phrase. EPA has consistently stated that the potential retirement of a facility can be used to shorten a source's remaining useful life only if the retirement is federally enforceable.[25] Thus, in order to affect the remaining useful life, a retirement commitment must be included in a pre-existing document that can be enforced in federal court, such as a consent decree entered by a federal court, or a state must incorporate the retirement date into its SIP. If a potential retirement is not federally enforceable, it cannot be relied upon to shorten the remaining useful life of a source.

EPA's 2007 Guidance on reasonable progress incorporates and refers to the best available retrofit technology ("BART") Guidelines,[26] which instruct states on how to calculate the remaining useful life of a source. EPA defines a source's "remaining useful life" as the difference between the date that controls would be installed and "the date the facility permanently stops

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[21] Final Guidance at 20.
[22] *Id.*
[23] *Id.* at 22.
[24] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) ("[A]n agency rule would be arbitrary and capricious if the agency has . . . entirely failed to consider an important aspect of the problem."); *Pub. Citizen v. Fed. Motor Carrier Safety Admin.*, 374 F.3d 1209, 1216 (D.C. Cir. 2004) ("A statutorily mandated factor, by definition, is an important aspect of any issue before an administrative agency, as it is for Congress in the first instance to define the appropriate scope of an agency's mission.").
[25] *E.g.*, 83 Fed. Reg. 62,204, 62,232 (Nov. 30, 2018) ("We are proposing to agree with Arkansas' cost analysis for dry scrubbers and switching to low sulfur coal for Independence Units 1 and 2, and with the state's decision to assume a 30-year capital cost recovery period in the cost analysis. It is appropriate to assume a 30-year capital cost recovery period in the cost analysis since Entergy's plans to cease coal combustion at the Independence facility are not state or federally-enforceable."); 83 Fed. Reg. 43,586, 43,604 (Aug. 27, 2018) (Considering the retirement of certain units where there was evidence that the units had actually been retired at the time of the rulemaking and that the plant had requested cancellation of its air permit).
[26] RPGs Guidance at 5-3. There is no conflict with the 2007 Guidance's interpretation of "remaining useful life" and the Final Guidance. *See* Final Guidance at 34.

operations."[27] If the remaining useful life affects the selection of controls, "this date should be assured by a federally- or State-enforceable restriction preventing further operation."[28] EPA discusses a situation where a source "intends to shut down a source by a given date, but wishes to retain the flexibility to continue operating beyond that date in the event."[29] In that instance, EPA instructs a state to include in its SIP the controls that would be required if the source continues to operate past the planned retirement date.[30] "The source would not be allowed to operate after the 5–year mark without such controls."[31]

Allowing states to avoid a four-factor analysis based on alleged intent to retire would render the other statutory factors meaningless and violate the requirements of the Regional Haze Rule.[32] Many states have already begun analyzing their sources to determine which should be brought forward for a four-factor analysis. Consequently, a source that retires by December 31, 2028 (or later), has at least eight years of potential emission reductions. Even considering this shortened remaining useful life, cost-effective controls, which often can be installed in months, can frequently be justified. For instance, a source could simply switch to a lower sulfur content coal or fuel oil, which would require little to no installation time and may be quite cost-effective. Despite EPA's advice, any source that demonstrably or potentially impacts visibility at a Class I area and would otherwise be subject to a four-factor analysis under section 51.308(f)(2)(i), regardless of its retirement date, must undergo a real analysis to determine if cost-effective controls are available.[33] EPA should revise the Final Guidance to reiterate that only enforceable retirements may alter the remaining useful life and otherwise require that states subject sources that intend to retire to a four-factor analysis if a state selects the source for analysis of emission control measures.

D. States cannot consider being under the URP when selecting sources for a four-factor analysis.

In Section II.B.3.e of the Final Guidance, EPA makes two flawed statements regarding a state's RPG that were not present in the Draft Guidance. First, EPA states "[t]he fact that visibility conditions in 2028 will be on or below the URP glidepath is not a sufficient basis by itself for a state to select no sources for analysis of control measures; however, the state may

[27] 40 C.F.R. pt. 51, App. Y § (IV)(D)(4)(k)(2).
[28] *Id.*
[29] *Id.* § (IV)(D)(4)(k)(3).
[30] *Id.*
[31] *Id.*
[32] The United States Court of Appeals for the Fifth Circuit recently found that EPA must consider statutory factors listed in a similar provision of the Clean Water Act when revising best available technology ("BAT") limits. *See Southwestern Elec. Power Co. v. EPA*, 920 F.3d 999, 1026-27 (5th Cir. 2019).
[33] EPA's draft guidance also allowed for states to forgo a four-factor analysis on sources secured by an enforceable commitment to retire by 2028. We disagree with that position for the reason expressed above. However, EPA tempered its reasoning in its draft guidance by stating that its position rested on the fact that due to the shortened second planning period (unlike future planning periods), there would be a shorter interval for states to install controls. Also, EPA did not state that states could extend source retirements beyond 2028 as it does in the final guidance.

consider this information when selecting sources."[34] EPA then cites to the 2017 Regional Haze Rule revisions; however, those citations make it absolutely clear that states cannot in fact follow this guidance:

> We disagree that the states should be able to reevaluate whether a control measure is necessary to make reasonable progress based on the RPGs. 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. [35]

Consequently, states have no path available to them to "consider this information when selecting sources."

Similarly, EPA's later advice that "[r]ather, that fact [that a state's RPG is below the URP] would serve to demonstrate that, after a state has gone through its source selection and control measure analysis, it has no 'robust demonstration' obligation per 40 CFR 51.308(f)(3)(ii)(A) and/or (B)"[36] is potentially at odds with the Regional Haze Rule. In the above cited portion of the 2017 Regional Haze Rule revision, EPA actually stated, "if 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."[37] A state's "robust demonstration" obligation does not end because it has merely "gone through its source selection and control measure analysis." Rather, as EPA actually explained, the state must have "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." [38] EPA must reconsider this provision, and delete it from the Final Guidance.

E. Previous installation of certain types of controls does not excuse a state from considering more stringent levels of control.

In section II.B.3.f of the Final Guidance, EPA discusses circumstances under which a state can choose not to select a source that has previously installed controls for a four-factor analysis.[39] Much of this information conflicts with previous guidance and the Regional Haze

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[34] Final Guidance at 22.
[35] 82 Fed. Reg. at 3093. *See also* 81 Fed. Reg. at 66,631; 81 Fed. Reg. at 326; RPGs Guidance at 4-1.
[36] Final Guidance at 22.
[37] 82 Fed. Reg. at 3093.
[38] *Id.*
[39] *Id.* In comparison to the blanket exemptions in EPA's Final Guidance, the Draft Guidance only considered exempting power plant units, "in certain limited situations," with "highly effective control technology within the 5 years prior to submission of the SIP, such as year-round operation of flue gas desulfurization (FGD) with an

Rule. First, EPA states, "[i]n general, if post-combustion controls were selected and installed fairly recently . . . to meet a [Clean Air Act] requirement, there will be only a low likelihood of a significant technological advancement that could provide further reasonable emission reductions having been made in the intervening period."[40] EPA presents no basis for making this conclusion.

There are many instances in which post-combustion controls have been installed in which those controls do not operate at peak efficiency. This includes controls that are not operated continuously, controls that were never designed to operate at peak efficiency (e.g., undersized sulfur dioxide ("SO_2") scrubber or selective catalytic reduction ("SCR") systems) and partially bypassed controls (e.g., SO_2 scrubber or SCR systems). In fact, EPA has made it a point in past actions to ensure that existing controls are examined to determine if they can be cost-effectively upgraded. For instance, the 2005 BART revision to the Regional Haze Rule devotes several paragraphs to specific potential scrubber upgrades it recommends be examined.[41]

EPA also demonstrated that scrubber upgrades to a number of coal-fired power plants utilizing outdated and inefficient scrubber systems were highly cost-effective, and could achieve removal efficiencies of ninety-five percent which is near the ninety-eight to ninety-nine percent removal efficiencies of newly-installed scrubber systems.[42] In fact, as EPA notes in its 2017 Regional Haze Rule revision, EPA disapproved Texas' four-factor analysis in part because "it did not include scrubber upgrades that would achieve highly cost-effective emission reductions that would lead to significant visibility improvements."[43] Consequently, EPA's blanket guidance that examination of potential upgrades to recently installed post-combustion controls is unlikely necessary is demonstrably false. Even if, considering the entire universe of potential post-combustion control upgrades, the vast majority cannot be cost-effectively upgraded to result in significant visibility benefits, which is unlikely, there is no justification in the Regional Haze Rule to skip an examination of the remaining units.

EPA goes on to present examples of pollutant-specific controls that have been installed due to a requirement outside of the regional haze program for which it "believes it may be reasonable for a state not to select a particular source for further analysis."[44] This list includes new source performance standard ("NSPS") controls installed since July 31, 2013; best available control technology ("BACT") or lowest achievable emission rate ("LAER") controls installed since July 31, 2013; power plants with FGD controls that meet the 2012 model attainment test systems ("MATS") standard; particulate matter ("PM") controls under National Emission

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effectiveness of at least 90 percent or year-round operation of selective catalytic reduction with an effectiveness of at least 90 percent." EPA specifically requested comment "on whether to include this additional screening mechanism and if so, then what criteria may be appropriate for its inclusion."

[40] *Id.*

[41] *See* 70 Fed. Reg. 39,103, 39,171 (July 6, 2005).

[42] *See* 81 Fed. Reg. at 305.

[43] *See* 82 Fed. Reg. at 3088.

[44] Final Guidance at 23.

Standards for Hazardous Air Pollutants ("NESHAP") since July 31, 2013; boilers that have installed an FGD or SCR system that operates year round and has a total efficiency of ninety percent; and any BART-eligible unit that has installed BART controls.[45] EPA reasons that due to their recent installation and the similarity of the requirements for those programs, it is unlikely that a four-factor analysis will result in additional cost-effective controls.[46] But, as EPA notes in its 2005 BART revision to the Regional Haze Rule, it reviewed some of these standards and concluded they may not be the most stringent available.[47] Furthermore, the 2017 revision to the Regional Haze Rule warned states that "we anticipate that a number of BART-eligible sources that installed only moderately effective controls (or no controls at all) *will need to be reassessed*. Under the 1999 [Regional Haze Rule and] 40 CFR 51.308(e)(5), BART-eligible sources are subject to the requirements of 40 CFR 51.308(d), which addresses regional haze SIP requirements for the first implementation period, in the same manner as other sources going forward."[48] This is in contrast to EPA's Final Guidance statement that "if a source installed and is currently operating controls to meet BART emission limits, it may be unlikely that there will be further available reasonable controls for such sources."[49] Therefore, a state must first subject a source to a four-factor analysis under section 51.308(f)(2)(i) before it is able to determine whether there are no emission reducing options available (including upgrades to existing controls).

Regarding which control measures states should consider in assessing reasonable progress, EPA states "there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures. A range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set."[50] This conflicts with past guidance and with the Regional Haze Rule. Although there is no requirement that controls required under the reasonable progress requirements of the Regional Haze Rule uniformly be the most stringent available, not considering this level of control bypasses section 51.308(f)(2)(i), which requires that the state perform a four-factor analysis. A state cannot consider "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" unless it considers all feasible controls available, including upgrades to existing controls.

EPA acknowledged that a range of controls should be evaluated in a four-factor analysis in its Draft Guidance:

> In order to define a control measure with sufficient specificity to assess its cost and potential for emission reductions, the state should specify and consider the range of control efficiencies that the measure is capable of achieving. For example, when

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[45] *Id.* at 23-25.
[46] *Id.* at 25.
[47] *See* 70 Fed. Reg. at 39,163-64.
[48] 82 Fed. Reg. at 3083 (emphasis added).
[49] Final Guidance at 25.
[50] *Id.* at 29.

> evaluating a flue gas desulfurization system to reduce SO_2 emissions, the state should consider both a system capable of achieving a 90 percent reduction in SO_2 emissions as well as a more advanced system capable of achieving a 97 or 98 percent reduction. The state should not limit its analysis to either an unrealistically high and prohibitively expensive control efficiency or to a control efficiency that is substantially lower than has been achieved at other sources.[51]

Furthermore, EPA does not require that states secure the operation of controls with this level of efficiency through an enforceable commitment.

Just because a source has the most effective or highly effective control technology does not mean that it is required to be operated to a level reflective of its maximum pollution reduction capability. Thus, states should not be screening such sources out of review during the second implementation period. By allowing states to "screen out" and choose not to select such sources for a full four-factor analysis, EPA may be allowing states to ignore very cost-effective emission reducing options like simply requiring sources with highly effective controls to operate those controls in the most effective manner to reduce air pollutants. EPA should revise the Final Guidance to recommend that sources with existing pollution control technology evaluate options that could improve the emissions reduced through more effective use of that control technology. This could include requiring year-round operation of controls, reducing capacity, imposing more effective percent reduction requirements, requiring sources to meet more stringent emission limits, or requiring that emission limits apply on shorter averaging times to ensure continuous levels of emission reduction.

F. States should ensure that modeled emissions are tied to enforceable limits for sources with appropriate averaging times that reflect year-round abilities of existing controls or operation.

EPA should revise the Final Guidance to recommend that wherever possible, whether they are screened in or out, states should make sure that the emissions relied upon in the state's RPG demonstration are enforceable, and also that they reflect the lowest emission rates feasible at the facility given its existing configuration. This is particularly true for major sources that are screened out on the basis of emissions that reflect unenforceable conditions.

However, this is also true for sources that are screened out on the basis of emissions that do not reflect their full capacity for emission reductions. For example, if a source is screened out with emissions that reflect using its controls only seventy-five percent of the time, the state should nevertheless require year-round operation of the control. Requirements reflecting existing capacity for emission reductions are inherently reasonable, and represent low hanging fruit necessitating reduced resource expenditure for potentially large gain. Moreover, states routinely rely on actual emissions in assessing current visibility and using that assessment as a jumping off point to determine if additional reductions are necessary. Where a state is to rely on operational

[51] Draft Guidance at 87.

realities, such reliance must be justified by enforceable emission limits. Indeed, failing to take advantage of such reasonable progress measures is an example of one of the pitfalls of using this type of a screening process in the first place. EPA should recommend that states assure reasonable progress by requiring that sources have enforceable limits or conditions reflecting their full emission reduction capacity if they are to be screened out.

G. States must include both "dominant" and "non-dominant" pollutants in their analyses of controls.

In Section II.B.3.a of the Final Guidance, EPA advises states that they can skip analyses of controls for sources with "non-dominant" pollutants. Specifically, EPA states:

> When selecting sources for analysis of control measures, a state may focus on the PM species that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors. Also, it may be reasonable for a state to not consider measures for control of the remaining pollutants from sources that have been selected on the basis of their emissions of the dominant pollutants.[52]

This position, absent from the Draft Guidance, directs states to produce deficient regional haze SIPs and is in conflict with the Regional Haze Rule's requirements and preamble language in the 2017 Regional Haze Rule revision.

The preamble specifically states that a "reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by . . . *failing to include cost-effective controls at sources with significant visibility impacts*, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a FIP.[53] This provision in the Guidance would allow states to arbitrarily determine that because one pollutant has a greater impact on visibility at a Class I area(s), the state may simply ignore other visibility impacting pollutants for one or all sources in the state emitting the non-dominant pollutants, despite the availability of cost-effective controls under reasonable progress criteria. It would also allow states to conclude that when examining a source that emits multiple pollutants that contribute to haze (e.g., SO_2, Nitrogen Oxide ("NOx")), potential reductions for the non-dominant pollutant can be summarily ignored. Furthermore, EPA does not provide any metric for what it considers a "dominant" pollutant.[54] For instance, if a state has determined that fifty-one percent of the visibility impact at a Class I area is due to SO_2, forty

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[52] Final Guidance at 11.
[53] 82 Fed. Reg. at 3088. EPA states elsewhere in its 2017 Regional Haze Rule revision, that "A state may refer to its own experience, past EPA actions, the preamble to this rule as proposed and this final rule preamble, and existing guidance documents for direction on what constitutes a reasoned determination." 82 Fed. Reg. at 3099.
[54] Merriam-Webster defines dominant as "(a) commanding, controlling, or prevailing over all others," or as "(b) very important, powerful, or successful."

percent is due to NOx, and nine percent is due to PM, would SO_2 be considered dominant (and consequently the only analyzed pollutant), or must its share of the visibility impact be greater?

This provision in the Final Guidance has potentially far-reaching negative impacts on the Regional Haze Rule's requirements that states make reasonable progress, as many large sources emit multiple types of visibility impacting pollutants. Still other sources may emit significant levels of non-dominant emissions for which emission reducing control or measures may be well within the framework of the four-factor analysis. If this is not corrected, a state could assume it would be justified in concluding that state-wide, SO_2 is its "dominant" pollutant and forego control analysis of a large gas-fired power plant emitting thousands of tons of NOx which could also significantly impact visibility at one or more Class I areas.

The Final Guidance also directly conflicts with multiple sections of the Regional Haze Rule. For instance, a state following the guidance would not be able to determine if it was even subject to section 51.308(f)(3)(ii)(B), because by arbitrarily excluding pollutants or entire sources from review it could not determine if it "reasonably [was] anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another State." Nor could that state "demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area." Similarly, if that state's RPG was above its URP, it could not satisfy section 51.308(f)(3)(ii)(A), which requires the same demonstration. Such a state would also not be able to reasonably satisfy its state-to-state consultation requirements under section 51.308(f)(2)(i), which requires it to "evaluate and determine the emission reduction measures that are necessary to make reasonable progress" and "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." By severely compromising the entire foundation of a state's technical demonstration, EPA is directing states to submit deficient SIPs. For these reasons, EPA should delete the above-quoted language from the Final Guidance.

H. States cannot eliminate VOCs and ammonia emissions from consideration.

In Section II.B.3.a. of the Final Guidance, EPA also advises states that irrespective of their particular state emissions inventories or the acknowledged potential impacts of VOCs and ammonia on Class I areas, they can completely disregard these pollutants. Specifically, EPA states:

> In the first implementation period, many states eliminated VOC and ammonia emissions from consideration based on the expectation that anthropogenic VOC emissions make only a small contribution to visibility impairment and that formation of nitrate and sulfate PM is most effectively reduced by reducing emissions of NOx and SO_2 rather than by anthropogenic emissions of ammonia. EPA believes that, in general, this

> would also be a reasonable approach for the second implementation period.[55]

This position is completely absent from EPA's regulations and was not present in the Draft Guidance.

VOCs are organic chemicals emitted by products or industrial processes that when released into the atmosphere can react with sunlight and NOx to form tropospheric ("ground-level") ozone. In addition, VOCs are important precursor of Secondary Aerosol Formation ("SOA"). SOA comprises a large fraction of atmospheric aerosol mass and can have significant effects on atmospheric chemistry, visibility, human health, and climate.[56] A major source of VOCs in the United States is the oil and gas industry, which includes wells, gas gatherings and processing facilities, storage, and transmission and distribution pipelines. According to data from EPA and the Energy Information Agency ("EIA"), more than 20 million tons of VOCs are emitted from point and non-point sources in the oil and gas industry every year. Studies on oil and gas emissions have indicated that VOC source signatures associated with oil and gas operations can be clearly differentiated from urban sources dominated by vehicular exhaust emissions.[57][58] According to a recent air quality study by the National Park Service ("NPS") in Carlsbad Caverns National Park, high levels of light alkanes such as ethane, propane, butane, and, pentane compounds were consistent with oil and gas emissions. However, high alkanes ("$>C_8$") and aromatics are assumed to contribute more significantly to SOA formation.[59]

In California alone, statewide agricultural operations produce an average of 272.12 tons per day ("tpd") of ammonia ("NH_3") emissions.[60] Of those 272.12 tpd, 158.50 tpd is attributed to "agricultural waste" specifically from dairy cattle.[61] In regions such as California's heavily polluted San Joaquin Valley, ammonia concentrations are found to be much higher than NOx

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[55] Final Guidance at 12.
[56] Ziemann, Paul J., & R. Atkinson, *Kinetics, products, and mechanisms of secondary organic aerosol formation*, 41, no. 19 Chem. Soc'y Reviews 6582, 6582 (2012).
[57] *See* Odum J.R., T. Hoffmann, F. Bowman, D. Collins, R.C. Flagan, & J.H. Seinfeld, *Gas/Particle Partitioning and Secondary Organic Aerosol Yields*, 30 Environ. Sci. Technol., 2580, 2580-2585 (1996).
[58] *See* Swarthout, R. F., Russo, R. S., Zhou, Y., Hart, A. H., and Sive, B. C., *Volatile organic compound distributions during the NACHTT campaign at the Boulder Atmospheric Observatory: Influence of urban and natural gas sources*, J. Geophys. Res. Atmos., 118, 10,614–10,637, (2013), *available at* https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/jgrd.50722.
[59] Ziemann, *supra* note 56, at 6583; *see also* Takekawa, Hideto, Hiroaki Minoura, and Satoshi Yamazaki, *Temperature dependence of secondary organic aerosol formation by photo-oxidation of hydrocarbons*, Atmospheric Environment 37, no. 24, 3413-3424 (2003).
[60] California Air Resources Board, 2016 SIP Emission Almanac Projection Data by EIC: Annual Average Emissions (Tons/Day) Statewide, Miscellaneous Processes 620-Farming Operations, https://www.arb.ca.gov/app/emsinv/2017/emseic_query.php?F_YR=2012&F_DIV=-4&F_SEASON=A&SP=SIP105ADJ&SPN=SIP105ADJ&F_AREA=CA&F_EICSUM=620.
[61] *Id.*

concentrations.[62] When mixed with the region's NOx emissions (primarily from mobile sources), this excess ammonia helps form high levels of haze causing ammonium nitrate, which accounts for the majority of PM2.5 emissions found in the San Joaquin Valley.[63]

The San Joaquin Valley is home to multiple communities such as Bakersfield, Fresno, and Visalia that rank amongst the very topmost polluted cities for both annual and twenty-four hour PM2.5 pollution. [64] The entire air basin is also listed as being in extreme nonattainment with the 1997 and 2006 PM2.5 NAAQS standards.[65] As it relates to regional haze pollution, the San Joaquin Valley is located directly adjacent to the Southern Sierra Nevada Mountains, home to heavily polluted Class 1 areas like Sequoia and Kings Canyon National Parks—both of which fall within the jurisdiction of the San Joaquin Valley Air District.

Despite ammonia being a major precursor to PM2.5 pollution in the region, its emissions are currently not controlled in the San Joaquin Valley under the state's various PM2.5 SIPs.[66] Beyond ammonia, agricultural sources in California also produce and average of 145.90 tpd of direct PM10 and 21.79 tpd of direct PM2.5 emissions.[67]

In its 2005 BART amendments to the Regional Haze Rule, EPA left it to the states to individually determine if these two pollutants, which EPA acknowledges can potentially impact visibility, should be addressed.[68] In the Draft Guidance, EPA acknowledged that much of its guidance on BART remained applicable to the second round of SIPs and included an entire appendix devoted to identifying which portions of the BART guidance remained applicable.[69] This appendix has been deleted in EPA's Final Guidance. By arbitrarily excluding potential visibility-impairing pollutants from review, EPA's guidance conflicts with the same sections of the Regional Haze Rule as described *supra* section III.G, primarily preamble language to the 2017 Regional Haze Rule revision and sections 51.308((f)(3)(ii)(A), 51.308((f)(3)(ii)(B), and 51.308(f)(2)(i). EPA should revise the Final Guidance to direct states to inventory and evaluate potential visibility-impairing pollutants including VOCs and ammonia and determine associated control measures necessary to make reasonable progress. .

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[62] San Joaquin Valley Air Pollution Control District, 2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards, at 5-6, http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf.
[63] *Id.* at 3-12.
[64] American Lung Association, 2019 State of the Air Report: Most Polluted Cities Ranking, https://www.lung.org/our-initiatives/healthy-air/sota/city-rankings/most-polluted-cities.html.
[65] San Joaquin Valley Air Pollution Control District, *supra* note 62, at ES-8.
[66] *See generally, id.* at 4-1 through 4-34.
[67] *See* California Air Resources Board, *supra* note 60.
[68] *See* 70 Fed. Reg. 39,104, 39,112-14 (July 6, 2005). EPA stated that scientific and technical data shows "that ammonia in the atmosphere can be a precursor to the formation of particles such as ammonium sulfate and ammonium nitrate . . . [and] certain aromatic VOC emissions such as toluene, xylene, and trimethyl-benzene are precursors to the formation of secondary organic aerosol." *Id.* at 39,114.
[69] Draft Guidance at Appendix D.

I. Light extinction thresholds should be tailored to Class I areas and low enough to bring in most sources of visibility-impairing pollution.

States choosing light extinction as a metric for visibility impacts should use Class I-specific figures to identify sources for a four-factor analysis. If a threshold is applied, states must ensure that the threshold is low enough to bring in most sources harming a Class I area. In the Final Guidance, EPA recommends visibility metrics and thresholds in terms of inverse megameters of light extinction.[70] Although light extinction may be acceptable as a metric, states should not use a generic extinction threshold for selecting sources for consideration of pollution controls for each of the Class I areas evaluated in their regional haze SIPs. If a light extinction threshold is too high, it can significantly limit the amount of sources a state evaluates for controls to make reasonable progress.

States must make clear how each source's visibility impacts are to be determined. States must explain whether the sources' potential emissions were modeled, what visibility-impairing pollutants were modeled for each source, whether all units were modeled for all sources, whether sources were modeled for impacts on the twenty percent worst days or some other timeframe, and identify and allow public review of and comment on the technical approach that the state employed to determine source-specific visibility extinction, pursuant to 40 C.F.R. § 51.308(f)(2). Any proposed extinction threshold for defining sources to target for controls is only as good as the underlying technical analysis to define if a source exceeds the extinction threshold. States must address these requirements and justify any and all extinction thresholds that they rely on for each Class I area impacted by states' sources.

For any souces that exceed an extinction threshold but are not subject to reduction requirements, states should provide a thorough four-factor analysis of controls or provide justification as to why a four-factor analysis would not likely lead to a determination that additional controls are needed to make reasonable progress. For any sources that a state claims already has adequate controls or justifies for other reasons that a four-factor analysis of controls would not result in additional controls, the state must document in its regional haze SIP why it makes this finding. To the extent such justification is relying on other regulatory or permit requirements, the state must document those regulatory or permit requirements in detail and indicate whether such requirements are already or will be submitted to EPA as part of the SIP

J. State's using the Q/d metric should include all visibility-impairing pollutants when calculating a source's annual emissions.

In Section II.B.3.b of the Final Guidance, EPA discusses the use of a source's annual emissions in tons divided by distance in kilometers between the source and the nearest Class I area (often referred to as Q/d) as a surrogate for source visibility impacts, along with a reasonably selected threshold for this metric.[71] As EPA notes, although Q/d is the least

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[70] Final Guidance at 19.
[71] Final Guidance at 13.

complicated technique, it should "be limited to source selection for the purpose of developing a list of sources for which a state may conduct a four-factor analysis" because the metric is a less reliable indicator of actual visibility impact.[72]

EPA should revise the Final Guidance to require states using the Q/d metric to include all visibility-impairing pollutants when determining the annual emissions being used to obtain a source or source category's estimated visibility impacts. As discussed further *supra* section III.H, states cannot eliminate certain emissions, such as VOCs and ammonia emissions, from consideration. Additionally, EPA should recommend that states using the Q/d metric not use the Q/d threshold from the first implementation period for the second implementation period. Rather, the Q/d threshold should be lower in order to address more sources, including sources that are lower emitting and sources that are further in distance than the sources addressed in the first implementation period.

IV. Determination of affected Class I areas in other states

A. States must use methods permitted by statute and regulation to identify its sources that impact visibility at Class I areas in other states, not merely any "reasonable method."

In Section II.B.2 of the Final Guidance, EPA inserts a blanket statement that jeopardizes making progress towards the Clean Air Act Class I visibility goal and obfuscates the Regional Haze Rule's requirements regarding how a state should identify its sources that impact the visibility at Class I areas in other states: "As an initial matter, a state has the flexibility to use any reasonable method for quantifying the impacts of its own emissions on out-of-state Class I areas, and it may use any reasonable assessment for this determination."[73]

EPA does not provide any explanation or examples of what it considers "reasonable." Thus, this statement would allow a state to use any methodology, regardless of its scientific rigor, to identify those sources. Furthermore, once having identified these sources, however loosely, the state can then "assess" those sources any way it wishes. Confusingly, EPA seems to distinguish between quantifying the impacts of these sources and assessing these impacts. This single statement would serve to hand a state seemingly unlimited discretion over a key step in preparing its SIP, in marked contrast to what it proposed.

As EPA states in its 2017 Regional Haze Rule revision:

> On July 8, 2016, we released Draft Guidance that discusses how states can determine which Class I areas they ''may affect'' and therefore must consider when selecting sources for inclusion in a four-factor analysis. The Draft Guidance discusses various approaches that states used during the first implementation

[72] *Id.*
[73] Final Guidance at 8.

> period, provides states with the flexibility to choose from among these approaches in the second implementation period, and recommends that states adopt ''a conservative . . . approach to determining whether their sources may affect visibility at out-of-state Class I areas.[74]

Indeed, EPA's Draft Guidance did provide actual guidance to the states on this issue:

> Once contributions by sources, groups of sources or geographic areas have been quantified in some manner, the EPA recommends that states adopt a conservative (more protective approach of visibility) approach to determining whether their sources may affect visibility at out-of-state Class I areas. For example, states could consider all Class I areas for which the state contributes at least one percent to anthropogenic light extinction from all U.S. sources on any day within the 20 percent most impaired days. States may choose a different threshold to determine which out-of-state Class I areas may be affected by the States sources, but must provide an adequate explanation of why the threshold is sufficiently protective of visibility.[75]

EPA followed this statement with more than twelve pages of highly technical guidance detailing approaches it deemed acceptable.[76] The Final Guidance deletes most of this and provides a summary approach void of technical rigor or analytical teeth. The Regional Haze Rule makes plain that a state's long-term strategy, including its application of the four statutory factors, be comprised of a robust initial step—the assessment of the state's emission sources on downwind states' Class I areas. However, by diminishing actual guidance and inventing this undefined and ambiguous standard, EPA creates confusion and ambiguity for states, leaving states to determine reasonability on a SIP-by-SIP basis. EPA should restore the discussion and directives to states from the Draft Guidance.

B. Application of a threshold for cumulative impacts to multiple Class I areas.

EPA should reconsider and revise the Final Guidance to recommend that states quantitatively document the results of the screening process for each Class I area rather than presenting only the impacts at the most affected or nearest Class I area. This allows the public to know the scope of the source's impacts and assures that the SIP comports with the letter and spirit of the regional haze program, a program grounded in the fact that regional haze is a regional problem and that Class I area impacts are felt typically by a multitude of sources' pollution that defy state boundaries.

EPA should also make clear that states must consider cumulative impacts of sources or groups of sources to all affected Class I areas. A source's cumulative impacts across Class I

[74] 82 Fed. Reg. at 3094.
[75] Draft Guidance at 58.
[76] Draft Guidance at 58-70.

areas provides a valuable screen to identify sources for further analysis. As EPA conceded and the court found in *Nat'l Parks Conservation Ass'n v. EPA*, in considering the visibility improvement expected from the use of controls, states must take into account the visibility impacts at all impacted Class I areas rather than focusing solely on the benefits at the most impacted areas.[77] This must include sources that have relatively small impacts in isolation but larger cumulative impacts either in the aggregate or across Class I areas.

V. Ambient data analysis

A. States must prioritize emissions within their borders to achieve reasonable progress.

International emissions contribute to visibility impacts. Rather than encouraging states to pursue an adjustment to the end goal of natural visiblity due to international emissions, EPA should be directing states to focus on the emissions within their borders for which requirements would help achieve reasonable progress. We encourage EPA to work with states, FLMs, stakeholders, and other countries to develop emissions inventories for cross-border pollution as well as scientifically valid methods for assessing long range emissions transport. However, the development of accurate accounting and modeling should not come with the expense of postponing or ignoring domestic emission-reducing measures. EPA's updated 2028 modeling[78] attempts to incorporate international emissions, but the agency itself makes clear that the science upon which the modeling rests is questionable.[79] EPA should reconsider and revise its Guidance to clarify that assessing international emissions is a work in progress and opportunity for partnership across a broad set of stakeholders, but the mandate of the Clean Air Act compels states to take measures to make reasonable progress by reducing emissions in their borders, not look to analysis to excuse doing so because other nations also contribute to regional haze.

We also urge EPA to revise the Final Guidance to clarify that affected states also have an obligation to take appropriate action to address international emissions.[80] Although EPA and the states are not required to "compensate" for international emissions, it is well within EPA and the states' rights and obligations to formally request reductions from international sources where appropriate, or to take permitting actions in the United States that will lead to emission reductions in other countries.

For example, Mexico's Carbon I and II power plants, which are less than twenty miles from the Texas border, are responsible for significant levels of pollution across several of the border states. Despite noting the significant impact of Mexican sources on its Class I areas, and

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[77] *Nat'l Parks Conservation Ass'n v. EPA*, 803 F.3d 151, 165 (3d Cir. 2015).
[78] EPA, Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling (Sept. 19, 2019), https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf ("Updated 2028 Modeling").
[79] *Id.* at 67.
[80] 64 Fed. Reg. 35,714, 35,755 (July 1, 1999) ("The States retain a duty to work with EPA in helping the Federal government use appropriate means to address international pollution transport concerns.").

requesting federal efforts to reduce impacts from international emissions,[81] Texas approved water discharge and mining permits for a coal mine in Maverick County. Rejecting these permits instead would have prevented the Mexican company Dos Republicas from mining high-sulfur coal that is transported and burned at the Carbon I & II facilities. EPA should remove its false implication that international emissions are entirely "uncontrollable" and should instead make clear that states must demonstrate that they are doing what is within their control to address international emissions—both generally and in particular.

EPA also discusses an "adjustment" to the URP for prescribed wildland fires. Wildfires, particularly in the West, have grown hotter, bigger, and more frequent with climate change. We recognize the role of prescribed fire in both managing fire size due to climate impacts and in restoration of natural ecosystems—which can, if effective, reduce the size and scale of fires later. There are, as a result of increased prescribed fire, potential benefits to both short- and long-term air quality. In planning for prescribed wildland fires, states should consider effects on visibility, alongside health and other concerns, including potential control measures and the potential benefits. A State cannot adjust a URP based on prescribed fires unless these fires actually result in visbility impairment on the "most-impaired" days. The Final Guidance should be clear that analysis of and planning for prescribed wildland fires need to be tailored to the planning period basis and would not automatically apply to the next planning period.

VI. Characterization of factors for emission control measures

A. States should identify and consider the best available emission control measures in the four-factor reasonable progress analysis.

In Section II.B.4.a of the Final Guidance, EPA advises states that they have the flexibility to reasonably determine which control measures to evaluate, and the agency lists examples of types of emission control measures states may consider.[82] EPA should reconsider its approach to ensure that the best controls for a source or source category are identified, evaluated, and the appropriate option determined. Identification of all available control measures is an important first step to ensure the best controls or emission reduction measures emerge from a four-factor analysis. However, EPA should revise the Final Guidance to ensure evaluation of the best control options.

1. EPA should reiterate and expand upon Step 1 of the BART-Guidelines regarding the identification of all available emission control techniques.

EPA should encourage states to consider various sources of information and types of emissions control techniques in developing its long-term strategy. Specifically, EPA should make clear that states must look to new source review control technology determinations, including major source BACT and LAER determinations, as well as state minor source BACT

[81] Texas Revisions to the State Implementation Plan (SIP) Concerning Regional Haze, at ES-2 (Feb. 25, 2009).
[82] Final Guidance at 29-30.

determinations. EPA should also recommend that states evaluate technologies that were considered in applicable new source performance standards, as well as those emission controls that were required in applicable new source performance standards.[83] EPA should also recommend that states consider the control techniques evaluated and required for similar source BART determinations.

In addition, EPA should recommend that states consider BACT determinations and other new source control requirements that states have adopted in minor new source review permits. Several states have minor source BACT provisions which may provide useful information for control technology considerations, and/or states have adopted targeted emission control requirements for source categories that do not have parallel federal requirements.[84]

Further, EPA should recommend that states investigate controls for source categories evaluated in reasonably available control measures ("RACM")/ reasonably available control technology ("RACT") and best available control measures ("BACM")/BACT determinations for nonattainment areas, a good starting point for information for control techniques available for a particular source category. States should also be encouraged to consult vendors or vendor groups such as the Institute of Clean Air Companies for control techniques for sources or source categories.

States should consider inherently lower-emitting processes, by themselves, and in combination with add-on controls. A state should not reject a combination of control measures altogether when the control measures could also be applied independently, unless the state is instead focusing on a control measure that is more effective at reducing emissions than the individual control measures.

In general, EPA should provide flexibility for states to consider innovative technologies tied to quantifiable and enforceable emission reduction requirements and to consider control techniques that some could view as "redefining the source" such as a change in fuel form. The BART Guidelines seemed to limit such controls from consideration for BART. Setting aside whether this was appropriate for BART determinations, States should not be constrained when evaluating measures to consider for the long-term strategy to make reasonable progress towards the national visibility goal.

In evaluating measures for the long-term strategy, states may need to address sources that were constructed many decades ago and/or sources to which pollution controls have not typically

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[83] As EPA acknowledges in the BART guidelines, the NSPS standards do not always require the most stringent level of available control technology for a source category. 40 C.F.R. Part 51, Appendix Y, Section IV.D.2. In some cases, EPA evaluates more stringent controls in an NSPS proposed rulemaking, but ultimately requires a less stringent control to set the NSPS standard. EPA should make clear that NSPS standards are likely insufficient for purposes of reasonable progress determinations because the standards will not be reflective of the reduction measures available and otherwise meeting the four factors as SIPs are being advanced.

[84] *See, e.g.*, Colorado Regulation No. 7 – Control of Ozone via Ozone Precursors and Control of Hydrocarbon via Oil and Gas Emissions, https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=8546&fileName=5%20CCR%201001-9.

been applied. There may be little experience with applying pollution controls to such sources. However, the lack of information on "available" control technologies should not be used as a justification to eliminate a source from consideration of controls (or to only evaluate less effective controls). In such cases, States should be encouraged to consider innovative technologies, technologies that may not have historically been applied to the source type but could be transferred to the source type, emission unit replacement with more energy efficient/less polluting technology, and other such measures in evaluating how to best reduce haze-forming pollution from the source or source type.

2. EPA should advise states how to determine "available" and "technically feasible" control techniques for long-term strategy measures.

EPA should elaborate on how to determine whether a control technique is considered "available" or "technically feasible" for a source or source category. Section IV(D)(1) of the BART Guidelines[85] states in part that that "available retrofit control options are those with a practical potential for application to the emissions unit . . ." and "technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; we do not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice." EPA should recommend that states take a broader view in determining what control strategies are "available" for a source or source category, especially if traditional pollution controls had not been historically applied to that source category. In such cases, states may need to examine more innovative options for pollution control at such sources or source categories, including the consideration of promising pollution control options that have not already been demonstrated in practice but which offer quantifiable emission reductions.

Section IV(D)(1) of the BART Guidelines includes provisions to determine whether a control option is "technically feasible." Those provisions, as well as the discussion on available technologies, generally track guidance on evaluations for BACT determinations set out in EPA's New Source Review Workshop Manual.[86]

Sources often make availability or technical infeasibility arguments to avoid having to consider a pollution control, pointing out that that the control has not been used on the specific type of coal the source utilizes or on the particular size plant. Given that states may be having to determine controls for sources or source categories that have not been traditionally controlled in the long-term strategies, EPA should encourage states in such situations to fully evaluate controls that can be transferred from other source categories or that can be altered to accommodate the specific source or source category in question. EPA should recommend in such situations that states consult with, for example, environmental consultants, research technical journals, or air pollution control conference articles. States should also consider technologies demonstrated outside of the United States. EPA's New Source Review Workshop Manual describes how to

[85] 40 C.F.R. § Pt. 51, App. Y.
[86] U.S. EPA, New Source Review Workshop Manual, at B.17-B.21 (Draft Oct. 1990).

identify all control options "with potential application to the source and pollutant under evaluation."[87]

In summary, EPA should reconsider and revise the Final Guidance to elaborate on how states should evaluate available and technically feasible control techniques with the goal of ensuring that all potential controls with a practical application to a source or source category are considered in the development of the long-term strategy.

B. Cost analyses for the long-term strategy.

1. States must adhere to the accounting principles of the Control Cost Manual.

EPA should require states to follow the accounting principles and generic factors of EPA's Control Cost Manual because states and EPA have historically determined whether the costs of control measures are "reasonable" based on the costs that other similar sources determined in other regulatory actions including permits. [88] If EPA does not require all states to use the same accounting principles, it will be extremely difficult to compare costs of control between sources to evaluate whether the controls are cost effective.

2. States should compile and make publicly available the documentation for generic cost estimates.

EPA's Final Guidance suggests that states may reduce time and effort in determining control costs by using generic cost estimates or estimation algorithms, such as the Control Strategy Tool.[89] However, we request that EPA require the documentation for such generic cost estimates to be compiled and made publicly available. As stated in Sierra Club and National Parks Conservation Association's comments on EPA's proposed revisions to the Control Cost Manual, the Integrated Planning Model's SCR cost database is based on Sargent & Lundy's confidential database and the underlying data and methods used to develop the regression equations have not been publicly reviewed and analyzed.[90] Given that the cost estimates may be a primary basis for rejecting a control measure, the underlying data for such cost estimates must be publicly available.

C. EPA should reconsider and revise the Final Guidance regarding how to address energy and non-air quality environmental impacts of control measures.

EPA should state that the third factor of energy and non-air quality environmental impacts should generally be based on the same methodology laid out in the BART Guidelines. Section 8.1.1 of the BART Guidelines indicates that states must consider the energy and non-air quality environmental impacts as part of the cost analyses. With respect to taking into account non-air quality environmental impacts, we agree in general to take into account such impacts in

[87] *Id.* at B.10-B.11.
[88] Final Guidance at 31.
[89] *Id.* at 32.
[90] *See* September 10, 2015 Comment Letter from Sierra Club and National Parks Conservation Association to U.S. EPA, Docket ID No. EPA-HQ-OAR-2015-0341, at 8.

the cost analysis if the costs can be quantified. Otherwise, such impacts may need to be discussed qualitatively and weighed in the four-factor analysis.

EPA should also revise the Final Guidance and recommend that states analyze the climate and environmental justice impacts of regional haze SIPs. Although the Regional Haze Rule does not define "non-air quality environmental impacts," the BART Guidelines, which inform a state's reasonable progress analysis, explain that the term should be interpreted broadly.[91] Climate change[92] and environmental justice[93] impacts are the types of non-air quality impacts that states should consider when they determine reasonable progress measures for specific sources. Incorporating climate change and environmental justice impacts into the regional haze analysis will further states' climate and environmental justice policy goals, and it will also help states ensure that their actions related to regional haze planning support their other work on climate and environmental justice issues. Most of the same sectors and sources implicated under the regional haze program are also implicated in climate and environmental justice initiatives. As a result, when states determine "the emissions reduction measures that are necessary to make reasonable progress," they should assess how those measures will either reduce or exacerbate greenhouse gas emissions and/or environmental justice impacts on nearby disproportionately burdened communities.

VII. Decisions on what control measures are necessary to make reasonable progress

A. States cannot allow sources to discontinue the use of currently operating controls.

In Section II.B.5.e of the Final Guidance, EPA advises states how currently controlled sources may be able to discontinue those controls under reasonable progress:

> It is also possible that a source may be operating an emission control device but could remain in compliance with applicable emission limits if it stopped operation of the device. The state may reasonably consider based on appropriate factors whether continued operation of that device is necessary to make reasonable progress, such that the regional haze SIP submission for the second implementation period must make such operation of the device (or attainment of an equivalent level of emission control) enforceable.[94]

Suggesting to states that they may discontinue the use of controls that are already operating is antithetical to the regional haze program. Rather, EPA should revise the Final Guidance to require states to evaluate more effective operation of existing controls, including year-round

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[91] 40 C.F.R. pt. 51, App. Y at § (IV)(D)(4)(i), (IV)(D)(4)(j).
[92] *See, e.g.*, 74 Fed. Reg. 66,496 (Dec. 15, 2009) (EPA endangerment finding); Intergovernmental Panel on Climate Change, Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (2015), https://www.ipcc.ch/report/ar5/syr/.
[93] *See* EPA, Learn about Environmental Justice, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice (last visited April 24, 2020); Exec. Order No. 12,898, Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations, 59 Fed. Reg. 7629 (Feb. 11, 1994).
[94] Final Guidance at 43.

operation requirements. Further, the Clean Air Act is clear that visibility is not a factor in determining reasonable progress measures required at a source.

In evaluating controls for a source that already had a control installed, such as a wet or dry scrubber for SO_2 or SCR or selective non-catalytic reduction ("SNCR") for NOx, states must be required to evaluate whether these controls can be more effectively operated. Companies tend to operate their air pollution control systems to the level needed to ensure compliance with applicable emission limits rather than to the maximum emission reduction capability of the pollution control technology. For example, there are electrical generating units ("EGUs") that are only operating their installed SCR or SNCR systems during the ozone season to meet limits under the Cross State Air Pollution Rule ("CSAPR"). Indeed, in projecting operations and emissions scenarios for evaluating the CSAPR program, EPA included assumptions for dispatchable SCR, SNCR, and also scrubbers, which reflected the fact that no emission limits or consent decrees required continuous operation of the pollution controls installed at many EGUs. EPA should thus recommend that states, at a minimum, require year-round operation of existing scrubbers, SCRs, SNCRs, or other controls as one of the control options considered.

Additionally, there are numerous examples of scrubbers, SCRs, and SNCRs that, when operated, are not operated to achieve the maximum emission reductions that could be accommodated within the existing control technology at a particular unit, primarily because the applicable emission limitation does not require operation of those pollution controls to achieve the maximum emission reductions. As mentioned *supra* section III.E, states should consider sources that already have in place the most stringent controls available for additional control in the development of the long-term strategy during the second implementation period.

EPA should revise the Final Guidance to recommend that sources with existing pollution control technology evaluate options that could improve the emissions reduced through more effective use of that control technology. This could include requiring year-round operation of controls, imposing more effective percent reduction requirements, requiring sources to meet more stringent emission limits, and requiring that emission limits apply on shorter averaging times to ensure continuous levels of emission reduction.

VIII. Regional scale modeling of the long-term strategy to set the RPGs for 2028

A. States should use regional scale modeling to support their regional haze SIPs.

In Section II.B.6 of the Final Guidance, EPA advises states that they are not required to use regional scale modeling to support their regional haze SIPs. Specifically, under Step 6, EPA states that a state must:

> Determine the visibility conditions in 2028 that will result from implementation of the LTS and other enforceable measures to set the RPGs for 2028. Typically, a state will do

> this through regional scale modeling, *although the Regional Haze Rule does not explicitly require regional scale modeling*.[95]

Were a state to forego estimating source or source categories emitting visibility-impairing pollutants, as the guidance provides, it would not be able to satisfy a number of basic requirements of the Regional Haze Rule. Estimating the visibility impacts from a collection of sources is a prerequisite of establishing a state's RPG. As EPA explains in its 2017 Regional Haze Rule revision, this is a key first step in a state setting its RPG: "the 2007 guidance clearly describes the goal-setting process as starting with the evaluation of control measures. First, we recommended that states '[i]dentify the key pollutants and sources and/or source categories that are contributing to visibility impairment at each Class I area.'"[96] If a state did not estimate the visibility impacts from source or source categories, it could not satisfy the requirement in Section 51.308(f)(3)(ii)(A) that it demonstrate, "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area." Indeed, this misplaced advice is not even internally consistent with other sections of the Final Guidance, which cover many techniques for estimating the visibility impacts of sources or source categories. Estimating the collective visibility impacts of sources or source categories to determine the RPG is a fundamental requirement of the regional haze program.

In fact, there is no known substitute for the use of photochemical air quality models to project the visibility impact from thousands of individual sources, influenced by complex meteorological fields and atmospheric chemical interactions at a Class I area, ten years into the future, as EPA makes clear in Appendix W to Part 51.[97] The use of air quality models has been a cornerstone of the technical demonstration of the regional haze program (and many other air programs) since its inception. Almost every EPA Regional Haze Rule revision and guidance either discusses the use of air quality models or assumes their use. In fact, EPA recently updated its modeling guidance for regional haze.[98] The very first sentence of the section specifically devoted to regional haze is: "[t]his section focuses on the modeling analysis needed to set RPGs that reflect the enforceable emission limitations, compliance schedules, and other measures included in the long-term strategy of a regional haze SIP."[99] Part 51 makes it clear that air quality

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[95] Final Guidance, Table 1, at 6 (emphasis added).
[96] *See* 82 Fed. Reg. at 3092-93. Notably, EPA does not abandon its 2007 Guidance and in fact refers to in several places in its rule revision.
[97] *See* 40 C.F.R. Pt. 51; App. W, Section 2.0 (a), "Guideline on Air Quality Models," ("Increasing reliance has been placed on concentration estimates from air quality models as the primary basis for regulatory decisions concerning source permits and emission control requirements. In many situations, such as review of a proposed new source, no practical alternative exists."); *see also id.* at Section 1.0 (b), ("The impacts of new sources that do not yet exist, and modifications to existing sources that have yet to be implemented, can only be determined through modeling.") This is precisely the challenge of setting RPGs – accounting for modifications to potentially dozens of existing sources (e.g., installation of controls).
[98] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.s and Regional Haze, EPA 454/R-18-009, (Nov. 2018).
[99] *Id.* at 143.

modeling is a necessary tool in the setting of RPGs and EPA should not imply otherwise in its guidance.

Instead of guiding states on modeling, EPA repeatedly informs states that they can use "surrogates" to estimate visibility impacts of a body of sources. Specifically, EPA states that "the Regional Haze Rule does not require states to develop estimates of individual source or source category visibility impacts, or to use an air quality model to do so. Reasonable surrogate metrics of visibility impact may be used instead."[100] EPA lists a number of surrogates that can be used for this purpose, including Q/d, wind trajectories, and daily light extinctions budgets and states that states can use "other reasonable techniques."[101] However, although more strongly worded in its Draft Guidance,[102] EPA does state in its Final Guidance, "[s]urrogate metric here refers to a quantitative metric that is correlated to some degree with visibility impacts as they would be estimated via air quality modeling."[103] Consequently, although EPA tells states that modeling is unnecessary and that surrogate measures can be used, modeling is required in order to check the validity of visibility surrogates. EPA should reconsider this provision, and clarify that modeling is needed to assess the collective visibility impacts of sources or source categories to establish RPGs.

IX. Progress, degradation, and URP glidepath checks

A. If a state's RPG is above the URP, the state's "robust demonstration" must include a consideration of specific items identified by EPA.

In section II.B.7.c of the Final Guidance, EPA discusses what could constitute a "robust demonstration," required under section 51.308(f)(3)(ii)(A) when a state's RPG is above the URP.[104] EPA states that a simple "narrative explanation of how the state has already conducted the source selection and control measures analyses in such a manner that addresses the requirements of 51.308(f)(3)(ii)" may suffice.[105] EPA then goes on to note that such a state *may* consider a long list of additional items, including reconsideration of its visibility threshold, acceptable cost threshold, additional technically feasible controls, how its determination criteria compares to that of other states, etc.[106]

In contrast, EPA's Draft Guidance did not state that a simple narrative would suffice. The Draft Guidance stated that such a demonstration *should* include consideration of a similar listing

[100] Final Guidance at 12.
[101] *Id.* at 13.
[102] Draft Guidance at 76 ("Before relying on Q/d as a surrogate for screening purposes, a state should investigate how well Q/d relates to visibility impacts for the 20 percent most impaired and 20 percent clearest days, in terms of both the central tendency of the relationship (e.g., the regression line) and the variability of the relationship (e.g., the error of the regression). This understanding should be developed through relevant modeling of some actual cases or model plant scenarios, or another appropriate approach.")
[103] Final Guidance at 10 n.25.
[104] *Id.* at 50.
[105] *Id.*
[106] *Id.* at 50-51.

of items. EPA's pivot from *should* consider to *may* consider substantially misinterprets and is directly at odds with what the robust demonstration required under section 51.308(f)(3)(ii)(A) should contain.

Moreover, states should not rely on EPA's Updated 2028 Modeling[107] to determine which Class I areas are projected to be at or below the URP. Projected conditions for 2028 are tied to the 2064 natural conditions endpoint adjustments to account for international anthropogenic contributions, as well as wildfires. By EPA's own admission as discussed *supra* section V.A, these adjustments lack scientific validation and should not be relied on to determine whether a Class I area is on track to meet its URP in 2028.[108] The result of the updated modeling adjustments reduced the number of Interagency Monitoring of Protected Visual Environments ("IMPROVE") sites projected to be above the glidepath from forty-seven to eight. IMPROVE monitors are not the same as Class I areas, however many Class I areas share monitors; only ninety-nine monitoring sites (representing 142 Class I areas) were evaluated.[109] EPA must reconsider and revise the Final Guidance to specify what a "robust demonstration" under section 51.308(f)(3)(ii)(A) requires and that a state's demonstration should include consideration of the specific list of items identified by the agency.

X. Additional requirements for regional haze SIPs

A. States must submit to EPA the emission inventory used in a regional haze SIP.

In section II.B.8.c of the Final Guidance, regarding section 51.308(f)(6)(v) which covers the requirements for the state's emissions inventory, EPA states that "[t]he emission inventories themselves are not required SIP elements and so are not required to be submitted according [sic] the procedures for SIP revisions. The emission inventories themselves are not subject to EPA review."[110] This conflicts with the Regional Haze Rule, is internally inconsistent with the rule and other state requirements, and is impracticable. First, EPA's statement conflicts with several sections of the Regional Haze Rule. For instance, section 51.308(f)(2)(iii) requires that the state must document the following:

> [T]he 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 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

[107] *See* Updated 2028 Modeling.
[108] *Id.* at 67.
[109] *Id.* at 3 n.6.
[110] Final Guidance at 55.

> the Administrator in compliance with the triennial reporting requirements of subpart A of this part.

Here, it is clear that a state is required to document the technical basis of all aspects of its regional haze demonstration. A state's emission inventory is a foundational aspect of its technical demonstration. In fact, EPA specifically calls out "emissions information," and clarifies that the emissions information must include "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."[111]

Plainly, a state is required to submit the emission inventory it is using as part of its technical demonstration to EPA, and that inventory must include certain specified elements. Because states are already required to submit specified emission inventories to EPA as part of other requirements ("Part A"), EPA clarifies that a state may refer to that submission instead of physically including it in its SIP. However, the mere fact that EPA specifies a state may use an already prepared work product does not shield it from a review of its suitability for the task at hand.[112] For instance, EPA has frequently stated that states may use the technical work of RPOs in their SIPs. That position has never been interpreted to mean information is shielded from EPA review.[113] Indeed, EPA has a duty to review that inventory in the context of the state's regional haze SIP submission.[114] Thus, a state's emission inventory is an inseverable part of its regional haze SIP and subject to EPA's review.

Despite this, EPA appears to imply in its guidance that it cannot bring to the state's attention potential faults in the emission inventory a state used to support its regional haze SIP, nor even examine that inventory in the context of its review of the state's regional haze SIP. EPA should revise the Final Guidance to advise states that a state's emission inventory is a part of the state's SIP and subject to EPA's review.

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[111] *Id.*

[112] *See* EPA's "Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations," EPA-454/B-17-002, at 11 (May 2017), ("[Inventory information provided to EPA] will allow the EPA to make a determination whether the emissions information used in Regional Haze analysis is sufficient for the purposes of the SIP.")

[113] For instance, in the Texas FIP, EPA observed that under the current regulation each state "must document the technical basis, including modeling, monitoring and emissions information, on which the State is relying to determine its apportionment of emission reduction obligations necessary for achieving *reasonable progress* in each mandatory Class I Federal area it affects." 79 Fed. Reg. 74,818, 74,829 (Dec. 16, 2014) (emphasis in original). While the current regulations provide that, "[s]tates may meet this requirement by relying on technical analyses developed by the regional planning organization and approved by all State participants," 40 C.F.R. § 51.308(d)(3)(iii), the Texas haze rule clarified that in situations "where a regional planning organization's analyses are limited, incomplete *or do not adequately assess the four factors*, however, then states must fill in any remaining gaps to meet this requirement." *Id.* (emphasis added).

[114] In the 2017 Regional Haze Rule revision, EPA makes it a point to review a number of circuit court opinions that affirm EPA's review authority, including the Eight Circuit's conclusion that EPA "must 'review the substantive content of the . . . determination." 82 Fed. Reg. at 3090 (quoting *Ariz. el rel. Darwin v. EPA*, 815 F.3d 519, 531 (9th Cir. 2016).

B. States must ensure that FLM opinions and concerns are made transparent to the public, considered by the state and addressed in the SIP.

In Section II.B.8.a of the Final Guidance, EPA provides guidance to the states regarding the FLM consultation requirements in the Regional Haze Rule, 40 C.F.R. § 51.308. Although EPA reiterates that states are required to consult with FLMs, EPA should reconsider and revise the Final Guidance to ensure that states give credence to the opinions and concerns expressed by FLMs. FLMs have affirmative duties under section 169A(a) and (d) of the Clean Air Act as well as mandates to protect and manage public lands under the Wilderness Act[115] and the Organics Act[116]. Therefore, EPA should revise the Final Guidance to direct states that to work collaboratively with FLM to develop regional haze SIPs that satisfy federal agency duties and public resource protections.

XI. Overarching recommendations

A. EPA should emphasize that the end result must be reasonable progress.

EPA should make clear in a revised Final Guidance that the end result of any state's implementation plan must be real, reasonable progress. Consequently, each new plan must require that states actually reduce their emissions that contribute to visibility impairment. The statute requires each haze plan to contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress . . . ."[117] Therefore, any interpretation of the Regional Haze Rule via guidance should direct a state's long-term strategy to be more than just a hand waving exercise—each plan must require adequate emission limits and other enforceable measures to make reasonable progress.[118] EPA should revise the Final Guidance to explicitly provide that actually requiring emission reductions which constitute reasonable progress must be the outcome of the four-factor analysis to meet the applicable requirements; deliberation, no matter how well documented, is not enough. Emission reductions recognized through the four-factor analysis must result in emission reduction measures enforceable through a state or federal regional haze plan.

B. Decisions on which controls to require as part of the long-term strategy cannot merely ratify past determinations.

EPA must also revise the Final Guidance to clarify that decisions on which controls to require as part of long-term strategy cannot rest solely on controls required by past SIPs and state rules. Although EPA stated in the Draft Guidance that decisions on whether controls for a source or source category are cost-effective or provide sufficient visibility improvement cannot rely solely on past decisions evaluating controls for similar sources[119], that language is completely absent from the Final Guidance. EPA must revise the Final Guidance to state this point. For

[115] 16 U.S.C. §§ 1131-1136.
[116] 54 U.S.C. § 100101.
[117] 42 U.S.C. § 7491(b)(2).
[118] *See id.*
[119] Draft Guidance at 97, 103.

example, costs or technologies which were previously considered unreasonable or infeasible at a later date may become more common and may nevertheless be necessary in the second or future planning periods to make reasonable progress. Likewise, making reasonable progress in the current and future planning periods will require the implementation of controls that individually account for smaller visibility impacts than those contemplated in the first planning period and in other past emission reducing rules and permits. Therefore, EPA must revise the Final Guidance to direct states to conduct new source-specific, four-factor emission reduction analyses.

C. EPA must ensure that long-term strategies include appropriate measures to prevent future as well as remedy existing impairment of visibility.

The Clean Air Act not only requires that existing visibility impairment be remedied, but that future impairment be prevented. 42 U.S.C. § 7491(a)(1). As such, it is imperative that each state's long-term strategy be required to include measures to prevent regional haze visibility impairment and that such plans take into account the effect of new sources, as well as existing sources of visibility impairment. EPA must revise its Guidance to comport with this requirement.

EPA has historically relied on the prevention of significant deterioration ("PSD") permitting program and the visibility new source review ("NSR") requirements mandated by 40 C.F.R. § 51.307[120] to address this requirement of the national visibility goal.[121] These provisions essentially mandate that new and modified major sources that are subject to major source permitting requirements do not adversely impact visibility in any Class I area. However, much has changed in the PSD and NSR permitting programs since 1980. The current PSD rules, as well as the major source nonattainment NSR rules, now exempt many modifications at existing major sources that were previously subject to PSD review. As a result, the PSD and visibility NSR rules do not provide as comprehensive Class I areas protections as they previously did, due to impacts from modified sources. Further, there have been significant increases in emissions near some Class I areas due to oil and gas emissions and other activities that are not adequately addressed by the PSD permitting program.

EPA must revise its Final Guidance to ensure that states prevent future impairment by analyzing new and modified emission sources and by requiring mitigation of the cumulative visibility-impairing emissions. As we discuss below, it is especially important for EPA to articulate that states consider minor, area, and other new growth, or modification of stationary sources that are not subject to the Class I area protections of the PSD permitting and visibility NSR requirements.

[120] 40 C.F.R. §51.307(b)(2) and (c) provides that the PSD requirements of 40 C.F.R. §51.166(o), (p)(1) through (2), and (q) apply to new and modified major proposing to locate in nonattainment areas that may have an impact on visibility in a mandatory Class I area.
[121] *See* 45 Fed. Reg. 80,089 (Dec. 2, 1980).

1. The 2002 PSD and nonattainment NSR Rule revisions exempt many modifications from PSD permitting that could result in large, visibility-impairing emission increases from existing major sources.

EPA has historically relied on the PSD and nonattainment/visibility NSR permitting programs to meet the requirement of preventing future impairment of visibility. The PSD permitting requirements specifically provide for ensuring that a new or modified major source will not adversely impact visibility in a Class I area[122], and the EPA's visibility NSR rules in 40 C.F.R. §51.307(c) require new and modified major sources proposing to locate in nonattainment areas that may impact visibility in a Class I area to meet these same requirements of the PSD program.[123] However, the December 2002 revisions to the PSD and nonattainment NSR permitting requirements significantly reduced the scope of modifications that would trigger PSD or nonattainment NSR as major modifications by drastically changing the methodology for determining whether a significant emission increase would occur as a result of a modification.[124]

Despite these significant regulatory changes which reduced the scope of modified sources subject to PSD and nonattainment NSR permitting, EPA has never re-evaluated its reliance on the major source permitting programs as sufficient to prevent future impairment of visibility. However, these rules, as revised in recent years, will likely allow significant increases[125] in actual emissions from existing sources to occur without any evaluation of the impacts on visibility and without even applying BACT or LAER, due to being exempt from PSD or nonattainment NSR permitting.

In summary, the PSD and nonattainment NSR rules as revised in 1992 and 2002 now exempt many modifications that would have previously been subject to major source permitting, including the visibility requirements of the PSD program and visibility NSR rules. Thus, while the rules still include vital provisions for the prevention of future visibility impairment, the PSD and visibility NSR rules are no longer adequate by themselves to ensure the prevention of future visibility impairment. In light of this, EPA should revise the Final Guidance to clarify that states may not solely rely on the PSD and visibility NSR programs to prevent future impairment of visibility. EPA must ensure that states specify requirements in their SIPs to prevent future visibility impairment from the new source growth in any state that may increase visibility-impairing pollution and thus affect Class I area visibility.

2. Minor, area, mobile, and other source emissions must be evaluated to prevent future, as well as remedy existing, impairment of visibility.

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[122] 40 C.F.R. §52.21(o), (p)(1) and (2), and (q).
[123] 40 C.F.R. §51.307(b)(2) and (c).
[124] 67 Fed. Reg. 80,185, 80,186-89 (Dec 31, 2002) (also known as "NSR Reform" Rule).
[125] *See* Joseph Goffman, et al., EPA's Attack on New Source Review and Other Air Quality Protection Tools (Nov. 1, 2019), http://eelp.law.harvard.edu/wp-content/uploads/NSR-paper-EELP.pdf.

Although the Final Guidance mentions minor, area, mobile, and other emission sources, most of the discussion addresses major stationary sources. EPA should be more explicit in its expectation that states evaluate sources and source categories that are not major stationary sources as well, including the potential for growth in emissions from these sources. For example, given the increases in emissions from oil and gas development over the last 10 years,[126] it is clear that the existing SIPs and FIPs do not currently include adequate mechanisms for preventing visibility impairment from these sources as production ebbs and flows with economic conditions and other factors, such as deregulation and technology. EPA must revise the Final Guidance to clarify that states need to address these sources in the aggregate, rather than source-by-source.

There are several examples of rules and programs that may be necessary in a long-term strategy to prevent future impairment of visibility in Class I areas. EPA should revise the Final Guidance to direct states to consider these examples and include them where appropriate in SIPs.

a. Methods to address visibility-impairing emissions from oil and gas development

EPA should revise the Final Guidance to explicitly note that it expects states to review area sources like oil and gas, and should provide additional guidance on how to do so. Undoubtedly, this should begin with requiring states to collect better data on the emissions from oil and gas.

In many states, emissions from oil and gas development are a significant threat to visibility and air quality in Class I areas. Such development often occurs on federal lands that are near to or abut Class I areas For example, oil and gas development contributes to visibility impairment in public lands in Utah and Colorado where the NPS found that oil and gas development and leasing in the two states would "cause visibility impairment" at Dinosaur National Monument.[127] Additionally, NPS recently found impacts from oil and gas emissions at Carlsbad Caverns and San Pedro Parks Wilderness Class I areas, among others, based on 2008 emissions inventories—which do not capture more recent growth—and include only a portion of emissions from the production process.[128] Examples of Class I areas currently or potentially

[126] "The U.S. Energy Information Administration ("EIA") reports that oil production growth in the United States has risen by about 3 million barrels per day (from 5.8 to 8.72 MMb/d) from January 2001 to July 2014 (EIA, 2014a). Natural gas production has increased from 53.74 to 70.46 billion cubic feet per day within this time period (EIA, 2014a). The trend is expected to continue with the number of oil and gas wells in the lower 48 states projected to increase by 84 percent between 2013 and 2040 (EIA, 2014b)." Thompson et al., Modeling to Evaluate Contribution of Oil and Gas Emissions to Air Pollution, 67 Journal of the Air & Waste Management Association Vol. 4, 445 (Sept. 2016), https://doi.org/10.1080/10962247.2016.1251508.

[127] Memorandum from Regional Director, Intermountain Region, National Park Service, to Planning and Environmental Coordinator, BLM 9 (2013); *see also* Memorandum from Superintendent, Dinosaur National Monument, National Park Service, to Field Office Manager, BLM Vernal Field Office 2 (Aug. 2017); Krish Vijayaraghavan et al., Ramboll Environ US Corporation, 2017); BLM, Colorado Air Resources Management Modeling Study (CARMMS): 2025 CAMx Modeling Results for the High, Low and Medium Oil and Gas Development Scenarios, 104-05 (Aug. 2017), https://www.blm.gov/documents/colorado/public-room/data.

[128] Thompson et al., *supra* note 126, at 456; *see also* Table C6, *available at* https://www.tandfonline.com/doi/suppl/10.1080/10962247.2016.1251508?scroll=top.

impacted by oil and gas emissions include: Theodore Roosevelt and Lostwoods (Bakken Shale in eastern Montana and North Dakota); Wind Cave and Badlands (Powder River Basin in northeast Wyoming); Bridger and Fitzpatrick Wilderness Areas (Pinedale Anticline and Jonah Fields in western Wyoming); Mesa Verde (North and South San Juan Basin); Carlsbad Caverns and Guadalupe Mountains (Permian Basin in southeastern New Mexico and western Texas); and Canyonlands and Arches (Uintah, Paradox, and Piceance Basins in Utah and Colorado).

Significant information is available to enable states and EPA to develop strategies to reduce visibility-impairing emissions from this significant source category. However, these prior analyses do not substitute for meaningful consideration of oil and gas emissions reductions sufficient to meet the Regional Haze Rule's "reasonable progress" mandate. NPCA's recent report, "Oil and Gas Sector Reasonable Progress Four-Factor Analysis for Five Source Categories" assesses emissions controls for the five primary sources of visibility-impairing (and health harming) pollution in the sector: gas-fired reciprocating internal combustion engines ("RICE"); diesel-fired RICE; gas-fired combustion turbines; gas-fired heater, boilers, and reboilers; and flaring and thermal incineration of excess gas and waste gas.[129] The controls and practices included in this document represent various requirements for sources across the country and should be considered by states with emissions from the oil and gas sector.

Resource Management Plans ("RMPs") or land use plans issued by federal agencies explain how the agency will manage areas of public land over a period of time, usually ten to fifteen years. RMPs and amendments to those plans are required to go through a public review process under the National Environmental Policy Act ("NEPA"), which must include an analysis of projected impacts to all resources, including air quality. Such plans would include projections of oil and gas development, among other land use projections, on federal lands. Unfortunately, numerous RMPs have not been revised for decades, and only a few consider the effect of emissions from the planning area. EPA should revise the Final Guidance to require that states consider RMPs and other land use plans in determining the appropriate measures to prevent future impairment of visibility to include in regional haze SIPs. However, if RMPs are outdated or fail to consider the effects of visibility-impairing pollution from development, EPA must also indicate that those RMPs not be relied upon.

Recent NEPA analyses conducted for projected oil and gas development in RMPs can be useful tools for obtaining data regarding anticipated growth in such emissions. However, neither NEPA assessments nor RMPs are tools for preventing future impairment from oil and gas development. First, if adverse impacts are projected, the federal agency may make recommendations on mitigation methods to avoid adverse impacts, but neither the federal agency nor the local or state air permitting agency are under any obligation to implement such mitigation measures. Second, the federal agency is often making projections of expected amounts of development and in the types and emission rates of emissions units utilized. Those projections do

[129] Vicki Stamper & Megan Williams, Nat'l Parks Conservation Ass'n, Oil and Gas Sector Reasonable Progress Four-Factor Analysis 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) ("NPCA Report").

not always reflect the level of development that actually occurs, or the specific emission units and emission rates that are utilized. The Colorado Air Resources Management Modeling Study is one example of the type of information which can be developed in conjunction with the RMP process.[130]

In developing long-term strategies, EPA should direct states to use available information such as county-level reported emissions data and RMP and site-specific NEPA analyses, and request additional information to round out and make inventories accurate. To aid in this data gathering, EPA should direct industry to produce emissions inventories and submit them to states alongside an evaluation of emissions-reduction strategies and control technologies for this significant source of visibility impairment. Further, EPA should revise the Final Guidance to explicitly advise states on creating and making publicly available oil and gas emissions data.

States with significant oil and/or gas development should be required to consider the adoption of emission control regulations for the oil and gas development industry to reduce visibility-impairing emissions from such development.[131] Many states already require measures to reduce emissions from the sector. For example, California has enacted extensive air pollution requirements for oil and gas production, processing, and storage.[132] Colorado has also adopted emission requirements for the oil and gas industry.[133] Pennsylvania has also revised the state's oil and gas drilling regulations.[134] While these regulations may not be sufficient as to visibility impairment from the sector's emissions, the regulations provide relevant examples of states' decisions to address threats to air quality that are not covered by federal major source permitting requirements. EPA should identify the source types and associated emission-reducing measures available in the sector and use them to develop guidance to specify EPA's expectations of states in assessing these sources and requiring emission reduction measures from them. EPA must reconsider and revise the Final Guidance to require states to apply these and other control measures in their regional haze SIPs.

b. Minor New Source Review permitting programs

A state's minor NSR permitting program can be a useful tool to impose emission limitations and otherwise ensure that new source growth occurs in a manner consistent with making reasonable progress towards the national visibility goal. EPA should revise the Final Guidance to direct states to model new or modified minor NSR sources for their impacts on visibility in Class I areas. States could thus determine if the source's emissions would be consistent with making reasonable progress towards the national visibility goal, similar to the requirement in 40 C.F.R. §51.307(c) of the visibility NSR rules. Such a provision would also be

[130] *See* BLM, Colorado Air Resources Management Modeling Study (Aug. 2017), https://www.blm.gov/documents/colorado/public-room/data.
[131] NPCA Report at 7-10.
[132] California Air Resources Board, Oil & Natural Gas Production (last reviewed July 18, 2017), https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilandgas2016.htm.
[133] Colo. Regulation No. 7, Section XII, https://www.colorado.gov/pacific/cdphe/air/oil-and-gas-compliance.
[134] *See* Environmental Protection Performance Standards at Oil and Gas Well Sites, 46 Pa. B. 6431 (Oct. 8, 2016), http://www.pacodeandbulletin.gov/Display/pabull?file=/secure/pabulletin/data/vol46/46-41/1757.html.

consistent with section 7410(a)(2)(D)(i)(II) of the Clean Air Act, which requires SIPs to include adequate provisions prohibiting any source type from emitting any air pollutant which will interfere with measures to protect visibility. States could include criteria to ensure that the sources most likely to interfere with making reasonable progress are addressed, based on total emissions of visibility-impairing pollutants, distance to Class I areas, and/or other criteria focused on modifications at existing major sources that avoid PSD or nonattainment NSR review. EPA should instruct states to add such provisions to their minor NSR programs as necessary to ensure that their long-term strategies adequately prevent future impairment to visibility. Such provisions should also be incorporated and made enforceable through regional haze SIPs relying on such emission reductions to make reasonable progress.

States that decide to rely on minor NSR programs to prevent future impairment should be required to examine the relevant definitions and exemptions that exist in their programs to ensure that the types of sources that need to be addressed to prevent future impairment are indeed subject to the states' minor NSR programs. A state's minor NSR program also may need to be revised to include emissions from emitting units not typically covered under PSD permitting requirements, such as fugitive emissions.

Applicability at minor NSR sources should be based on projected changes in allowable or actual emissions from a baseline reflective of recent emissions. If a state is intending to rely on its minor NSR program to prevent future impairment of visibility, then the minor NSR program must be written in a manner to truly accomplish that intention. As other Clean Air Act programs fail to adequately integrate limits for new or modified sources, regional haze SIPs should be used directly for this purpose.

c. Provisions for other potential threats to visibility impairment

There are a number of source types other than those covered by a minor NSR permit program or oil and gas development that could potentially impair visibility. In recognition of this, EPA should revise its Final Guidance to recommend that states specifically include the analyses of these potential sources in their long-term strategies, and if necessary, adopt provisions to address them. For instance, if construction activities threaten future impairment, states should adopt control measures to mitigate air pollution at construction sites. As an example, the Sacramento Metropolitan Air Quality Management District applies air emissions requirements to construction sites.[135] California also has stricter mobile source emissions requirements (including for non-road engines) that apply under federal rules, and states with significant mobile source growth threatening future impairment could consider adopting such standards as their own.[136] EPA should encourage states to consider various measures to address

[135] *See* Sacramento Metro. Air Quality Management Dist., CEQA Guide, Ch. 3: Construction-Generated Criteria Air Pollutant and Precursor Emissions (April 2019), http://www.airquality.org/LandUseTransportation/Documents/Ch3ConstructionFinal4-2019.pdf.

[136] Congress preempted states from setting emission standards for mobile sources, except that California could set its own standards with EPA's permission and other states could opt into the stricter California standards (generally for ozone SIP purposes). 42 U.S.C. § 7543(e)(2)(B)(i)-(ii).

potential future Class I visibility impairment, based on the recent or planned growth in new source emissions expected for the state, that could threaten future impairment of visibility in any Class I area.

Additionally, to the extent that states have limited information on such sources, EPA should require that states collect and submit actual emissions increase data on minor modifications at existing sources in order to gather more information on the extent of minor source growth and on new minor, area, and other source growth.

Visibility-impairing emissions need to be inventoried and modeled from many sectors in order to properly inform the next round of haze plans. Several states have started collecting and submitting oil and gas emissions data to be inventoried and modeled for purposes of regional haze. For instance, the Western Regional Air Partnership has started collecting from its oil and gas producing states emissions for their modeling inventory.[137] However, there are several states not in the western region of the country, such as Pennsylvania and Virginia, which are significant producers of oil and gas, and should also be collecting and submitting oil and gas emissions data.[138] Furthermore, as noted *supra* section III.H, there is no inventory of emissions from the agricultural sector; states should develop such inventories and submit them with their regional haze SIPs.

Emissions data from wood burning devices should be modeled. As EPA has explained, the smoke from these devices "contains harmful particle pollution, also known as fine particulate matter or PM2.5, along with other pollutants including carbon monoxide, volatile organic compounds (VOCs), black carbon, and air toxics such as benzene."[139] EPA has also confirmed that residential wood combustion "accounts for 44 percent of total stationary and mobile polycyclic organic matter (POM) emissions, nearly 25 percent of all area source air toxic cancer risks and 15 percent of noncancer respiratory effects."[140] Furthermore, wood burning devices are a significant source of heating for many communities near Class I areas that struggle with regional haze pollution problems. Wood burning devices materially contribute to the significant proportion of particulate matter (fine and course) and VOC emissions that come from residential wood combustion in Arizona, Massachusetts, Minnesota, Nevada, Washington and other states, adding to regional haze visibility problems in Class I areas around the country.

While the collection and evaluation of much of this data should inform the next round of haze plans, we note that for the oil and gas sector, this data is sufficiently available such that regulation of the sector is appropriate and much needed in this second round of regional haze

[137] *See* Western Regional Air Partnership ("WRAP"), EGU Emissions Analysis Project, https://www.wrapair2.org/EGU.aspx.
[138] *See* U.S. Energy Info. Admin., Pennsylvania State Profile and Energy Estimates (last updated Aug. 15, 2019), https://www.eia.gov/state/?sid=PA; U.S. Energy Info. Admin., Virginia State Profile and Energy Estimates (last updated Sept. 15, 2019), https://www.eia.gov/state/?sid=VA.
[139] EPA, Fact Sheet: Overview of Final Updates to Air Emissions Requirements for New Residential Wood Heaters, at 1 (Feb 4, 2015), https://www.epa.gov/sites/production/files/2015-02/documents/20150204fs-overview.pdf.
[140] EPA, Strategies for Reducing Residential Wood Smoke, Publ'n No. EPA-456/B-13-001 at 4 (Mar. 2013), https://www.epa.gov/sites/production/files/documents/strategies.pdf.

planning. EPA should specify that in order for a state to satisfy the requirements of proposed 40 C.F.R. § 51.308(f), states must consider the cumulative impacts from minor and other source growth that may affect future visibility impairment. With this information, states can determine the number and types of new source growth and magnitude of emissions that may threaten future visibility impairment, which can then assist states in developing targeted measures to prevent future visibility impairment and address regional haze from these source types. Such measures should be required to be part of the long-term strategy of the regional haze SIP.

In summary, EPA must revise the Final Guidance to require long-term strategies to include measures to ensure the prevention of future visibility impairment, as well as the remedying of existing visibility impairment in Class I areas, in accordance with the national visibility goal of the Clean Air Act. While the PSD and visibility NSR programs have some effective provisions for ensuring that new and modified sources subject to those permitting requirements do not threaten future visibility impairment, those programs are not sufficient to fully address the statutory requirement of preventing future impairment to visibility. EPA should require states to evaluate the threats to future impairment to visibility in any Class I area and to adopt provisions within regional haze SIPs to minimize emissions from such sources, and otherwise ensure that new source growth occurs in a manner consistent with making reasonable progress towards the national visibility goal.

XII. Conclusion

The Conservation Organizations respectfully ask that EPA reconsider and revise the Final Guidance as mentioned above.

Sincerely,

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Attachment 3

Alcoa Press Release announcing closure of the Alcoa Intalco Works facility.[1]

For Immediate Release: April 22, 2020

Alcoa

ALCOA INTALCO WORKS

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Alcoa Corporation Announces Full Curtailment of Intalco Works

FERNDALE, Wash. — Alcoa Corporation today announced that it will fully curtail its Intalco Works smelter located in Whatcom County amid declining market conditions.

The curtailment is expected to be complete by the end of July 2020, and the announced curtailment is included in the Company's first-quarter 2020 earnings press release, posted at www.alcoa.com.

"While our employees have worked diligently to improve the facility, the smelter is uncompetitive, and current market conditions have exacerbated the facility's challenges," said Alcoa President and CEO Roy Harvey. "This is difficult because of the impact on our employees, and we will ensure appropriate support as we work to safely curtail the facility."

Since the beginning of the year, aluminum prices have fallen more than 20 percent, down 45% from highs in 2018. In the first quarter of 2020, the Intalco smelter lost $24 million.

Steve Emig, Intalco Plant Manager, said the site's approximately 700 employees have worked together to address numerous challenges in an attempt to make the site competitive in the global market.

"Unfortunately, we cannot control the larger market dynamics," Emig said. "While this is a sad day, I remain proud of our Intalco team. We will work together during this difficult transition, focusing on safety and providing all available support to our employees."

Intalco will be working with its employees, the International Association of Machinists and Aerospace Workers (IAMAW) Union, and other stakeholders to minimize the impact of the curtailment.

Intalco, established in 1966, has 279,000 metric tons of nameplate operating capacity; 49,000 metric tons of production was curtailed earlier.

The Alcoa Foundation will continue its annual giving, donating $200,000 to qualifying non-profit organizations in the local community in 2020.

[1] "Ferndale's Alcoa Works to Close in July," The Fourth Corner News, https://thefourthcorner.com/ferndales-alcoa-intalco-works-to-close-in-july/ (April 22, 2020).

Exhibit 3

May 8, 2020

Via Federal Express and Email

Administrator Andrew Wheeler
Office of the Administrator
United States Environmental Protection Agency
William Jefferson Clinton Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460
Wheeler.andrew@epa.gov

Re: Petition for Reconsideration of Guidance on Regional Haze State Implementation Plans for the Second Implementation Period

Dear Administrator Wheeler:

I. Introduction

National Parks Conservation Association, Sierra Club, Natural Resources Defense Council, Western Environmental Law Center, Appalachian Mountain Club, Coalition to Protect America's National Parks, and Earthjustice (hereinafter "Conservation Organizations") hereby petition[1] the Administrator of the United States Environmental Protection Agency ("EPA") to reconsider the entitled "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" (hereinafter "Final Guidance" or "Guidance")[2] and replace it with

[1] This Petition is filed pursuant to section 4(d) of the Administrative Procedure Act ("APA"), 5 U.S.C. § 553(e), and, to the extent it may be applicable and relevant, section 307(d)(7)(B) of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B).
[2] EPA issued the Final Guidance on August 20, 2019 via Memorandum from Peter Tsirigotis, Director at EPA Office of Air Quality Planning and Standards to EPA Air Division Directors.

guidance that comports with the Clean Air Act ("CAA") and the Regional Haze Rule, and aids states in making progress towards achieving the national goal of natural visibility conditions at all Class I areas.[3] The Final Guidance is a significant departure from the Draft Guidance[4] issued in 2016 for the second planning period and contains provisions that are expressly at odds with the Clean Air Act and Regional Haze Rule. The table below summarizes how key provisions of the Final Guidance should be revised to comply with the requirements of the applicable statutes and regulations.

The Guidance unlawfully directs states on how they may exclude certain emission sources from four-factor consideration and delay or altogether avoid reducing emissions necessary to meet Congress's mandate that the states make reasonable progress towards the national goal of restoring natural visibility to Class I area national parks and wilderness areas. 42 U.S.C. § 7491(b)(2). The Guidance not only conflicts with the text and purpose of the Clean Air Act and the Regional Haze Rule itself, but it conflicts with EPA's 2016 Draft Guidance by arbitrarily constraining EPA review authority, diminishing the science of regional haze, and recasting technical and analytical requirements for State Implementation Plans ("SIPs"). Implementation of the Final Guidance will result in inconsistencies between SIPs, create arbitrary exceptions allowing states to avoid controlling emission sources, impede progress toward the national goal of a restoring natural visibility, and may actually degrade visibility at some Class I areas.

Section of the Petition	Summary of Issue	Applicable Regional Haze Rule or other Regulations[5]
III.A.	States must comprehensively identify sources of human-caused visibility-impairing emissions across source categories and cannot arbitrarily defer some sources to another implementation period.	Section 51.308(f)(3)(ii) of the Regional Haze Rule and Clean Air Act section 169A(b)
III.B.	States have only limited discretion to decide which sources they consider for reasonable progress. SIPs will be found deficient where they fail to require emission reductions that collectively make reasonable progress towards natural visibility at all Class I areas in each planning period; no backsliding is permitted.	82 Fed. Reg. at 3,088 and sections 51.308(f)(2)(i), 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)(B)
III.C.	States cannot arbitrarily circumvent a four-factor analysis for sources that intend to retire.	Sections 51.308(f)(2)(i), 51.308(f)(2)(iv)(C)

[3] 42 U.S.C. §§ 7491, 7492; 82 Fed. Reg. 3078 (Jan. 10, 2017); 71 Fed. Reg. 60,612 (Oct.13, 2006); 70 Fed. Reg. 39,104 (July 6, 2005); 64 Fed. Reg. 35,714 (July 1, 1999).

[4] Draft Guidance on Progress Tracking Metrics, Long-term strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, (hereinafter "Draft Guidance") 81 Fed. Reg. 44,608 (July 8, 2016).

[5] Clean Air Act section 110(k)(5) provides EPA the authority to review a SIP and assess the adequacy of that SIP. Therefore any aspect of this guidance that interferes with that authority is in conflict.

III.D.	States cannot consider being under the uniform rate of progress ("URP") when selecting sources for a four-factor analysis. The glidepath is not a safe harbor; rather a state must take measures necessary to make progress towards natural visibility at any Class I areas its emissions affect.	82 Fed. Reg. at 3,093
III.E.	Previous installation of certain types of controls does not excuse a state from considering more stringent levels of control.	Section 51.308(f)(2)(iv)(D)
III.G.	States must include both "dominant" and "non-dominant" pollutants in their analyses of controls.	82 Fed. Reg. at 3,088 and sections 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)((B), 51.308(f)(2)(i)
III.H.	States cannot eliminate volatile organic compounds ("VOCs") and ammonia emissions from consideration.	82 Fed. Reg. at 3,088 and sections 51.308(f)(3)(ii)(A), 51.308(f)(3)(ii)(B), 51.308(f)(2)(i)
IV.A.	States must use methods permitted by statute and regulation to identify its sources that potentially affect visibility at Class I areas in other states, not merely any "reasonable method."	82 Fed. Reg. at 3,094 and sections 51.308(f)(2)(i), 51.308(d)(3)(iv)
IV.B.	States must consider cumulative impacts of sources or groups of sources to all affected Class I areas.	Section 51.308(f)(2)(i)
V.A.	States must prioritize emissions within their borders to achieve reasonable progress.	Sections 51.308(f)(1)(vi)(B), 51.308(f)(2)(iv)(D), and Clean Air Act section 169A(b)
VI.B.	States must adhere to the accounting principles of the Control Cost Manual and should compile and make publicly available the documentation for generic cost estimates.	Section 51.308(f)(2)(i)
VII.A.	States cannot allow sources to discontinue the use of currently operating controls.	Section 51.308(f)(2) and Clean Air Act section 169A(b)(2)
VIII	States should use regional scale modeling to support their regional haze SIPs.	Section 51.308(f)(3)(ii)(A), Appendix W to Part 51
IX.A.	If a state's reasonable progress goal ("RPG") is above the URP, the state's "robust demonstration" must include a consideration of specific items identified by EPA.	Section 51.308(f)(3)(ii)
X.A.	States must submit to EPA the emission inventory used in a regional haze SIP.	Section 51.308(f)(2)(iii), Clean Air Act section

		110(k)(5), and EPA's Emission Inventory Guidance[6]
X.B.	States must ensure that Federal Land Managers' ("FLMs") opinions and concerns are made transparent to the public, considered by the state and addressed in the SIP.	Sections 51.308(i), 51.308(f)(4) and Clean Air Act sections 169A(a) and (d)
XI.B.	Decisions on which controls to require as part of the long-term strategy cannot merely ratify past determinations.	Section 51.308(f)(2)(i)
XI.C.	EPA must ensure that long-term strategies include appropriate measures to prevent future as well as remedy existing impairment of visibility.	Clean Air Act section 169A(a)

This Petition seeks reconsideration and substantial revision of the Final Guidance so that the Guidance will direct states to deliver on the statutory objective of preventing future and remedying existing Class I area visibility impairment that results from human-caused pollution. As issued, the Final Guidance conflicts with this statutory objective, previous rulemaking and guidance; misdirects states as to how they can go about complying with their legal obligations to make reasonable progress towards restoring natural visibility to protected public lands; and otherwise fails to set expectations that comport with legal requirements for the second planning period.

In addition to the provisions noted in the table above, the Conservation Organizations incorporate several recommendations from their Comments on EPA's Draft Guidance[7] and request that EPA reconsider and revise the Final Guidance to direct states with regard to the following issues:

- States should ensure that modeled emissions are tied to enforceable limits for sources with appropriate averaging times that reflect year-round abilities of existing controls or operation.
- Light extinction thresholds should be tailored to Class I areas and low enough to bring in most sources of visibility-impairing pollution.
- States should include all visibility-impairing pollutants when calculating a source's annual emissions.
- States should identify and consider the best available emission control measures in the four-factor reasonable progress analysis.

[6] EPA, Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations (May 2017), https://www.epa.gov/sites/production/files/2017-07/documents/ei_guidance_may_2017_final_rev.pdf.

[7] Conservation Organizations incorporate by reference their full Comments on the 2016 proposed Draft Guidance.

- States should analyze the climate and environmental justice impacts of measures to achieve reasonable progress.

The gains made in the first regional haze planning period established a critical, if delayed, foundation for our national parks and wilderness areas to make progress towards the natural visibility which they and their visitors and neighboring communities are due. The Final Guidance not only hinders future gains but in some cases actually jeopardizes the gains made in the first planning period. Conservation Organizations urge EPA to reconsider its Final Guidance and instead issue a revised guidance that directs states to fulfill regulatory requirements for reasonable progress in the second planning period to help attain clearer skies at America's prized national parks and wildernesses.

II. SIP development steps

As EPA states in the Final Guidance, the key steps to developing a regional haze SIP start with identifying the twenty percent most anthropogenically impaired days and the twenty percent clearest days and determining baseline, current, and natural visibility conditions for each Class I area within the state, and then determining which Class I area(s) in other states may be affected by the state's own emissions.[8] States must then screen sources and conduct a four-factor analysis of which controls are required before establishing reasonable progress goals.[9] Once a state has determined the reasonable progress measures to require at specific sources, the state must quantify the "reasonable progress goal"—i.e., the visibility improvement that will result from implementing the controls merited by a four-factor analysis.[10] Additional steps include regional scale modeling of the long-term strategy to set the RPGs for 2028 and progress, degradation, and URP glidepath checks.[11]

Some of the most problematic provisions of the Final Guidance, which are contrary to several requirements of the Regional Haze Rule and Clean Air Act, involve the selection of sources for analysis. After discussing these provisions, this Petition discusses the determination of affected Class I areas in other states, ambient data analysis, the characterization of factors for emission control measures, decisions on what control measures are necessary to make reasonable progress, regional scale modeling of the long-term strategy to set the RPGs for 2028, progress, degradation, and URP glidepath checks, and additional requirements for regional haze SIPs. After addressing how these various provisions of the Guidance are contrary to the regulatory requirements, the Petition provides several overarching recommendations that EPA should consider when revising the Guidance, including advising states that in order for a SIP to be approvable it must result in measures to reduce visibility impairing pollution beyond those required from the past planning period and reflective of an adequate reasonable progress analysis.

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[8] Final Guidance at 5.
[9] *Id.*
[10] *Id.*
[11] *Id.* at 5-6.

III. Selection of sources for analysis

A. Selection of sources under section 51.308(f)(3)(ii)(A).

In the Final Guidance, EPA presents a statement at the beginning of the section II.B.3 that is in conflict with the Regional Haze Rule's requirements:

> A key flexibility of the regional haze program is that a state is not required to evaluate all sources of emissions in each implementation period. Instead, a state may reasonably select a set of sources for an analysis of control measures. . . . Accordingly, it is reasonable and permissible for a state to distribute its own analytical work, and the compliance expenditures of source owners, over time by addressing some sources in the second implementation period and other sources in later periods.[12]

This statement by EPA is contrary to the requirements in section 51.308(f)(3)(ii) of the Regional Haze Rule and section 169A(b) of the Clean Air Act.

In a footnote, EPA indicates that "analysis of control measures" refers to an analysis of what emission control measures for a particular source are necessary in order to make reasonable progress and must include consideration of the four statutory factors and consideration of the five additional factors listed in 40 C.F.R. § 51.308(f)(2)(iv).[13] This important requirement of how sources should be selected by states for analyses is presented as if it were a secondary consideration. In other words, EPA's Guidance now advises states that they can arbitrarily delay the selection of sources for evaluation, or exclude certain sources as noted *infra*, and thereby "distribute [their] analytical work" and the "compliance expenditures of source owners" as if it is a stand-alone, top-level decision that states can make, divorced of the need to apply the four statutory factors and the five additional factors to actually make reasonable progress.

If a state were to arbitrarily "distribute its own analytical work, and the compliance expenditures of source owners, over time"[14] as the guidance provides, it would not be able to address section 51.308(f)(3)(ii)(B), which requires:

> If a State contains sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another State for which a demonstration by the other State is required under (f)(3)(ii)(A), the State must demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to

[12] *Id.* at 9.
[13] *Id.* at 9 n.22.
[14] *Id.* at 9.

> include in its own long-term strategy. The State must provide a robust demonstration, including documenting the criteria used to determine which sources or groups or sources were evaluated and how the four factors required by paragraph (f)(2)(i) were taken into consideration in selecting the measures for inclusion in its long-term strategy.

A state that arbitrarily excludes sources from consideration cannot determine if it actually has "sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area." To satisfy that requirement, a state must first have a reasonable understanding of the emissions from all of its sources and it must have a reasoned methodology for excluding sources from a four-factor analysis (e.g., those sources are inconsequential or do not have cost-effective control options). Similarly, if a state, which arbitrarily excludes sources from evaluation, has a RPG that is above the URP, it cannot satisfy section 51.308(f)(3)(ii)(A)[15], which requires that it demonstrate "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the long-term strategy." In contrast, not only was this advice absent from EPA's Draft Guidance, the Draft Guidance provided detailed, valid information on source selection.[16]

Additionally, as mentioned *infra* section IV.A, the Final Guidance also arbitrarily allows states to decide whether they contribute to out-of-state Class I areas by claiming states can use any reasonable method for quantifying the impacts of its own emissions on out-of-state Class I areas.[17] The Final Guidance also allows a state to disregard its impacts on an out-of-state Class I area that a neighboring state may identify as being affected by emissions from the state developing the long-term strategy.[18] By allowing states to arbitrarily make these determinations, EPA is attempting to slice the program into inconsequential bits and pieces that set the

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[15] EPA noted in the 2017 Regional Haze Rule revision:

[I]n a situation where the RPG for the most impaired days is set above the glidepath, a contributing state must make the same demonstration with respect to its own long-term strategy that is required of the state containing the Class I area, namely that there are no other measures needed to provide for reasonable progress. The intent of this proposal was to ensure that states perform rigorous analyses, and adopt measures necessary for reasonable progress, with respect to Class I areas that their sources contribute to, regardless of whether such areas are located within their borders.

82 Fed. Reg. at 3099. *See also* 81 Fed. Reg. 66,331, 66,631 (Sept. 27, 2016) ("[A]n evaluation of the four statutory factors is required . . . regardless of the Class I area's position on the glidepath. . . . [T]he URP does not establish a 'safe harbor' for the state in setting its progress goals."); 81 Fed. Reg. 295, 326 (Jan. 5, 2016) ("[T]he uniform rate of progress is not a 'safe harbor' under the Regional Haze Rule"); EPA, Guidance for Setting Reasonable Progress Goals under the Regional Haze Program (hereinafter "RPGs Guidance") (June 2007) 4–1, https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/20070601_wehrum_reasonable_progress_goals_reghaze.pdf.

[16] Draft Guidance at 57-83.

[17] Final Guidance at 8.

[18] *Id.* at 9.

provisions of the Final Guidance against fulfilling the requirements of the Clean Air Act and Regional Haze Rule that compel a comprehensive "regional" approach to restoring visibility. EPA should strike the above-mentioned language discussing selection of sources under section 51.308(f)(3)(ii)(A) from the Final Guidance and restore the language from the Draft Guidance.

B. States have only limited discretion to decide which sources they consider for reasonable progress.

In Section II.B.3.d of the Final Guidance, EPA states, "[t]he source-selection step is intended to add flexibility and discretion to the state planning process – ultimately, the state decides which sources to consider for reasonable progress."[19] This blanket statement, written as if a state has unbounded discretion to determine which sources it evaluates under reasonable progress, is incorrect. A state cannot arbitrarily determine which sources it evaluates under the Regional Haze Rule's reasonable progress requirements. Ultimately, a state's source selection criteria is a part of its long-term strategy. As EPA indicated in the Regional Haze Rule revision, a state does not have discretion to arbitrarily exclude sources from a four-factor analysis. Specifically, EPA stated:

> [W]e expect states to exercise reasoned judgment when choosing which sources, groups of sources or source categories to analyze. Consistent with CAA section 169A(g)(1) and our action on the Texas SIP, a state's reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by arbitrarily including costly controls at sources that do not meaningfully impact visibility or failing to include cost-effective controls at sources with significant visibility impacts, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a [Federal Implementation Plans ("FIPs")]. [20]

A state with a RPG below the URP that followed this guidance and arbitrarily excluded sources from a four-factor analysis runs afoul of section 51.308(f)(3)(ii)(A), which requires a "robust demonstration" that "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the long-term strategy." If a state that followed this guidance had emission sources that potentially affect visibility at a Class I area in another state, it would similarly be unable to satisfy the same requirement found in section 51.308(f)(3)(ii)(B). EPA should reconsider this provision, and delete it from the Final Guidance.

C. States cannot arbitrarily circumvent a four-factor analysis for sources that intend to retire.

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[19] Final Guidance at 20.
[20] 82 Fed. Reg. at 3088.

In Section II.B.3.d of the Final Guidance, EPA also states "[i]f a source is expected to close by December 31, 2028, under an enforceable requirement, a state may consider that to be sufficient reason to not select the source at the source selection step."[21] EPA goes on to extend this deadline by adding an indeterminate grace period: "The year 2028 is not a bright line for these considerations, so a state may be able to justify not selecting a source for analysis of control measures because there is an enforceable requirement for the source to cease operation by a date after 2028."[22] EPA further advises states that consideration of source retirement and replacement schedules required by Section 51.308(f)(2)(iv)(C) are automatically considered if a state decides to not subject sources which will retire by 2028 to a four-factor analysis.[23]

This is a departure from EPA's long-standing requirement in the regional haze program and is in conflict with basic requirements of the Regional Haze Rule. Remaining useful life is one of the four statutory factors that a state must consider when selecting the sources for which it will determine what control measures are necessary to make reasonable progress.[24]

The Clean Air Act does not define the phrase "remaining useful life." However, EPA, in regulations and guidance, has clarified the meaning of the phrase. EPA has consistently stated that the potential retirement of a facility can be used to shorten a source's remaining useful life only if the retirement is federally enforceable.[25] Thus, in order to affect the remaining useful life, a retirement commitment must be included in a pre-existing document that can be enforced in federal court, such as a consent decree entered by a federal court, or a state must incorporate the retirement date into its SIP. If a potential retirement is not federally enforceable, it cannot be relied upon to shorten the remaining useful life of a source.

EPA's 2007 Guidance on reasonable progress incorporates and refers to the best available retrofit technology ("BART") Guidelines,[26] which instruct states on how to calculate the remaining useful life of a source. EPA defines a source's "remaining useful life" as the difference between the date that controls would be installed and "the date the facility permanently stops

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[21] Final Guidance at 20.
[22] *Id.*
[23] *Id.* at 22.
[24] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) ("[A]n agency rule would be arbitrary and capricious if the agency has . . . entirely failed to consider an important aspect of the problem."); *Pub. Citizen v. Fed. Motor Carrier Safety Admin.*, 374 F.3d 1209, 1216 (D.C. Cir. 2004) ("A statutorily mandated factor, by definition, is an important aspect of any issue before an administrative agency, as it is for Congress in the first instance to define the appropriate scope of an agency's mission.").
[25] *E.g.*, 83 Fed. Reg. 62,204, 62,232 (Nov. 30, 2018) ("We are proposing to agree with Arkansas' cost analysis for dry scrubbers and switching to low sulfur coal for Independence Units 1 and 2, and with the state's decision to assume a 30-year capital cost recovery period in the cost analysis. It is appropriate to assume a 30-year capital cost recovery period in the cost analysis since Entergy's plans to cease coal combustion at the Independence facility are not state or federally-enforceable."); 83 Fed. Reg. 43,586, 43,604 (Aug. 27, 2018) (Considering the retirement of certain units where there was evidence that the units had actually been retired at the time of the rulemaking and that the plant had requested cancellation of its air permit).
[26] RPGs Guidance at 5-3. There is no conflict with the 2007 Guidance's interpretation of "remaining useful life" and the Final Guidance. *See* Final Guidance at 34.

operations."[27] If the remaining useful life affects the selection of controls, "this date should be assured by a federally- or State-enforceable restriction preventing further operation."[28] EPA discusses a situation where a source "intends to shut down a source by a given date, but wishes to retain the flexibility to continue operating beyond that date in the event."[29] In that instance, EPA instructs a state to include in its SIP the controls that would be required if the source continues to operate past the planned retirement date.[30] "The source would not be allowed to operate after the 5–year mark without such controls."[31]

Allowing states to avoid a four-factor analysis based on alleged intent to retire would render the other statutory factors meaningless and violate the requirements of the Regional Haze Rule.[32] Many states have already begun analyzing their sources to determine which should be brought forward for a four-factor analysis. Consequently, a source that retires by December 31, 2028 (or later), has at least eight years of potential emission reductions. Even considering this shortened remaining useful life, cost-effective controls, which often can be installed in months, can frequently be justified. For instance, a source could simply switch to a lower sulfur content coal or fuel oil, which would require little to no installation time and may be quite cost-effective. Despite EPA's advice, any source that demonstrably or potentially impacts visibility at a Class I area and would otherwise be subject to a four-factor analysis under section 51.308(f)(2)(i), regardless of its retirement date, must undergo a real analysis to determine if cost-effective controls are available.[33] EPA should revise the Final Guidance to reiterate that only enforceable retirements may alter the remaining useful life and otherwise require that states subject sources that intend to retire to a four-factor analysis if a state selects the source for analysis of emission control measures.

D. States cannot consider being under the URP when selecting sources for a four-factor analysis.

In Section II.B.3.e of the Final Guidance, EPA makes two flawed statements regarding a state's RPG that were not present in the Draft Guidance. First, EPA states "[t]he fact that visibility conditions in 2028 will be on or below the URP glidepath is not a sufficient basis by itself for a state to select no sources for analysis of control measures; however, the state may

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[27] 40 C.F.R. pt. 51, App. Y § (IV)(D)(4)(k)(2).
[28] *Id.*
[29] *Id.* § (IV)(D)(4)(k)(3).
[30] *Id.*
[31] *Id.*
[32] The United States Court of Appeals for the Fifth Circuit recently found that EPA must consider statutory factors listed in a similar provision of the Clean Water Act when revising best available technology ("BAT") limits. *See Southwestern Elec. Power Co. v. EPA*, 920 F.3d 999, 1026-27 (5th Cir. 2019).
[33] EPA's draft guidance also allowed for states to forgo a four-factor analysis on sources secured by an enforceable commitment to retire by 2028. We disagree with that position for the reason expressed above. However, EPA tempered its reasoning in its draft guidance by stating that its position rested on the fact that due to the shortened second planning period (unlike future planning periods), there would be a shorter interval for states to install controls. Also, EPA did not state that states could extend source retirements beyond 2028 as it does in the final guidance.

consider this information when selecting sources."[34] EPA then cites to the 2017 Regional Haze Rule revisions; however, those citations make it absolutely clear that states cannot in fact follow this guidance:

> We disagree that the states should be able to reevaluate whether a control measure is necessary to make reasonable progress based on the RPGs. 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. [35]

Consequently, states have no path available to them to "consider this information when selecting sources."

Similarly, EPA's later advice that "[r]ather, that fact [that a state's RPG is below the URP] would serve to demonstrate that, after a state has gone through its source selection and control measure analysis, it has no 'robust demonstration' obligation per 40 CFR 51.308(f)(3)(ii)(A) and/or (B)"[36] is potentially at odds with the Regional Haze Rule. In the above cited portion of the 2017 Regional Haze Rule revision, EPA actually stated, "if 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."[37] A state's "robust demonstration" obligation does not end because it has merely "gone through its source selection and control measure analysis." Rather, as EPA actually explained, the state must have "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." [38] EPA must reconsider this provision, and delete it from the Final Guidance.

E. Previous installation of certain types of controls does not excuse a state from considering more stringent levels of control.

In section II.B.3.f of the Final Guidance, EPA discusses circumstances under which a state can choose not to select a source that has previously installed controls for a four-factor analysis.[39] Much of this information conflicts with previous guidance and the Regional Haze

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[34] Final Guidance at 22.
[35] 82 Fed. Reg. at 3093. *See also* 81 Fed. Reg. at 66,631; 81 Fed. Reg. at 326; RPGs Guidance at 4-1.
[36] Final Guidance at 22.
[37] 82 Fed. Reg. at 3093.
[38] *Id.*
[39] *Id.* In comparison to the blanket exemptions in EPA's Final Guidance, the Draft Guidance only considered exempting power plant units, "in certain limited situations," with "highly effective control technology within the 5 years prior to submission of the SIP, such as year-round operation of flue gas desulfurization (FGD) with an

Rule. First, EPA states, "[i]n general, if post-combustion controls were selected and installed fairly recently . . . to meet a [Clean Air Act] requirement, there will be only a low likelihood of a significant technological advancement that could provide further reasonable emission reductions having been made in the intervening period."[40] EPA presents no basis for making this conclusion.

There are many instances in which post-combustion controls have been installed in which those controls do not operate at peak efficiency. This includes controls that are not operated continuously, controls that were never designed to operate at peak efficiency (e.g., undersized sulfur dioxide ("SO_2") scrubber or selective catalytic reduction ("SCR") systems) and partially bypassed controls (e.g., SO_2 scrubber or SCR systems). In fact, EPA has made it a point in past actions to ensure that existing controls are examined to determine if they can be cost-effectively upgraded. For instance, the 2005 BART revision to the Regional Haze Rule devotes several paragraphs to specific potential scrubber upgrades it recommends be examined.[41]

EPA also demonstrated that scrubber upgrades to a number of coal-fired power plants utilizing outdated and inefficient scrubber systems were highly cost-effective, and could achieve removal efficiencies of ninety-five percent which is near the ninety-eight to ninety-nine percent removal efficiencies of newly-installed scrubber systems.[42] In fact, as EPA notes in its 2017 Regional Haze Rule revision, EPA disapproved Texas' four-factor analysis in part because "it did not include scrubber upgrades that would achieve highly cost-effective emission reductions that would lead to significant visibility improvements."[43] Consequently, EPA's blanket guidance that examination of potential upgrades to recently installed post-combustion controls is unlikely necessary is demonstrably false. Even if, considering the entire universe of potential post-combustion control upgrades, the vast majority cannot be cost-effectively upgraded to result in significant visibility benefits, which is unlikely, there is no justification in the Regional Haze Rule to skip an examination of the remaining units.

EPA goes on to present examples of pollutant-specific controls that have been installed due to a requirement outside of the regional haze program for which it "believes it may be reasonable for a state not to select a particular source for further analysis."[44] This list includes new source performance standard ("NSPS") controls installed since July 31, 2013; best available control technology ("BACT") or lowest achievable emission rate ("LAER") controls installed since July 31, 2013; power plants with FGD controls that meet the 2012 model attainment test systems ("MATS") standard; particulate matter ("PM") controls under National Emission

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effectiveness of at least 90 percent or year-round operation of selective catalytic reduction with an effectiveness of at least 90 percent." EPA specifically requested comment "on whether to include this additional screening mechanism and if so, then what criteria may be appropriate for its inclusion."

[40] *Id.*

[41] *See* 70 Fed. Reg. 39,103, 39,171 (July 6, 2005).

[42] *See* 81 Fed. Reg. at 305.

[43] *See* 82 Fed. Reg. at 3088.

[44] Final Guidance at 23.

Standards for Hazardous Air Pollutants ("NESHAP") since July 31, 2013; boilers that have installed an FGD or SCR system that operates year round and has a total efficiency of ninety percent; and any BART-eligible unit that has installed BART controls.[45] EPA reasons that due to their recent installation and the similarity of the requirements for those programs, it is unlikely that a four-factor analysis will result in additional cost-effective controls.[46] But, as EPA notes in its 2005 BART revision to the Regional Haze Rule, it reviewed some of these standards and concluded they may not be the most stringent available.[47] Furthermore, the 2017 revision to the Regional Haze Rule warned states that "we anticipate that a number of BART-eligible sources that installed only moderately effective controls (or no controls at all) *will need to be reassessed*. Under the 1999 [Regional Haze Rule and] 40 CFR 51.308(e)(5), BART-eligible sources are subject to the requirements of 40 CFR 51.308(d), which addresses regional haze SIP requirements for the first implementation period, in the same manner as other sources going forward." [48] This is in contrast to EPA's Final Guidance statement that "if a source installed and is currently operating controls to meet BART emission limits, it may be unlikely that there will be further available reasonable controls for such sources."[49] Therefore, a state must first subject a source to a four-factor analysis under section 51.308(f)(2)(i) before it is able to determine whether there are no emission reducing options available (including upgrades to existing controls).

Regarding which control measures states should consider in assessing reasonable progress, EPA states "there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures. A range of technically feasible measures available to reduce emissions would be one way to justify a reasonable set."[50] This conflicts with past guidance and with the Regional Haze Rule. Although there is no requirement that controls required under the reasonable progress requirements of the Regional Haze Rule uniformly be the most stringent available, not considering this level of control bypasses section 51.308(f)(2)(i), which requires that the state perform a four-factor analysis. A state cannot consider "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" unless it considers all feasible controls available, including upgrades to existing controls.

EPA acknowledged that a range of controls should be evaluated in a four-factor analysis in its Draft Guidance:

> In order to define a control measure with sufficient specificity to assess its cost and potential for emission reductions, the state should specify and consider the range of control efficiencies that the measure is capable of achieving. For example, when

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[45] *Id.* at 23-25.
[46] *Id.* at 25.
[47] *See* 70 Fed. Reg. at 39,163-64.
[48] 82 Fed. Reg. at 3083 (emphasis added).
[49] Final Guidance at 25.
[50] *Id.* at 29.

> evaluating a flue gas desulfurization system to reduce SO_2 emissions, the state should consider both a system capable of achieving a 90 percent reduction in SO_2 emissions as well as a more advanced system capable of achieving a 97 or 98 percent reduction. The state should not limit its analysis to either an unrealistically high and prohibitively expensive control efficiency or to a control efficiency that is substantially lower than has been achieved at other sources.[51]

Furthermore, EPA does not require that states secure the operation of controls with this level of efficiency through an enforceable commitment.

Just because a source has the most effective or highly effective control technology does not mean that it is required to be operated to a level reflective of its maximum pollution reduction capability. Thus, states should not be screening such sources out of review during the second implementation period. By allowing states to "screen out" and choose not to select such sources for a full four-factor analysis, EPA may be allowing states to ignore very cost-effective emission reducing options like simply requiring sources with highly effective controls to operate those controls in the most effective manner to reduce air pollutants. EPA should revise the Final Guidance to recommend that sources with existing pollution control technology evaluate options that could improve the emissions reduced through more effective use of that control technology. This could include requiring year-round operation of controls, reducing capacity, imposing more effective percent reduction requirements, requiring sources to meet more stringent emission limits, or requiring that emission limits apply on shorter averaging times to ensure continuous levels of emission reduction.

F. States should ensure that modeled emissions are tied to enforceable limits for sources with appropriate averaging times that reflect year-round abilities of existing controls or operation.

EPA should revise the Final Guidance to recommend that wherever possible, whether they are screened in or out, states should make sure that the emissions relied upon in the state's RPG demonstration are enforceable, and also that they reflect the lowest emission rates feasible at the facility given its existing configuration. This is particularly true for major sources that are screened out on the basis of emissions that reflect unenforceable conditions.

However, this is also true for sources that are screened out on the basis of emissions that do not reflect their full capacity for emission reductions. For example, if a source is screened out with emissions that reflect using its controls only seventy-five percent of the time, the state should nevertheless require year-round operation of the control. Requirements reflecting existing capacity for emission reductions are inherently reasonable, and represent low hanging fruit necessitating reduced resource expenditure for potentially large gain. Moreover, states routinely rely on actual emissions in assessing current visibility and using that assessment as a jumping off point to determine if additional reductions are necessary. Where a state is to rely on operational

[51] Draft Guidance at 87.

realities, such reliance must be justified by enforceable emission limits. Indeed, failing to take advantage of such reasonable progress measures is an example of one of the pitfalls of using this type of a screening process in the first place. EPA should recommend that states assure reasonable progress by requiring that sources have enforceable limits or conditions reflecting their full emission reduction capacity if they are to be screened out.

G. States must include both "dominant" and "non-dominant" pollutants in their analyses of controls.

In Section II.B.3.a of the Final Guidance, EPA advises states that they can skip analyses of controls for sources with "non-dominant" pollutants. Specifically, EPA states:

> When selecting sources for analysis of control measures, a state may focus on the PM species that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors. Also, it may be reasonable for a state to not consider measures for control of the remaining pollutants from sources that have been selected on the basis of their emissions of the dominant pollutants.[52]

This position, absent from the Draft Guidance, directs states to produce deficient regional haze SIPs and is in conflict with the Regional Haze Rule's requirements and preamble language in the 2017 Regional Haze Rule revision.

The preamble specifically states that a "reasonable progress analysis must consider a meaningful set of sources and controls that impact visibility. If a state's analysis fails to do so, for example, by . . . *failing to include cost-effective controls at sources with significant visibility impacts*, then the EPA has the authority to disapprove the state's unreasoned analysis and promulgate a FIP.[53] This provision in the Guidance would allow states to arbitrarily determine that because one pollutant has a greater impact on visibility at a Class I area(s), the state may simply ignore other visibility impacting pollutants for one or all sources in the state emitting the non-dominant pollutants, despite the availability of cost-effective controls under reasonable progress criteria. It would also allow states to conclude that when examining a source that emits multiple pollutants that contribute to haze (e.g., SO_2, Nitrogen Oxide ("NOx")), potential reductions for the non-dominant pollutant can be summarily ignored. Furthermore, EPA does not provide any metric for what it considers a "dominant" pollutant.[54] For instance, if a state has determined that fifty-one percent of the visibility impact at a Class I area is due to SO_2, forty

[52] Final Guidance at 11.
[53] 82 Fed. Reg. at 3088. EPA states elsewhere in its 2017 Regional Haze Rule revision, that "A state may refer to its own experience, past EPA actions, the preamble to this rule as proposed and this final rule preamble, and existing guidance documents for direction on what constitutes a reasoned determination." 82 Fed. Reg. at 3099.
[54] Merriam-Webster defines dominant as "(a) commanding, controlling, or prevailing over all others," or as "(b) very important, powerful, or successful."

percent is due to NOx, and nine percent is due to PM, would SO_2 be considered dominant (and consequently the only analyzed pollutant), or must its share of the visibility impact be greater?

This provision in the Final Guidance has potentially far-reaching negative impacts on the Regional Haze Rule's requirements that states make reasonable progress, as many large sources emit multiple types of visibility impacting pollutants. Still other sources may emit significant levels of non-dominant emissions for which emission reducing control or measures may be well within the framework of the four-factor analysis. If this is not corrected, a state could assume it would be justified in concluding that state-wide, SO_2 is its "dominant" pollutant and forego control analysis of a large gas-fired power plant emitting thousands of tons of NOx which could also significantly impact visibility at one or more Class I areas.

The Final Guidance also directly conflicts with multiple sections of the Regional Haze Rule. For instance, a state following the guidance would not be able to determine if it was even subject to section 51.308(f)(3)(ii)(B), because by arbitrarily excluding pollutants or entire sources from review it could not determine if it "reasonably [was] anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another State." Nor could that state "demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area." Similarly, if that state's RPG was above its URP, it could not satisfy section 51.308(f)(3)(ii)(A), which requires the same demonstration. Such a state would also not be able to reasonably satisfy its state-to-state consultation requirements under section 51.308(f)(2)(i), which requires it to "evaluate and determine the emission reduction measures that are necessary to make reasonable progress" and "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." By severely compromising the entire foundation of a state's technical demonstration, EPA is directing states to submit deficient SIPs. For these reasons, EPA should delete the above-quoted language from the Final Guidance.

H. States cannot eliminate VOCs and ammonia emissions from consideration.

In Section II.B.3.a. of the Final Guidance, EPA also advises states that irrespective of their particular state emissions inventories or the acknowledged potential impacts of VOCs and ammonia on Class I areas, they can completely disregard these pollutants. Specifically, EPA states:

> In the first implementation period, many states eliminated VOC and ammonia emissions from consideration based on the expectation that anthropogenic VOC emissions make only a small contribution to visibility impairment and that formation of nitrate and sulfate PM is most effectively reduced by reducing emissions of NOx and SO_2 rather than by anthropogenic emissions of ammonia. EPA believes that, in general, this

> would also be a reasonable approach for the second implementation period.[55]

This position is completely absent from EPA's regulations and was not present in the Draft Guidance.

VOCs are organic chemicals emitted by products or industrial processes that when released into the atmosphere can react with sunlight and NOx to form tropospheric ("ground-level") ozone. In addition, VOCs are important precursor of Secondary Aerosol Formation ("SOA"). SOA comprises a large fraction of atmospheric aerosol mass and can have significant effects on atmospheric chemistry, visibility, human health, and climate.[56] A major source of VOCs in the United States is the oil and gas industry, which includes wells, gas gatherings and processing facilities, storage, and transmission and distribution pipelines. According to data from EPA and the Energy Information Agency ("EIA"), more than 20 million tons of VOCs are emitted from point and non-point sources in the oil and gas industry every year. Studies on oil and gas emissions have indicated that VOC source signatures associated with oil and gas operations can be clearly differentiated from urban sources dominated by vehicular exhaust emissions.[57][58] According to a recent air quality study by the National Park Service ("NPS") in Carlsbad Caverns National Park, high levels of light alkanes such as ethane, propane, butane, and, pentane compounds were consistent with oil and gas emissions. However, high alkanes ("$>C_8$") and aromatics are assumed to contribute more significantly to SOA formation.[59]

In California alone, statewide agricultural operations produce an average of 272.12 tons per day ("tpd") of ammonia ("NH_3") emissions.[60] Of those 272.12 tpd, 158.50 tpd is attributed to "agricultural waste" specifically from dairy cattle.[61] In regions such as California's heavily polluted San Joaquin Valley, ammonia concentrations are found to be much higher than NOx

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[55] Final Guidance at 12.
[56] Ziemann, Paul J., & R. Atkinson, *Kinetics, products, and mechanisms of secondary organic aerosol formation*, 41, no. 19 Chem. Soc'y Reviews 6582, 6582 (2012).
[57] *See* Odum J.R., T. Hoffmann, F. Bowman, D. Collins, R.C. Flagan, & J.H. Seinfeld, *Gas/Particle Partitioning and Secondary Organic Aerosol Yields*, 30 Environ. Sci. Technol., 2580, 2580-2585 (1996).
[58] *See* Swarthout, R. F., Russo, R. S., Zhou, Y., Hart, A. H., and Sive, B. C., *Volatile organic compound distributions during the NACHTT campaign at the Boulder Atmospheric Observatory: Influence of urban and natural gas sources*, J. Geophys. Res. Atmos., 118, 10,614–10,637, (2013), *available at* https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/jgrd.50722.
[59] Ziemann, *supra* note 56, at 6583; *see also* Takekawa, Hideto, Hiroaki Minoura, and Satoshi Yamazaki, *Temperature dependence of secondary organic aerosol formation by photo-oxidation of hydrocarbons*, Atmospheric Environment 37, no. 24, 3413-3424 (2003).
[60] California Air Resources Board, 2016 SIP Emission Almanac Projection Data by EIC: Annual Average Emissions (Tons/Day) Statewide, Miscellaneous Processes 620-Farming Operations, https://www.arb.ca.gov/app/emsinv/2017/emseic_query.php?F_YR=2012&F_DIV=-4&F_SEASON=A&SP=SIP105ADJ&SPN=SIP105ADJ&F_AREA=CA&F_EICSUM=620.
[61] *Id.*

concentrations.[62] When mixed with the region's NOx emissions (primarily from mobile sources), this excess ammonia helps form high levels of haze causing ammonium nitrate, which accounts for the majority of PM2.5 emissions found in the San Joaquin Valley.[63]

The San Joaquin Valley is home to multiple communities such as Bakersfield, Fresno, and Visalia that rank amongst the very topmost polluted cities for both annual and twenty-four hour PM2.5 pollution. [64] The entire air basin is also listed as being in extreme nonattainment with the 1997 and 2006 PM2.5 NAAQS standards.[65] As it relates to regional haze pollution, the San Joaquin Valley is located directly adjacent to the Southern Sierra Nevada Mountains, home to heavily polluted Class 1 areas like Sequoia and Kings Canyon National Parks—both of which fall within the jurisdiction of the San Joaquin Valley Air District.

Despite ammonia being a major precursor to PM2.5 pollution in the region, its emissions are currently not controlled in the San Joaquin Valley under the state's various PM2.5 SIPs.[66] Beyond ammonia, agricultural sources in California also produce and average of 145.90 tpd of direct PM10 and 21.79 tpd of direct PM2.5 emissions.[67]

In its 2005 BART amendments to the Regional Haze Rule, EPA left it to the states to individually determine if these two pollutants, which EPA acknowledges can potentially impact visibility, should be addressed.[68] In the Draft Guidance, EPA acknowledged that much of its guidance on BART remained applicable to the second round of SIPs and included an entire appendix devoted to identifying which portions of the BART guidance remained applicable.[69] This appendix has been deleted in EPA's Final Guidance. By arbitrarily excluding potential visibility-impairing pollutants from review, EPA's guidance conflicts with the same sections of the Regional Haze Rule as described *supra* section III.G, primarily preamble language to the 2017 Regional Haze Rule revision and sections 51.308((f)(3)(ii)(A), 51.308((f)(3)(ii)(B), and 51.308(f)(2)(i). EPA should revise the Final Guidance to direct states to inventory and evaluate potential visibility-impairing pollutants including VOCs and ammonia and determine associated control measures necessary to make reasonable progress. .

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[62] San Joaquin Valley Air Pollution Control District, 2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards, at 5-6, http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf.
[63] *Id.* at 3-12.
[64] American Lung Association, 2019 State of the Air Report: Most Polluted Cities Ranking, https://www.lung.org/our-initiatives/healthy-air/sota/city-rankings/most-polluted-cities.html.
[65] San Joaquin Valley Air Pollution Control District, *supra* note 62, at ES-8.
[66] *See generally, id.* at 4-1 through 4-34.
[67] *See* California Air Resources Board, *supra* note 60.
[68] *See* 70 Fed. Reg. 39,104, 39,112-14 (July 6, 2005). EPA stated that scientific and technical data shows "that ammonia in the atmosphere can be a precursor to the formation of particles such as ammonium sulfate and ammonium nitrate . . . [and] certain aromatic VOC emissions such as toluene, xylene, and trimethyl-benzene are precursors to the formation of secondary organic aerosol." *Id.* at 39,114.
[69] Draft Guidance at Appendix D.

I. Light extinction thresholds should be tailored to Class I areas and low enough to bring in most sources of visibility-impairing pollution.

States choosing light extinction as a metric for visibility impacts should use Class I-specific figures to identify sources for a four-factor analysis. If a threshold is applied, states must ensure that the threshold is low enough to bring in most sources harming a Class I area. In the Final Guidance, EPA recommends visibility metrics and thresholds in terms of inverse megameters of light extinction.[70] Although light extinction may be acceptable as a metric, states should not use a generic extinction threshold for selecting sources for consideration of pollution controls for each of the Class I areas evaluated in their regional haze SIPs. If a light extinction threshold is too high, it can significantly limit the amount of sources a state evaluates for controls to make reasonable progress.

States must make clear how each source's visibility impacts are to be determined. States must explain whether the sources' potential emissions were modeled, what visibility-impairing pollutants were modeled for each source, whether all units were modeled for all sources, whether sources were modeled for impacts on the twenty percent worst days or some other timeframe, and identify and allow public review of and comment on the technical approach that the state employed to determine source-specific visibility extinction, pursuant to 40 C.F.R. § 51.308(f)(2). Any proposed extinction threshold for defining sources to target for controls is only as good as the underlying technical analysis to define if a source exceeds the extinction threshold. States must address these requirements and justify any and all extinction thresholds that they rely on for each Class I area impacted by states' sources.

For any souces that exceed an extinction threshold but are not subject to reduction requirements, states should provide a thorough four-factor analysis of controls or provide justification as to why a four-factor analysis would not likely lead to a determination that additional controls are needed to make reasonable progress. For any sources that a state claims already has adequate controls or justifies for other reasons that a four-factor analysis of controls would not result in additional controls, the state must document in its regional haze SIP why it makes this finding. To the extent such justification is relying on other regulatory or permit requirements, the state must document those regulatory or permit requirements in detail and indicate whether such requirements are already or will be submitted to EPA as part of the SIP

J. State's using the Q/d metric should include all visibility-impairing pollutants when calculating a source's annual emissions.

In Section II.B.3.b of the Final Guidance, EPA discusses the use of a source's annual emissions in tons divided by distance in kilometers between the source and the nearest Class I area (often referred to as Q/d) as a surrogate for source visibility impacts, along with a reasonably selected threshold for this metric.[71] As EPA notes, although Q/d is the least

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[70] Final Guidance at 19.
[71] Final Guidance at 13.

complicated technique, it should "be limited to source selection for the purpose of developing a list of sources for which a state may conduct a four-factor analysis" because the metric is a less reliable indicator of actual visibility impact.[72]

EPA should revise the Final Guidance to require states using the Q/d metric to include all visibility-impairing pollutants when determining the annual emissions being used to obtain a source or source category's estimated visibility impacts. As discussed further *supra* section III.H, states cannot eliminate certain emissions, such as VOCs and ammonia emissions, from consideration. Additionally, EPA should recommend that states using the Q/d metric not use the Q/d threshold from the first implementation period for the second implementation period. Rather, the Q/d threshold should be lower in order to address more sources, including sources that are lower emitting and sources that are further in distance than the sources addressed in the first implementation period.

IV. Determination of affected Class I areas in other states

A. States must use methods permitted by statute and regulation to identify its sources that impact visibility at Class I areas in other states, not merely any "reasonable method."

In Section II.B.2 of the Final Guidance, EPA inserts a blanket statement that jeopardizes making progress towards the Clean Air Act Class I visibility goal and obfuscates the Regional Haze Rule's requirements regarding how a state should identify its sources that impact the visibility at Class I areas in other states: "As an initial matter, a state has the flexibility to use any reasonable method for quantifying the impacts of its own emissions on out-of-state Class I areas, and it may use any reasonable assessment for this determination."[73]

EPA does not provide any explanation or examples of what it considers "reasonable." Thus, this statement would allow a state to use any methodology, regardless of its scientific rigor, to identify those sources. Furthermore, once having identified these sources, however loosely, the state can then "assess" those sources any way it wishes. Confusingly, EPA seems to distinguish between quantifying the impacts of these sources and assessing these impacts. This single statement would serve to hand a state seemingly unlimited discretion over a key step in preparing its SIP, in marked contrast to what it proposed.

As EPA states in its 2017 Regional Haze Rule revision:

> On July 8, 2016, we released Draft Guidance that discusses how states can determine which Class I areas they ''may affect'' and therefore must consider when selecting sources for inclusion in a four-factor analysis. The Draft Guidance discusses various approaches that states used during the first implementation

[72] *Id.*
[73] Final Guidance at 8.

> period, provides states with the flexibility to choose from among these approaches in the second implementation period, and recommends that states adopt ‘‘a conservative . . . approach to determining whether their sources may affect visibility at out-of-state Class I areas.[74]

Indeed, EPA's Draft Guidance did provide actual guidance to the states on this issue:

> Once contributions by sources, groups of sources or geographic areas have been quantified in some manner, the EPA recommends that states adopt a conservative (more protective approach of visibility) approach to determining whether their sources may affect visibility at out-of-state Class I areas. For example, states could consider all Class I areas for which the state contributes at least one percent to anthropogenic light extinction from all U.S. sources on any day within the 20 percent most impaired days. States may choose a different threshold to determine which out-of-state Class I areas may be affected by the States sources, but must provide an adequate explanation of why the threshold is sufficiently protective of visibility.[75]

EPA followed this statement with more than twelve pages of highly technical guidance detailing approaches it deemed acceptable.[76] The Final Guidance deletes most of this and provides a summary approach void of technical rigor or analytical teeth. The Regional Haze Rule makes plain that a state's long-term strategy, including its application of the four statutory factors, be comprised of a robust initial step—the assessment of the state's emission sources on downwind states' Class I areas. However, by diminishing actual guidance and inventing this undefined and ambiguous standard, EPA creates confusion and ambiguity for states, leaving states to determine reasonability on a SIP-by-SIP basis. EPA should restore the discussion and directives to states from the Draft Guidance.

B. Application of a threshold for cumulative impacts to multiple Class I areas.

EPA should reconsider and revise the Final Guidance to recommend that states quantitatively document the results of the screening process for each Class I area rather than presenting only the impacts at the most affected or nearest Class I area. This allows the public to know the scope of the source's impacts and assures that the SIP comports with the letter and spirit of the regional haze program, a program grounded in the fact that regional haze is a regional problem and that Class I area impacts are felt typically by a multitude of sources' pollution that defy state boundaries.

EPA should also make clear that states must consider cumulative impacts of sources or groups of sources to all affected Class I areas. A source's cumulative impacts across Class I

[74] 82 Fed. Reg. at 3094.
[75] Draft Guidance at 58.
[76] Draft Guidance at 58-70.

areas provides a valuable screen to identify sources for further analysis. As EPA conceded and the court found in *Nat'l Parks Conservation Ass'n v. EPA*, in considering the visibility improvement expected from the use of controls, states must take into account the visibility impacts at all impacted Class I areas rather than focusing solely on the benefits at the most impacted areas.[77] This must include sources that have relatively small impacts in isolation but larger cumulative impacts either in the aggregate or across Class I areas.

V. Ambient data analysis

A. States must prioritize emissions within their borders to achieve reasonable progress.

International emissions contribute to visibility impacts. Rather than encouraging states to pursue an adjustment to the end goal of natural visiblity due to international emissions, EPA should be directing states to focus on the emissions within their borders for which requirements would help achieve reasonable progress. We encourage EPA to work with states, FLMs, stakeholders, and other countries to develop emissions inventories for cross-border pollution as well as scientifically valid methods for assessing long range emissions transport. However, the development of accurate accounting and modeling should not come with the expense of postponing or ignoring domestic emission-reducing measures. EPA's updated 2028 modeling[78] attempts to incorporate international emissions, but the agency itself makes clear that the science upon which the modeling rests is questionable.[79] EPA should reconsider and revise its Guidance to clarify that assessing international emissions is a work in progress and opportunity for partnership across a broad set of stakeholders, but the mandate of the Clean Air Act compels states to take measures to make reasonable progress by reducing emissions in their borders, not look to analysis to excuse doing so because other nations also contribute to regional haze.

We also urge EPA to revise the Final Guidance to clarify that affected states also have an obligation to take appropriate action to address international emissions.[80] Although EPA and the states are not required to "compensate" for international emissions, it is well within EPA and the states' rights and obligations to formally request reductions from international sources where appropriate, or to take permitting actions in the United States that will lead to emission reductions in other countries.

For example, Mexico's Carbon I and II power plants, which are less than twenty miles from the Texas border, are responsible for significant levels of pollution across several of the border states. Despite noting the significant impact of Mexican sources on its Class I areas, and

[77] *Nat'l Parks Conservation Ass'n v. EPA*, 803 F.3d 151, 165 (3d Cir. 2015).
[78] EPA, Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling (Sept. 19, 2019), https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf ("Updated 2028 Modeling").
[79] *Id.* at 67.
[80] 64 Fed. Reg. 35,714, 35,755 (July 1, 1999) ("The States retain a duty to work with EPA in helping the Federal government use appropriate means to address international pollution transport concerns.").

requesting federal efforts to reduce impacts from international emissions,[81] Texas approved water discharge and mining permits for a coal mine in Maverick County. Rejecting these permits instead would have prevented the Mexican company Dos Republicas from mining high-sulfur coal that is transported and burned at the Carbon I & II facilities. EPA should remove its false implication that international emissions are entirely "uncontrollable" and should instead make clear that states must demonstrate that they are doing what is within their control to address international emissions—both generally and in particular.

EPA also discusses an "adjustment" to the URP for prescribed wildland fires. Wildfires, particularly in the West, have grown hotter, bigger, and more frequent with climate change. We recognize the role of prescribed fire in both managing fire size due to climate impacts and in restoration of natural ecosystems—which can, if effective, reduce the size and scale of fires later. There are, as a result of increased prescribed fire, potential benefits to both short- and long-term air quality. In planning for prescribed wildland fires, states should consider effects on visibility, alongside health and other concerns, including potential control measures and the potential benefits. A State cannot adjust a URP based on prescribed fires unless these fires actually result in visbility impairment on the "most-impaired" days. The Final Guidance should be clear that analysis of and planning for prescribed wildland fires need to be tailored to the planning period basis and would not automatically apply to the next planning period.

VI. Characterization of factors for emission control measures

A. States should identify and consider the best available emission control measures in the four-factor reasonable progress analysis.

In Section II.B.4.a of the Final Guidance, EPA advises states that they have the flexibility to reasonably determine which control measures to evaluate, and the agency lists examples of types of emission control measures states may consider.[82] EPA should reconsider its approach to ensure that the best controls for a source or source category are identified, evaluated, and the appropriate option determined. Identification of all available control measures is an important first step to ensure the best controls or emission reduction measures emerge from a four-factor analysis. However, EPA should revise the Final Guidance to ensure evaluation of the best control options.

1. EPA should reiterate and expand upon Step 1 of the BART-Guidelines regarding the identification of all available emission control techniques.

EPA should encourage states to consider various sources of information and types of emissions control techniques in developing its long-term strategy. Specifically, EPA should make clear that states must look to new source review control technology determinations, including major source BACT and LAER determinations, as well as state minor source BACT

[81] Texas Revisions to the State Implementation Plan (SIP) Concerning Regional Haze, at ES-2 (Feb. 25, 2009).
[82] Final Guidance at 29-30.

determinations. EPA should also recommend that states evaluate technologies that were considered in applicable new source performance standards, as well as those emission controls that were required in applicable new source performance standards.[83] EPA should also recommend that states consider the control techniques evaluated and required for similar source BART determinations.

In addition, EPA should recommend that states consider BACT determinations and other new source control requirements that states have adopted in minor new source review permits. Several states have minor source BACT provisions which may provide useful information for control technology considerations, and/or states have adopted targeted emission control requirements for source categories that do not have parallel federal requirements.[84]

Further, EPA should recommend that states investigate controls for source categories evaluated in reasonably available control measures ("RACM")/ reasonably available control technology ("RACT") and best available control measures ("BACM")/BACT determinations for nonattainment areas, a good starting point for information for control techniques available for a particular source category. States should also be encouraged to consult vendors or vendor groups such as the Institute of Clean Air Companies for control techniques for sources or source categories.

States should consider inherently lower-emitting processes, by themselves, and in combination with add-on controls. A state should not reject a combination of control measures altogether when the control measures could also be applied independently, unless the state is instead focusing on a control measure that is more effective at reducing emissions than the individual control measures.

In general, EPA should provide flexibility for states to consider innovative technologies tied to quantifiable and enforceable emission reduction requirements and to consider control techniques that some could view as "redefining the source" such as a change in fuel form. The BART Guidelines seemed to limit such controls from consideration for BART. Setting aside whether this was appropriate for BART determinations, States should not be constrained when evaluating measures to consider for the long-term strategy to make reasonable progress towards the national visibility goal.

In evaluating measures for the long-term strategy, states may need to address sources that were constructed many decades ago and/or sources to which pollution controls have not typically

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[83] As EPA acknowledges in the BART guidelines, the NSPS standards do not always require the most stringent level of available control technology for a source category. 40 C.F.R. Part 51, Appendix Y, Section IV.D.2. In some cases, EPA evaluates more stringent controls in an NSPS proposed rulemaking, but ultimately requires a less stringent control to set the NSPS standard. EPA should make clear that NSPS standards are likely insufficient for purposes of reasonable progress determinations because the standards will not be reflective of the reduction measures available and otherwise meeting the four factors as SIPs are being advanced.

[84] *See, e.g.*, Colorado Regulation No. 7 – Control of Ozone via Ozone Precursors and Control of Hydrocarbon via Oil and Gas Emissions, https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=8546&fileName=5%20CCR%201001-9.

been applied. There may be little experience with applying pollution controls to such sources. However, the lack of information on "available" control technologies should not be used as a justification to eliminate a source from consideration of controls (or to only evaluate less effective controls). In such cases, States should be encouraged to consider innovative technologies, technologies that may not have historically been applied to the source type but could be transferred to the source type, emission unit replacement with more energy efficient/less polluting technology, and other such measures in evaluating how to best reduce haze-forming pollution from the source or source type.

2. EPA should advise states how to determine "available" and "technically feasible" control techniques for long-term strategy measures.

EPA should elaborate on how to determine whether a control technique is considered "available" or "technically feasible" for a source or source category. Section IV(D)(1) of the BART Guidelines[85] states in part that that "available retrofit control options are those with a practical potential for application to the emissions unit . . ." and "technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; we do not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice." EPA should recommend that states take a broader view in determining what control strategies are "available" for a source or source category, especially if traditional pollution controls had not been historically applied to that source category. In such cases, states may need to examine more innovative options for pollution control at such sources or source categories, including the consideration of promising pollution control options that have not already been demonstrated in practice but which offer quantifiable emission reductions.

Section IV(D)(1) of the BART Guidelines includes provisions to determine whether a control option is "technically feasible." Those provisions, as well as the discussion on available technologies, generally track guidance on evaluations for BACT determinations set out in EPA's New Source Review Workshop Manual.[86]

Sources often make availability or technical infeasibility arguments to avoid having to consider a pollution control, pointing out that that the control has not been used on the specific type of coal the source utilizes or on the particular size plant. Given that states may be having to determine controls for sources or source categories that have not been traditionally controlled in the long-term strategies, EPA should encourage states in such situations to fully evaluate controls that can be transferred from other source categories or that can be altered to accommodate the specific source or source category in question. EPA should recommend in such situations that states consult with, for example, environmental consultants, research technical journals, or air pollution control conference articles. States should also consider technologies demonstrated outside of the United States. EPA's New Source Review Workshop Manual describes how to

[85] 40 C.F.R. § Pt. 51, App. Y.
[86] U.S. EPA, New Source Review Workshop Manual, at B.17-B.21 (Draft Oct. 1990).

identify all control options "with potential application to the source and pollutant under evaluation."[87]

In summary, EPA should reconsider and revise the Final Guidance to elaborate on how states should evaluate available and technically feasible control techniques with the goal of ensuring that all potential controls with a practical application to a source or source category are considered in the development of the long-term strategy.

B. Cost analyses for the long-term strategy.

1. States must adhere to the accounting principles of the Control Cost Manual.

EPA should require states to follow the accounting principles and generic factors of EPA's Control Cost Manual because states and EPA have historically determined whether the costs of control measures are "reasonable" based on the costs that other similar sources determined in other regulatory actions including permits. [88] If EPA does not require all states to use the same accounting principles, it will be extremely difficult to compare costs of control between sources to evaluate whether the controls are cost effective.

2. States should compile and make publicly available the documentation for generic cost estimates.

EPA's Final Guidance suggests that states may reduce time and effort in determining control costs by using generic cost estimates or estimation algorithms, such as the Control Strategy Tool.[89] However, we request that EPA require the documentation for such generic cost estimates to be compiled and made publicly available. As stated in Sierra Club and National Parks Conservation Association's comments on EPA's proposed revisions to the Control Cost Manual, the Integrated Planning Model's SCR cost database is based on Sargent & Lundy's confidential database and the underlying data and methods used to develop the regression equations have not been publicly reviewed and analyzed.[90] Given that the cost estimates may be a primary basis for rejecting a control measure, the underlying data for such cost estimates must be publicly available.

C. EPA should reconsider and revise the Final Guidance regarding how to address energy and non-air quality environmental impacts of control measures.

EPA should state that the third factor of energy and non-air quality environmental impacts should generally be based on the same methodology laid out in the BART Guidelines. Section 8.1.1 of the BART Guidelines indicates that states must consider the energy and non-air quality environmental impacts as part of the cost analyses. With respect to taking into account non-air quality environmental impacts, we agree in general to take into account such impacts in

[87] *Id.* at B.10-B.11.
[88] Final Guidance at 31.
[89] *Id.* at 32.
[90] *See* September 10, 2015 Comment Letter from Sierra Club and National Parks Conservation Association to U.S. EPA, Docket ID No. EPA-HQ-OAR-2015-0341, at 8.

the cost analysis if the costs can be quantified. Otherwise, such impacts may need to be discussed qualitatively and weighed in the four-factor analysis.

EPA should also revise the Final Guidance and recommend that states analyze the climate and environmental justice impacts of regional haze SIPs. Although the Regional Haze Rule does not define "non-air quality environmental impacts," the BART Guidelines, which inform a state's reasonable progress analysis, explain that the term should be interpreted broadly.[91] Climate change[92] and environmental justice[93] impacts are the types of non-air quality impacts that states should consider when they determine reasonable progress measures for specific sources. Incorporating climate change and environmental justice impacts into the regional haze analysis will further states' climate and environmental justice policy goals, and it will also help states ensure that their actions related to regional haze planning support their other work on climate and environmental justice issues. Most of the same sectors and sources implicated under the regional haze program are also implicated in climate and environmental justice initiatives. As a result, when states determine "the emissions reduction measures that are necessary to make reasonable progress," they should assess how those measures will either reduce or exacerbate greenhouse gas emissions and/or environmental justice impacts on nearby disproportionately burdened communities.

VII. Decisions on what control measures are necessary to make reasonable progress

A. States cannot allow sources to discontinue the use of currently operating controls.

In Section II.B.5.e of the Final Guidance, EPA advises states how currently controlled sources may be able to discontinue those controls under reasonable progress:

> It is also possible that a source may be operating an emission control device but could remain in compliance with applicable emission limits if it stopped operation of the device. The state may reasonably consider based on appropriate factors whether continued operation of that device is necessary to make reasonable progress, such that the regional haze SIP submission for the second implementation period must make such operation of the device (or attainment of an equivalent level of emission control) enforceable.[94]

Suggesting to states that they may discontinue the use of controls that are already operating is antithetical to the regional haze program. Rather, EPA should revise the Final Guidance to require states to evaluate more effective operation of existing controls, including year-round

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[91] 40 C.F.R. pt. 51, App. Y at § (IV)(D)(4)(i), (IV)(D)(4)(j).
[92] *See, e.g.*, 74 Fed. Reg. 66,496 (Dec. 15, 2009) (EPA endangerment finding); Intergovernmental Panel on Climate Change, Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (2015), https://www.ipcc.ch/report/ar5/syr/.
[93] *See* EPA, Learn about Environmental Justice, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice (last visited April 24, 2020); Exec. Order No. 12,898, Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations, 59 Fed. Reg. 7629 (Feb. 11, 1994).
[94] Final Guidance at 43.

operation requirements. Further, the Clean Air Act is clear that visibility is not a factor in determining reasonable progress measures required at a source.

In evaluating controls for a source that already had a control installed, such as a wet or dry scrubber for SO_2 or SCR or selective non-catalytic reduction ("SNCR") for NOx, states must be required to evaluate whether these controls can be more effectively operated. Companies tend to operate their air pollution control systems to the level needed to ensure compliance with applicable emission limits rather than to the maximum emission reduction capability of the pollution control technology. For example, there are electrical generating units ("EGUs") that are only operating their installed SCR or SNCR systems during the ozone season to meet limits under the Cross State Air Pollution Rule ("CSAPR"). Indeed, in projecting operations and emissions scenarios for evaluating the CSAPR program, EPA included assumptions for dispatchable SCR, SNCR, and also scrubbers, which reflected the fact that no emission limits or consent decrees required continuous operation of the pollution controls installed at many EGUs. EPA should thus recommend that states, at a minimum, require year-round operation of existing scrubbers, SCRs, SNCRs, or other controls as one of the control options considered.

Additionally, there are numerous examples of scrubbers, SCRs, and SNCRs that, when operated, are not operated to achieve the maximum emission reductions that could be accommodated within the existing control technology at a particular unit, primarily because the applicable emission limitation does not require operation of those pollution controls to achieve the maximum emission reductions. As mentioned *supra* section III.E, states should consider sources that already have in place the most stringent controls available for additional control in the development of the long-term strategy during the second implementation period.

EPA should revise the Final Guidance to recommend that sources with existing pollution control technology evaluate options that could improve the emissions reduced through more effective use of that control technology. This could include requiring year-round operation of controls, imposing more effective percent reduction requirements, requiring sources to meet more stringent emission limits, and requiring that emission limits apply on shorter averaging times to ensure continuous levels of emission reduction.

VIII. Regional scale modeling of the long-term strategy to set the RPGs for 2028

A. States should use regional scale modeling to support their regional haze SIPs.

In Section II.B.6 of the Final Guidance, EPA advises states that they are not required to use regional scale modeling to support their regional haze SIPs. Specifically, under Step 6, EPA states that a state must:

> Determine the visibility conditions in 2028 that will result from implementation of the LTS and other enforceable measures to set the RPGs for 2028. Typically, a state will do

> this through regional scale modeling, *although the Regional Haze Rule does not explicitly require regional scale modeling*.[95]

Were a state to forego estimating source or source categories emitting visibility-impairing pollutants, as the guidance provides, it would not be able to satisfy a number of basic requirements of the Regional Haze Rule. Estimating the visibility impacts from a collection of sources is a prerequisite of establishing a state's RPG. As EPA explains in its 2017 Regional Haze Rule revision, this is a key first step in a state setting its RPG: "the 2007 guidance clearly describes the goal-setting process as starting with the evaluation of control measures. First, we recommended that states '[i]dentify the key pollutants and sources and/or source categories that are contributing to visibility impairment at each Class I area.'"[96] If a state did not estimate the visibility impacts from source or source categories, it could not satisfy the requirement in Section 51.308(f)(3)(ii)(A) that it demonstrate, "there are no additional emission reduction measures for anthropogenic sources or groups of sources in the State that may reasonably be anticipated to contribute to visibility impairment in the Class I area." Indeed, this misplaced advice is not even internally consistent with other sections of the Final Guidance, which cover many techniques for estimating the visibility impacts of sources or source categories. Estimating the collective visibility impacts of sources or source categories to determine the RPG is a fundamental requirement of the regional haze program.

In fact, there is no known substitute for the use of photochemical air quality models to project the visibility impact from thousands of individual sources, influenced by complex meteorological fields and atmospheric chemical interactions at a Class I area, ten years into the future, as EPA makes clear in Appendix W to Part 51.[97] The use of air quality models has been a cornerstone of the technical demonstration of the regional haze program (and many other air programs) since its inception. Almost every EPA Regional Haze Rule revision and guidance either discusses the use of air quality models or assumes their use. In fact, EPA recently updated its modeling guidance for regional haze.[98] The very first sentence of the section specifically devoted to regional haze is: "[t]his section focuses on the modeling analysis needed to set RPGs that reflect the enforceable emission limitations, compliance schedules, and other measures included in the long-term strategy of a regional haze SIP."[99] Part 51 makes it clear that air quality

[95] Final Guidance, Table 1, at 6 (emphasis added).
[96] *See* 82 Fed. Reg. at 3092-93. Notably, EPA does not abandon its 2007 Guidance and in fact refers to in several places in its rule revision.
[97] *See* 40 C.F.R. Pt. 51; App. W, Section 2.0 (a), "Guideline on Air Quality Models," ("Increasing reliance has been placed on concentration estimates from air quality models as the primary basis for regulatory decisions concerning source permits and emission control requirements. In many situations, such as review of a proposed new source, no practical alternative exists."); *see also id.* at Section 1.0 (b), ("The impacts of new sources that do not yet exist, and modifications to existing sources that have yet to be implemented, can only be determined through modeling.") This is precisely the challenge of setting RPGs – accounting for modifications to potentially dozens of existing sources (e.g., installation of controls).
[98] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.s and Regional Haze, EPA 454/R-18-009, (Nov. 2018).
[99] *Id.* at 143.

modeling is a necessary tool in the setting of RPGs and EPA should not imply otherwise in its guidance.

Instead of guiding states on modeling, EPA repeatedly informs states that they can use "surrogates" to estimate visibility impacts of a body of sources. Specifically, EPA states that "the Regional Haze Rule does not require states to develop estimates of individual source or source category visibility impacts, or to use an air quality model to do so. Reasonable surrogate metrics of visibility impact may be used instead."[100] EPA lists a number of surrogates that can be used for this purpose, including Q/d, wind trajectories, and daily light extinctions budgets and states that states can use "other reasonable techniques."[101] However, although more strongly worded in its Draft Guidance,[102] EPA does state in its Final Guidance, "[s]urrogate metric here refers to a quantitative metric that is correlated to some degree with visibility impacts as they would be estimated via air quality modeling."[103] Consequently, although EPA tells states that modeling is unnecessary and that surrogate measures can be used, modeling is required in order to check the validity of visibility surrogates. EPA should reconsider this provision, and clarify that modeling is needed to assess the collective visibility impacts of sources or source categories to establish RPGs.

IX. Progress, degradation, and URP glidepath checks

A. If a state's RPG is above the URP, the state's "robust demonstration" must include a consideration of specific items identified by EPA.

In section II.B.7.c of the Final Guidance, EPA discusses what could constitute a "robust demonstration," required under section 51.308(f)(3)(ii)(A) when a state's RPG is above the URP.[104] EPA states that a simple "narrative explanation of how the state has already conducted the source selection and control measures analyses in such a manner that addresses the requirements of 51.308(f)(3)(ii)" may suffice.[105] EPA then goes on to note that such a state *may* consider a long list of additional items, including reconsideration of its visibility threshold, acceptable cost threshold, additional technically feasible controls, how its determination criteria compares to that of other states, etc.[106]

In contrast, EPA's Draft Guidance did not state that a simple narrative would suffice. The Draft Guidance stated that such a demonstration *should* include consideration of a similar listing

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[100] Final Guidance at 12.
[101] *Id.* at 13.
[102] Draft Guidance at 76 ("Before relying on Q/d as a surrogate for screening purposes, a state should investigate how well Q/d relates to visibility impacts for the 20 percent most impaired and 20 percent clearest days, in terms of both the central tendency of the relationship (e.g., the regression line) and the variability of the relationship (e.g., the error of the regression). This understanding should be developed through relevant modeling of some actual cases or model plant scenarios, or another appropriate approach.")
[103] Final Guidance at 10 n.25.
[104] *Id.* at 50.
[105] *Id.*
[106] *Id.* at 50-51.

of items. EPA's pivot from *should* consider to *may* consider substantially misinterprets and is directly at odds with what the robust demonstration required under section 51.308(f)(3)(ii)(A) should contain.

Moreover, states should not rely on EPA's Updated 2028 Modeling[107] to determine which Class I areas are projected to be at or below the URP. Projected conditions for 2028 are tied to the 2064 natural conditions endpoint adjustments to account for international anthropogenic contributions, as well as wildfires. By EPA's own admission as discussed *supra* section V.A, these adjustments lack scientific validation and should not be relied on to determine whether a Class I area is on track to meet its URP in 2028.[108] The result of the updated modeling adjustments reduced the number of Interagency Monitoring of Protected Visual Environments ("IMPROVE") sites projected to be above the glidepath from forty-seven to eight. IMPROVE monitors are not the same as Class I areas, however many Class I areas share monitors; only ninety-nine monitoring sites (representing 142 Class I areas) were evaluated.[109] EPA must reconsider and revise the Final Guidance to specify what a "robust demonstration" under section 51.308(f)(3)(ii)(A) requires and that a state's demonstration should include consideration of the specific list of items identified by the agency.

X. Additional requirements for regional haze SIPs

A. States must submit to EPA the emission inventory used in a regional haze SIP.

In section II.B.8.c of the Final Guidance, regarding section 51.308(f)(6)(v) which covers the requirements for the state's emissions inventory, EPA states that "[t]he emission inventories themselves are not required SIP elements and so are not required to be submitted according [sic] the procedures for SIP revisions. The emission inventories themselves are not subject to EPA review."[110] This conflicts with the Regional Haze Rule, is internally inconsistent with the rule and other state requirements, and is impracticable. First, EPA's statement conflicts with several sections of the Regional Haze Rule. For instance, section 51.308(f)(2)(iii) requires that the state must document the following:

> [T]he 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 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

[107] *See* Updated 2028 Modeling.
[108] *Id.* at 67.
[109] *Id.* at 3 n.6.
[110] Final Guidance at 55.

> the Administrator in compliance with the triennial reporting requirements of subpart A of this part.

Here, it is clear that a state is required to document the technical basis of all aspects of its regional haze demonstration. A state's emission inventory is a foundational aspect of its technical demonstration. In fact, EPA specifically calls out "emissions information," and clarifies that the emissions information must include "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."[111]

Plainly, a state is required to submit the emission inventory it is using as part of its technical demonstration to EPA, and that inventory must include certain specified elements. Because states are already required to submit specified emission inventories to EPA as part of other requirements ("Part A"), EPA clarifies that a state may refer to that submission instead of physically including it in its SIP. However, the mere fact that EPA specifies a state may use an already prepared work product does not shield it from a review of its suitability for the task at hand. [112] For instance, EPA has frequently stated that states may use the technical work of RPOs in their SIPs. That position has never been interpreted to mean information is shielded from EPA review.[113] Indeed, EPA has a duty to review that inventory in the context of the state's regional haze SIP submission.[114] Thus, a state's emission inventory is an inseverable part of its regional haze SIP and subject to EPA's review.

Despite this, EPA appears to imply in its guidance that it cannot bring to the state's attention potential faults in the emission inventory a state used to support its regional haze SIP, nor even examine that inventory in the context of its review of the state's regional haze SIP. EPA should revise the Final Guidance to advise states that a state's emission inventory is a part of the state's SIP and subject to EPA's review.

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[111] *Id.*

[112] *See* EPA's "Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations," EPA-454/B-17-002, at 11 (May 2017), ("[Inventory information provided to EPA] will allow the EPA to make a determination whether the emissions information used in Regional Haze analysis is sufficient for the purposes of the SIP.")

[113] For instance, in the Texas FIP, EPA observed that under the current regulation each state "must document the technical basis, including modeling, monitoring and emissions information, on which the State is relying to determine its apportionment of emission reduction obligations necessary for achieving *reasonable progress* in each mandatory Class I Federal area it affects." 79 Fed. Reg. 74,818, 74,829 (Dec. 16, 2014) (emphasis in original). While the current regulations provide that, "[s]tates may meet this requirement by relying on technical analyses developed by the regional planning organization and approved by all State participants," 40 C.F.R. § 51.308(d)(3)(iii), the Texas haze rule clarified that in situations "where a regional planning organization's analyses are limited, incomplete *or do not adequately assess the four factors*, however, then states must fill in any remaining gaps to meet this requirement." *Id.* (emphasis added).

[114] In the 2017 Regional Haze Rule revision, EPA makes it a point to review a number of circuit court opinions that affirm EPA's review authority, including the Eight Circuit's conclusion that EPA "must 'review the substantive content of the . . . determination." 82 Fed. Reg. at 3090 (quoting *Ariz. el rel. Darwin v. EPA*, 815 F.3d 519, 531 (9th Cir. 2016).

B. States must ensure that FLM opinions and concerns are made transparent to the public, considered by the state and addressed in the SIP.

In Section II.B.8.a of the Final Guidance, EPA provides guidance to the states regarding the FLM consultation requirements in the Regional Haze Rule, 40 C.F.R. § 51.308. Although EPA reiterates that states are required to consult with FLMs, EPA should reconsider and revise the Final Guidance to ensure that states give credence to the opinions and concerns expressed by FLMs. FLMs have affirmative duties under section 169A(a) and (d) of the Clean Air Act as well as mandates to protect and manage public lands under the Wilderness Act[115] and the Organics Act[116]. Therefore, EPA should revise the Final Guidance to direct states that to work collaboratively with FLM to develop regional haze SIPs that satisfy federal agency duties and public resource protections.

XI. Overarching recommendations

A. EPA should emphasize that the end result must be reasonable progress.

EPA should make clear in a revised Final Guidance that the end result of any state's implementation plan must be real, reasonable progress. Consequently, each new plan must require that states actually reduce their emissions that contribute to visibility impairment. The statute requires each haze plan to contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress . . . ."[117] Therefore, any interpretation of the Regional Haze Rule via guidance should direct a state's long-term strategy to be more than just a hand waving exercise—each plan must require adequate emission limits and other enforceable measures to make reasonable progress.[118] EPA should revise the Final Guidance to explicitly provide that actually requiring emission reductions which constitute reasonable progress must be the outcome of the four-factor analysis to meet the applicable requirements; deliberation, no matter how well documented, is not enough. Emission reductions recognized through the four-factor analysis must result in emission reduction measures enforceable through a state or federal regional haze plan.

B. Decisions on which controls to require as part of the long-term strategy cannot merely ratify past determinations.

EPA must also revise the Final Guidance to clarify that decisions on which controls to require as part of long-term strategy cannot rest solely on controls required by past SIPs and state rules. Although EPA stated in the Draft Guidance that decisions on whether controls for a source or source category are cost-effective or provide sufficient visibility improvement cannot rely solely on past decisions evaluating controls for similar sources[119], that language is completely absent from the Final Guidance. EPA must revise the Final Guidance to state this point. For

[115] 16 U.S.C. §§ 1131-1136.
[116] 54 U.S.C. § 100101.
[117] 42 U.S.C. § 7491(b)(2).
[118] *See id.*
[119] Draft Guidance at 97, 103.

example, costs or technologies which were previously considered unreasonable or infeasible at a later date may become more common and may nevertheless be necessary in the second or future planning periods to make reasonable progress. Likewise, making reasonable progress in the current and future planning periods will require the implementation of controls that individually account for smaller visibility impacts than those contemplated in the first planning period and in other past emission reducing rules and permits. Therefore, EPA must revise the Final Guidance to direct states to conduct new source-specific, four-factor emission reduction analyses.

C. EPA must ensure that long-term strategies include appropriate measures to prevent future as well as remedy existing impairment of visibility.

The Clean Air Act not only requires that existing visibility impairment be remedied, but that future impairment be prevented. 42 U.S.C. § 7491(a)(1). As such, it is imperative that each state's long-term strategy be required to include measures to prevent regional haze visibility impairment and that such plans take into account the effect of new sources, as well as existing sources of visibility impairment. EPA must revise its Guidance to comport with this requirement.

EPA has historically relied on the prevention of significant deterioration ("PSD") permitting program and the visibility new source review ("NSR") requirements mandated by 40 C.F.R. § 51.307[120] to address this requirement of the national visibility goal.[121] These provisions essentially mandate that new and modified major sources that are subject to major source permitting requirements do not adversely impact visibility in any Class I area. However, much has changed in the PSD and NSR permitting programs since 1980. The current PSD rules, as well as the major source nonattainment NSR rules, now exempt many modifications at existing major sources that were previously subject to PSD review. As a result, the PSD and visibility NSR rules do not provide as comprehensive Class I areas protections as they previously did, due to impacts from modified sources. Further, there have been significant increases in emissions near some Class I areas due to oil and gas emissions and other activities that are not adequately addressed by the PSD permitting program.

EPA must revise its Final Guidance to ensure that states prevent future impairment by analyzing new and modified emission sources and by requiring mitigation of the cumulative visibility-impairing emissions. As we discuss below, it is especially important for EPA to articulate that states consider minor, area, and other new growth, or modification of stationary sources that are not subject to the Class I area protections of the PSD permitting and visibility NSR requirements.

[120] 40 C.F.R. §51.307(b)(2) and (c) provides that the PSD requirements of 40 C.F.R. §51.166(o), (p)(1) through (2), and (q) apply to new and modified major proposing to locate in nonattainment areas that may have an impact on visibility in a mandatory Class I area.
[121] *See* 45 Fed. Reg. 80,089 (Dec. 2, 1980).

1. The 2002 PSD and nonattainment NSR Rule revisions exempt many modifications from PSD permitting that could result in large, visibility-impairing emission increases from existing major sources.

EPA has historically relied on the PSD and nonattainment/visibility NSR permitting programs to meet the requirement of preventing future impairment of visibility. The PSD permitting requirements specifically provide for ensuring that a new or modified major source will not adversely impact visibility in a Class I area[122], and the EPA's visibility NSR rules in 40 C.F.R. §51.307(c) require new and modified major sources proposing to locate in nonattainment areas that may impact visibility in a Class I area to meet these same requirements of the PSD program.[123] However, the December 2002 revisions to the PSD and nonattainment NSR permitting requirements significantly reduced the scope of modifications that would trigger PSD or nonattainment NSR as major modifications by drastically changing the methodology for determining whether a significant emission increase would occur as a result of a modification.[124]

Despite these significant regulatory changes which reduced the scope of modified sources subject to PSD and nonattainment NSR permitting, EPA has never re-evaluated its reliance on the major source permitting programs as sufficient to prevent future impairment of visibility. However, these rules, as revised in recent years, will likely allow significant increases[125] in actual emissions from existing sources to occur without any evaluation of the impacts on visibility and without even applying BACT or LAER, due to being exempt from PSD or nonattainment NSR permitting.

In summary, the PSD and nonattainment NSR rules as revised in 1992 and 2002 now exempt many modifications that would have previously been subject to major source permitting, including the visibility requirements of the PSD program and visibility NSR rules. Thus, while the rules still include vital provisions for the prevention of future visibility impairment, the PSD and visibility NSR rules are no longer adequate by themselves to ensure the prevention of future visibility impairment. In light of this, EPA should revise the Final Guidance to clarify that states may not solely rely on the PSD and visibility NSR programs to prevent future impairment of visibility. EPA must ensure that states specify requirements in their SIPs to prevent future visibility impairment from the new source growth in any state that may increase visibility-impairing pollution and thus affect Class I area visibility.

2. Minor, area, mobile, and other source emissions must be evaluated to prevent future, as well as remedy existing, impairment of visibility.

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[122] 40 C.F.R. §52.21(o), (p)(1) and (2), and (q).
[123] 40 C.F.R. §51.307(b)(2) and (c).
[124] 67 Fed. Reg. 80,185, 80,186-89 (Dec 31, 2002) (also known as "NSR Reform" Rule).
[125] *See* Joseph Goffman, et al., EPA's Attack on New Source Review and Other Air Quality Protection Tools (Nov. 1, 2019), http://eelp.law.harvard.edu/wp-content/uploads/NSR-paper-EELP.pdf.

Although the Final Guidance mentions minor, area, mobile, and other emission sources, most of the discussion addresses major stationary sources. EPA should be more explicit in its expectation that states evaluate sources and source categories that are not major stationary sources as well, including the potential for growth in emissions from these sources. For example, given the increases in emissions from oil and gas development over the last 10 years,[126] it is clear that the existing SIPs and FIPs do not currently include adequate mechanisms for preventing visibility impairment from these sources as production ebbs and flows with economic conditions and other factors, such as deregulation and technology. EPA must revise the Final Guidance to clarify that states need to address these sources in the aggregate, rather than source-by-source.

There are several examples of rules and programs that may be necessary in a long-term strategy to prevent future impairment of visibility in Class I areas. EPA should revise the Final Guidance to direct states to consider these examples and include them where appropriate in SIPs.

a. Methods to address visibility-impairing emissions from oil and gas development

EPA should revise the Final Guidance to explicitly note that it expects states to review area sources like oil and gas, and should provide additional guidance on how to do so. Undoubtedly, this should begin with requiring states to collect better data on the emissions from oil and gas.

In many states, emissions from oil and gas development are a significant threat to visibility and air quality in Class I areas. Such development often occurs on federal lands that are near to or abut Class I areas For example, oil and gas development contributes to visibility impairment in public lands in Utah and Colorado where the NPS found that oil and gas development and leasing in the two states would "cause visibility impairment" at Dinosaur National Monument.[127] Additionally, NPS recently found impacts from oil and gas emissions at Carlsbad Caverns and San Pedro Parks Wilderness Class I areas, among others, based on 2008 emissions inventories—which do not capture more recent growth—and include only a portion of emissions from the production process.[128] Examples of Class I areas currently or potentially

[126] "The U.S. Energy Information Administration ("EIA") reports that oil production growth in the United States has risen by about 3 million barrels per day (from 5.8 to 8.72 MMb/d) from January 2001 to July 2014 (EIA, 2014a). Natural gas production has increased from 53.74 to 70.46 billion cubic feet per day within this time period (EIA, 2014a). The trend is expected to continue with the number of oil and gas wells in the lower 48 states projected to increase by 84 percent between 2013 and 2040 (EIA, 2014b)." Thompson et al., Modeling to Evaluate Contribution of Oil and Gas Emissions to Air Pollution, 67 Journal of the Air & Waste Management Association Vol. 4, 445 (Sept. 2016), https://doi.org/10.1080/10962247.2016.1251508.

[127] Memorandum from Regional Director, Intermountain Region, National Park Service, to Planning and Environmental Coordinator, BLM 9 (2013); *see also* Memorandum from Superintendent, Dinosaur National Monument, National Park Service, to Field Office Manager, BLM Vernal Field Office 2 (Aug. 2017); Krish Vijayaraghavan et al., Ramboll Environ US Corporation, 2017); BLM, Colorado Air Resources Management Modeling Study (CARMMS): 2025 CAMx Modeling Results for the High, Low and Medium Oil and Gas Development Scenarios, 104-05 (Aug. 2017), https://www.blm.gov/documents/colorado/public-room/data.

[128] Thompson et al., *supra* note 126, at 456; *see also* Table C6, *available at* https://www.tandfonline.com/doi/suppl/10.1080/10962247.2016.1251508?scroll=top.

impacted by oil and gas emissions include: Theodore Roosevelt and Lostwoods (Bakken Shale in eastern Montana and North Dakota); Wind Cave and Badlands (Powder River Basin in northeast Wyoming); Bridger and Fitzpatrick Wilderness Areas (Pinedale Anticline and Jonah Fields in western Wyoming); Mesa Verde (North and South San Juan Basin); Carlsbad Caverns and Guadalupe Mountains (Permian Basin in southeastern New Mexico and western Texas); and Canyonlands and Arches (Uintah, Paradox, and Piceance Basins in Utah and Colorado).

Significant information is available to enable states and EPA to develop strategies to reduce visibility-impairing emissions from this significant source category. However, these prior analyses do not substitute for meaningful consideration of oil and gas emissions reductions sufficient to meet the Regional Haze Rule's "reasonable progress" mandate. NPCA's recent report, "Oil and Gas Sector Reasonable Progress Four-Factor Analysis for Five Source Categories" assesses emissions controls for the five primary sources of visibility-impairing (and health harming) pollution in the sector: gas-fired reciprocating internal combustion engines ("RICE"); diesel-fired RICE; gas-fired combustion turbines; gas-fired heater, boilers, and reboilers; and flaring and thermal incineration of excess gas and waste gas.[129] The controls and practices included in this document represent various requirements for sources across the country and should be considered by states with emissions from the oil and gas sector.

Resource Management Plans ("RMPs") or land use plans issued by federal agencies explain how the agency will manage areas of public land over a period of time, usually ten to fifteen years. RMPs and amendments to those plans are required to go through a public review process under the National Environmental Policy Act ("NEPA"), which must include an analysis of projected impacts to all resources, including air quality. Such plans would include projections of oil and gas development, among other land use projections, on federal lands. Unfortunately, numerous RMPs have not been revised for decades, and only a few consider the effect of emissions from the planning area. EPA should revise the Final Guidance to require that states consider RMPs and other land use plans in determining the appropriate measures to prevent future impairment of visibility to include in regional haze SIPs. However, if RMPs are outdated or fail to consider the effects of visibility-impairing pollution from development, EPA must also indicate that those RMPs not be relied upon.

Recent NEPA analyses conducted for projected oil and gas development in RMPs can be useful tools for obtaining data regarding anticipated growth in such emissions. However, neither NEPA assessments nor RMPs are tools for preventing future impairment from oil and gas development. First, if adverse impacts are projected, the federal agency may make recommendations on mitigation methods to avoid adverse impacts, but neither the federal agency nor the local or state air permitting agency are under any obligation to implement such mitigation measures. Second, the federal agency is often making projections of expected amounts of development and in the types and emission rates of emissions units utilized. Those projections do

[129] Vicki Stamper & Megan Williams, Nat'l Parks Conservation Ass'n, Oil and Gas Sector Reasonable Progress Four-Factor Analysis 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) ("NPCA Report").

not always reflect the level of development that actually occurs, or the specific emission units and emission rates that are utilized. The Colorado Air Resources Management Modeling Study is one example of the type of information which can be developed in conjunction with the RMP process.[130]

In developing long-term strategies, EPA should direct states to use available information such as county-level reported emissions data and RMP and site-specific NEPA analyses, and request additional information to round out and make inventories accurate. To aid in this data gathering, EPA should direct industry to produce emissions inventories and submit them to states alongside an evaluation of emissions-reduction strategies and control technologies for this significant source of visibility impairment. Further, EPA should revise the Final Guidance to explicitly advise states on creating and making publicly available oil and gas emissions data.

States with significant oil and/or gas development should be required to consider the adoption of emission control regulations for the oil and gas development industry to reduce visibility-impairing emissions from such development.[131] Many states already require measures to reduce emissions from the sector. For example, California has enacted extensive air pollution requirements for oil and gas production, processing, and storage.[132] Colorado has also adopted emission requirements for the oil and gas industry.[133] Pennsylvania has also revised the state's oil and gas drilling regulations.[134] While these regulations may not be sufficient as to visibility impairment from the sector's emissions, the regulations provide relevant examples of states' decisions to address threats to air quality that are not covered by federal major source permitting requirements. EPA should identify the source types and associated emission-reducing measures available in the sector and use them to develop guidance to specify EPA's expectations of states in assessing these sources and requiring emission reduction measures from them. EPA must reconsider and revise the Final Guidance to require states to apply these and other control measures in their regional haze SIPs.

b. Minor New Source Review permitting programs

A state's minor NSR permitting program can be a useful tool to impose emission limitations and otherwise ensure that new source growth occurs in a manner consistent with making reasonable progress towards the national visibility goal. EPA should revise the Final Guidance to direct states to model new or modified minor NSR sources for their impacts on visibility in Class I areas. States could thus determine if the source's emissions would be consistent with making reasonable progress towards the national visibility goal, similar to the requirement in 40 C.F.R. §51.307(c) of the visibility NSR rules. Such a provision would also be

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[130] *See* BLM, Colorado Air Resources Management Modeling Study (Aug. 2017), https://www.blm.gov/documents/colorado/public-room/data.
[131] NPCA Report at 7-10.
[132] California Air Resources Board, Oil & Natural Gas Production (last reviewed July 18, 2017), https://ww3.arb.ca.gov/regact/2016/oilandgas2016/oilandgas2016.htm.
[133] Colo. Regulation No. 7, Section XII, https://www.colorado.gov/pacific/cdphe/air/oil-and-gas-compliance.
[134] *See* Environmental Protection Performance Standards at Oil and Gas Well Sites, 46 Pa. B. 6431 (Oct. 8, 2016), http://www.pacodeandbulletin.gov/Display/pabull?file=/secure/pabulletin/data/vol46/46-41/1757.html.

consistent with section 7410(a)(2)(D)(i)(II) of the Clean Air Act, which requires SIPs to include adequate provisions prohibiting any source type from emitting any air pollutant which will interfere with measures to protect visibility. States could include criteria to ensure that the sources most likely to interfere with making reasonable progress are addressed, based on total emissions of visibility-impairing pollutants, distance to Class I areas, and/or other criteria focused on modifications at existing major sources that avoid PSD or nonattainment NSR review. EPA should instruct states to add such provisions to their minor NSR programs as necessary to ensure that their long-term strategies adequately prevent future impairment to visibility. Such provisions should also be incorporated and made enforceable through regional haze SIPs relying on such emission reductions to make reasonable progress.

States that decide to rely on minor NSR programs to prevent future impairment should be required to examine the relevant definitions and exemptions that exist in their programs to ensure that the types of sources that need to be addressed to prevent future impairment are indeed subject to the states' minor NSR programs. A state's minor NSR program also may need to be revised to include emissions from emitting units not typically covered under PSD permitting requirements, such as fugitive emissions.

Applicability at minor NSR sources should be based on projected changes in allowable or actual emissions from a baseline reflective of recent emissions. If a state is intending to rely on its minor NSR program to prevent future impairment of visibility, then the minor NSR program must be written in a manner to truly accomplish that intention. As other Clean Air Act programs fail to adequately integrate limits for new or modified sources, regional haze SIPs should be used directly for this purpose.

c. Provisions for other potential threats to visibility impairment

There are a number of source types other than those covered by a minor NSR permit program or oil and gas development that could potentially impair visibility. In recognition of this, EPA should revise its Final Guidance to recommend that states specifically include the analyses of these potential sources in their long-term strategies, and if necessary, adopt provisions to address them. For instance, if construction activities threaten future impairment, states should adopt control measures to mitigate air pollution at construction sites. As an example, the Sacramento Metropolitan Air Quality Management District applies air emissions requirements to construction sites.[135] California also has stricter mobile source emissions requirements (including for non-road engines) that apply under federal rules, and states with significant mobile source growth threatening future impairment could consider adopting such standards as their own.[136] EPA should encourage states to consider various measures to address

[135] *See* Sacramento Metro. Air Quality Management Dist., CEQA Guide, Ch. 3: Construction-Generated Criteria Air Pollutant and Precursor Emissions (April 2019), http://www.airquality.org/LandUseTransportation/Documents/Ch3ConstructionFinal4-2019.pdf.

[136] Congress preempted states from setting emission standards for mobile sources, except that California could set its own standards with EPA's permission and other states could opt into the stricter California standards (generally for ozone SIP purposes). 42 U.S.C. § 7543(e)(2)(B)(i)-(ii).

potential future Class I visibility impairment, based on the recent or planned growth in new source emissions expected for the state, that could threaten future impairment of visibility in any Class I area.

Additionally, to the extent that states have limited information on such sources, EPA should require that states collect and submit actual emissions increase data on minor modifications at existing sources in order to gather more information on the extent of minor source growth and on new minor, area, and other source growth.

Visibility-impairing emissions need to be inventoried and modeled from many sectors in order to properly inform the next round of haze plans. Several states have started collecting and submitting oil and gas emissions data to be inventoried and modeled for purposes of regional haze. For instance, the Western Regional Air Partnership has started collecting from its oil and gas producing states emissions for their modeling inventory.[137] However, there are several states not in the western region of the country, such as Pennsylvania and Virginia, which are significant producers of oil and gas, and should also be collecting and submitting oil and gas emissions data.[138] Furthermore, as noted *supra* section III.H, there is no inventory of emissions from the agricultural sector; states should develop such inventories and submit them with their regional haze SIPs.

Emissions data from wood burning devices should be modeled. As EPA has explained, the smoke from these devices "contains harmful particle pollution, also known as fine particulate matter or PM2.5, along with other pollutants including carbon monoxide, volatile organic compounds (VOCs), black carbon, and air toxics such as benzene."[139] EPA has also confirmed that residential wood combustion "accounts for 44 percent of total stationary and mobile polycyclic organic matter (POM) emissions, nearly 25 percent of all area source air toxic cancer risks and 15 percent of noncancer respiratory effects."[140] Furthermore, wood burning devices are a significant source of heating for many communities near Class I areas that struggle with regional haze pollution problems. Wood burning devices materially contribute to the significant proportion of particulate matter (fine and course) and VOC emissions that come from residential wood combustion in Arizona, Massachusetts, Minnesota, Nevada, Washington and other states, adding to regional haze visibility problems in Class I areas around the country.

While the collection and evaluation of much of this data should inform the next round of haze plans, we note that for the oil and gas sector, this data is sufficiently available such that regulation of the sector is appropriate and much needed in this second round of regional haze

[137] *See* Western Regional Air Partnership ("WRAP"), EGU Emissions Analysis Project, https://www.wrapair2.org/EGU.aspx.
[138] *See* U.S. Energy Info. Admin., Pennsylvania State Profile and Energy Estimates (last updated Aug. 15, 2019), https://www.eia.gov/state/?sid=PA; U.S. Energy Info. Admin., Virginia State Profile and Energy Estimates (last updated Sept. 15, 2019), https://www.eia.gov/state/?sid=VA.
[139] EPA, Fact Sheet: Overview of Final Updates to Air Emissions Requirements for New Residential Wood Heaters, at 1 (Feb 4, 2015), https://www.epa.gov/sites/production/files/2015-02/documents/20150204fs-overview.pdf.
[140] EPA, Strategies for Reducing Residential Wood Smoke, Publ'n No. EPA-456/B-13-001 at 4 (Mar. 2013), https://www.epa.gov/sites/production/files/documents/strategies.pdf.

planning. EPA should specify that in order for a state to satisfy the requirements of proposed 40 C.F.R. § 51.308(f), states must consider the cumulative impacts from minor and other source growth that may affect future visibility impairment. With this information, states can determine the number and types of new source growth and magnitude of emissions that may threaten future visibility impairment, which can then assist states in developing targeted measures to prevent future visibility impairment and address regional haze from these source types. Such measures should be required to be part of the long-term strategy of the regional haze SIP.

In summary, EPA must revise the Final Guidance to require long-term strategies to include measures to ensure the prevention of future visibility impairment, as well as the remedying of existing visibility impairment in Class I areas, in accordance with the national visibility goal of the Clean Air Act. While the PSD and visibility NSR programs have some effective provisions for ensuring that new and modified sources subject to those permitting requirements do not threaten future visibility impairment, those programs are not sufficient to fully address the statutory requirement of preventing future impairment to visibility. EPA should require states to evaluate the threats to future impairment to visibility in any Class I area and to adopt provisions within regional haze SIPs to minimize emissions from such sources, and otherwise ensure that new source growth occurs in a manner consistent with making reasonable progress towards the national visibility goal.

XII. Conclusion

The Conservation Organizations respectfully ask that EPA reconsider and revise the Final Guidance as mentioned above.

Sincerely,

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Exhibit 4

OIL AND GAS SECTOR

REASONABLE PROGRESS

FOUR-FACTOR ANALYSIS OF CONTROLS

PART I:

NATURAL GAS-FIRED INTERNAL COMBUSTION ENGINES AND NATURAL GAS-FIRED COMBUSTION TURBINES

Prepared for National Parks Conservation Association

Prepared by Vicki Stamper & Megan Williams

February 10, 2020

Table of Contents

LIST OF TERMS

2SLB	Two-stroke lean-burn
4SLB	Four-stroke lean-burn
4SRB	Four-stroke rich-burn
A/F	Air-to-fuel ratio
ACT	Alternative control techniques
AFRC	Air/fuel ratio controller
APCD	Air pollution control district
AQMD	Air Quality Management District
BACT	Best Available Control Technology
BARCT	Best Available Retrofit Control Technology
BART	Best Available Retrofit Technology
BAT	Best Available Technology
BSFC	Brake-specific fuel consumption
CARB	California Air Resources Board
CEPCI	Chemical Engineering Plant Cost Index
CAA	Clean Air Act
CI	Compression ignition
CO	Carbon monoxide
CO_2	Carbon dioxide
CSAPR	Cross-State Air Pollution Rule
DOE	U.S. Department of Energy
DLNC	Dry low NOx combustors
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
g/bhp-hr	Grams per brake horsepower-hour
g/hp-hr	Grams per horsepower-hour
HAP	Hazardous air pollutant
HC	hydrocarbon
hp	horsepower
kW	Kilowatt
INGAA	Interstate Natural Gas Association of America
IR	Ignition timing retard
LB	Lean-burn
LEC	Low emission combustion
MCF	Thousand cubic feet
MW	Megawatt
MMBtu	Million British Thermal Unit (heat input)

LIST OF TERMS

NAAQS	National Ambient Air Quality Standards
NESCAUM	Northeast States for Coordinated Air Use Management
NESHAP	National Emission Standards for Hazardous Air Pollutants
NSPS	New Source Performance Standards
NOx	Nitrogen oxides
NSCR	Nonselective catalytic reduction
NSPS	New Source Performance Standards
OTC	Ozone Transport Commission
PEMS	Parametric emissions monitoring system
$PM_{2.5}$	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)
SCAQMD	South Coast Air Quality Management District
SCR	Selective catalytic reduction
SI	Spark ignition
SJVAPCD	San Joaquin Valley Air Pollution Control District
SO_2	Sulfur dioxide
TCEQ	Texas Commission on Environmental Quality
TSD	Technical support document
VOC	Volatile organic compound

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.
>
> . . .

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] 40 C.F.R. § 51.308(f).

[2] *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)).[3]

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 (SO_2), directly emitted particulate matter, volatile organic compounds (VOCs), and ammonia. NOx, SO_2, VOCs, and ammonia, initially emitted as gases, often convert into fine (i.e., less than 2.5 micrometers in diameter) particulate matter ($PM_{2.5}$) 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.[4] 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.[5] 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[6] and marketed gas production in the United States to be 13% higher in 2021 than it was in 2018.[7] In many areas of the country, these increases in production are projected to continue well into the future. For

[3] 42 U.S.C. § 7491(b)(2).
[4] EIA, Crude Oil Production, Annual-Thousand Barrels, 2013 to 2018, *available at:* https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm.
[5] EIA, Natural Gas Gross Withdrawals and Production, Marketed Production, Annual Million Cubic Feet, 2013 to 2018, *available at:* https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm.
[6] EIA Short-Term Energy Outlook, U.S. Liquid Fuels, January 14, 2020, *available at:* https://www.eia.gov/outlooks/steo/report/us_oil.php.
[7] EIA, Short-Term Energy Outlook, Natural Gas, January 14, 2020, *available at:* https://www.eia.gov/outlooks/steo/report/natgas.php.

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 sources of visibility-impairing emissions associated with oil and gas development. Various engines, typically fired by natural gas, 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 gas engines, diesel generators, and/or combustion turbines. Those engines and combustion turbines emit significant quantities of NOx and VOCs and of SO_2 for diesel-fired engines. SO_2 and NOx emissions from flaring can be significant. Particulate matter emissions from construction and maintenance, as well as diesel-fired engines, can also be of concern for visibility impairment.

This report presents a four-factor analysis of reasonable progress controls for NOx and VOCs for two significant emissions sources associated with oil and gas development: natural gas-fired reciprocating internal combustion engines (RICE) and natural gas-fired combustion turbines. 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 to the extent it exists; (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 and gas turbines 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 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

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[8] As discussed in Report: New Mexico oil, gas boom to continue, by Susan Montoya Bryan/Associated Press, September 3, 2019, Albuquerque Journal, *available at:* https://www.abqjournal.com/1361629/report-new-mexico-oil-gas-boom-to-continue.html.

[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.

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."[11] EPA amends its NSPS for various reasons (e.g., changes in test methods or protocols, clarifications), but thorough reviews and revisions occur far 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 and natural gas turbines and 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 and Natural Gas Turbines

NSPS Subpart in 40 C.F.R. Part 60	Emission Source(s)	Date of Promulgation of Most Recent Revisions
GG	Stationary Gas Turbines	9/20/79 (first promulgation of NSPS for gas turbines and revised standards promulgated at Subpart KKKK)
IIII	Stationary Compression Ignition Internal Combustion Engines	7/11/06 (NSPS for source category first promulgated, and reflects most recent review of emission standards)
JJJJ	Stationary Spark Ignition Internal Combustion Engines	1/18/08 (NSPS for source category first promulgated, and reflects most recent review of emission standards)
KKKK	Stationary Combustion Turbines constructed, reconstructed or modified after 2/18/05	7/6/2006 (first promulgation of NSPS Subpart KKKK, and reflects most recent review of emission standards)

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 for RICE units and natural gas turbines 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.

[11] *See* Section 111(a)(1) of the Clean Air Act, 42 U.S.C. § 7411(a)(1).

II. CONTROL OF NOx 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:

> 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]

[12] EPA, AP-42, Fifth Edition, Volume 1, Chapter 3: Stationary Internal Combustion Sources.

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:

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 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.[14]

NOx Removal Efficiency:	*10-40%*
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. . . .

[13] EPA-453/R-93-032 *Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines* (July 1993), *available at*: https://www3.epa.gov/airquality/ctg_act/199307_nox_epa453_r-93-032_internal_combustion_engines.pdf [hereinafter referred to as "EPA 1993 Alternative Control Techniques Document for RICE"].
[14] *Id.* at 2-5.

> 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.[15]

NOx Removal Efficiency:	*0-40%*
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).[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).[17]

B. RICH-BURN 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.

[15] *Id.* at 2-5 and 2-9.
[16] *Id.* at 2-9.
[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.

> 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:

> 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

[18] EPA 1993 Alternative Control Techniques Document for RICE at 2-9 to 2-10.
[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"].
[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.

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 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 NO_X, CO, and HC to water (H_2O), carbon dioxide (CO_2), and diatomic nitrogen (N_2). The chemical stoichiometry requires that O_2 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. . . .
>
> 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]

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[22] *See* EPA's 1993 Alternative Control Techniques Document for RICE Table 2-12 at 2-30.
[23] EPA 1993 Alternative Control Techniques Document for RICE at 2-10 to 2-11.
[24] EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-19.

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 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^{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^{C}/R Incorporated performed a linear

[25] OTC Technical *Information Oil and Gas Sector Significant Stationary Sources of NOx Emissions* October 17, 2012, *available at*: https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf at 45.
[26] *Id.*
[27] Memo from E^{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.

regression analysis[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:

NSCR Annual Cost = $4.77 x (hp) + $5,697 (2009$)

The capital cost equation for retrofitting an AFRC and NSCR on a 4SRB engine was determined by E^C/R Incorporated to be, as follows:

NSCR Capital Cost = $24.9 x (hp) + $13,118 (2009$)

These relationships are derived from a data set that includes engines ranging in size from 50–3,000 hp.

The E^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.[29] The assumed 10-year life was not based on the catalyst replacement timeframe, because the E^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.[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.[31] The state of Colorado also recently assumed a 15-year life of NSCR for RICE units.[32] Given that EPA assumed a selective catalytic reduction (SCR) system at an industrial fossil fuel-fired boiler has a life of 20-25 years,[33] 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

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[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."

[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.

[30] Memo from E^C/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010), at 4 and at 11, 13, and 15.

[31] *See* August 11, 2000, E.H. Pechan & Associates, Inc., NOx Emissions Control Costs for Stationary Reciprocating Internal Combustion Engines in the NOx SIP Call States, at 5 and at A-2, *available at*: https://www3.epa.gov/ttn/ecas/regdata/cost/pechan8-11.pdf. *See also* EPA, Regulatory Impact Analysis for the NOx SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).

[32] *See* Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category, circa 2008 [hereinafter referred to as "CDPHE RP for RICE"], at 8, *available at*: https://www.colorado.gov/pacific/sites/default/files/AP_PO_Reciprocating-Internal-Combustion-Engine-RICE-engines_0.pdf.

[33] *See* EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, at pdf page 80, *available at*: https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf.

interest rate.[34] The bank prime rate fluctuates over time, and the highest it has been in the past five years is 5.5%.[35] In its cost calculation spreadsheet for SCR provided with its Control Cost Manual, EPA also used an interest rate of 5.5%.[36] 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.

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[37]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF NSCR AND AFRC, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2009$
RICH-BURN	50	$5,303	$3,251/ton	$813/ton
	200	$5,859	$898/ton	$224/ton
	500	$6,971	$427/ton	$107/ton
	1,000	$8,824	$270/ton	$68/ton
	2,500	$14,382	$176/ton	$44/ton

TABLE NOTES:
- Cost data are assumed to be in 2009$, based on E^C/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.

[34] EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, *available at*: https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

[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.

[37] *See* Memo from E^C/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.

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.

Table 3. Capital and Operating Costs of NSCR with AFCR[42]

SOURCE CATEGORY	**CAPITAL COSTS, 2003$***	**ANNUAL OPERATING AND MAINTENANCE COSTS, 2003$***
RICH-BURN RICE > 500 hp	$35,000	$6,000
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

[38] Colorado Regulation Number 7, *see* Section XVII.E.3.a.
[39] CDPHE RP for RICE.
[40] *Id.* at 4.
[41] *Id.* at 8.
[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.

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 NO_x limit, based on a 15-year life and 5.5% interest rate.

Table 4. Cost Effectiveness to Reduce NOx Emissions from Rich-Burn RICE with NSCR and an AFRC To Meet a 1 g/hp-hr NO_x Limit [51]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF NSCR AND AFRC, 2003$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2003$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2003$
RICH-BURN	500	$9,487	$582/ton	$145/ton

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.[52]

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[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.
[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.

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.[53] 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.[54] 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.

CARB's 2001 guidance discusses RICE units derated[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."[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.[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."[58]

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[53] EPA 1993 Alternative Control Techniques Document for RICE Table 3-1 at 3-14.

[54] IWDW 2014 Oil and Gas Emissions Inventories, *available at:* http://views.cira.colostate.edu/wiki/wiki/9170/2014-oil-and-gas-emissions-inventories.

[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.

[56] *See* CARB 2001 Guidance at IV-1.

[57] *Id.*; *also see* South Coast Air Quality Management District Preliminary Draft Staff Report for Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines (July 2019), D-4, *available at:* http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/rule-1110-2-pdsr_07172019.pdf?sfvrsn=6.

[58] *See* CARB 2011 Guidance at IV-1.

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:[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.
>
> "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."[60] Specifically, the following engine test data demonstrate emission rates under 50 ppmv (corrected to 15% oxygen) for pump engines:

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[59] Santa Barbara County APCD Rule 333 CONTROL OF EMISSIONS FROM RECIPROCATING INTERNAL COMBUSTION ENGINES, 333.C at 333-2, *available at:* https://ww3.arb.ca.gov/drdb/sb/curhtml/r333.pdf.

[60] *See* CARB 2001 Guidance at IV-5.

Table 5. Pump Engine Test Data[61]

CA AIR DISTRICT	ENGINE TYPE	ENGINE SIZE[62]	CONTROL TECHNOLOGY	# OF TESTS	NOx EMISSIONS [ppmv corrected to 15% oxygen]
Santa Barbara	Air-balanced oil pumps	195 hp	NSCR	18	2-14
Santa Barbara	Beam- and crank-balanced oil pumps	131 hp	Leaning of A/F mixture	4	12-35
Santa Barbara	Beam- and crank-balanced oil pumps	39-46 hp	Leaning of A/F mixture	16	8-28
Santa Barbara	Beam- and crank-balanced oil pumps	39-49 hp	Leaning of A/F mixture	18	7-33
Ventura	Beam- and air-balanced oil pumps	Not specified	NSCR	5	50
Ventura	Beam- and air-balanced oil pumps	Not specified	NSCR	3	25
TABLE NOTE: the field gas used in these engines was either naturally low in sulfur or treated to pipeline-quality natural gas					

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."[63] 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:

[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.

[63] *See* CARB 2001 Guidance at IV-6.

Table 6. NOx Emission Limits for All Rich-Burn Non-Agricultural Operations Engines Rated at > 50 bhp[64]

ENGINE TYPE		NOx LIMIT [ppmvd corrected to 15% O2]	EQUIVALENT NOx LIMIT Converted to g/bhp-hr
4SRB	Cyclic Loaded, Field Gas Fueled	50	0.7
	Limited Use	25	0.4
	All other	11	0.2
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)[65]			

SJVAPCD completed a cost effectiveness analysis for the second phase of its internal combustion engine rule (Rule 4702) in 2003.[66] 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.

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.[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.[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.[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.

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[64] SJVAPCD Rule 4702 Internal Combustion Engines, Tables 1 and 2, *available at*: https://www.valleyair.org/rules/currntrules/r4702.pdf.

[65] SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), at B-3, *available at*: https://ww3.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjvapcd_4702_report.pdf.

[66] *Id.*

[67] *Id.* at B-2 and at Table 3.

[68] Santa Barbara County APCD Rule 333 CONTROL OF EMISSIONS FROM RECIPROCATING INTERNAL COMBUSTION ENGINES, 333.C at 333-2.

[69] November 2016, RAMBOLL ENVIRON, San Juan and Permian Basin 2014 Oil and Gas Emission Inventory Inputs Final Report, at 25 and Appendix A at A-1, *available at*: https://www.wrapair2.org/pdf/2016-11y_Final%20GSJB-Permian%20EI%20Inputs%20Report%20(11-09).pdf.

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 below:

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[70]

ENGINE TYPE	SIZE (hp)	ANNUALIZED COSTS OF NSCR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 2,000 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 4,500 HR/YR, 2009$	COST EFFECTIVENESS OF NSCR AND AFRC AT 8,000 HR/YR, 2009$
RICH-BURN	50	$5,303	$3,383/ton	$1,504/ton	$846/ton
	75	$5,396	$2,295/ton	$1,020/ton	$574/ton
	100	$5,489	$1,751/ton	$778/ton	$438/ton
	250	$6,045	$771/ton	$343/ton	$193/ton
	500	$6,971	$445/ton	$198/ton	$111/ton

TABLE NOTES:
- Cost data are assumed to be in 2009$, based on E^C/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.[71] 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.[72]

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, JJJJ, for the year in which the ownership of the engine changes.[73] In the response to

[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

comments on its NSPS Subpart JJJJ rulemaking,[74] EPA provides many examples of the successful application of NSCR on small rich-burn engines and variable-load engines (noted as pumpjack engines or compressor engines) that justify its standards as achievable and demonstrated for very small rich-burn RICE.[75]

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.[76] 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 CO_2 emissions[77]
- 1 to 2% reduction in power output[78]
- Increased solid waste disposal from spent catalysts.[79]

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.[80]

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[74] 73 Fed. Reg. 3,568-3,614 (Jan. 18, 2008).
[75] *See* EPA's Response to Public Comments on Spark-Ignition (SI) New Source Performance Standards (NSPS)/National Emission Standards for Hazardous Air Pollutants (NESHAP), posted to EPA's docket on January 2, 2008, Docket ID EPA-HQ-OAR-2005-0030-0249, at 95-100, *available at*: https://www.regulations.gov/document?D=EPA-HQ-OAR-2005-0030-0249.
[76] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.
[77] *See* EPA 1993 Alternative Control Techniques Document for RICE Table 3-1 at 3-14.
[78] *Id.* Table 2-4 at 2-8.
[79] CDPHE RP for RICE at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, EPA, Office of Air Quality Planning and Standards, RTP).
[80] Institute of Clean Air Companies, Typical Installation Timelines for NOx Emissions Control Technologies on Industrial Sources, December 4, 2006 at 9, *available at:* https://cdn.ymaws.com/www.icac.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.

D. LEAN-BURN 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[81]

According to EPA, "[n]ew spark-ignition engines equipped with LEC technology are, by definition, lean-burn engines."[82] 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."[83] 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.[84]

LEC NOx Removal Efficiency:	*87%*
Controlled NOx Emission Rates:	*1-2 g/hp-hr*
	70 to 140 ppmv

[81] EPA, Final Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500-0508, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance, August 2016, Appendix A at 5-3, *available at:* https://www.regulations.gov/document?D=EPA-HQ-OAR-2015-0500-0508 [hereinafter referred to as "2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls"].
[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.
[87] INGAA, Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry (July 2014), *available at*: https://www.ingaa.org/File.aspx?id=22780.
[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.[89] In its analysis, CARB determined that LEC was a RACT level of control, and CARB set a NOx RACT limit of 125 ppmv.[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.[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.[92] LEC can achieve 80 to 90% NOx reductions or even higher.[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).[94] CARB described these engines as "located in gas fields statewide and [] used to drive compressors at gas wells."[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."[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."[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."[98] CARB's cost data for LEC are presented in the table below.

[89] CARB 2001 Guidance.
[90] *Id.* at IV-6.
[91] *Id.* at IV.9.
[92] *Id.* at II-2, IV-10.
[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.
[94] *Id.* at II-2.
[95] *Id.* at IV-7.
[96] *Id.*
[97] *Id.*
[98] *Id*. at V-2.

Table 8. Capital Costs of LEC, 2001$[99]

POWER OUTPUT (hp)	LEC CAPITAL COSTS
50-150	$14,000
151-300	$24,000
301-500	$42,000
501-1,000	$63,000
1,001-1,500	$148,000

CARB calculated cost effectiveness for LEC assuming 80% NOx control, a 10-year life of the controls, and a 10% interest rate.[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%.[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.[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.

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[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.
[100] CARB 2001 Guidance at V-4.
[101] *See, e.g.*, https://fred.stlouisfed.org/series/DPRIME.
[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[103]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF LEC, 2001$	COST EFFECTIVENESS OF LEC TO REDUCE NOx BY 80%–90%, 2,000 HOURS/YEAR, 2001$	COST EFFECTIVENESS OF LEC TO REDUCE NOx BY 80%–90%, 8,000 HOURS/YEAR, 2001$
LEAN-BURN	50	$1,857	$941/ton-$837/ton	$235/ton-$209/ton
	200	$3,184	$403/ton-$359/ton	$101/ton-$90/ton
	500	$5,572	$282/ton-$251/ton	$71/ton-$63/ton
	1,000	$8,358	$212/ton-$188/ton	$53/ton-$47/ton
	1,500	$19,635	$332/ton-$295/ton	$83/ton-$74/ton

The above analyses demonstrate, with the exception of lean-burn engines rated at 50 hp that only operated 2,000 hours per year, that 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:[104]

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

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).[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."[106] Specifically, in EPA's Updated Information on NOx

[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).
[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.
[105] *See* EPA 1993 Alternative Control Techniques Document for RICE, Table 2-13 at 2-36.
[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.

<u>Application of LEC to lean-burn RICE is cost effective for a wide range of engine sizes and types.</u>

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 SELECTIVE CATALYTIC REDUCTION

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 (NH3) into the exhaust, which reacts with NOx to form N2 and H20 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.[110]

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").[111] The OTC is a multi-state organization created under the CAA to address ozone problems in the Northeast and Mid-Atlantic U.S.[112] 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.[113] For example, in the 2012 OTC Report,[114] 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,[115] Miratech Corporation which offers an SCR system for lean-burn engines used in natural gas compression,[116] 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[117], and Caterpillar

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[110] EPA 1993 Alternative Control Techniques Document for RICE.
[111] *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%20%20Gas%20Sector%20TSD%2010-17-12.pdf.
[112] *See* https://otcair.org/about.asp.
[113] *See* 2012 OTC Report at 25-26.
[114] *Id.* at 26-27.
[115] *See* https://matthey.com/en/products-and-services/emission-control-technologies/mobile-emissions-control/selective-catalytic-reaction.
[116] *See* https://www.miratechcorp.com/products/cbl/.
[117] *See* http://intermountainelectronics.com/uploads/media/Media_633929646982817973.pdf.

which offers SCR systems for several of its engines.[118] 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.[119] 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.[120] 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.[121] 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."[122] 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.[123] For two- and four-stroke lean-burn engines greater than 100 hp, CARB set a BARCT limit 65 ppmv or 90% reduction in NO_x emissions.[124] CARB indicated that "[i]t 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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[118] *See* https://www.cat.com/en_GB/search/search-results.html?search=selective+catalytic+reduction&pagePath=%252Fcontent%252Fcatdotcom%252Fen_GB%252Fproducts%252Fnew%252Fpower-systems%252Foil-and-gas.

[119] *See* 2012 OTC Report at 27-28 and 40-41.

[120] *See* SQAQMD 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."[125] 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[126]

ENGINE TYPE		NOx LIMIT [ppmvd corrected to 15% O2]	EQUIVALENT NOx LIMIT [g/bhp-hr]
2SLB	Gaseous Fueled; >50 hp and <100 hp	75	1.0
4SLB	Limited Use	65	0.9
	Used for gas compression	65 or 93% reduction	0.9
	All other	11	0.15

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.[127] 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]."[128] 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."[129]

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.*

[126] SJVAPCD Rule 4702 Internal Combustion Engines, *available at*: https://www.valleyair.org/rules/currntrules/r4702.pdf.

[127] SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), *available at*: https://ww3.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjvapcd_4702_report.pdf.

[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[130]

POWER OUTPUT (hp)	INSTALLED SCR CAPITAL COSTS, 1999$	ANNUAL OPERATING AND MAINTENANCE COSTS, 1999$
50	$45,000	$20,102
200	$45,000	$26,102
500	$60,000	$35,102
1,000	$149,000	$78,102
1,500	$185,000	$117,102
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.[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.[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.[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%.[134] Such removal rates are achievable with SCR at lean-burn RICE, as discussed above.[135] However, the lower NOx rate of 11 ppmv that SJVAPCD has adopted for lean-burn engines not

[130] *Id.* Table 5.
[131] *Id.* Table 2 and 3.
[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.
[133] *See* EPA's Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80.
[134] EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.
[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.[136] 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.[137] 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 NO_x 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[138]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF SCR, 1999$	COST EFFECTIVENESS OF SCR, 2,000 HOURS PER YEAR, 1999$	COST EFFECTIVENESS OF SCR, 8,000 HOURS PER YEAR, 1999$
4SLB	50	$24,585	$13,567/ton	$3,392/ton
	200	$30,585	$4,244/ton	$1,061/ton
	500	$41,080	$2,281/ton	$570/ton
	1,000	$92,946	$2,574/ton	$644/ton
	1,500	$135,533	$2,512/ton	$628/ton

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

[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 SJAPCD'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%.[139] 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:

Capital cost = \$107.1 x (hp) + \$27,186

Annual cost = \$83.64 x (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.[140] 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,[141] 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.

[139] EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.
[140] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 5-11 to 5-12.
[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[142]

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF SCR, 2001$	COST EFFECTIVENESS OF SCR, 2,000 HOURS PER YEAR, 2001$	COST EFFECTIVENESS OF SCR, 8,000 HOURS PER YEAR, 2001$
4SLB	50	$17,509	$10,194/ton	$2,548/ton
	200	$29,368	$4,289/ton	$1,072/ton
	500	$53,086	$3,108/ton	$777/ton
	1,000	$92,617	$2,714/ton	$679/ton
	1,500	$132,148	$2,583/ton	$646/ton

<u>Application of SCR to lean-burn RICE is cost effective for a wide range of engine sizes and types.</u>

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.[143] 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.[144] 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 CO_2 emissions
- 1 to 2% reduction in power output[145]

[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).
[144] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.
[145] *See* EPA 1993 Alternative Control Techniques Document for RICE, Table 2-7 at 2-15.

- Increased solid waste disposal from spent catalysts[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.[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.[148] It is reasonable to assume a similar time for the installation of SCR at a lean-burn natural gas-fired RICE unit.

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.[149] *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."[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."[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 – that is, $1,100/ton in 1999 dollars.[152] For engines in the size range of 150 to 500 hp, electrification of

[146] *See* CDPHE RP for RICE at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6th ed., EPA/452/B-02-001, EPA, Office of Air Quality Planning and Standards, RTP).
[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.
[148] 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls at 15.
[149] CARB 2001 Guidance at I-7.
[150] *Id.* at IV-2.
[151] *Id.* at V-2.
[152] *Id.* at V-3.

engines was somewhat more cost effective at $900/ton in 1999 dollars.[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."[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.[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.[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.[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."[158]

The Fact Sheet documents the costs of replacing five existing gas-fired reciprocating compressors with four electric compressors.[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.[160] The Fact Sheet states that the total cost of the replacement was $6,050,000, including the cost of the motor and compressor.[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 per year.[162] 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

[153] *Id.*
[154] *Id.* at VII-2.
[155] *Id.* at V-4 to V-4.
[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.
[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.
[158] *See* https://www.epa.gov/natural-gas-star-program/natural-gas-star-program.
[159] *See* EPA, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, PRO Fact Sheet No. 103 Install Electric Compressors, 2011.
[160] *Id.* at 2.
[161] *Id.*
[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.

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.[163] 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).[164] 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.[165] 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.[166] 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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[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 Natural Gas-Fired RICE Units with Electric Compressor Engines[167]

	Costs at Operating Hours per Year		
	2,000 hours/yr	**4,000 hrs/yr**	**8,000 hrs/yr**
Annualized Capital Costs of New Electric Engines	$506,385	$506,385	$506,385
Annual Operating Costs of New Engines and Excluding Costs of Gas for Replaced Engines	$992,940	$1,380,880	$2,156,761
Total Annual Costs	$1,887,265	$1,887,265	$2,663,146
NOx Removed, tpy	542 tpy	1,084 tpy	2,168 tpy
NOx Cost Effectiveness at Stated Hours/Year	$2,766/ton	$1,741/ton	$1,228/ton

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[168]
- 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).[169] From the perspective of cost effectiveness, the potential increase in NOx emissions from

[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.
[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.

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.[170]

There are many benefits associated with replacing gas-fired reciprocating compressor engines with electric compressor engines. Those benefits include: [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.[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.[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.[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 MCF per horsepower.[175] Using the 100-year global warming potential identified by EPA,[176] that equates to roughly 10,000 tons per year of CO_2 equivalent emissions that would be avoided with no natural gas releases due to blowdowns with electric compressor engines. Thus, the total CO_2 equivalent emissions

[170] CARB 2001 Guidance at V-2.
[171] *See* EPA, PRO Fact Sheet No. 103 Install Electric Compressors at 2.
[172] *Id.* at 1.
[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.
[174] *See* EPA, PRO Fact Sheet No. 103 Install Electric Compressors at 2.
[175] *Id.* at 1.
[176] *See* https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#Learn%20why.

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,[177] for drill rigs,[178] and in oil pumps.[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.[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.[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 gas turbine.

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,[182] which provided a summary of state NOx regulations for gas engines.[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.

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

[177] Armendariz, Al, Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements, prepared for Environmental Defense Fund, January 26, 2009, at 29-30, *available at*: https://www.edf.org/sites/default/files/9235_Barnett_Shale_Report.pdf.
[178] *Id.* at 18.
[179] CARB 2001 Guidance at IV-2.
[180] *See* 40 C.F.R. Part 60, §60.4230(a)(5) and Subpart JJJJ. 73 Fed. Reg. 3568 (1/18/08).
[181] 40 C.F.R. Part 60, Subpart JJJJ, Table 1.
[182] *See* 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix B at 14-15.
[183] *Id.*

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.[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."[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."[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[187]

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
CA-Antelope Valley AQMD[188]	Rule 1110.2	Both	50–500 hp	45 ppmvd (0.67 g/hp-hr (RB) or 0.62 g/hp-hr (LB))
			>500	36 ppmvd (0.54 g/hp-hr (RB) or 0.49 g/hp-hr (LB))
			Portable	80 ppmvd (1.19 g/hp-hr (RB) or 1.10 g/hp-hr (LB))
CA-Bay Area AQMD[189]	Reg. 9, Rule 8	RB	>50 bhp &/or not Low Usage (<100	25 ppmv (0.37 g/hp-hr)

[184] *See* CDPHE RP for RICE at 10.
[185] 40 C.F.R. § 51.100(o).
[186] HSC Code § 40406 (California Code), *available at*: https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=40406.&lawCode=HSC.
[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.
[188] https://ww3.arb.ca.gov/drdb/av/curhtml/r1110-2.pdf.
[189] http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-8-nitrogen-oxides-and-carbon-monoxide-from-stationary-internal-combustion-engines/documents/rg0908.pdf?la=en.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
			hrs/yr) &/or not registered as portable	
		LB	>50 bhp &/or not Low Usage (<100 hrs/yr) &/or not registered as portable	65 ppmv (0.89 g/hp-hr)
CA-Mojave Desert APCD[190]	Rule 1160 (Adopted 12/20/93)	RB	>500 bhp &/or >100 hours/4 quarters, and only if located in the Federal Ozone Nonattainment area	50 ppmv (0.75 g/hp-hr)
		LB		140 ppmv (1.92 g/hp-hr)
	----------------- Proposed Amendments 1/22/18[191]	RB		50 ppmv (0.75 g/hp-hr)
		LB		125 ppmv (1.71 g/hp-hr)
CA-Sacramento AQMD[192]	Rule 412	RB	>50 bhp & exemptions for 50-525 hp if low op hours (200-40 hrs)	25 ppmv (0.37 g/hp-hr) Alt Limit: 90% NOx Reduction
		LB	>50 bhp	65 ppmv (0.89 g/hp-hr) Alt Limit: 90% NOx reduction
CA-Santa Barbara AQMD[193]	Rule 333	RB	>50 bhp Noncyclically-loaded[194]	50 ppmvd (0.75 g/hp-hr) or 90% NOx reduction
		RB	>50 bhp Cyclically-loaded[195]	300 ppmvd (4.48 g/hp-hr)
		LB	>50 bhp & < 100 bhp	200 ppmvd (2.74 g/hp-hr)
		LB	≥100 bhp	125 ppmvd

190 http://mdaqmd.ca.gov/home/showdocument?id=438.
191 http://mdaqmd.ca.gov/home/showdocument?id=6631.
192 http://www.airquality.org/ProgramCoordination/Documents/rule412.pdf.
193 https://ww3.arb.ca.gov/drdb/sb/curhtml/r333.pdf.
194 Noncyclically loaded means an engine that is not cyclically loaded. *See* Santa Barbara AQMD Rule 333.C.
195 "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.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
				(1.71 g/hp-hr) or 80% NOx reduction
CA – San Diego AQMD[196]	Rule 69.4.1	RB	>50 bhp &>200 hrs/yr	25 ppmvd (0.37 g/hp-hr)
		LB	>50 bhp &>200 hrs/yr	65 ppmvd (0.89 g/hp-hr)
CA-San Joaquin Valley APCD[197]	Ruel 4702	RB	>50 bhp, Cyclic loaded, Field Gas Fueled	50 ppmvd (0.75 g/hp-hr)
		RB	>50 bhp & <4,000 hrs/yr	25 ppmvd (0.37 g/hp-hr)
		RB	>50 bhp and all others (engines not waste gas-fueled or cyclic loaded or limited hours)	11 ppmvd (0.16 g/hp-hr)
		2SLB	>50 bhp & <100 bhp	75 pmvd (1.03 g/hp-hr)
		LB	>50 bhp & <4,000 hrs/yr	65 ppmvd (0.89 g/hp-hr)
		LB	>50 bph and used for gas compression	65 ppmvd (0.89 g/hp-hr) or 93% NOx reduction
		LB	>100 hp and not limited use (<4,000 hrs), not used for gas compression, or not waste-gas fueled	11 ppmvd (0.15 g/hp-hr)
CA- San Luis Obispo APCD[198]	Rule 431	RB	>50bhp &>200 hrs/yr	50 ppmvd (0.75 g/hp-hr) or 90% NOx Reduction
		LB	>50bhp &>200 hrs/yr	125 ppmvd (1.71 g/hp-hr) or 80% NOx Reduction
CA - SCAQMD[199]	Rules 1110.2 and 1100	RB & LB	>50 bhp	11 ppmvd (0.16 g/hp-hr (RB) 0.15 g/hp-hr (LB))

[196] https://www.sandiegocounty.gov/content/dam/sdc/apcd/PDF/Rules_and_Regulations/Prohibitions/APCD_R69-4-1.pdf.
[197] https://ww3.arb.ca.gov/drdb/sju/curhtml/r4702.pdf.
[198] https://ww3.arb.ca.gov/drdb/slo/curhtml/r431.pdf.
[199] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
CA- Ventura County AQMD[200]	Rule 74.9	RB	>50 bhp & >200 hrs/yr	25 ppmvd (0.37 g/hp-hr) or 94% NOx reduction
		LB	>50 bhp & > 200 hrs/yr	45 ppmvd (0.62 g/hp-hr) or 90% NOx reduction
TX- Houston-Galveston-Brazoria Area[201]	30 TAC 117.2010(c)(2) Emission Specs for 8hr ozone demo	RB & LB	>50 hp	0.50 g/hp-hr (33 ppmvd (RB) 36 ppmv (LB))
TX- Dallas -Ft. Worth Area[202]	30 TAC 117.2110(1) Emission Specs for 8hr ozone demo	RB	>50 hp	0.50 g/hp-hr
		LB	In service before 6/1/07	0.70 g/hp-hr
		LB	Placed into service, modified, reconstructed, or relocated after 6/1/07	0.50 g/hp-hr
NJ[203]	Rule 7:27-19.8	RB	>500 bph	1.5 g/bhp-hr
		LB	>500 bhp	2.5 g/bhp-hr
		LB & used for generating electricity	≥148 kW	1.5 g/bhp-hr or 80% NOx reduction
		2SLB	≥200 bhp & <500 bhp	3.0 g/bhp-hr
		4SLB	≥200 bhp & <500 bhp	2.0 g/bhp-hr

200 http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.9.pdf.
201 https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=2010.
202 http://txrules.elaws.us/rule/title30_chapter117_sec.117.2110.
203 https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
		RB&LB	Constructed or modified after 3/7/07, engines used to generate electricity with output ≥37 kW	0.90 g/bhp-hr or 90% NOx reductions (for modified units)
NY[204]	6 CCR-NY 227-2.4 (f)	RB & LB	>200 bhp	1.5 g/bhp-hr
MA[205]	310 CMR 7.19:(8)(c)	RB	>3 MMBtu/hr and >1,000 hrs	1.5 g/bhp-hr
		LB	>3 MMBtu/hr and >1,000 hrs	3.0 g/bhp-hr
MD[206]	COMAR 26.11.29.02.C.	RB	RICE used to compress nat gas ≥2400 hp	110 ppmv (1.64 g/hp-hr)
		LB	RICE used to compress nat gas ≥2,400 hp	125 ppmv (1.71 g/hp-hr)
CT[207]	22a-174-22e(d)(6a)	RB	>3 MMBtu/hr, until 5/31/23 Beginning 6/1/23	2.5 g/bhp-hr 1.5 g/bhp-hr
		LB	>3 MMBtu/hr, until 5/31/23 Beginning 6/1/23	2.5 g/bhp-hr 1.5 g/bhp-hr
IL (Chicago are and Metro East area)[208]	Title 35 Part 217, § 217.388a)1)	RB	Applies to specific engines listed in App G and those >500 bhp	150 ppmv (2.24 g/hp-hr)
		LB except Worthington engines not listed in App G	Applies to specific engines listed in App G and >500 bhp	210 ppmv (2.88 g/hp-hr)
		LB Worthington engines not listed in App G	>500 bhp & >8 MMbhp-hrs	365 ppmv (5.0 g/hp-hr)

204 https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).
205 https://www.mass.gov/files/documents/2018/01/05/310cmr7.pdf.
206 http://mdrules.elaws.us/comar/26.11.29.
207 https://www.ct.gov/deep/lib/deep/air/regulations/20160114_draft_sec22e_dec2015(revised).pdf.
208 http://www.epa.state.il.us/air/rules/rice/217-subpart-q.pdf.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
GA (45 county area – ozone)[209]	Rule 391-3-1-.02.(2)(mmm)	RB & LB	≥100kW&<25 MW, in operation <4/1/00	160 ppmv (2.19–2.39 g/hp-hr)
	Applies only to engines used to generate electricity	RB & LB	≥100k W&<25 MW, in operation >4/1/00	80 ppmv (1.10–1.19 g/hp-hr)
MI[210]	R 336.1818	RB	>1 ton/day NOx engines per avg ozone control period day in 1995	1.5 g/bhp-hr
		LB		3.0 g/bhp-hr
CO[211]	Reg. No 7, Sections XVIII.E. 2 and 3	RB	>500 hp constructed before 2/1/09	Install and operate both a NSCR and an AFRC by 7/1/2010
		RB or LB constructed or relocated to Colorado ≥1/1/11	≥100 hp & <500 hp	1.0 g/hp-hr
		RB or LB constructed or relocated ≥7/1/10	≥500 hp	1.0 g/hp-hr
MT[212]	ARM 17.8.1603	RB engines at "oil and gas well facilities" (which does not include Compressor engines) which completed or modified >3/16/79 and facility PTE NOx >25 tpy	>85 bhp	Install and operate NSCR or its equivalent to control air emissions
UT[213]	R307-510	Gas-fired engine at a well site that began	≥100 hp	1.0 g/hp-hr

[209] http://rules.sos.ga.gov/GAC/391-3-1-.02.
[210] https://www.michigan.gov/documents/deq/deq-aqd-air-rules-apc-part8_314769_7.pdf.
[211] https://www.colorado.gov/pacific/cdphe/aqcc-regs.
[212] https://deq.mt.gov/Portals/112/DEQAdmin/DIR/Documents/legal/Chapters/CH08-16.pdf.
[213] https://rules.utah.gov/publicat/code/r307/r307-510.htm.

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
		operations, installed new engines or made modifications to existing engines after 1/1/16		

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

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.

Table 16. Other NOx Limits Applicable to Natural Gas-fired Stationary RICE Units

State	Determination	Applicabiltiy [hp]	NOx Limits and Engine Type Applicability [RB, LB or BOTH]
NEW JERSEY[214]	State of the Art (SOTA) Emission Performance Levels	NO SIZE SPECIFIED	0.15 g/hp-hr (BOTH)[215]
PENNSYLVANIA[216]	Best Available Technology (BAT) Emission Limits for new SI RICE permitted on or after 8/8/18	≤100	1.0 g/hp-hr
		>100 TO ≤500	0.7 g/hp-hr (LB) 0.25 g/hp-hr (RB)[217]
		>500	0.5 g/hp-hr (LB) 0.2 g/hp-hr (RB)
		≥2,370	0.3 g/hp-hr uncontrolled (LB) **or** 0.05 g/hp-hr with control (LB)[218]
PENNSYLVANIA[219]	Best Available Technology (BAT) Emission Limits for existing SI RICE permitted on or after	≤100	2.0 g/hp-hr
		>100 TO ≤500	1.0 g/hp-hr (LB)

[214] NJ DEP State of the Art Manual for Reciprocating Internal Combustion Engines (2003), *available at*: https://www.state.nj.us/dep/aqpp/downloads/sota/sota13.pdf.

[215] 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.

[216] 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* Tables 8 and 9, *available at*: http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904.

[217] 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.

[218] 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.

[219] *Id.*

State	Determination	Applicabiltiy [hp]	NOx Limits and Engine Type Applicability [RB, LB or BOTH]
	2/2/13 but prior to 8/8/18		0.25 g/hp-hr (RB)[220]
		>500	0.50 g/hp-hr (LB) 0.20 g/hp-hr RB)
PENNSYLVANIA [221]	Best Available Technology (BAT) Emission limits for existing SI RICE permitted prior to 2/2/13	<1,500	2.0 g/hp-hr
WYOMING[222]	Oil and Gas Production Facilities Permitting Guidance Applicable to Natural Gas-Fired Pumping Units	≤50 hp AND MEETS BACT	2.0 g/hp-hr
TEXAS[223]	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	≥100 bhp (RB) ≥500 bhp (LB)	1 g/bhp-hr

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

[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.*

[222] WYDEQ Oil and Gas Production Facilities Permitting Guidance (last revised December 2018), *available at:* http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/FINAL_2018_Oil%20and%20Gas%20Guidance.pdf.

[223] TCEQ Air Quality Standard Permit for Oil and Gas Handling and Production Facilities (effective November 8, 2012), *available at:* https://www.tceq.texas.gov/assets/public/permitting/air/Announcements/oilgas-sp.pdf.

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.[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 UNITS.

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 NO, 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.

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

[224] Prevention of Significant Deterioration Air Construction Permit Application for Mid-Kansas Electric Company, LLC Rubart Station (July 2012), *available at:* http://www.kdheks.gov/bar/midkanec/Mid-Kansas_Rubart_Station_PSD_Air_Permit_App_12_19_12.pdf.

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 RECIPROCATING INTERNAL COMBUSTION ENGINES

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/MMBtu,[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.

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,

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[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/ch03/final/c03s02.pdf.
[226] EPA AP-42, Introduction at 8-9.
[227] EPA, AP-42, Section 3.2 at 3.2-3.

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:[228]

> 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:
>
> $$2CO + O_2 \rightarrow 2CO_2$$
>
> Oxidation of hydrocarbons (unburnt and partially burnt fuel) to carbon dioxide and water:
>
> $$C_xH_{2x+2} + [(3x+1)/2]O_2 \rightarrow xCO_2 + (x+1)H_2O$$

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%.[229] If a lean-burn engine is equipped with SCR for NOx control, an oxidation catalyst can be added to the SCR design.[230]

Cost information of oxidation catalyst was provided to EPA in 2010 to help determine national impacts associated with EPA's RICE NESHAP.[231] The analysis, performed by E^C/R Incorporated, was based on 2009 cost data for oxidation catalyst from industry groups, vendors, and manufacturers of RICE control technology. E^C/R Incorporated performed a linear regression analysis[232] 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:

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[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*: http://www.meca.org/resources/MECA_stationary_IC_engine_report_0515_final.pdf.
[229] *Id.*
[230] *Id.* at 7.
[231] Memo from EC/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010).
[232] *Id.* at 5-6.

2SLB Oxidation Catalyst Total Annual Cost = $11.4 x HP + $13,928

2SLB Oxidation Catalyst Total Capital Cost = $47.1 x HP + $41,603

4SLB Oxidation Catalyst Total Annual Cost = $1.81 x HP + $3,442

4SLB Oxidation Catalyst Total Capital Cost = $1.81 x HP + $3,442

Where HP equals the engine size in horsepower.

E^C/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.[233] 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.[234]

ENGINE TYPE	HORSEPOWER	TOTAL CAPITAL COSTS	TOTAL ANNUALIZED COSTS
2SLB	50	$43,958	$12,619
	75	$45,136	$12,853
	100	$46,313	$13,088
	250	$53,378	$14,496
	500	$65,153	$16,843
	1000	$88,703	$21,536
	1500	$112,253	$26,229
4SLB	50	$3,533	$3,381
	75	$3,578	$3,425
	100	$3,623	$3,468
	250	$3,895	$3,727
	500	$4,347	$4,160
	1000	$5,252	$5,025
	1500	$6,157	$5,890

[233] *Id.* at 5-6 and Appendix A.

[234] Cost calculations based on E^c/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.[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.[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.[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.[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.[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.[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.[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.

<u>VOC Controls for Rich-Burn RICE</u>

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."[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

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[235] SCAQMD, Draft Staff Report, Proposed Amended Rule 1110.2 – Emissions from Gaseous- and Liquid-Fueled Engines, September 2019, at D-1, *available at*: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/rule-1110-2-draft-staff-report---final.pdf?sfvrsn=6.
[236] *See* CDPHE RP for RICE at 3. *See also* Colorado Regulation No. 7, Part E, Section I.B., *available at*: https://drive.google.com/file/d/16qTQLSTX1T49DYWp3voXRNl4_g-vbhQT/view.
[237] Colorado Regulation 7 (5 CCR 1001-9) Part E 1. Control of Emissions from Engines.
[238] *Id.* at Section I.C.4. of Part E.
[239] Prevention of Significant Deterioration Air Construction Permit Application for Mid-Kansas Electric Company, LLC Rubart Station (July 2012), *available at:* http://www.kdheks.gov/bar/midkanec/Mid-Kansas_Rubart_Station_PSD_Air_Permit_App_12_19_12.pdf.
[240] Application for a Prevention of Significant Deterioration (PSD) Authorization and Significant Revision to Class I Air Quality Permit for Irving Generating Station, Tucson Electric Power (2017), *available at*: https://webcms.pima.gov/UserFiles/Servers/Server_6/File/Government/Environmental%20Quality/Air/TEP%20PSD%20Webpage/17-12-19-Sundt-RICE-Project-Revised-Application.pdf.
[241] *Id.* Table 5-3 at 5-10. Showing sources from Texas, Oregon, Kansas, and Hawaii receiving permits between 2013 to 2016.
[242] CDPHE RP for RICE at 6.

NSCR must be considered as a reasonable progress control option to reduce VOC emissions from rich-burn RICE.

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. [243]

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).[244] 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.[245] 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.[246] 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).[247] Instead, the turbine shaft power is used as mechanical power to drive a compressor.

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[243] *See*, *e.g.*, 76 Fed. Reg. 52,738 at 52,761 (Aug. 23, 2011); *see also* Innovative Environmental Solutions, Inc. & Optimized Technical Solutions, Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry, July 2014, at 26, note 1, *available at*: https://www.ingaa.org/File.aspx?id=22780.

[244] EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-1, *available at*: https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_3._technology_characterization_-_combustion_turbines.pdf.

[245] *Id.* at 3-2.

[246] 40 C.F.R. § 60.331(q).

[247] EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at S-2, 3-6, and A-2.

Regardless of the purpose of the gas-fired combustion turbines, the air pollution controls for the associated visibility-impairing pollutants are the same.

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.[248] That DOE Report, "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines" dated November 5, 1999 (hereinafter "1999 DOE Report")[249] 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,[250] 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.[251] 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.[252] 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.

[248] *See* 2012 OTC Report at 66-67.
[249] Bill Major, ONSITE SYCOM Energy Corporation, and Bill Powers, Powers Engineering, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, prepared for U.S. Department of Energy, November 5, 1999, Appendix A at A-5 (Table A-4), *available at*: https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf.
[250] NESCAUM, December 2000, Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines, Technologies & Cost Effectiveness, at III-21 through III-24 and at III-40 [hereinafter "NESCAUM 2000 Status Report"], *available at*: http://www.nescaum.org/documents/nox-2000.pdf/view.
[251] *See* EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf 12 and 98 (reference 19).
[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.

> 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 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.

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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).
[255] EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.
[256] *See* GE Power, Water Injection for NOx Reduction, at https://www.ge.com/power/services/gas-turbines/upgrades/water-injection-for-nox-reduction.
[257] 2012 OTC Report at 62.
[258] *Id.*

Table 18. Capital and Operating Costs of Water or Steam Injection for Select Combustion Turbines[259]

Turbine Make/Model	Size, MW	Size, hp	Capital Costs of Water/Steam Injection 1999$	Annual Costs (Excluding Capital Recovery), 1999$
Solar Centaur 50	4.2 MW	5,632 hp	$405,500	$79,000
Allison 501-KB5	4.0 MW	5,364 hp	$291,000	$100,000
GE LM2500	22.7 MW	30,441 hp	$1,083,175	$294,000
GE MS7001F	161 MW	215,904 hp	$4,834,770	$1,325,000

The 1999 DOE report determined the annualized costs of control assuming only a 15-year life of controls and a 10% interest rate.[260] 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.[261] 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.[262] 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.[263] 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,[264] a lower interest rate of 5.5% was assumed.[265] In its 2019 cost calculation spreadsheet for SCR provided with its

[259] *See* 1999 DOE Report, Appendix A at A-5 (Table A-4).
[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.
[262] *See*, *e.g.*, Sargent & Lundy Combined-Cycle Plant Life Assessments, *available at*: https://sargentlundy.com/wp-content/uploads/2017/05/Combined-Cycle-PowerPlant-LifeAssessment.pdf; GE Power Generation, GE Gas Turbine Design Philosophy, *available at*: https://www.ge.com/content/dam/gepower-pgdp/global/en_US/documents/technical/ger/ger-3434d-ge-gas-turbine-design-philosophy.pdf; NREL, Annual Technology Baseline, Natural Gas Plants, *available at*: https://atb.nrel.gov/electricity/2018/index.html?t=cg; Solar Turbines, Industrial Power Generation, Taurus 70, Benefits and Features, *available at*: https://www.solarturbines.com/en_US/products/power-generation-packages/taurus-70.html.
[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] US EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.
[265] *See e.g.*, https://fred.stlouisfed.org/series/DPRIME.

Control Cost Manual, EPA used an interest rate of 5.5%.[266] 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.[267] 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.[268] In its 2016 TSD for the CSAPR rule, EPA did not escalate the costs of controls from 1999 dollars.[269] 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 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[270]

Turbine Make/Model	Size, MW	Size, hp	Annualized Costs of Water/Steam Injection 1999$	Cost Effectiveness of Water/Steam Injection to Meet 42 ppm NOx Rate (1999$)	Cost Effectiveness of Water/Steam Injection to Meet 25 ppm NOx Rate (1999$)
Solar Centaur 50	4.2	5,632	$109,230	$1,496/ton	$1,265/ton
Allison 501-KB5	4.0	5,364	$121,694	$1,323/ton	$1,153/ton
GE LM2500	22.7	30,441	$374,750	$846/ton	$752/ton
GE MS7001F	161	215,904	$1,685,429	$409/ton	$373/ton

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.[271] 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%."[272] This is presumably an average

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[266] *Available at* https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[267] *Id.* at A-3
[268] 2016 EPA CSAPR TSD for Non-EGU Emissions Controls, November 2015, Appendix A at 3-10 through 3-12.
[269] *Id.*
[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 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.
[272] 2012 OTC Report at 16.

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."[273] 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 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.[274] 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[275]

Turbine Make/Model	Size, MW	Size, hp	Annualized Costs of Water/Steam Injection 1999$	Cost Effectiveness of Water/Steam Injection to Meet 42 ppm NOx Rate (1999$)	Cost Effectiveness of Water/Steam Injection to Meet 25 ppm NOx Rate (1999$)
Solar Centaur 50	4.2	5,632	$85,649	$2,675/ton	$2,257/ton
Allison 501-KB5	4.0	5,364	$90,021	$2,232/ton	$1,940/ton
GE LM2500	22.7	30,441	$255,506	$1,316/ton	$1,166/ton
GE MS7001F	161	215,904	$1,060,507	$587/ton	$533/ton

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%,

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[273] *Id.*

[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.

but still high compared to today's interest rates.[276] The cost algorithms of EPA's 2016 TSD for the CSAPR Rule are reprinted below.[277]

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

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.[278] 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[279]

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

[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.
[278] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.
[279] *See*, *e.g.*, EPA's 1993 ACT for Stationary Gas Turbines at 2-41.

cost effectiveness analysis,[280] 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[281]

Turbine Model	Size, MW	Annual Water Use at 91% Capacity Factor	Annual Water Use at 40% Capacity Factor
Solar Centaur 50	4.2	1,401,407	616,003
Allison 501-KB5	4.0	1,889,269	830,448
GE LM2500	22.7	7,093,130	3,117,859
GE MS7001F	161	95,166,555	41,831,453

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."[282] Water quality may be more of an issue for remote sites, especially if surface water or well water is used for the water supply.[283] 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.[284]

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,[285] 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.[286] Dry low NOx combustors are also available for retrofit for

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280 *See* 1999 DOE Report, Appendix A at A-5.
281 *Id.*
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.

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[287] 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."[288] Many DLNBs can achieve reduced NOx rates across the full load range of a gas turbine.[289] DLNBs are also available to retrofit to several types of combustion turbines. General Electric has dry low NOx burner retrofit options for many of its turbine makes and models, and Solar Turbines has an extensive line of retrofit kits including Solar Turbines' SoLoNOx™ technology.[290] To retrofit such DLNBs, the turbines' combustors must be replaced and there may be changes necessary to associated piping and turbine combustion controls.[291]

DLNBs can achieve 60% to 84% reductions in NOx emissions.[292] For the turbines for which DLNBs are available, NOx rates have generally ranged from 9–15 ppm.[293] The 1999 DOE Report assumed only a 25 ppmv NOx rate would be achieved at most of the combustion turbines with DLN combustion, although the DOE report also calculated costs for a larger turbine to meet a 9 ppmv NOx rate.[294] The 1999 DOE Report indicates that the operation and maintenance costs increase with the lower NOx rate being achieved.[295] 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 ppmvd NOx with Solar Turbines' SoLoNOx™ burners, including the Solar Centaur 50L which is rated at 6,276 horsepower (< 5 MW).[296] 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).[297] GE

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[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.
[288] EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.
[289] As discussed in 2012 OTC Report at 62.
[290] *Id.* at 66.
[291] *Id.*
[292] *Id. See also* 2015 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12.
[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.
[296] *See*, *e.g.*, Atlantic Coast Pipeline and Dominion Transmission, Inc., Supply Header Project, Resource Report 9, Air and Noise Quality, September 2015, at 9-24.
[297] *See* https://www.solarturbines.com/en_US/services/equipment-optimization/system-upgrades/safety-and-sustainability/solonox-upgrades.html.

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.[298]

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.[299] 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."[300] 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 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]

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[298] *See* https://www.genewsroom.com/press-releases/ge-completes-worlds-first-dln10-ultra-low-nox-combustion-upgrade-nine-ge-9e-gas.

[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.

[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 230-C, *available at*: https://www.dec.ny.gov/dardata/boss/afs/permits/929200000800015_r3.pdf.

Table 22. Summary of Cost Effectiveness for DLN Combustion (1999$) at 91% Capacity Factor[303]

Turbine Make/Model	Size, MW	Size, hp	Annualized Costs of DLN Combustion 1999$	Cost Effectiveness of Dry Low NOx Combustion to meet 25 ppm NOx Rate	Cost Effectiveness of Dry Low NOx Combustion to Meet 9 ppm NOx Rate
Allison 501-KB7	4.9	6,571	$33,491	$259/ton	
Solar Centaur 50	4.0	5,364	$14,164	$164/ton	
Solar Centaur 60	5.2	6,973	$14,164	$128/ton	
GE LM2500	22.7	30,441	$179,639	$360/ton	
GE Frame 7FA	169.9	227,839	$455,472 (25 ppmv) $474,109 (9 ppmv)	$96/ton	$92/ton

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.

Table 23. Summary of Cost Effectiveness for DLN Combustion (1999$) at 40% Annual Capacity Factor[304]

Turbine Make/Model	Size, MW	Size, hp	Cost Effectiveness of Dry Low NOx Combustion to meet 25 ppm NOx Rate	Cost Effectiveness of Dry Low NOx Combustion to Meet 9 ppm NOx Rate
Allison 501-KB7	4.9	6,571	$590/ton	
Solar Centaur 50	4.0	5,364	$373/ton	
Solar Centaur 60	5.2	6,973	$292/ton	
GE LM2500	22.7	30,441	$820/ton	
GE Frame 7FA	169.9	227,839	$218/ton	$208/ton

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.

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.

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.[305] The cost algorithms of EPA's 2016 TSD for the CSAPR Rule for DLN combustion are reprinted below.[306]

Total Capital Investment (1999 dollars) = 2860.6 x (MMBtu/hr) + 25427

Total Annual Costs (1999 dollars) = 584.5 x (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).[307] 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.[308] 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.

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[309]

Turbine Make/Model	Size, hp	Capacity Factor	Cost Effectiveness of Retrofit DLN Combustion to meet 50 ppm NOx Rate	Cost Effectiveness of Retrofit DLN Combustion to Meet 25 ppm NOx Rate
Solar Centaur	4,700	91%	$1,217/ton	$940/ton
Solar Centaur	4,700	40%	$2,769/ton	$2,140/ton
Solar Mars	13,000	91%	$359/ton	$296/ton
Solar Mars	13,000	40%	$816/ton	$673/ton

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

[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.
[307] *See* NESCAUM 2000 Status Report at III-16.
[308] *Id.*
[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.

management or other charges associated with the project beyond the equipment and installation."[310] 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.[311]

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.[312] 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.[313] A non-air quality environmental impact is that DLNBs "tend to create harmonics in the combustor that result in significant vibration and acoustic noise."[314]

EPA has indicated that the length of time to install DLNBs is 6–12 months.[315]

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.

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

[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.

ppm.[316] The 1999 DOE Report stated that SCR was the "primary post-combustion NOx control method in use" as of 1999.[317]

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 N_2, H_2O, and CO_2. 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.[318] 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.[319] 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.[320] 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.[321] The NOxCat ETZ catalyst is specifically designed for simple-cycle power generating turbines and other high temperature turbine applications.[322] The NOxCat VNX and ZNX catalysts can achieve up to 99% NOx reduction and are most effective at a temperature range of 550 to 800 degrees Fahrenheit.[323] 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.[324]

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.[325] Further, aeroderivative turbines typically have somewhat lower exhaust gas temperatures which can work better

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[316] *See*, *e.g.*, EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18; 2012 OTC Report at 63.
[317] 1999 DOE Report at 1-5.
[318] *Id.*
[319] *Id.*
[320] *See* EPA, Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, at pdf page 36.
[321] *See* BASF, SCR Catalysts for Power Generation, *available at*: http://www.basf-qtech.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/scr-cat-pow-gen.
[322] *See* BASF, NOxCat ETZ, *available at*: http://www.basf-qtech.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/nOx-Cat- ETZ.
[323] *See* BASF, NOxCat VNX & ZNX for Power Generation, *available at*: http://www.basf-qtech.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/nox-cat-VNX-ZNX-pow-gen.
[324] *Id.*
[325] *See, e.g.*, Buzanowki, M. and S. McMenamin, Automated Exhaust Temperature Control for Simple-Cycle Power Plants, 2/11/2011, Power Magazine, *available at*: https://www.powermag.com/automated-exhaust-temperature-control-for-simple-cycle-power-plants/?printmode=1.

with conventional SCR systems than frame-type turbines.[326] 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.[327] Conventional catalysts can achieve 80% or greater NOx removal over a wide temperature range of approximately 625 to 900 degrees Fahrenheit.[328] SCR vendors have experience installing SCR to achieve low NOx emission rates on numerous simple cycle turbines of all types and sizes.[329]

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.[330] For these cost ranges, EPA cites to the NESCAUM 2000 Status Report.[331] 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.[332] 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.

Table 25. Cost Effectiveness for High Temperature SCR Retrofit on Simple Cycle Gas Turbines.[333]

Turbine Size, MW	Turbine Size, hp	Uncontrolled NOx, ppm	Controlled NOx, ppm	Cost Effectiveness of SCR, $/ton (2000$), at listed capacity factor	Capacity Factor
75	100,590	154	15	$849	45%
75	100,590	154	15	$664	65%
75	100,590	154	15	$566	85%
75	100,590	42	7	$2,980	45%
75	100,590	42	7	$2,247	65%

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326 Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand Curve Reset, prepared for New York Independent System Operator, Inc., at iv, *available at*: http://files.brattle.com/files/7644_independent_evaluation_of_scr_systems_for_frame-type_combustion_turbines.pdf.

327 *See* EPA, Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, at pdf pages 20-21.

328 *Id.* at pdf page 20.

329 *See*, *e.g.*, McGinty, Bob, Mitsubishi Hitachi Power Systems, Gas Turbine & Industrial SCR Systems, Lessons Learned Firing NG and ULSD in Large Frame Simple Cycle Gas Turbine Hot SCR Systems, *available at*: http://cemteks.com/cemtekswp/wp-content/uploads/2016/12/lessons_learned_firing_ng_and_ulsd_in_large_frame_simple_cycle_gas_turbine_hot_scr_systems.pdf; Chupka, Mark, The Brattle Group, and Anthony Licata, Licata Energy & Environmental Consulting, Inc., Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines, Report for ICAP Demand Curve Reset, prepared for New York Independent System Operator, Inc.

330 US EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction (June 2019) at pdf page 12.

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).

333 *Id.* at III-24.

Turbine Size, MW	Turbine Size, hp	Uncontrolled NOx, ppm	Controlled NOx, ppm	Cost Effectiveness of SCR, $/ton (2000$), at listed capacity factor	Capacity Factor
75	100,590	42	7	$1,859	85%
75	100,590	15	3	$8,441	45%
75	100,590	15	3	$6,303	65%
75	100,590	15	3	$5,171	85%
5	7,000	142	15	$3,395	45%
5	7,000	142	15	$2,523	65%
5	7,000	142	15	$2,061	85%
5	7,000	42	5	$11,335	45%
5	7,000	42	5	$8,341	65%
5	7,000	42	5	$6,756	85%

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.

The NESCAUM cost effectiveness numbers in Table 25 above reflect a 15-year equipment life and an interest rate of 7.5%.[334] The NESCAUM cost effectiveness numbers were also primarily based on the 1999 DOE report.[335] 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.[336] 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

[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.

amortized to reflect a 25-year equipment life and a 5.5% interest rate.[337] 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,[338] 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.[339]

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[340]

Turbine Model	Size, MW	Size, hp	Uncontrolled NOx, ppm at 15% O2	Controlled NOx with SCR, ppm at 15% O2	Annualized Costs of SCR, 1999$	Cost Effectiveness of Conventional SCR at Stated Capacity Factor, 1999$	Capacity Factor
Solar Centaur 50	4.2	5,632	42	9	$135,475	$11,794/ton	40%
Solar Centaur 50	4.2	5,632	42	9	$143,368	$5,486/ton	91%
GE LM2500	22.7	30,441	42	9	$295,872	$6,098/ton	40%
GE LM2500	22.7	30,441	42	9	$317,134	$3,049/ton	91%
GE Frame 7FA	161	215,904	42	9	$1,426,883	$3,050/ton	40%
GE Frame 7FA	161	215,904	42	9	$1,317,285	$1,679/ton	91%

[337] 1999 DOE Report at 3-9 to 3-10, Appendix A at A-6 to A-7.
[338] 2012 OTC Report at 16.
[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.
[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 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[341]

Turbine Model	Size, MW	Size, hp	Uncontrolled NOx, ppm at 15% O2	Controlled NOx with SCR, ppm at 15% O2	Annualized Costs of SCR, 1999$	Cost Effectiveness of High Temperature SCR at Stated Capacity Factor, 1999$	Capacity Factor
Solar Taurus 60	5.2	6,973	42	9	$179,385	$13,238/ton	40%
Solar Taurus 60	5.2	6,973	42	9	$188,760	$6,123/ton	91%
GE LM2500	22.7	30,441	42	9	$324,122	$6,680/ton	40%
GE LM2500	22.7	30,441	42	9	$364,879	$3,305/ton	91%
GE Frame 7FA	161	215,904	42	9	$1,379,722	$3,695/ton	40%
GE Frame 7FA	161	215,904	42	9	$1,680,250	$1,978/ton	91%

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."[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

[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 outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines.

[342] *See* EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.

from $1.5 million to $2.9 million with the annual costs ranging from $63,000 to $727,000.[343] 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.[344] The cost basis of these costs is not identified, but presumably the costs are from the 2010-2015 timeframe.[345] 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.[346] These limits are required to be met by 2024.[347] 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.[348] 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.[349]

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.[350]
- 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.[351] The use of regenerated catalyst can reduce the amount of spent catalyst that needs to be disposed of.[352]

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343 SCAQMD, Preliminary Draft Staff Report, Proposed Amendments to Regulation XX Regional Clean Air Incentives Market (RECLAIM) NOx RECLAIM, July 21, 2015, at 183, ***available at***: https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/pdsr-072115.pdf?sfvrsn=2.
344 *Id.* at 182.
345 It is assumed the cost data were collected before 2014. *See* November 26, 2014 report entitled "NOx RECLAIM BARCT INDEPENDENT EVALUATION OF COST ANALYSIS PERFORMED BY SCAQMD STAFF FOR BARCT IN THE NON-REFINERY SECTOR," available on SCAQMD's website at https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/noxreclaimbarct-nonconf-nonrefinery_112614.pdf?sfvrsn=2.
346 *See* Rule 1134(d)(4), Table II, ***available at***: http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1134.pdf.
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.
349 *See* September 2007, SJVAPCD, Amendments to Rule 4703 (Stationary Gas Turbines), Initial Study and Negative Declaration, at 5, ***available at***: https://www.valleyair.org/notices/Docs/priorto2008/08-08-07/Negative%20Declaration.pdf.
350 EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf pages 15-16, and 48.
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.[353] 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).[354] 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.[355] 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.[356] 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 SIMPLE CYCLE TURBINES BY EPA AND STATE AND LOCAL AGENCIES

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.[357] 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.[358] 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 for existing gas turbines that were modified on or after February 18, 2005. These standards are

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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.
[354] *See* 1999 DOE Report at 2-11.
[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/.
[357] 70 Fed. Reg. 8,314-8,332 (Feb. 18, 2005), 71 Fed. Reg. 38,482-38,506 (July 6, 2006).
[358] 44 Fed. Reg. 52,798.

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]

Turbine Size/Range	Approximate Turbine size range, hp[360]	Subpart KKKK NOx limits for modified sources after 2/2005, ppmv	Control that NOx limit reflects
≤50 MMBtu/hr	≤6,850 hp	150	Probably none
>50 MMBtu/hr and ≤850 MMBtu/hr	>6,850 hp and ≤116,456 hp	42	Water/Steam Injection
>850 MMBtu/hr	>116,456 hp	15	DLNC

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 virtually all simple cycle turbines. We reviewed some of the remaining states' regulations to determine

[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.

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, the gas turbine 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,[364] 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."[365] 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."[366] 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.

[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 29. Summary of State/Local Air Agency NOx Emission Limits for Existing Simple Cycle Gas-fired Combustion Turbines that Require NOx Pollution Controls[367]

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA – Sacramento Metro AQMD[368]	Rule 413.301.3	>0.3 MW or 3 MMBtu/hr (RACT)	42
	Rule 413.302.1	<2.9MW or >2.9 MW but <877 hrs/yr (BARCT[369])	42
		>877 hrs/yr & 2.9-10 MW (BARCT)	25
		>877 hrs/yr or >10 MW without SCR (BARCT)	15
		>877 hrs/yr or >10 MW with SCR (BARCT)	9
CA – Bay Area AQMD[370]	Regulation 9-9-301 Effective 1/1/2010:	5-50 MMBtu	42 ppmv or 2.12 lb/MWhr
		>50-150 MMBtu/hr & no retrofit available	42 ppmv or 1.97 lb/MWhr
		>5-150 MMBtu/hr & Water/Steam Injection Enhancement available	35 ppmv or 1.64 lb/MWhr
		>50 150 MMBtu/hr & DLNC available	25 ppmv or 1.17 lb/MWhr
		>150- 250 MMBtu/hr	15 ppmv or 0.70 lb/MWhr
		>250-500 MMBtu/hr	9 ppmv or 0.43 lb/MWhr
		>500 MMBtu/hr	5 ppmv or 0.15 lb/MWhr
		<877 hrs/yr & 50-250 MMBtu/hr	25 ppmv or 1.97 lb/MWhr
		250-500+ MMBtu/yr	25 ppmv or 1.17-0.72 lb/MWhr

[367] 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.
[368] http://www.airquality.org/ProgramCoordination/Documents/rule413.pdf.
[369] Best Available Retrofit Control Technology (BARCT) was to be met by May 31, 1997.
[370] http://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-9-nitrogen-oxides-and-carbon-monoxide-from-stationary-gas-turbines/documents/rg0909.pdf?la=en.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA-SCAQMD[371]	Rule 1134	>0.3-2.9 MW	25 (reference limit) x EFF/25%[372]
	Effective 12/31/95:	2.9-10.0 MW	9 (reference limit) x EFF/25%
		2.9-10.0 MW (no SCR)	15 (reference limit) x EFF/25%
		>10.0 MW	9 (reference limit) x EFF/25%
		>10.0 MW and no SCR	12 (reference limit) x EFF/25%
	By 1/1/24:	>0.3 MW	2.5
		Compressor gas turbine	3.5
CA – SJVAPCD[373]	Rule 4703 Tier 3 limits[374]	>0.3 MW to <3 MW	9
		3-10 MW pipeline gas turbine	8 (steady state) and 12 (non-steady state)
		>3-10 MW & <877 hrs/yr	9
		>10 MW & <200 hr/yr	25
		3-10 MW & >877 hrs/yr and >10 MW and 200-877 hrs/yr	5
		>10 MMW	3-5[375]
	Rule 74.23	0.3-2.9 MW	42

[371] http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1134.pdf.
[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%.
[373] https://www.valleyair.org/rules/currntrules/r4703.pdf.
[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.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA – Ventura County APCD[376]		2.9-10.0 MW	25 x EFF/25
		>10.0 MW w/SCR	9 x EFF/24
		>10 MW w/o SCR	15 x EFF/25
		>4.0 MW & <877 hrs/yr	42
	Currently proposed revisions: By 1/1/24:	All turbines	2.5
CA – San Diego APCD[377]	Rule 69.3.1	≥1.0 & <2.9 MW	42
		≥2.9 & <10.0 MW	25 x EFF/25
		≥10.0 MW w/o installed post combustion air pollution controls	15 x EFF/25
		≥10.0 with installed post-combustion air pollution controls	9 x EFF/25
CA-Yolo Solano AQMD[378]	Rule 2.34	0.3-2.9 MW & >877 hrs/yr AND >4 MW & less than 877 hrs/yr	42
		2.9-10 MW	25
		>10.0 MW	9
CA-Imperial County APCD[379]	Rule 400.1	>1 MW & >400 hr/yr	42
CA-Mojave Desert AQMD[380]	Rule 1159	>4MW & >877 hrs/yr	42
CA – Placer County APCD[381]	Rule 250	>0.3-2.9 MW&>877 hrs/yr	42

[376] http://vcapcd.org/Rulebook/Reg4/RULE%2074.23.pdf.
[377] https://ww3.arb.ca.gov/drdb/sd/curhtml/r69-3-1.pdf.
[378] https://ww3.arb.ca.gov/drdb/ys/curhtml/r2-34.pdf.
[379] https://ww3.arb.ca.gov/drdb/imp/curhtml/r400-1.pdf.
[380] https://ww3.arb.ca.gov/drdb/moj/curhtml/r1159.htm.
[381] https://ww3.arb.ca.gov/drdb/pla/curhtml/r250.pdf.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
		>4 MW & <877 hrs/yr	42
		2.9-10 MW	25
		>10.0 MW	9
CA – Tehama County APCD	Rule 4: 37	>0.3 MW (exempt if <4 MW&<877 hrs/yr)	42
TX/Houston Galveston Brazoria Ozone NAA[382]	30 TAC 117.310(a)(11)	Emission specs for mass emission cap and trade >10.0 MW	0.032 lb/MMBtu (9 ppmv)
	30 TAC 117.305(c)	Turbines >10.0 MW	42
	30 TAC 117.2010(c)(5)	1.0< &>10.0 MW	0.15 lb/MMBtu
TX/Dallas[383]	30 TAC 117.410(a)(5)	Emission Specs for 8 hr ozone Demo >10.0 MW	0.032 lb/MMBtu (9 ppmv)
	30 TAC 117.405(b)(3)	RACT >10,000 hp	0.15 lb/MMBtu
TX/Beaumont Port Arthur[384]	30 TAC 117.105 (c)	RACT>10.0 MW	42
GA (45 county area – ozone)	Rule 391-3-1-.02.(2)(nnn)1.(i) This appears to be an existing source requirement, with compliance required by 5/1/03	>25 MW, permitted <4/1/00	30
	Rule 391-3-1-.02.(2)(nnn)1.(iii)	>25 MW, permitted after 4/1/00[385]	6
WI (Milwaukee 7 county area)[386]	NR 428.22(1)(g)	>50 MW	25

[382] https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=5&ti=30&pt=1&ch=117&sch=B&div=3&rl=Y.
[383] https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=5&ti=30&pt=1&ch=117&sch=B&div=4&rl=Y.
[384] https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=117&rl=105.
[385] This appears to be a new source requirement because compliance was required upon startup.
[386] https://docs.legis.wisconsin.gov/code/admin_code/nr/400/428/IV/22.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
		25-50 MW	42
NJ[387]	7:27-19.5(d)	>25 MMBtu/hr (case by case exemptions allowed for limits on water supply or no commercially available DLNCs)	2.2 lb/MWhr
	7:27-19.5(g)1 (Table 7)	HEDD Simple Cycle Gas Turbine (Power Generators) >15 MW	1.00 lb/MWhr
DE[388]	Title 7, §1112.3.5 (Table 3-2)	Gas turbines >15 MMBtu/hr	42
IL (Chicago are and Metro East area)[389]	Title 35 Part 217, §217.388a.1.E.	Gas turbines >2.5 MW (4,694 bhp)	42
PA[390]	Ch. 129.97(g)(2)(iv)	Gas turbines > 6,000bhp	42
MD (certain counties)[391]	COMAR 26.11.09.08G(2)	Turbines with Capacity Factor >15%	42
VA (northern VA)[392]	9VAC5-40-7430 (9VAC5-40-7410 requires compliance with RACT)	Turbines >10 MMBtu/hr RACT Limit	42
OH (Cleveland 8 county area)[393]	3745-110-03(E)(1)	>3.5 MW	42
CT[394]	22a-174-22e	Simple Cycle combustion turbines>5 MMBtu/hr	55

[387] https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf.
[388] http://regulations.delaware.gov/AdminCode/title7/1000/1100/1112.shtml#TopOfPage.
[389] http://www.epa.state.il.us/air/rules/rice/217-subpart-q.pdf.
[390] http://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/025/chapter129/s129.97.html&searchunitkeywords=129.97&origQuery=129.97&operator=OR&title=null.
[391] http://mdrules.elaws.us/comar/26.11.09.08.
[392] https://law.lis.virginia.gov/admincode/title9/agency5/chapter40/section7430/.
[393] https://www.epa.ohio.gov/portals/27/regs/3745-110/3745-110-03_Final.pdf.
[394] https://www.ct.gov/deep/lib/deep/air/regulations/20160114_draft_sec22e_dec2015(revised).pdf.

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
		Phase I limits (2018-2023) Ozone Season	50
MA[395]	310 CMR 7.19:(7)(a)1	>25 MMBtu/hr	65
NY[396]	6CRR-NY 227-2-4(e)	>10 MMBtu/hr	50
	6CRR-NY 227-3.4(a)(2) New Rule – compliance by 5/1/25[397]	>15 MW	25
LA (Baton Rouge 5 Counties & Region of Influence)[398]	LAC 33.03, Chapter 22, §2201.D.1 (Table D-1A)[399]	≥5-10 MW	0.24 lb/MMBtu (65 ppmv)
		≥10 <MW	0.16 lb/MMBtu (43 ppmv)
MO (St Louis Area)[400]	10 CSR 10-5.510(3)(C)1	>10 MMBtu/hr	75
NC (Charlotte 6 County Area)[401]	15A NCAC 02D.1408	>100 and ≤ 250 MMBtu/hr	75

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),

395 https://www.mass.gov/files/documents/2018/01/05/310cmr7.pdf.
396 https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).
397 https://www.dec.ny.gov/regulations/116185.html.
398 https://www.deq.louisiana.gov/resources/category/regulations-lac-title-33.
399 These are emission factors, used in setting facility emission caps.
400 https://www.sos.mo.gov/cmsimages/adrules/csr/current/10csr/10c10-5.pdf.
401 https://files.nc.gov/ncdeq/Air%20Quality/rules/rules/D1408.pdf.

which were adopted in 2007, also reflect application of SCR.[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.[403] In addition, SCR was proposed to be installed at the Charles Compressor Station to be located in Maryland,[404] the Northampton Compressor Station to be located in North Carolina,[405] and the Marts Compressor Station to be located in West Virginia.[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 GAS-FIRED COMBUSTION TURBINES IN THE OIL AND GAS INDUSTRY.

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

[402] *See* September 2007, SJVAPCD, Amendments to Rule 4703 (Stationary Gas Turbines), Initial Study and Negative Declaration, at 5, *available at*: https://www.valleyair.org/notices/Docs/priorto2008/08-08-07/Negative%20Declaration.pdf. The fact that these limits require SCR to meet is reflected in permits for two compressor stations – the Wheeler Ridge Compressor Station and the Kettleman Compressor Station. *See* March 25, 2015 Title V Permit for Southern California Gas Co. Wheeler Ridge Compressor Station, *available at*: https://www.valleyair.org/notices/Docs/2015/03-25-15_(S-1134792)/S-1134792.pdf; February 5, 2018 Title V Permit for Pacific Gas and Electric Company – Kettleman Compressor Station, *available at*: http://www.valleyair.org/notices/Docs/2018/2-5-18_(C-1161601)/C-1161601.pdf.

[403] *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.

[404] *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.

[405] *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.

[406] *See* Permit No. R13-3271, issued July 21, 2016, *available at*: https://dep.wv.gov/daq/Documents/July%202016%20Permits%20and%20Evals/041-00076_PERM_13-3271.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.[407] 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 that natural gas-fired RICE.[408] However,

[407] EPA, AP-42, Section 3.1, Tables 3.1-1 and 3.1-2, *available at*: https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf.

[408] 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.

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.[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.[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.[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.[412] That said, the data collected by CARB in 2004 indicated 31 natural gas-fired combustion turbines using oxidation catalyst.[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,[414] the Charles Compressor Station to be located in Maryland,[415] the Northampton Compressor Station to be located in North Carolina,[416] and the Marts Compressor Station to be located in West Virginia.[417] These draft and final permits provide

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[409] EPA AP-42, Introduction at 8-10.

[410] EPA, AP-42, Section 3.1, at 3.1-7.

[411] *See* CARB, Report to the Legislature, Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts, May 2004, Appendix A, *available at*: https://ww3.arb.ca.gov/research/apr/reports/l2069.pdf.

[412] *See* December 11, 2018 Memo from RTI International to Melanie King, EPA, at 3, in EPA's docket for its Risk and Technology Review for the Stationary Gas Turbine NESHAP, Docket ID EPA-HQ-OAR-2017-0688-0066, *available at*: www.regulations.gov.

[413] *See* CARB, Report to the Legislature, Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts, May 2004, Appendix A.

[414] *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.

[415] *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.

[416] *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.

[417] *See* Permit No. R13-3271, issued July 21, 2016, *available at*: https://dep.wv.gov/daq/Documents/July%202016%20Permits%20and%20Evals/041-00076_PERM_13-3271.pdf.

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.

Exhibit 5

UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF KANSAS

UNITED STATES OF AMERICA, the STATE OF ARKANSAS on behalf of the Arkansas Department of Environmental Quality, the IDAHO DEPARTMENT OF ENVIRONMENTAL QUALITY, the STATE OF KANSAS, STATE OF MONTANA ex rel. DEPARTMENT OF ENVIRONMENTAL QUALITY, the STATE OF NEBRASKA on behalf of the Nebraska Department of Environmental Quality, the STATE OF OREGON on behalf of the Oregon Department of Environmental Quality, the STATE OF UTAH on behalf of the Utah Department of Environmental Quality, the WASHINGTON STATE DEPARTMENT OF ECOLOGY, and the PUGET SOUND CLEAN AIR AGENCY	)	NO: ______________
Plaintiffs,	)	
v.	)	
ASH GROVE CEMENT COMPANY	)	
Defendant.	)	

CONSENT DECREE

TABLE OF CONTENTS

WHEREAS, Plaintiff, the United States of America, on behalf of the United States Environmental Protection Agency (herein "U.S. EPA") has, simultaneously with the lodging of this Consent Decree, filed a Complaint against Defendant Ash Grove Cement Company ("Defendant"), pursuant to Sections 113(b) and 167 of the Clean Air Act ("Clean Air Act or Act"), 42 U.S.C. §§ 7413(b) and 7477, for injunctive relief and the assessment of civil penalties for violations of one or more of the following statutory and regulatory requirements of the Act at one or more of each of Defendant's Portland cement plants which collectively are located in nine (9) different states within the United States: the Prevention of Significant Deterioration ("PSD") provisions of the Act, 42 U.S.C. §§ 7470-7492; and/or the nonattainment New Source Review ("nonattainment NSR") provisions of the Act, 42 U.S.C. §§ 7501-7515; the New Source Performance Standards ("NSPS") provisions of the Act, 42 U.S.C. § 7411; the federally-approved and enforceable state implementation plans ("SIPs"), which incorporate and/or implement the above-listed federal PSD and/or nonattainment NSR requirements and NSPS Requirements; Title V of the Act, 42 U.S.C. §§ 7661-7661f; and Title V's implementing federal and state regulations;

WHEREAS, this Consent Decree sets forth injunctive relief in which Defendant has agreed to substantially reduce its emissions of sulfur dioxide, nitrogen oxide, and particulate matter at all nine of its Portland cement manufacturing facilities in the United States in such a manner that would resolve Defendant's alleged violations of the PSD, NNSR, NSPS, and Title V requirements of the Act;

WHEREAS, the State of Arkansas on behalf of the Arkansas Department of Environmental Quality, the Idaho Department of Environmental Quality, the State of Kansas, the State of Montana on behalf of the Montana Department of Environmental Quality, the State of

Nebraska on behalf of the Nebraska Department of Environmental Quality, the State of Oregon on behalf of the Oregon Department of Environmental Quality, the State of Utah on behalf of the Utah Department of Environmental Quality, the Washington State Department of Ecology, and the Puget Sound Clean Air Agency (collectively, "State Agency Plaintiffs") have joined as Co-Plaintiffs;

WHEREAS, U.S. EPA has provided notice of the violations alleged herein to the Defendant and to each of the states where Defendant's Facilities identified in the Complaint are located, and to the Puget Sound Clean Air Agency, pursuant to Section 113(a) of the Act, 42 U.S.C. § 7413(a), and Defendant stipulates that it has received actual notice of the violations alleged in the Complaint and that it does not contest the adequacy of the notice provided;

WHEREAS, Defendant denies the allegations of the Complaint of the United States and the State Plaintiffs and does not admit that it has any liability to the United States or the State Plaintiffs for civil penalties or injunctive relief arising out of the transactions and occurrences alleged in the Complaint;

WHEREAS, the Parties recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated by the Parties in good faith and will avoid litigation between the Parties and that this Consent Decree is fair, reasonable, and in the public interest.

NOW, THEREFORE, before the taking of any testimony, without the adjudication or admission of any issue of fact or law except as provided in Section I (Jurisdiction and Venue), below, and with the consent of the Parties, IT IS HEREBY ADJUDGED, ORDERED, AND DECREED as follows:

SECTION I: JURISDICTION AND VENUE

1. This Court has jurisdiction of the subject matter herein and over the Parties consenting hereto pursuant to Sections 113(b), 167, and 304(a) of the Act, 42 U.S.C. §§ 7413(b), 7477, and 7604(a), and pursuant to 28 U.S.C. §§ 1331, 1345, 1355 and 1367(a). Venue is proper under Sections 113(b) and 304(c) of the Act, 42 U.S.C. §§ 7413(b) and 7604(c), and under 28 U.S.C. §§ 1391(b) and (c) and 1395(a). For purposes of this Consent Decree and the underlying Complaint, Defendant waives all objections and defenses it may have to the Court's jurisdiction over this action, to the Court's jurisdiction over the Defendant, and to venue in this District. For the purposes of the Complaint filed by the Plaintiffs in this matter and resolved by the Consent Decree, Defendant waives any defense or objection based on standing.

2. For purposes of this Consent Decree, Defendant agrees that the Complaint states claims upon which relief may be granted pursuant to Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477; Section 111 of the Act, 42 U.S.C. § 7411; and Title V of the Act, 42 U.S.C. §§ 7661-7661f; and Title V's implementing federal and state laws and regulations.

SECTION II: APPLICABILITY

4. The obligations of this Consent Decree apply to and are binding upon the United States, the State Agency Plaintiffs and upon the Defendant, and any successors, assigns, or other entities or persons otherwise bound by law.

5. At least 30 Days prior to any transfer of ownership or operation of any Facility identified in Paragraph 8.x, Defendant shall provide a copy of this Consent Decree to the proposed transferee and shall simultaneously provide written notice of the prospective transfer, together with a copy of the proposed written agreement, to U.S. EPA, the United States, and the Affected State(s) in accordance with Section XXI (Notices) of this Consent Decree. No transfer

of ownership or operation of a Facility identified in Paragraph 8.x, whether in compliance with the procedures of this Paragraph or otherwise, shall relieve Defendant of its obligation to ensure that the terms of the Decree are implemented, unless:

a. the transferee agrees, in writing, to undertake the obligations required by Sections V (NO_x Control Technology, Emission Limits, and Monitoring Requirements), VI (SO_2 Control Technology, Emission Limits, and Monitoring Requirements), Section VII (PM Control Technology, Emission Limits and Monitoring Requirements), Section IX (Temporary Cessation of Kiln Operation), Section XI (Prohibition on Netting Credits or Offsets from Required Controls), Section XII (Permits), Section XIII (Review and Approval of Submittals), Section XIV (Reporting Requirements), Section XV (Stipulated Penalties), Section XVI (Force Majeure), Section XVII (Dispute Resolution), Section XVIII (Information Collection and Retention) and the requirements of Appendix A, B, and C of this Consent Decree applicable to such Facility and further agrees in writing to be substituted for the Defendant as a Party under the Decree with respect to such Facility and thus become bound by the terms thereof;

b. the United States and the Affected State(s) determine that the transferee has the financial and technical ability to assume the Consent Decree's obligations applicable to such Facility;

c. the United States and the Affected State(s) consent, in writing, to relieve Defendant of its Consent Decree obligations applicable to such Facility; and

d. the transferee becomes a party to this Consent Decree with respect to the transferred Facility, pursuant to Section XXIV (Modification).

5. Any attempt to transfer ownership or operation of any of the Facilities identified in Paragraph 8.x, or any portion thereof, without complying with Paragraph 4 constitutes a violation of this Consent Decree.

6. The Defendant shall provide a copy of this Consent Decree to all officers, employees, and agents whose duties might reasonably include compliance with any provision of this Decree, as well as to any contractor retained to perform work required under this Consent Decree. Defendant shall condition any such contract upon performance of the work in conformity with the terms of this Consent Decree.

7. In any action to enforce this Consent Decree, Defendant shall not raise as a defense the failure by any of its officers, directors, employees, agents, or contractors to take any actions necessary to comply with the provisions of this Consent Decree.

SECTION III: DEFINITIONS

8. Terms used in this Consent Decree that are defined in the Act or in regulations promulgated by U.S. EPA pursuant to the Act shall have the meanings assigned to them in the Act or such regulations, unless otherwise provided in this Decree. Definitions stated in this Consent Decree are exclusively for the purpose of interpreting and applying the Consent Decree terms and are not intended to establish any type of determination under circumstances not covered by the Consent Decree. Whenever the terms set forth below are used in this Consent Decree, the following definitions shall apply:

a. "12-Month Rolling Tonnage Limit" shall mean, with respect to Midlothian Kiln 3 after Reconstruction and the Montana City Kiln after Replacement, the maximum allowable tons of emission of a specified air pollutant from such Kiln during any consecutive period of twelve months, expressed as Tons of such air pollutant.

Compliance with the 12-Month Rolling Tonnage Limit for NO_x or SO_2 shall be determined on a monthly basis by summing the total Tons of air pollutant in question emitted from the Kiln during the most recent complete month and the previous eleven (11) months, as measured pursuant to Section V.B. (NO_x Continuous Emission Monitoring Systems) or Section VI.B. (SO_2 Continuous Emission Monitoring Systems), of this Consent Decree. Compliance with the 12-Month Rolling Tonnage Limit for PM shall be determined on a monthly basis by compliance with the performance testing and continuous parametric monitoring requirements in Section VII.B (PM Continuous Parametric Monitoring Systems). A new compliance determination of the 12-Month Rolling Tonnage Limit shall be calculated for each new complete month in accordance with the provisions of this Consent Decree. In calculating each compliance determination of the 12-Month Rolling Tonnage Limit for NO_x and SO_2 at any Kiln, the total Tons of such air pollutant emitted from the Kiln shall include all emissions of that air pollutant during each Startup, Shutdown, or Malfunction that occurs during the 12-month period at issue.

b. "30-Day Rolling Average Emission Limit" shall mean, with respect to any Kiln at a Facility, the maximum allowable rate of emission of a specified air pollutant from such Kiln or Kilns, as applicable, and shall be expressed as pounds of such air pollutant emitted per Ton of clinker produced. Compliance with the 30-Day Rolling Average Emission Limit shall be determined in accordance with the following procedure, beginning on the date on which the 30-Day Rolling Average Emission Limit applies pursuant to Appendix A, or pursuant to Section V (NO_x Control Technology, Emission Limits and Monitoring Requirements), or Section VI (SO_2

Control Technology, Emission Limits and Monitoring Requirements): first, sum the total pounds of the air pollutant in question emitted from the Kiln or Kilns during that Operating Day and the previous twenty-nine (29) Operating Days as measured pursuant to Section V.B. (NO_x Continuous Emission Monitoring Systems), or Section VI.B. (SO_2 Continuous Emission Monitoring Systems), as applicable; second, sum the total Tons of clinker produced by the Kiln or Kilns during the same Operating Day and previous 29 Operating Days; and third, divide the total number of pounds of the air pollutant emitted from the Kiln or Kilns during the thirty (30) Operating Days by the total Tons of clinker produced by such Kiln or Kilns during the same 30 Operating Days. A new compliance determination of the 30-Day Rolling Average Emission Limit shall be calculated for each new Operating Day in accordance with the provisions of this Consent Decree. In calculating each compliance determination of the 30-Day Rolling Average Emission Limit in accordance with this Paragraph 8.b, for NO_x or SO_2 at any Facility, the total pounds of such air pollutant emitted from the Kiln or Kilns during a specified period (Operating Day or 30-Day Period) shall include all emissions of that pollutant from the subject Kiln that occur during the specified period, including emissions during each Startup, Shutdown, or Malfunction, except to the extent a Malfunction qualifies as a Force Majeure event under Section XVI and Defendant has complied with the requirements of that Section. Compliance with the 30-Day Rolling Average Emission Limits established in Section VII (PM Control Technology, Emission Limits and Monitoring Requirements) shall be demonstrated by operating the PM CPMS at each Kiln consistent with the performance testing and continuous parametric monitoring requirements in Section VII.B (PM Continuous Parametric Monitoring Systems).

c. "30-Day Rolling Average Emission Rate" shall mean, with respect to each Kiln subject to Appendix A, the rate of emission of NO_x expressed as pounds (lbs.) per Ton of clinker produced at such Kiln(s) and calculated in accordance with the following procedure: first, sum the total pounds of the pollutant in question emitted from the specified Kiln(s) during an Operating Day and the previous twenty-nine (29) Operating Days, as measured pursuant to Section V.B. (NO_x Continuous Emission Monitoring Systems); second, sum the total Tons of clinker produced by that Kiln during the same Operating Day and previous 29 Operating Days; and third, divide the total number of pounds of NO_x emitted from the Kiln(s) during the thirty (30) Operating Days referred to above by the total Tons of clinker produced at such Kiln(s) during the same 30 Operating Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Operating Day. In calculating each 30-Day Rolling Average Emission Rate, the total pounds of NO_x emitted from a Kiln during a specified period (Operating Day or 30-Day Period) shall include all emissions of that pollutant from the subject Kiln that occur during the specified period, including emissions during each Startup, Shutdown, or Malfunction, except to the extent a Malfunction qualifies as a Force Majeure event under Section XVI and Defendant has complied with the requirements of that Section;

d. "Affected State" shall mean any State Agency Plaintiff having jurisdiction over a Facility addressed in this Consent Decree;

e. “Baghouse” shall mean a pollution control system used for the removal and collection of Particulate Matter from Kiln flue gases;

f. “Business Day” means any Day, except for Saturday, Sunday, and federal holidays. In computing any period of time used as a deadline for submission under this Consent Decree, where the last Day would fall on a Saturday, Sunday, or federal holiday, the period shall run until the close of business of the next Business Day;

g. “CEMS” or “Continuous Emission Monitoring System” shall mean, for obligations involving NO_x and SO_2, under this Consent Decree, the total equipment and software required to sample and condition (if applicable), to analyze, and to provide a record of NO_x and SO_2 emission rates, and the raw data necessary to support the reported emission rates, and that have been installed and calibrated in accordance with 40 C.F.R. § 60.13 and 40 C.F.R. Part 60 Appendix B and Appendix F;

h. “CPMS” or “Continuous Parametric Monitoring System” shall mean, for obligations involving PM under this Consent Decree, the total equipment and software required to establish and monitor a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit in accordance with 40 C.F.R. § 63.1350;

i. “Commence” or “Commencement” of operation of a Control Technology shall mean to begin the introduction of the reagent employed by the Control Technology, as applicable to that technology, or where the technology is otherwise activated;

j. “Complaint” shall mean the complaint filed by the United States and State Agency Plaintiffs in this action;

k. “Consent Decree” or “Decree” shall mean this Decree and each Appendix attached hereto (listed in Section XXX (Appendices)), but in the event of any conflict between the text of this Decree and any Appendix, the text of this Decree shall control;

l. “Continuously Operate” or “Continuous Operation” shall mean that when a Control Technology is used at a Kiln, it shall be operated at all times of Kiln Operation, excluding Malfunction of the Control Technology, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for such Control Technology and the Kiln. For example, the requirement to continuously operate SNCR does not require that the SNCR be operated under conditions where the Kiln has not reached or is no longer maintaining the minimum temperature for reagent injection.

m. “Contractor” shall mean any person or entity hired by Defendant to perform services on its behalf necessary to comply with the provisions of this Consent Decree;

n. “Control Technology” shall mean Selective Non-Catalytic Reduction; Dry Absorbent Addition; Semi-Dry Flue Gas Desulphurization (“Semi-Dry Scrubber”); or Baghouse.

o. “Date of Lodging of the Consent Decree” or “Date of Lodging” shall mean the date the Consent Decree is filed for lodging with the Clerk of the Court for the United States District Court for the District of Kansas;

p. “Day” shall mean a calendar day unless expressly stated to be a Business Day;

q. “Defendant” or “Ash Grove” shall mean Ash Grove Cement Company;

r. “Demonstration Phase” shall mean that period of time identified in Appendix A, following optimization, and at the conclusion of which, Defendant will propose a 30-Day Rolling Average Emission Limit for NO_x that is achievable through the implementation of SNCR Control Technology at the Montana City Kiln, and that is consistent with optimized operation of the Louisville ACL Kiln and Seattle Kiln, and that will be applied in accordance with Sections V (NO_x Control Technology, Emission Limits, and Monitoring Requirements) of this Consent Decree;

s. "Demonstration Phase 30-Day Rolling Average Emission Limit" shall mean the 30-Day Rolling Average Emission Limit that applies upon Defendant's commencement of Continuous Operation of SNCR Control Technology at the Montana City Kiln and until the Defendant proposes a 30-Day Rolling Average Emission Limit for NO_x applicable to the Montana City Kiln in accordance with the procedures of Appendix A to this Consent Decree;

t. "Dry Absorbent Addition" or "DAA" shall mean a pollution control system that combines a dry alkaline reagent directly with the Kiln gas stream to achieve the reduction of sulfur dioxide emissions;

u. "Effective Date" shall have the meaning given in Paragraph 138;

v. "Emission Limit" shall mean the maximum allowable Emission Rate of a specified air pollutant from any Kiln or Kilns and shall be expressed as pounds of such air pollutant emitted per Ton of clinker produced;

w. "Emission Rate" for a specified air pollutant from any Kiln or Kilns shall mean the number of pounds of such air pollutant emitted per Ton of clinker measured in accordance with this Consent Decree.

x. "Facilities" shall mean the following nine (9) Portland cement manufacturing facilities used for the production of Portland cement. Each of these facilities may be referred to as a "Facility."

(1) Foreman Cement Plant, 4343 Highway 108, Foreman, Arkansas, 71836 (hereinafter "Foreman, Arkansas");

(2) Chanute Cement Plant, 1801 Santa Fe Ave., Chanute, Kansas, 66720 (hereafter "Chanute, Kansas");

(3) Durkee Cement Plant, 33060 Shirttail Creek Rd., Durkee, Oregon 97905-0287 (hereinafter "Durkee, Oregon");

(4) Leamington Cement Plant, 600 West Highway 132, Leamington, Utah 84638 (hereinafter "Leamington, Utah");

(5) Seattle Cement Plant, 3801 E. Marginal Away, S., Seattle, Washington 98134-1147 (hereinafter "Seattle, Washington");

(6) Louisville Cement Plant, 16215 Highway 50, Louisville, Nebraska 68037 (hereinafter "Louisville, Nebraska");

(7) Midlothian Cement Plant, 900 Gifco Road, Midlothian, Texas 76065 (hereinafter "Midlothian, Texas");

(8) Montana City Cement Plant, 100 Highway 518, Clancy, Montana 59634-9701 (hereinafter "Montana City, Montana");

(9) Inkom Cement Plant, 230 Cement Road, Inkom, Idaho 83245-1543 (hereinafter "Inkom, Idaho");

y. "Kiln" as used in this Consent Decree shall mean a device, including any associated preheater or precalciner devices, inline raw mills, inline coal mills or alkali bypasses that produces clinker by heating limestone and other materials for subsequent production of portland cement. Because the inline raw mill is considered an integral part of the Kiln, for purposes of determining the appropriate emissions limit, the term

Kiln also applies to the exhaust of the inline raw mill. The following are identified as the individual Kilns at each Facility:

(1) Foreman, Arkansas: Foreman Kiln 4;

(2) Chanute, Kansas: Chanute Kiln 1;

(3) Durkee, Oregon: Durkee Kiln 1;

(4) Leamington, Utah: Leamington Kiln 1;

(5) Seattle, Washington: Seattle Kiln 1 or "the Seattle Kiln";

(6) Louisville, Nebraska: Louisville ACL Kiln , Louisville HW Kiln;

(7) Midlothian, Texas: Midlothian Kiln 1, Midlothian Kiln 2, Midlothian Kiln 3;

(8) Montana City, Montana: Montana City Kiln 1 or "the Montana City Kiln"; and

(9) Inkom, Idaho: Inkom Kiln 1, Inkom Kiln 2.

z. "Kiln Operation" shall mean any period when any raw materials are fed into the Kiln and any combustion is occurring in the Kiln;

aa. "Malfunction" as used in this Consent Decree shall have the same meaning as defined at 40 C.F.R. § 60.2;

bb. "National Ambient Air Quality Standards" or "NAAQS" shall mean national ambient air quality standards that are promulgated pursuant to Section 109 of the Act, 42 U.S.C. § 7409;

cc. "New Source Performance Standards" or "NSPS" shall mean those standards and emission limitations applicable to the emissions of NO_x, SO_2, and PM from existing, modified or reconstructed Portland cement manufacturing facilities, codified at 40 C.F.R. Part 60, Subpart F;

dd. “NO_x” shall mean oxides of nitrogen, measured in accordance with the provisions of this Consent Decree;

ee. “Non-attainment NSR” shall mean the non-attainment area New Source Review (NSR) program within the meaning of Part D of Subchapter I of the Act, 42 U.S.C. §§ 7501-7515, 40 C.F.R. Part 51, and any applicable State Implementation Plan.

ff. “Operating Day” shall mean any Day on which Kiln Operation has occurred;

gg. “Operating Month” shall mean any calendar month in which Kiln Operation has occurred;

hh. “Paragraph” shall mean a portion of this Decree identified by an Arabic numeral;

ii. “Particulate,” “Particulate Matter” or “PM” shall have the same meaning as in 40 C.F.R. Part 63, Subpart LLL.

jj. “Parties” shall mean the United States, the State Agency Plaintiffs and their agencies and political subdivisions having jurisdiction over a Facility, and Ash Grove;

kk. “PSD” shall mean the Prevention of Significant Deterioration program within the meaning of Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-7492, 40 C.F.R. Part 52, and any applicable State Implementation Plan;

ll. “Reconstruct” or “Reconstruction” shall mean the replacement of components of an existing Kiln to such an extent that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new Kiln. For purposes of this definition, "fixed capital cost" shall mean the capital needed to provide all the depreciable components. The evaluation as to whether a Kiln has been Reconstructed shall be performed consistent with guidance issued by EPA in applying the definition of "reconstruction" in 40 C.F.R. § 60.15(b).

mm. "Replace" or "Replacement" shall mean the construction of a new Kiln or Reconstruction of an existing Kiln at the Montana City Facility pursuant to Section V (NO_x Control Technology, Emission Limits, and Monitoring Requirements), Section VI (SO_2 Control Technology, Emission Limits, and Monitoring Requirements) or Section VII (PM Control Technology, Emission Limits, and Monitoring Requirements) of this Consent Decree;

nn. "Retire" or "Retirement" shall mean, with respect to any Kiln, (1) to permanently Shut Down the Kiln; and (2) to file an application in accordance with the Affected State's SIP to remove permanently any legal authorization for further operation of the Kiln;

oo. "Section" shall mean a portion of this Decree identified by a Roman numeral;

pp. "Selective Non-Catalytic Reduction" or "SNCR" shall mean a pollution control system that injects an ammonia-based reagent into the gas stream without the use of a catalyst for the purpose of reducing NO_x emissions;

qq. "Shut Down" shall mean the cessation of kiln operation. Shutdown begins when feed to the kiln is halted and ends when continuous kiln rotation ceases;

rr. "Site Specific Operating Limit" or "SSOL" is the parametric limit used to monitor the operation of the particulate control device. The SSOL is also referred to as the "site specific CPMS limit" in 40 CFR Part 63 Subpart LLL. The SSOL requirements are contained in paragraph 60 and Appendix C of this Decree.

ss. "SO_2" shall mean the pollutant sulfur dioxide, measured in accordance with the provisions of this Consent Decree;

tt. "Startup" shall mean the time from when a shutdown kiln first begins firing fuel until it begins producing clinker. Startup begins when a shutdown kiln turns on the induced draft fan and begins firing fuel in the main burner. Startup ends when feed is being continuously introduced into the kiln for at least 120 minutes or when the feed rate exceeds 60 percent of the kiln design limitation rate, whichever occurs first;

uu. "State Agency Plaintiff" or "State" shall mean any of the following: the State of Arkansas on behalf of the Arkansas Department of Environmental Quality, the Idaho Department of Environmental Quality, the State of Kansas, the State of Montana on behalf of the Montana Department of Environmental Quality, the State of Nebraska on behalf of the Nebraska Department of Environmental Quality, the State of Oregon on behalf of the Oregon Department of Environmental Quality, the State of Utah on behalf of the Utah Department of Environmental Quality, the Washington State Department of Ecology, and the Puget Sound Clean Air Agency. State Agency Plaintiff shall include, for the foregoing, any agencies and political subdivisions having jurisdiction over a Facility;

vv. "Temporary Cessation," "Temporary Cessation of Kiln Operation" or "Temporarily Cease Kiln Operation" shall mean the period when a Kiln is not in a state of Kiln Operation and Defendant has provided the required notice pursuant to Paragraph 67 of Section IX (Temporary Cessation of Kiln Operation) of this Consent Decree;

ww. "Title V permit" shall mean a permit required by and issued in accordance with the requirements of 42 U.S.C. §§ 7661 - 7661f;

xx. "Ton" or "Tons" shall mean short ton or short tons;

yy. "United States" shall mean the United States of America, acting on behalf of U.S. EPA;

zz. "U.S. EPA" shall mean the United States Environmental Protection Agency and any of its successor departments or agencies; and

aaa. "Semi -Dry Flue Gas Desulphurization System," "Semi-Dry FGD," or "Semi-Dry Scrubber" shall mean a pollution control system that employs semi-dry gas scrubber technology to achieve the reduction of sulfur dioxide emissions.

SECTION IV: CIVIL PENALTY

9. Within thirty (30) Days after the Effective Date of this Consent Decree, Defendant shall pay to the United States as a civil penalty the sum of $1,666,000 together with interest accruing from the Effective Date through the date of payment, at the rate specified in 28 U.S.C. § 1961 as of the Effective Date. Defendant shall pay the civil penalty due under this Paragraph 9 by FedWire Electronic Funds Transfer ("EFT") to the U.S. Department of Justice in accordance with written instructions to be provided to Defendant following lodging of the Consent Decree by the Financial Litigation Unit of the U.S. Attorney's Office for the District of Kansas, 1200 Epic Center, 301 N. Main, Wichita, Kansas, 67202. At the time of payment, Defendant shall send a copy of the EFT authorization form and the EFT transaction record,

together with a transmittal letter, which shall state that the payment is for the civil penalty owed pursuant to the Consent Decree in United States, *et al.* v. Ash Grove Cement Company, and shall reference the civil action number and DOJ case number 90-5-2-1-09875, to the United States in accordance with Section XXI of this Decree (Notices); by email to acctsreceivable.CINWD@epa.gov; and to:

U.S. EPA Cincinnati Finance Office
26 Martin Luther King Drive
Cincinnati, Ohio 45268.

10. Within thirty (30) Days after the Effective Date of this Consent Decree, Defendant shall pay civil penalties, together with interest accruing from the Effective Date through the date of payment at the rate identified in Paragraph 9, in the following amounts to the following Affected States in accordance with the payment instructions below:

State Agency	**Amount**	**Payment Instructions**
State of Arkansas	$103,000	Arkansas Department of Environmental Quality Fiscal 5301 Northshore Drive North Little Rock, AR 72118-5317

Idaho Department of Environmental Quality	$103,000	Check payable in amount of $77,250, stating "Wood Stove Change-Out Supplemental Environmental Project" in the memo line and mailed to: Fiscal Office Idaho Department of Environmental Quality 1410 N. Hilton Boise, Idaho 83706 Check payable in amount of $25,750, stating "Civil Penalty Payment" in memo line and mailed to: Fiscal Office Idaho Department of Environmental Quality 1410 N. Hilton Boise, Idaho 83706
State of Kansas	$113,000	Check payable and mailed to: Kansas Department of Health and Environment Address: Kansas Department of Health and Environment 1000 SW Jackson Street, Suite 310 Topeka, Kansas 66612-1366 Attn: Sheila Pendleton The memorandum portion of the check shall identify the case number.
State of Montana	$103,000	Check or money order, made payable to the "Montana Department of Environmental Quality," and sent to the Department at John L. Arrigo, Administrator Enforcement Division Department of Environmental Quality 1520 East Sixth Avenue P.O. Box 200901 Helena, MT 59620-0901

State of Nebraska	$103,000	Checks shall be made to Cass County District Court Clerk and shall be mailed with notice referring to this action, to: Katherine J. Spohn Deputy Attorney General 2115 State Capitol Lincoln, NE 68508-8920
State of Oregon	$103,000	In accordance with Oregon DEQ's directive on state Supplemental Environmental Projects (SEPs), Defendant shall fund a SEP for woodstove change outs in Lakeview, Oregon per the application submitted to DEQ from the South Central Oregon Economic Development District (SCOEDD). Check in the amount of $82,400 payable to SCOEDD with SEP in the memo line, mailed to: SCOEDD c/o Betty Riley PO Box 1529 Klamath Falls, OR 97601 Check in the amount of $20,600 payable to State Treasurer, State of Oregon, mailed to: DEQ, Business Office 811 S.W. Sixth Avenue Portland, OR 97204
State of Utah	$103,000	Check payable and mailed to: Utah Division of Air Quality Multi Agency State Office Building 195 North 1950 West, Fourth Floor Salt Lake City, Utah 84116

Washington State Department of Ecology	$20,600	Check payable and mailed to: Department of Ecology Cashiering Unit P.O. Box 47611 Olympia, WA 98504-7611 The Memorandum on the check should reference NR13168001 and "Ash Grove Settlement"
Puget Sound Clean Air Agency	$82,400	Check payable to "Puget Sound Clean Air Agency": Craig Kenworthy Executive Director Puget Sound Clean Air Agency 1904 3rd Ave, Suite 105 Seattle WA USA 98101
TOTAL	**$834,000**	

11. Defendant shall not deduct any penalties paid under this Section in calculating its federal or state or local income tax.

SECTION V: NO_x CONTROL TECHNOLOGY, EMISSION LIMITS AND MONITORING REQUIREMENTS

A. NO_x Control Technology and Emission Limits

12. Subject to Section IX (Temporary Cessation of Kiln Operation), Defendant shall install the NO_x Control Technology and comply with the Emission Limits for the specific Kilns within its system according to Paragraphs 13 through 31. Defendant shall Continuously Operate each NO_x Control Technology.

Foreman, Arkansas

13. Defendant shall have installed and Commenced Continuous Operation of the SNCR technology at Foreman Kiln 4 by the date specified in the table below in this Paragraph 13:

Kiln	Control Technology	Date of Installation and Deadline for Commencement of Continuous Operation	30-Day Rolling Average Emission Limit (lbs. NO_x /Ton of clinker)
Kiln 4	SNCR	12/31/15	1.5

Defendant shall Continuously Operate the SNCR technology by no later than the date specified in the table above.

14. Beginning on the Operating Day which is the 30th Operating Day after the date by which Defendant is required to Commence Continuous Operation of the SNCR technology at Foreman Kiln 4 identified in Paragraph 13, Defendant shall demonstrate compliance and thereafter maintain compliance with the 30-Day Rolling Average Emission Limit for NO_x specified in Paragraph 13 at that Kiln.

Chanute, Kansas

15. Defendant shall have installed and Commenced Continuous Operation of the SNCR technology at Chanute Kiln 1 by the date specified in the table below in this Paragraph 15:

Kiln	Control Technology	Date of Installation and Deadline for Commencement of Continuous Operation	30-Day Rolling Average Emission Limit (lbs. NO_x /Ton of clinker)
Kiln 1	SNCR	12/31/15	1.5

Defendant shall Continuously Operate the SNCR technology by no later than the date specified in the table above.

16. Beginning on the Operating Day which is the 30th Operating Day after the date by which Defendant is required to Commence Continuous Operation of the SNCR technology at Chanute Kiln 1 identified in Paragraph 15 Defendant shall demonstrate compliance and

thereafter maintain compliance with the 30-Day Rolling Average Emission Limit for NO_x specified in Paragraph 15 at that Kiln.

Durkee, Oregon

17. Defendant shall have installed and Commenced Continuous Operation of the SNCR technology at Durkee Kiln 1 by the date specified in the table below in this Paragraph 17:

Kiln	Control Technology	Date of Installation and Deadline for Commencement of Continuous Operation	30-Day Rolling Average Emission Limit (lbs. NO_x /Ton of clinker)
Kiln 1	SNCR	3/31/15	2.0

Defendant shall Continuously Operate the SNCR technology by no later than the date specified in the table above.

18. Beginning on the Operating Day which is the 30^{th} Operating Day after the date by which Defendant is required to Commence Continuous Operation of the SNCR technology at Durkee Kiln 1 identified in Paragraph 17, Defendant shall demonstrate compliance and thereafter maintain compliance with the 30-Day Rolling Average Emission Limit for NO_x specified in Paragraph 17 at that Kiln.

Leamington, Utah

19. Defendant shall have installed and Commenced Continuous Operation of the SNCR Control Technology at Leamington Kiln 1 by the date specified in the table below in this Paragraph 19:

Kiln	Control Technology	Date of Installation and Deadline for Commencement of Continuous Operation	30-Day Rolling Average Emission Limit (lbs. NO_x /Ton of clinker)
Kiln 1	SNCR	12/10/2013	2.8

Defendant shall Continuously Operate the SNCR technology by no later than the date specified in the table above.

20. Beginning on the Operating Day which is the 30th Operating Day after the date by which Defendant is required to Commence Continuous Operation of the SNCR technology at Leamington Kiln 1 identified in Paragraph 19, Defendant shall demonstrate compliance and thereafter maintain compliance with the 30-Day Rolling Average Emission Limit for NO_x specified in Paragraph 19 at that Kiln. Defendant need not demonstrate compliance at the stack venting exhaust gases from the Leamington coal mill. However, Defendant shall control indirect-fired coal mill feed gas from the kiln exhaust according to the standard protocol of the coal mill system. Defendant shall not adjust, increase or activate the coal mill feed gas in order to affect the emissions at the main stack in any way or to reduce the amount of reagent Ash Grove uses in the SNCR.

Seattle, Washington

21. Defendant shall submit pursuant to Section XXI of this Consent Decree (Notices) an optimization protocol for the Seattle Kiln in accordance with the applicable procedures of Appendix A to this Consent Decree, hereinafter the Seattle Kiln NO_x Emission Reduction Report, for the purpose of optimizing the operation of the Seattle Kiln to reduce NO_x emissions to the maximum extent practicable from that Kiln. The Seattle Kiln NO_x Emission Reduction Report shall conform to the applicable procedures set forth in Appendix A for the establishment of a 30-Day Rolling Average Emission Limit for NO_x at the Seattle Kiln. Consistent with the requirements and deadlines specified in Appendix A, Defendant shall demonstrate compliance and thereafter maintain compliance with the proposed 30-Day Rolling Average Emission Limit for NO_x at the Seattle Kiln. Defendant need not demonstrate compliance at the stack venting

exhaust gases from the Seattle coal mill. However, Defendant shall control indirect-fired coal mill feed gas from the kiln exhaust according to the standard protocol of the coal mill system. Defendant shall not adjust, increase or activate the coal mill feed gas in order to affect the emissions at the main stack in any way.

22. U.S. EPA, in consultation with the Puget Sound Clean Air Agency, shall review the Seattle Kiln NO_x Emission Reduction Report in accordance with Section XIII (Review and Approval of Submittals). Consistent with the requirements and deadlines specified in Appendix A, Defendant shall take all actions required pursuant to that review, including but not limited to achieving and maintaining compliance with the 30-Day Rolling Average Emission Limit for NO_x at the Seattle Kiln approved, conditionally approved, or partially approved by U.S. EPA pursuant to Section XIII (Review and Approval of Submittals).

Louisville, Nebraska

23. Louisville ACL Kiln.

a. Defendant shall submit pursuant to Section XXI of this Consent Decree (Notices) an optimization protocol for the Louisville ACL Kiln in accordance with the applicable procedures of Appendix A to this Consent Decree, hereinafter the Louisville ACL Kiln NO_x Emission Reduction Report, for the purpose of optimizing the operation of Louisville ACL Kiln to reduce NO_x emissions to the maximum extent practicable from that Kiln. The Louisville ACL Kiln NO_x Emission Reduction Report shall conform to the applicable procedures and schedule set forth in Appendix A for the establishment of a 30-Day Rolling Average Emission Limit for NO_x at the Louisville ACL Kiln. Consistent with the requirements and deadlines specified in Appendix A, Defendant shall demonstrate compliance and thereafter maintain compliance with the proposed 30-Day Rolling Average Emission Limit for NO_x at the Louisville ACL Kiln.

b. U.S. EPA, in consultation with the State of Nebraska, shall review the Louisville ACL Kiln NO_x Emission Reduction Report in accordance with Section XIII (Review and Approval of Submittals). Consistent with the requirements and deadlines specified in Appendix A, Defendant shall take all actions required pursuant to that review, including but not limited to achieving and maintaining compliance with the 30-Day Rolling Average Emission Limit for NO_x at the Louisville ACL Kiln approved, conditionally approved, or partially approved by U.S. EPA pursuant to Section XIII (Review and Approval of Submittals).

24. Louisville HW Kiln.

a. Defendant shall have installed and Commenced Continuous Operation of the SNCR technology at the Louisville HW Kiln by the date specified in the table below in this Paragraph 24.a:

Kiln	**Control Technology**	**Date of Installation and Deadline for Commencement of Continuous Operation**	**30-Day Rolling Average Emission Limit (lbs. NO_x/Ton of clinker)**
HW Kiln	SNCR	9/10/2014	3.5

Defendant shall Continuously Operate the SNCR technology by no later than the date specified in the table above.

b. Beginning on the Operating Day which is the 30th Operating Day after the date by which Defendant is required to Commence Continuous Operation of the SNCR technology at Louisville HW Kiln identified in Paragraph 24.a, Defendant shall demonstrate compliance and thereafter maintain compliance with the 30-Day

Rolling Average Emission Limit for NOx specified in Paragraph 24.a at that Kiln. Defendant need not demonstrate compliance at the stack venting exhaust gases from the Louisville HW coal mill. However, Defendant shall control indirect-fired coal mill feed gas from the kiln exhaust according to the standard protocol of the coal mill system. Defendant shall not adjust, increase or activate the coal mill feed gas in order to affect the emissions at the main stack in any way or to reduce the amount of reagent Ash Grove uses in the SNCR.

Midlothian, Texas

25. Defendant shall Retire Midlothian Kiln 1 and Midlothian Kiln 2 by the dates specified in the table below in this Paragraph 25. Defendant shall not Operate Midlothian Kiln 3 after the dates specified in the table below in this Paragraph 25 unless and until Midlothian Kiln 3 has been Reconstructed.

Kiln	**Control Technology**	**Deadline for Retirement or Commencement of Continuous Operation**	**30-Day Rolling Average Emission Limits (lbs. NO_x/Ton of clinker)**
Kiln 1	Retire	9/10/2014	0
Kiln 2	Retire	9/10/2014	0
Kiln 3	Retire or Reconstruct with SNCR	First Operating Day after 9/10/2014	1.5

If Defendant Reconstructs Midlothian Kiln 3, then commencing on the date specified in the table above, Defendant shall Continuously Operate the SNCR Control Technology on Midlothian Kiln 3.

26. If Defendant Reconstructs Midlothian Kiln 3, then beginning on the Operating Day which is the 30th Operating Day after the date identified in Paragraph 25 by which Defendant is required to Operate the Reconstructed Midlothian Kiln 3, Defendant shall demonstrate compliance and thereafter maintain compliance at the stack for Kiln 3 with the 30-Day Rolling Average Emission Limit for NO_x specified in Paragraph 25. By no later than September 10, 2015, Defendant shall demonstrate compliance and maintain compliance with a 12-Month Rolling Tonnage Limit for NO_x of 975 tons per year at Midlothian Kiln 3.

Montana City, Montana

27. By no later than 60 Days after the Effective Date, Defendant shall Continuously Operate Low NO_x Burner technology at Montana City Kiln 1 specified in the table below in this Paragraph 27. In addition, Defendant shall have installed and Commenced Continuous Operation of the SNCR Control Technology at Montana City Kiln 1 by the date specified in the table below in this Paragraph 27:

Kiln	Control Technology	Date of Installation and Deadline for Commencement of Continuous Operation	Demonstration Phase 30-Day Rolling Average Emission Limit (lbs. NO_x/Ton of clinker)	30-Day Rolling Average Emission Limit (lbs. NO_x /Ton of clinker)
Kiln 1	Low NO_x Burner	60 Days after Effective Date	--	*See* Appendix A
	SNCR	9/10/2014	8.0	

Beginning on the Operating Day which is the 30th Operating Day after September 10, 2014, Defendant shall demonstrate compliance and thereafter maintain compliance with the Demonstration Phase 30-Day Rolling Average Emission Limit for NO_x of 8.0 lb/ton of clinker at the Montana City Kiln.

28. Pursuant to Appendix A, Defendant shall propose to U.S. EPA and the Montana Department of Environmental Quality a 30-Day Rolling Average Emission Limit for NO_x applicable to Montana City Kiln 1 that is no less stringent than 8.0 lb NO_x/ton of clinker and that represents the optimal performance and Continuous Operation of the SNCR Control Technology.

a. Within 30 Days after proposing a 30-Day Rolling Average Emission Limit for NO_x at Montana City Kiln 1 under Appendix A, Defendant shall demonstrate compliance and thereafter maintain compliance with the proposed 30-Day Rolling Average Emission Limit for NO_x at the Kiln. U.S. EPA shall review the proposed 30-Day Rolling Average Emission Limit for NO_x applicable to Montana City Kiln 1 in consultation with the Montana Department of Environmental Quality. Within 30 Operating Days after U.S. EPA has notified Defendant of the completion of its review of the proposed 30-Day Rolling Average Emission Limit for NO_x, Defendant shall demonstrate compliance and thereafter maintain compliance with the 30-Day Rolling Average Emission Limit for NO_x approved, conditionally approved, or partially approved by U.S. EPA pursuant to Section XIII (Review and Approval of Submittals).

b. If, on or before May 4, 2015, Defendant provides notice to EPA pursuant to Section XXI of the Consent Decree (Notices) that it intends to Replace Montana City Kiln 1 and shall Retire the existing Montana City Kiln 1 within 42 months, then Defendant's obligations under Appendix A shall terminate immediately, but Defendant shall continue to comply with the Demonstration Phase 30-Day Rolling Average Emission Limit for NO_x and continuously operate the SNCR for the time period prior to Retirement of Montana City Kiln 1.

29. If Defendant elects to Replace Montana City Kiln 1 in accordance with Section X (Election to Retire and Replace Kilns), then Defendant shall:

a. Prior to Replacing Montana City Kiln 1 and prior to termination pursuant to Section XXV of this Consent Decree (Termination), submit an application for a federally enforceable preconstruction permit for the Replacement of the Montana City Kiln that is issued under the federally-approved minor or major new source review program and which incorporates, at a minimum, a proposed 30-Day Rolling Average Emission Limit for NO_x that is no less stringent than 1.5 lb/ton clinker, or the applicable NSPS, whichever is more stringent. Such application for a federally enforceable preconstruction permit shall also contain, at a minimum, a proposed 12-Month Rolling Tonnage Limit for NO_x of no more than 700 tons per year. Defendant shall thereafter take all other actions necessary to obtain such permits or approvals after filing the applications including, but not limited to, responding to reasonable requests for additional information by the permitting authority in a timely fashion, and conducting any environmental or other assessment lawfully required by the permitting authority.

b. Within 180 Days after Defendant commences Operation of the Replaced Montana City Kiln, Defendant shall demonstrate compliance and maintain compliance with the Control Technology and other applicable requirements of Paragraph 29.a. applicable to the Replaced Montana City Kiln, or those Control Technology and Emission Limits for NO_x imposed by the federally enforceable preconstruction permit(s), whichever are more stringent.

<u>Inkom, Idaho</u>

30. Prior to Startup of Inkom Kiln 1 and/or Inkom Kiln 2, Defendant shall first apply for and obtain applicable permits required under: (1) the PSD provisions of the Act, 42 U.S.C. §§ 7470-7492 and/or the nonattainment NSR provisions of the Act, 42 U.S.C. §§ 7501-7515; or (2) the federally-approved and enforceable SIP which incorporates and/or implements the federal PSD and/or nonattainment NSR requirements. At a minimum, any such application for the foregoing permit(s) shall require that Defendant install and Commence Continuous Operation of SNCR Control Technology at each Kiln, as specified in the table below in this Paragraph 30:

Kiln	**Control Technology**	**Date of Installation and Deadline for Commencement of Continuous Operation**	**30-Day Rolling Average Emission Limit (lbs. NO_x /Ton of clinker)**
Kiln 1	SNCR	Upon Startup	1.5
Kiln 2	SNCR	Upon Startup	1.5

Defendant shall Continuously Operate the SNCR Control Technology by no later than the date specified in the table above.

31. Beginning on the Operating Day which is the 30th Day after the date by which Defendant is required to Commence Continuous Operation of the SNCR technology at Inkom Kiln 1 and Inkom Kiln 2 identified in Paragraph 30, Defendant shall demonstrate compliance and thereafter maintain compliance with the 30-Day Rolling Average Emission Limit for NO_x specified in the table in Paragraph 30 at Inkom Kiln 1 and Inkom Kiln 2, or those Emission Limits for NO_x required under the federally enforceable preconstruction permit(s) required in Paragraph 30, above, whichever are more stringent.

B. NO_x Continuous Emission Monitoring Systems

32. At each Kiln identified in Paragraph 8.y of this Decree other than the Midlothian Kilns and the Inkom Kilns, Defendant shall install and make operational no later than twelve months after the Effective Date a NO_x continuous emissions monitoring system (CEMS) at each stack which collects emissions from such Kiln in accordance with the requirements of 40 C.F.R. Part 60. Notwithstanding the foregoing, Defendant shall install and make operational a NO_x CEMS at each stack which collects emissions from Midlothian Kiln 3 in accordance with the requirements of 40 C.F.R. Part 60 within 60 Days after achieving the maximum production rate at which the Reconstructed Kiln will be operated, but not later than 180 Days after Defendant first Operates the Reconstructed Kiln. Defendant shall install and make operational a NO_x CEMS at each stack which collects emissions from Inkom Kiln 1 or Inkom Kiln 2 in accordance with the requirements of 40 C.F.R. Part 60 not later than 180 Days after Startup of the Kiln. Defendant is not required to install or operate NO_x CEMS on the stack(s) of the indirect fired coal mills serving the Leamington, Louisville HW and Seattle Kilns.

33. On or before the date that a NO_x CEMS is required pursuant to Paragraph 32, Defendant shall determine and record the daily clinker production rates by either one of the two following methods:

a. Install, calibrate, maintain, and operate a permanent weigh scale system to measure and record weight rates of the amount of clinker produced in tons of mass per hour.; or

b. Install, calibrate, maintain, and operate a permanent weigh scale system to measure and record weight rates of the amount of feed to the kiln in tons of mass per hour. Defendant shall calculate hourly clinker production rate using a kiln specific feed-to-clinker ratio based on reconciled clinker production determined for accounting purposes and recorded feed rates. This ratio should be updated no less frequently than once per month. If this ratio changes at clinker reconciliation, the new ratio must be used going forward, but it is not necessary to retroactively change clinker production rates previously estimated.

34. Except during CEMS breakdowns, repairs, calibration checks, and zero span adjustments, the CEMS required pursuant to Paragraph 32 shall be operated at all times during Kiln Operation. Each such CEMS shall be used at each Kiln to demonstrate compliance with the NO_x Emission Limits established in Section V.A (NO_x Control Technology and Emission Limits) and Appendix A, as applicable, of this Consent Decree. If Defendant Reconstructs or Replaces the Montana City Kiln, it shall commence operation of the NO_x CEMS for that Kiln within 60 Days after achieving the maximum production rate at which the Montana City Replacement Kiln will be operated, but not later than 180 Days after Defendant first Operates the Montana City Replacement Kiln .

35. Each NO_x CEMS required pursuant to Paragraph 32 shall monitor and record the applicable NO_x emission rate from each Kiln stack in units of lbs. of NO_x per Ton of clinker produced at such Kiln and shall be installed, certified, calibrated, maintained, and operated in accordance with the applicable requirements of 40 C.F.R. Part 60.

36. For purposes of this Consent Decree, all emissions of NO_x from Kilns shall be measured by CEMS. During any time when CEMs are inoperable and otherwise not measuring emissions of NO_x from any Kiln, Defendant shall apply the missing data substitution procedures used by the Affected State or the missing data substitution procedures in 40 C.F.R. Part 75, Subpart D, whichever is deemed appropriate by the Affected State.

SECTION VI: SO_2 CONTROL TECHNOLOGY, EMISSION LIMITS AND MONITORING REQUIREMENTS

A. SO_2 Control Technology and Emission Limits

37. Defendant shall, as applicable, install the SO_2 Control Technology and comply with the Emission Limits for the specific Kilns within their system according to Paragraphs 38 through 50. Defendant shall Continuously Operate each SO_2 Control Technology.

Foreman, Arkansas

38. Defendant shall demonstrate compliance and thereafter maintain compliance with the 30-Day Rolling Average Emission Limit for SO_2 at Foreman Kiln 4 on the 30th Operating Day following the date specified in the table below in this Paragraph 38:

Kiln	Date on Which 30-Day Rolling Average Emission Limit Applies	30-Day Rolling Average Emission Limit (lbs. SO_2/Ton of clinker)
Kiln 4	12/31/15	0.6

Chanute, Kansas

39. Defendant shall demonstrate compliance and thereafter maintain compliance with the 30-Day Rolling Average Emission Limit for SO_2 at Chanute Kiln 1 on the 30th Operating Day following the date specified in the table below in this Paragraph 39:

Kiln	Date on Which 30-Day Rolling Average Emission Limit Applies	30-Day Rolling Average Emission Limit (lbs. SO_2/Ton of clinker)
Kiln 1	12/31/15	0.6

Durkee, Oregon

40. Defendant shall demonstrate compliance and thereafter maintain compliance with the 3-hour Emission Limit for SO_2 at Durkee Kiln 1 by performing the emissions testing

required under Paragraph 55 and comparing the average of the valid test runs to the limit specified in the table below in this Paragraph 40:

Kiln	**Date on Which Emission Limit Applies**	**Emission Limit (lbs. SO_2 /Ton of clinker)**
Kiln 1	3/31/2015	0.4

<u>Leamington, Utah</u>

41. Defendant shall demonstrate compliance and thereafter maintain compliance with the 3-hour Emission Limit for SO_2 at Leamington Kiln 1 by performing the emissions testing required under Paragraph 55 and comparing the average of the valid test runs to the limit specified in the table below in this Paragraph 41:

Kiln	**Date on Which Emission Limit Applies**	**Emission Limit (lbs. SO_2/Ton of clinker)**
Kiln 1	9/10/2013	0.4

Defendant need not demonstrate compliance with the 3-hour Rolling Average Emission Limit for SO_2 at the stack venting exhaust gases from the Leamington coal mill. However, Defendant shall control indirect-fired coal mill feed gas from the kiln exhaust according to the standard protocol of the coal mill system. Defendant shall not adjust, increase or activate the coal mill feed gas in order to affect the emissions at the main stack in any way.

<u>Seattle, Washington</u>

42. Defendant shall demonstrate compliance and thereafter maintain compliance with the 30-Day Rolling Average Emission Limit for SO_2 at Seattle Kiln 1 on the 30th Operating Day following the date specified in the table below in this Paragraph 42:

Kiln	Date on Which 30-Day Rolling Average Emission Limit Applies	30-Day Rolling Average Emission Limit (lbs. SO_2/Ton of clinker)
Kiln 1	9/10/2013	0.4

Defendant need not demonstrate compliance with the 30-Day Rolling Average Emission Limit for SO_2 at the stack venting exhaust gases from the Seattle coal mill. However, Defendant shall control indirect-fired coal mill feed gas from the kiln exhaust according to the standard protocol of the coal mill system. Defendant shall not adjust, increase or activate the coal mill feed gas in order to affect the emissions at the main stack in any way.

Louisville, Nebraska

43. Defendant shall demonstrate compliance and thereafter maintain compliance with the 30-Day Rolling Average Emission Limit for SO_2 at the Louisville HW Kiln and Louisville ACL Kiln by the date specified in the table below in this Paragraph 43:

Kiln	Control Technology	Date of Installation and Deadline for Commencement of Continuous Operation	30-Day Rolling Average Emission Limit (lbs. SO_2 /Ton of clinker)
HW Kiln	DAA	9/10/2015	2.6
ACL Kiln	DAA	9/10/2015	3.0

Defendant shall Continuously Operate the DAA Control Technology by no later than the dates specified in the table above at Louisville HW Kiln and Louisville ACL Kiln.

44. Beginning on the Operating Day which is the 30th Operating Day after the date by which Defendant is required to Commence Continuous Operation of the DAA Control Technology at Louisville HW Kiln and at the Louisville ACL Kiln identified in Paragraph 43, Defendant shall demonstrate compliance and thereafter maintain compliance with the 30-Day

Rolling Average Emission Limits for SO_2 each applicable to the Louisville HW Kiln and the Louisville ACL Kiln specified in Paragraph 43 at that Kiln. Defendant need not demonstrate compliance with the 30-Day Rolling Average Emission Limit for SO_2 at the stack venting exhaust gases from the Louisville HW coal mill. However, Defendant shall control indirect-fired coal mill feed gas from the kiln exhaust according to the standard protocol of the coal mill system. Defendant shall not adjust, increase or activate the coal mill feed gas in order to affect the emissions at the main stack in any way or to reduce the amount of reagent Ash Grove uses in the DAA.

Midlothian, Texas

45. Defendant shall Retire Midlothian Kiln 1 and Midlothian Kiln 2 by the dates specified in the table below in Paragraph 25 and in this Paragraph 45. Defendant shall not Operate Midlothian Kiln 3 after the date specified in the table below in this Paragraph 45 unless Defendant has Reconstructed Kiln 3.

Kiln	**Control Technology**	**Date of Retirement or Installation and Deadline for Commencement of Continuous Operation**	**30-Day Rolling Average Emission Limits (lbs. SO_2 /Ton of clinker)**
Kiln 1	Retire	9/10/2014	0
Kiln 2	Retire	9/10/2014	0
Kiln 3	Retire or Reconstruct with Inherent Scrubbing	First Operating Day after 9/10/2014	0.4

Commencing on the date specified in the table above, Defendant shall Continuously Operate Midlothian Kiln 3 in a manner consistent with good air pollution control practice for minimizing emissions during all times of Kiln Operation.

46. If Defendant Reconstructs Midlothian Kiln 3, then beginning on the Operating Day which is the 30th Operating Day after the date identified in Paragraph 45 for Commencement of Continuous Operation of the Reconstructed Kiln 3, at the stack for Kiln 3 Defendant shall demonstrate compliance and thereafter maintain compliance with the 30-Day Rolling Average Emission Limit for SO_2 identified in Paragraph 45. By no later than September 10, 2015, Defendant shall demonstrate compliance and maintain compliance with a 12-Month Rolling Tonnage Limit for SO_2 of 260 tons per year at Midlothian Kiln 3.

Montana City, Montana

47. Defendant shall have installed and Commenced Continuous Operation of the Semi-Dry Scrubbing Control Technology at the Montana City Kiln by the date specified in the table below in this Paragraph 47:

Kiln	Control Technology	Date of Installation and Deadline for Commencement of Continuous Operation	30-Day Rolling Average Emission Limit (lbs. SO_2 /Ton of clinker)
Kiln 1	Semi-Dry Scrubbing	9/10/2014	2.0

Starting on the 210th Operating Day following the date specified in the table above in this Paragraph 47, Defendant shall demonstrate compliance and thereafter maintain compliance with the 30-Day Rolling Average Emission Limit for SO_2 applicable to Montana City Kiln 1 and as identified in this Paragraph 47.

48. If Defendant elects to Replace Montana City Kiln 1 in accordance with Section X (Election to Retire and Replace Kilns), then Defendant shall:

a. Prior to Replacing Montana City Kiln 1 and prior to termination pursuant to Section XXV of this Consent Decree (Termination), submit an application for a federally enforceable preconstruction permit for the Replacement of Montana

City Kiln 1 that is issued under the federally-approved minor or major new source review program and which incorporates, at a minimum, a proposed 30-Day Rolling Average Emission Limit for SO_2 that is no less stringent than 0.4 lb/ton clinker, or the applicable NSPS, whichever is more stringent. Such application for a federally enforceable preconstruction permit shall also contain, at a minimum, a proposed 12-Month Rolling Tonnage Limit for SO_2 of no greater than 200 tons per year. Defendant shall thereafter take all other actions necessary to obtain such permits or approvals after filing the applications including, but not limited to, responding to reasonable requests for additional information by the permitting authority in a timely fashion, and conducting any environmental or other assessment lawfully required by the permitting authority.

b. Within 180 Days after Defendant commences Operation of the Replaced Montana City Kiln, Defendant shall demonstrate compliance and maintain compliance with applicable requirements of Paragraph 48.a. at the Replaced Montana City Kiln, or those Control Technology requirements and Emission Limit(s) for SO_2 imposed by the federally enforceable preconstruction permit(s), whichever are more stringent.

Inkom, Idaho

49. Prior to Startup of Inkom Kiln 1 and/or Inkom Kiln 2, Defendant shall first apply for and obtain applicable permits required under: (1) the PSD provisions of the Act, 42 U.S.C. §§ 7470-7492 and/or the nonattainment NSR provisions of the Act, 42 U.S.C. §§ 7501-7515; or (2) the federally-approved and enforceable SIP which incorporates and/or implements the federal PSD and/or nonattainment NSR requirements. At a minimum, any such application for the

foregoing permit(s) shall require that Defendant achieve and maintain compliance with the Emission Limits, as specified in the table below in this Paragraph 49:

Kiln	**Date on Which 30-Day Rolling Average Emission Limit for SO_2 Applies**	**30-Day Rolling Average Emission Limit (lbs. SO_2 /Ton of clinker)**
Kiln 1	Upon Startup	0.4
Kiln 2	Upon Startup	0.4

50. Beginning on the 30th Operating Day of each Inkom Kiln 1 and Inkom Kiln 2 identified in Paragraph 49, Defendant shall demonstrate compliance and thereafter maintain compliance with the 30-Day Rolling Average Emission Limit for SO_2 specified in the table in Paragraph 49 at Inkom Kiln 1 and Inkom Kiln 2, or those Emission Limits for SO_2 required under the federally enforceable preconstruction permit(s) required in Paragraph 49, above, whichever are more stringent.

B. SO_2 Continuous Emission Monitoring Systems

51. At each Kiln identified in Paragraph 8.y of this Decree except Durkee Kiln 1, Leamington Kiln 1, the Midlothian Kilns and the Inkom Kilns, Defendant shall install and make operational no later than twelve months after the Effective Date a SO_2 continuous emissions monitoring system (CEMS) at each stack which collects emissions from such Kiln in accordance with the requirements of 40 C.F.R. Part 60. Notwithstanding the foregoing, Defendant shall install and make operational an SO_2 CEMS at each stack which collects emissions from Midlothian Kiln 3 in accordance with the requirements of 40 C.F.R. Part 60 within 60 Days after achieving the maximum production rate at which the Reconstructed Kiln will be operated, but not later than 180 Days after Defendant first Operates the Reconstructed Kiln. Defendant shall install and make operational an SO_2 CEMS at each stack which collects emissions from Inkom

Kiln 1 or Inkom Kiln 2 in accordance with the requirements of 40 C.F.R. Part 60 not later than 180 Days after Startup of the Kiln. Defendant is not required to install or operate SO_2 CEMS on the stack(s) of the indirect fired coal mills serving the Leamington, Louisville HW and Seattle Kilns.

52. Except during CEMS breakdowns, repairs, calibration checks, and zero span adjustments, the CEMS required pursuant to Paragraph 51 shall be operated at all times during Kiln Operation. Each such CEMS shall be used at each Kiln to demonstrate compliance with the SO_2 Emission Limits established in Section V.A (SO_2 Control Technology and Emission Limits) of this Consent Decree. If Defendant Replaces the Montana City Kiln, it shall commence operation of the SO_2 CEMS for that Kiln within 60 Days after achieving the maximum production rate at which the Replaced Montana City Kiln will be operated, but not later than 180 Days after Defendant first Operates the Replaced Montana City Kiln.

53. Each SO_2 CEMS required pursuant to Paragraph 51 shall monitor and record the applicable SO_2 emission rate from each Kiln stack in units of lbs. of SO_2 per Ton of clinker produced at such Kiln and shall be installed, certified, calibrated, maintained, and operated in accordance with the applicable requirements of 40 C.F.R. Part 60.

54. For purposes of this Consent Decree, all emissions of SO_2 from Kilns other than Durkee Kiln 1 and Leamington Kiln 1 shall be measured by CEMS. During any time when CEMs are inoperable and otherwise not measuring emissions of SO_2 from any Kiln, Defendant shall apply the missing data substitution procedures used by the Affected State or the missing data substitution procedures in 40 C.F.R. Part 75, Subpart D, whichever is deemed appropriate by the Affected State.

55. Within 12 months of the Effective Date, Defendant shall conduct an SO_2 source

test for Durkee Kiln 1 and Leamington Kiln 1 and submit an application to the Durkee and Leamington Title V permitting authority requesting that a condition be added to the Title V permit, if no such condition already exists, requiring Kiln stack SO_2 testing at least once every two (2) years.

SECTION VII: PM CONTROL TECHNOLOGY, EMISSION LIMITS AND MONITORING REQUIREMENTS

A. PM Control Technology and Emission Limits

56. At each of the Kilns identified in Paragraph 8.y and by each of the dates specified in the table below, Defendant shall demonstrate compliance and thereafter maintain compliance with the PM limit specified in the table. Compliance shall be demonstrated using a three run EPA Method 5 or Method 5I performance test and that performance test shall be repeated no less frequently than every 365 Operating Days thereafter. If performance testing would be required less than 15 Operating Days after the Kiln has completed Startup after being down for more than 24 hours, then performance testing may be deferred up to 15 Operating Days after completion of the Startup. Defendant need not demonstrate compliance at the stack venting exhaust gases from the Leamington, Louisville HW and Seattle coal mills. However, Defendant shall control indirect-fired coal mill feed gas from the kiln exhaust according to the standard protocol of the coal mill system. Defendant shall not adjust, increase or activate the coal mill feed gas in order to affect the emissions at the main stack in any way. The methods specified in this Decree for demonstrating compliance with the PM limits in the table below are not intended to change the means by which Defendant demonstrates compliance with standards not addressed by this Decree.

57. Subject to Section IX of this Consent Decree (Temporary Cessation of Kiln Operation), Defendant shall install and Commence Continuous Operation of each Baghouse Control Technology by the deadline shown below.

Kiln	**Date of Installation and Deadline for Commencement of Continuous Operation of Baghouse**	**Emission Limit (lbs. PM/Ton of clinker)**
Chanute Kiln 1	12/31/2015	0.086
Durkee Kiln 1	3/31/2015	0.07
Foreman Kiln 4	12/31/2015	0.086
Leamington Kiln 1	12/10/2013	0.07
Louisville ACL Kiln	9/10/2014	0.07
Louisville HW Kiln	9/10/2014	0.07
Midlothian Kiln 3	9/10/2014	0.07
Montana City Kiln 1	9/10/2014	0.07
Seattle Kiln 1	9/10/2013	0.07

58. Prior to Startup of Inkom Kiln 1 and/or Inkom Kiln 2, Defendant shall first apply for and obtain applicable permits required under: (1) the PSD provisions of the Act, 42 U.S.C. §§ 7470-7492 and/or the nonattainment NSR provisions of the Act, 42 U.S.C. §§ 7501-7515; or (2) the federally-approved and enforceable SIP which incorporates and/or implements the federal PSD and/or nonattainment NSR requirements. At a minimum, any such application for the

foregoing permit(s) shall require that Defendant achieve and maintain compliance with the Emission Limits, as specified in the table below in this Paragraph 58:

Kiln	**Date on Which Emission Limit for PM Applies**	**Emission Limit (lbs. PM /Ton of clinker)**
Kiln 1	Upon Startup	0.02, or the NSPS for new kilns, whichever is more stringent
Kiln 2	Upon Startup	0.02, or the NSPS for new kilns, whichever is more stringent

Within 60 Days after achieving the maximum production rate at which a particular Inkom Kiln will be operated, but not later than 180 Days after the particular Kiln first Operates, Defendant shall demonstrate compliance using a three run EPA Method 5 or Method 5I stack test and thereafter achieve and maintain compliance with the Emission Limit for PM specified in the table in this Paragraph 58 at Inkom Kiln 1 and Inkom Kiln 2, or the Emission Limit(s) for PM required under the federally enforceable preconstruction permit(s) required in this Paragraph 58, above, whichever are more stringent, using the PM Continuous Parametric Monitoring System required by Paragraph 59.

B. PM Continuous Parametric Monitoring Systems

59. At each Kiln identified in Paragraph 8.y of this Decree and by the deadline identified in Paragraph 57, Defendant shall install and make operational a PM continuous parametric monitoring system (CPMS) at each stack from which the Kiln directly discharges emissions, in accordance with the requirements of Appendix B and 40 C.F.R. §63.1350(b) and (d). Defendant is not required to install or operate PM CPMS on the stack(s) of the indirect fired coal mills serving the Leamington, Louisville HW and Seattle Kilns unless otherwise required to do so under any other applicable regulation. Location of the PM CPMS at Foreman will be in a position to monitor operating parameter data from both the Kiln and clinker cooler. If Defendant

Replaces the Montana City Kiln, it shall commence operation of the PM CPMS for that Kiln within 60 Days after achieving the maximum production rate at which the Replacement Kiln 1 will be operated, but not later than 180 Days after Defendant first Operates the Replaced Montana City Kiln. Location of the PM CPMS at the Replaced Montana City Kiln shall be in a position to monitor operating parameter data from both the Kiln and clinker cooler (if the Montana City clinker cooler's exhaust is vented to the main stack).

60. Ash Grove shall use a PM CPMS to establish a Site-Specific Operating Limit (SSOL) for PM corresponding to the results of the performance test demonstrating compliance with the PM limit. Ash Grove shall conduct a performance test using EPA Method 5 or Method 5I at appendix A-3 of 40 C.F.R. Part 60. Pursuant to Section XXI of this Decree (Notices), Ash Grove may propose an alternative monitoring protocol that is at least as accurate as a PM CPMS installed or to be installed at a Kiln pursuant to Paragraph 59 by the deadline required in that Paragraph, whereby Ash Grove demonstrates continuous compliance with the applicable limit in Paragraph 57 as a 30-Day Rolling Average Emission Limit. EPA shall review the alternative monitoring protocol pursuant Section XIII of this Decree (Review and Approval of Submittals). If approved or approved with conditions, Ash Grove shall comply with the approved alternative monitoring protocol and take all actions required pursuant thereto, and shall not be required to install and operate a PM CPMS under Paragraph 59, to establish an SSOL under this Paragraph and to perform annual performance testing under Paragraph 56 at any Kiln for which an alternative monitoring protocol has been approved.

<u>SECTION VIII: OTHER INJUNCTIVE RELIEF</u>

61. Defendant shall implement the Environmental Mitigation Projects ("Project" or "Projects") described in Appendix C to this Consent Decree.

62. Defendant, shall maintain, and, within 30 Days upon U.S. EPA's request, provide to U.S. EPA all documents that substantiate work completed on the Projects in accordance with Section XXI (Notices).

63. Defendant certifies that Defendant is not otherwise required by law to perform any of the Projects, that Defendant is unaware of any other person who is required by law to perform any of the Projects, and that Defendant will not use any of the Projects, or portion thereof, to satisfy any obligations that it may have under other applicable requirements of law.

64. Beginning six (6) months after the Effective Date of this Consent Decree, and continuing until completion of each Project, Defendant shall provide U.S. EPA with semi-annual or annual updates concerning the progress of the Project in the semi-annual or annual reports required (as applicable) in Section XIV (Reporting Requirements) of this Consent Decree.

65. Within sixty (60) Days following the completion of all Projects required under this Consent Decree, Defendant shall submit to U.S. EPA a report that documents the date that each Project was completed, Defendant's results from implementing all Projects, including the emission reductions or other environmental benefits achieved (including the emission reductions achieved for NOx, SO_2, and PM), and the money expended by Defendant in implementing each Project.

66. In connection with any communication to the public or to shareholders regarding Defendant's actions or expenditures relating in any way to the Projects, Defendant shall include prominently in the communication the information that the actions and expenditures were required as part of a negotiated consent decree to resolve allegations that Defendant violated the Clean Air Act.

SECTION IX: TEMPORARY CESSATION OF KILN OPERATION

67. If Defendant has Temporarily Ceased Kiln Operation of any Kiln on the date by which Defendant is required to install and/or Continuously Operate any Control Technology at that Kiln under Section V (NO_x Control Technology, Emission Limits, and Monitoring Requirements), Section VI (SO_2 Control Technology, Emission Limits, and Monitoring Requirements), or Section VII (PM Control Technology, Emission Limits, and Monitoring Requirements), Defendant shall provide written notice to U.S. EPA and the Affected State(s) within ten (10) Days after such Temporary Cessation began, specifying the date on which such period of Temporary Cessation began. Defendant shall provide such written notice pursuant to Section XXI (Notices).

68. If Defendant has provided the written notice as required in Paragraph 67, above, Defendant shall not be required to install and Continuously Operate the Control Technology at that Kiln by the dates required in Section V (NO_x Control Technology, Emission Limits, and Monitoring Requirements), Section VI (SO_2 Control Technology, Emission Limits, and Monitoring Requirements), and Section VII (PM Control Technology, Emission Limits, and Monitoring Requirements) of this Consent Decree with respect to that Kiln. However, Defendant shall not recommence Kiln Operation after the date required in Section V (NO_x Control Technology, Emission Limits, and Monitoring Requirements), Section VI (SO_2 Control Technology, Emission Limits, and Monitoring Requirements), and Section VII (PM Control Technology, Emission Limits, and Monitoring Requirements) of this Consent Decree with respect to that Kiln unless the Defendant has 1) installed and Commenced Continuous Operation of the Control Technology required by this Consent Decree for that Kiln, 2) commenced compliance with all requirements for that Kiln contained in Section V (NO_x Control Technology,

Emission Limits, and Monitoring Requirements), Section VI (SO_2 Control Technology, Emission Limits, and Monitoring Requirements), and Section VII (PM Control Technology, Emission Limits and Monitoring Requirements) and 3) provided notice to U.S. EPA and the Affected State(s) within 30 Days after recommencing Kiln Operation. If Defendant recommences Kiln Operation without installing and Commencing Continuous Operation of the Control Technology required under this Decree and does not demonstrate compliance with all requirements for that Kiln contained in Section V (NO_x Control Technology, Emission Limits, and Monitoring Requirements), Section VI (SO_2 Control Technology Emission Limits, and Monitoring Requirements), and/or Section VII (PM Control Technology, Emission Limits and Monitoring Requirements), Defendant shall be liable for stipulated penalties pursuant to Section XV (Stipulated Penalties).

69. Notwithstanding Paragraph 68, above, if Defendant Temporarily Ceases Kiln Operation for twenty-four (24) consecutive months subsequent to the Effective Date of this Consent Decree, prior to recommencing Kiln Operation Defendant shall first apply for and obtain applicable permits required under: (1) the PSD provisions of the Act, 42 U.S.C. §§ 7470-7492 and/or the nonattainment NSR provisions of the Act, 42 U.S.C. §§ 7501-7515; or (2) the applicable federally-approved and enforceable SIP which incorporates and/or implements the federal PSD and/or nonattainment NSR requirements, as applicable.

SECTION X: ELECTION TO RETIRE AND REPLACE KILNS

70. At least 180 Days prior to submitting a written request by Defendant to terminate this Consent Decree, Defendant shall provide written notice to U.S. EPA, Director of the Air Enforcement Division, and the State of Montana, stating whether Defendant intends to Replace Montana City Kiln 1.

SECTION XI: PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS

71. Except as specifically stated to the contrary in this Consent Decree, NOx, SO_2 and PM emission reductions resulting from compliance with the requirements of this Consent Decree shall not be considered as a creditable contemporaneous emission decrease for the purpose of obtaining a netting credit under the Clean Air Act's Non-attainment NSR and PSD programs.

72. The limitations on the generation and use of netting credits or offsets set forth in Paragraph 71 do not apply to emission reductions achieved by Defendant that are surplus to those required under this Consent Decree ("surplus emission reductions"). For purposes of this Paragraph, surplus emission reductions are the reductions over and above those required under this Consent Decree that result from Defendant's compliance with federally enforceable emissions limits that are more stringent than limits imposed under this Consent Decree or from Defendant's compliance with emissions limits otherwise required under applicable provisions of the Clean Air Act or with an applicable SIP that contains more stringent limits than those imposed under this Consent Decree.

73. Nothing in this Consent Decree is intended to preclude the emission reductions generated under this Consent Decree from being considered by U.S. EPA or a State as creditable contemporaneous emission decreases for the purpose of attainment demonstrations submitted pursuant to § 110 of the Act, 42 U.S.C. § 7410, or in determining impacts on NAAQS, PSD increments, or air quality-related values, including visibility in a Class I area.

74. Notwithstanding this Section XI (Prohibition on Netting Credits or Offsets from Required Controls), nothing in this Consent Decree prohibits Defendant from relying upon the emission reductions for purposes of determining whether there is a net emissions increase or

significant net emissions increase of any pollutant where the construction approval relying on that netting analysis was issued prior to the Date of Lodging of this Consent Decree.

75. Notwithstanding this Section XI (Prohibition on Netting Credits or Offsets from Required Controls), nothing in this Consent Decree prohibits Defendant from relying upon the emission reductions resulting from compliance with this Consent Decree for purposes of determining whether there is a net emissions increase or significant net emissions increase of NO_x, SO_2 or PM from the Replacement of the Montana City Kiln if, within twelve (12) consecutive months of commencing operation of the Montana City Replacement Kiln, Defendant achieves and maintains a 12-Month Rolling Tonnage Limit for NO_x of 700 tons per year, a 12-Month Rolling Tonnage Limit for SO_2 of 200 tons per year and a 12-Month Rolling Tonnage Limit for PM of 32.7 tons per year.

SECTION XII: PERMITS

76. Where any compliance obligation under this Consent Decree requires Defendant to obtain a federal, State, or local permit or approval, Defendant shall submit a timely and complete application for such permit or approval and take all other actions necessary to obtain all such permits or approvals, allowing for all legally required processing and review including requests for additional information by the permitting or approval authority. The inability of Defendant to obtain a permit in adequate time to allow compliance with the deadlines stated in this Consent Decree shall be considered a Force Majeure event if Defendant demonstrates that it exercised best efforts to timely fulfill its permitting obligations and has otherwise satisfied the requirements of Section XVI of this Consent Decree (Force Majeure). If, after demonstrating compliance with the requirements of this Paragraph, Defendant determines that it is unable to timely obtain a permit or approval necessary to install and continuously operate a Control

Technology under this Consent Decree, then Defendant shall immediately notify EPA and the Affected State pursuant to Section XVI of this Consent Decree (Force Majeure) and shall request an extension of time necessary to obtain such permit or approval and install and shake down the required improvements. If EPA and the Affected State determine that Defendant's inability to timely obtain any such required permit or approval is a *force majeure* event, then the provisions of Paragraph 108 shall apply to extend the deadline for installation and commencement of Continuous Operation of the Control Technology and for achieving and maintaining compliance with any applicable Emission Limits. Subject to the requirements of this Section, nothing in this Consent Decree shall be construed to require Ash Grove to apply for or obtain a PSD or Non-attainment NSR permit or SIP amendment to permit any actions required under this Consent Decree, unless otherwise required by law.

77. In addition to having first obtained any required preconstruction permits or other approvals pursuant to Paragraph 76, within 12 months after the commencement of Continuous Operation of each Control Technology required to be installed, upgraded, or operated on a Kiln under this Consent Decree or, if no Control Technology is required, within 12 months after the Effective Date of this Consent Decree, Defendant shall apply to the Affected State to include the requirements and limitations enumerated in this Consent Decree in a construction permit or other permit or approval (other than a Title V permit) which is federally enforceable, issued under the SIP of the Affected State, and issued under authority independent of the Affected State's authority to issue Title V permits. The permit or approval shall require compliance with any applicable 30-Day Rolling Average Emission Limit and any monitoring requirements, including those in Sections V.B, VI.B, and VII.B of this Decree. Following submission of the application for the permit or approval, Defendant shall cooperate with the appropriate permitting authority

by promptly submitting all information that such permitting authority seeks following its receipt of the application for the permit. The methods specified in this Decree for demonstrating compliance with the limits in this Decree are not intended to change the means by which Defendant demonstrates compliance with standards not addressed by this Decree. The requirements of this Paragraph are satisfied if a preconstruction permit was obtained, that permit serves as a state operating permit under the Affected State's SIP and that permit contains the elements identified in this Paragraph.

78. Within 120 Days after the establishment of any Emission Limits pursuant to Appendix A of this Consent Decree, Defendant shall submit applications to the appropriate permitting authority to incorporate all Appendix A Emission Limits, and any associated requirements and limitations, including those in Sections V (NO_x Control Technology, Emission Limits and Monitoring Requirements), VI (SO_2 Control Technology, Emission Limits and Monitoring Requirements), and Section VII (PM Control Technology, Emission Limits and Monitoring Requirements) of this Decree, into federally enforceable construction or other permits (other than Title V permits) which are federally enforceable. Following submission of the permit application by Defendant to the Affected State, Defendant shall cooperate with the appropriate permitting authority by promptly submitting all information that such permitting authority seeks following its receipt of the permit application.

79. Upon issuance of any permit or approval required under Paragraphs 77 and 78, Defendant shall file any applications necessary to incorporate the requirements of that permit into the Title V operating permit of the appropriate Facility. Defendant shall not challenge the inclusion in any such permit of the Emission Limits expressly prescribed in this Consent Decree (including, where applicable, 30-Day Rolling Average Emission Limits determined in

accordance with Appendix A), but nothing in this Consent Decree is intended nor shall it be construed to require the establishment of Emission Limits other than those Emission Limits expressly prescribed in this Consent Decree nor to preclude Defendant from challenging any more stringent Emission Limits should they be proposed for reasons independent of this Consent Decree.

80. The Parties agree that the incorporation of any Emission Limits and any other requirements and limitations into the Title V permits for Defendant's Facilities shall be in accordance with the applicable federal, State or local rules or laws.

81. For each Kiln, Defendant shall provide U.S. EPA with a copy of each application for a permit to address or comply with any provision of this Consent Decree, as well as a copy of any permit proposed as a result of such application, to allow for timely U.S. EPA participation in any public comment opportunity.

82. In lieu of incorporating the terms of the Consent Decree directly into a permit issued under a SIP pursuant to Paragraphs 77 and 78, Defendant may request an Affected State to submit the portions of the Consent Decree applicable to the Facilities in that Affected State to the U.S. EPA for approval under the State's SIP in accordance with 42 U.S.C. § 7410(k). Upon approval by the U.S. EPA, those portions of this Consent Decree will be incorporated into the Affected State's SIP, and subsequently incorporated into Title V permits for each Facility consistent with applicable requirements in 40 C.F.R. Part 70 or State-specific rules adopted and approved consistent with Part 70. Defendant agrees not to contest the submittal of any such proposed SIP revision that incorporates the terms of this Consent Decree to U.S. EPA, or U.S. EPA's approval of such submittal, or the incorporation of the applicable portions of this Consent Decree through these SIP requirements into the Title V permits.

83. Notwithstanding the reference to Title V permits in this Consent Decree, the enforcement of such permits shall be in accordance with their own terms and the Act. The Title V permits shall not be enforceable under this Consent Decree, although any term or limit established by or under this Consent Decree shall be enforceable under this Consent Decree regardless of whether such term has or will become part of a Title V permit, subject to the terms of Section XXV (Termination) of this Consent Decree.

SECTION XIII: REVIEW AND APPROVAL OF SUBMITTALS

84. After review of any plan, report, or other document that is required to be submitted pursuant to this Consent Decree, U.S. EPA, after consultation with the Affected State, shall in writing: (a) approve the submission; (b) approve the submission upon specified conditions; (c) approve part of the submission and disapprove the remainder; or (d) disapprove the submission.

85. If the submission is approved pursuant to Paragraph 84, Defendant shall take all actions required by the plan, report, or other document, in accordance with the schedules and requirements of the plan, report, or other document, as approved. If the submission is conditionally approved or approved only in part, pursuant to Paragraph 84.b or c, Defendant shall, upon written direction of U.S. EPA, after consultation with the Affected State, take all actions required by the approved plan, report, or other item that U.S. EPA, after consultation with the Affected State, determines are technically severable from any disapproved portions, subject to Defendant's right to dispute only the specified conditions or the disapproved portions, under Section XVII of this Decree (Dispute Resolution).

86. If the submission is disapproved in whole or in part pursuant to Paragraph 84.c or d, Defendant shall, within 45 Days or such other time as the Parties agree to in writing, correct

all deficiencies and resubmit the plan, report, or other item, or disapproved portion thereof, for approval, in accordance with the preceding Paragraphs. If the resubmission is approved in whole or in part, Defendant shall proceed in accordance with the preceding Paragraph.

87. Any stipulated penalties applicable to an original submission that is disapproved in whole or in part pursuant to Paragraph 84.c or d, as provided in Section XV (Stipulated Penalties) of this Decree, shall continue to accrue during the period specified in Paragraph 97, but any stipulated penalties that accrue following the receipt of the submission shall not be payable unless the resubmission is untimely or is disapproved in whole or in part; provided that, if the original submission was so deficient as to constitute a material breach of Defendant's obligations under this Decree, the stipulated penalties applicable to the original submission shall be due and payable notwithstanding any subsequent resubmission.

88. If a resubmitted plan, report, or other item, or portion thereof, is disapproved in whole or in part, U.S. EPA and the Affected State may again require Defendant to correct any deficiencies in accordance with the preceding Paragraphs, or may themselves correct any deficiencies and seek stipulated penalties, subject to Defendant's right to invoke Dispute Resolution under Section XVII of this Consent Decree.

SECTION XIV: REPORTING REQUIREMENTS

89. Defendant shall submit the following reports: Within 30 Days after the end of each half calendar year (*i.e.*, June 30, December 31) after the Effective Date, until termination of this Decree pursuant to Section XXV (Termination), Defendant shall submit a semi-annual report to U.S. EPA and the Affected States for the immediately preceding half calendar year period that shall:

a. Identify any and all dates on which Defendant has installed, or describe the progress of installation of, each Control Technology required for each Kiln under Section V (NO_x Control Technology, Emission Limits and Monitoring Requirements), Section VI (SO_2 Control Technology, Emission Limits and Monitoring Requirements), and Section VII (PM Control Technology, Emission Limits and Monitoring Requirements) and describe any problems encountered or anticipated during such installation, together with implemented or proposed solutions;

b. Identify any and all dates on which Defendant has completed installation of, or describe the progress of installation of, each continuous monitoring system required under Section V.B. (NO_x Continuous Emission Monitoring Systems), Section VI.B (SO_2 Continuous Emission Monitoring Systems), and Section VII.B (PM Continuous Parametric Monitoring Systems) and describe any problems encountered or anticipated during such installation, together with implemented or proposed solutions;

c. Provide, in electronic format able to be manipulated with Microsoft Excel, all CEMS data and CPMS data collected for each Kiln, reduced to 1 hour averages, in accordance with 40 C.F.R. Part 60.13(h)(2), including an explanation of any periods of CEMs or CPMS downtime together with any missing data for which Defendant applied missing data substitution procedures, under Section V.B. (NO_x Continuous Emission Monitoring Systems), Section VI.B (SO_2 Continuous Emission Monitoring Systems), and Section VII.B (PM Continuous Parametric Monitoring Systems);

d. Demonstrate compliance with all applicable 30-Day Rolling Average Emission Limits of this Consent Decree, including but not limited to those in Sections V (NO_x Control Technology, Emission Limits and Monitoring Requirements), Section VI (SO_2 Control Technology, Emission Limits and Monitoring Requirements), and Section VII (PM Control Technology, Emission Limits and Monitoring Requirements) of this Consent Decree;

e. Provide a complete description and status of all actions Defendant has undertaken to comply with each of the Appendices of this Consent Decree;

f. Demonstrate compliance with any applicable 30-Day Rolling Average Emission Limits established under Appendix A of this Consent Decree;

g. Describe the status of permit applications and any proposed SIP revisions made to implement the requirements of this Consent Decree; and

h. Describe the status of any operation and maintenance work relating to activities required under this Consent Decree.

The semi-annual report shall also include a description of any non-compliance with the requirements of this Consent Decree and an explanation of the violation's likely cause and of the remedial steps taken, or to be taken, to prevent or minimize such violation.

90. If Defendant violates, or has reason to believe that it may violate, any requirement of this Consent Decree, Defendant shall notify the United States and the Affected State of such violation and its likely duration, in writing, within ten (10) Business Days of the Day Defendant first becomes aware of the violation, with an explanation of the violation's likely cause and of the remedial steps taken, or to be taken, to prevent or minimize such violation and to mitigate any adverse effect of such violation. Defendant shall investigate the cause of the violation and

shall then submit an amendment to the report required under Paragraph 89, including a full explanation of the cause of the violation, within 30 Days of the Day Defendant becomes aware of the cause of the violation. Nothing in this Paragraph or the following Paragraph relieves Defendant of its obligation to provide the notice required by Section XVI of this Consent Decree (Force Majeure) if Defendant contends a Force Majeure event occurred.

91. Whenever any violation of this Consent Decree, or of any applicable permits required under this Consent Decree, or any other event affecting Defendant's performance under this Decree, or the performance of any Facility, may pose an immediate threat to the public health or welfare or the environment, Defendant shall notify U.S. EPA and the Affected State, orally or by electronic or facsimile transmission as soon as possible, but no later than 24 hours after Defendant first knew, or should have known, of the violation or event. This procedure is in addition to the requirements set forth in the preceding Paragraph.

92. All reports shall be submitted to the persons designated in Section XXI of this Consent Decree (Notices).

93. Each report submitted by Defendant under this Section shall be signed by an official of the submitting party and include the following certification:

> I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

This certification requirement does not apply to emergency or similar notifications where compliance would be impractical.

94. The reporting requirements of this Consent Decree do not relieve Defendant of any reporting obligations required by the Clean Air Act or implementing regulations, or by any other federal, State, or local law, regulation, permit, or other requirement.

95. Any information provided pursuant to this Consent Decree may be used by the United States in any proceeding to enforce the provisions of this Consent Decree and as otherwise permitted by law.

SECTION XV: STIPULATED PENALTIES

96. Defendant shall be liable for stipulated penalties to the United States and Affected State(s) for violations of this Consent Decree as specified in Table 1 below, unless excused under Section XVI (Force Majeure). A violation includes failing to perform any obligation required by the terms of this Decree, including any work plan or schedule approved under this Decree, according to all applicable requirements of this Decree and within the specified time schedules established by or approved under this Decree. Violation of an Emission Limit that is based on a 30-Day Rolling Average is a violation on every Day on which the average is based. Each subsequent Day of violation after a violation of a 30-Day Rolling Average Emission Limit is subject to the corresponding penalty per Day specified in Table 1, below. Where a violation of a 30-Day Rolling Average Emission Limit (for the same pollutant and from the same source) recurs within periods of less than thirty (30) Days, Defendant shall not pay a daily stipulated penalty for any Day of recurrence for which a stipulated penalty is already payable. Stipulated penalties may only be assessed once for a given Day or month within any averaging period for violation of any particular Emission Limit. Stipulated penalties for consecutive periods of

violation of an Emission Limit shall be calculated based upon the violation of the Emission Limit for the same pollutant from the same Kiln.

TABLE 1

Consent Decree Violation	Stipulated Penalty
Failure to pay the civil penalty as specified in Section IV (Civil Penalty) of this Consent Decree.	$7,500 for each Day
Failure to comply with a 30-Day Rolling Average Emission Limit for NO_x or SO_2 where the emissions are less than 5% in excess of the limits set forth in this Consent Decree.	$1,500 for each Day during any 30-Day rolling period where the violation is less than 5% in excess of the Limit.
Failure to comply with a 30-Day Rolling Average Emission Limit for NO_x or SO_2 where the emissions are equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree	$3,000 for each Day during any 30-Day rolling period where the violation is equal to or greater than 5% but less than 10% in excess of the Limit.
Failure to comply with a 30-Day Rolling Average Emission Limit for NO_x or SO_2 where the emissions are equal to or greater than 10% in excess of the limits set forth in this Consent Decree	$5,000 for each Day during any 30-Day rolling period where the violation is equal to or greater than 10% in excess of the Limit.
Failure to comply with any PM Emission Limit based on performance test data	$5,000 for each Day of violation
Failure to comply with a 12-Month Rolling Tonnage Limit at Midlothian Kiln 3 for NO_x or SO_2 where the tons of pollutant are less than 5% in excess of the applicable 12-Month Rolling Tonnage Limit set forth in this Consent Decree.	$7,500 for each month during the initial 12 months, and $10,000 for each consecutive month thereafter of a violation of the 12-Month Rolling Tonnage Limit where the violation is less than 5% in excess of the Limit.

Failure to comply with a 12-Month Rolling Tonnage Limit at Midlothian Kiln 3 for NO_x or SO_2 where the tons of pollutant are greater than 5% and less than 10% in excess of the applicable 12-Month Rolling Tonnage Limit set forth in this Consent Decree.	\$10,000 for each month during the initial 12 months, and \$15,000 for each consecutive month thereafter of a violation of the 12-Month Rolling Tonnage Limit where the violation is greater than 5% and less than 10% in excess of the Limit.
Failure to comply with a 12-Month Rolling Tonnage Limit at Midlothian Kiln 3 for NO_x or SO_2 where the tons of pollutant are greater than 10% in excess of the applicable 12-Month Rolling Tonnage Limit set forth in this Consent Decree.	\$20,000 for each month during the initial 12 months, and \$32,500 for each consecutive month thereafter of a violation of the 12-Month Rolling Tonnage Limit where the violation is greater than 10% in excess of the Limit.
Failure to install or Commence Continuous Operation or Continuously Operate Control Technology at a Kiln required by the deadlines established in Sections V, VI and VII of this Consent Decree.	\$5,000 for each consecutive Day during the first 20 Days, \$ 10,000 for each consecutive Day for the next 40 Days, and \$32,500 for each consecutive Day thereafter.
Failure to install or Commence Continuous Operation or Continuously Operate Control Technology at a Kiln upon re-commencing operation of that Kiln following Temporary Cessation of Kiln Operation under Section IX of this Consent Decree	\$100,000 for the first Day upon re-commencing Kiln Operation and \$32,500 for each Day thereafter
Failure to apply for any permit or permit amendment or seek a SIP approval required by Section XII (Permits)	\$1,000 for each Day for each such failure
Failure to install or operate a CEMS or other monitoring device in conformance with the requirements of Section V.B. (NOx Continuous Emission Monitoring Systems), Section VI.B (SO_2 Continuous Emission Monitoring Systems), Section VII.B (PM Continuous Parametric Monitoring Systems), or Appendix B, as applicable.	\$1,000 for each Day for each such failure
PM CPMS deviations from the Site Specific Operating Limit leading to more than four required performance tests in a 12-month period (rolling monthly)	\$1,000 for each Day for each such failure

Failure to timely inspect, repair, or retest after a deviation of the Site Specific Operating Limit, as required in Appendix B	$750 for each Day during the first 10 Days, $1,000 per Day thereafter
Failure to timely submit, modify, or implement, as approved, a report, plan, study, analysis, protocol, or other submittal required by this Consent Decree	$750 for each Day during the first 10 Days, $1,000 per Day thereafter
Any other violation of this Consent Decree	$1,000 for each Day for each violation

97. Subject to the provisions of Paragraph 96 above, stipulated penalties under this Section shall begin to accrue on the Day after performance is due or on the Day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases. Stipulated penalties shall accrue simultaneously for separate violations of this Consent Decree. The United States or Affected State(s), or all of the foregoing, may seek stipulated penalties under this Section. Where both the United States and the Affected State(s) seek stipulated penalties for the same violation of this Consent Decree, Defendant shall pay two thirds (2/3) of the amount in demand to the United States and one third (1/3) to the Affected State(s). If the stipulated penalty arises in relation to the Seattle Kiln, the portion of the penalty due to the Affected State shall be paid to Puget Sound Clean Air Agency.

98. Defendant shall pay any stipulated penalty within thirty (30) Days of receiving the United States' and/or the Affected State(s') written demand.

99. The United States may, in the unreviewable exercise of its discretion, reduce or waive stipulated penalties otherwise due the United States under this Consent Decree. An Affected State may, in its unreviewable exercise of its discretion, reduce or waive stipulated penalties otherwise due the Affected State under this Consent Decree.

100. Defendant may assert an affirmative defense to stipulated penalties if it exceeds an emission rate due to Startup, Shutdown or Malfunction emissions provided that Defendant timely meets the notification requirements in Paragraph 90 and proves by a preponderance of the evidence that the excess emissions:

a. Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

b. Could not have been prevented through careful planning, proper design or better operation and maintenance practices, and

c. Did not stem from any activity or event that could have been foreseen and avoided, or planned for, and

d. Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance, and

e. Repairs were made as expeditiously as possible when the applicable emission limits were being exceeded;and

f. The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions, and

g. If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage, and

h. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health, and

i. All emissions monitoring and control systems were kept in operation if at all possible consistent with safety and good air pollution control practices, and

j. All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs, and

k. At all times, the affected facility was operated in a manner consistent with good practices for minimizing emissions, and

l. A written root cause analysis has been prepared the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

101. Stipulated penalties shall continue to accrue as provided in this Section, during any Dispute Resolution, but need not be paid until the following:

a. If the dispute is resolved by agreement between the Parties or by a decision of the United States or the Affected State that is not appealed to the Court, Defendant shall pay accrued penalties determined to be owing, together with interest accruing from the 31st Day after the written demand in Paragraph 97, within 30 Days of the effective date of the agreement or the receipt of U.S. EPA's or the Affected State's decision or order.

b. If the dispute is appealed to the Court and the United States or the Affected State is the prevailing party, in whole or in part, as may be determined by the Court, Defendant shall pay all accrued penalties determined by the Court to be owing, together with interest accruing from the 31st Day after the written demand in

Paragraph 97, within 60 Days of receiving the Court's decision or order, except as provided in Subparagraph c, below.

c. If any Party appeals the District Court's decision, Defendant shall pay all accrued penalties determined to be owing, together with interest accruing from the 31st Day after the written demand in Paragraph 97, within 15 Days of receiving the final appellate court decision.

102. Defendant shall pay stipulated penalties owing to the United States and an Affected State in the manner set forth and with the confirmation notices to the persons specified in Paragraphs 9 and 10, except that the transmittal letter shall state that the payment is for stipulated penalties and shall state for which violation(s) the penalties are being paid. Defendant shall pay stipulated penalties owing to an Affected State in accordance with the instructions provided below:

TABLE 2

State Agency	**Payment Instructions**
State of Arkansas	Arkansas Department of Environmental Quality Fiscal 5301 Northshore Drive North Little Rock, AR 72118-5317
Idaho Department of Environmental Quality	Check payable and mailed to: Fiscal Office Idaho Department of Environmental Quality 1410 N. Hilton Boise, Idaho 83706

State of Kansas	Check payable and mailed to: Kansas Department of Health and Environment Address: Kansas Department of Health and Environment 1000 SW Jackson Street, Suite 310 Topeka, Kansas 66612-1366 Attn: Sheila Pendleton The memorandum portion of the check shall identify the case number.
State of Montana	Check or money order, made payable to the "Montana Department of Environmental Quality," and sent to the Department at John L. Arrigo, Administrator Enforcement Division Department of Environmental Quality 1520 East Sixth Avenue P.O. Box 200901 Helena, MT 59620-0901
State of Nebraska	Checks shall be made to Cass County District Court Clerk and shall be mailed with notice referring to this action, to: Katherine J. Spohn Deputy Attorney General 2115 State Capitol Lincoln, NE 68508-8920
State of Oregon	Check payable to State Treasurer, State of Oregon, mailed to: DEQ, Business Office 811 S.W. Sixth Avenue Portland, OR 97204
State of Utah	Check payable and mailed to: Utah Division of Air Quality Multi Agency State Office Building 195 North 1950 West, Fourth Floor Salt Lake City, Utah 84116

Washington State Department of Ecology	Check payable and mailed to: Department of Ecology Cashiering Unit P.O. Box 47611 Olympia, WA 98504-7611 The Memorandum on the check should reference NR13168001 and “Ash Grove Settlement”
Puget Sound Clean Air Agency	Check payable to “Puget Sound Clean Air Agency”: Craig Kenworthy Executive Director Puget Sound Clean Air Agency 1904 3rd Ave, Suite 105 Seattle WA USA 98101

103. Defendant shall not deduct stipulated penalties paid under this Section in calculating their federal income tax.

104. If Defendant fails to pay stipulated penalties according to the terms of this Consent Decree, Defendant shall be liable for interest on such penalties, as provided for in 28 U.S.C. § 1961, accruing as of the date payment became due. Nothing in this Paragraph shall be construed to limit the United States or any Affected State from securing any remedy otherwise provided by law for Defendant’s failure to pay any stipulated penalties.

105. Subject to the provisions of Section XIX of this Consent Decree (Effect of Settlement/Reservation of Rights), the stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to the United States or an Affected State for Defendant’s violation of this Consent Decree or applicable law. Where a violation of this Consent Decree is also a violation of any applicable statute or regulation, Defendant shall be allowed a credit, dollar for dollar, for any stipulated penalties paid, against

any statutory penalties imposed for such violation, including penalties resulting from enforcement pursuant to Paragraphs 128 and 129.

SECTION XVI: FORCE MAJEURE

106. "Force Majeure" (for purposes of this Consent Decree) is defined as any event arising from causes beyond the control of Defendant, of any entity controlled by Defendant or Defendant's Contractors that causes a delay or impediment to performance in complying with any obligation under this Consent Decree despite the Defendant's best efforts to fulfill the obligation. The requirement that the Defendant exercise best efforts to fulfill the obligation includes using best efforts to anticipate any potential Force Majeure event and best efforts to address the effects of any such event (a) as it is occurring and (b) after it has occurred to prevent or minimize any resulting delay and the effects of such event to the greatest extent possible. Force Majeure does not include the Defendant's financial inability to perform any obligation under this Consent Decree. Force majeure may include Defendant's inability after demonstrating compliance with the requirements of Paragraph 76 to obtain a permit or approval such that there is adequate time to install, commence operation, and shake down improvements necessary to satisfy a compliance obligation under this Consent Decree.

107. If any event occurs or has occurred that may delay the performance of any obligation under this Consent Decree that Defendant claims was caused by a force majeure event, Defendant shall provide notice orally or by electronic or facsimile transmission to the representatives of U.S. EPA and the Affected State(s) designated to receive notice pursuant to Section XXI (Notices) within 7 Business Days of when Defendant first knew that the event might cause a delay. Within 21 Days thereafter, Defendant shall provide in writing to U.S. EPA and the Affected State(s) an explanation and description of the reasons for the delay; the

anticipated duration of the delay; all actions taken or to be taken to prevent or minimize the delay; a schedule for implementation of any measures to be taken to prevent or mitigate the delay or the effect of the delay; Defendant's rationale for attributing such delay to a force majeure event if it intends to assert such a claim; and a statement as to whether, in the opinion of Defendant, such event may cause or contribute to an endangerment to public health, welfare or the environment. Defendant shall include with any notice all available documentation supporting the claim that the delay was attributable to a force majeure. Failure to comply with the above requirements shall preclude Defendant from asserting any claim of force majeure for that event for the period of time of such failure to comply, and for any additional delay caused by such failure. Defendant shall be deemed to know of any circumstance of which Defendant, any entity controlled by Defendant, or Defendant's contractors knew or should have known.

108. If U.S. EPA, after a reasonable opportunity for review and comment by the Affected State, agrees that the delay or anticipated delay is attributable to a force majeure event, the time for performance of the obligations under this Consent Decree that are affected by the force majeure event will be extended by U.S. EPA, after a reasonable opportunity for review and comment by the State, for such time as is necessary to complete those obligations. An extension of the time for performance of the obligations affected by the force majeure event shall not, of itself, extend the time for performance of any other obligation. U.S. EPA will notify Defendant in writing of the length of the extension, if any, for performance of the obligations affected by the force majeure event.

109. If U.S. EPA, after a reasonable opportunity for review and comment by the Affected State, does not agree that the delay or anticipated delay has been or will be caused by a force majeure event, U.S. EPA will notify Defendant in writing of its decision.

110. If Defendant elects to invoke the dispute resolution procedures set forth in Section XVII (Dispute Resolution), it shall do so no later than 15 Days after receipt of U.S. EPA's notice. In any such proceeding, Defendant shall have the burden of demonstrating by a preponderance of the evidence that the delay or anticipated delay has been or will be caused by a force majeure event, that the duration of the delay or the extension sought was or will be warranted under the circumstances, that best efforts were exercised to avoid and mitigate the effects of the delay, and that Defendant complied with the requirements of Paragraphs 106 and 107, above. If Defendant carries this burden, the delay at issue shall be deemed not to be a violation by Defendant of the affected obligation of this Consent Decree identified to U.S. EPA and the Court.

SECTION XVII: DISPUTE RESOLUTION

111. Unless otherwise expressly provided for in this Consent Decree, the dispute resolution procedures of this Section shall be the exclusive mechanism to resolve disputes arising under or with respect to this Consent Decree. Defendant's failure to seek resolution of a dispute under this Section shall preclude Defendant from raising any such issue as a defense to an action by the United States or Affected State(s) to enforce any obligation of Defendant arising under this Decree.

112. Informal Dispute Resolution for Emission Limit Setting Process under Appendix A. If Defendant invokes Dispute Resolution regarding an EPA established alternative final 30-Day Rolling Average Emission Limit, Defendant shall simultaneously initiate the process set forth in this Paragraph to hire an independent contractor who will be tasked to analyze the Emission Limits established by EPA and proposed by Defendant and to provide, for the benefit of both U.S. EPA and Defendant, the reports, analysis, and services identified in this Paragraph, below, by the specified deadlines. Defendant shall bear all costs associated with the contractor's

work up to $150,000, and shall provide the contractor access to records, employees, contracts, and facilities which are reasonably necessary to complete the report required by this Paragraph. If costs to perform the work set forth in the Scope of Work (SOW) requirements described in Paragraph 112.b are expected to be higher than $150,000, Defendant and U.S. EPA will, upon written mutual agreement, limit or modify the nature and/or scope of the work to be performed under Paragraph 112.b to meet the expenditure limitation. For purposes of this Paragraph, "independent" shall mean a qualified professional with at least 5 years of experience relating to the operations of and/or emissions from cement kilns or similar sources and who has not previously been employed or retained by Defendant in any capacity (unless otherwise approved by U.S. EPA).

a. Defendant shall submit to U.S. EPA for approval, the name and qualifications of a proposed contractor for this engagement at the time it submits its Written Notice of Dispute in accordance with Section XXI (Notices). If U.S. EPA disapproves of the contractor, Defendant is required to propose to U.S. EPA within 15 Days of the disapproval a different contractor, also subject to U.S. EPA's approval. If U.S. EPA disapproves the third contractor, U.S. EPA may choose and identify to Defendant the Contractor to be employed. Defendant shall enter into a contract with the Contractor, containing the Statement of Work requirements in Paragraph 112.b, below (as modified to meet the expenditure limitations), within 7 Days of U.S. EPA's approval or final identification of the Contractor.

b. As part of the contract, Defendant shall provide to the Contractor a SOW which will include a requirement or direction to:

i. Analyze the baseline data, if available, as well as the Demonstration Report, proposed Emission Limits, data collected during the demonstration phase and any other relevant data from the Facility;

ii. Submit to U.S. EPA and Defendant, a report on the appropriate 30-day rolling emission limit, consistent with the methodology set forth in and information collected through Appendix A, as applicable, based upon the injection rates and the operational parameters approved as part of the Optimization Report required by Appendix A, as applicable. The conclusions of this report shall be based on all of the information and data collected during the baseline, Optimization and Demonstration Periods, as applicable, as well as any additional site-specific information available to the Contractor. The report shall include a section on whether the data collected during the Demonstration Period is representative of normal operations of the unit, as well as a recommended final Emission Limit using the protocol and procedures in Appendix A, as applicable;

iii. Make available to U.S. EPA any and all data evaluated, and reveal all communications with Defendant in the course of work pursuant to the SOW. The contractor shall also be tasked in the SOW to attend up to 40 hours of meetings specifically requested by U.S. EPA, to answer questions concerning any analysis or work undertaken pursuant to the SOW. Defendant may attend any such meeting between U.S. EPA and the contractor. The SOW shall make clear that the contractor is free to discuss their analysis, findings and the content of their report with U.S. EPA prior to the completion of the report; and

iv. Complete the contractor report within 45 Days from the time of the effective date of the contract.

c. The results of the contractor report will inform the parties in the process of engaging in informal dispute resolution on the proposed and final permit limit.

113. If the United States and Affected State are unable to reach agreement on a final 30-Day Rolling Average Emission Limit within 20 Days after receipt of the contractor report by EPA, Defendant may request formal dispute resolution under Paragraph 115 of this Consent Decree. The contractor report shall be part of the Dispute Resolution record in any formal dispute proceedings under this Consent Decree.

114. <u>Informal Dispute Resolution with Respect to All Other Disputes</u>. Any dispute subject to Dispute Resolution under this Consent Decree shall first be the subject of informal negotiations. The dispute shall be considered to have arisen when Defendant sends the United States and Affected State(s) a written Notice of Dispute. Such Notice of Dispute shall state clearly the matter in dispute. The period of informal negotiations shall not exceed 20 Days from the date the dispute arises, unless that period is modified by written agreement. If the Parties cannot resolve a dispute by informal negotiations, then the position advanced by the United States, after consultation with the Affect State(s), shall be considered binding unless, within 10 Days after the conclusion of the informal negotiation period, Defendant invokes formal dispute resolution procedures as set forth below.

115. <u>Formal Dispute Resolution</u>. Defendant shall invoke formal dispute resolution procedures, within the time period provided in the preceding Paragraph, by serving on the United

States and Affected State(s) a written Statement of Position regarding the matter in dispute. The Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting Defendant's position and any supporting documentation relied upon by Defendant.

116. The United States, after consultation with the Affected State(s), shall serve its Statement of Position within 45 Days of receipt of Defendant's Statement of Position. The United States' Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting that position and any supporting documentation relied upon by the United States. The United States' Statement of Position shall be binding on Defendant, unless Defendant files a motion for judicial review of the dispute in accordance with the following Paragraph.

117. Defendant may seek judicial review of the dispute by filing with the Court and serving on the United States and Affected State(s), in accordance with Section XXI of this Consent Decree (Notices), a motion requesting judicial resolution of the dispute. The motion must be filed within 20 Days of receipt of the United States Statement of Position pursuant to the preceding Paragraph. The motion shall contain a written statement of Defendant's position on the matter in dispute, including any supporting factual data, analysis, opinion, or documentation, and shall set forth the relief requested and any schedule within which the dispute must be resolved for orderly implementation of the Consent Decree.

118. The United States, after consultation with the Affected State(s), shall respond to Defendant's motion within the time period allowed by the Local Rules of this Court. Defendant may file a reply memorandum, to the extent permitted by the Local Rules.

119. Standard of Review. Except as otherwise provided in this Consent Decree, the Court shall decide all disputes pursuant to the applicable principles of law. The disputing parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute in the Parties initial filings with the Court under Paragraphs 117 and 118 of this Consent Decree. Except as otherwise provided in this Consent Decree, in any dispute brought under this Section XVII (Dispute Resolution), Defendant shall bear the burden of demonstrating that its position complies with this Consent Decree.

120. The invocation of dispute resolution procedures under this Section shall not, by itself, extend, postpone, or affect in any way any obligation of Defendant under this Consent Decree, unless and until final resolution of the dispute so provides. Stipulated penalties with respect to the disputed matter shall continue to accrue from the first Day of noncompliance, but payment shall be stayed pending resolution of the dispute as provided in Paragraph 101. If Defendant does not prevail on the disputed issue, stipulated penalties shall be assessed and paid as provided in Section XV (Stipulated Penalties).

SECTION XVIII: INFORMATION COLLECTION AND RETENTION

121. The United States and each Affected State and their representatives, including attorneys, contractors, and consultants, shall have the right of entry into any facility covered by this Consent Decree, at all reasonable times, upon presentation of credentials, to:

a. monitor the progress of activities required under this Consent Decree;

b. verify any data or information submitted to the United States or the Affected State in accordance with the terms of this Consent Decree;

c. conduct performance testing;

d. obtain documentary evidence, including photographs and similar data; and

e. assess Defendant's compliance with this Consent Decree.

122. Upon request, Defendant shall provide U.S. EPA and the Affected State and their authorized representatives copies of analytical data from Kiln performance testing performed by Defendant. Upon request, U.S. EPA and the Affected State shall provide Defendant copies of analytical data from Kiln performance testing performed by U.S. EPA or the Affected State.

123. Until five years after the termination of this Consent Decree, Defendant shall retain, and shall instruct its contractors and agents to preserve, all non-identical copies of all documents, records, or other information (including documents, records, or other information in electronic form) in its or its contractors' or agents' possession or control, or that come into its or its contractors' or agents' possession or control, and that relate in any manner to Defendant's performance of its obligations under this Consent Decree. This information-retention requirement shall apply regardless of any contrary corporate or institutional policies or procedures. At any time during this information-retention period, upon request by the United States or the Affected State, Defendant shall provide copies of any documents, records, or other information required to be maintained under this Paragraph.

124. At the conclusion of the information-retention period provided in the preceding Paragraph, Defendant shall notify the United States and the Affected State at least 90 Days prior to the destruction of any documents, records, or other information subject to the requirements of the preceding Paragraph and, upon request by the United States or Affected State, Defendant shall deliver any such documents, records, or other information to U.S. EPA or Affected State. Defendant may assert that certain documents, records, or other information is privileged under the attorney-client privilege or any other privilege recognized by federal law. If Defendant asserts such a privilege, it shall provide the following: (1) the title of the document, record, or

information; (2) the date of the document, record, or information; (3) the name and title of each author of the document, record, or information; (4) the name and title of each addressee and recipient; (5) a description of the subject of the document, record, or information; and (6) the privilege asserted by Defendant. However, no documents, records, or other information created or generated pursuant to the requirements of this Consent Decree shall be withheld on grounds of privilege.

125. Defendant may also assert that information required to be provided under this Section is protected as Confidential Business Information ("CBI") under 40 C.F.R. Part 2. As to any information that Defendant seeks to protect as CBI, Defendant shall follow the procedures set forth in 40 C.F.R. Part 2.

126. This Consent Decree in no way limits or affects any right of entry and inspection, or any right to obtain information, held by the United States or Affected State pursuant to applicable federal or state laws, regulations, or permits, nor does it limit or affect any duty or obligation of Defendant to maintain documents, records, or other information imposed by applicable federal or state laws, regulations, or permits.

SECTION XIX: EFFECT OF SETTLEMENT/RESERVATION OF RIGHTS

127. Resolution of Liability. With respect to the emissions of NO_x, SO_2, and PM (including PM_{10} and $PM_{2.5}$) from the Facilities identified in Paragraph 8.x, entry of this Consent Decree shall resolve all civil liability of Defendant to the United States and the Affected States for any violations of the following requirements resulting from or arising out of a construction, reconstruction or modification that commenced prior to the Date of Lodging of the Consent Decree:

a. The PSD requirements at Part C of Subchapter I of the Act, 42 U.S.C. § 7475, and the regulations promulgated thereunder at 40 C.F.R. §§ 52.21 and 51.166; "Plan Requirements for Non-attainment Areas" at Part D of Subchapter I of the Act, 42 U.S.C. §7503 and the regulations promulgated thereunder at 40 C.F.R. §§ 51.165(a) and (b), 40 C.F.R. Part 51 (Appendix S), and 40 C.F.R. § 52.24; any applicable federally-enforceable State, regional, or local regulations that implement, adopt, or incorporate the specific federal regulatory requirements identified above; and, any applicable State, regional, or local regulations that implement, adopt, or incorporate the specific federal regulatory requirements identified above.

b. Title V of the Clean Air Act, 42 U.S.C. §§ 7661-7661f; any applicable federally-enforceable State, regional, or local regulations that implement, adopt, or incorporate the specific federal regulatory requirements of Title V; and, any applicable State, regional, or local regulations that implement, adopt, or incorporate the specific federal regulatory requirements of Title V, but only to the extent that such claims are based on the Defendant's failure to obtain an operating permit that reflects applicable requirements imposed under Parts C or D of Subchapter I of the Clean Air Act as a result of construction or modification of those portions of the Facilities identified in Paragraph 8.x that: (a) are affected facilities under 40 C.F.R. Part 60, Subparts F, Y or OOO, and/or affected sources under 40 C.F.R. Part 63, Subpart LLL, and (b) where that construction or modification commenced prior to the Date of Lodging; and

c. The New Source Performance Standards Provisions of the Clean Air Act, 42 U.S.C. § 7411; and the regulations codified at 40 C.F.R. Part 60, Subparts F, Y or OOO; any applicable federally-enforceable State, regional, or local regulations that implement, adopt, or incorporate the specific federal regulatory requirements identified above; and, any applicable State, regional, or local regulations that implement, adopt, or incorporate the specific federal regulatory requirements identified above.

128. Notwithstanding the resolution of liability in Paragraph 127, nothing in this Consent Decree precludes the United States and/or the Affected States from seeking from Defendant injunctive relief, penalties, or other appropriate relief for violations by Defendant of the regulatory requirements identified in Paragraph 127 resulting from (1) construction or modification that commenced prior to the Date of Lodging of the Consent Decree, if the resulting violations are not arising from the conduct specifically resolved by Paragraph 127 or do not relate to NO_x, SO_2 or PM (including PM_{10} and $PM_{2.5}$); or (2) any construction, Reconstruction or modification that commences after the Date of Lodging of the Consent Decree.

129. The United States and the Affected States reserve all legal and equitable remedies available to enforce the provisions of this Consent Decree. This Consent Decree shall not be construed to limit the rights of the United States or the Affected States to obtain penalties or injunctive relief under the Act or implementing regulations, or under other federal or State laws, regulations, or permit conditions, except as expressly specified in Paragraph 127. The United States and the Affected States further reserve all legal and equitable remedies to address any imminent and substantial endangerment to the public health or welfare or the environment

arising at, or posed by, one or more of the Defendant's Facilities, whether related to the violations addressed in this Consent Decree or otherwise.

130. In any subsequent administrative or judicial proceeding initiated by the United States or the Affected States for injunctive relief, civil penalties, other appropriate relief relating to the Facilities or Defendant's violations, Defendant shall not assert, and may not maintain, any defense or claim based upon the principles of waiver, *res judicata*, collateral estoppel, issue preclusion, claim preclusion, claim-splitting, or other defenses based upon any contention that the claims raised by the United States or an Affected State in the subsequent proceeding were or should have been brought in the instant case, except with respect to claims that have been specifically resolved pursuant to Paragraph 127 of this Decree.

131. This Consent Decree is not a permit, or a modification of any permit, under any federal, State, or local laws or regulations. Defendant is responsible for achieving and maintaining complete compliance with all applicable federal, State, and local laws, regulations, and permits; and the Defendant's compliance with this Consent Decree shall be no defense to any action commenced pursuant to any such laws, regulations, or permits, except as set forth herein. The United States and the Affected States do not, by their consent to the entry of this Consent Decree, warrant or aver in any manner that Defendant's compliance with any aspect of this Consent Decree will result in compliance with provisions of the Act, 42 U.S.C. § 7401 *et seq.*, or with any other provisions of federal, State, or local laws, regulations, or permits.

132. This Consent Decree does not limit or affect the rights of Defendant or of the United States or the Affected States against any third parties, not party to this Consent Decree, nor does it limit the rights of third parties, not party to this Consent Decree, against Defendant, except as otherwise provided by law.

133. This Consent Decree shall not be construed to create rights in, or grant any cause of action to, any third party not party to this Consent Decree.

SECTION XX: COSTS

134. The Parties shall bear their own costs of this action, including attorneys' fees, except that the United States and the Affected State(s) shall be entitled to collect the costs (including attorneys' fees) incurred in any action necessary to collect any portion of the civil penalty or any stipulated penalties due but not paid by Defendant.

SECTION XXI: NOTICES

135. Unless otherwise specified herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and addressed as follows:

To U.S. EPA:

Phillip Brooks
U.S. Environmental Protection Agency
MC 2242A
1200 Pennsylvania Ave. NW
Washington, D.C. 20460

And

For all submissions referring to the Foreman and Midlothian Facilities:
David Garcia, Associate Director Air/Toxics and Inspection Coordination Branch
U.S. EPA Region 6
1445 Ross Avenue
Suite 1200, MC 6EN-A
Dallas, Texas 75202

For all submissions referring to the Louisville and Chanute Facilities:
Rebecca Weber
U.S. EPA Region VII
11201 Renner Blvd.
Lenexa, KS 66219

For all submissions referring to the Montana City and Leamington Facilities:

Cynthia Reynolds, 8ENF-AT
U.S. EPA Region VIII
1595 Wynkoop St.
Denver, CO 80202-1129

For all submissions referring to the Inkom, Seattle and Durkee Facilities:
John Keenan
U.S. EPA Region X
1200 Sixth Avenue Suite 900
Seattle, WA 98101

To the United States (in addition to the U.S. EPA addresses above):

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
Box 7611 Ben Franklin Station
Washington, D.C. 20044-7611
Re: DOJ No. 90-5-2-1-08221

To State Agency Plaintiffs:

For all submissions referring to the Foreman Facility, to the State of Arkansas:
Arkansas Department of Environmental Quality
Attn: Mike Porta
5301 Northshore Drive
North Little Rock, AR 72118-5317

For all submissions referring to the Inkom Facility, to the Idaho Department of Environmental Quality
Mike Simon
Idaho Department of Environmental Quality
1410 N. Hilton
Boise, ID 83706

For all submissions referring to the Chanute Facility, to the Kansas Department of Health and Environment:
Timothy E. Keck, Deputy Chief Counsel
Kansas Department of Health and Environment
1000 SW Jackson, Suite 560
Topeka, KS 66612-1371

For all submissions referring to the Montana City Facility, to the State of Montana:
John L. Arrigo, Administrator
Enforcement Division
Department of Environmental Quality

1520 East Sixth Avenue
P.O. Box 200901
Helena, MT 59620-0901

For all submissions referring to the Louisville Facility, to the Nebraska Department of Environmental Quality
Shelley Schneider
Nebraska Department of Environmental Quality
1200 N Street, Suite 400
Lincoln, NE 68509-8922

For all submissions referring to the Durkee Facility, to the State of Oregon:
Linda Hayes-Gorman, Eastern Region Administrator
Oregon Department of Environmental Quality
475 NE Bellevue Dr. #110
Bend, OR 97702

For all submissions referring to the Seattle Facility, to the Puget Sound Clean Air Agency:
Laurie Halvorson, Director - Compliance and Legal
Puget Sound Clean Air Agency
1904 Third Avenue - Suite 105
Seattle, WA 98101

For all submissions referring to the Leamington Facility, to the State of Utah:
Utah Division of Air Quality
Attn: Rusty Ruby
Multi Agency State Office Building
195 North 1950 West, Fourth Floor
Salt Lake City, Utah 84116

For all submissions referring to the Seattle Facility, the Washington State Department of Ecology:
Stuart Clark
Air Quality Manager
Washington State Department of Ecology
PO Box 47600
Olympia, WA 98504-7600

To Ash Grove Cement Company:

Curtis Lesslie
Vice President Environmental Affairs
Ash Grove Cement Company
11011 Cody St.
Overland Park, KS 66210

Steve Ryan
Vice President & General Counsel
Ash Grove Cement Company
11011 Cody St.
Overland Park, KS 66210

Tom Wood
Outside Counsel to Ash Grove Cement Company
Stoel Rives LLP
900 SW Fifth Ave.; Suite 2600
Portland, OR 97204

136. Any Party may, by written notice to the other Parties, change its designated notice recipient or notice address provided above. In addition, any Party may submit any written notification, submission, or communication under this Decree by electronic means.

137. Notices submitted pursuant to this Section shall be deemed submitted upon mailing, unless otherwise provided in this Consent Decree or by mutual agreement of the Parties in writing.

SECTION XXII: EFFECTIVE DATE

138. The Effective Date of this Consent Decree shall be the date upon which this Consent Decree is entered by the Court or a motion to enter the Consent Decree is granted, whichever occurs first.

SECTION XXIII: RETENTION OF JURISDICTION

139. The Court shall retain jurisdiction over this case until termination of this Consent Decree, for the purpose of resolving disputes arising under this Decree or entering orders modifying this Decree, pursuant to Sections XVII (Dispute Resolution) and XXIV (Modification), or effectuating or enforcing compliance with the terms of this Decree.

SECTION XXIV: MODIFICATION

140. The terms of this Consent Decree, including the Appendices, may be modified only by a subsequent written agreement signed by any Affected State(s), the United States, and Defendant. With the exception of submittals under Appendix A and Appendix B that are approved or conditionally approved pursuant to Section XIII (Review and Approval of Submittals), and which are incorporated by reference in this Consent Decree upon such approval or conditional approval, where the modification constitutes a material change to this Decree it shall be effective only upon approval by the Court.

141. Any disputes concerning modification of this Decree shall be resolved pursuant to Section XVII of this Decree (Dispute Resolution), provided, however, that, instead of the burden of proof provided by Paragraph 119, the Party seeking the modification bears the burden of demonstrating that it is entitled to the requested modification in accordance with Federal Rule of Civil Procedure 60(b).

SECTION XXV: TERMINATION

142. Termination as to an Individual Facility. After Defendant has satisfied the requirements of Sections V (NO_x Control Technology, Emission Limits, and Monitoring Requirements), VI (SO_2 Control Technology, Emission Limits, and Monitoring Requirements), Section VII (PM Control Technology, Emission Limits and Monitoring Requirements), and Section XII (Permits) of this Decree and has Continuously Operated any Control Technology as required by this Consent Decree for that Kiln for a period of two years at an individual Facility, Defendant may serve upon the United States and the Affected State a Request for Termination of the Consent Decree as it relates to that Facility, stating that Defendant has satisfied those requirements, together with all necessary supporting documentation. If the United States and the

Affected State agree that the Decree as it relates to an individual Facility may be terminated, the Parties shall submit, for the Court's approval, a joint stipulation terminating those provisions of the Decree. Notwithstanding the foregoing, operation of the Replacement Montana City Kiln for two years is not required prior to termination so long as the SO_2 and NO_x Emission Limits required by Paragraphs 29 and 48, or more stringent limits, are included in the preconstruction permit required under those Paragraphs.

143. Complete Termination. After the Defendant has satisfied the requirements of Sections V (NO_x Control Technology, Emission Limits, and Monitoring Requirements), VI (SO_2 Control Technology, Emission Limits, and Monitoring Requirements), Section VII (PM Control Technology, Emission Limits, and Monitoring Requirements), Section VIII (Other Injunctive Relief) and Section XII (Permits) of this Decree and has maintained Continuous Operation of all Control Technology as required by this Consent Decree for a period of two years at all Facilities, has complied with all other requirements of this Consent Decree, and has paid the civil penalty and any accrued stipulated penalties as required by this Consent Decree, Defendant may serve upon the United States and the Affected States a Request for Termination, stating that Defendant has satisfied those requirements, together with all necessary supporting documentation. If the United States and the Affected State(s) agree that the Decree may be terminated, the Parties shall submit, for the Court's approval, a joint stipulation terminating the Decree.

144. If the United States and the Affected State(s) do not agree that the Decree as a whole, or as it relates to an individual Facility, may be terminated, Defendant may invoke Dispute Resolution under Section XVII of this Decree. However, Defendant shall not seek Dispute Resolution of any dispute regarding termination under this Section XXV of this Consent Decree until sixty (60) Days after service of its Request for Termination.

SECTION XXVI: PUBLIC PARTICIPATION

145. This Consent Decree shall be lodged with the Court for a period of not less than 30 Days for public notice and comment in accordance with 28 C.F.R. § 50.7. The United States reserves the right to withdraw or withhold its consent if the comments regarding the Consent Decree disclose facts or considerations indicating that the Consent Decree is inappropriate, improper, or inadequate. Defendant consents to entry of this Consent Decree without further notice and agrees not to withdraw from or oppose entry of this Consent Decree by the Court or to challenge any provision of the Decree, unless the United States has notified Defendant in writing that it no longer supports entry of the Consent Decree.

SECTION XXVII: SIGNATORIES/SERVICE

146. The Assistant Attorney General or Acting Assistant Attorney General for the Environment and Natural Resources Division of the Department of Justice and each undersigned representative of Defendant and the State Agency Plaintiffs certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind the Party he or she represents to this document.

147. This Consent Decree may be signed in counterparts, and its validity shall not be challenged on that basis. Defendant agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rules 4 and 5 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons. Defendant shall identify, on the attached signature page, the name, address and telephone number of an agent who is authorized to accept service of process by mail on behalf of Defendant with respect to all matters arising under or relating to this Consent Decree. All Parties

agree that Defendant need not file an answer or otherwise respond to the Complaint in this action unless or until the Court expressly declines to enter this Consent Decree.

SECTION XXVIII: INTEGRATION

148. This Consent Decree constitutes the final, complete, and exclusive agreement and understanding among the Parties with respect to the settlement embodied in the Decree and supersedes all prior agreements and understandings, whether oral or written, concerning the settlement embodied herein. No other document, nor any representation, inducement, agreement, understanding or promise constitutes any part of this Decree or the settlement it represents, nor shall it be used in construing the terms of this Decree.

SECTION XXIX: FINAL JUDGMENT

149. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment of the Court as to the United States and State Agency Plaintiffs and Defendant. The Court finds that there is no just reason for delay and therefore enters this judgment as a final judgment under Fed. R. Civ. P. 54 and 58.

SECTION XXX: APPENDICES

150. The following Appendices are attached to and incorporated as part of this Consent Decree:

"Appendix A" contains the Control Technology Demonstration/NO_x Emission Reduction Report Requirements that apply to each Kiln under this Decree subject to those requirements.

"Appendix B" contains the PM Continuous Parametric Monitoring System Requirements that apply to each Kiln under this Decree subject to those requirements.

"Appendix C" contains the Environmental Mitigation Project Requirements.

All terms in the Appendices shall be construed in a manner consistent with this Decree.

Dated and entered this ___ ___Day of _________, ____________.

____
UNITED STATES DISTRICT COURT JUDGE
District of Kansas

Signature Page to the Consent Decree in *United States et al v. Ash Grove Cement Company*

FOR PLAINTIFF UNITED STATES OF AMERICA:

[redacted] Date: 6/17/13

ROBERT G. DREHER
Acting Assistant Attorney General
Environment and Natural Resources Division
United States Department of Justice

[redacted] Date: 5/28/13

ANDREW C. HANSON
Trial Attorney
Environmental Enforcement Section
Environment and Natural Resources Division
United States Department of Justice
P.O. Box 7611
Washington, D.C. 20044-7611
(202) 514-9859 (Tel.)
(202) 616-6584 (Fax)
andrew.hanson2@usdoj.gov

Signature Page to the Consent Decree in *United States et al v. Ash Grove Cement Company*

FOR PLAINTIFF UNITED STATES OF AMERICA:

BARRY R. GRISSOM
United States Attorney, District of Kansas

[redacted]

EMILY METZGER #10750
Assistant United States Attorney
1200 Epic Center
301 N. Main
Wichita, Kansas 67202
(316) 269-6481
Emily.metzger@usdoj.gov

Date: May 6, 2013

Signature Page to the Consent Decree in *United States et al v. Ash Grove Cement Company*

FOR THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY:

[redacted]

CYNTHIA GILES
Assistant Administrator
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

Date: 4/18/13

[redacted]

PHILLIP A. BROOKS
Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

Date: 4/15/2013

Signature Page to the Consent Decree in *United States et al v. Ash Grove Cement Company*

FOR THE U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION 6:

[redacted]

Date: 2·27·13

JOHN BLEVINS
Director
Compliance Assurance and Enforcement Division
U.S. Environmental Protection Agency, Region 6
1445 Ross Avenue
Dallas, Texas 75202

Signature Page to the Consent Decree in *United States et al v. Ash Grove Cement Company*

FOR THE U.S. ENVIRONMENTAL PROTECTION AGENCY
REGION 7:

[redacted]

KARL BROOKS
Regional Administrator
U.S. Environmental Protection Agency
Region 7
11201 Renner Blvd.
Lenexa, Kansas 66219

Date: 4/18/13

[redacted]

DAVID COZAD
Regional Counsel
U.S. Environmental Protection Agency
Region 7
11201 Renner Blvd.
Lenexa, Kansas 66219

Date: 4/15/13

Signature Page to the Consent Decree in ***United States et al v. Ash Grove Cement Company***

FOR THE U.S. ENVIRONMENTAL PROTECTION AGENCY
REGION 8:

[redacted]

Date: MAR 22 2013

ANDREW M. GAYDOSH
Assistant Regional Administrator
Office of Enforcement, Compliance and
Environmental Justice
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, CO 80202

Signature Page to the Consent Decree in ***United States et al v. Ash Grove Cement Company***

FOR THE STATE OF ARKANSAS on behalf of the
Arkansas Department of Environmental Quality:

[redacted]

Date: 4/16/13

KENDRA AKIN JONES
Assistant Attorney General
On Behalf of the Arkansas Department
Of Environmental Quality
323 Center Street, Ste. 400
Little Rock, AR 72201
(501) 682-7383

Signature Page to the Consent Decree in *United States et al v. Ash Grove Cement Company*

FOR THE IDAHO DEPARTMENT OF ENVIRONMENTAL QUALITY:

[redacted]

Date: 4/16/13

for CURT FRANSEN
Director
Idaho Department of Environmental Quality
1410 N. Hilton
Boise, ID 83706

Signature Page to the Consent Decree in *United States et al v. Ash Grove Company*

FORE THE STATE OF KANSAS:

[redacted]

ROBERT MOSER
Secretary
Kansas Department of Health and Environment
1000 SW Jackson, Suite 580
Topeka, Kansas 66612

Date: 4/22/13

[redacted]

TIMOTHY E. KECK #14993
Deputy Chief Counsel
Kansas Department of Health and Environment
1000 SW Jackson, Suite 560
Topeka, Kansas 66612

Date: 4/22/13

Signature Page to the Consent Decree in *United States et al v. Ash Grove Cement Company*

FOR THE STATE OF MONTANA
DEPARTMENT OF ENVIRONMENTAL QUALITY

[redacted]

TRACY STONE-MANNING
Director
Montana Department of Environmental Quality

Date: 4/1/13

[redacted]

NORMAN J. MULLEN
Attorney
Montana Department of Environmental Quality

Date: 4-2-13

Signature Page to the Consent Decree in ***United States et al v. Ash Grove Cement Company***

FOR THE STATE OF NEBRASKA, on behalf of the
Nebraska Department of Environmental Quality:

[redacted]

Date: February 5, 2013

KATHERINE J. SPOHN
Deputy Attorney General
Office of the Nebraska Attorney General
2115 State Capitol
Lincoln, NE 68509-8920
Nebraska Bar Number 22979
(402) 471-2682
Email: katie.spohn@nebraska.gov

Signature Page to the Consent Decree in *United States et al v. Ash Grove Cement Company*

FOR THE STATE OF OREGON on behalf of the
Oregon Department of Environmental Quality:

[redacted]

Date: 2-13-13

STEPHANIE M. PARENT OSB #925908
Senior Assistant Attorney General
Oregon Department of Justice
Trial Division/Special Litigation Unit
1515 SW Fifth Street, Suite 410
Portland, OR 97201
Phone: (971) 673-1880
Fax: (971) 673-5000
Stephanie.M.Parent@doj.state.or.us

Signature Page to the Consent Decree in *United States et al v. Ash Grove Cement Company*

FOR THE PUGET SOUND CLEAN AIR AGENCY:

[redacted] Date: 2/7/2013

CRAIG KENWORTHY
Executive Director
Puget Sound Clean Air Agency
1904 3rd Avenue, Suite 105
Seattle WA 98101

Signature Page to the Consent Decree in *United States et al v. Ash Grove Cement Company*

FOR THE STATE OF UTAH on behalf of the
Utah Department of Environmental Quality:

[redacted]

BRYCE C. BIRD,
Director
Utah Division of Air Quality
Multi Agency State Office Building
195 North 1950 West, Fourth Floor
Salt Lake City, Utah 84116

Date: 04/11/2013

Signature Page to the Consent Decree in ***United States et al v. Ash Grove Cement Company***

FOR THE WASHINGTON STATE
DEPARTMENT OF ECOLOGY:

[redacted]

Date: 4/2/13

KATHARINE G. SHIREY
Assistant Attorney General
2425 Bristol Court SW, 2nd Floor
P.O. Box 40117
Olympia, WA 98504-0117

[redacted]

Date: 4/2/13

STUART CLARK
Manager
Air Quality Program
Washington State Department of Ecology
P.O. Box 47600
Olympia, WA 98504-7600

Signature Page to the Consent Decree in ***United States et al v. Ash Grove Cement Company***

FOR DEFENDANT ASH GROVE
CEMENT COMPANY:
[redacted]
MICHAEL HRIZUK
Senior Vice-President—Manufacturing
11011 Cody St.
Overland Park, KS 66210

Date: April 12, 2013

The following is the name and address of Defendant Ash Grove Cement Company's agent for service pursuant to Paragraph 147.

Thomas R. Wood
Stoel Rives LLP
900 SW Fifth Ave.
Suite 2600
Portland OR 97204-1268
(503) 204-9396

Appendix A to Consent Decree
Control Technology Demonstration Requirements/NO_x Emission Reduction Requirements

I. Scope and Applicability

Ash Grove Cement Company (Ash Grove) shall comply with the requirements contained in this Appendix A in proposing and establishing 30-Day Rolling Average Emission Limits for Nitrogen Oxide (“NO_x”) for the Montana City Kiln, Seattle Kiln, and the Louisville ACL Kiln (“Affected Kilns”). Terms in this Appendix A have the same meaning as in the Consent Decree unless otherwise specified.

The Affected Kilns include kilns of varying type, age, design and operating capacities. Raw materials employed in the Affected Kilns vary substantially. Fuels used in the Affected Kilns vary by location and may include fuel oil, natural gas, coal, petroleum coke, tire-derived fuel, hazardous waste derived fuel, used oils and other materials reused as fuel. Affected Kilns will be limited to those fuels and the amounts allowed by their various operating permits.

Supporting data required to be submitted under this protocol may contain information relating to operation of any Affected Kiln and production data that Ash Grove considers to be proprietary. In such a situation, Ash Grove may submit the information to EPA as confidential business information (CBI).

II. Montana City Kiln SNCR Control Technology Demonstration Requirements

(1) Summary

For the Montana City Kiln, Ash Grove shall take the following steps to establish a 30-Day Rolling Average Emission Limit for NO_x at that Kiln:

a. **Design Report:** Ash Grove shall prepare and submit to EPA for approval a Design Report for SNCR Control Technology for NO_x at the Montana City Kiln, based on similar SNCR Control Technology installations and the control requirements of this Consent Decree;

b. **Baseline Data Collection**: Prior to initiating operation of SNCR Control Technology at the Montana City Kiln, Ash Grove shall either: (i) collect new baseline emissions and operational data for a 180-Day period; or (ii) obtain EPA’s approval of baseline emissions and operational data from a period prior to the date of any baseline data collection period. Such baseline emissions and operational data shall be representative of the full range of normal kiln operations, including regular operating changes in raw mix chemistry due to different clinker manufacture and changes in production levels.

c. **Startup and Optimization Period:** Following completion of installation of SNCR Control Technology at the Montana City Kiln, Ash Grove shall undertake a startup and optimization program for the SNCR Control Technology;

d. **Demonstration Program:** Upon completion of the startup and optimization program specified above, Ash Grove shall operate SNCR Control Technology at the Montana City Kiln in an optimized manner for a period of 300 Operating Days for the purpose of establishing a 30-Day Rolling Average Emission Limit for NO_x;

e. **Demonstration Report:** Ash Grove shall prepare and submit to EPA for approval, a Final Report following completion of the Demonstration Program Period for SNCR Control Technology used to establish a 30-Day Rolling Average Emission Limit for NO_x at the Montana City Kiln.

(2) Montana City Kiln SNCR Design Report

a. No later than 3/14/2014 Ash Grove shall submit to EPA for approval a Design Report for SNCR Control Technology to be installed at the Montana City Kiln. The Design Report will contain the information contained in any permit application or de minimis notification which may be required under state or federal law. EPA shall review and comment on the Design Report within 45 Days of receipt. Ash Grove shall respond to any comments received within 30 Days of receipt. The Design Report shall comply with the following minimum requirements and shall be subject to the review requirements of Section XIII (Review and Approval) of the Consent Decree.

b. Selective Non-Catalytic Reduction ("SNCR"): Ash Grove shall design the SNCR system at the Montana City Kiln to deliver the proposed reagent to the exhaust gases of the kiln system at a rate and location to minimize NO_X emissions to the greatest extent practicable. At a minimum, the system must be capable of injecting ammonia at a rate of 1.2 mols of reagent to 1.0 mols of NO_x (1.2:1 molar ratio). Ash Grove shall specify in the Design Report the reagent(s) selected, the locations selected for reagent injection, and other design parameters based on maximum emission reduction effectiveness, good engineering judgment, vendor standards, available data, kiln operability, and regulatory restrictions on reagent storage and use.

(3) Montana City Kiln Baseline Data Collection

a. Prior to commencement of Continuous Operation of SNCR Control Technology, Ash Grove shall either: (a) collect new baseline emissions and operational data for a 180-Day period; or (b) obtain EPA approval pursuant to Section XIII (Review and Approval) of the Consent Decree of existing baseline emissions and operational data collected from a period of time prior to the initiation of the baseline collection period. Such baseline emissions and operational data shall include the data required by Paragraph 3.b of Section II of this Appendix A for periods of time representing the full range of normal kiln operations including changes in raw mix chemistry due to differing clinker manufacture, and changes in production levels. Ash Grove shall select the data collection period to ensure the baseline data collection period will be representative of the normal Kiln Operation.

b. Within 45 Days following the completion of the baseline data collection period or EPA's approval of the use of existing data, Ash Grove shall submit to EPA the baseline data collected during the baseline data collection period. Unless otherwise agreed to by EPA, the baseline data will include the following information either derived from available direct monitoring or as estimated from monitored or measured data:

i. Kiln flue gas temperature at the inlet to the fabric filter or electrostatic precipitator as applicable or at the Kiln stack (daily average);

ii. Kiln production rate in tons of clinker (daily total);

iii. Raw material feed rate in tons (daily total);

iv. Type and percentage of each raw material used and the total feed rate (daily);

v. NO_x concentrations and mass rates for each Kiln (daily average for concentrations and daily totals for mass rates) as measured at the Kiln stack gas analyzer location;

vi. Flue gas volumetric flow rate (daily average in acfm or dscfm, as appropriate);

vii. Sulfate in feed (calculated to a daily average percentage);

viii. Feed burnability (C3S) (at least once daily);

ix. Temperatures near the burning zone;

x. Back end kiln temperature;

xi. Back end kiln oxygen;

xii. Kiln fuel feed rate and type of fuel by weight or total heat input (daily average);

xiii. Fuel distribution, if fuel is injected at more than one location, how much is injected at each location (daily average);

xiv. Primary (and secondary and tertiary, where available) air rate into the Kiln, preheater and/or precalciner (as applicable) or blower/fan settings;

xv. Documentation of any Startup, Shut Down, or Malfunction events; and

xvi. An explanation of any gaps in the data or missing data.

Ash Grove shall submit the baseline data to EPA in an electronic format and shall explain the reasons for any data not collected for each of the parameters listed in this Paragraph of this Appendix A. Ash Grove shall submit all data in a format consistent with and able to be manipulated by Microsoft Excel.

(4) Montana City Kiln Startup and Optimization Period

a. Ash Grove shall install and begin operating the SNCR Control Technology according to the requirements of Section V (NO_x Control Technology, Emission Limits and Monitoring Requirements) of the Consent Decree. Ash Grove shall Commence Operation of SNCR Control Technology in accordance with the final Design Report by adding reagent to the SNCR system.

b. By 9/10/2014, Ash Grove shall commence Continuous Operation of the SNCR Control Technology. Any shakedown of the SNCR must be completed by 9/10/2014. Ash Grove will commence optimization of the SNCR Control Technology within 90 Days of the commencement of Continuous Operation of the SNCR.

c. Not later than 90 Days prior to the start of the optimization of the SNCR Control Technology, Ash Grove will submit to U.S. EPA a protocol for optimizing each SNCR Control Technology ("Optimization Protocol") to minimize emissions of NO_x to the greatest extent practicable. U.S.EPA shall review and comment on the Protocol within 45 Days of receipt and Ash Grove will respond to any comments with 30 Days of their receipt. The Optimization Protocol shall describe procedures that shall be used to evaluate the impact of different SNCR Control Technology operating parameters on the rate of emission reduction achieved by each applicable SNCR Control Technology and shall contain:

i. The steps taken to commence Continuous Operation of the SNCR Control Technology;

ii. The initial reagent injection rate (as a molar ratio of the average pollutant concentration calculated during the baseline period) for each SNCR Control Technology;

iii. A description of all sampling procedures that will be undertaken during the optimization of each SNCR Control Technology;

iv. Detailed description of the plan to increase the reagent injection rate for each Control Technology. At a minimum, Ash Grove shall test SNCR at three molar ratios of 0.75, 1.0, and 1.2.

v. The factors that will determine the maximum reagent injection rates and pollutant emission rates for the SNCR Control Technology (including maintenance of Kiln productivity and product quality);

vi. Explanation of how any observed effects on Kiln emissions, Kiln Operation or product quality will be evaluated;

vii. A proposal for the evaluation of the cost effectiveness of the incremental addition of reagent(s) and any incremental reduction in emissions of an air contaminant; and

viii. A detailed protocol for evaluating SNCR Control Technology operation and reagent injection rates with respect to alternate fuel scenarios to the extent that alternate fuels are anticipated.

d. The optimization period will be conducted in accordance with the approved Optimization Protocol and shall last no longer than 150 Operating Days.

e. Within 30 Days following the completion of the optimization period for the SNCR Control Technology, Ash Grove shall provide to EPA an Optimization Report demonstrating conformance with the Optimization Protocol for the SNCR Control Technology and establishing the operating parameters for the Control Technology determined under the Optimization Protocol. Ash Grove shall include in the report: the proposed optimized injection rate to be used continuously during the Demonstration Phase, a discussion of any problems encountered with the operation of the SNCR Control Technology, and a detailed discussion of the results of the Optimization on emissions from the kiln system. The provisions of Section XIII (Review and Approval of Submittals) shall apply to EPA's review of the Optimization Report, except that EPA shall review and comment on the Optimization Report within 45 Days of receipt of the Optimization Report and Ash Grove shall respond to any comments received within 30 Days of their receipt of EPA's comments. Ash Grove's submittal of and EPA's review of the Optimization Report shall not toll Ash Grove's obligation to fulfill other requirements of this Appendix.

f. As part of the optimization, the SNCR Control Technology will be presumed to be optimized at a molar ratio of 1.2 if it reduces NOx significantly, and does not impair product quality or production levels, impair kiln system reliability or impair compliance with then applicable emission requirements. For the Affected Kiln to be deemed to be optimized at a molar ratio of less than 1.2, the Optimization Report must demonstrate that, during periods of normal operation, a higher rate of emission reduction or operation cannot be sustained without creating a meaningful risk of impairing product quality or production levels, impairing kiln system reliability or impairing compliance with then applicable emission requirements or if the SNCR Control Technology cannot sustain operation at design values.

g. During the Optimization Period, Ash Grove, to the extent practicable, shall operate the SNCR Control Technology in a manner consistent with good air pollution control practice for minimizing emissions. Ash Grove will adjust its optimization of a SNCR Control Technology as may be necessary to avoid, mitigate or abate an identifiable non-compliance with an emission limitation or standard for pollutants other than NO_x. In the event Ash Grove determines, prior to the expiration of 150 operating days, that its ability to optimize the SNCR Control Technology will be affected by potential impairments to product quality or production levels, kiln system reliability or increased emissions of other pollutants, then Ash Grove shall promptly advise EPA of this determination, and include these considerations as part of its recommendation in its Optimization Report. In the event that Ash Grove determines, prior to the expiration of 150 Operating Days that the SNCR Control Technology has been optimized, Ash Grove shall promptly advise EPA of this determination.

(5) Montana City Kiln SNCR Control Technology Demonstration Period

a. The Demonstration Period shall commence within 7 Days after Ash Grove's receipt of the final approval by EPA of the Optimization Report. During the Demonstration Period, Ash Grove shall operate the SNCR Control Technology for a period of 300 Operating Days consistent with the operating parameters determined during the Optimization Period for the SNCR Control Technology and identified in the approved Optimization Report.

b. If operation of an Affected Kiln is disrupted by excessive startups and shutdowns during the Demonstration Period, Ash Grove may request or EPA may decide to extend the Demonstration Period. In granting any such request, the amount the time that the Demonstration Period will be extended is subject to the Section XVII (Dispute Resolution) provisions of this Consent Decree.

c. If evidence arises during the Demonstration Period that product quality, production levels, kiln system reliability, or compliance with an emission limitation or standard is impaired by reason of longer term operation of an SNCR Control Technology in a manner consistent with the parameters identified in the Optimization Report, then Ash Grove may, upon notice to, and approval by, EPA, temporarily modify the manner of operation of the Facility process or the SNCR Control Technology to mitigate the effects and request that EPA suspend or extend the Demonstration Period for further technical evaluation of the effects of a process optimization or SNCR Control Technology or permanently modify the manner of operation of the Control Technology to mitigate the effects. EPA's decision in response to any such Ash Grove request is subject to the Section XVII (Dispute Resolution) provisions of this Consent Decree.

d. During the Demonstration Period, Ash Grove shall collect the same data required during the baseline period and identified in this Appendix A. The Demonstration Report shall include the data collected as required in this Paragraph in an electronic form in an Excel spreadsheet or a format compatible and able to be manipulated by Excel.

e. At least every 3 months during the Demonstration Period (unless that period lasts less than 3 months in which case this requirement does not apply), Ash Grove shall submit a periodic report to EPA. Each periodic report shall include the data collected during the Demonstration Period to that point, and shall include all of the information in Paragraph 3.b of Section II of this Appendix A. In addition, the periodic report shall include all 30-Day Rolling Average Emission Rates calculated from the beginning of the Demonstration Period until the preparation of the periodic report. The report data shall be submitted electronically in an Excel spreadsheet or a format compatible and able to be manipulated by Excel.

f. Within 60 Days following completion of the Demonstration Period for the SNCR Control Technology, Ash Grove shall submit a Demonstration Report to EPA, based upon and including all of the data collected during the Demonstration Period that identifies a proposed 30-Day Rolling Average Emission Limit for NO_x. The proposed 30-Day Rolling Average Emission Limit for NO_x shall be based upon an analysis of CEMS data and clinker production data collected during the Demonstration Period, while the process and SNCR Control Technology parameters were optimized in determining the proposed final NO_x Emission Limit achievable for the Montana City Kiln. Total pounds of NO_x emitted during an individual Operating Day will be calculated from collected CEMS data for that Day. Hours or Days when there is no Kiln Operation may be excluded from the analyses. However, Ash Grove shall provide an explanation in the Demonstration Report for any data excluded from the analyses. In any event, Ash Grove shall include all data required to be collected during the Demonstration Period in the Final Demonstration Report.

g. Ash Grove shall propose a 30-Day Rolling Average Emission Limit for NO_x in the Demonstration Report as provided in the preceding Paragraph and in accordance with the definition of that term in the Consent Decree. The final 30-Day Rolling Average Emission Limits shall be calculated in accordance with the following formula:

$X = \mu + 1.65\sigma$ where:

X = 30-Day Rolling Average Emission Limit (lb/Ton of clinker)
μ = arithmetic mean of all of the 30-Day rolling averages
σ = standard deviation of all of the 30-Day rolling averages, as calculated in the following manner:

$$\sigma = \sqrt{\frac{1}{N}\sum_{i=1}^{N}(x_i - \bar{x})^2}$$

h. In no event shall the 30-Day Rolling Average Emission Limit for NO_x proposed by Defendant in the Demonstration Report at the Montana City Kiln be less stringent than 8.0 lb/ton of clinker.

i. Notwithstanding Section XIII of this Consent Decree (Review and Approval of Submittals), EPA shall either approve the proposed 30-Day Rolling Average Emission Limit or establish an alternative final 30-Day Rolling Average Emission Limit. If EPA approves Ash Grove's proposed 30-day Rolling Average Emission limit, Ash Grove shall demonstrate compliance and maintain compliance with EPA's final 30-day Rolling Average Emission Limit within 30 Days of receipt of EPA's notice. If EPA establishes an alternative final 30-Day Rolling Average Emission Limit that differs from Ash Grove's proposed 30-Day Rolling Average Emission Limit, Ash Grove shall demonstrate compliance and maintain compliance with EPA's final 30-Day Rolling Average Emission Limit within 60 Days of receipt of EPA's notice. If Ash Grove invokes Dispute Resolution, it shall follow the procedures set forth in Paragraph 112 (Informal Dispute Resolution for Emission Limit Setting Process under Appendix A) to hire an independent contractor to review and make a non-binding recommendation regarding the appropriate final 30-Day Rolling Average Emission Limit. During the period of Dispute Resolution, Ash Grove shall demonstrate compliance and maintain compliance with EPA's final 30-Day Rolling Average Emission Limit.

III. NO_x Emission Reduction Study and Demonstration Phase Requirements for Seattle Kiln and Louisville ACL Kiln

This Section III of the Appendix A applies to the Seattle Kiln and the Louisville ACL Kiln, and sets forth the requirements for reducing NO_x emissions through optimized operation of those Kilns. The NO_x Emission Reduction Study and Demonstration Phase Requirements for these Kilns shall consist of three phases:

- Baseline Data Collection
- Process Optimization
- Demonstration

These phases and their associated requirements are described more fully below.

(1) Baseline Data Collection

a. Beginning no later than 120 Operating Days after the Effective Date of the Consent Decree, for the Seattle Kiln and Louisville ACL Kiln Ash Grove shall: (a) commence collection of new baseline emissions and operational data from each Kiln for a 180-Operating Day period; or (b) obtain EPA approval pursuant to Section XIII (Review and Approval of Submittals) of the Consent Decree to use existing baseline emissions and operational data from one or both Kilns collected from a period of time prior to the Effective Date of the Consent Decree. Such baseline emissions and operational data shall include the data required in Paragraph 3.b of Section II of this Appendix A, relating to the Montana City Kiln. The baseline period shall represent the full range of normal kiln operations including changes in raw mix chemistry due to differing clinker manufacture, and changes in production levels. Ash Grove shall select the data collection period to ensure the baseline data collection period will be representative of the normal Kiln Operation. Within 45 Days following the completion of the baseline data collection period or EPA's approval of the use of existing data, Ash Grove shall submit to EPA the baseline data collected during the baseline data collection period.

(2) Seattle and Louisville ACL Kiln Emission Reduction Study and Process Optimization Period

a. By no later than the date by which the Baseline Data Report must be submitted, Ash Grove shall submit to EPA pursuant to Section XXI of the Consent Decree (Notices) a protocol for optimization of operation of the Louisville ACL Kiln and the Seattle Kiln ("Process Optimization Protocol" or "Protocol"). Each Protocol will include optimization of key operating parameters resulting in the minimization of emissions of NO_x to the greatest extent practicable without incurring unreasonable cost and without causing an exceedance of any other applicable emission limit and without materially impairing production quality or quantity. At a minimum, the Protocol must address:

i. Adjustments to the combustion zone temperature to minimize NO_x formation;

ii. Optimization of air flow and oxygen levels;

iii. Improvement of fuel efficiency;

iv. Adjustments to the existing Kiln including, but not limited to, introduction of air at different locations in the Kiln to create reducing zones for NO_x reduction and adjustments to the primary air;

v. Adjustment of the balance between fuel supplied to each burner at the Kiln and/or calciner to improve overall combustion while maintaining product quality;

vi. Adjustments to combustion to improve overall NO_x levels by:

1. Adjusting fuel fineness to improve emission rates;
2. Adjusting the proportions of primary, secondary and tertiary air, where applicable, supplied to the kiln system while maintaining product quality; and
3. Adjustments to the raw mix chemical and physical properties using onsite raw materials to improve kiln stability and maintain product

quality, including but not limited to, fineness of the raw mix. As part of this optimization measure, Ash Grove shall take additional measurements using existing monitoring equipment at relevant process locations to evaluate the impact of raw mix refinements.

EPA shall review each Optimization Protocol pursuant to Section XIII of the Consent Decree (Review and Approval of Submittals).

b. As part of the Protocol submitted pursuant to Section III of this Appendix A, Ash Grove shall propose a schedule for optimizing each of the measures identified in the Protocol. The schedule shall not be shorter than 90 Operating Days, nor last longer than 120 Operating Days from the beginning of the Process Optimization Phase. Within 30 Days following approval of the Optimization Protocol and the schedules therein, Ash Grove will commence the optimization of the Kiln according to the terms of the Protocol and EPA's approval of such. Subject to Section IX (Temporary Cessation of Kiln Operation), all Process Optimizations shall be completed within 180 Days of the EPA approval of the Optimization Protocol.

c. Within 30 Days following the optimization period in each approved Protocol at each Kiln, Ash Grove shall provide to EPA a Process Optimization Report demonstrating conformance with the Protocol required under this section and establishing the operating parameters determined under the Protocol. Each Process Optimization Report shall:

i. identify all potential process and/or operational changes that can be implemented to reduce emissions of NO_x at the Louisville ACL Kiln and Seattle Kiln;

ii. estimate the amount of NO_x emission reductions that can be obtained through implementation of each of the individual process and/or operational changes;

iii. assess process and/or operational changes appropriate for implementation;

iv. assess which potential process and/or operational changes are inappropriate for implementation;

v. determine the appropriate period of time for implementing those process and/or operational changes that are appropriate for implementation;

vi. estimate the amount of NO_x emissions that can be reduced through all of the individual process and/or operational changes that are appropriate for implementation;

vii. discuss any problems encountered with the operation of the Kilns during the Optimization and the impact of the Optimization on emissions;

viii. recommend the process and/or operational changes to be implemented as measures to reduce NO_x emissions from the Kiln and include a detailed analysis of why such changes are proposed and, if applicable, why any changes are not proposed to be implemented; and

ix. include a proposed implementation schedule for the proposed measures.

j. The provisions of Section XIII (Review and Approval of Submittals) shall apply to EPA's review of the Optimization Report, except that EPA shall review and comment on the Optimization Report within 45 Days of receipt of the Optimization Report and Ash Grove shall respond to any comments received within 30 Days of their receipt of EPA's and comments. Ash Grove's submittal of and EPA's review of the Optimization Report shall not toll Ash Grove's obligation to fulfill other requirements of this Appendix.

(3) Seattle Kiln and Louisville ACL Kiln Demonstration Period

a. Upon completion of the optimization requirements of each Optimization Protocol approved by EPA pursuant to Section III of this Appendix A for the Louisville ACL Kiln and the Seattle Kiln, Ash Grove shall commence a Demonstration Period for each such Kiln. Each Demonstration Period shall commence within 7 Days after Ash Grove's receipt of the final approval by EPA of the Optimization Report for the respective Kiln. During the Demonstration Period, Ash Grove shall operate each Kiln for a period of 180 Operating Days consistent with the operating parameters in the approved Optimization Protocol and identified in the approved Optimization Report for the respective Kiln.

b. If operation of the Seattle Kiln or Louisville ACL Kiln is disrupted by excessive startups and shutdowns during the Demonstration Period for that Kiln, Ash Grove may request or EPA may decide to extend the Demonstration Period for that Kiln. EPA shall grant or deny any request and shall state the amount the time that the Demonstration Period will be extended. EPA's decision is subject to the Section XVII (Dispute Resolution) provisions of this Consent Decree. Ash Grove may not suspend Demonstration Period data collection prior to the completion of 180 Operating Days until and unless EPA has granted the request.

c. Within 90 Days following the start of each Demonstration Period for each Kiln subject to Section III of this Appendix A, Ash Grove shall submit a report to EPA. Each report shall include the 30-Day Rolling Average Emission Rate calculated from the beginning of the Demonstration Period until the preparation of the periodic report. The report data shall be submitted electronically in an Excel spreadsheet or a format compatible and able to be manipulated by Excel.

d. Within 60 Days following completion of the Demonstration Period for each Kiln subject to Section III of this Appendix A, Ash Grove shall submit a Demonstration

Report to EPA, based upon and including all of the data collected during the Demonstration Period that identifies proposed 30-Day Rolling Average Emission Limits for NO_x at the Louisville ACL Kiln and the Seattle Kiln. Each 30-Day Rolling Average Emission Limit for NO_x shall be based upon an analysis of CEMS data and clinker production data collected during the Demonstration Period, while the Kiln was optimized in accordance with Optimization Protocol approved by EPA pursuant to Section III of this Appendix A. Total pounds of an affected pollutant emitted during an individual Operating Day will be calculated from collected CEMS data for that Day. Hours or Days when there is no Kiln Operation may be excluded from the analyses. However, Ash Grove shall provide an explanation in the Demonstration Report(s) for any data excluded from the analyses. In any event, Ash Grove shall include all data required to be collected during the Demonstration Period in the Final Demonstration Report(s).

e. For the Louisville ACL Kiln and the Seattle Kiln, Ash Grove shall propose 30-Day Rolling Average Emission Limits for NO_x for each Kiln in each Demonstration Report as provided in the preceding Paragraph and in accordance with the definition of "30-Day Rolling Average Emission Limit" in the Consent Decree. The final 30-Day Rolling Average Emission Limit shall be calculated in accordance with the following formula:

$X = \mu + 1.65\sigma$ where:

X = 30-Day Rolling Average Emission Limit (lb/Ton of clinker)
μ = arithmetic mean of all of the 30-Day rolling averages
σ = standard deviation of all of the 30-Day rolling averages, as calculated in the following manner:

$$\sigma = \sqrt{\frac{1}{N}\sum_{i=1}^{N}(x_i - \bar{x})^2}$$

Notwithstanding Section XIII of this Consent Decree (Review and Approval of Submittals), EPA shall either approve the proposed 30-Day Rolling Average Emission Limit or establish an alternative final 30-Day Rolling Average Emission Limit. If EPA approves Ash Grove's proposed 30-day Rolling Average Emission limit, Ash Grove shall demonstrate compliance and maintain compliance with EPA's final 30-day Rolling Average Emission Limit within 30 days of receipt of EPA's notice. If EPA establishes an alternative final 30-Day Rolling Average Emission Limit that differs from Ash Grove's proposed 30-Day Rolling Average Emission Limit, Ash Grove shall demonstrate compliance and maintain compliance with EPA's final 30-Day Rolling Average Emission Limit within 30 days of receipt of EPA's notice. If Ash Grove invokes Dispute Resolution, it shall follow the procedures set forth in Paragraph 112 (Informal Dispute Resolution for Emission Limit Setting Process under Appendix A) to hire an independent contractor to review and make a non-binding recommendation regarding the appropriate final 30-Day Rolling Average Emission Limit. During the period of Dispute

Resolution, Ash Grove shall demonstrate compliance and maintain compliance with EPA's final 30-Day Rolling Average Emission Limit.

Appendix B to Consent Decree
PM Continuous Parametric Monitoring System Requirements

I. CPMS

(1) A PM Continuous Parametric Monitoring System ("CPMS") is a monitoring system which uses an operating principle based on in-stack or extractive light scatter, light scintillation or beta attenuation. Ash Grove shall examine the fuel and process conditions of each stack as well as the capabilities of these devices before selecting a particular CPMS technology under this Decree. The reportable measurement output from the PM CPMS may be expressed as milliamps, stack concentration or other raw data signal. If Ash Grove wishes to use a CPMS other than those described in this Paragraph or to install a PM CEM, Ash Grove may propose an alternate CPMS or CEM to EPA for approval no later than 120 days prior to the CPMS installation date required under this Decree.

(2) Except during CPMS breakdowns, repairs, calibration checks, and zero span adjustments, the CPMS required pursuant to this CD shall be operated at all times during Kiln Operation.

II. Site-Specific Operating Limit

(1) The Site Specific Operating Limit (SSOL) will be established as required in Paragraph 60.

(2) Each CPMS shall be used at each Kiln to demonstrate compliance with the SSOL.

(3) Defendant shall reassess and adjust each SSOL, developed in accordance with Paragraph 59 and 60 and in accordance with Section II of this Appendix and in accordance with the results of each most recent PM performance test demonstrating compliance with the PM Emission Limit. The SSOL will correspond to the highest 1 hour average CPMS output value recorded during any performance test demonstrating compliance.

(4) Each CPMS required pursuant to Paragraph 59 shall monitor and record the output data for all periods of Kiln Operation and the CPMS is not out-of-control. Compliance with the SSOL must be demonstrated by using all quality-assured hourly average data collected by the CPMS for all hours of Kiln Operation to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30 Operating Day rolling average basis, updated at the end of each new Kiln Operating Day.

III. Deviations of the CPMS

(1) To determine continuous compliance, Ash Grove must record the PM CPMS output data for all periods of Kiln Operation when the PM CPMS is not out-of-control. Ash Grove must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw

data signal) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day. Use the following equation to determine the 30 kiln operating day average.

$$30\text{kiln operating day} = \frac{\sum_{i=1}^{n} Hpv_i}{n}$$

where:

Hpvi = The hourly parameter value for hour i; n is the number of valid hourly parameter values collected over 30 kiln operating days.

(2) For any deviation from the SSOL established in accordance with Paragraph 60 of the Decree, Ash Grove shall:

a. Within 48 hours of the deviation, visually inspect the PM Control Technology;

b. If inspection of the PM Control Technology identifies the cause of the deviation, take corrective action as soon as possible, and return the CPMS measurement to within the SSOL;

c. Within 45 Days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the SSOL consistent with Section II of this Appendix B, above. Ash Grove is not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this subparagraph; and

d. Except as identified in Section III(3) below, deviation from the SSOL does not a constitute a violation of the Consent Decree and is not subject to stipulated penalties under Section XV of this Decree (Stipulated Penalties).

(3) Any deviation of the 30 day rolling average from the established SSOL leading to more than four required performance tests in a 12-consecutive month period (rolling monthly) shall be treated as a separate violation of this Consent Decree and subject to stipulated penalties under Section XV of this Decree (Stipulated Penalties).

IV. <u>Alkali Bypass</u>

(1) If any of Ash Grove's kiln gases are diverted through an alkali bypass, Ash Grove must account for the PM emitted from the alkali bypass stack by following the procedures in this Appendix B.

(2) Ash Grove must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the exhaust gas flow rate to the atmosphere from the alkali bypass stack according to the requirements of 40 C.F.R. 63.1350(n).

(3) Ash Grove will conduct an annual EPA Method 5 or Method 5I performance test to determine total PM emissions from the alkali bypass as well as the Kiln.

(4) Ash Grove will use the maximum exhaust gas flow rate from the alkali bypass during Ash Groves annual performance test demonstrating compliance with the PM Emission Limit as the SSOL for each alkali bypass. Ash Grove must continuously monitor the flow rate until the next performance test. If there is an increase of the monitored flow rate from the maximum established during the last performance test by more than 10 percent, Ash Grove must retest the Kiln and alkali bypass to determine compliance.

V. <u>Performance Tests</u>

For each performance test, Ash Grove shall conduct three separate runs under the conditions that exist when the Kiln is operating at the highest load or capacity level reasonably expected to occur. Ash Grove shall conduct each test run to collect a minimum sample volume of 2 dry standard cubic meter ("dscm") for determining compliance with a new source limit and 1 dscm for determining compliance with a existing source limit. Ash Grove shall calculate the average of the results from three runs to determine compliance. Ash Grove need not determine the PM collected in the impingers (''back half'') of the EPA Method 5 or Method 5I particulate sampling train to demonstrate compliance with the PM Emission Limits of this Consent Decree. This shall not preclude the permitting authority from requiring a determination of the ''back half'' for other purposes nor shall it be deemed to exempt Ash Grove from any other applicable PM limit.

Appendix C to Consent Decree
Environmental Mitigation Projects

In compliance with and in addition to the requirements in Section VIII of this Consent Decree (Other Injunctive Relief), Defendant shall comply with the requirements of this Appendix to ensure that the benefits for the federally directed Environmental Mitigation Projects below are achieved.

Clean Diesel Replacement Projects

1. Defendant shall implement the following schedule to replace the identified in-service diesel engines with diesel engines that have emission control equipment further described in this Paragraph 1 of this Appendix C, designed to reduce approximately 28 tons per year of emissions of NOx, particulates and/or ozone precursors (the "Projects" or "Project"):

    a. By December 31, 2013, at the Foreman, Arkansas plant, Defendant shall replace the 2003 Terex Haul Truck, Model TA-40, Engine Serial Number 06R0718605 with a replacement Truck with a Tier 4 engine in accordance with Tier 4 engine standards under 40 CFR Part 89;

    b. By December 31, 2013, at the Chanute, Kansas plant, Defendant shall replace the currently unregulated Tier 0, 1986 CAT Dozer, Model D8L, Engine Serial Number 48W22583 with a replacement dozer with a Tier 2 engine in accordance with Tier 2 engine standards under 40 CFR Part 89; and

    c. By December 31, 2013, at the Midlothian, Texas plant, Defendant shall replace the current Tier 0 1977 Euclid Haul Truck, Model 302LD, Engine Serial Number 10623360 with a replacement Truck with a Tier 4 engine in accordance with Tier 4 engine standards under 40 CFR Part 89.

2. Defendant shall provide a mechanism by which each replaced engine in Paragraph 1 of this Appendix C above is properly disposed of, which must include destruction of the engine block.

3. Nothing in this Consent Decree shall be interpreted to prohibit Defendant from completing any of the Projects ahead of schedule.

4. In accordance with the requirements of Paragraph 65 of the Consent Decree, within 60 Days following the completion of each Project, Defendant shall submit to U.S. EPA for approval a report that documents:

    a. The date the Project was completed;

    b. The results of implementation of the Project, including the estimated emission reductions or other environmental benefits achieved; and

c. The cost incurred by Defendant in implementing the Project.

Environmental Justice at Ecology

Pollution and environmental contamination can affect everyone living in Washington, but some people are significantly more burdened than others. Research shows that people of color, low-income people, and indigenous people are disproportionately harmed by environmental hazards like toxic contamination, diesel emissions, and climate change. These environmental exposures have real impacts on the lives of many in Washington, such as:

- Higher rates of illness and disease
- More frequent hospitalization
- Lower life expectancy

We're committed to making decisions that do not place disproportionate burdens on disadvantaged communities. And we seek to lift the weight of pollution and contamination borne by those communities. Focusing our time and resources toward strategic actions to address these long-standing inequities will lead to improvements in health and the environment, and more resilient communities in Washington.

I want to...

- Find out about Ecology's public meetings and comment periods
- Learn more about Ecology's commitment to non-discrimination
- Find out more about Ecology's language access services

> *"I have a deep personal commitment to environmental justice. It's one of my highest priorities. For me, environmental justice is about achieving the highest environmental quality for Washington's diverse communities. We will work strategically to eliminate environmental and health disparities in communities of color, indigenous communities, and economically disadvantaged communities." Laura Watson, Ecology Director*

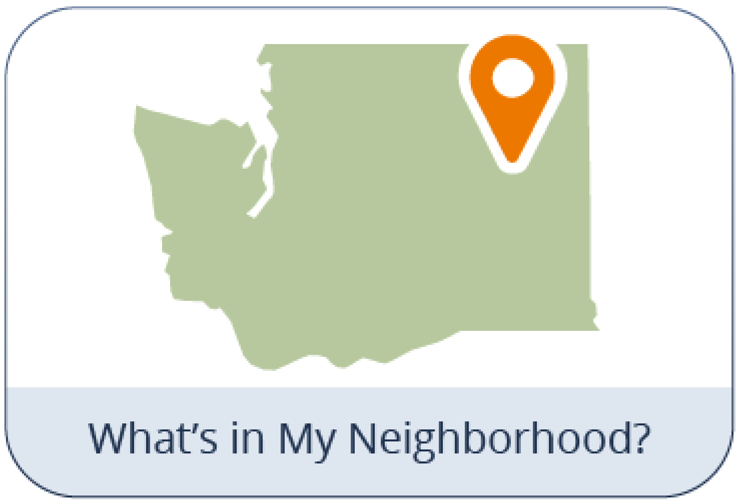
Environmental justice at Ecology

Environmental justice is a priority in our efforts to restore and protect land, air, and water. Below are some examples of our work to meaningfully engage communities, and strategically address environmental issues in areas with environmental justice considerations.

What's in My Neighborhood?

We developed and maintain a map of contaminated cleanup sites around the state. This easy-to-use, interactive map allows everyone living in Washington to be able to find contaminated cleanup sites near them. It also provides the latest information on cleanup efforts at each site.

To see what's in your neighborhood, take a look at our map.



Funding affordable housing & public participation in Bellingham

We're working on 12 contaminated cleanup sites in Bellingham Bay. One of them is called "Georgia Pacific West," an area that has contaminated soil and groundwater from former industrial operations.

We awarded the Port of Bellingham an Integrated Planning Grant to help determine the extent of contamination, and then the Port will work with local affordable housing organizations to study viability of providing healthy and affordable housing options on the site.

Gentrification can be a big problem with cleanup efforts. As areas are cleaned up and developed, local communities are priced out of affordable places to live. This project will help provide affordable homes for those people who could be priced out of the area. Plans also include a food campus for local producers that will incorporate storage, workforce training kitchens, retail and event space, as well as affordable housing. Construction could start as early as 2021.

Using Public Participation Grants, we also help fund, and collaborate with, a local non-profit calld RE Sources to help reach and connect with people in the community. Read more about their environmental justice efforts in Bellingham Bay.

Also, see our website for more information about cleanup efforts in Bellingham Bay.

Striving for equity in the Lower Duwamish Waterway

We're leading efforts to control sources of pollution from the drainage area surrounding the Lower Duwamish Waterway (LDW) Superfund site in Seattle. The LDW Superfund site is a 5-mile portion of the Duwamish River that flows into Elliott Bay. The U.S. Environmental Protection Agency (EPA) oversees cleanup of the river sediments.

Before sediment cleanup can begin, we need to control the sources of pollution to the river sediments. That means we must investigate more than 20,000 acres of land that drains into the river. Source control means finding the sources and extent of contamination, then taking actions to stop or reduce them before they reach the LDW.

The Duwamish Valley communities are diverse, encompassing a broad range of backgrounds, cultures, and languages. To effectively engage and involve the community, we conduct environmental justice analyses of project areas using the Environmental Protection Agency's Environmental Justice Screening and Mapping tool. We then tailor outreach strategies to address equity issues.

Providing language access to cleanup information is an important part of public involvement. To assess language needs, we use census data to identify populations speaking languages other than English. We provide translation of written materials and interpretation services in various languages including Spanish, Vietnamese, and Chinese.

Ensuring that public meetings and open houses integrate with peoples' lives is crucial to support meaningful involvement. This means holding events in locations accessible by public transportation, as well as providing interpretation services, food, and childcare.

Working with community organizations allows us to further connect with the community. We partner with the Duwamish River Cleanup Coalition (DRCC) to involve the public in the cleanup process and address community concerns. We provide funding to DRCC through the Public Participation Grant program.

See our Lower Duwamish Waterway website for more information.

Cleaning up 100 years of pollution in the Tacoma smelter plume

For almost 100 years, the Asarco Company operated a copper smelter in Tacoma. Air pollution from the smelter settled on the surface soil of more than 1,000 square miles of the Puget Sound basin. Arsenic, lead, and other heavy metals are still in the soil as a result of this pollution. We started cleanup work in the area in 2006, and we continue to work with local communities to protect public and environmental health.

The communities affected by the Tacoma smelter plume are diverse. Our outreach and cleanup efforts are modified to meet the needs of the various communities.

We fund and work with local health departments through interagency agreements. The health departments in turn fund community projects and conduct targeted outreach. Our goal is to fund those closest to the work.

Some examples include:

- Public Health Seattle & King County works with local community grantees like Tilth Alliance to help get the information out to the communities
- Tacoma-Pierce County Health Department offers free soil sampling and offers a toolkit and resources to get free mulch to cover bare dirt; the program is specifically targeted to families with children

We created a Dirt Alert map to provide information on free soil sampling in the service area. The service area is a small area of the plume where arsenic concentrations are the highest. In this area, we operate the Yard Program and the Soil Safety Program. We offer free sampling and soil replacement to residential properties with the highest concentrations of arsenic and lead. The map makes it easy for anyone to find out if they live in the affected area, if their soil was replaced, or is eligible for cleanup.

We have conducted extensive outreach in the yard sampling service area. Our initial emphasis was on sampling soil at schools and childcare play areas through the Soil Safety Program. Our Healthy Action outreach materials are available in a variety of languages.

We work with businesses to help them voluntarily clean up their soil.

For more information, see our Tacoma Smelter website.

Converting brownfields into affordable housing

For more than 30 years, we've been cleaning up contaminated properties — more than 7,000 completed cleanups so far. Removing toxic threats helps protect human health and the environment, and opens the door to put properties back into use. We're working to make it easier for affordable housing developers to redevelop once-contaminated properties into housing that communities can afford.

To learn more about our efforts, see our "Affordable housing-related cleanup" web page.

Prioritizing Volkswagen settlement funds

We're investing Volkswagen settlement and penalty funds in programs that are drastically reducing harmful emissions from transportation sources. We're prioritizing investments that maximize air pollution reductions and improve public health in communities that have historically borne a disproportionate share of the air pollution burden in Washington.

We worked with partners to use a variety of tools to identify and consider beneficial impacts of projects in these communities. See our "Improving air quality & public health" web page for more information.

Protecting communities from threats of climate change

Climate change poses a threat to Washington's snowpack, coastlines, forests, and agricultural economy. But climate change also adds to existing health disparities and increases the burdens on the state's most vulnerable and sensitive populations.

Extreme heat events and increasing air pollution mean increases in diseases like asthma, diabetes, heart disease, and COPD, and it may mean that these diseases become more prevalent.

The impacts to vulnerable and sensitive populations of urban heat islands, food deserts, and homelessness will also be magnified by the effects of climate change.

Climate change worsens environmental injustice. The health concerns influenced by climate change are more acute for communities who already face disproportionate exposure to diesel emissions, toxic contamination, and other forms of pollution.

Other factors, like a person's age, language spoken, disability, and their access to affordable health care, technology, and the internet, may create barriers to receiving essential information and resources needed to protect health or ensure well-being for their families and communities.

Scientists and researchers at the Washington State Department of Health built a database of geographic, demographic, environmental, and health information to help understand health data and identify health disparities in Washington.

Ecology uses this powerful tool to develop criteria to evaluate potential investments from the $140 million settlement the state received from the Volkswagen diesel cheating scandal. Using the database helps us direct funding for electric transit and school buses, cleaner diesel vehicles, and charging infrastructure for zero-emission vehicles toward projects that benefit communities disproportionately burdened with air pollution.

Related links

- Accessibility services
- Recommendations for Prioritizing EJ in Washington State Government (pdf)
- EJSCREEN online mapping tool (EPA)
- Washington Tracking Network online environmental health mapping tool (Dept of Health)
- Environmental justice at EPA

Contact information

Millie Piazza
Environmental Justice & Title VI Senior Advisor
360-407-6177
millie.piazza@ecy.wa.gov

Exhibit 7

The Council's Work

The Governor's Interagency Council on Health Disparities was established by the Legislature in 2006 when it passed, and the Governor signed a bill to create it.

- The Council creates an action plan for eliminating health disparities by race, ethnicity, and gender in Washington.
- The Council convenes advisory committees to assist in the planning and development of specific issues in collaboration with several state agencies and non-government stakeholders.
- The Council has developed many recommendations to support language assistance .

Contact the Council

Email Us
360-236-4100
360-236-4088 (fax)
PO Box 47990
Olympia, WA 98504-7990

Notices

Notice of Non-Discrimination

Exhibit 8

THE GOVERNOR'S INTERAGENCY COUNCIL ON HEALTH DISPARITIES

State Policy Action Plan to Eliminate Health Disparities

January 2020

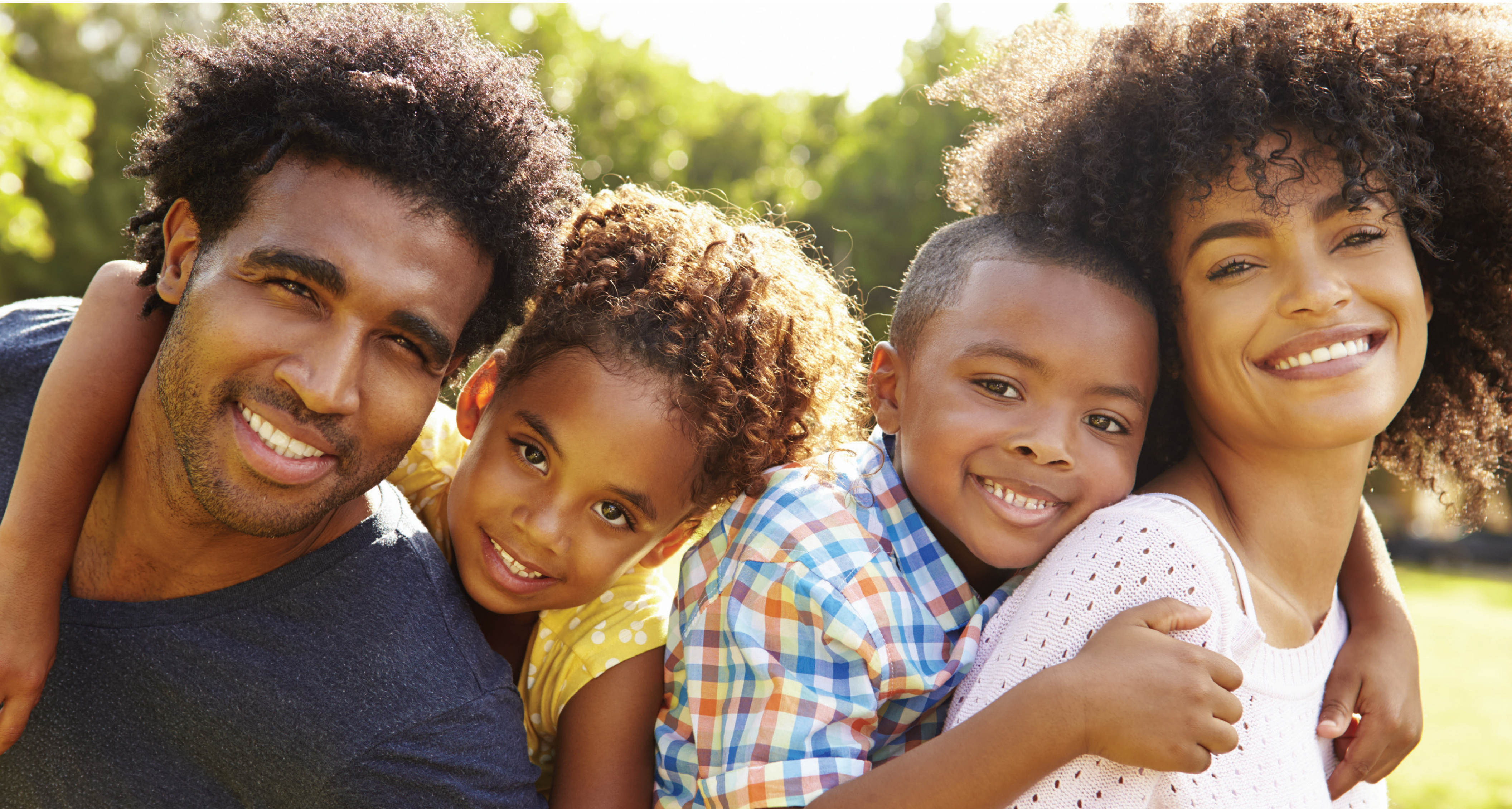
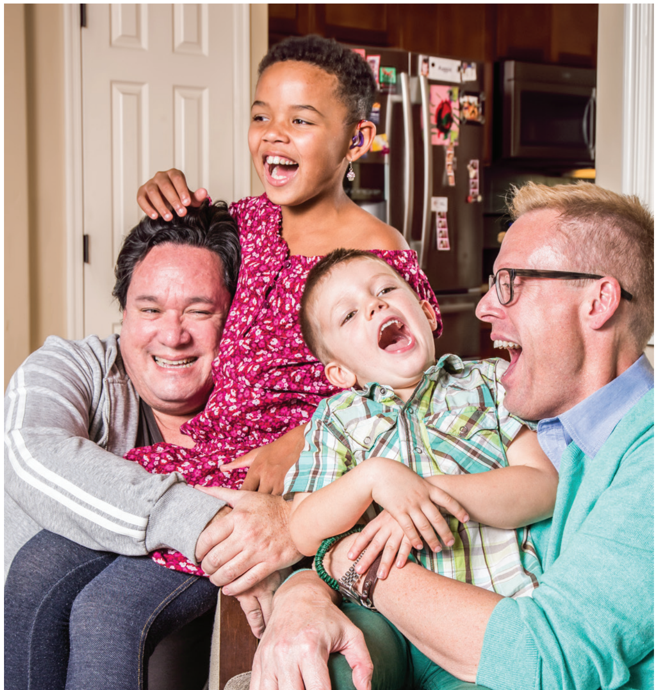


TABLE OF CONTENTS

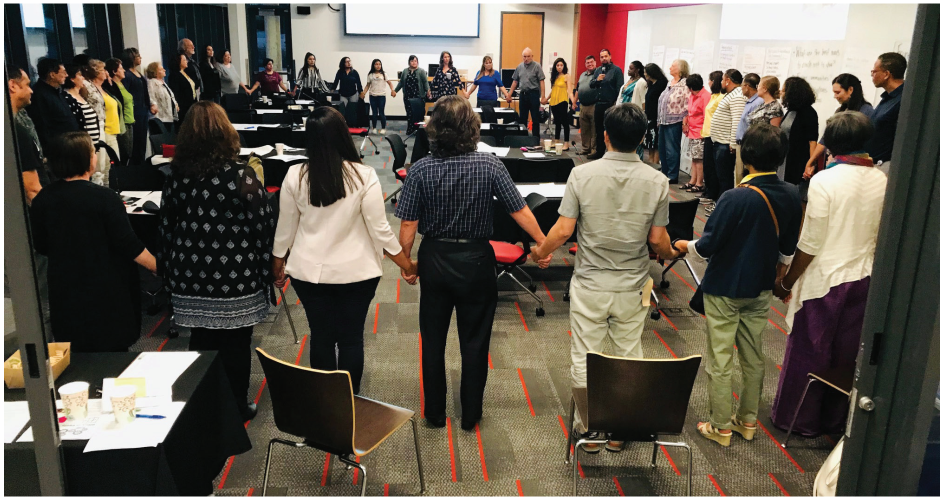


INTRODUCTION

The Governor's Interagency Council on Health Disparities (Council) is charged with creating a state policy action plan to eliminate health inequities by race/ethnicity and gender. This report outlines strategies to address health inequities by: (1) recommending the passage of legislation to create and fund a Washington State Office of Equity, (2) reiterating the recommendations from the Council's Literature Review on Inequities in Reproductive Health Access, and (3) recommending the continued support and use of Health Impact Reviews to promote health and equity in legislative decision making. In addition, this report includes an update on the work of the Environmental Justice Task Force, which the Council was directed to convene through a proviso in the 2019-2020 biennial operating budget.

The recommendations in this report, including those the Council is endorsing from other reports, focus on the social determinants of health and root causes of health inequities. By focusing upstream on these determinants of health, the Council believes its recommendations will ultimately work to reduce inequities for all health outcomes, including those listed in its authorizing statute (RCW 43.20.280).

Above: Office of Equity Task Force members. Back row, l-r: RaShelle Davis, Rep. Melanie Morgan, Maria Siguenza, Allison Spector, Karen Johnson, Mandeep Kaundal. Middle row, l-r: Sen. Manka Dhingra, Michelle Gonzalez, Toshiko Hasegawa, Mystique Hurtado. Front row, l-r: Benjamin Danielson, Jan Ward Olmstead. Full list of members available on page 3.



Closing circle at the Council's Everett Community Forum on Sept. 5, 2019

EQUITY OFFICE TASK FORCE

The Legislature directed the Council to convene and staff an Equity Office Task Force through a proviso in the 2019-2021 operating budget (Engrossed Substitute House Bill 1109, Section 221, subsection 7).

The Task Force is charged with developing a proposal for the creation of a Washington State Office of Equity, submitting a preliminary report to the Governor and the Legislature by December 15, 2019, and submitting a final proposal by July 1, 2020.

The Task Force is directed to include the following recommendations in its final proposal:

1. A mission statement and vision statement for the office;
2. A definition of "equity," which must be used by the office to guide its work;
3. The organizational structure of the office, which must include a community liaison for the office;
4. A plan to engage executive-level management from all agencies;
5. Mechanisms for facilitating state policy and systems change to promote equity, promoting community outreach and engagement, and establishing standards for the collection, analysis, and reporting of disaggregated data regarding race and ethnicity;
6. Mechanisms for accountability to ensure that performance measures around equity are met across all agencies, including recommendations on audits of agencies and other accountability tools as deemed appropriate; and,
7. A budget proposal including estimates for costs and staffing.

The Task Force convened for its first meeting on August 19 in Tacoma with subsequent meetings in Vancouver on September 16, Yakima on October 21, Tumwater on November 25, and Olympia on December 16. The Task Force has been intentional in creating opportunities to listen, learn, and seek input from communities impacted by inequity to guide its work, including both government-to-government engagement with tribes as sovereign nations and more general community engagement.

Specific engagement activities have included hosting community forums in Everett on September 5 and in Yakima on October 20, administering an online survey that had 214 responses, and employing a community engagement coordinator position to share information directly with communities across the state and seek input to guide the Task Force's work.

In addition, the Task Force staff met with leaders of the Yakama Nation prior to its public meeting in Yakima and members and staff attended the 30th Annual Centennial Accord meeting on November 6-7 to learn about tribes' priorities and speak to tribal leaders about the Task Force's work.

To inform the development of its recommendations, the Task Force sought community input, explored existing efforts and infrastructure in the state related to diversity, equity, and inclusion (DEI), and looked at model equity initiatives undertaken by government jurisdictions in the state and nationally.

The Task Force's December 2019 Preliminary Report to the Governor and the Legislature is expected to inform legislation for the upcoming 2020 legislative session to create a Washington State Office of Equity.

RECOMMENDATION 1:

The Council recommends the passage of legislation to create and fund a Washington State Office of Equity.

Responsible Party: Legislature
Measure: Passage of Legislation
Timeline: 2020

Table 1 - Equity Office Task Force Membership

Governor's Interagency Council on Health Disparities	Benjamin Danielson (co-chair), Jan Olmstead (co-chair)
Legislators * * One legislator seat, to be appointed by the President of the Senate, remains vacant.	Sen. Manka Dhingr, Rep. Mia Gregerson (alternate) Rep. Jeremie Dufault, Alec Regimbal (alternate) Rep. Melanie Morgan
Office of the Governor	RaShelle Davis
Commission of African American Affairs	Ed Prince
Diversity, Equity, and Inclusion Council	Karen A. Johnson
Commission on Asian Pacific American Affairs	Toshiko Hasegawa, Carrie Huie Pascua (alternate)
Human Rights Commission	Sharon Ortiz
Commission on Hispanic Affairs	Maria Siguenza
WA State Women's Commission	Michelle Gonzalez, Marie Vela (alternate)
Governor's Office of Indian Affairs	Craig Bill, Mystique Hurtado (alternate)
Office of Minority and Womens' Business Enterprises	Lisa van der Lugt Rex Brown (alternate), Dawn Rains (alternate)
Disability Community	Elizabeth Gordon, Mandeep Kaundal (alternate)
LGBTQ+ Community	Allison Spector

EQUITABLE REPRODUCTIVE HEALTH ACCESS

In 2018, the Washington State Legislature passed Substitute Senate Bill 6219 (SSB 6219). The bill directed the Council to conduct a literature review on disparities in access to reproductive healthcare in Washington State and to propose recommendations to reduce those disparities.

Council staff conducted a review of literature between April and August 2018 to identify barriers to accessing reproductive healthcare. Barriers served as a means to understand disparities in access in order to provide greater understanding of the potential root causes of disparities and to develop relevant, specific recommendations. Staff completed key informant interviews to gain additional context and background information and to refine staff understanding of the literature and recommendations for some population groups.

Council staff evaluated recommendations identified in the literature as well as reports from Washington State agencies and community-based organizations addressing reproductive health. Recommendations that could be addressed at the state level were then further evaluated to determine if they could be acted on by the Washington State Legislature or a state agency.

In January 2019, the Council submitted its report, Literature Review on Inequities in Reproductive Health Access, which identified 14 populations experiencing inequities, 45 unique barriers to access, and 14 recommendations to improve access in the areas of criminal justice, education, healthcare providers, health insurance, and state funding.

RECOMMENDATION 2:

The Council reaffirms the recommendations submitted in its January 2019, Literature Review on Inequities in Reproductive Health Access.

Responsible Parties: Various (see recommendations)
Measure: To be determined
Timeline: To be determined

HEALTH IMPACT REVIEWS

RCW 43.20.285 authorizes the State Board of Health (Board) in collaboration with the Council to conduct Health Impact Reviews (HIRs). HIRs are objective, non-partisan, evidence-based analyses that provides the Governor and Legislators with information about how legislative proposals may impact health and health equity in Washington State.

Since 2014, Council staff have completed 81 HIRs at the request of 48 different legislators. Staff have completed requests on a range of policy topics including, behavioral health, education, and criminal justice, to name just a few. HIRs rely primarily on evidence published in the scientific literature. However, additional staff capacity has allowed staff to complete key informant interviews to address gaps in published literature and to better understand how legislative proposals may impact people in Washington State, which has been of particular interest to the Council.

The Board currently employs 1.6 FTE to complete HIRs. The additional capacity (0.6 FTE) was included in the Board's budget during the last biennium through Foundational Public Health Services. The added capacity will allow the Board and Council to conduct more HIRs, thereby improving the state's ability to use evidence to inform policy and to promote health and health equity.

HEALTH IMPACT REVIEWS (CON'TD)

In addition to providing legislators with information on specific proposals, HIR findings have been used to inform related policy work. For example, in fiscal year 2019, analysts completed an interim request on ESSB 5395, concerning comprehensive sexual health education. The Office of Superintendent of Public Instruction requested Council staff provide a briefing on the HIR findings to the legislatively mandated Sexual Health Education Workgroup (ESHB 1109 Section 501[3][h]). Specifically, the group was tasked with considering the merits and challenges associated with requiring all schools to offer comprehensive sexual health education to students in all grades. Workgroup members were particularly interested in the HIR finding that inclusive comprehensive sexual health curriculum has the potential to reduce health inequities for multiple student groups.

Similarly, in fiscal year 2019, analysts completed a request on HB 1932, concerning vapor products. The analysis focused on provisions which would ban the sale of flavored vapor products in Washington State. Overall, the HIR found evidence that banning the sale of flavored vapor products would likely decrease initiation and use of vapor products and other tobacco products among youth and young adults, thereby improving health outcomes. The review could not conclude how the bill would impact health inequities. Shortly after analysts began conducting the review, the Centers for Disease Control and Prevention announced that, in collaboration with the U.S. Food and Drug Administration, state and local health departments, and other clinical and public health partners, it was investigating outbreaks of severe lung injury associated with e-cigarette and vapor products.

Results of the HIR were used in the state's response to the outbreak of severe lung injury associated with vaping products. On September 27, 2019 Governor Jay Inslee issued Executive Order 19-03, addressing the Vaping Use Public Health Crisis. As a part of the Executive Order, Governor Inslee directed the Washington State Department of Health to, "request that the State Board of Health use its emergency rulemaking authority to impose a ban on all flavored vapor products, including flavored THC vapor products". At the Board's October 9 meeting, staff briefed the Board on the HIR findings for HB 1932. The Board adopted the emergency rulemaking order to create chapter 246-80 WAC, Vapor Products and Flavors rule. Among its provisions, the emergency rule bans the sale of flavored vapor products, including flavored THC vapor products. The emergency rule went into effect on October 10, 2019 and will be in effect for 120 days.

The understanding of HIRs as a policy tool and ways in which requesters use findings continue to develop. While legislators initially requested HIRs primarily to support policies that may positively impact health and health equity, legislators are more frequently requesting HIRs on proposed legislation to understand potential unintended consequences. Other requesters have also used HIRs to understand whether a bill would have the intended impact. Requesters have used findings from HIRs to adjust their proposals to eliminate or address potential concerns.

Requesters have indicated that HIRs are important for informing legislative decision-making by providing important information to talk with other legislators, delivering unbiased data and information, and giving weight and credibility to proposals. Consequently, the demand for HIRs continues to grow and surpass staff capacity.

RECOMMENDATION 3:

The Council recommends that legislators and the Governor continue to support and make requests for Health Impact Reviews to ensure legislative policy development promotes health and equity for all Washingtonians.

Responsible Party: Legislature, Governor, State Board of Health
Measure: Number of requested and completed HIRs per fiscal year
Timeline: Ongoing

ENVIRONMENTAL JUSTICE TASK FORCE

Section 221, subsection 48 of the 2019-2021 biennial operating budget (Engrossed Substitute Senate Bill 1109) directed the Council to convene and staff an Environmental Justice Task Force. The Task Force is responsible for recommending strategies to incorporate environmental justice principles into future state agency actions. The task force must submit a final report by October 31, 2020 to include:

1. Guidance for using the Washington Environmental Health Disparities Map, hosted on the Department of Health's website to identify communities that are highly impacted by environmental justice issues with current demographic data.
2. Best practices for increasing meaningful and inclusive community engagement that takes into account barriers to participation.
3. Measurable goals for reducing environmental health disparities for each community in Washington state and ways in which state agencies may focus their work towards meeting those goals.
4. Model policies that prioritize highly impacted communities and vulnerable populations for the purpose of reducing environmental health disparities and advancing a healthy environment for all residents.

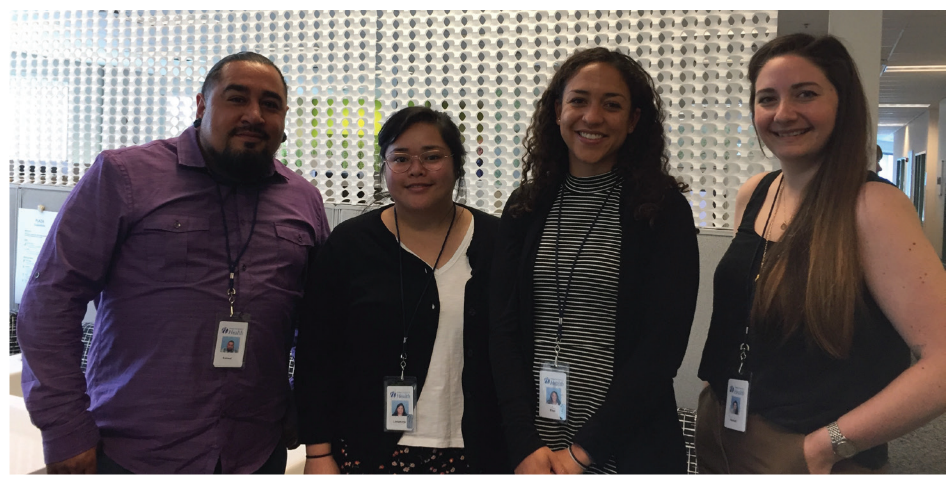
The Environmental Protection Agency defines environmental justice as, "...the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies."[1]

Environmental justice is one important outcome of a truly equitable society and is a critical part of the work to eliminate health disparities.
To date, the Environmental Justice Task Force has held two meetings, one in Lakewood on September 30 and the other in Yakima on November 21. In 2020, the Task Force will meet in Vancouver on January 14 and in Spokane on April 2. Future meeting location and dates for the spring and summer of 2020 are forthcoming.

The Task Force is supported by two subcommittees that will meet monthly. The Task Force, as well as each subcommittee, has its own set of objectives and timeline to address the four required outcomes for the final report.

One subcommittee will focus on providing guidance to state agencies for how to use the Washington Environmental Health Disparities map and the other subcommittee will provide recommendations for best practices for meaningful community engagement.

The Task Force and its subcommittees will also recommend measurable goals and model policies that prioritize environmental justice in the state. Task Force membership is included in Table 2 on the following page.



Office of Equity Task Force and Environmental Justice Task Force staff.
From l-r: Esmael Lopez, LinhPhung Huynh, Elise Rasmussen, Hannah Fernald

[1]Accessed at: EPA web page online on 11/24/2019

Table 2 - Environmental Justice Task Force Membership

Governor's Interagency Council on Health Disparities	Victor Rodriguez (co-chair)
Statewide Environmental Justice Issues	David Mendoza (co-chair)
Puget Sound Partnership	Larry Epstein, Leah Kintner (alternate)
Department of Transportation	Allison Camden, Megan White (alternate)
Public Lands (Dept. of Natural Resources)	Cassie Bordelon
Department of Health	Laura Johnson
Department of Commerce	Michael Furze, Sarah Vorpahl (alternate)
Department of Agriculture	Ignacio Marquez
Department of Ecology	Millie Piazza
CBO: Tacoma League of Young Professionals	Emily Pinckney
Union/Organized Labor Association: UAW Local 4121	Judy Twedt
CBO: Community to Community Development	Tomás Madrigal
CBO: Asian Pacific Islander Coalition	Rowena Pineda
Statewide Agricultural Interests: WA State Farm Bureau	John Stuhlmiller
Business Interests: Association of WA Business	Gary Chandler, Peter Godlewski (alternate)
Tribal Leader	Unconfirmed

COUNCIL MEMBERSHIP

The Council has 17 members: a chair appointed by the Governor; representatives of 14 state agencies, boards, and commissions; and two members of the public who represent health care consumers. A list of current Council members is provided below. The interagency structure of the Council allows it to have a statewide and broad approach to addressing health disparities. The Council considers not only health and health care issues, but also the social factors that influence health, such as education, poverty, employment, and the environment.

Table 3 - Governor's Interagency Council on Health Disparities Membership

Governor's Representative and Council Chair	Benjamin Danielson
Consumer Representative and Council Vice Chair	Victor Rodriguez
Consumer Representative	Leah Wainman
Commission on African American Affairs	Sara Franklin-Phillips
Commission on Asian Pacific American Affairs	Lydia Faitalia
Commission on Hispanic Affairs	Anita Ahumada, Diana Lindner (alternate)
Department of Agriculture	Jill Wisehart
Department of Commerce	Diane Klontz
American Indian Health Commission[2]	Willie Frank, Jan Ward Olmstead (alternate)
Department of Children, Youth, and Families	Greg Williamson
Department of Ecology	Millie Piazza, Rian Sallee (alternate)
Department of Health	Paj Nandi
Department of Social and Health Services	Marietta Bobba
Health Care Authority	Jessie Dean , Lena Nachand (alternate)
Office of Superintendent of Public Instruction	Haley Lowe
State Board of Health	Stephen Kutz, Michelle Davis (alternate)
Workforce Training and Education Coordinating Board	Liz Coleman

[2] The Governor's Office of Indian Affairs delegated authority to the American Indian Health Commission to appoint a representative to the Council

striving to eliminate health disparities by race/ethnicity and gender in washington state

HEALTH EQUITY

Governor's Interagency Council on Health Disparities

healthequity@sboh.wa.gov / www.healthequity.wa.gov / facebook/WAHealthEquity / twitter/WAHealthEquity

Exhibit 9

Environmental Justice Task Force Meeting Materials

Filter: Show all

2020 | 2019

September 30, Lakewood - Task Force Meeting

November 21, Yakima - Task Force Meeting

December 10, Tacoma - Community Engagement Subcommittee Meeting

December 11, Remote - Mapping Subcommittee Meeting

Important Information to Know

Timelines and Deadlines

- A proposed final agenda is distributed one week before each meeting via email and posted to our website.
- Meeting materials are posted to our website 24 hours in advance of the meeting.
- Written and electronic testimony is accepted until 12:00 Noon the Friday before each meeting.
- Draft meeting minutes are posted with the following month's meeting materials.
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Public Involvement Resources

- Learn how to be involved. Give public comments at a meeting .
- Learn how to request public records .

Formal Communications

- Letter to the Governor - Office of Equity In This Moment (June 2020)
- Letter to House of Representatives - Office of Equity In This Moment (June 2020)
- Letter to Senate - Office of Equity In This Moment (June 2020)

Contact the Council

Email Us
360-236-4100
360-236-4088 (fax)
PO Box 47990
Olympia, WA 98504-7990

Notices

Notice of Non-Discrimination

Exhibit 10

Environmental Justice Task Force Meeting Materials

Filter: Show all ▾

2020 | **2019**

- **January 8, Mapping Subcommittee - Call In Only** ›
- **January 9, Community Engagement Subcommittee - Pacific** ›
- **January 14, Task Force - Vancouver** ›
- **February 4, Community Engagement Subcommittee - Bullitt Center** ›
- **February 12, Mapping Subcommittee - Call In Only** ›
- **March 3, Community Engagement Subcommittee - Tacoma** ›
- **March 11, Mapping Subcommittee - Call In Only** ›
- **April 2, Task Force - Teleconference** ›
- **April 7, Community Engagement Subcommittee - TBD** ›
- **April 8, Mapping Subcommittee - Call In Only** ›
- **May 5, Community Engagement Subcommittee** ›
- **May 13, Mapping Subcommittee - Call In Only** ›
- **May 18, Task Force - Virtual Only** ›

June 17, Community Engagement Subcommittee

June 22, Task Force - Virtual Only

July 16, Task Force Feedback Listening Session

July 21, Mapping Subcommittee - Call In Only

July 22, Community Engagement Subcommittee

August 7, Task Force - Virtual Only

August 18, Task Force Work Group - Virtual Only

September 11, Task Force - Virtual Only

September 25, Task Force - Virtual Only

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Olympia, WA 98504-7990

Notices

Notice of Non-Discrimination

Exhibit 11

An official website of the United States government.

EPA United States Environmental Protection Agency

Learn About Environmental Justice

President Clinton signing the EJ Executive Order in 1994.

Environmental justice (EJ) is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies.

Fair treatment means no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental and commercial operations or policies.

Meaningful involvement means:

- People have an opportunity to participate in decisions about activities that may affect their environment and/or health;
- The public's contribution can influence the regulatory agency's decision;
- Community concerns will be considered in the decision making process; and
- Decision makers will seek out and facilitate the involvement of those potentially affected.

Want to learn more about the EPA's Office of Environmental Justice?

- Factsheet on the EPA's Office of Environmental Justice
- Memorandum on EPA's Environmental Justice and Community Revitalization (released 23 February 2018)

Read the accomplishment reports to learn more about the progress that the EPA has made in advancing environmental justice principles? Click here to read annual progress reports on the Agency's most recent EJ accomplishments.

> “Whether by conscious design or institutional neglect, communities of color in urban ghettos, in rural 'poverty pockets,' or on economically impoverished Native-American reservations face some of the worst environmental devastation in the nation.”
>
> Dr. Robert Bullard

- Overview
- Executive Order 12898
- Interagency Working Group
- Laws and Statutes
- Integrating EJ at EPA

EPA and Environmental Justice

EPA's goal is to provide an environment where all people enjoy the same degree of protection from environmental and health hazards and equal access to the decision-making process to maintain a healthy environment in which to live, learn, and work.

EPA's environmental justice mandate extends to all of the Agency's work, including:

- setting standards
- permitting facilities
- awarding grants
- issuing licenses
- regulations
- reviewing proposed actions by the federal agencies

EPA works with all stakeholders to constructively and collaboratively address environmental and public health issues and concerns. The Office of Environmental Justice (OEJ) coordinates the Agency's efforts to integrate environmental justice into all policies, programs, and activities. OEJ's mission is to facilitate Agency efforts to protect environment and public health in minority, low-income, tribal and other vulnerable communities by integrating environmental justice in all programs, policies and activities.

Executive Order 12898

Executive Order 12898 directed federal agencies to develop environmental justice strategies to help federal agencies address disproportionately high and adverse human health or environmental effects of their programs on minority and low-income populations.

The Presidential Memorandum accompanying the order underscores certain provisions of existing law that can help ensure that all communities and persons across the nation live in a safe and healthy environment.

Federal Interagency Working Group

The executive order established an Interagency Working Group on Environmental Justice (EJ IWG) chaired by the EPA Administrator and comprised of the heads of 11 departments or agencies and several White House offices. The EJ IWG now includes 17 agencies and meets on a monthly basis to continue collaborative efforts.

Laws and Statutes

The statutes that EPA implements provide the Agency with authority to consider and address environmental justice concerns. These laws encompass the breadth of the Agency's activities including:

- Setting standards
- Permitting facilities
- Making grants
- Issuing licenses or regulations
- Reviewing proposed actions of other federal agencies

These laws often require the Agency to consider a variety of factors that generally include one or more of the following:

- Public health
- Cumulative impacts
- Social costs
- Welfare impacts

Moreover, some statutory provisions, such as under the Toxics Substances Control Act, explicitly direct the Agency to target low-income populations for assistance. Other statutes direct the Agency to consider vulnerable populations in setting standards. In all cases, the way in which the Agency chooses to implement and enforce its authority can have substantial effects on the achievement of environmental justice for all communities.

Integrating EJ at EPA

Since OEJ was created, there have been significant efforts across EPA to integrate environmental justice into the Agency's day-to-day operations. Read more about how EPA's EJ 2020 Action Agenda will help EPA advance environmental justice through its programs, policies and activities, and support our cross-agency strategy on making a visible difference in environmentally overburdened, underserved, and economically distressed communities.

Every regional and headquarter office has an environmental justice coordinator who serves as a focal point within that organization. This network of individuals provides outreach and educational opportunities to external, as well as internal, individuals and organizations. To find out more about Agency efforts to address environmental justice, contact an EJ coordinator based on your location or area of interest.

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