

Appendix X: Public Comments  
Received with DOH-CAB Responses  
and Final Permit Amendments

# Comments Received



## United States Department of the Interior



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NATIONAL PARK SERVICE  
Interior Regions 8, 9, 10, and 12  
333 Bush Street, Suite 500  
San Francisco, CA 94104-2828

IN REPLY REFER TO:  
1.A.2 (PW-NR)

July 18, 2022

Marianne Rossio (to be submitted via electronic to [marianne.rossio@doh.hawaii.gov](mailto:marianne.rossio@doh.hawaii.gov))  
Hawaii Department of Health, Clean Air Branch  
2827 Waimano Home Road, Suite #130  
Pearl City, Oahu 96872

Dear Ms. Rossio:

Thank you for the opportunity to review the proposed Hawaii Regional Haze State Implementation Plan (SIP) for the Second Implementation Period (2018–2028). The National Park Service (NPS) participated in early engagement and federal land manager consultation with the Hawaii Department of Health Clean Air Branch (DOH-CAB) during SIP development from July 2019 through May 2022. We appreciate the commitment of DOH-CAB to both the spirit and the process of the regional haze rule. DOH-CAB consistently exhibits exemplary communication and dedication to the reasonable reduction of haze-causing pollutants affecting visibility in our shared Class I areas. Following consultation, DOH-CAB provided for public transparency by summarizing NPS input in the public notice and, more importantly, is now acting on additional opportunities to improve the draft SIP and reduce air pollution in the state of Hawaii. We thank DOH-CAB for their quality work and efforts to advance progress toward natural visibility conditions.

The NPS supports the emissions reduction measures DOH-CAB has identified in the SIP. These include the commitment to federally enforceable retirements of boilers at two facilities, and a requirement to switch to a cleaner fuel at a third. We understand that decisions on potential controls for two facilities, the Maalaea Generating Station on Maui and the Mauna Loa Macadamia Nut Corporation Plant on Hawaii, will be addressed in an upcoming SIP revision. The NPS looks forward to reviewing supplemental SIP materials when they become available and will consider providing additional feedback on these two facilities at that time.

Hawai'i is home to two NPS-managed Class I areas—Haleakalā National Park on Maui and Hawai'i Volcanoes National Park on Hawai'i. The NPS values clean air and clear views and recognizes these as essential to our visitor experience and the very purpose of our Class I areas. Visitors from around the world come to these special places each year to explore dynamic volcanic landscapes, experience the wild rain forest, walk in the footsteps of native Hawaiians, and gaze into distant galaxies visible through the dark night skies.

DOH-CAB's consideration and implementation of emission controls shows commitment to improving regional haze in the state. The NPS appreciates the steps Hawaii DOH-CAB is taking to reduce haze-causing pollution and address regional haze in our national parks in this planning period.

We look forward to continuing to work directly with DOH-CAB and welcome opportunities for further dialogue as Hawaii progresses towards a final SIP and SIP revision. Please contact Jalyn Cummings ([jalyn\\_cummings@nps.gov](mailto:jalyn_cummings@nps.gov)) or Melanie Peters ([melanie\\_peters@nps.gov](mailto:melanie_peters@nps.gov)) if you have questions or need additional information.

Sincerely,

Martha Crusius  
Program Manager, Park Planning and Environmental Compliance  
National Park Service, Interior Regions 8, 9, 10, and 12

cc:

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**KARIN KIMURA**  
*Director*  
*Environmental Division*

July 22, 2022

**USPS CERTIFIED MAIL (No. 7013 0600 0000 7932 5933)**  
**RETURN RECEIPT REQUESTED**

Ms. Marianne Rossio  
Clean Air Branch  
State of Hawai'i Department of Health  
2827 Waimano Home Road  
Hale Ola Building, Room 130  
Pearl City, Hawai'i 96782

**Subject:           Regional Haze Draft State Implementation Plan Comments**  
**Hawaiian Electric Company, Inc.**  
**Maui Electric Company, Ltd.**  
**Hawai'i Electric Light Company, Inc.**

Dear Ms. Rossio:

Hawaiian Electric<sup>1</sup> appreciates the Department of Health's (DOH) efforts in preparing the draft Hawai'i State Department of Health Regional Haze State Implementation Plan Second Planning Period (draft SIP) which is intended to comply with the Regional Haze Rule (RHR) 40 CFR Part 51, Subpart P and was posted for public review and comment on or about June 24, 2022. Hawaiian Electric also appreciates the opportunity to provide comments on the draft SIP. Hawaiian Electric's prior comments and communications that are in the administrative record are incorporated in this letter, some of which are included in Appendix P to the draft SIP.

While Hawaiian Electric agrees with certain aspects of the draft SIP, Hawaiian Electric has significant concerns with other portions, particularly the potential for NO<sub>x</sub> controls at the Maalaea Generating Station (Maalaea) for units M1-M3 and M7 and the associated very minimal visibility benefits. Additionally, one of the Federal Land Managers (FLM), the National Park Service (NPS), recommended re-evaluating cost calculations for NO<sub>x</sub> controls at Maalaea and, if found to be cost effective, the installation of selective catalytic reduction (SCR) systems on additional units not currently proposed for such controls in the draft SIP (Appendix P Page 15). These NO<sub>x</sub> controls would involve high costs for emission controls that will further affect Hawaiian Electric customers negatively by potentially increasing electricity rates with little proven visibility improvement at the Class I areas, one with an active volcano: Haleakalā and Hawai'i Volcanoes National Parks. Additionally, given the

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<sup>1</sup> "Hawaiian Electric" or the "Company" refers to Hawaiian Electric Company, Inc. (or "HE"), Hawai'i Electric Light Company, Inc. (or "HL") and/or Maui Electric Company, Limited (or "ME"). On December 20, 2019, the State of Hawai'i Department of Commerce and Consumer Affairs ("DCCA") approved Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc. and Maui Electric Company, Limited's application to do business under the trade name "Hawaiian Electric" for the period from December 20, 2019 to December 19, 2024. See Certificate of Registration No. 4235929, filed December 20, 2019 in the Business Registration Division of the DCCA.

assumptions made in the draft SIP, Hawaiian Electric has concerns about how the visibility analysis was conducted in this decadal period, and will subsequently be conducted during the next Regional Haze decadal period.

As discussed further below, in order to assure the integrity of the grid Hawaiian Electric is requesting that the deadline for shutting down the Kanoelehua-Hill boilers Hill 5 & 6 and Kahului boilers K1-K4 be revised to December 31, 2028 which is permissible under the Regional Haze rule.

As presented in the draft SIP at page 103, Table 7.5-4 summarizes DOH’s proposed control measures and implementation dates for Hawaiian Electric.

Facility <sup>a</sup>	Unit	Unit Nos.	Shut Down	Fuel Switch	SCR	LNB w/ OFA/FGR	FITR
Kanoelehua-Hill	Boilers	Hill 5&6	12/31/27	--	--	--	--
Puna	Boiler	--	--	See note <sup>b</sup>	--	--	--
Kahului	Boilers	K1, K2, K3, & K4	12/31/27	--	--	--	--
Maalaea	DEGs	M1, M2, & M3	--	--	--	--	12/31/27 See note <sup>c</sup>
		M7	--	--	12/31/27 See note <sup>d</sup>	--	--

- a. Potential control measures for Mauna Loa Macadamia Nut Corporation Plant, not listed in the table as a facility evaluated, will be provided in supplemental documents as indicated in Chapter 6.
- b. Fuel switch to ULSD by four (4) years from permit issuance.
- c. Compliance with the NO<sub>x</sub> emissions limit for FITR will be verified with annual source testing.
- d. Compliance with the NO<sub>x</sub> emissions limit for SCR will be verified with a CEMS.

As noted above in addition to these control measures, the DOH in conjunction with the EPA and the FLM including the NPS, is considering whether additional NO<sub>x</sub> control measures should be required at Maalaea. Even absent these additional NO<sub>x</sub> controls, based on Hawaiian Electric’s revised cost table for SCR on the Maalaea diesel engine generators submitted to DOH on June 15, 2022, it is estimated that the NO<sub>x</sub> controls proposed (as reflected in the tables above) will cost Hawaiian Electric and potentially its rate payers \$2,777,000 dollars in capital expenditures for M1-M3 (FITR) and M7 (SCR) and \$402,000 dollars in annual operating costs for M7 (SCR) with, as we have commented previously and as admitted by DOH, little improvement in visibility because NO<sub>x</sub> is not a significant contributor to haze in Hawaii’s warm climate.

The following are Hawaiian Electric’s specific comments on the draft SIP, which are intended to incorporate Hawaiian Electric’s prior comments and correspondence submitted to the DOH with respect to the four-factor analysis reports and compliance with the Regional Haze Rule.

1. Elimination of the Oahu sources from consideration is appropriate.

Hawaiian Electric agrees with the DOH’s determination that sources on Oahu are sufficiently distant from the two national parks, taking into account in particular the

prevailing winds that will virtually never cause their emissions to impair visibility in Hawai'i's distant Class I areas. Based on these factors among others, Hawaiian Electric believes that the DOH is correct in concluding that controls on Oahu sources are not reasonable for RHR purposes (draft SIP Page 64, other cites omitted). This conclusion is also consistent with the DOH and EPA's determination during the first decadal review.<sup>2</sup>

2. Additional NO<sub>x</sub> controls are costly and have questionable benefit.

Hawaiian Electric agrees with DOH's statements in the draft SIP that NO<sub>x</sub> is not a significant contributor to haze: a) Nitrate haze formation is primarily a cold weather phenomenon, and is very low in Hawai'i given its warm year-round conditions; b) This is also supported by the very low nitrate haze impacts shown by Hawai'i's Improve data (draft SIP Page 19).

However, in contrast to the above-noted statements, the DOH has imposed NO<sub>x</sub> controls and has also indicated in the draft SIP that it is continuing to review certain sources at Maalaea for possible additional NO<sub>x</sub> controls in response to the NPS review of potential costs based on an analysis using non-applicable equations<sup>3</sup> in EPA's Control Cost Manual (draft SIP Appendix P, Page 14). Because, as the DOH itself admits in the draft SIP, NO<sub>x</sub> is not a significant contributor to haze and Hawaiian Electric previously demonstrated that NO<sub>x</sub> controls are not necessary or effective for visibility improvement in Hawai'i, Hawaiian Electric does not agree that additional NO<sub>x</sub> controls are necessary particularly at Maalaea on Maui which is typically downwind of the Class I areas relative to the prevailing winds.

The DOH in the draft SIP has indicated that the data submitted for Maalaea are incomplete and that a vendor quote would be useful. Despite DOH's comments, a sufficient vendor site-specific analysis was provided on June 1, 2022 that should be sufficient for Maalaea and no further controls should be required.<sup>4</sup> Maalaea's analysis is discussed in more detail below.

In addition to the fact that it is unclear whether any measurable visibility benefit would be gained by additional NO<sub>x</sub> controls, the DOH has underestimated the costs of controls for Hawaiian Electric throughout the draft SIP which in turn makes it appear that many of those controls, including the possible additional NO<sub>x</sub> controls for Maalaea, are reasonable because they fall at or below the \$5,800 per ton threshold for implementation.

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<sup>2</sup> Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii. EPA Region 9. May 14, 2012.

<sup>3</sup> The NPS used EPA cost estimate equations for SCR on a boiler as their basis for estimating the costs of SCR for an internal combustion engine. This method is not applicable because the exhaust characteristics of a boiler and engine are quite different. For example, the exhaust flow rate per btu of fuel fired is much higher on an engine requiring a larger SCR catalyst bed and/or creating a greater backpressure/power loss.

<sup>4</sup> Analysis was provided to the DOH along with updated costs, but apparently was not presented to the NPS because Hawaiian Electric requested that certain of the data be kept confidential. We are providing that data here without further seeking to keep the information confidential.

3. DOH estimation of costs of controls are understated.

The DOH has underestimated the costs of control measures in several respects, including with respect to the interest rate applied to the cost of capital and construction multipliers.

- a. Hawaiian Electric's June 16, 2021 letter (draft SIP Appendix P, Pages 36-73) presented justifications for the relevant interest rate and a Hawai'i construction cost multiplier used in the four-factor analysis; yet DOH did not fully adopt these adjustments (draft SIP Page 99), which results in an underestimation of the true cost of controls. The use of the lower costs is exacerbated by the fact that in several instances the DOH has approved controls even though the estimated costs exceeded the \$5,800 dollar threshold because DOH asserted that the costs were sufficiently close to the threshold.<sup>5</sup>

Hawaiian Electric disagreed with the DOH's initial use of the prime interest rate of 3.25% in its economic analysis as the cost of capital in annualizing capital costs. As explained in Hawaiian Electric's letter dated June 16, 2021, Hawaiian Electric's true cost of capital is greater than 7% and is documented in proceedings with the State of Hawai'i Public Utilities Commission (PUC). Use of an artificially low interest rate in DOH's calculations makes controls such as selective catalytic reduction (SCR) that require high capital expenses seem more economically reasonable than they truly are. In an apparent response to Hawaiian Electric's comments, the DOH adjusted their interest rate assumption to 6.56% for Hawai'i Island sources and 5.31% for Maui sources. However, these values are still lower than Hawaiian Electric's true cost of debt which in 2021 was greater than 7% and would likely be even higher today due to inflation. Since Hawaiian Electric's firm-specific interest rate is fully documented before a state regulatory agency such as the PUC, it is much more appropriate for use when annualizing the capital costs of potential expenditures than the rate generated by DOH.<sup>6</sup> We would note that the 7% rate was suggested by KPLP in their four factor report as well, see Appendix D.

Hawaiian Electric also disagrees with the DOH's exclusion of a "Hawai'i Construction Cost Multiplier" in the DOH's SCR capital cost estimates and instead uses unadjusted generic EPA cost equations. The EPA's cost equations provide average costs for controls in the U.S., but significantly understate Hawai'i-specific increased labor, material, and shipping costs for construction.

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<sup>5</sup> See draft SIP at 100-101. For Maalaea: FITR for M2 (\$6,257), SCR for M7 (\$5,977), and the fuel switch at Puna which was right at the threshold.

<sup>6</sup> Hawaiian Electric's average cost of capital is explained in a letter to DOH June 21, 2021 and on page 28 of the Hawaiian Electric Light Company, Inc. General Rate Case, Docket No. 2018-0368, Decision and Order No. 37237, dated July 28, 2020 available at: <https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A20G29A85103D00049> and similar data for Maui Electric on Attachment 4 (Page 2 of 9) Rate Case dated June 1, 2019 available at <https://puc.hawaii.gov/wp-content/uploads/2020/07/03-29-2019-MECO-RBA-Review-Transmittal-Trans-No-19-03-2019-03-29-HECO-RBA-Provision-Tariff.pdf>



As explained in Hawaiian Electric's June 16, 2021 letter to the DOH, use of a multiplier of at least 1.2 (i.e., 20% increase) is appropriate and conservative.

#### 4. Timing of Controls Implementation

There are some older generating units that Hawaiian Electric anticipates shutting down in the future due to the projected increase of renewable generation that is scheduled to come online. In these instances, rather than install new expensive controls on these sources, based on discussions with Hawaiian Electric the DOH in the draft SIP requires Hawaiian Electric to shutdown these sources by December 31, 2027 (Kanoelehua-Hill boilers Hill 5 & 6 and Kahului boilers K1-K4). Although at the time this shutdown date in 2027 appeared reasonable, circumstances outside of Hawaiian Electric's control have changed since that time. More recently, many supply chain issues are delaying anticipated operation dates for renewable projects that could make compliance with the shutdown schedule while still preserving the reliability of the grid more difficult. It is Hawaiian Electric's understanding based on EPA guidance that the State of Hawai'i in the draft SIP could still take credit for these shutdowns as part of the reasonable progress demonstration for this decadal period even if the shutdown were achieved by December 31, 2028 (one year later than currently proposed). This is confirmed in an e-mail from EPA's Office of Air Quality Planning and Standards (OAQPS) to Hawaiian Electric's consultant, Robert Paine of AECOM. Accordingly, to help minimize grid reliability concerns, Hawaiian Electric requests that the deadline for shutdown for Kanoelehua-Hill boilers Hill 5 & 6 and Kahului boilers K1-K4 be revised to December 31, 2028.

#### 5. Maalaea Facility

The NPS's review of the four-factor analysis for Maalaea Generating Station identified in the draft SIP (Appendix P, Pages 12-15) questioned the references used by Hawaiian Electric to derive cost effectiveness estimates and referred instead to the EPA Cost Control Manual, which is not an appropriate source for controls in Hawai'i, nor where Hawaiian Electric presented a site-specific versus a generic estimate.

The 2012 internal engineering report Hawaiian Electric used to estimate capital costs of SCR and installation was prepared by Black and Veatch as a study for Hawaiian Electric and was never intended to be used externally; therefore, Hawaiian Electric shared the cost estimate tables with the DOH in a letter dated June 1, 2022 with a request for confidential treatment.

Hawaiian Electric's cost estimates are relevant and were based on vendor quotes obtained for the Maalaea engines with Hawai'i-specific and site-specific considerations. It is more appropriate than the analysis performed by the NPS using the 7<sup>th</sup> edition of the EPA Cost Control Manual, which are based on generic information for boilers (not engines).

The NPS noted that the annual operating costs used in the four-factor analysis cited EPA's technical support document dated 2015 which in turn referenced 2010 and 2006 documents. Based on Hawaiian Electric's current research, despite the date of these documents, they are the most current EPA control costing for diesel engine generators.

In contrast, to reviewing references for diesel generators, the NPS analysis operating cost estimates were based on EPA equations relevant to boilers not diesel engines and are therefore not as relevant.

Finally, in a letter dated June 15, 2022, after the Black and Veatch information was provided to the DOH, the cost data which were based on 2019 costs were updated to 2021 costs to provide an updated estimate.

5. Hawaiian Electric incorporates information from its prior correspondence to the DOH and includes a summary of certain issues addressed in that correspondence because of their significance.
  - a. On numerous occasions during this process, Hawaiian Electric has pointed the DOH to the Company's Renewable Portfolio and the state Renewable Portfolio Standards mandate to reach 100 percent renewables by 2045 as well as other state statutes including the state Greenhouse Gas regulations,<sup>7</sup> all of which serve to support Hawaiian Electric's assertion that these requirements are sufficient to meet the RHR reasonable progress even absent the controls that are proposed. Hawaiian Electric also proposed several methods for making these requirements federally enforceable. There were several documents including the DOH 5-Year Regional Haze Progress Report for Federal Implementation Plan dated October 2027 and a survey<sup>8</sup> that the DOH responded to that suggested this same proposition.
  - b. The August 2021 EPA study, which is still valid according to EPA's Office of Air Quality and Planning Standards (OAQPS), suggests that Hawai'i is much closer to natural background than indicated in the proposed SIP documents raising issues with respect to necessity for the control measures identified by the DOH. (Source: <https://www.epa.gov/system/files/documents/2021-08/epa-454-r-21-007.pdf>)
  - c. The DOH should account for international and natural contributions to understand the current state of anthropogenic haze relative to a path to "natural background".
    - i. The DOH's current estimates of the volcanic sulfate emissions are understated. For example, the EGU + industrial SO<sub>2</sub> emissions from Maui and Hawai'i counties are roughly the same according to the 2017 EPA National Emissions Inventory. However, the DOH's estimate of the anthropogenic-caused sulfate haze for Hawai'i Volcanoes National Park is about four times as high as that at the Haleakalā IMPROVE monitor. Since the emissions from each island are comparable, the DOH may be underestimating the volcanic impact and overstating the anthropogenic improvement needed to reach "natural" conditions.

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<sup>7</sup> Act 234 of the 2007 codified in Hawaii Revised Statutes, Chapter 342B. Hawaii Administrative Rules, Chapter 11-60.1 et seq.

<sup>8</sup> 2018 Western States Planning Readiness Survey for Regional Haze State Implementation Plans for The Second Implementation Period Survey Results and Discussion  
[https://www.wrapair2.org/pdf/WRAP%202018%20RH%20Planning%20Readiness%20Survey%20-%20Synthesis%20Report%20FINAL%20\(including%20figures%20and%20attachments\).PDF](https://www.wrapair2.org/pdf/WRAP%202018%20RH%20Planning%20Readiness%20Survey%20-%20Synthesis%20Report%20FINAL%20(including%20figures%20and%20attachments).PDF)

- ii. The DOH's assumption that the volcanic emissions do not contribute at all to nitrate haze may be incorrect. The article in Journal of Volcanology and Geothermal Research dated February 2022 explains that volcanos can create considerable thermal NO<sub>x</sub> from hot lava contact with air as well as volcano-induced lightning. (Source: <https://www.sciencedirect.com/science/article/pii/S037702732100278X>)
- iii. The visibility data highlighted in several figures in the proposed SIP show data for the years 2014 – 2018. There was significant volcanic activity during this period which gives the impression that visibility improvement has not been made and the Hawai'i Class I areas are far from natural visibility conditions. It should be noted that more recent visibility data through 2020 show visibility impairment is much lower. (Source: [http://views.cira.colostate.edu/fed/Sites/?appkey=SBA\\_AgrvVisibility](http://views.cira.colostate.edu/fed/Sites/?appkey=SBA_AgrvVisibility))
- iv. In addition to these general comments, Hawaiian Electric has the following comments that are applicable in this period, but are also included herein in anticipation of the next decadal period:
  - a) Hawaiian Electric encourages DOH to eliminate NO<sub>x</sub> from evaluation as a haze precursor because NO<sub>x</sub> contribution to visibility impairment is minimal. EPA guidance allows states to eliminate potential haze precursor emissions that have a minimal visibility impact.
  - b) However, if NO<sub>x</sub> must be evaluated, Hawaiian Electric encourages the DOH to incorporate recognition of the lower potential of NO<sub>x</sub> to form nitrate haze (evidenced by the lower nitrate haze in the monitoring data) in decisions on what controls are reasonable. This could be done using a more meaningful visibility impairment metric, or at least a lower \$/ton threshold for NO<sub>x</sub> versus SO<sub>2</sub>). In contrast, for example, in this decadal period review, both of DOH's screening approaches (Q/D and WEP/AOI) weighted NO<sub>x</sub> and SO<sub>2</sub> emissions equally. Likewise, the DOH used the same cost-effectiveness threshold to select/eliminate controls. Although Statewide anthropogenic emissions of NO<sub>x</sub> (ton/year) are higher than SO<sub>2</sub> (ton/year), the DOH's estimates that SO<sub>2</sub> visibility impairment, after "screening out" volcanic impacts, is approximately 15 times higher than nitrate impacts at Haleakalā National Park and approximately 90 times higher at Hawai'i Volcanoes National Park. There is no basis to weigh NO<sub>x</sub> controls the same as SO<sub>2</sub> and adding further NO<sub>x</sub> controls for haze mitigation is simply not supported by the science or monitoring data.
  - c) The DOH's RHR decadal review would be more meaningful if the DOH had used an "adjusted" Glidepath. An example is shown in

the EPA study<sup>9</sup> which suggests that Hawai'i is much closer to natural background than indicated in the proposed SIP documents. Accordingly, Hawaiian Electric strongly encourages the DOH in this and future decadal reviews to adopt an adjusted glidepath which filters out international contributions and natural sources. International contributions were not included although the draft SIP recognizes that the rules allow them to do so (draft SIP Executive Summary). Unless the DOH understands and accounts for these contributions, the DOH will not be able to confidently understand how much Hawai'i anthropogenic sources contribute to impairment or where the Class I areas are relative to a path to "natural background." See Hawaiian Electric letter of April 12, 2022.

In summary, Hawaiian Electric agrees with certain aspects of the draft SIP; however, Hawaiian Electric does not agree with other positions, in particular the need for additional NO<sub>x</sub> controls at the Maalaea facility and the related the cost estimates. Hawaiian Electric urges the DOH to review the additional information Hawaiian Electric has submitted with respect to the controls at Maalaea in conjunction with the updated costs (including the Black and Veatch report) and the appropriate interest rates and construction adjustments to properly review the estimated costs for NO<sub>x</sub> controls.

Should you have any questions or concerns, please contact Marisa Melzer at (808) 543-4513 or maria.melzer@hawaiianelectric.com.

Sincerely,



Enclosures: 1) Hawaiian Electric's Comments on Regional Haze Rule Modeling dated April 12, 2022  
2) Hawaiian Electric's Revised Cost Tables for Maalaea dated June 15, 2022  
3) Email from EPA to Robert Paine dated June 1, 2022

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<sup>9</sup> <https://www.epa.gov/system/files/documents/2021-08/epa-454-r-21-007.pdf>



**KARIN KIMURA**  
*Director*  
*Environmental Division*

April 12, 2022

**SENT VIA EMAIL (marianne.rossio@doh.hawaii.gov)**

Ms. Marianne Rossio  
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State of Hawai'i Department of Health  
2827 Waimano Home Road  
Hale Ola Building, Room 130  
Pearl City, Hawai'i 96782

**Subject: Comments on Regional Haze Rule Modeling  
Hawai'i Electric Light Company, Inc.  
Maui Electric Company, Ltd.**

Dear Ms. Rossio:

This letter is intended to convey Hawaiian Electric's<sup>1</sup> concerns regarding the WRAP modeling and potential impact to future Regional Haze decadal period reviews and proposed emissions controls. Hawaiian Electric urges the Department of Health (DOH) to develop and adopt an adjusted Uniform Rate of Progress (URP) glidepath and endpoint that takes into consideration contributions from international and volcanic emissions to the visibility in the two Class I areas in Hawai'i.

Hawaiian Electric received the March 21, 2022 email from Mike Madsen of your office regarding the modeling conducted with Western Regional Air Partnership (WRAP), Ramboll, and EPA for Hawai'i. Mr. Madsen's email was in response to Hawaiian Electric's recent review of the EPA's Updated 2028 Regional Haze Modeling for Hawaii, Virgin Islands, and Alaska Technical Support Document dated August 13, 2021. In that document, it appears that the current visibility status at Haleakala Crater National Park is already below the 2064 goal for the Regional Haze program. However, in Mr. Madsen's email he indicated that a white paper<sup>2</sup> that predates the above referenced document (8/5/2021) contained the glidepath that the DOH is planning to use, and it did not include international emissions.

For Hawai'i's Regional Haze State Implementation Plan (SIP), the DOH has declined to adjust the 2064 end point natural visibility condition to account for international emissions due to the variability in the data. This is a difficult proposition since according to the updated model, the 2028 visibility excluding U.S. anthropogenic contributions are above the 2064 goal suggesting that the identified glidepath is unachievable irrespective of any emissions controls.

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<sup>1</sup> "Hawaiian Electric" or the "Company" refers to Hawaiian Electric Company, Inc. (or "HE"), Hawai'i Electric Light Company, Inc. (or "HL") and/or Maui Electric Company, Limited (or "ME"). On December 20, 2019, the State of Hawai'i Department of Commerce and Consumer Affairs ("DCCA") approved Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc. and Maui Electric Company, Limited's application to do business under the trade name "Hawaiian Electric" for the period from December 20, 2019 to December 19, 2024. See Certificate of Registration No. 4235929, filed December 20, 2019 in the Business Registration Division of the DCCA.

<sup>2</sup> Recommendations For The Hale1-Hacr1 Improve Monitoring Site Combination And Volcano Adjustment For Sites Representing Hawai'i Class I Areas For The Regional Haze Rule (EPA 8/5/2021)

Following Hawaiian Electric and its consultant's, AECOM Technical Services Inc., review of the WRAP modeling, Hawaiian Electric recommends that DOH adopt an adjusted URP glidepath for Regional Haze Rule (RHR) reviews. A glidepath that does not account for international contributions is, as noted, unattainable and results in a metric that is not meaningful. Hawaiian Electric also recommends that continued attention be given to better understanding the impact of natural volcanic emissions on visibility impairment so it can be appropriately considered in determinations of whether emissions controls, if any, are necessary to make reasonable progress under the RHR. The following paragraphs further explain these points.

The purpose of the RHR is to make reasonable progress remedying impairment of visibility in Class I areas from manmade air pollution emitted in the United States with the goal to get as close as possible to natural visibility conditions in these priority areas by 2064. It is important to note that the RHR specifically notes<sup>3</sup> that states such as Hawai'i are not expected to be able to mitigate haze caused by anthropogenic emissions from outside the United States. This seems to be in contradiction to DOH's current position.

One method to measure progress towards the RHR goals is comparing visibility measurements over time to a theoretical URP glidepath. States are required to develop a URP glidepath for each Class I area in its state, which is a straight-line rate of improvement that would be needed to reach natural background conditions in 2064 accounting for natural haze.<sup>4,5</sup> The RHR does not necessarily require that progress be consistent with this URP glidepath, but it is a very important metric, and there is an increased burden on the state to demonstrate that its SIP is adequate to demonstrate reasonable progress on visibility if the improvement is not keeping pace with the URP. Accordingly, it is important that the URP glidepath used to gauge progress is accurately determined and meaningful.

To help a State assure its glidepath is meaningful, the RHR allows states to adopt an "adjusted glidepath" accounting for visibility contributions that are outside of the program's control (e.g., international anthropogenic contributions and prescribed wildfires). These contributions are added to the estimated 2064 natural conditions endpoint to show a more realistic "adjusted" target. Without this adjustment, the state will be requiring additional domestic emission reductions to offset the unaccounted-for international haze, which as noted above is not consistent with the clear directive in the RHR. In addition, if the reasonable progress without the URP adjustment is not keeping pace with the glidepath, then there is additional and unnecessary work that the state has to deal with to explain why it cannot meet an impossible goal of zeroing out international-caused haze. This issue will become more and more intractable in future decadal reviews as the RHR endpoint is approached, and it becomes apparent that even if all domestic haze is eliminated, the state

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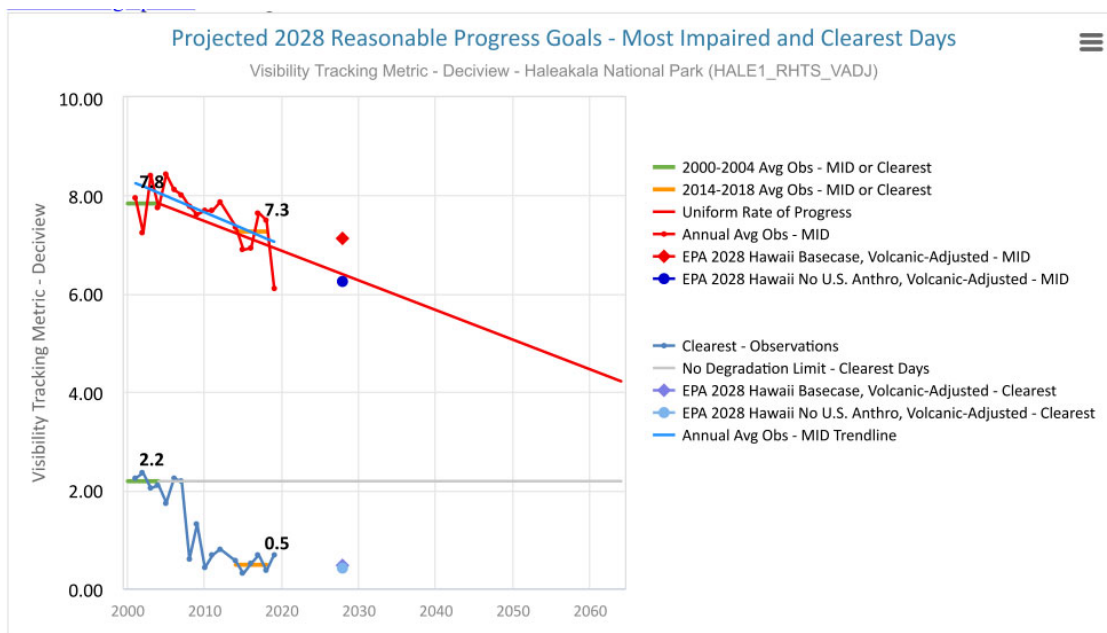
<sup>3</sup> 64 FR 35736 (July 1, 1999). The rule states that "The EPA does not expect States to restrict emissions from domestic sources to offset the impacts of international transport of pollution. We believe that States should evaluate the impacts of current and projected emissions from international sources in their regional haze programs, particularly in cases where it has already been well documented that such sources are important."

<sup>4</sup> In the case of Hawai'i, natural haze (mostly sulfate haze, but also nitrate haze) caused by volcanic activity (even routine emissions from fissures in the absence of lava and ash eruptions) is a significant contributor that must be removed from measurements to account for anthropogenic visibility impairment in the absence of natural causes. This removal of volcanic haze contributions is very challenging, and EPA admits in its August 5, 2021 white paper<sup>3</sup> that the adjusted set of observations that attempts to remove volcanic haze is still contaminated with some residual volcanic haze components.

<sup>5</sup> EPA, August 5, 2021. Recommendations for the HALE1-HACR1 Improve Monitoring Site Combination and Volcano Adjustment for Sites Representing Hawaii Class I Areas for the Regional Haze Rule (white\_paper\_for\_regional\_haze\_hi\_volcano\_adjust\_final.pdf (epa.gov))

cannot meet the unadjusted glidepath because it ends in an unattainable goal due to the continued presence of international-caused haze.

The significance is illustrated in the unadjusted URP glidepath shown below for Haleakala National Park, which Hawaiian Electric understands the DOH obtained from work with Ramboll, WRAP and EPA. This unadjusted URP glidepath uses a 2064 natural visibility endpoint of 4.1 deciviews (DV). However, this is a completely unachievable level. This is demonstrated by the model's projected visibility value for 2028 with U.S. anthropogenic sources removed which is the blue dot at ~6.25 DV. This indicates that even if all U.S. anthropogenic emissions were eliminated, visibility impairment would not be below 6.25 DV. Although this value is close to this unadjusted glidepath in 2028, this unadjusted glidepath will become increasingly unattainable in the future. This clearly illustrates the unreasonableness of the 2064 unadjusted goal.



To have a meaningful URP glidepath for decadal reviews of the RHR, Hawaiian Electric urges the DOH to develop (if not already available) and adopt an adjusted glidepath taking into consideration international impacts as allowed by the RHR. Additionally, Hawaiian Electric encourages the DOH to continue work to better understand the contribution of volcanic emissions to the visibility in the two Class I areas in Hawai'i and accurately address it in the glidepath endpoint.

Ms. Marianne Rossio  
Comments on Regional Haze Modeling  
April 12, 2022  
Page 4 of 4

Should you have any questions or concerns, please contact Marisa Melzer at  
(808) 543-4513 or maria.melzer@hawaiianelectric.com.

Sincerely,



Ec: Michael Madsen (michael.madsen@doh.hawaii.gov)  
Dale Sakata (dale.k.sakata@hawaii.gov)  
Dale Hamamoto (dale.hamamoto@doh.hawaii.gov)  
Colin Erickson (colin.erickson@doh.hawaii.gov)  
Clayton Takamoto (clayton.takamoto@doh.hawaii.gov)





**KARIN KIMURA**  
*Director*  
*Environmental Division*

June 15, 2022

**SENT VIA EMAIL (marianne.rossio@doh.hawaii.gov)**

Ms. Marianne Rossio  
Clean Air Branch  
State of Hawai'i Department of Health  
2827 Waimano Home Road  
Hale Ola Building, Room 130  
Pearl City, Hawai'i 96782

**Subject: Revised Cost Tables for Regional Haze  
Maalaea Generating Station (Maalaea)  
Maui Electric Company, Ltd.**

Dear Ms. Rossio:

On June 1, 2022, Hawaiian Electric<sup>1</sup> submitted revised and updated cost tables for the Maalaea Revised Four-Factor Analysis, Table 4-3, "NO<sub>x</sub> Cost Effectiveness of SCR on the Maalaea Diesel Engine Generators". Upon further review, two errors were identified within the Annualized Capital Cost calculations (see the SCR-DG-2019 and SCR-DG-2021 tabs of the attached workbook).

1. The Nominal Design Output used in the above referenced table submitted on June 1, 2022 was 5.9 MW and is now revised to 5.6 MW (nominal output included in the Maalaea Covered Source Permit, CSP No. 0067-01-C) in the attached workbook. This value is used to present the Annualized Capital Cost on a per megawatt (MW) basis.
2. For the revised costs calculation in 2019 dollars submitted on June 1, 2022, the Maui General Excise Tax was not added for the Process Contingency; Project Contingency; Home Office Expenses; and Startup, Commissioning, Testing costs. The tax amounts are now included in the attached workbook. No changes were made to the revised cost calculation updated to 2021 dollars with respect to the taxes as they were included in the June 1, 2022 version.

As a result, the Annualized Capital Cost in 2019 dollars increased from \$33,611/MW to \$35,656/MW, an approximate 6% increase from the June 1, 2022 version. The Annualized Capital Cost updated to 2021 dollars increased from \$39,441/MW to \$41,554/MW, an approximate 5% increase from the June 1, 2022 version. A table presenting the Cost Effectiveness of installing selective catalytic reduction systems for the diesel engine generators based on these revisions is on the following page.

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<sup>1</sup> "Hawaiian Electric" or the "Company" refers to Hawaiian Electric Company, Inc. (or "HE"), Hawai'i Electric Light Company, Inc. (or "HL") and/or Maui Electric Company, Limited (or "ME"). On December 20, 2019, the State of Hawai'i Department of Commerce and Consumer Affairs ("DCCA") approved Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc. and Maui Electric Company, Limited's application to do business under the trade name "Hawaiian Electric" for the period from December 20, 2019 to December 19, 2024. See Certificate of Registration No. 4235929, filed December 20, 2019 in the Business Registration Division of the DCCA.

NOx Cost Effectiveness (\$/ton) Revised 6/13/2022		
Unit	2019 Dollars	2021 Dollars
M1	15,433	17,986
M2	22,767	26,533
M3	15,345	17,883
M4	9,977	11,627
M5	7,301	8,509
M6	10,682	12,449
M7	5,442	6,342
M8	10,708	12,479
M9	8,696	10,134
M10	7,995	9,318
M11	8,155	9,505
M12	11,345	13,222
M13	10,334	12,044
X1	26,259	30,603
X2	25,571	29,801

Additionally, two typos were identified within the workbook that do not impact the calculations:

1. Within both SCR-DG-2019 and SCR-DG-2021 tabs of the workbook, the referenced units were **M5** – M9 in the June 1, 2022 version. This has been revised to **M4** – M9.
2. Within the SCR-DG-2021 tab of the workbook, the label “Annualized Capital Cost (2019 dollars)” was changed to “Annualized Capital Cost (2021 dollars)”

Please find the enclosed tables and workbook revised on June 13, 2022.

Should you have any questions or concerns, please contact Marisa Melzer at (808) 543-4513 or maria.melzer@hawaiianelectric.com.

Sincerely,



- Enclosures: 1) Revised SCR Cost Tables for Maalaea Diesel Engine Generators 2019 Dollars (Revised June 13, 2022)  
 2) Revised SCR Cost Tables for Maalaea Diesel Engine Generators 2021 Dollars (Revised June 13, 2022)
- Attachment: 1) Revised Excel Workbook, Maalaea DG SCR Costing Tables 2019 and 2021 Dollars 20220613
- Ec w/ Att: Michael Madsen (michael.madsen@doh.hawaii.gov)  
 Lyle T. Leonard (lyle.t.leonard@hawaii.gov)  
 Dale Hamamoto (dale.hamamoto@doh.hawaii.gov)  
 Colin Erickson (colin.erickson@doh.hawaii.gov)  
 Clayton Takamoto (clayton.takamoto@doh.hawaii.gov)

**Table 4-3. NO<sub>x</sub> Cost Effectiveness of SCR on the Maalaea Diesel Engine Generators (Revised 6/13/2022)**

	<b>Design Nominal Output (MW)</b>	<b>Nominal Engine Power (Hp)</b>	<b>Control Option</b>	<b>2017 NO<sub>x</sub> Emissions<sup>A</sup> (tpy)</b>	<b>2017 Operating Hours (hrs/yr)</b>	<b>Control Efficiency</b>	<b>Controlled NO<sub>x</sub> Emissions (tpy)</b>	<b>NO<sub>x</sub> Reduced (tpy)</b>	<b>Capital Recovery<sup>B</sup> (\$)</b>	<b>Annual Operating Cost<sup>C</sup> (\$)</b>	<b>Total Annualized Cost<sup>D</sup> (\$)</b>	<b>NO<sub>x</sub> Cost Effectiveness (\$/ton)</b>
M1	2.5	3,600	SCR	10.0	346.4	90%	1.0	9.0	89,139	49,755	138,894	15,433
M2	2.5	3,600	SCR	5.8	206.8	90%	0.6	5.2	89,139	29,703	118,843	22,767
M3	2.5	3,600	SCR	10.0	340.9	90%	1.0	9.0	89,139	48,965	138,104	15,345
M4	5.6	7,762	SCR	80.8	1,698.0	90%	8.1	72.7	199,672	525,853	725,525	9,977
M5	5.6	7,762	SCR	82.7	1,110.0	90%	8.3	74.4	199,672	343,755	543,427	7,301
M6	5.6	7,762	SCR	61.1	1,252.0	90%	6.1	55.0	199,672	387,731	587,403	10,682
M7	5.6	7,762	SCR	122.9	1,299.0	90%	12.3	110.6	199,672	402,287	601,959	5,442
M8	5.6	7,798	SCR	61.3	1,257.0	90%	6.1	55.2	199,672	391,085	590,757	10,708
M9	5.6	7,798	SCR	102.2	1,929.0	90%	10.2	92.0	199,672	600,162	799,834	8,696
M10	12.5	17,520	SCR	580.3	5,335.8	90%	58.0	522.3	445,696	3,729,808	4,175,504	7,995
M11	12.5	17,520	SCR	506.2	4,677.7	90%	50.6	455.6	445,696	3,269,786	3,715,482	8,155
M12	12.5	17,520	SCR	405.9	5,291.4	90%	40.6	365.3	445,696	3,698,772	4,144,468	11,345
M13	12.5	17,520	SCR	419.5	4,944.2	90%	42.0	377.6	445,696	3,456,073	3,901,770	10,334
X1	2.5	3,600	SCR	5.2	235.0	90%	0.5	4.7	89,139	33,754	122,893	26,259
X2	2.5	3,600	SCR	5.3	228.6	90%	0.5	4.8	89,139	32,835	121,974	25,571

<sup>A</sup> Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

<sup>B</sup> Capital recovery is based on a cost of \$35,656 per MW based on a 2012 internal engineering report for units M4 - M9. The cost has been scaled to 2019 dollars using the Chemical Engineering Plant Cost Index. See Appendix A for the calculation details.

<sup>C</sup> Annual operating cost is based on a cost of \$0.0399 per engine horsepower per operating hour based on EPA costing. The cost has been scaled to 2019 dollars using the Chemical Engineering Plant Cost Index. See Appendix A for the calculation details.

<sup>D</sup> Total Annualized Cost = Capital Recovery + Annual Operating Cost

**Table 4-3. NO<sub>x</sub> Cost Effectiveness of SCR on the Maalaea Diesel Engine Generators (Revised and Updated to 2021 Dollars 6/13/2022)**

	<b>Design Nominal Output (MW)</b>	<b>Nominal Engine Power (Hp)</b>	<b>Control Option</b>	<b>2017 NO<sub>x</sub> Emissions<sup>A</sup> (tpy)</b>	<b>2017 Operating Hours (hrs/yr)</b>	<b>Control Efficiency</b>	<b>Controlled NO<sub>x</sub> Emissions (tpy)</b>	<b>NO<sub>x</sub> Reduced (tpy)</b>	<b>Capital Recovery<sup>B</sup> (\$)</b>	<b>Annual Operating Cost<sup>C</sup> (\$)</b>	<b>Total Annualized Cost<sup>D</sup> (\$)</b>	<b>NO<sub>x</sub> Cost Effectiveness (\$/ton)</b>
M1	2.5	3,600	SCR	10.0	346.4	90%	1.0	9.0	103,886	57,986	161,871	17,986
M2	2.5	3,600	SCR	5.8	206.8	90%	0.6	5.2	103,886	34,617	138,503	26,533
M3	2.5	3,600	SCR	10.0	340.9	90%	1.0	9.0	103,886	57,065	160,951	17,883
M4	5.6	7,762	SCR	80.8	1,698.0	90%	8.1	72.7	232,704	612,846	845,550	11,627
M5	5.6	7,762	SCR	82.7	1,110.0	90%	8.3	74.4	232,704	400,624	633,328	8,509
M6	5.6	7,762	SCR	61.1	1,252.0	90%	6.1	55.0	232,704	451,874	684,579	12,449
M7	5.6	7,762	SCR	122.9	1,299.0	90%	12.3	110.6	232,704	468,838	701,542	6,342
M8	5.6	7,798	SCR	61.3	1,257.0	90%	6.1	55.2	232,704	455,783	688,487	12,479
M9	5.6	7,798	SCR	102.2	1,929.0	90%	10.2	92.0	232,704	699,448	932,152	10,134
M10	12.5	17,520	SCR	580.3	5,335.8	90%	58.0	522.3	519,429	4,346,838	4,866,267	9,318
M11	12.5	17,520	SCR	506.2	4,677.7	90%	50.6	455.6	519,429	3,810,713	4,330,142	9,505
M12	12.5	17,520	SCR	405.9	5,291.4	90%	40.6	365.3	519,429	4,310,667	4,830,096	13,222
M13	12.5	17,520	SCR	419.5	4,944.2	90%	42.0	377.6	519,429	4,027,819	4,547,248	12,044
X1	2.5	3,600	SCR	5.2	235.0	90%	0.5	4.7	103,886	39,338	143,224	30,603
X2	2.5	3,600	SCR	5.3	228.6	90%	0.5	4.8	103,886	38,266	142,152	29,801

<sup>A</sup> Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

<sup>B</sup> Capital recovery is based on a cost of \$41,554 per MW based on a 2012 internal engineering report for units M4 - M9. The cost has been scaled to 2021 dollars using the Chemical Engineering Plant Cost Index. See Appendix A for the calculation details.

<sup>C</sup> Annual operating cost is based on a cost of \$0.0465 per engine horsepower per operating hour based on EPA costing. The cost has been scaled to 2021 dollars using the Chemical Engineering Plant Cost Index. See Appendix A for the calculation details.

<sup>D</sup> Total Annualized Cost = Capital Recovery + Annual Operating Cost

## Melzer, Marisa

---

**From:** Paine, Robert <bob.paine@aecom.com>  
**Sent:** Wednesday, July 6, 2022 10:08 AM  
**To:** Melzer, Marisa; Oshiro, Stanton  
**Subject:** FW: Regional Haze Rule question

[This email is coming from an EXTERNAL source. Please use caution when opening attachments or links in suspicious email.]

---

**From:** Paine, Robert  
**Sent:** Saturday, July 2, 2022 11:25 PM  
**To:** Royer, Todd <todd.royer@aecom.com>  
**Subject:** FW: Regional Haze Rule question

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**From:** Timin, Brian <[Timin.Brian@epa.gov](mailto:Timin.Brian@epa.gov)>  
**Sent:** Tuesday, June 1, 2021 8:48 PM  
**To:** Paine, Bob <[bob.paine@aecom.com](mailto:bob.paine@aecom.com)>  
**Cc:** Palma, Elizabeth <[Palma.Elizabeth@epa.gov](mailto:Palma.Elizabeth@epa.gov)>; Koerber, Mike <[Koerber.Mike@epa.gov](mailto:Koerber.Mike@epa.gov)>  
**Subject:** [EXTERNAL] RE: Regional Haze Rule question

Bob,

Sorry it took so long to get back to you on this question. There is not an exact answer to the question, but in general, we would expect the source to have an *enforceable* shutdown date on or before 12/31/28. In that case, the state could take credit for the shutdown in the long-term strategy as well as in setting the reasonable progress goals for the relevant Class I areas. However, an enforceable shutdown date after 2028 can still be used to shorten the “remaining useful life” factor for a source, which may make the control measure less cost effective. Here is the relevant language from page 34 of the 2019 Regional Haze Guidance:

In the situation of an enforceable requirement for the source to cease operation before the end of the useful life of the controls under consideration, a state may use the enforceable shutdown date as the end of the remaining useful life. To the extent such a requirement is being relied upon for a reasonable progress determination, the measure would need to be included in the SIP and/or be federally enforceable. See 40 CFR 51.308(f)(2). The length of the useful life is the number of years prior to the shutdown date during which the new emission control would be operating, taking into account the date that a possible new emission limit under consideration for the LTS would become enforceable if it were adopted into the SIP and the time normally needed for EPA to review and approve such emission limit. In the situation where an enforceable shutdown date does not exist, the remaining useful life of a control under consideration should be full period of useful life of that control as recommended by EPA’s Control Cost Manual.

If the shutdown occurs after 2028, the long-term strategy should still include the enforceable shutdown, but the 2028 reasonable progress goals (based on modeling) should not account for the shutdown.

Thanks,  
Brian

---

**From:** Paine, Bob <[bob.paine@aecom.com](mailto:bob.paine@aecom.com)>  
**Sent:** Monday, May 24, 2021 7:06 PM  
**To:** Koerber, Mike <[Koerber.Mike@epa.gov](mailto:Koerber.Mike@epa.gov)>  
**Cc:** Timin, Brian <[Timin.Brian@epa.gov](mailto:Timin.Brian@epa.gov)>; Palma, Elizabeth <[Palma.Elizabeth@epa.gov](mailto:Palma.Elizabeth@epa.gov)>  
**Subject:** Regional Haze Rule question

Mike, perhaps this question has come up from a state or region regarding the 2<sup>nd</sup> decadal review of the Regional Haze Rule.

If a state wants to take credit for the Second Decadal Review for a source that will be permanently shut down, what is the latest date by which the source needs to cease operations?

Regards,

Bob Paine, CCM, QEP  
Associate Vice President  
Environment  
D 978.905.2352  
[bob.paine@aecom.com](mailto:bob.paine@aecom.com)

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**KARIN KIMURA**  
*Director*  
*Environmental Division*

July 22, 2022

**USPS CERTIFIED MAIL (No. 7013 0600 0000 7932 5933)  
RETURN RECEIPT REQUESTED**

Ms. Marianne Rossio  
Clean Air Branch  
State of Hawai'i Department of Health  
2827 Waimano Home Road  
Hale Ola Building, Room 130  
Pearl City, Hawai'i 96782

**Subject: Regional Haze Draft State Implementation Plan Comments  
Hawaiian Electric Company, Inc.  
Maui Electric Company, Ltd.  
Hawai'i Electric Light Company, Inc.**

Dear Ms. Rossio:

Hawaiian Electric<sup>1</sup> appreciates the Department of Health's (DOH) efforts in preparing the draft Hawai'i State Department of Health Regional Haze State Implementation Plan Second Planning Period (draft SIP) which is intended to comply with the Regional Haze Rule (RHR) 40 CFR Part 51, Subpart P and was posted for public review and comment on or about June 24, 2022. Hawaiian Electric also appreciates the opportunity to provide comments on the draft SIP. Hawaiian Electric's prior comments and communications that are in the administrative record are incorporated in this letter, some of which are included in Appendix P to the draft SIP.

While Hawaiian Electric agrees with certain aspects of the draft SIP, Hawaiian Electric has significant concerns with other portions, particularly the potential for NO<sub>x</sub> controls at the Maalaea Generating Station (Maalaea) for units M1-M3 and M7 and the associated very minimal visibility benefits. Additionally, one of the Federal Land Managers (FLM), the National Park Service (NPS), recommended re-evaluating cost calculations for NO<sub>x</sub> controls at Maalaea and, if found to be cost effective, the installation of selective catalytic reduction (SCR) systems on additional units not currently proposed for such controls in the draft SIP (Appendix P Page 15). These NO<sub>x</sub> controls would involve high costs for emission controls that will further affect Hawaiian Electric customers negatively by potentially increasing electricity rates with little proven visibility improvement at the Class I areas, one with an active volcano: Haleakalā and Hawai'i Volcanoes National Parks. Additionally, given the

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<sup>1</sup> "Hawaiian Electric" or the "Company" refers to Hawaiian Electric Company, Inc. (or "HE"), Hawai'i Electric Light Company, Inc. (or "HL") and/or Maui Electric Company, Limited (or "ME"). On December 20, 2019, the State of Hawai'i Department of Commerce and Consumer Affairs ("DCCA") approved Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc. and Maui Electric Company, Limited's application to do business under the trade name "Hawaiian Electric" for the period from December 20, 2019 to December 19, 2024. See Certificate of Registration No. 4235929, filed December 20, 2019 in the Business Registration Division of the DCCA.

assumptions made in the draft SIP, Hawaiian Electric has concerns about how the visibility analysis was conducted in this decadal period, and will subsequently be conducted during the next Regional Haze decadal period.

As discussed further below, in order to assure the integrity of the grid Hawaiian Electric is requesting that the deadline for shutting down the Kanoelehua-Hill boilers Hill 5 & 6 and Kahului boilers K1-K4 be revised to December 31, 2028 which is permissible under the Regional Haze rule.

As presented in the draft SIP at page 103, Table 7.5-4 summarizes DOH’s proposed control measures and implementation dates for Hawaiian Electric.

Facility <sup>a</sup>	Unit	Unit Nos.	Shut Down	Fuel Switch	SCR	LNB w/ OFA/FGR	FITR
Kanoelehua-Hill	Boilers	Hill 5&6	12/31/27	--	--	--	--
Puna	Boiler	--	--	See note <sup>b</sup>	--	--	--
Kahului	Boilers	K1, K2, K3, & K4	12/31/27	--	--	--	--
Maalaea	DEGs	M1, M2, & M3	--	--	--	--	12/31/27 See note <sup>c</sup>
		M7	--	--	12/31/27 See note <sup>d</sup>	--	--

- a. Potential control measures for Mauna Loa Macadamia Nut Corporation Plant, not listed in the table as a facility evaluated, will be provided in supplemental documents as indicated in Chapter 6.
- b. Fuel switch to ULSD by four (4) years from permit issuance.
- c. Compliance with the NO<sub>x</sub> emissions limit for FITR will be verified with annual source testing.
- d. Compliance with the NO<sub>x</sub> emissions limit for SCR will be verified with a CEMS.

As noted above in addition to these control measures, the DOH in conjunction with the EPA and the FLM including the NPS, is considering whether additional NO<sub>x</sub> control measures should be required at Maalaea. Even absent these additional NO<sub>x</sub> controls, based on Hawaiian Electric’s revised cost table for SCR on the Maalaea diesel engine generators submitted to DOH on June 15, 2022, it is estimated that the NO<sub>x</sub> controls proposed (as reflected in the tables above) will cost Hawaiian Electric and potentially its rate payers \$2,777,000 dollars in capital expenditures for M1-M3 (FITR) and M7 (SCR) and \$402,000 dollars in annual operating costs for M7 (SCR) with, as we have commented previously and as admitted by DOH, little improvement in visibility because NO<sub>x</sub> is not a significant contributor to haze in Hawaii’s warm climate.

The following are Hawaiian Electric’s specific comments on the draft SIP, which are intended to incorporate Hawaiian Electric’s prior comments and correspondence submitted to the DOH with respect to the four-factor analysis reports and compliance with the Regional Haze Rule.

1. Elimination of the Oahu sources from consideration is appropriate.

Hawaiian Electric agrees with the DOH’s determination that sources on Oahu are sufficiently distant from the two national parks, taking into account in particular the



prevailing winds that will virtually never cause their emissions to impair visibility in Hawai'i's distant Class I areas. Based on these factors among others, Hawaiian Electric believes that the DOH is correct in concluding that controls on Oahu sources are not reasonable for RHR purposes (draft SIP Page 64, other cites omitted). This conclusion is also consistent with the DOH and EPA's determination during the first decadal review.<sup>2</sup>

2. Additional NO<sub>x</sub> controls are costly and have questionable benefit.

Hawaiian Electric agrees with DOH's statements in the draft SIP that NO<sub>x</sub> is not a significant contributor to haze: a) Nitrate haze formation is primarily a cold weather phenomenon, and is very low in Hawai'i given its warm year-round conditions; b) This is also supported by the very low nitrate haze impacts shown by Hawai'i's Improve data (draft SIP Page 19).

However, in contrast to the above-noted statements, the DOH has imposed NO<sub>x</sub> controls and has also indicated in the draft SIP that it is continuing to review certain sources at Maalaea for possible additional NO<sub>x</sub> controls in response to the NPS review of potential costs based on an analysis using non-applicable equations<sup>3</sup> in EPA's Control Cost Manual (draft SIP Appendix P, Page 14). Because, as the DOH itself admits in the draft SIP, NO<sub>x</sub> is not a significant contributor to haze and Hawaiian Electric previously demonstrated that NO<sub>x</sub> controls are not necessary or effective for visibility improvement in Hawai'i, Hawaiian Electric does not agree that additional NO<sub>x</sub> controls are necessary particularly at Maalaea on Maui which is typically downwind of the Class I areas relative to the prevailing winds.

The DOH in the draft SIP has indicated that the data submitted for Maalaea are incomplete and that a vendor quote would be useful. Despite DOH's comments, a sufficient vendor site-specific analysis was provided on June 1, 2022 that should be sufficient for Maalaea and no further controls should be required.<sup>4</sup> Maalaea's analysis is discussed in more detail below.

In addition to the fact that it is unclear whether any measurable visibility benefit would be gained by additional NO<sub>x</sub> controls, the DOH has underestimated the costs of controls for Hawaiian Electric throughout the draft SIP which in turn makes it appear that many of those controls, including the possible additional NO<sub>x</sub> controls for Maalaea, are reasonable because they fall at or below the \$5,800 per ton threshold for implementation.

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<sup>2</sup> Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii. EPA Region 9. May 14, 2012.

<sup>3</sup> The NPS used EPA cost estimate equations for SCR on a boiler as their basis for estimating the costs of SCR for an internal combustion engine. This method is not applicable because the exhaust characteristics of a boiler and engine are quite different. For example, the exhaust flow rate per btu of fuel fired is much higher on an engine requiring a larger SCR catalyst bed and/or creating a greater backpressure/power loss.

<sup>4</sup> Analysis was provided to the DOH along with updated costs, but apparently was not presented to the NPS because Hawaiian Electric requested that certain of the data be kept confidential. We are providing that data here without further seeking to keep the information confidential.

3. DOH estimation of costs of controls are understated.

The DOH has underestimated the costs of control measures in several respects, including with respect to the interest rate applied to the cost of capital and construction multipliers.

- a. Hawaiian Electric's June 16, 2021 letter (draft SIP Appendix P, Pages 36-73) presented justifications for the relevant interest rate and a Hawai'i construction cost multiplier used in the four-factor analysis; yet DOH did not fully adopt these adjustments (draft SIP Page 99), which results in an underestimation of the true cost of controls. The use of the lower costs is exacerbated by the fact that in several instances the DOH has approved controls even though the estimated costs exceeded the \$5,800 dollar threshold because DOH asserted that the costs were sufficiently close to the threshold.<sup>5</sup>

Hawaiian Electric disagreed with the DOH's initial use of the prime interest rate of 3.25% in its economic analysis as the cost of capital in annualizing capital costs. As explained in Hawaiian Electric's letter dated June 16, 2021, Hawaiian Electric's true cost of capital is greater than 7% and is documented in proceedings with the State of Hawai'i Public Utilities Commission (PUC). Use of an artificially low interest rate in DOH's calculations makes controls such as selective catalytic reduction (SCR) that require high capital expenses seem more economically reasonable than they truly are. In an apparent response to Hawaiian Electric's comments, the DOH adjusted their interest rate assumption to 6.56% for Hawai'i Island sources and 5.31% for Maui sources. However, these values are still lower than Hawaiian Electric's true cost of debt which in 2021 was greater than 7% and would likely be even higher today due to inflation. Since Hawaiian Electric's firm-specific interest rate is fully documented before a state regulatory agency such as the PUC, it is much more appropriate for use when annualizing the capital costs of potential expenditures than the rate generated by DOH.<sup>6</sup> We would note that the 7% rate was suggested by KPLP in their four factor report as well, see Appendix D.

Hawaiian Electric also disagrees with the DOH's exclusion of a "Hawai'i Construction Cost Multiplier" in the DOH's SCR capital cost estimates and instead uses unadjusted generic EPA cost equations. The EPA's cost equations provide average costs for controls in the U.S., but significantly understate Hawai'i-specific increased labor, material, and shipping costs for construction.

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<sup>5</sup> See draft SIP at 100-101. For Maalaea: FITR for M2 (\$6,257), SCR for M7 (\$5,977), and the fuel switch at Puna which was right at the threshold.

<sup>6</sup> Hawaiian Electric's average cost of capital is explained in a letter to DOH June 21, 2021 and on page 28 of the Hawaiian Electric Light Company, Inc. General Rate Case, Docket No. 2018-0368, Decision and Order No. 37237, dated July 28, 2020 available at: <https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A20G29A85103D00049> and similar data for Maui Electric on Attachment 4 (Page 2 of 9) Rate Case dated June 1, 2019 available at <https://puc.hawaii.gov/wp-content/uploads/2020/07/03-29-2019-MECO-RBA-Review-Transmittal-Trans-No-19-03-2019-03-29-HECO-RBA-Provision-Tariff.pdf>

As explained in Hawaiian Electric's June 16, 2021 letter to the DOH, use of a multiplier of at least 1.2 (i.e., 20% increase) is appropriate and conservative.

#### 4. Timing of Controls Implementation

There are some older generating units that Hawaiian Electric anticipates shutting down in the future due to the projected increase of renewable generation that is scheduled to come online. In these instances, rather than install new expensive controls on these sources, based on discussions with Hawaiian Electric the DOH in the draft SIP requires Hawaiian Electric to shutdown these sources by December 31, 2027 (Kanoelehua-Hill boilers Hill 5 & 6 and Kahului boilers K1-K4). Although at the time this shutdown date in 2027 appeared reasonable, circumstances outside of Hawaiian Electric's control have changed since that time. More recently, many supply chain issues are delaying anticipated operation dates for renewable projects that could make compliance with the shutdown schedule while still preserving the reliability of the grid more difficult. It is Hawaiian Electric's understanding based on EPA guidance that the State of Hawai'i in the draft SIP could still take credit for these shutdowns as part of the reasonable progress demonstration for this decadal period even if the shutdown were achieved by December 31, 2028 (one year later than currently proposed). This is confirmed in an e-mail from EPA's Office of Air Quality Planning and Standards (OAQPS) to Hawaiian Electric's consultant, Robert Paine of AECOM. Accordingly, to help minimize grid reliability concerns, Hawaiian Electric requests that the deadline for shutdown for Kanoelehua-Hill boilers Hill 5 & 6 and Kahului boilers K1-K4 be revised to December 31, 2028.

#### 5. Maalaea Facility

The NPS's review of the four-factor analysis for Maalaea Generating Station identified in the draft SIP (Appendix P, Pages 12-15) questioned the references used by Hawaiian Electric to derive cost effectiveness estimates and referred instead to the EPA Cost Control Manual, which is not an appropriate source for controls in Hawai'i, nor where Hawaiian Electric presented a site-specific versus a generic estimate.

The 2012 internal engineering report Hawaiian Electric used to estimate capital costs of SCR and installation was prepared by Black and Veatch as a study for Hawaiian Electric and was never intended to be used externally; therefore, Hawaiian Electric shared the cost estimate tables with the DOH in a letter dated June 1, 2022 with a request for confidential treatment.

Hawaiian Electric's cost estimates are relevant and were based on vendor quotes obtained for the Maalaea engines with Hawai'i-specific and site-specific considerations. It is more appropriate than the analysis performed by the NPS using the 7<sup>th</sup> edition of the EPA Cost Control Manual, which are based on generic information for boilers (not engines).

The NPS noted that the annual operating costs used in the four-factor analysis cited EPA's technical support document dated 2015 which in turn referenced 2010 and 2006 documents. Based on Hawaiian Electric's current research, despite the date of these documents, they are the most current EPA control costing for diesel engine generators.

In contrast, to reviewing references for diesel generators, the NPS analysis operating cost estimates were based on EPA equations relevant to boilers not diesel engines and are therefore not as relevant.

Finally, in a letter dated June 15, 2022, after the Black and Veatch information was provided to the DOH, the cost data which were based on 2019 costs were updated to 2021 costs to provide an updated estimate.

5. Hawaiian Electric incorporates information from its prior correspondence to the DOH and includes a summary of certain issues addressed in that correspondence because of their significance.
  - a. On numerous occasions during this process, Hawaiian Electric has pointed the DOH to the Company's Renewable Portfolio and the state Renewable Portfolio Standards mandate to reach 100 percent renewables by 2045 as well as other state statutes including the state Greenhouse Gas regulations,<sup>7</sup> all of which serve to support Hawaiian Electric's assertion that these requirements are sufficient to meet the RHR reasonable progress even absent the controls that are proposed. Hawaiian Electric also proposed several methods for making these requirements federally enforceable. There were several documents including the DOH 5-Year Regional Haze Progress Report for Federal Implementation Plan dated October 2027 and a survey<sup>8</sup> that the DOH responded to that suggested this same proposition.
  - b. The August 2021 EPA study, which is still valid according to EPA's Office of Air Quality and Planning Standards (OAQPS), suggests that Hawai'i is much closer to natural background than indicated in the proposed SIP documents raising issues with respect to necessity for the control measures identified by the DOH. (Source: <https://www.epa.gov/system/files/documents/2021-08/epa-454-r-21-007.pdf>)
  - c. The DOH should account for international and natural contributions to understand the current state of anthropogenic haze relative to a path to "natural background".
    - i. The DOH's current estimates of the volcanic sulfate emissions are understated. For example, the EGU + industrial SO<sub>2</sub> emissions from Maui and Hawai'i counties are roughly the same according to the 2017 EPA National Emissions Inventory. However, the DOH's estimate of the anthropogenic-caused sulfate haze for Hawai'i Volcanoes National Park is about four times as high as that at the Haleakalā IMPROVE monitor. Since the emissions from each island are comparable, the DOH may be underestimating the volcanic impact and overstating the anthropogenic improvement needed to reach "natural" conditions.

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<sup>7</sup> Act 234 of the 2007 codified in Hawaii Revised Statutes, Chapter 342B. Hawaii Administrative Rules, Chapter 11-60.1 et seq.

<sup>8</sup> 2018 Western States Planning Readiness Survey for Regional Haze State Implementation Plans for The Second Implementation Period Survey Results and Discussion  
[https://www.wrapair2.org/pdf/WRAP%202018%20RH%20Planning%20Readiness%20Survey%20-%20Synthesis%20Report%20FINAL%20\(including%20figures%20and%20attachments\).PDF](https://www.wrapair2.org/pdf/WRAP%202018%20RH%20Planning%20Readiness%20Survey%20-%20Synthesis%20Report%20FINAL%20(including%20figures%20and%20attachments).PDF)

- ii. The DOH's assumption that the volcanic emissions do not contribute at all to nitrate haze may be incorrect. The article in Journal of Volcanology and Geothermal Research dated February 2022 explains that volcanos can create considerable thermal NO<sub>x</sub> from hot lava contact with air as well as volcano-induced lightning. (Source: <https://www.sciencedirect.com/science/article/pii/S037702732100278X>)
- iii. The visibility data highlighted in several figures in the proposed SIP show data for the years 2014 – 2018. There was significant volcanic activity during this period which gives the impression that visibility improvement has not been made and the Hawai'i Class I areas are far from natural visibility conditions. It should be noted that more recent visibility data through 2020 show visibility impairment is much lower. (Source: [http://views.cira.colostate.edu/fed/Sites/?appkey=SBA\\_AgrvVisibility](http://views.cira.colostate.edu/fed/Sites/?appkey=SBA_AgrvVisibility))
- iv. In addition to these general comments, Hawaiian Electric has the following comments that are applicable in this period, but are also included herein in anticipation of the next decadal period:
  - a) Hawaiian Electric encourages DOH to eliminate NO<sub>x</sub> from evaluation as a haze precursor because NO<sub>x</sub> contribution to visibility impairment is minimal. EPA guidance allows states to eliminate potential haze precursor emissions that have a minimal visibility impact.
  - b) However, if NO<sub>x</sub> must be evaluated, Hawaiian Electric encourages the DOH to incorporate recognition of the lower potential of NO<sub>x</sub> to form nitrate haze (evidenced by the lower nitrate haze in the monitoring data) in decisions on what controls are reasonable. This could be done using a more meaningful visibility impairment metric, or at least a lower \$/ton threshold for NO<sub>x</sub> versus SO<sub>2</sub>). In contrast, for example, in this decadal period review, both of DOH's screening approaches (Q/D and WEP/AOI) weighted NO<sub>x</sub> and SO<sub>2</sub> emissions equally. Likewise, the DOH used the same cost-effectiveness threshold to select/eliminate controls. Although Statewide anthropogenic emissions of NO<sub>x</sub> (ton/year) are higher than SO<sub>2</sub> (ton/year), the DOH's estimates that SO<sub>2</sub> visibility impairment, after "screening out" volcanic impacts, is approximately 15 times higher than nitrate impacts at Haleakalā National Park and approximately 90 times higher at Hawai'i Volcanoes National Park. There is no basis to weigh NO<sub>x</sub> controls the same as SO<sub>2</sub> and adding further NO<sub>x</sub> controls for haze mitigation is simply not supported by the science or monitoring data.
  - c) The DOH's RHR decadal review would be more meaningful if the DOH had used an "adjusted" Glidepath. An example is shown in

the EPA study<sup>9</sup> which suggests that Hawai'i is much closer to natural background than indicated in the proposed SIP documents. Accordingly, Hawaiian Electric strongly encourages the DOH in this and future decadal reviews to adopt an adjusted glidepath which filters out international contributions and natural sources. International contributions were not included although the draft SIP recognizes that the rules allow them to do so (draft SIP Executive Summary). Unless the DOH understands and accounts for these contributions, the DOH will not be able to confidently understand how much Hawai'i anthropogenic sources contribute to impairment or where the Class I areas are relative to a path to "natural background." See Hawaiian Electric letter of April 12, 2022.

In summary, Hawaiian Electric agrees with certain aspects of the draft SIP; however, Hawaiian Electric does not agree with other positions, in particular the need for additional NO<sub>x</sub> controls at the Maalaea facility and the related the cost estimates. Hawaiian Electric urges the DOH to review the additional information Hawaiian Electric has submitted with respect to the controls at Maalaea in conjunction with the updated costs (including the Black and Veatch report) and the appropriate interest rates and construction adjustments to properly review the estimated costs for NO<sub>x</sub> controls.

Should you have any questions or concerns, please contact Marisa Melzer at (808) 543-4513 or maria.melzer@hawaiianelectric.com.

Sincerely,



Enclosures: 1) Hawaiian Electric's Comments on Regional Haze Rule Modeling dated April 12, 2022  
2) Hawaiian Electric's Revised Cost Tables for Maalaea dated June 15, 2022  
3) Email from EPA to Robert Paine dated June 1, 2022

Ec: Marianne Rossio (marianne.rossio@doh.hawaii.gov)  
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<sup>9</sup> <https://www.epa.gov/system/files/documents/2021-08/epa-454-r-21-007.pdf>



**KARIN KIMURA**  
*Director*  
*Environmental Division*

April 12, 2022

**SENT VIA EMAIL (marianne.rossio@doh.hawaii.gov)**

Ms. Marianne Rossio  
Clean Air Branch  
State of Hawai'i Department of Health  
2827 Waimano Home Road  
Hale Ola Building, Room 130  
Pearl City, Hawai'i 96782

**Subject: Comments on Regional Haze Rule Modeling  
Hawai'i Electric Light Company, Inc.  
Maui Electric Company, Ltd.**

Dear Ms. Rossio:

This letter is intended to convey Hawaiian Electric's<sup>1</sup> concerns regarding the WRAP modeling and potential impact to future Regional Haze decadal period reviews and proposed emissions controls. Hawaiian Electric urges the Department of Health (DOH) to develop and adopt an adjusted Uniform Rate of Progress (URP) glidepath and endpoint that takes into consideration contributions from international and volcanic emissions to the visibility in the two Class I areas in Hawai'i.

Hawaiian Electric received the March 21, 2022 email from Mike Madsen of your office regarding the modeling conducted with Western Regional Air Partnership (WRAP), Ramboll, and EPA for Hawai'i. Mr. Madsen's email was in response to Hawaiian Electric's recent review of the EPA's Updated 2028 Regional Haze Modeling for Hawaii, Virgin Islands, and Alaska Technical Support Document dated August 13, 2021. In that document, it appears that the current visibility status at Haleakala Crater National Park is already below the 2064 goal for the Regional Haze program. However, in Mr. Madsen's email he indicated that a white paper<sup>2</sup> that predates the above referenced document (8/5/2021) contained the glidepath that the DOH is planning to use, and it did not include international emissions.

For Hawai'i's Regional Haze State Implementation Plan (SIP), the DOH has declined to adjust the 2064 end point natural visibility condition to account for international emissions due to the variability in the data. This is a difficult proposition since according to the updated model, the 2028 visibility excluding U.S. anthropogenic contributions are above the 2064 goal suggesting that the identified glidepath is unachievable irrespective of any emissions controls.

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<sup>1</sup> "Hawaiian Electric" or the "Company" refers to Hawaiian Electric Company, Inc. (or "HE"), Hawai'i Electric Light Company, Inc. (or "HL") and/or Maui Electric Company, Limited (or "ME"). On December 20, 2019, the State of Hawai'i Department of Commerce and Consumer Affairs ("DCCA") approved Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc. and Maui Electric Company, Limited's application to do business under the trade name "Hawaiian Electric" for the period from December 20, 2019 to December 19, 2024. See Certificate of Registration No. 4235929, filed December 20, 2019 in the Business Registration Division of the DCCA.

<sup>2</sup> Recommendations For The Hale1-Hacr1 Improve Monitoring Site Combination And Volcano Adjustment For Sites Representing Hawai'i Class I Areas For The Regional Haze Rule (EPA 8/5/2021)

Following Hawaiian Electric and its consultant's, AECOM Technical Services Inc., review of the WRAP modeling, Hawaiian Electric recommends that DOH adopt an adjusted URP glidepath for Regional Haze Rule (RHR) reviews. A glidepath that does not account for international contributions is, as noted, unattainable and results in a metric that is not meaningful. Hawaiian Electric also recommends that continued attention be given to better understanding the impact of natural volcanic emissions on visibility impairment so it can be appropriately considered in determinations of whether emissions controls, if any, are necessary to make reasonable progress under the RHR. The following paragraphs further explain these points.

The purpose of the RHR is to make reasonable progress remedying impairment of visibility in Class I areas from manmade air pollution emitted in the United States with the goal to get as close as possible to natural visibility conditions in these priority areas by 2064. It is important to note that the RHR specifically notes<sup>3</sup> that states such as Hawai'i are not expected to be able to mitigate haze caused by anthropogenic emissions from outside the United States. This seems to be in contradiction to DOH's current position.

One method to measure progress towards the RHR goals is comparing visibility measurements over time to a theoretical URP glidepath. States are required to develop a URP glidepath for each Class I area in its state, which is a straight-line rate of improvement that would be needed to reach natural background conditions in 2064 accounting for natural haze.<sup>4,5</sup> The RHR does not necessarily require that progress be consistent with this URP glidepath, but it is a very important metric, and there is an increased burden on the state to demonstrate that its SIP is adequate to demonstrate reasonable progress on visibility if the improvement is not keeping pace with the URP. Accordingly, it is important that the URP glidepath used to gauge progress is accurately determined and meaningful.

To help a State assure its glidepath is meaningful, the RHR allows states to adopt an "adjusted glidepath" accounting for visibility contributions that are outside of the program's control (e.g., international anthropogenic contributions and prescribed wildfires). These contributions are added to the estimated 2064 natural conditions endpoint to show a more realistic "adjusted" target. Without this adjustment, the state will be requiring additional domestic emission reductions to offset the unaccounted-for international haze, which as noted above is not consistent with the clear directive in the RHR. In addition, if the reasonable progress without the URP adjustment is not keeping pace with the glidepath, then there is additional and unnecessary work that the state has to deal with to explain why it cannot meet an impossible goal of zeroing out international-caused haze. This issue will become more and more intractable in future decadal reviews as the RHR endpoint is approached, and it becomes apparent that even if all domestic haze is eliminated, the state

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<sup>3</sup> 64 FR 35736 (July 1, 1999). The rule states that "The EPA does not expect States to restrict emissions from domestic sources to offset the impacts of international transport of pollution. We believe that States should evaluate the impacts of current and projected emissions from international sources in their regional haze programs, particularly in cases where it has already been well documented that such sources are important."

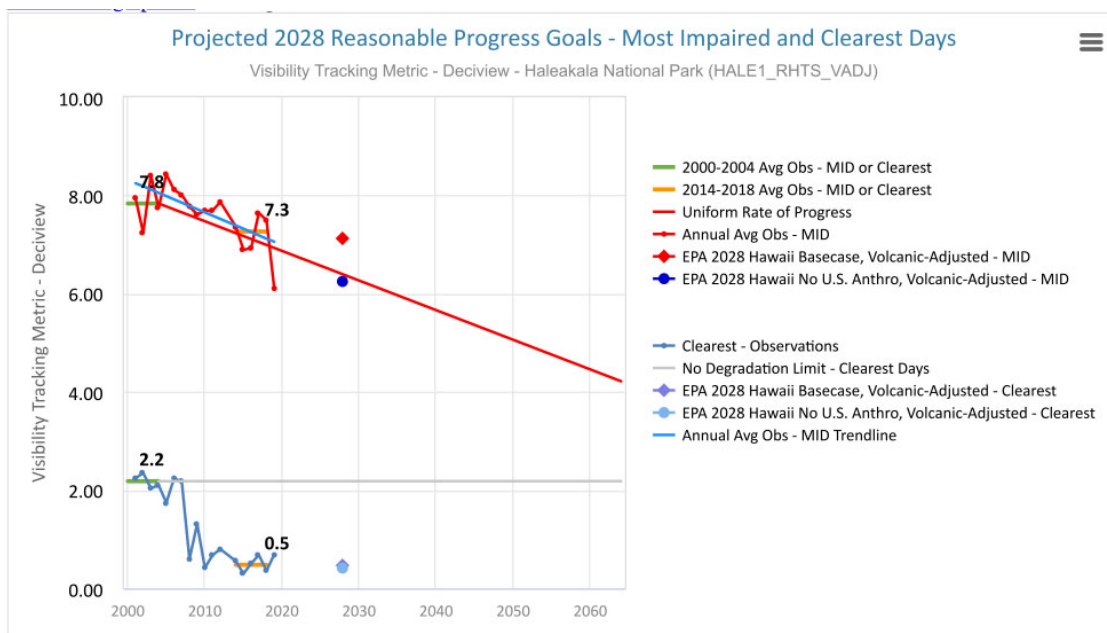
<sup>4</sup> In the case of Hawai'i, natural haze (mostly sulfate haze, but also nitrate haze) caused by volcanic activity (even routine emissions from fissures in the absence of lava and ash eruptions) is a significant contributor that must be removed from measurements to account for anthropogenic visibility impairment in the absence of natural causes. This removal of volcanic haze contributions is very challenging, and EPA admits in its August 5, 2021 white paper<sup>3</sup> that the adjusted set of observations that attempts to remove volcanic haze is still contaminated with some residual volcanic haze components.

<sup>5</sup> EPA, August 5, 2021. Recommendations for the HALE1-HACR1 Improve Monitoring Site Combination and Volcano Adjustment for Sites Representing Hawaii Class I Areas for the Regional Haze Rule (white\_paper\_for\_regional\_haze\_hi\_volcano\_adjust\_final.pdf (epa.gov))



cannot meet the unadjusted glidepath because it ends in an unattainable goal due to the continued presence of international-caused haze.

The significance is illustrated in the unadjusted URP glidepath shown below for Haleakala National Park, which Hawaiian Electric understands the DOH obtained from work with Ramboll, WRAP and EPA. This unadjusted URP glidepath uses a 2064 natural visibility endpoint of 4.1 deciviews (DV). However, this is a completely unachievable level. This is demonstrated by the model's projected visibility value for 2028 with U.S. anthropogenic sources removed which is the blue dot at ~6.25 DV. This indicates that even if all U.S. anthropogenic emissions were eliminated, visibility impairment would not be below 6.25 DV. Although this value is close to this unadjusted glidepath in 2028, this unadjusted glidepath will become increasingly unattainable in the future. This clearly illustrates the unreasonableness of the 2064 unadjusted goal.



To have a meaningful URP glidepath for decadal reviews of the RHR, Hawaiian Electric urges the DOH to develop (if not already available) and adopt an adjusted glidepath taking into consideration international impacts as allowed by the RHR. Additionally, Hawaiian Electric encourages the DOH to continue work to better understand the contribution of volcanic emissions to the visibility in the two Class I areas in Hawai'i and accurately address it in the glidepath endpoint.

Ms. Marianne Rossio  
Comments on Regional Haze Modeling  
April 12, 2022  
Page 4 of 4

Should you have any questions or concerns, please contact Marisa Melzer at  
(808) 543-4513 or maria.melzer@hawaiianelectric.com.

Sincerely,



Ec: Michael Madsen (michael.madsen@doh.hawaii.gov)  
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**KARIN KIMURA**  
*Director*  
*Environmental Division*

June 15, 2022

**SENT VIA EMAIL (marianne.rossio@doh.hawaii.gov)**

Ms. Marianne Rossio  
Clean Air Branch  
State of Hawai'i Department of Health  
2827 Waimano Home Road  
Hale Ola Building, Room 130  
Pearl City, Hawai'i 96782

**Subject: Revised Cost Tables for Regional Haze  
Maalaea Generating Station (Maalaea)  
Maui Electric Company, Ltd.**

Dear Ms. Rossio:

On June 1, 2022, Hawaiian Electric<sup>1</sup> submitted revised and updated cost tables for the Maalaea Revised Four-Factor Analysis, Table 4-3, "NO<sub>x</sub> Cost Effectiveness of SCR on the Maalaea Diesel Engine Generators". Upon further review, two errors were identified within the Annualized Capital Cost calculations (see the SCR-DG-2019 and SCR-DG-2021 tabs of the attached workbook).

1. The Nominal Design Output used in the above referenced table submitted on June 1, 2022 was 5.9 MW and is now revised to 5.6 MW (nominal output included in the Maalaea Covered Source Permit, CSP No. 0067-01-C) in the attached workbook. This value is used to present the Annualized Capital Cost on a per megawatt (MW) basis.
2. For the revised costs calculation in 2019 dollars submitted on June 1, 2022, the Maui General Excise Tax was not added for the Process Contingency; Project Contingency; Home Office Expenses; and Startup, Commissioning, Testing costs. The tax amounts are now included in the attached workbook. No changes were made to the revised cost calculation updated to 2021 dollars with respect to the taxes as they were included in the June 1, 2022 version.

As a result, the Annualized Capital Cost in 2019 dollars increased from \$33,611/MW to \$35,656/MW, an approximate 6% increase from the June 1, 2022 version. The Annualized Capital Cost updated to 2021 dollars increased from \$39,441/MW to \$41,554/MW, an approximate 5% increase from the June 1, 2022 version. A table presenting the Cost Effectiveness of installing selective catalytic reduction systems for the diesel engine generators based on these revisions is on the following page.

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<sup>1</sup> "Hawaiian Electric" or the "Company" refers to Hawaiian Electric Company, Inc. (or "HE"), Hawai'i Electric Light Company, Inc. (or "HL") and/or Maui Electric Company, Limited (or "ME"). On December 20, 2019, the State of Hawai'i Department of Commerce and Consumer Affairs ("DCCA") approved Hawaiian Electric Company, Inc., Hawai'i Electric Light Company, Inc. and Maui Electric Company, Limited's application to do business under the trade name "Hawaiian Electric" for the period from December 20, 2019 to December 19, 2024. See Certificate of Registration No. 4235929, filed December 20, 2019 in the Business Registration Division of the DCCA.

NOx Cost Effectiveness (\$/ton) Revised 6/13/2022		
Unit	2019 Dollars	2021 Dollars
M1	15,433	17,986
M2	22,767	26,533
M3	15,345	17,883
M4	9,977	11,627
M5	7,301	8,509
M6	10,682	12,449
M7	5,442	6,342
M8	10,708	12,479
M9	8,696	10,134
M10	7,995	9,318
M11	8,155	9,505
M12	11,345	13,222
M13	10,334	12,044
X1	26,259	30,603
X2	25,571	29,801

Additionally, two typos were identified within the workbook that do not impact the calculations:

1. Within both SCR-DG-2019 and SCR-DG-2021 tabs of the workbook, the referenced units were **M5** – M9 in the June 1, 2022 version. This has been revised to **M4** – M9.
2. Within the SCR-DG-2021 tab of the workbook, the label “Annualized Capital Cost (2019 dollars)” was changed to “Annualized Capital Cost (2021 dollars)”

Please find the enclosed tables and workbook revised on June 13, 2022.

Should you have any questions or concerns, please contact Marisa Melzer at (808) 543-4513 or maria.melzer@hawaiianelectric.com.

Sincerely,



- Enclosures: 1) Revised SCR Cost Tables for Maalaea Diesel Engine Generators 2019 Dollars (Revised June 13, 2022)  
 2) Revised SCR Cost Tables for Maalaea Diesel Engine Generators 2021 Dollars (Revised June 13, 2022)
- Attachment: 1) Revised Excel Workbook, Maalaea DG SCR Costing Tables 2019 and 2021 Dollars 20220613
- Ec w/ Att: Michael Madsen (michael.madsen@doh.hawaii.gov)  
 Lyle T. Leonard (lyle.t.leonard@hawaii.gov)  
 Dale Hamamoto (dale.hamamoto@doh.hawaii.gov)  
 Colin Erickson (colin.erickson@doh.hawaii.gov)  
 Clayton Takamoto (clayton.takamoto@doh.hawaii.gov)

**Table 4-3. NO<sub>x</sub> Cost Effectiveness of SCR on the Maalaea Diesel Engine Generators (Revised 6/13/2022)**

	<b>Design Nominal Output (MW)</b>	<b>Nominal Engine Power (Hp)</b>	<b>Control Option</b>	<b>2017 NO<sub>x</sub> Emissions<sup>A</sup> (tpy)</b>	<b>2017 Operating Hours (hrs/yr)</b>	<b>Control Efficiency</b>	<b>Controlled NO<sub>x</sub> Emissions (tpy)</b>	<b>NO<sub>x</sub> Reduced (tpy)</b>	<b>Capital Recovery<sup>B</sup> (\$)</b>	<b>Annual Operating Cost<sup>C</sup> (\$)</b>	<b>Total Annualized Cost<sup>D</sup> (\$)</b>	<b>NO<sub>x</sub> Cost Effectiveness (\$/ton)</b>
M1	2.5	3,600	SCR	10.0	346.4	90%	1.0	9.0	89,139	49,755	138,894	15,433
M2	2.5	3,600	SCR	5.8	206.8	90%	0.6	5.2	89,139	29,703	118,843	22,767
M3	2.5	3,600	SCR	10.0	340.9	90%	1.0	9.0	89,139	48,965	138,104	15,345
M4	5.6	7,762	SCR	80.8	1,698.0	90%	8.1	72.7	199,672	525,853	725,525	9,977
M5	5.6	7,762	SCR	82.7	1,110.0	90%	8.3	74.4	199,672	343,755	543,427	7,301
M6	5.6	7,762	SCR	61.1	1,252.0	90%	6.1	55.0	199,672	387,731	587,403	10,682
M7	5.6	7,762	SCR	122.9	1,299.0	90%	12.3	110.6	199,672	402,287	601,959	5,442
M8	5.6	7,798	SCR	61.3	1,257.0	90%	6.1	55.2	199,672	391,085	590,757	10,708
M9	5.6	7,798	SCR	102.2	1,929.0	90%	10.2	92.0	199,672	600,162	799,834	8,696
M10	12.5	17,520	SCR	580.3	5,335.8	90%	58.0	522.3	445,696	3,729,808	4,175,504	7,995
M11	12.5	17,520	SCR	506.2	4,677.7	90%	50.6	455.6	445,696	3,269,786	3,715,482	8,155
M12	12.5	17,520	SCR	405.9	5,291.4	90%	40.6	365.3	445,696	3,698,772	4,144,468	11,345
M13	12.5	17,520	SCR	419.5	4,944.2	90%	42.0	377.6	445,696	3,456,073	3,901,770	10,334
X1	2.5	3,600	SCR	5.2	235.0	90%	0.5	4.7	89,139	33,754	122,893	26,259
X2	2.5	3,600	SCR	5.3	228.6	90%	0.5	4.8	89,139	32,835	121,974	25,571

<sup>A</sup> Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

<sup>B</sup> Capital recovery is based on a cost of \$35,656 per MW based on a 2012 internal engineering report for units M4 - M9. The cost has been scaled to 2019 dollars using the Chemical Engineering Plant Cost Index. See Appendix A for the calculation details.

<sup>C</sup> Annual operating cost is based on a cost of \$0.0399 per engine horsepower per operating hour based on EPA costing. The cost has been scaled to 2019 dollars using the Chemical Engineering Plant Cost Index. See Appendix A for the calculation details.

<sup>D</sup> Total Annualized Cost = Capital Recovery + Annual Operating Cost

**Table 4-3. NO<sub>x</sub> Cost Effectiveness of SCR on the Maalaea Diesel Engine Generators (Revised and Updated to 2021 Dollars 6/13/2022)**

	<b>Design Nominal Output (MW)</b>	<b>Nominal Engine Power (Hp)</b>	<b>Control Option</b>	<b>2017 NO<sub>x</sub> Emissions<sup>A</sup> (tpy)</b>	<b>2017 Operating Hours (hrs/yr)</b>	<b>Control Efficiency</b>	<b>Controlled NO<sub>x</sub> Emissions (tpy)</b>	<b>NO<sub>x</sub> Reduced (tpy)</b>	<b>Capital Recovery<sup>B</sup> (\$)</b>	<b>Annual Operating Cost<sup>C</sup> (\$)</b>	<b>Total Annualized Cost<sup>D</sup> (\$)</b>	<b>NO<sub>x</sub> Cost Effectiveness (\$/ton)</b>
M1	2.5	3,600	SCR	10.0	346.4	90%	1.0	9.0	103,886	57,986	161,871	17,986
M2	2.5	3,600	SCR	5.8	206.8	90%	0.6	5.2	103,886	34,617	138,503	26,533
M3	2.5	3,600	SCR	10.0	340.9	90%	1.0	9.0	103,886	57,065	160,951	17,883
M4	5.6	7,762	SCR	80.8	1,698.0	90%	8.1	72.7	232,704	612,846	845,550	11,627
M5	5.6	7,762	SCR	82.7	1,110.0	90%	8.3	74.4	232,704	400,624	633,328	8,509
M6	5.6	7,762	SCR	61.1	1,252.0	90%	6.1	55.0	232,704	451,874	684,579	12,449
M7	5.6	7,762	SCR	122.9	1,299.0	90%	12.3	110.6	232,704	468,838	701,542	6,342
M8	5.6	7,798	SCR	61.3	1,257.0	90%	6.1	55.2	232,704	455,783	688,487	12,479
M9	5.6	7,798	SCR	102.2	1,929.0	90%	10.2	92.0	232,704	699,448	932,152	10,134
M10	12.5	17,520	SCR	580.3	5,335.8	90%	58.0	522.3	519,429	4,346,838	4,866,267	9,318
M11	12.5	17,520	SCR	506.2	4,677.7	90%	50.6	455.6	519,429	3,810,713	4,330,142	9,505
M12	12.5	17,520	SCR	405.9	5,291.4	90%	40.6	365.3	519,429	4,310,667	4,830,096	13,222
M13	12.5	17,520	SCR	419.5	4,944.2	90%	42.0	377.6	519,429	4,027,819	4,547,248	12,044
X1	2.5	3,600	SCR	5.2	235.0	90%	0.5	4.7	103,886	39,338	143,224	30,603
X2	2.5	3,600	SCR	5.3	228.6	90%	0.5	4.8	103,886	38,266	142,152	29,801

<sup>A</sup> Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

<sup>B</sup> Capital recovery is based on a cost of \$41,554 per MW based on a 2012 internal engineering report for units M4 - M9. The cost has been scaled to 2021 dollars using the Chemical Engineering Plant Cost Index. See Appendix A for the calculation details.

<sup>C</sup> Annual operating cost is based on a cost of \$0.0465 per engine horsepower per operating hour based on EPA costing. The cost has been scaled to 2021 dollars using the Chemical Engineering Plant Cost Index. See Appendix A for the calculation details.

<sup>D</sup> Total Annualized Cost = Capital Recovery + Annual Operating Cost

## Melzer, Marisa

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**From:** Paine, Robert <bob.paine@aecom.com>  
**Sent:** Wednesday, July 6, 2022 10:08 AM  
**To:** Melzer, Marisa; Oshiro, Stanton  
**Subject:** FW: Regional Haze Rule question

[This email is coming from an EXTERNAL source. Please use caution when opening attachments or links in suspicious email.]

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**From:** Paine, Robert  
**Sent:** Saturday, July 2, 2022 11:25 PM  
**To:** Royer, Todd <todd.royer@aecom.com>  
**Subject:** FW: Regional Haze Rule question

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**From:** Timin, Brian <[Timin.Brian@epa.gov](mailto:Timin.Brian@epa.gov)>  
**Sent:** Tuesday, June 1, 2021 8:48 PM  
**To:** Paine, Bob <[bob.paine@aecom.com](mailto:bob.paine@aecom.com)>  
**Cc:** Palma, Elizabeth <[Palma.Elizabeth@epa.gov](mailto:Palma.Elizabeth@epa.gov)>; Koerber, Mike <[Koerber.Mike@epa.gov](mailto:Koerber.Mike@epa.gov)>  
**Subject:** [EXTERNAL] RE: Regional Haze Rule question

Bob,

Sorry it took so long to get back to you on this question. There is not an exact answer to the question, but in general, we would expect the source to have an *enforceable* shutdown date on or before 12/31/28. In that case, the state could take credit for the shutdown in the long-term strategy as well as in setting the reasonable progress goals for the relevant Class I areas. However, an enforceable shutdown date after 2028 can still be used to shorten the “remaining useful life” factor for a source, which may make the control measure less cost effective. Here is the relevant language from page 34 of the 2019 Regional Haze Guidance:

In the situation of an enforceable requirement for the source to cease operation before the end of the useful life of the controls under consideration, a state may use the enforceable shutdown date as the end of the remaining useful life. To the extent such a requirement is being relied upon for a reasonable progress determination, the measure would need to be included in the SIP and/or be federally enforceable. See 40 CFR 51.308(f)(2). The length of the useful life is the number of years prior to the shutdown date during which the new emission control would be operating, taking into account the date that a possible new emission limit under consideration for the LTS would become enforceable if it were adopted into the SIP and the time normally needed for EPA to review and approve such emission limit. In the situation where an enforceable shutdown date does not exist, the remaining useful life of a control under consideration should be full period of useful life of that control as recommended by EPA’s Control Cost Manual.

If the shutdown occurs after 2028, the long-term strategy should still include the enforceable shutdown, but the 2028 reasonable progress goals (based on modeling) should not account for the shutdown.

Thanks,  
Brian

---

**From:** Paine, Bob <[bob.paine@aecom.com](mailto:bob.paine@aecom.com)>  
**Sent:** Monday, May 24, 2021 7:06 PM  
**To:** Koerber, Mike <[Koerber.Mike@epa.gov](mailto:Koerber.Mike@epa.gov)>  
**Cc:** Timin, Brian <[Timin.Brian@epa.gov](mailto:Timin.Brian@epa.gov)>; Palma, Elizabeth <[Palma.Elizabeth@epa.gov](mailto:Palma.Elizabeth@epa.gov)>  
**Subject:** Regional Haze Rule question

Mike, perhaps this question has come up from a state or region regarding the 2<sup>nd</sup> decadal review of the Regional Haze Rule.

If a state wants to take credit for the Second Decadal Review for a source that will be permanently shut down, what is the latest date by which the source needs to cease operations?

Regards,

Bob Paine, CCM, QEP  
Associate Vice President  
Environment  
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July 24, 2022

Marianne Rossio  
Clean Air Branch  
Department of Health  
2827 Waimano Home Road, Suite #130  
Pearl City, Hawaii 96872

*Comments submitted to: CAB@doh.hawaii.gov*

Re: Conservation Organizations' Comments on Hawaii Department of Health, Clean Air Branch, Draft Regional Haze State Implementation Plan for the Second Planning Period (2018-2028) (Docket No. 22-CA-PA-08)

Dear Ms. Rossio:

National Parks Conservation Association and Coalition to Protect America's National Parks ("Conservation Organizations") submit the following comments, attached technical report,<sup>1</sup> and additional 11 exhibits identified in the comments and listed on pages 17 and 18 regarding the Hawaii Department of Health, Clean Air Branch's ("DOH-CAB"), Draft Regional Haze State Implementation Plan for the Second Planning Period (2018-2028) (Docket No. 22-CA-PA-08) ("Proposed SIP").<sup>23</sup> The Conservation Organizations regret that the requested short extension was not provided.<sup>4</sup> The Conservation Organizations also regret that the State's deadline for comments fell outside of the workweek, on a Sunday. The Conservation

<sup>1</sup> Vicki Stamper & Megan Williams, "OIL AND GAS SECTOR REASONABLE PROGRESS FOUR-FACTOR ANALYSIS OF CONTROLS FOR FIVE SOURCE CATEGORIES: NATURAL GAS-FIRED ENGINES, NATURAL GAS-FIRED TURBINES, DIESEL-FIRED ENGINES, NATURAL GAS-FIRED HEATERS AND BOILERS AND FLARING AND INCINERATION," (March 6, 2020), which is incorporated in full as part of these comments. (Ex. 1) ("Stamper Expert Report March 2020").

<sup>2</sup> The Exhibits were transmitted via email to the email address identified above, CAB@doh.hawaii.gov.

<sup>3</sup> Hawaii Department of Health, State of Hawaii Clean Air Branch ("DOH-CAB") Draft Regional Haze State Implementation Plan for the Second Planning Period (2018-2028) (Docket No. 22-CA-PA-08), <https://health.hawaii.gov/cab/files/2022/06/DRAFT-2021HI-RHSIP.pdf>. (Ex. 2) ("Proposed SIP").

<sup>4</sup> Letter from Natalie Levine, to Michael Madsen, Clean Air Branch, Department of Health, Requesting Extension of Comment Period for Hawaii's Draft Regional Haze State Implementation Plan for the Second Implementation Period, (June 30, 2022). (Ex. 3).

Organizations appreciate the letter from you, which responded to our request and allowed for the submittal of these comments and exhibits via email, rather than by postmarked mail.<sup>5</sup>

**National Parks Conservation Association** (“NPCA”) is a national organization whose mission is to protect and enhance America’s national parks for present and future generations. NPCA performs its work through advocacy and education, with its main office in Washington, D.C. and 24 regional and field offices. NPCA has over 1.5 million members nationwide, including 6,499 NPCA members and supporters in Hawaii. NPCA is active nationwide in advocating for strong air quality requirements to protect our parks, including submission of petitions and comments relating to visibility issues, regional haze State Implementation Plans, climate change and mercury impacts on parks, and emissions from power plants, oil and gas operations and other sources of pollution affecting national parks and communities. NPCA’s members live near, work at, and recreate in all the national parks, including those directly affected by emissions from Hawaii’s sources.

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

The Conservation Organizations have concerns with Hawaii’s Proposed SIP, many of which echo concerns raised in the National Park Service’s (“NPS”) consultation comments included in Appendix P of the Proposed SIP. We reviewed the NPS’s analyses and concur with the analyses. This letter details these concerns, in particular regarding three sources and requests that DOH-CAB make substantial edits to the Proposed SIP prior to submission to the U.S. Environmental Protection Agency (“EPA”) to ensure reasonable progress is made in Hawaii’s Class I areas.

<sup>5</sup> DOH-CAB Public Notice, (Conservation Organizations’ review of current Public Notices posted revealed that other public comments were allowed to be submitted via email, while public comments for the regional haze SIP were required to be “postmarked” and sent to “Pearl City, Oahu,” as explained in the public notice as follows: “[a]ll written comments on Hawaii’s draft RH-SIP must be addressed to the Clean Air Branch at the above address on Oahu and must be postmarked or received by July 24, 2022.”), <https://health.hawaii.gov/cab/files/2022/06/22-CA-PA-08.pdf>. (Ex. 4); *see also*, Letter from Marianne Rossio, P.E. Manager, Clean Air Branch, Hawaii Department of Health, to Natalie Levine, Climate and Conservation Program Manager, National Parks Conservation Association, Response to Request for an Extension of the Comment Period for Hawaii’s Draft Regional Haze State Implementation Plan for the Second Implementation Period, (July 8, 2022). (Ex. 5).

## I. BACKGROUND INFORMATION

Hawaii has two Class I areas, Haleakalā National Park on Maui Island and Hawai'i Volcanoes National Park on Hawaii Island. DOH-CAB evaluated the following four sources, and proposed the following actions:<sup>6</sup>

### Hawaii Island Sources:

- Kanoiehua-Hill Power Plant – Permanent shut down of Boilers Hill 5 and Hill 6 by 2028.
- Puna Power Plant – Fuel switch from fuel oil No. 6 to ULSD for the plant's boiler by four years from permit issuance.

### Maui Island Sources:

- Kahului Power Plant – Permanent shut down of Boilers K-1, K-2, K-3, and K-4 by 2028.
- Maalaea Power Plant – Preliminary evaluation found that fuel injection timing retard (FITR) for Diesel Engine Generators M1, M2, and M3 and selective catalytic reduction (SCR) for Diesel Engine Generator M7 by 2028 are required. After further review, more units from this facility may require controls. Therefore, controls for the Maalaea Generating Station will be addressed in an RH-SIP revision.

Based on NPCA's research, we know these sources contribute to visibility impairment at Hawaii's Class I areas. As discussed below, we urge DOH-CAB to revise its Proposed SIP as follows.

- (1) Make the necessary corrections to the Four-Factor Analyses at the unit at the Maalaea Power Plant, which will result in emission limits;
- (2) As expeditiously as possible, either obtain from the sources or conduct the incomplete and needed Four-Factor Analyses, including SIP provisions.
- (3) Ensure that emission limitations (and shut down requirements) and monitoring, recordkeeping and reporting requirements are included in the SIP as regulatory provisions and submitted to EPA for approval, which first go through public notice and comment, and
- (4) Fully consider environmental justice impacts of emissions.

These revisions and considerations are necessary to not only clear the air in our national parks, but in our communities, including environmental justice communities that may be impacted.

<sup>6</sup> Proposed SIP at PDF 4.

## II. ISSUES IDENTIFIED IN THE PROPOSED SIP

### A. Uniform Rate of Progress (URP) is not a “Safe Harbor”

Throughout its Proposed SIP DOH-CAB asserts that because Hawaii’s Class I areas are currently below the adjusted uniform rate of progress needed to achieve the 2064 visibility end goal and are projected to remain below the rate of progress through 2028, DOH-CAB’s sources need not install as stringent controls during this planning period. As EPA’s 2021 July 2021 Clarification Memo stated, SIPs “that conclude that additional controls, including potentially cost-effective and otherwise reasonable controls, are not needed because the Class I areas in the state (and those out-of-state areas affected by emissions from the state) are below their uniform rates of progress (URPs)” have not “answer[ed] the question of whether the amount of progress made in any particular implementation period is ‘reasonable progress.’”<sup>7</sup> EPA explained that its “2017 RHR preamble and the August 2019 Guidance clearly state that it is not appropriate to use the URP in this way, *i.e.*, as a ‘safe harbor.’”<sup>8</sup>

The EPA Clarification memo provides:

The URP is a planning metric used to gauge the amount of progress made thus far and the amount left to make. It is not based on consideration of the four statutory factors and, therefore, cannot answer the question of whether the amount of progress made in any particular implementation period is “reasonable progress.” This concept was explained in the RHR preamble. Therefore, states must select a reasonable number of sources and evaluate and determine emission reduction measures that are necessary to make reasonable progress by considering the four statutory factors.<sup>9</sup>

Therefore, it is inappropriate for DOH-CAB to use visibility conditions (including fire and volcano activity), and the status of the glideslope to justify less stringent requirements in this plan. By doing so, DOH-CAB fails to make reasonable progress to continue to clean up haze pollution incrementally. We urge the state to modify the Proposed SIP by requiring more stringent measures of pollution

<sup>7</sup> Memorandum from Peter Tsirigotis, Director, Office of Air Quality Planning and Standards, to Regional Air Division Directors Regions 1-10, “Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period,” (July 9, 2019), at 15, <https://www.epa.gov/visibility/clarifications-regarding-regional-haze-state-implementation-plans-second-implementation>. (“Clarification Memo”).

<sup>8</sup> Clarification Memo at 15-16; *see also* Memorandum from Peter Tsirigotis, Director at EPA Office of Air Quality Planning and Standards, to EPA Air Division Directors Regions, “Guidance on Regional Haze State Implementation Plans for the Second Implementation Period,” EPA-457/B-19-003, at 25 (Aug. 2019), [https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019\\_-\\_regional\\_haze\\_guidance\\_final\\_guidance.pdf](https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf). (“Guidance”).

<sup>9</sup> Clarification Memo at 15-16.

reduction to satisfy the requirement to make meaningful reasonable progress, and not lean improperly on the URP to justify doing nothing.

## **B. DOH-CAB Failed to Require and Conduct the Appropriate Four-Factor Analyses for Its Sources and Must Correct the Proposed SIP Before Submittal To EPA**

As presented above DOH-CAB's Proposed SIP only included proposed controls for two of its sources and DOH-CAB must make the following corrections to its Four-Factor Analyses these two sources.

### **1. DOH-CAB Must Correct Its Errors at the Maalaeu Power Plant**

We reviewed the consultation comments submitted by the NPS and as mentioned earlier, concur with that analysis.<sup>10</sup>

#### ***a. Corrections Needed for Units M10, M11, M12, M13***

The NPS's comments explained that the four 12.5 MW diesel engine generators (M10, M11, M12, and M13) are currently firing diesel with a maximum sulfur content of 0.4 percent by weight.<sup>11</sup> The NPS's analysis further explained that the engines M10–M13 together account for 1,912 tons/year of NO<sub>x</sub> emissions, this is approximately 69% of the total NO<sub>x</sub> emissions at the facility and these four engines are rated at 17,520 hp each.<sup>12</sup> Hawaii DOH-CAB's cost-effectiveness for SCR on the four largest engines, M10–M13, were as follows:<sup>13</sup>

- \$8,757/ton NO<sub>x</sub> removed for M10,
- \$8,895/ton NO<sub>x</sub> removed for M11,
- \$12,423/ton NO<sub>x</sub> removed for M12, and
- \$11,292/ton NO<sub>x</sub> removed for M13.

As the NPS consultation comments noted, because DOH-CAB's proposed cost-effectiveness threshold was \$5,800/ton, all the above costs were not considered cost-effective. Notably, DOH-CAB's control cost threshold justification was thin in that it relied solely on the Chemical Engineering Plant Cost Index (CEPCI)<sup>14</sup> to escalate costs between 2009 and 2019, which is a period of ten years. Using CEPCI for this purpose was inappropriate because ten years is far outside the time window

<sup>10</sup> National Park Service (NPS) Regional Haze SIP feedback for the Hawaii State Department of Health Clean Air Branch, and workbooks (May 26, 2022). (Ex. 6). ("NPS Consultation Comments").

<sup>11</sup> NPS Consultation Comments at 4.

<sup>12</sup> NPS Consultation Comments at 4.

<sup>13</sup> Proposed SIP, Table 4-3 at 147.

<sup>14</sup> Proposed SIP at 76.

suitable for escalation, which is usually regarded as five years.<sup>15</sup> Escalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate.<sup>16</sup> Moreover, DOH-CAB's Proposed SIP acknowledged that its:

[C]ontrol cost threshold is a *guideline* for evaluating cost effective controls and is not considered a definitive line. Control measures that are above the control cost threshold may still be considered reasonable.<sup>17</sup>

Thus, from DOH-CAB's perspective, the \$5,800 figure is not cast-in-stone, rather it is a guideline it considers when evaluating whether costs are reasonable.

The NPS correctly-applied the applicable EPA SCR cost spreadsheet, and assumed a 20-year life, a 5.31% interest rate, and a NOx removal efficiency of 90% and found SCR would have a cost effectiveness of \$931/ton to \$1,240/ton of NOx removed.<sup>18</sup> The NPS explained that "[t]his is a preliminary analysis because information was not available for all input parameters." The fact the DOH-CAB did not make the input parameters available to the public is contrary to the regulatory requirements to make all supporting information available to the public so that the Federal Land Managers and the public can review and comment. Without the input parameters, neither the NPS nor the Conservation Organizations' experts can review and comment on the cost-effectiveness options for these diesel engines. Therefore, as the NPS explained, "[a]s a result, some values required by the [NPS] worksheet (e.g., annual MW-hours) have been estimated and others (such as net plant heat rate, electricity and labor costs, etc.) were left at their default values."<sup>19</sup> However, what is abundantly clear, is that "[t]he results suggest that SCR may be significantly more cost-effective than the estimates provided in the four-factor analysis."<sup>20</sup> Indeed, a cost effectiveness of \$931/ton to \$1,240/ton of NOx removed is clearly cost-effectively.

DOH-CAB must correct the errors in the Four-Factor Analyses for the four 12.5 MW diesel engine generators (M10, M11, M12, and M13) Maalaeu Power Plant, following those identified by the NPS. Once that is done, the figures will be cost-effective and DOH-CAB's SIP must require that the source meet emissions limits that reflect installation and operation of SCR controls at units M10, M11, M12, and M13.

<sup>15</sup> EPA Control Cost Manual Section 1 Chapter 2, Cost Estimation: Concepts and Methodology, at 19 (Nov. 2017). (Ex. 7).

<sup>16</sup> Control Cost Manual Section 1 Chapter 2, Cost Estimation: Concepts and Methodology, at 19 (Nov. 2017), (Ex. 7).

<sup>17</sup> Proposed SIP at 76. (emphasis added)

<sup>18</sup> NPS Consultation Comments at 6-7.

<sup>19</sup> NPS Consultation Comments at 7.

<sup>20</sup> NPS Consultation Comments at 7.

The cost-effective figures calculated by the NPS are significantly lower than the cost-effectiveness thresholds being established for the second round regional haze plans by several states, including Arizona (\$4,000 to \$6,500/ton<sup>21</sup>), New Mexico (\$7,000 per ton<sup>22</sup>), Oregon (\$10,000/ton<sup>23</sup>), Washington (\$6,300/ton for Kraft pulp and paper power boilers<sup>24</sup>), and Colorado (\$10,000/ton).<sup>25</sup> Thus, the NPS Four-Factor Analyses demonstrate the reasonableness of requiring additional meaningful NOx emissions reductions from the four 12.5 MW diesel engine generators (M10, M11, M12, and M13) at the Maalaeu Power Plant.

### ***b. Additional Analyses Needed for Units M1, M2, M3***

The Proposed SIP included requirements for FITR on Units M1, M2 and M3. The Conservation Organizations suggest that DOH-CAB evaluate replacement of the engines with Tier 4 engines. NPCA commissioned a comprehensive report on reasonable progress Four-Factor Analysis for the oil and gas industry. That report included cost estimates for replacement of older engines with the lowest emitting Tier 4 engines and demonstrates how it can be very cost effective depending on how frequently the engines were operated.<sup>26</sup> We included that report as an exhibit to these comments. DOH-CAB must evaluate replacement of the M1, M2 and M3 engines with Tier 4 engines and use the information in NPCA-commissioned March 2020 report included with these comments.

## **C. The Proposed SIP and Appendix P Lack Clarity in What DOH-CAB Intends to Include in Its SIP Submittal for the Source Retirement Provisions, Emission Limitations and Monitoring, Recordkeeping and Reporting Provisions**

### **1. The Legal Requirements**

The CAA requires that states submit implementation plans that “contain such emission limits, schedules of compliance and other measures as may be

<sup>21</sup> See, e.g., Arizona Department of Environmental Quality, 2021 Regional Haze Four-Factor Initial Control Determination, Tucson Electric Power Irvington Generating Station, at 15, <https://www.azdeq.gov/2021-regional-haze-sip-planning>. (Ex. 8).

<sup>22</sup> NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, [https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED\\_EHD-RH2\\_8\\_25\\_2020.pdf](https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf). (Ex. 9).

<sup>23</sup> Letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2 (Sept. 9, 2020), <https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf>. (Ex. 10).

<sup>24</sup> Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, <https://fortress.wa.gov/ecy/ezshare/AQ/RegionalHaze/docs/RespondFLM20210111.pdf>. (Ex. 11).

<sup>25</sup> Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, November 17 to 19, 2021 Public Hearing, Prehearing Statement, at 7, <https://drive.google.com/drive/u/1/folders/1TK41unOYnMKp5uuakhZiDK0-fuziE58y>. (Ex. 12).

<sup>26</sup> Stamper Expert Report March 2020 at 99-101.

necessary to make reasonable progress toward meeting the national goal” of achieving natural visibility conditions at all Class I Areas.<sup>27</sup> The RHR requires that states must revise and update their 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).<sup>28</sup>

Furthermore, EPA’s RH 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.<sup>29</sup>

Thus, EPA’s RH Guidance recognizes EPA’s long-standing position that SIPs must contain provisions with enforceable emissions limitations and the other enforceable requirements for the SIP measures.

Additionally, 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.<sup>30</sup> State-issued permits must not frustrate SIP requirements.<sup>31</sup> For example, sources with PSD and minor source construction permits under Title I must not hold permits that allow emissions that conflict with SIP requirements.<sup>32</sup> Thus, the RP emission limits and other requirements included in DOH-CAB’s regional haze SIP must be practically enforceable and adopted into the SIP, which means they need to contain the elements necessary for enforceability.

<sup>27</sup> Guidance at 42-43 (While NPCA filed a Petition for Reconsideration regarding EPA’s issuance of the 2019 Guidance, it does not dispute the information in the Guidance referenced here regarding enforceable limitations, which cite to the “General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990, 74 Fed. Reg. 13,498 (April 16, 1992).

<sup>28</sup> 74 Fed. Reg. 13,568 (emphasis added).

<sup>29</sup> Guidance at 42-43.

<sup>30</sup> 74 Fed. Reg. 13,498, 13,568 (April 16, 1992).

<sup>31</sup> Furthermore, to the extent stationary sources are granted permits by rule or other mechanisms, these other categories that allow construction and operation must also complement SIP requirements.

<sup>32</sup> Additionally, as discussed below, 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).



## **2. DOH-CAB's Proposed SIP Does not Reference the Specific Provisions in the Permits that it Intends to Request that EPA Approve as Federally Enforceable**

The introductory material in the Proposed SIP provided the following explanations for how it intends to meet the Clean Air Act's emission limitation requirements:

- Air permits for the Kahului Generating Station on Maui and the Kanoelehua-Hill and Puna Generating Stations on the Big Island, subject to emission reductions, *have been revised* to incorporate the federally enforceable regional haze control measures.
- The permit for the Maalaea Generating Station *will be amended* to incorporate regional haze controls during an RH-SIP revision.<sup>33</sup>

Thus, prior to proposing this SIP and soliciting public comment on the control measures, DOH-CAB explained that it already issued air permits with provisions for Kahului Generating Station, Kanoelehua-Hill, Puna Generating Stations. Contrary to the requirement to fully consider public comments, it appears DOH-CAB may not intend to revise any of those decisions regarding those sources as a result of this proposed rulemaking since those requirements were already incorporated and finalized in the air permits.

In Chapter 6 of the Proposed SIP DOH-CAB explained that it “sent letters to Hawaiian Electric requesting permit applications to incorporate the regional haze control measures selected for the Kahului, Kanoelehua-Hill, Maalaea, and Puna power plants.”<sup>34</sup> In response to the State's request, Hawaiian Electric “responded with new information that was not provided in Hawaiian Electric's four-factor analyses for these facilities.” At this point, the Proposed SIP referred broadly to Chapter 7 for “additional evaluation and permit amendments to incorporate the federally enforceable regional haze control measures.”<sup>35</sup> The Proposed SIP did not explain where in Chapter 7 one should look to find the control measures.

In Chapter 7 DOH-CAB explained briefly it “will incorporate the regional haze provisions into permits for these sources as follows” and then included the below table and list of four footnotes below the table as excerpted below, with the notation “(please refer to Appendix P for details):”<sup>36</sup>

<sup>33</sup> Proposed SIP at PDF 5.

<sup>34</sup> Proposed SIP at 79.

<sup>35</sup> Proposed SIP at 79.

<sup>36</sup> Proposed SIP at 102-103.

Facility <sup>a</sup>	Unit	Unit Nos.	Shut Down	Fuel Switch	SCR	LNB w/ OFA/FGR	FITR
Kanoelehua-Hill	Boilers	Hill 5&6	12/31/27	--	--	--	--
Puna	Boiler	--	--	See note <sup>b</sup>	--	--	--
Kahului	Boilers	K1, K2, K3, & K4	12/31/27	--	--	--	--
Maalaea	DEGs	M1, M2, & M3	--	--	--	--	12/31/27 See note <sup>c</sup>
		M7	--	--	12/31/27 See note <sup>d</sup>	--	--

a. Potential control measures for Mauna Loa Macadamia Nut Corporation Plant, not listed in the table as a facility evaluated, will be provided in supplemental documents as indicated in Chapter 6.  
b. Fuel switch to ULSD by four (4) years from permit issuance.  
c. Compliance with the NO<sub>x</sub> emissions limit for FITR will be verified with annual source testing.  
d. Compliance with the NO<sub>x</sub> emissions limit for SCR will be verified with a CEMS.

Appendix P of the Proposed SIP includes the following: the Regional Haze FLM consultation information; the DOH-CAB and source consultation information; and the “Hawaiian Electric Permit Amendments and Technical Support Documents.”<sup>37</sup> There is a cover page for each category of information. For example, one of the cover pages indicates that for “Draft Permit Amendment and TSD for CSP No. 0067-01-C they will “(**[... BE SUBMITTED AS A SUPPLEMENT TO HAWAII'S RH SIP]**)”,<sup>38</sup> which apparently is one of the missing Four-Factor Analyses. Thus, the Conservation Organizations will plan to review and comment on that permit amendment in a future public notice and comment SIP process. Comments on the two sources with permit information of concern to the Conservation Organizations are as follows.

**“Draft Permit Amendment for CSP No. 0232-01-C.”**<sup>39</sup> The Proposed SIP contains the draft permit amendment for the Maui Electric Company, Ltd. (Maui Electric), Kahului Generating Station, covering Four (4) Boilers. Although the Proposed SIP indicated that DOH-CAB issued a final permit for the retirement of Boilers K-1, K-2, K-3, and K-4 at the Kahului Generating Station by December 31, 2027, the Proposed SIP did not include the final permit in the SIP. The permit amendment included for the Kahului Generating Station in Appendix P was clearly marked as “draft” (as were all the permits in the Appendix). The Proposed SIP did not explain this discrepancy. Neither the Proposed SIP nor Appendix P explain whether the draft permit is a SIP permit or a Title V permit. Additionally, the draft

<sup>37</sup> Proposed SIP, Appendix P at 119.

<sup>38</sup> Proposed SIP, Appendix P at 119 (Note: cover page only, no draft permit amendments followed. Red ink is as it appears in the appendix.).

<sup>39</sup> Proposed SIP, Appendix P at 120.

permit had an expiration date and it is unclear how that impacts the Act's SIP requirement, which requires that SIP measures must be permanent. Furthermore, the Proposed SIP included the draft Attachment to the permit not the entire permit. By only including the draft Attachment to the permit and not the entire permit, the ability of the public to comment due on the provisions of the proposed additions was restricted. For example, the Attachment includes cross-references to sections of the permit they were not provided access to (e.g., Section F cross-references Standard Condition No. 28). Standard Condition No. 28 is not in the Attachment. Additionally, the SIP must not contain conflicting methods for determining compliance and because the entire permit was not provided, the Conservation Organizations could not assess whether there were/are conflicting methods of compliance. Furthermore, the Proposed SIP is unclear if it intends to include the entire Permit Amendment/Attachment in the SIP as regulatory text, or just portions. The Proposed SIP must so specify. We urge DOH-CAB to renotify the SIP, provide clarification and full access to the missing information.

*“Draft Permit Amendment for CSP No. 0234-01-C.”*<sup>40</sup> The Proposed SIP contains the draft permit amendment for the Hawaii Electric Light Company, Inc. (Hawaii Electric Light) Kanoelehua-Hill Generating Station covering Two (2) Boilers, One (1) Combustion Turbine, and Four (4) Diesel Engines. The Conservation Organizations' concerns with the draft permit amendments for the Kanoelehua-Hill Generating Station are the same as those identified for the Kahului Generating Station.

#### **D. Hawaii's Proposed SIP Failed to include all Sources: The Proposed SIP Lacks a Four-Factor Analysis and Emission Limits for the Mauna Loa Macadamia Nut Corporation Plant**

The Mauna Loa Macadamia Nut Corporation Plant was ranked as one of the top three contributors to visibility impairment at Hawai'i Volcanoes National Park on Hawaii Island for nitrates, a concern identified by the NPS, which the Conservation Organizations share. The Four-Factor Analysis for Mauna Loa Macadamia Nut Corporation Plant was determined to be incomplete. Appendix P to the Proposed SIP indicated that the industry consultation documents from the source would:

**BE SUBMITTED AS A SUPPLEMENT TO HAWAII'S RH SIP**<sup>41</sup>

In addition to the Four-Factor Analysis from the source being incomplete, DOH-CAB failed to conduct a Four-Factor Analysis, which it was required to do since the source fail to do so. According to DOH-CAB, potential control measures for this plant will be provided in supplemental documents as a RH-SIP revision.

<sup>40</sup> Proposed SIP, Appendix P at 177.

<sup>41</sup> Proposed SIP, Appendix P at 356. (Note: red ink is as it appears in the appendix.)

DOH-CAB must provide public notice and comment of its Proposed SIP prior to submitting to EPA.

**E. DOH-CAB Must Do More to Analyze Environmental Justice Impacts of its Regional Haze SIP, and Must Ensure Its SIP Will Reduce Emissions and Minimize Harms to Disproportionately Impacted Communities**

DOH-CAB attempted to address environmental justice issues and communities impacted by Hawaii’s polluting sources. Sources that harm the air in our treasured Class I areas are also located in environmental justice areas across the State. Although the Proposed SIP contained a one-paragraph section titled Environmental Justice as follows:<sup>42</sup>

Mitigating haze-causing pollution is a vital part of our efforts to address environmental justice concerns to reduce visibility impairing emissions from anthropogenic sources that may disproportionately affect those who are socially or economically disadvantaged. The purpose of Hawaii’s RH-SIP is for implementing requirements of EPA’s Regional Haze Rule by achieving emission reductions to improve visibility in Hawaii’s national parks. The permit modifications incorporating regional haze control measures for large sources on Hawaii and Maui Islands are important measures to reduce anthropogenic visibility impacts. The DOH-CAB strongly supports 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. A hard copy of the RH-SIP was provided at designated DOH offices located on all main Hawaiian Islands for personal viewing. The RH-SIP was also posted on DOH-CAB’s website for communities to give feedback on the proposed strategy for reducing visibility impairing pollutants.

The information provided in the above paragraph excerpted from the Proposed SIP shows DOH-CAB’s support for 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.” It also explains where and how the public could access the Proposed SIP.<sup>43</sup> But the Proposed SIP did not to meet the environmental justice and civil rights requirements. By fully evaluating the vulnerable communities and counties impacted by these sources, we believe DOH-CAB will identify emission-reducing options that if required will improve air quality and help achieve reasonable progress in this round of regional haze rulemaking.

Historically, conservation and environmental work has concerned itself with protecting nature from people and has thus “siloe” its work (*e.g.*, mainstream conservation vs. environmental justice.) While this siloe approach has led to the

<sup>42</sup> Proposed SIP at 13.

<sup>43</sup> Proposed SIP at 13.

protection of many vulnerable habitats, it ignores the reality that people live in concert with and are a part of nature; to protect one and not the other is a job half done. By considering viewshed protection and environmental justice at the same time, we can collectively begin to dismantle the silos that exist in conservation and environmental work and chart a new path forward.

## **1. DOH-CAB can facilitate EPA’s consideration of environmental justice to comply with Federal Executive Orders**

There are specific legal grounds for considering environmental justice when determining reasonable progress controls. Under the CAA, states are permitted to include in a SIP measures that are authorized by state law but go beyond the minimum requirements of federal law.<sup>44</sup> Ultimately, EPA will review the Final Haze Plan that submits, and EPA will be required to ensure that its action on DOH-CAB’s Haze Plan addresses any disproportionate environmental impacts of the pollution that contributes to haze, and is subject to the current Administration’s “Executive Order on Tackling the Climate Crisis at Home and Abroad.”<sup>45</sup> Hawaii can facilitate EPA’s compliance with these Executive Orders by considering environmental justice in its SIP submission.

## **2. DOH-CAB ignored EPA’s Regional Haze Guidance and Clarification Memo, which directs states to take environmental justice concerns and impacts into consideration**

EPA’s 2021 Clarification Memo directs states to take into consideration environmental justice concerns and impacts in issuing any SIP revision for the second planning period.<sup>46</sup> EPA’s 2019 Regional Haze Guidance for the Second Planning Period specifies, “States may also consider any beneficial non-air quality environmental impacts.”<sup>47</sup> This includes consideration of environmental justice in keeping with other agency policies. For example, EPA also pointed to another agency program that states could rely upon for guidance in interpreting how to apply the non-air quality environmental impacts standard:

<sup>44</sup> See *Union Elec. Co v. EPA*, 427 U.S. 246, 265 (1976) (“States may submit implementation plans more stringent than federal law requires and . . . the Administrator must approve such plans if they meet the minimum requirements of s 110(a)(2).”); *Ariz. Pub. Serv. Co. v. EPA*, 562 F.3d 1116, 1126 (10th Cir. 2009) (citing *Union Elec. Co.*, 427 U.S. at 265) (“States may submit implementation plans more stringent than federal law requires and [ ] the [EPA] must approve such plans if they meet the minimum [CAA] requirements of § 110(a)(2).”); *BCCA Appeal Group v. EPA*, 355 F.3d 817, 826 n.6 (5th Cir. 2003) (“...the states can adopt more stringent air pollution control measures than federal law requires...”)

<sup>45</sup> Exec. Order No. 14008, 86 Fed. Reg. 7,619 (Jan. 27, 2021).

<sup>46</sup> Clarification Memo at 16.

<sup>47</sup> Guidance at 49.

When there are significant potential non-air environmental impacts, characterizing those impacts will usually be very source- and place-specific. Other EPA guidance intended for use in environmental impact assessments under the National Environmental Policy Act may be informative, but not obligatory to follow, in this task.<sup>48</sup>

Additionally, a collection of EPA policies, guidance and directives related to the National Environmental Policy Act (“NEPA”) is available at <https://www.epa.gov/nepa/national-environmental-policy-act-policies-and-guidance>. One of these policies concerns Environmental Justice.<sup>49</sup> Hawaii should consider these sources of information in conducting a meaningful environmental justice analysis.

### **3. EPA must consider environmental justice when it reviews and takes action on Hawaii’s SIP**

As occurred in the first planning period, if a state fails to submit its SIP on time, or if EPA finds that all or part of a state’s SIP does not satisfy the Regional Haze regulations, then EPA must promulgate its own Federal Implementation Plan (“FIP”) to cover the SIP’s inadequacy. Should EPA promulgate a FIP that reconsiders a state’s Four-Factor Analyses, it is completely free to reconsider any aspect of that state’s analysis. The two Presidential Executive Orders referenced above require that federal agencies integrate Environmental Justice principles into their decision-making. EPA has a lead role in coordinating these efforts, and EPA Administrator Regan directed all EPA offices to clearly integrate environmental justice considerations into their plans and actions.<sup>50</sup> Consequently, should EPA promulgate a FIP for Hawaii sources, it has an obligation to integrate Environmental Justice principles into its decision-making. The non-air quality environmental impacts of compliance portion of the third factor, is a pathway for doing so.

### **4. DOH-CAB must consider environmental justice under Title VI of the Civil Rights Act**

As EPA must consider Environmental Justice, so must DOH-CAB and all other entities that accept Federal funding. Under Title VI of the Civil Rights Act of 1964, “no person shall, on the ground of race, color, national origin, sex, age or

<sup>48</sup> Guidance at 33.

<sup>49</sup> See EPA, “EPA Environmental Justice Guidance for National Environmental Policy Act Reviews,” <https://www.epa.gov/nepa/environmental-justice-guidance-national-environmental-policy-act-reviews>.

<sup>50</sup> See EPA News Release, “EPA Administrator Announces Agency Actions to Advance Environmental Justice, Administrator Regan Directs Agency to Take Steps to Better Serve Historically Marginalized Communities,” (April 7, 2021), <https://www.epa.gov/newsreleases/epa-administrator-announces-agency-actions-advance-environmental-justice>.

disability be excluded from participation in, be denied the benefits of, or be subjected to discrimination under any program or activity...”. DOH-CAB has an obligation to ensure the fair treatment of communities that have been environmentally impacted by sources of pollution. That means going beyond the flawed analysis conducted and ensuring “meaningful involvement” of impacted communities; environmental justice also requires the “fair treatment” of these communities in the development and implementation of agency programs and activities, including those related to the SIP.

DOH-CAB must conduct a thorough analysis of the current and potential effects to impacted communities from sources considered in the SIP. By not conducting this analysis and including the benefits of projected decline in emissions to these communities in their determination of the included emission sources, Hawaii is not fulfilling its obligations under Title VI. Moreover, the state is making a mockery of Title VI by not using the SIP requirements to bring about the co-benefits of stronger reductions measures and reduce harms based on continued emissions.

## **CONCLUSION**

In conclusion, we request that DOH-CAB revise the Proposed SIP in the following ways before submitting to the EPA:

1. Remove reliance on URP as a “safe harbor.” That Hawaii’s Class 1 areas are on or below the so-called glidepath is not an excuse for avoiding emission reductions.
2. Require additional SIP measures of air pollution reduction in order to satisfy the Act’s requirement that reasonable progress is made.
3. Clarify provisions regarding emission limits, source retirements, monitoring, record keeping and reporting requirements.
4. Conduct and provide an opportunity for public comment on the missing Four-Factor Analyses.
5. Reduce impacts of air pollution at both the Class I areas and on the environmental justice communities.

Thank you for the opportunity to review the Proposed SIP. We look forward to seeing a revised plan that takes our comments into consideration.

Sincerely,

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Enclosures



## List of Exhibits

1. Vicki Stamper & Megan Williams, “OIL AND GAS SECTOR REASONABLE PROGRESS FOUR-FACTOR ANALYSIS OF CONTROLS FOR FIVE SOURCE CATEGORIES: NATURAL GAS-FIRED ENGINES, NATURAL GAS-FIRED TURBINES, DIESEL-FIRED ENGINES, NATURAL GAS-FIRED HEATERS AND BOILERS AND FLARING AND INCINERATION,” (March 6, 2020).
2. Hawaii Department of Health, State of Hawaii Clean Air Branch, Draft Regional Haze State Implementation Plan for the Second Planning Period (2018-2028) (Docket No. 22-CA-PA-08), <https://health.hawaii.gov/cab/files/2022/06/DRAFT-2021HI-RHSIP.pdf>.
3. Letter from Natalie Levine, to Michael Madsen, Clean Air Branch, Department of Health, Requesting Extension of Comment Period for Hawaii’s Draft Regional Haze State Implementation Plan for the Second Implementation Period, (June 30, 2022).
4. DOH-CAB Public Notice for Regional Haze SIP, <https://health.hawaii.gov/cab/files/2022/06/22-CA-PA-08.pdf>.
5. Letter from Marianne Rossio, P.E. Manager, Clean Air Branch, Hawaii Department of Health, to Natalie Levine, Climate and Conservation Program Manager, National Parks Conservation Association, Response to Request for an Extension of the Comment Period for Hawaii’s Draft Regional Haze State Implementation Plan for the Second Implementation Period, (July 8, 2022).
6. National Park Service (NPS) Regional Haze SIP feedback for the Hawaii State Department of Health Clean Air Branch, (May 26, 2022).
7. EPA Control Cost Manual Section 1 Chapter 2, Cost Estimation: Concepts and Methodology, (Nov. 2017).
8. Arizona Department of Environmental Quality, 2021 Regional Haze Four-Factor Initial Control Determination, Tucson Electric Power Irvington Generating Station, <https://www.azdeq.gov/2021-regional-haze-sip-planning>.
9. NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, [https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED\\_EHD-RH2\\_8\\_25\\_2020.pdf](https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf).

10. Letter from Oregon Department of Environmental Quality to Collins Forest Products, (Sept. 9, 2020), <https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf>.
11. Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, <https://fortress.wa.gov/ecy/ezshare/AQ/RegionalHaze/docs/RespondFLM20210111.pdf>.
12. Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, November 17 to 19, 2021 Public Hearing, Prehearing Statement.

Exhibit 1

**OIL AND GAS SECTOR  
REASONABLE PROGRESS  
FOUR-FACTOR ANALYSIS OF CONTROLS  
FOR FIVE SOURCE CATEGORIES:**

**NATURAL GAS-FIRED ENGINES  
NATURAL GAS-FIRED TURBINES  
DIESEL-FIRED ENGINES  
NATURAL GAS-FIRED HEATERS AND BOILERS  
FLARING AND INCINERATION**

Prepared for National Parks Conservation Association

by Vicki Stamper & Megan Williams

March 6, 2020

# Exhibit 1

## EXECUTIVE SUMMARY

States are required to revise and submit revisions to their regional haze state implementation plans to make reasonable progress toward the national visibility goal, with the next revision due to the U.S. Environmental Protection Agency by July 31, 2021. In this second round of regional haze plans, each state needs to look broadly at the sources of visibility-impairing emissions within its state and determine the sources or source categories for which to conduct a four-factor analysis of emission reducing measures. Oil and gas development is a significant source of visibility-impairing emissions in many states, including emissions of nitrogen oxides (NO<sub>x</sub>), volatile organic compounds (VOCs), sulfur dioxide (SO<sub>2</sub>), and particulate matter (PM).

This report conducts a four-factor analysis of reasonable progress controls for five air emission source categories within the oil and gas development industry: natural gas-fired reciprocating internal combustion engines (RICE), natural gas-fired combustion turbines, diesel-fired RICE, natural gas-fired heaters and boilers, and flaring. This report includes a compilation of information on available pollution control options for visibility-impairing pollutants, provides cost of controls (where available) and documents the cost effectiveness of controls for various size units and a range of operating levels. The report also provides information for specific pollution controls regarding the three other reasonable progress factors: the time necessary for compliance to install the controls, the energy and non-air quality environmental impacts of the controls, and the remaining useful life of both the source category and the pollution control in question, if it differs from that of the source category.

With respect to the cost of controls, the authors used control cost data that were relied upon by federal, state, and local air agencies. Also, capital costs of control were amortized based on the expected useful life of the unit unless a shorter useful life of the specific pollution control was expected, all of which is documented in the report. The authors did not escalate costs to current dollars, because in many cases, the cost information was more than five years old, and EPA's Control Cost Manual cautions against attempting to escalate costs more than five years from the original cost analysis. Last, the authors compiled information on federal, state, and local air emission limitations that were required to be met by existing sources and thus required a retrofit of pollution controls to the source category. This assessment includes an evaluation of the lowest emission limits required of existing sources by state and local agencies and correlates those emission limits to specific pollution controls. Looking to state regional haze plans, the authors note that determinations of cost effectiveness for a particular source category should be based on the costs that similar sources have had to incur to meet Clean Air Act requirements.

Although the authors attempted to identify the pollution control methods that were both cost effective and the most effective at reducing visibility-impairing emissions and evaluated varying levels of operation, it is recognized that air pollution control determinations to retrofit existing sources cannot always be implemented via a "one-size-fits-all" approach. Thus, in some cases, a few different options for retrofit pollution controls are recommended for a source category, with the primary reasons for differentiating recommended pollution controls being based on size of the unit and/or operating capacity factor. Below the authors summarize the pollution controls that are presumed to be the best control options for each source category, with a focus on NO<sub>x</sub> pollution controls.

## Exhibit 1

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

SOURCE CATEGORY	NO <sub>x</sub> POLLUTION CONTROL	NO <sub>x</sub> COST EFFECTIVENESS (\$/TON)	PERCENT NO <sub>x</sub> REMOVAL, AND EMISSION RATES	OTHER POLLUTION CONTROLS
Natural Gas (NG)-Fired RICE Compressors	Replace with Electric Compressors	\$1,228–\$2,766/ton (2011 \$)	100% Removal of NO <sub>x</sub> and All Other Pollutants	Power Compressors with Renewable Energy
NG-Fired RICE Rich Burn >50 hp	Nonselective Catalytic Reduction (NSCR) and Air Fuel Ratio Controller (AFRC)	\$44–\$3,383/ton (2009\$)	94–98% 11–67 ppmv 0.16–1.0 g/hp-hr	VOC Controls integrated into NSCR.
NG-Fired RICE Lean Burn >50 hp	Low Emission Combustion (LEC)	\$47–\$941/ton (2001\$)	87–93% 75–150 ppmv 1.0–2.0 g/hp-hr	Oxidation Catalyst for VOC Emissions
	Selective Catalytic Combustion (SCR)	\$628–\$13,567/ton (1999\$–2001\$)	90–99% 11–73 ppmv 0.15–1.0 g/hp-hr	
NG-Fired Combustion Turbines	SCR (alone or with Dry Low NO <sub>x</sub> Combustion)	\$566–\$13,238/ton (1999–2000\$)	80–95+% 3-15 ppmv	Oxidation Catalyst for VOC Emissions
	Dry Low NO <sub>x</sub> Combustion	\$208–\$2,140/ton (1999\$–2000\$)	80–95% 9-25 ppmv	
Diesel-Fired RICE	Use Electric Engines and Tier 4 Gen Sets ----- OR Replace Older Engines w/ Tier 4	\$564–\$9,921/ton (2010\$)	94% 0.5 g/hp-hr  ----- 49%–96% 0.3-3.5 g/hp-hr	Catalytic Diesel Particulate Filter For PM (81%-97.5% control)
	Replace w/ NG RICE	Implemented by several companies	85–94%	Use of Ultra-Low Sulfur Diesel Fuel
	Retrofit with SCR	\$3,759–\$6,781/ton	90%	
Heaters/Boilers >20 MMBtu/hr	Ultra-Low NO <sub>x</sub> Burners (ULNB)	\$545–\$3,270/ton (2018\$)	93% 6 ppmv	Other Options:  Lower heater-treater temperatures
	SCR	\$1,025–\$6,149/ton (2018\$)	97% 2.5 ppmv	
Heaters/Boilers >5 and ≤20 MMBtu/hr	ULNB	\$727–\$5,232/ton (2018\$)	93% 6 ppmv	Install insulation on separators
Heaters/Boilers ≤5 MMBtu/hr	Replacement of Heater with New Unit with ULNB	\$4,055–\$10,809/ton (2005\$)	82–89% 9-20 ppmv	

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

## Exhibit 1

As shown in the table above, there are technically feasible and cost effective options to control NO<sub>x</sub>, VOCs, PM, and SO<sub>2</sub> from these four source categories of combustion-related emissions from the oil and gas sector and, in most cases, there are many examples of state and local air agency rules that require these or similar levels of control for existing sources. While many of these state and local rules were adopted to address the National Ambient Air Quality Standards (NAAQS), cost effectiveness of controls is generally part of the rulemaking process under reasonably available control technology (RACT) and best available retrofit control technology (BARCT – which applies in California) determinations. Given that state and local air agencies have found the costs of these controls to be reasonable for imposition of various pollution control requirements, these costs should be considered reasonable to impose to meet other Clean Air Act requirements including under the Regional Haze Program.

For flaring of waste gases, the following control options are recommended:

- Prevent flaring of excess gases through capture and use requirements instead of flaring
- Prevent flaring at gas sweetening and other processing plants by proper maintenance, training, installing duplicative equipment to minimize upsets
- Require documentation of flaring episodes with all relevant info to estimate emissions and to assess causes and actions to mitigate
- Thermal incineration should be considered in lieu of flaring due to ability for improved VOC destruction and available NO<sub>x</sub> and SO<sub>2</sub> controls (if sour/acid gas is being combusted)

The ultimate goal to reduce VOC, NO<sub>x</sub>, PM, and SO<sub>2</sub> emissions from excessive flaring should be to eliminate or minimize flaring to the maximum extent possible and to use, and not waste, excess gas produced.

# Exhibit 1

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# Exhibit 1

## 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
BLM	U.S. Bureau of Land Management
CARB	California Air Resources Board
CEPCI	Chemical Engineering Plant Cost Index
CAA	Clean Air Act
CDPF	Catalyzed diesel particulate filter
CDPHE	Colorado Department of Public Health and Environment
CI	Compression ignition
CEMS	Continuous emissions monitoring system
CO	Carbon monoxide
CO <sub>2</sub>	Carbon dioxide
CSAPR	Cross-State Air Pollution Rule
DRE	Destruction and removal efficiency
DPF	Diesel particulate filter
DOE	U.S. Department of Energy
DLNC	Dry low NO <sub>x</sub> combustors
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FGR	Flue gas recirculation
4CAQTF	Four Corners Air Quality Task Force
GPU	Gas production unit
Gen Set	Generator-Set Engine
g/bhp-hr	Grams per brake horsepower-hour
g/hp-hr	Grams per horsepower-hour
HAP	Hazardous air pollutant

## Exhibit 1

### LIST OF TERMS

HC	hydrocarbon
H <sub>2</sub> S	Hydrogen sulfide
hp	horsepower
kW	Kilowatt
INGAA	Interstate Natural Gas Association of America
IR	Ignition timing retard
LB	Lean-burn
LEC	Low emission combustion
LNB	Low NO <sub>x</sub> burners
MCF	Thousand cubic feet
MW	Megawatt
MMBtu	Million British Thermal Unit (heat input)
MMscf	Million standard cubic feet
NAAQS	National Ambient Air Quality Standards
NESCAUM	Northeast States for Coordinated Air Use Management
NESHAP	National Emission Standards for Hazardous Air Pollutants
NPS	National Park Service
NSPS	New Source Performance Standards
NO <sub>x</sub>	Nitrogen oxides
NMHC	Non-methane hydrocarbons
NSCR	Nonselective catalytic reduction
NSPS	New Source Performance Standards
OTC	Ozone Transport Commission
PEMS	Parametric emissions monitoring system
PM	Particulate matter
PM <sub>2.5</sub>	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)

## Exhibit 1

### LIST OF TERMS

SMAQMD	Sacramento Metropolitan Air Quality Management District
SCAQMD	South Coast Air Quality Management District
SCR	Selective catalytic reduction
SI	Spark ignition
SJVAPCD	San Joaquin Valley Air Pollution Control District
SNCR	Selective noncatalytic reduction
SO <sub>2</sub>	Sulfur dioxide
SO <sub>x</sub>	Sulfur oxides
TCEQ	Texas Commission on Environmental Quality
TSD	Technical support document
THC	Total hydrocarbons
ULSD	Ultra-low sulfur diesel
ULNB	Ultra-low NO <sub>x</sub> burners
VCAPCD	Ventura County Air Pollution Control District
VOC	Volatile organic compound

## Exhibit 1

### 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.<sup>1</sup> 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.<sup>2</sup> 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

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<sup>1</sup> 40 C.F.R. § 51.308(f).

<sup>2</sup> *Id.*

## Exhibit 1

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).<sup>3</sup>

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 (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), directly emitted particulate matter (PM), volatile organic compounds (VOCs), and ammonia. NO<sub>x</sub>, SO<sub>2</sub>, VOCs, and ammonia, initially emitted as gases, often convert into fine (i.e., less than 2.5 micrometers in diameter) particulate matter (PM<sub>2.5</sub>) 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.<sup>4</sup> 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.<sup>5</sup> 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<sup>6</sup> and marketed gas production in the United States to be 13% higher in 2021 than it was in 2018.<sup>7</sup> In many areas of the country, these increases in production are projected to continue well into the future. For

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<sup>3</sup> 42 U.S.C. § 7491(b)(2).

<sup>4</sup> 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](https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm).

<sup>5</sup> 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](https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm).

<sup>6</sup> EIA Short-Term Energy Outlook, U.S. Liquid Fuels, January 14, 2020, *available at*: [https://www.eia.gov/outlooks/steo/report/us\\_oil.php](https://www.eia.gov/outlooks/steo/report/us_oil.php).

<sup>7</sup> EIA, Short-Term Energy Outlook, Natural Gas, January 14, 2020, *available at*: <https://www.eia.gov/outlooks/steo/report/natgas.php>.

## Exhibit 1

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.<sup>8</sup>

There are several combustion-related sources of visibility-impairing emissions associated with oil and gas development. Various engines, typically fired by natural gas or diesel, are used in the drilling and completion phase, in the processing of natural gas, and at compressor stations. On-site power sources are often used, in the form of natural gas-fired engines, diesel generators, and/or combustion turbines. Natural gas-fired boilers and heaters are also used throughout the oil and gas production and process segments of the industry, to generate power, and to create steam and process heat. Those engines and combustion turbines emit significant quantities of NO<sub>x</sub> and VOCs and also of SO<sub>2</sub> and PM for diesel-fired engines. Flaring of excess and waste gas can be a significant source of SO<sub>2</sub> and NO<sub>x</sub> emissions.

This report presents a four-factor analysis of reasonable progress controls for NO<sub>x</sub> and VOCs, and SO<sub>2</sub> and PM as appropriate, for five significant air emissions source categories associated with oil and gas development: natural gas-fired reciprocating internal combustion engines (RICE), natural gas-fired combustion turbines, diesel-fired RICE, natural gas-fired boilers and heaters, and flaring/incineration of waste or excess gas. This report (1) proposes pollution controls and/or measures for such sources considering the control technology available and the most effective controls; (2) compiles cost data with a focus on data relied upon by federal, state, and local air agencies in regulatory decisions; (3) evaluates non-air quality environmental and energy impacts of controls; and (4) considers the remaining useful life of the equipment.

It is important to note that, while New Source Performance Standards (NSPS) exist for these source categories, the existence of an NSPS does not negate the need for a four-factor analysis of controls to achieve reasonable progress towards the national visibility goal for several reasons. First, it has been many years since the NSPS standards for RICE units, gas turbines, and small boilers have been re-evaluated. Although EPA correctly states in its 2019 Regional Haze guidance that “[t]he [CAA] requires EPA to review, and if necessary, revise NSPS every 8 years,”<sup>9</sup> 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.<sup>10</sup> The applicability date of an NSPS (or of a revised NSPS emission standard) is set as either the date of publication of any proposed or of any final rulemaking establishing the standard. Third, when EPA adopts or revises NSPS for a source category, EPA is establishing an emission standard applicable to all of the source types and variable fuels, operating conditions, etc. that exist for that source category. Thus, the NSPS are generally applicable emission standards and not a source-specific evaluation of controls.

Further, while EPA’s Regional Haze guidance states that, if a new or modified unit is subject to and complying with an NSPS promulgated or reviewed since July 31, 2013, it is unlikely that new or existing controls are available or more effective, no such assumption should be made without considering the

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<sup>8</sup> 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>.

<sup>9</sup> EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019, at 23, note 44.

<sup>10</sup> 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.

## Exhibit 1

specific emission and operational characteristics of the source in question. EPA’s statements are problematic and need clarification. One cannot simply determine the last time the NSPS for a source category was amended and assume that if the amendments occurred within the last eight years, the NSPS is up to date. Section 111(b)(1)(B) of the CAA requires EPA to review and revise each NSPS at least every eight years, to essentially determine if the NSPS currently reflect the “degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.”<sup>11</sup> EPA amends its NSPS for various reasons (e.g., changes in test methods or protocols, clarifications), but thorough reviews and revisions generally occur much less frequently — in many cases less frequently than every eight years as required by the CAA. Table 1 below shows the NSPS applicable to RICE units, turbines, and small boilers and provides the most recent date of EPA’s comprehensive review and revision. The NSPS rules applicable to RICE units and gas turbines were last subject to a comprehensive revision to reflect the best-demonstrated technology well before July 31, 2013.

**Table 1. NSPS Categories that Address RICE, Natural Gas Turbines, and Small Boilers**

<b>NSPS Subpart in 40 C.F.R. Part 60</b>	<b>Emission Source(s)</b>	<b>Date of Promulgation of Most Recent Revisions</b>
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	2/27/06 (reflects most recent review of the emission standards)
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	6/28/11 (reflects most recent adoption of emission standards for this source category)
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)
O000	Crude Oil and Natural Gas Production, Transmission, and Distribution for which Construction, Modification, or Reconstruction Commenced after 8/23/11 and on or before 9/15/15	6/3/2016 (reflects most recent review the emission standards)
O000a	Crude Oil and Natural Gas Production, Transmission, and Distribution from which Construction, Modification, or Reconstruction Commenced after 9/18/15	6/3/2016 (NSPS Subpart first promulgated)

<sup>11</sup> See Section 111(a)(1) of the Clean Air Act, 42 U.S.C. § 7411(a)(1).

## Exhibit 1

Thus, while the NSPS may be a place to start in evaluating pollution controls for air emissions sources associated with the oil and gas industry, it is also necessary to evaluate if more stringent requirements and pollution controls have been required in state rules or local air rules, air permits, or other requirements. Review of state regulations and state implementation plans, particularly to address national ambient air quality standards (NAAQS) which requires reductions in emissions from existing sources, is necessary to fully evaluate controls for emission sources associated with oil and gas development to achieve reasonable progress towards the national visibility goal.

The information provided below reflects a comprehensive review of the pollution controls and techniques and associated emissions levels applicable to each of the source categories, along with data on cost of controls where available, non-air quality environmental and energy impacts, and the reasonable useful life of the emission source being evaluated.

## II. CONTROL OF NO<sub>x</sub> 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



## Exhibit 1

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.<sup>12</sup>

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:

<sup>12</sup> EPA, AP-42, Fifth Edition, Volume 1, Chapter 3: Stationary Internal Combustion Sources.

## Exhibit 1

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:<sup>13</sup>

#### 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

<sup>13</sup> 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](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"].

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to 940 ppmv). Available data show that the achievable NO<sub>x</sub> 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 NO<sub>x</sub> emission reductions.<sup>14</sup>

*NO<sub>x</sub> Removal Efficiency:* 10-40%  
*Controlled NO<sub>x</sub> 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 NO<sub>x</sub> formation. . . .

Ignition timing can be adjusted on all new or existing rich-burn engines. Sustained NO<sub>x</sub> reduction with changes in ambient conditions and engine load, however, is best accomplished using an electronic ignition control system.

The achievable NO<sub>x</sub> emission reduction ranges from virtually no reduction to as high as 40 percent. Based on an average uncontrolled NO<sub>x</sub> emission level of 15.8 g/hp-hr (1,060 ppmv), the expected range of controlled NO<sub>x</sub> 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 NO<sub>x</sub> reductions using IR are engine-specific.<sup>15</sup>

*NO<sub>x</sub> Removal Efficiency:* 0-40%  
*Controlled NO<sub>x</sub> 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 NO<sub>x</sub> 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).<sup>16</sup>

Limited cost data indicate that combustion controls for rich-burn RICE costs between \$400 to \$1,000 per ton of NO<sub>x</sub> reduced for engines greater than 500 horsepower (hp).<sup>17</sup>

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<sup>14</sup> *Id.* at 2-5.

<sup>15</sup> *Id.* at 2-5 and 2-9.

<sup>16</sup> *Id.* at 2-9.

<sup>17</sup> *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.

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## B. RICH-BURN RICE: PRESTRATIFIED CHARGE (PSC)

Prestratified charge (PSC) is a combustion modification that converts rich-burn engines to lean-burn engines by retrofitting the air injectors to make a leaner A/F ratio. PSC is described by EPA in its Alternative Control Techniques Document for RICE, as follows:

This add-on control technique facilitates combustion of a leaner A/F. The increased air content acts as a heat sink, reducing combustion temperatures, thereby reducing NO<sub>x</sub> formation rates. Because this control technique is installed upstream of the combustion process, PSC<sup>®</sup> 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<sup>®</sup> to date has been installed on engines ranging in size up to approximately 2,000 hp.

The vendor offers guaranteed controlled NO<sub>x</sub> 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 NO<sub>x</sub> 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<sup>®</sup>, but the degree of the increase is engine-specific. The effect on BSFC is a decrease for moderate controlled NO<sub>x</sub> emission levels (4 to 7 g/hp-hr, or 290 to 500 ppmv), but an increase for controlled NO<sub>x</sub> emission levels of 2 g/hp-hr (140 ppmv) or less.<sup>18</sup>

<i>PSC NO<sub>x</sub> Removal Efficiency:</i>	<i>87% (85-90%, EPA 2000)<sup>19</sup></i>
<i>Controlled NO<sub>x</sub> Emission Rates:</i>	<i>2 g/hp-hr</i>
	<i>140 ppmv</i>

PSC NO<sub>x</sub> reduction efficiency depends on how much the air content can be increased without adversely affecting the performance of the engine; achieving lower NO<sub>x</sub> rates with PSC will result in sacrifices in engine power output. PSC, generally, can only achieve a NO<sub>x</sub> emission rate as low as 2 g/bhp-hr. EPA re-affirmed the limitations of PSC in its 2000 Updated Information on NO<sub>x</sub> Emissions and Control Techniques for RICE, stating:

<sup>18</sup> EPA 1993 Alternative Control Techniques Document for RICE at 2-9 to 2-10.

<sup>19</sup> EPA-457/R-00-001 *Stationary Reciprocating Internal Combustion Engines Updated Information on NO<sub>x</sub> 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 NO<sub>x</sub> Emissions and Control Techniques”].

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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.<sup>20</sup>

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.<sup>21</sup>

Even the best-case NOx emissions reductions for PSC are generally lower than the emissions reductions that can be accomplished with the nonselective catalytic reduction (NSCR) technologies discussed below. And NSCR also generally costs less, with capital and annual costs less than PSC for almost all engine sizes, according to data from EPA.<sup>22</sup> However, for fuels with higher sulfur content (e.g., waste gases), PSC technology can be effective at achieving NOx emissions reductions where higher sulfur fuels would adversely impact catalyst material used in post-combustion control technologies such as NSCR.

### C. RICH-BURN RICE: NONSELECTIVE CATALYTIC REDUCTION (NSCR)

The use of NSCR technology began in the 1970s with the application of 3-way catalysts to gasoline-fueled motor vehicles in order to simultaneously control carbon monoxide, VOCs, and NOx emissions. In automobiles, the technology is known as a “catalytic convertor.” Since then, NSCR has been widely applied to stationary engines. NSCR is usually also accompanied by an air/fuel ratio controller (AFRC), which is used to adjust the combustion parameters across the operating range of the engine in order to maintain the conditions needed for the efficient operation of the NSCR system (e.g., sufficient excess oxygen in the exhaust gas).

NSCR is described by EPA in its Alternative Control Techniques Document for RICE, as follows:

Nonselective catalytic reduction is essentially the same catalytic reduction technique used in automobile applications and is also referred to as a three-way catalyst system because the catalyst reactor simultaneously reduces NO<sub>x</sub>, CO, and HC to water (H<sub>2</sub>O), carbon dioxide (CO<sub>2</sub>), and diatomic nitrogen (N<sub>2</sub>). The chemical stoichiometry requires that O<sub>2</sub> 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. . . .

<sup>20</sup> *Id.* at 4-21.

<sup>21</sup> 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.

<sup>22</sup> See EPA's 1993 Alternative Control Techniques Document for RICE Table 2-12 at 2-30.

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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.<sup>23</sup>

<i>NSCR NOx Removal Efficiency:</i>	<i>90-98%</i>
<i>Controlled NOx Emission Rates:</i>	<i>0.3 to 1.6 g/hp-hr</i> <i>20 to 110 ppmv</i>

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.<sup>24</sup> 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.<sup>25</sup> 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.<sup>26</sup> 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

<sup>23</sup> EPA 1993 Alternative Control Techniques Document for RICE at 2-10 to 2-11.

<sup>24</sup> EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-19.

<sup>25</sup> 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.

<sup>26</sup> *Id.*

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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).<sup>27</sup> The analysis, performed by E<sup>C</sup>/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<sup>C</sup>/R Incorporated performed a linear regression analysis<sup>28</sup> on the data set to determine the following linear equation for annual cost, which includes annual operating and maintenance costs plus annualized capital costs based on a 7% interest rate and 10-year life of controls:

$$\text{NSCR Annual Cost} = \$4.77 \times (\text{hp}) + \$5,697 \text{ (2009\$)}$$

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

$$\text{NSCR Capital Cost} = \$24.9 \times (\text{hp}) + \$13,118 \text{ (2009\$)}$$

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

The E<sup>C</sup>/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.<sup>29</sup> The assumed 10-year life was not based on the catalyst replacement timeframe, because the E<sup>C</sup>/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.<sup>30</sup> 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.<sup>31</sup> The state of Colorado also recently assumed a 15-year life of

<sup>27</sup> Memo from E<sup>C</sup>/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](https://www.epa.gov/sites/production/files/2014-02/documents/5_2011_ctrlcostmemo_exist_si.pdf).

<sup>28</sup> *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.”

<sup>29</sup> 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.

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

<sup>31</sup> 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).

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NSCR for RICE units.<sup>32</sup> Given that EPA assumed a selective catalytic reduction (SCR) system at an industrial fossil fuel-fired boiler has a life of 20-25 years,<sup>33</sup> it seems very likely that NSCR would have a useful life of at least fifteen years if not longer. For the purpose of the NSCR cost analyses presented herein, a 15-year life of the NSCR system was assumed.

In addition, a lower interest rate than 7% is assumed in determining annualized costs of controls for this report, to be consistent with EPA's Control Cost Manual which recommends the use of the bank prime interest rate.<sup>34</sup> The bank prime rate fluctuates over time, and the highest it has been in the past five years is 5.5%.<sup>35</sup> In its cost calculation spreadsheet for SCR provided with its Control Cost Manual, EPA also used an interest rate of 5.5%.<sup>36</sup> Thus, a 5.5% interest rate has been used for the revised cost calculations presented herein.

Table 2 shows the cost effectiveness of NSCR and an AFRC achieving 94% NOx reduction efficiency and operating at 2,000 hours per year and 8,000 hours per year, based on these cost equations from EPA's 2010 RICE NESHAP, adjusted to reflect a 5.5% interest rate and 15-year life of controls.

Note that lower NOx emission limits have been required by some states and local agencies that reflect a higher NOx removal efficiency than the 94% assumed in the table below (see Section II.G.) and the costs of employing NSCR to meet these lower limits will be even more cost effective than what is shown here.

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<sup>32</sup> 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](https://www.colorado.gov/pacific/sites/default/files/AP_PO_Reciprocating-Internal-Combustion-Engine-RICE-engines_0.pdf).

<sup>33</sup> 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](https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf).

<sup>34</sup> EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16, *available at*: [https://www.epa.gov/sites/production/files/2017-12/documents/epacmcostestimationmethodchapter\\_7thedition\\_2017.pdf](https://www.epa.gov/sites/production/files/2017-12/documents/epacmcostestimationmethodchapter_7thedition_2017.pdf).

<sup>35</sup> See, e.g., <https://fred.stlouisfed.org/series/DPRIME>.

<sup>36</sup> *Available at*: <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution>.



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**Table 2. Cost Effectiveness to Reduce NO<sub>x</sub> Emissions from Rich-Burn RICE with NSCR and an AFRC, Based on EPA RICE NESHAP Cost Equations for Existing Stationary Spark-Ignition (SI) Engines<sup>37</sup>**

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
<p>TABLE NOTES:</p> <ul style="list-style-type: none"> <li>• Cost data are assumed to be in 2009\$, based on E<sup>C</sup>/R Incorporated analysis of vendor and industry group data for engines ranging from 50–3,000 hp (EPA RICE NESHAP, 2010).</li> <li>• Recalculated for 15-year life of controls and 5.5% interest rate.</li> <li>• Assumes 94% NO<sub>x</sub> removal efficiency.</li> </ul>				

Colorado requires emissions from rich-burn RICE greater than 500 hp be controlled using NSCR with an AFRC. This requirement applies statewide to engines for which control costs are below \$5,000 per ton of NO<sub>x</sub> reduced.<sup>38</sup> In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the RICE Stationary Source Category, including a NO<sub>x</sub> emission 4-Factor analysis for reasonable progress toward the national visibility goal.<sup>39</sup> 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.”<sup>40</sup> 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.”<sup>41</sup>

Colorado’s Reasonable Progress Evaluation for RICE listed the capital and annual operating costs for retrofitting existing engines with NSCR and an AFRC, which are reiterated in Table 3.

<sup>37</sup> See Memo from E<sup>C</sup>/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 NO<sub>x</sub> emissions are based on EPA’s 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and a 94% NO<sub>x</sub> removal efficiency.

<sup>38</sup> Colorado Regulation Number 7, see Section XVII.E.3.a.

<sup>39</sup> CDPHE RP for RICE.

<sup>40</sup> *Id.* at 4.

<sup>41</sup> *Id.* at 8.

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**Table 3. Capital and Operating Costs of NSCR with AFCR<sup>42</sup>**

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."<sup>43</sup> Colorado's use of a 15-year life of controls is also consistent with previous EPA analysis.<sup>44</sup> 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.<sup>45</sup> 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.<sup>46</sup> As previously discussed, it is more appropriate to use a lower interest rate of 5.5%.<sup>47</sup> Thus, the cost data were revised to be consistent with the EPA's Control Cost Manual in assuming a 5.5% interest rate in amortizing the capital costs.<sup>48</sup>

Colorado presented the cost effectiveness of retrofitting RICE greater than or equal to 500 hp with NSCR and an AFCR based on 2008 NO<sub>x</sub> 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.<sup>49</sup> Again, using EPA's uncontrolled emission rate of 15.8 g/bhp-hr, the NO<sub>x</sub> emissions reduction efficiency of meeting a 1 g/hp-hr NO<sub>x</sub> limit for these engines is approximately 94%.<sup>50</sup>

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<sub>x</sub> limit, based on a 15-year life and 5.5% interest rate.

<sup>42</sup> *Id.*

<sup>43</sup> *Id.* at 10.

<sup>44</sup> EPA, Regulatory Impact Analysis for the NO<sub>x</sub> SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).

<sup>45</sup> CDPHE RP for RICE at 8.

<sup>46</sup> EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.

<sup>47</sup> See, e.g., <https://fred.stlouisfed.org/series/DPRIME>.

<sup>48</sup> See, e.g., <https://fred.stlouisfed.org/series/DPRIME>.

<sup>49</sup> See Colorado Regulation Number 7, see Section XVII.E.2.b.

<sup>50</sup> EPA 1993 Alternative Control Techniques Document for RICE.

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**Table 4. Cost Effectiveness to Reduce NO<sub>x</sub> Emissions from Rich-Burn RICE with NSCR and an AFRC To Meet a 1 g/hp-hr NO<sub>x</sub> Limit<sup>51</sup>**

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: <ul style="list-style-type: none"> <li>• Cost data are assumed to be in 2003\$, based on Colorado’s Reasonable Progress Evaluation for the RICE Source Category.</li> <li>• Analysis assumes 15-year life of controls and 5.5% interest rate.</li> <li>• Analysis assumes 94% NO<sub>x</sub> removal efficiency.</li> </ul>				

### **NSCR for Smaller Rich-Burn RICE and Cyclically-Loaded RICE (< 500 hp)**

California Air Districts have long been regulating NO<sub>x</sub> 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 NO<sub>x</sub> emissions from a broad range of stationary RICE.<sup>52</sup>

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.<sup>53</sup> 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, NO<sub>x</sub> emissions from these smaller pumping engines, on a regional scale, can be significant. For example, NO<sub>x</sub> 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 NO<sub>x</sub> emissions.<sup>54</sup> The average rated horsepower of these engines is 21 hp and the magnitude of these NO<sub>x</sub> emissions – inventoried in 2014 – was close to 4,000 tons.

<sup>51</sup> 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 NO<sub>x</sub> emissions are based on EPA’s 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032) and a 94% NO<sub>x</sub> removal efficiency.

<sup>52</sup> CARB 2001 Guidance.

<sup>53</sup> EPA 1993 Alternative Control Techniques Document for RICE Table 3-1 at 3-14.

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

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CARB's 2001 guidance discusses RICE units derated<sup>55</sup> 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."<sup>56</sup>

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.<sup>57</sup>

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."<sup>58</sup>

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:<sup>59</sup>

"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.

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<sup>55</sup> 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.

<sup>56</sup> See CARB 2001 Guidance at IV-1.

<sup>57</sup> *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](http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/rule-1110-2-pdsr_07172019.pdf?sfvrsn=6).

<sup>58</sup> See CARB 2011 Guidance at IV-1.

<sup>59</sup> 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>.

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“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 NO<sub>x</sub> 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.”<sup>60</sup> Specifically, the following engine test data demonstrate emission rates under 50 ppmv (corrected to 15% oxygen) for pump engines:

**Table 5. Pump Engine Test Data<sup>61</sup>**

CA AIR DISTRICT	ENGINE TYPE	ENGINE SIZE <sup>62</sup>	CONTROL TECHNOLOGY	# OF TESTS	NO <sub>x</sub> 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

<sup>60</sup> See CARB 2001 Guidance at IV-5.

<sup>61</sup> *Id.* at IV-5 to IV-6.

<sup>62</sup> 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.

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CA AIR DISTRICT	ENGINE TYPE	ENGINE SIZE <sup>62</sup>	CONTROL TECHNOLOGY	# OF TESTS	NOx EMISSIONS [ppmv corrected to 15% oxygen]
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.”<sup>63</sup> Essentially, CARB guidance proposed considering in its cost effectiveness analysis, the additional cost of field gas treatment including the material and labor costs of piping the treated fuel from the gas processing unit to the engine.

As of January 1, 2017, the San Joaquin Valley Air Pollution Control District (SJVAPCD) requires emissions from rich-burn RICE meet the following NOx limits:

**Table 6. NOx Emission Limits for All Rich-Burn Non-Agricultural Operations Engines Rated at > 50 bhp<sup>64</sup>**

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) <sup>65</sup>			

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

<sup>63</sup> See CARB 2001 Guidance at IV-6.

<sup>64</sup> SJVAPCD Rule 4702 Internal Combustion Engines, Tables 1 and 2, *available at*: <https://www.valleyair.org/rules/currenrules/r4702.pdf>.

<sup>65</sup> SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), at B-3, *available at*: [https://www3.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjvapcd\\_4702\\_report.pdf](https://www3.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjvapcd_4702_report.pdf).

<sup>66</sup> *Id.*

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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.<sup>67</sup>

To use more current data on NSCR costs applied to cyclically-loaded units, the E<sup>c</sup>/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<sup>c</sup>/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 NO<sub>x</sub> at cyclically-loaded engines as is required by the Santa Barbara emission limit.<sup>68</sup> 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.<sup>69</sup> Thus, to give a range of cost effectiveness of NSCR at cyclically-loaded units, cost effectiveness of NSCR was determined for a low, medium, and high number of operating hours per year. As with other NSCR cost effectiveness analyses, a 15-year life and a 5.5% interest rate were assumed. The results of this cost effectiveness analyses are presented in Table 7.

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<sup>67</sup> *Id.* at B-2 and at Table 3.

<sup>68</sup> Santa Barbara County APCD Rule 333 CONTROL OF EMISSIONS FROM RECIPROCATING INTERNAL COMBUSTION ENGINES, 333.C at 333-2.

<sup>69</sup> 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](https://www.wrapair2.org/pdf/2016-11y_Final%20GSJB-Permian%20EI%20Inputs%20Report%20(11-09).pdf).

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**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<sup>70</sup>**

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<sup>C</sup>/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.<sup>71</sup> 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.<sup>72</sup>

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.<sup>73</sup> In the response to comments on its NSPS Subpart JJJJ rulemaking,<sup>74</sup> EPA provides many examples of the successful application of NSCR on small rich-burn engines and variable-load engines (noted as pumpjack engines or

<sup>70</sup> *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%.

<sup>71</sup> 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.”

<sup>72</sup> CARB 2001 Guidance at II-1.

<sup>73</sup> SJVAPCD Rule 4702 Internal Combustion Engines Section 5.1

<sup>74</sup> 73 Fed. Reg. 3,568-3,614 (Jan. 18, 2008).



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compressor engines) that justify its standards as achievable and demonstrated for very small rich-burn RICE.<sup>75</sup>

### 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 NO<sub>x</sub> emission limits of 1 g/bhp-hr (67 ppmvd) and even lower NO<sub>x</sub> 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.<sup>76</sup> 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<sub>2</sub> emissions<sup>77</sup>
- 1 to 2% reduction in power output<sup>78</sup>
- Increased solid waste disposal from spent catalysts.<sup>79</sup>

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.<sup>80</sup>

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<sup>75</sup> 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>.

<sup>76</sup> EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.

<sup>77</sup> See EPA 1993 Alternative Control Techniques Document for RICE Table 3-1 at 3-14.

<sup>78</sup> *Id.* Table 2-4 at 2-8.

<sup>79</sup> CDPHE RP for RICE at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6<sup>th</sup> ed., EPA/452/B-02-001, EPA, Office of Air Quality Planning and Standards, RTP).

<sup>80</sup> Institute of Clean Air Companies, Typical Installation Timelines for NO<sub>x</sub> 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](https://cdn.ymaws.com/www.icac.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf).

# Exhibit 1

## D. LEAN-BURN RICE: LOW EMISSION COMBUSTION (LEC)

Low emission combustion (LEC) retrofit kits are designed to achieve extremely lean A/F in order to minimize NO<sub>x</sub> 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<sup>81</sup>

According to EPA, “[n]ew spark-ignition engines equipped with LEC technology are, by definition, lean-burn engines.”<sup>82</sup> A wide range of emission rates are achievable with LEC technology, with emissions generally no higher than 2 g/hp-hr and often significantly lower. EPA’s updated information on stationary RICE NO<sub>x</sub> 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.”<sup>83</sup> 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 NO<sub>x</sub> 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.<sup>84</sup>

<i>LEC NO<sub>x</sub> Removal Efficiency:</i>	<i>87%</i>
<i>Controlled NO<sub>x</sub> Emission Rates:</i>	<i>1-2 g/hp-hr</i> <i>70 to 140 ppmv</i>

<sup>81</sup> 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 NO<sub>x</sub> 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 NO<sub>x</sub> Emissions Controls”].

<sup>82</sup> EPA 2000 Updated Information on NO<sub>x</sub> Emissions and Control Techniques at 4-3.

<sup>83</sup> *Id.* at 4-12.

<sup>84</sup> EPA 1993 Alternative Control Techniques Document for RICE.

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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.<sup>85</sup>

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.”<sup>86</sup>

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).”<sup>87</sup>

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.<sup>88</sup>

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<sup>85</sup> EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-9.

<sup>86</sup> *Id.* at 4-11.

<sup>87</sup> 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>.

<sup>88</sup> EPA 2000 Updated Information on NOx Emissions and Control Techniques at 4-4.

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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.<sup>89</sup> In its analysis, CARB determined that LEC was a RACT level of control, and CARB set a NOx RACT limit of 125 ppmv.<sup>90</sup> 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.<sup>91</sup> 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.<sup>92</sup> LEC can achieve 80 to 90% NOx reductions or even higher.<sup>93</sup>

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).<sup>94</sup> CARB described these engines as “located in gas fields statewide and [] used to drive compressors at gas wells.”<sup>95</sup> 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.”<sup>96</sup> 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.”<sup>97</sup>

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.”<sup>98</sup> CARB’s cost data for LEC are presented in the table below.

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<sup>89</sup> CARB 2001 Guidance.

<sup>90</sup> *Id.* at IV-6.

<sup>91</sup> *Id.* at IV.9.

<sup>92</sup> *Id.* at II-2, IV-10.

<sup>93</sup> 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.

<sup>94</sup> *Id.* at II-2.

<sup>95</sup> *Id.* at IV-7.

<sup>96</sup> *Id.*

<sup>97</sup> *Id.*

<sup>98</sup> *Id.* at V-2.

## Exhibit 1

**Table 8. Capital Costs of LEC, 2001\$<sup>99</sup>**

<b>POWER OUTPUT (hp)</b>	<b>LEC CAPITAL COSTS</b>
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% NO<sub>x</sub> control, a 10-year life of the controls, and a 10% interest rate.<sup>100</sup> 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%.<sup>101</sup> 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.<sup>102</sup> 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% NO<sub>x</sub> removal efficiency with LEC. As discussed above, an 80% NO<sub>x</sub> control efficiency is the low-end of NO<sub>x</sub> removal rates that can be achieved with LEC at lean-burn engines. CARB’s BARCT limit is based on 90% NO<sub>x</sub> reduction. Thus, CARB’s cost analyses were also revised to include cost effectiveness for 90% NO<sub>x</sub> control as well as 80% NO<sub>x</sub> 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% NO<sub>x</sub> control and 90% NO<sub>x</sub> control—are presented in Table 9 below.

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<sup>99</sup> *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.

<sup>100</sup> CARB 2001 Guidance at V-4.

<sup>101</sup> See, e.g., <https://fred.stlouisfed.org/series/DPRIME>.

<sup>102</sup> EPA, Regulatory Impact Analysis for the NO<sub>x</sub> SIP Call, IP, and Section 126 Petitions, September 1998, at 5-5 (Table 5-3).

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**Table 9. Cost Effectiveness to Reduce NO<sub>x</sub> Emissions by 80%–90% from Lean-Burn RICE with LEC Operating at 2,000 and 8,000 Hours per Year<sup>103</sup>**

ENGINE TYPE	SIZE, hp	ANNUALIZED COSTS OF LEC, 2001\$	COST EFFECTIVENESS OF LEC TO REDUCE NO <sub>x</sub> BY 80%–90%, 2,000 HOURS/YEAR, 2001\$	COST EFFECTIVENESS OF LEC TO REDUCE NO <sub>x</sub> 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 that, with the exception of lean-burn engines rated at 50 hp that only operated 2,000 hours per year, the cost effectiveness of LEC at lean-burn engines is essentially between \$80–\$400/ton for a wide range of engine sizes and a wide range of operating hours.

In its Technical Support Document for Non-EGU NO<sub>x</sub> 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:<sup>104</sup>

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

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).<sup>105</sup> 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.”<sup>106</sup> Specifically, in EPA’s Updated Information on NO<sub>x</sub>

<sup>103</sup> 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 NO<sub>x</sub> emissions are based on EPA’s 1993 Alternative Control Techniques for RICE (EPA-453/R-93-032).

<sup>104</sup> 2016 EPA CSAPR TSD for Non-EGU NO<sub>x</sub> 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.

<sup>105</sup> See EPA 1993 Alternative Control Techniques Document for RICE, Table 2-13 at 2-36.

<sup>106</sup> EPA 2000 Updated Information on NO<sub>x</sub> Emissions and Control Techniques at 4-33.

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Emissions and Control Techniques for RICE, its analysis of LEC retrofit for lean-burn SI engines showed, “cost effectiveness below \$500 per ton of NO<sub>x</sub> reduced [in 1997\$] for all engines larger than 2,000 bhp,” which reflected an 80% capacity factor, 88% control, and a 7% interest rate.<sup>107</sup>

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% NO<sub>x</sub> control. CARB’s BARCT NO<sub>x</sub> limit of 125 ppmv should be considered as an achievable NO<sub>x</sub> emission limit with LEC at a lean-burn engine.

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

While the cost estimates and cost algorithms in this section are of a cost basis that is close to twenty years old, it is important to note that, from at least 2001, several state and local air agencies have found that the costs of control to achieve NO<sub>x</sub> 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 NO<sub>x</sub> 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<sub>2</sub> emissions, as well as a corresponding decrease in emissions of other air pollutants<sup>108</sup>
- No effect on power output.<sup>109</sup>

### E. LEAN-BURN RICE: SELECTIVE CATALYTIC REDUCTION (SCR)

Selective catalytic reduction (SCR) is an add-on (post combustion) NO<sub>x</sub> reduction technology that has been in use as early as the 1970s and has been applied to numerous source categories including stationary RICE units. In its 1993 Alternative Control Techniques Document for Stationary RICE, EPA described SCR systems as follows:

Selective catalytic reduction is an add-on control technique that injects ammonia (NH<sub>3</sub>) into the exhaust, which reacts with NO<sub>x</sub> to form N<sub>2</sub> and H<sub>2</sub>O in the catalyst reactor. The two primary catalyst formulations are base-metal (usually vanadium pentoxide) and zeolite. Spent catalysts containing vanadium pentoxide may be considered a hazardous material in some areas, requiring special disposal considerations. Zeolite catalyst formulations do not contain hazardous materials.

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<sup>107</sup> *Id.* at 5-9.

<sup>108</sup> See EPA 1993 Alternative Control Techniques Document for RICE, Table 2-7 at 2-15.

<sup>109</sup> *Id.*

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Selective catalytic reduction applies to all lean-burn SI engines and can be retrofitted 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.<sup>110</sup>

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

<sup>110</sup> EPA 1993 Alternative Control Techniques Document for RICE.

<sup>111</sup> 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>.

<sup>112</sup> See <https://otcair.org/about.asp>.

<sup>113</sup> See 2012 OTC Report at 25-26.

<sup>114</sup> *Id.* at 26-27.

<sup>115</sup> See <https://matthey.com/en/products-and-services/emission-control-technologies/mobile-emissions-control/selective-catalytic-reaction>.

<sup>116</sup> See <https://www.miratechcorp.com/products/cbl/>.

<sup>117</sup> See [http://intermountainelectronics.com/uploads/media/Media\\_633929646982817973.pdf](http://intermountainelectronics.com/uploads/media/Media_633929646982817973.pdf).



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which offers SCR systems for several of its engines.<sup>118</sup> Although EPA's 1993 Alternative Control Techniques Document indicates achievable NO<sub>x</sub> emission rates of 1.7 g/hp-hr, the OTC identified NO<sub>x</sub> rates achievable with SCR at lean-burn engines of 0.2 to 1.0 g/bhp-hr, with the lower NO<sub>x</sub> rates achievable at four-stroke lean-burn engines and/or engines that also have some combustion control upgrades.<sup>119</sup> Moreover, two air districts in California—South Coast Air Quality Management District (SCAQMD) and SJVAPCD—have adopted NO<sub>x</sub> emission limits of 11 ppmv, which equates to 0.15 g/hp-hr, for lean-burn engines.<sup>120</sup> Based on this more recent information, the NO<sub>x</sub> reduction efficiency and achievable NO<sub>x</sub> emission rates are:

- *NO<sub>x</sub> Removal Efficiency:* 90-95+%
- *Controlled NO<sub>x</sub> 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.<sup>121</sup> 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.”<sup>122</sup> Thus, for those engines for which effective LEC retrofits are not available, SCR is available to achieve high levels of NO<sub>x</sub> control.

As previously stated, CARB issued guidance to California Air Districts in 2001 on the best available retrofit technologies for controlling NO<sub>x</sub> emissions from a broad range of stationary RICE.<sup>123</sup> For two- and four-stroke lean-burn engines greater than 100 hp, CARB set a BARCT limit 65 ppmv or 90% reduction in NO<sub>x</sub> emissions.<sup>124</sup> 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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<sup>118</sup> See [https://www.cat.com/en\\_GB/search/search-results.html?search=selective+catalytic+reduction&pagePath=%252Fcontent%252Fcatdotcom%252Fen\\_GB%252Fproducts%252Fnew%252Fpower-systems%252Ffoil-and-gas](https://www.cat.com/en_GB/search/search-results.html?search=selective+catalytic+reduction&pagePath=%252Fcontent%252Fcatdotcom%252Fen_GB%252Fproducts%252Fnew%252Fpower-systems%252Ffoil-and-gas).

<sup>119</sup> See 2012 OTC Report at 27-28 and 40-41.

<sup>120</sup> See SCAQMD Rule 1110.2, Table I and SJVAPCD Rule 4702, Table 2. The SCAQMD 11 ppmv limit applies to engines at facilities that are not in the Regional Clean Air Incentives Market (RECLAIM) as of January 5, 2018, and SCAQMD has indicated there are 18 engines currently meeting the 11 ppmv limit. See <http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1110.2/par1110-2-wg2-final.pdf?sfvrsn=6> at Slide 32. The SJVAPCD 11 ppmv limit does not apply to lean-burn engines used for gas compression, or those engines of limited use operation (less than 4,000 hours per year), or those engines that are waste gas-fuel—a higher limit of 65 ppmv applies to these engines.

<sup>121</sup> See, e.g., EPA 2000 Updated Information on NO<sub>x</sub> Emissions and Control Techniques at 4-13.

<sup>122</sup> *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.”).

<sup>123</sup> See CARB 2001 Guidance.

<sup>124</sup> *Id.*

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kits available, SCR may be used as an alternative to achieve the BARCT emission limits.”<sup>125</sup> 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<sup>126</sup>**

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.<sup>127</sup> 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].”<sup>128</sup> 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.”<sup>129</sup>

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

<sup>125</sup> *Id.*

<sup>126</sup> SJVAPCD Rule 4702 Internal Combustion Engines, *available at*:  
<https://www.valleyair.org/rules/currentrules/r4702.pdf>.

<sup>127</sup> SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), *available at*:  
[https://ww3.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjavpcd\\_4702\\_report.pdf](https://ww3.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjavpcd_4702_report.pdf).

<sup>128</sup> *Id.* at B-2.

<sup>129</sup> *Id.*

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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<sup>130</sup>**

<b>POWER OUTPUT (hp)</b>	<b>INSTALLED SCR CAPITAL COSTS, 1999\$</b>	<b>ANNUAL OPERATING AND MAINTENANCE COSTS, 1999\$</b>
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.<sup>131</sup> 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.<sup>132</sup> With respect to the SCR equipment life, SCR systems can likely last much longer than 15 years. EPA states that SCR at boilers, refineries, industrial boilers, etc. have a useful life of 20-30 years.<sup>133</sup> To be consistent with EPA’s statements on SCR, this report will assume a 20-year life for SCR 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%.<sup>134</sup> Such removal rates are achievable with SCR at lean-burn RICE, as discussed above.<sup>135</sup> However, the lower NOx rate of 11 ppmv that SJVAPCD has adopted for lean-burn engines not

<sup>130</sup> *Id.* Table 5.

<sup>131</sup> *Id.* Table 2 and 3.

<sup>132</sup> 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>.

<sup>133</sup> *See* EPA’s Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80.

<sup>134</sup> EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.

<sup>135</sup> *See, e.g.*, 2012 OTC Rep at 19.

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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 NO<sub>x</sub> 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.<sup>136</sup> 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.<sup>137</sup> 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<sub>x</sub> 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 NO<sub>x</sub> Emissions by 95% from 4SLB RICE with SCR Operating at 2,000 and 8,000 Hours per Year<sup>138</sup>**

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 NO<sub>x</sub> emission limit with SCR, which corresponds to a NO<sub>x</sub> emissions reduction efficiency of

<sup>136</sup> See SJVAPCD Rule 4702 Cost Effectiveness Analysis (July 17, 2003), Table 5, notes F and H.

<sup>137</sup> 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.

<sup>138</sup> 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). NO<sub>x</sub> emission reductions are based on SJAPCD's assumed 91% removal efficiency. Uncontrolled NO<sub>x</sub> emissions are based on EPA's 1993 Alternative Control Techniques Document for RICE (EPA-453/R-93-032).

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95%.<sup>139</sup> However, the lower NOx rate of 11 ppmv that SJVAPCD has adopted for lean-burn engines not used for compression and not operated at limited use (less than 4,000 hours per year) would also be achievable with SCR alone or with combustion controls plus SCR. A NOx limit of 11 ppmv reflects 99% control from uncontrolled levels.

More recently, EPA's 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls developed the following cost equations for SCR on natural gas four-stroke lean-burn engines, based on cost calculations for engines of varying size and annual capacity factor from SJVAPCD's 2003 cost effectiveness analysis:

$$\text{Capital cost} = \$107.1 \times (\text{hp}) + \$27,186$$

$$\text{Annual cost} = \$83.64 \times (\text{hp}) + \$14,718$$

The annual cost equation given above includes capital costs amortized assuming a 7% interest, which as discussed above is too high, and a 10-year equipment life, which should be 20 years as discussed above.<sup>140</sup> 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,<sup>141</sup> 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.

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<sup>139</sup> EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.

<sup>140</sup> See 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 5-11 to 5-12.

<sup>141</sup> *Id.*

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**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<sup>142</sup>**

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

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

While the cost estimates and cost algorithms are of a cost basis that is twenty years old, the cost data have been relied on extensively.<sup>143</sup> 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.<sup>144</sup> 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<sub>2</sub> emissions
- 1 to 2% reduction in power output<sup>145</sup>

<sup>142</sup> 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).

<sup>143</sup> 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).

<sup>144</sup> EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.

<sup>145</sup> See EPA 1993 Alternative Control Techniques Document for RICE, Table 2-7 at 2-15.

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- Increased solid waste disposal from spent catalysts<sup>146</sup>
- 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.<sup>147</sup> 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.<sup>148</sup> 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 NO<sub>x</sub> control option for RICE, with the potential to significantly reduce NO<sub>x</sub> emissions.<sup>149</sup> *Replacement of on-site engines with electric motors will reduce on-site NO<sub>x</sub> 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.”<sup>150</sup> 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 NO<sub>x</sub> 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.”<sup>151</sup> However, on a cost per ton of NO<sub>x</sub> 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 –

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<sup>146</sup> See CDPHE RP for RICE at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6<sup>th</sup> ed., EPA/452/B-02-001, EPA, Office of Air Quality Planning and Standards, RTP).

<sup>147</sup> 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.

<sup>148</sup> 2016 EPA CSAPR TSD for Non-EGU NO<sub>x</sub> Emissions Controls at 15.

<sup>149</sup> CARB 2001 Guidance at I-7.

<sup>150</sup> *Id.* at IV-2.

<sup>151</sup> *Id.* at V-2.

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that is, \$1,100/ton in 1999 dollars.<sup>152</sup> For engines in the size range of 150 to 500 hp, electrification of engines was somewhat more cost effective at \$900/ton in 1999 dollars.<sup>153</sup> 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.”<sup>154</sup>

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.<sup>155</sup> 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.<sup>156</sup> 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.<sup>157</sup> 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.”<sup>158</sup>

The Fact Sheet documents the costs of replacing five existing gas-fired reciprocating compressors with four electric compressors.<sup>159</sup> 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.<sup>160</sup> The Fact Sheet states that the total cost of the replacement was \$6,050,000, including the cost of the motor and compressor.<sup>161</sup> 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

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<sup>152</sup> *Id.* at V-3.

<sup>153</sup> *Id.*

<sup>154</sup> *Id.* at VII-2.

<sup>155</sup> *Id.* at V-4 to V-4.

<sup>156</sup> 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.

<sup>157</sup> 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>.

<sup>158</sup> See <https://www.epa.gov/natural-gas-star-program/natural-gas-star-program>.

<sup>159</sup> See EPA, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, PRO Fact Sheet No. 103 Install Electric Compressors, 2011.

<sup>160</sup> *Id.* at 2.

<sup>161</sup> *Id.*



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per year.<sup>162</sup> For electric compressors that operated less than every hour of the year, these operating costs can be scaled back by multiplying the projected electricity cost for continual operation by the ratio of the number of hours operated per year to 8,760 hours per year. Maintenance costs were assumed to be approximately 10% of the capital costs, and the maintenance costs would be lower than apply to gas-fired engines.<sup>163</sup> 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).<sup>164</sup> 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.<sup>165</sup> 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.<sup>166</sup> 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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<sup>162</sup> *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.

<sup>163</sup> *Id.*

<sup>164</sup> *Id.*

<sup>165</sup> *Id.* A heating value of natural gas of 1,020 British Thermal Units (BTU) per standard cubic feet (SCF) of gas was also assumed.

<sup>166</sup> See EPA 1993 Alternative Control Techniques Document for RICE, Table 2-1 at 2-3.

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**Table 14. NOx Cost Effectiveness to Replace Natural Gas-Fired RICE Units with Electric Compressor Engines<sup>167</sup>**

	Costs at Operating Hours per Year (2011 \$)		
	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
<b>Assumptions</b>			
<ul style="list-style-type: none"> <li>• Existing Gas-Fired Reciprocating Compressor Engines: 2–2,650 hp, 2–4,684 hp, 1–893 hp</li> <li>• Replacement Electric Compressor Engines: 4–1,750 hp</li> <li>• Efficiency of Existing Gas-Fired Engines: 20%</li> <li>• Efficiency of Electric Engines: 50%</li> <li>• 30 Year Life of Electric Engines, 5.5% Interest Rate</li> <li>• Cost of Electricity: \$0.075 per kilowatt-hour; Cost of Natural Gas: \$3.00/MCF<sup>168</sup></li> <li>• Annual Maintenance Costs: 10% of Capital Costs of New Electric Engines</li> </ul>			

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

<sup>167</sup> The basis for the capital and operating costs are from EPA’s PRO Fact Sheet No. 103 Install Electric Compressors.

<sup>168</sup> 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>.

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engines).<sup>169</sup> From the perspective of cost effectiveness, the potential increase in NOx emissions from the power generating source would not significantly impact cost effectiveness of replacing gas-fired engines with electric engines.

The costs in Table 14 assume that the engines are located relatively close to the power grid and thus do not take into account any costs to bring electricity to the site. For a site that is not relatively close to the power grid, CARB estimated it could cost \$5,000 to \$10,000 (in 1999 dollars) to set up the site for electric motor operation and states that some utilities may waive or refund those costs if monthly energy usage matches the cost to connect to the grid.<sup>170</sup>

There are many benefits associated with replacing gas-fired reciprocating compressor engines with electric compressor engines. Those benefits include:<sup>171</sup>

- 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.<sup>172</sup> 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.<sup>173</sup> 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.<sup>174</sup> 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

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<sup>169</sup> 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.

<sup>170</sup> CARB 2001 Guidance at V-2.

<sup>171</sup> See EPA, PRO Fact Sheet No. 103 Install Electric Compressors at 2.

<sup>172</sup> *Id.* at 1.

<sup>173</sup> 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.

<sup>174</sup> See EPA, PRO Fact Sheet No. 103 Install Electric Compressors at 2.

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MCF per horsepower.<sup>175</sup> Using the 100-year global warming potential identified by EPA,<sup>176</sup> that equates to roughly 10,000 tons per year of CO<sub>2</sub> equivalent emissions that would be avoided with no natural gas releases due to blowdowns with electric compressor engines. Thus, the total CO<sub>2</sub> equivalent emissions that could be reduced by replacing the five gas-fired engines with electric compressors powered with renewable energy would be about 12,000 tons per year.

There are several examples of electric engines being used in the oil and gas industry for compression, both at the wellhead and in compressor stations,<sup>177</sup> for drill rigs,<sup>178</sup> and in oil pumps.<sup>179</sup> 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 NO<sub>x</sub> 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. NO<sub>x</sub> 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.<sup>180</sup> The most stringent NO<sub>x</sub> 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.<sup>181</sup> In considering reasonable progress controls for gas-fired spark-ignition RICE units, the applicable NSPS standards should be considered the “floor” of potential NO<sub>x</sub> controls to consider for an existing RICE unit.

Numerous states and local air agencies have adopted similar or more stringent NO<sub>x</sub> 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,<sup>182</sup> which provided a summary of state NO<sub>x</sub> regulations for gas engines.<sup>183</sup> 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 NO<sub>x</sub> emission limitations for existing gas-fired engines. We reviewed many of the remaining states’ regulations to determine whether there were NO<sub>x</sub> limitations for existing natural gas-fired stationary RICE units.

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<sup>175</sup> *Id.* at 1.

<sup>176</sup> See <https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#Learn%20why>.

<sup>177</sup> 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](https://www.edf.org/sites/default/files/9235_Barnett_Shale_Report.pdf).

<sup>178</sup> *Id.* at 18.

<sup>179</sup> CARB 2001 Guidance at IV-2.

<sup>180</sup> See 40 C.F.R. Part 60, §60.4230(a)(5) and Subpart JJJJ. 73 Fed. Reg. 3568 (1/18/08).

<sup>181</sup> 40 C.F.R. Part 60, Subpart JJJJ, Table 1.

<sup>182</sup> See 2016 EPA CSAPR TSD for Non-EGU NO<sub>x</sub> Emissions Controls, Appendix B at 14-15.

<sup>183</sup> *Id.*

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Table 15 is a summary of the NO<sub>x</sub> 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 NO<sub>x</sub> limits were most likely adopted to address nonattainment issues with the ozone NAAQS and possibly also the PM<sub>2.5</sub> NAAQS. However, Colorado adopted a NO<sub>x</sub> 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.<sup>184</sup> Regardless of the reason for adopting the NO<sub>x</sub> emission limits, what becomes clear in this analysis is that numerous states and local governments have adopted NO<sub>x</sub> limitations that require NSCR at rich burn RICE units and either LEC or SCR at lean-burn RICE units. The lowest, most broadly applicable NO<sub>x</sub> 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) NO<sub>x</sub> 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.”<sup>185</sup> 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.”<sup>186</sup> 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<sup>187</sup>**

State/Local	Regulation	Rich-Burn (RB) or Lean-Burn (LB) or Both	Applicability	NO <sub>x</sub> Limit and units (equivalent g/hp-hr)
CA-Antelope Valley AQMD <sup>188</sup>	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))

<sup>184</sup> See CDPHE RP for RICE at 10.

<sup>185</sup> 40 C.F.R. § 51.100(o).

<sup>186</sup> HSC Code § 40406 (California Code), available at:

[https://leginfo.legislature.ca.gov/faces/codes\\_displaySection.xhtml?sectionNum=40406.&lawCode=HSC](https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=40406.&lawCode=HSC).

<sup>187</sup> This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to RICE units, and in case of any errors in this table.

<sup>188</sup> <https://ww3.arb.ca.gov/drdb/av/curhtml/r1110-2.pdf>.

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State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
			Portable	80 ppmvd (1.19 g/hp-hr (RB) or 1.10 g/hp-hr (LB))
CA-Bay Area AQMD <sup>189</sup>	Reg. 9, Rule 8	RB	>50 bhp &/or not Low Usage (<100 hrs/yr) &/or not registered as portable	25 ppmv (0.37 g/hp-hr)
		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 <sup>190</sup>	Rule 1160 <sup>191</sup>	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)
		RB		50 ppmv (0.75 g/hp-hr)
		LB		125 ppmv (1.71 g/hp-hr)
CA-Sacramento AQMD <sup>192</sup>	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 <sup>193</sup>	Rule 333	RB	>50 bhp Noncyclically-loaded <sup>194</sup>	50 ppmvd (0.75 g/hp-hr) or 90% NOx reduction
		RB	>50 bhp	300 ppmvd (4.48 g/hp-hr)

<sup>189</sup> <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>.

<sup>190</sup> <http://mdaqmd.ca.gov/home/showdocument?id=438>.

<sup>191</sup> <http://mdaqmd.ca.gov/home/showdocument?id=6631>.

<sup>192</sup> <http://www.airquality.org/ProgramCoordination/Documents/rule412.pdf>.

<sup>193</sup> <https://ww3.arb.ca.gov/drdb/sb/curhtml/r333.pdf>.

<sup>194</sup> Noncyclically loaded means an engine that is not cyclically loaded. See Santa Barbara AQMD Rule 333.C.

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State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
			Cyclically-loaded <sup>195</sup>	
		LB	>50 bhp & < 100 bhp	200 ppmvd (2.74 g/hp-hr)
		LB	≥100 bhp	125 ppmvd (1.71 g/hp-hr) or 80% NOx reduction
CA – San Diego AQMD <sup>196</sup>	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 <sup>197</sup>	Rule 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 ppmvd (1.03 g/hp-hr)
		LB	>50 bhp & <4,000 hrs/yr	65 ppmvd (0.89 g/hp-hr)
		LB	>50 bhp 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)
	Rule 431	RB	>50bhp & >200 hrs/yr	50 ppmvd (0.75 g/hp-hr)

<sup>195</sup> “Cyclically-loaded” means “an engine that under normal operating conditions has an external load that varies by 40% or more of rated brake horsepower during any load cycle or is used to power a well reciprocating pump including beam-balanced or crank-balanced pumps. Engines powering air-balanced pumps are noncyclically-loaded engines.” See Santa Barbara AQMD Rule 333.C.

<sup>196</sup> [https://www.sandiegocounty.gov/content/dam/sdc/apcd/PDF/Rules\\_and\\_Regulations/Prohibitions/APCD\\_R69-4-1.pdf](https://www.sandiegocounty.gov/content/dam/sdc/apcd/PDF/Rules_and_Regulations/Prohibitions/APCD_R69-4-1.pdf).

<sup>197</sup> <https://ww3.arb.ca.gov/drdb/sju/curhtml/r4702.pdf>.

## Exhibit 1

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
CA- San Luis Obispo APCD <sup>198</sup>				or 90% NOx Reduction
		LB	>50bhp & >200 hrs/yr	125 ppmvd (1.71 g/hp-hr) or 80% NOx Reduction
CA - SCAQMD <sup>199</sup>	Rules 1110.2 and 1100	RB & LB	>50 bhp	11 ppmvd (0.16 g/hp-hr (RB) 0.15 g/hp-hr (LB))
CA- Ventura County AQMD <sup>200</sup>	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 <sup>201</sup>	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 <sup>202</sup>	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 <sup>203</sup>	Rule 7:27-19.8	RB	>500 bhp	1.5 g/bhp-hr
		LB	>500 bhp	2.5 g/bhp-hr

<sup>198</sup> <https://ww3.arb.ca.gov/drdb/slo/curhtml/r431.pdf>.

<sup>199</sup> <http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf>.

<sup>200</sup> <http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.9.pdf>.

<sup>201</sup> [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](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).

<sup>202</sup> [http://txrules.elaws.us/rule/title30\\_chapter117\\_sec.117.2110](http://txrules.elaws.us/rule/title30_chapter117_sec.117.2110).

<sup>203</sup> <https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf>.



## Exhibit 1

State/Local	Regulation	Rich-Burn (RB) or Lean-Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-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
		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 <sup>204</sup>	6 CCR-NY 227-2.4 (f)	RB & LB	>200 bhp	1.5 g/bhp-hr
MA <sup>205</sup>	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 <sup>206</sup>	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 <sup>207</sup>	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) <sup>208</sup>	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)

<sup>204</sup> [https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originContext=documenttoc&transitionType=CategoryPageItem&contextData=\(sc.Default\)](https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default)).

<sup>205</sup> <https://www.mass.gov/files/documents/2018/01/05/310cmr7.pdf>.

<sup>206</sup> <http://mdrules.elaws.us/comar/26.11.29>.

<sup>207</sup> [https://www.ct.gov/deep/lib/deep/air/regulations/20160114\\_draft\\_sec22e\\_dec2015\(revised\).pdf](https://www.ct.gov/deep/lib/deep/air/regulations/20160114_draft_sec22e_dec2015(revised).pdf).

<sup>208</sup> <http://www.epa.state.il.us/air/rules/rice/217-subpart-g.pdf>.

## Exhibit 1

State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent 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)
GA (45 county area – ozone) <sup>209</sup>	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 <sup>210</sup>	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 <sup>211</sup>	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 <sup>212</sup>	ARM 17.8.1603	RB engines at “oil and gas well facilities” (which does not include Compressor engines) which completed or modified	>85 bhp	Install and operate NSCR or its equivalent to control air emissions

<sup>209</sup> <http://rules.sos.ga.gov/GAC/391-3-1-.02>.

<sup>210</sup> [https://www.michigan.gov/documents/deq/deq-aqd-air-rules-apc-part8\\_314769\\_7.pdf](https://www.michigan.gov/documents/deq/deq-aqd-air-rules-apc-part8_314769_7.pdf).

<sup>211</sup> <https://www.colorado.gov/pacific/cdphe/aqcc-regis>.

<sup>212</sup> <https://deq.mt.gov/Portals/112/DEQAdmin/DIR/Documents/legal/Chapters/CH08-16.pdf>.

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State/Local	Regulation	Rich-Burn (RB) or Lean- Burn (LB) or Both	Applicability	NOx Limit and units (equivalent g/hp-hr)
		>3/16/79 and facility PTE NOx >25 tpy		
UT <sup>213</sup>	R307-510	Gas-fired engine at a well site that began operations, installed new engines or made modifications to existing engines after 1/1/16	≥100 hp	1.0 g/hp-hr

**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.

<sup>213</sup> <https://rules.utah.gov/publicat/code/r307/r307-510.htm>.

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**Table 16. Other NO<sub>x</sub> Limits Applicable to Natural Gas-fired Stationary RICE Units**

State	Determination	Applicability [hp]	NO <sub>x</sub> Limits and Engine Type Applicability [RB, LB or BOTH]
NEW JERSEY <sup>214</sup>	State of the Art (SOTA) Emission Performance Levels	NO SIZE SPECIFIED	0.15 g/hp-hr (BOTH) <sup>215</sup>
PENNSYLVANIA <sup>216</sup>	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) <sup>217</sup>
		>500	0.5 g/hp-hr (LB) 0.2 g/hp-hr (RB)
		≥2,370	0.3 g/hp-hr uncontrolled (LB) <b>or</b> 0.05 g/hp-hr with control (LB) <sup>218</sup>
PENNSYLVANIA <sup>219</sup>	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)

<sup>214</sup> 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>.

<sup>215</sup> Generally applied controls to meet State of the Art Emission Performance Levels:

Rich-burn: NSCR

Lean-burn: SCR or LEC

Basis: “In determining SOTA performance levels for RICE engines, permitting agencies, industry associations, manufacturers of RICE and manufacturers of emissions control equipment were contacted to obtain updated information on emissions and control technologies. Databases for recent permitted and tested engines from New Jersey, California and USEPA were reviewed.” *Id.* at 8.

<sup>216</sup> 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>.

<sup>217</sup> PA DEP determined that NSCR is required for all rich burn engines rated greater than or equal to 100 bhp. PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. *See* Appendix C at 75, *available at*: <http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904>.

<sup>218</sup> Lean-burn engines greater than or equal to 2,370 hp have a dual BAT: (1) engines with a NO<sub>x</sub> emission rate of 0.30 g/bhp-hr do not require SCR based on economic feasibility; and (2) engines with a NO<sub>x</sub> emission rate of 0.050 g/bhp-hr require SCR.

<sup>219</sup> *Id.*

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State	Determination	Applicability [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) <sup>220</sup>
		>500	0.50 g/hp-hr (LB) 0.20 g/hp-hr RB)
PENNSYLVANIA <sup>221</sup>	Best Available Technology (BAT) Emission limits for existing SI RICE permitted prior to 2/2/13	<1,500	2.0 g/hp-hr
WYOMING <sup>222</sup>	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 <sup>223</sup>	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

<sup>220</sup> PA DEP determined that NSCR is required for all rich burn engines rated greater than or equal to 100 bhp. PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) And the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. See Appendix C at 75, available at: <http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904>.

<sup>221</sup> *Id.*

<sup>222</sup> 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](http://deq.wyoming.gov/media/attachments/Air%20Quality/New%20Source%20Review/Guidance%20Documents/FINAL_2018_Oil%20and%20Gas%20Guidance.pdf).

<sup>223</sup> 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>.

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Rubart Station was determined to be SCR with a NO<sub>x</sub> BACT limit equivalent to 0.07 g/hp-hr for loads of 50% or higher.<sup>224</sup>

As Table 15 shows, twenty-three state and local air pollution control agencies have adopted NO<sub>x</sub> 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 NO<sub>x</sub> control listed in Table 15, including NO<sub>x</sub> 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 NO<sub>x</sub> 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 – NO<sub>x</sub> CONTROLS FOR EXISTING RICH-BURN AND LEAN-BURN NATURAL GAS-FIRED RICE

The above analyses and state/local rule data demonstrate that numerous state and local air agencies have found that NSCR is a cost effective NO<sub>x</sub> 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<sub>x</sub>, 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 NO<sub>x</sub> 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 NO<sub>x</sub> removed or even higher for engines that operate 2,000 hours per year.

As states evaluate regulation of NO<sub>x</sub> 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 NO<sub>x</sub> 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 NO<sub>x</sub>.

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<sup>224</sup> 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](http://www.kdheks.gov/bar/midkanec/Mid-Kansas_Rubart_Station_PSD_Air_Permit_App_12_19_12.pdf).

## Exhibit 1

It also must be recognized that it may be as or more cost effective for NO<sub>x</sub> control, and more beneficial for regional haze, to replace gas-fired RICE units with electric engines rather than install NO<sub>x</sub> pollution controls. Moreover, electric engines have numerous benefits that should be considered with regard to the energy and non-air impacts factor of a reasonable progress analysis. These additional benefits include reducing on-site emissions of all pollutants, reduced noise levels, more efficient operation and maintenance requirements (including less frequent maintenance required), and decreased methane emissions due to blowdowns because the electric engines do not require as frequent maintenance and do not have as many upsets. In addition, if the power for the electric engines can be derived from renewable energy sources, the greenhouse gas reductions can be very significant. Indeed, with renewable energy becoming an increasingly greater proportion of electricity generation and with coal-fired electricity generation being phased out, these added benefits of replacing gas-fired RICE units with electric engines should be considered in the four-factor analysis of controls. Electrification of engines may be less cost effective than some of the NO<sub>x</sub> controls evaluated above such as NSCR and LEC, but the potential added benefits with electric motors will likely weigh in favor of electrification as the most effective reasonable progress control for RICE.

### III. CONTROL OF VOC EMISSIONS FROM NATURAL GAS-FIRED RICE

VOC emissions from natural gas-fired RICE units result from incomplete combustion. The same is true for CO emissions. The combustion conditions that favor lower NO<sub>x</sub> 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 NO<sub>x</sub> 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,<sup>225</sup> 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."<sup>226</sup> EPA also states that "actual emissions may vary considerably from the published emission factors due to variations in engine operating conditions."<sup>227</sup> That said, EPA's emission factors for uncontrolled VOCs are an order of magnitude lower than uncontrolled NO<sub>x</sub> emissions from RICE units. For that reason, this report focuses extensively on NO<sub>x</sub> emission controls for RICE units. However, there are emission controls feasible and implemented for VOCs from RICE units.

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<sup>225</sup> 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>.

<sup>226</sup> EPA AP-42, Introduction at 8-9.

<sup>227</sup> EPA, AP-42, Section 3.2 at 3.2-3.

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### VOC Controls for Lean-Burn RICE

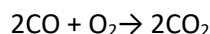
For lean-burn natural gas-fired RICE, as well as natural gas-fired combustion turbines, the primary method available for reducing VOC emissions is the use of an oxidation catalyst. For rich-burn RICE, NSCR is the pollution control of choice to address VOCs, as its three-way catalyst generally reduces NOx, CO, and VOCs with proper operation, although an oxidation catalyst can be installed downstream of the NSCR to improve VOC control.

A 2015 report issued by the Manufacturers of Emission Controls Association on emission controls for stationary internal combustion engines states as follows regarding oxidation catalyst for lean-burn engines:<sup>228</sup>

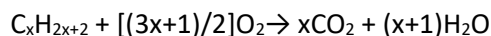
Oxidation catalysts (or two-way catalytic converters) are widely used on diesel engines and lean-burn gas engines to reduce hydrocarbon and carbon monoxide emissions. Specifically, oxidation catalysts are effective for the control of CO, NMHCs, VOCs, and formaldehyde and other [hazardous air pollutants (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:



Oxidation of hydrocarbons (unburnt and partially burnt fuel) to carbon dioxide and water:



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

Cost information of oxidation catalyst was provided to EPA in 2010 to help determine national impacts associated with EPA's RICE NESHAP.<sup>231</sup> The analysis, performed by E<sup>C</sup>/R Incorporated, was based on 2009 cost data for oxidation catalyst from industry groups, vendors, and manufacturers of RICE control

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<sup>228</sup> 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](http://www.meca.org/resources/MECA_stationary_IC_engine_report_0515_final.pdf).

<sup>229</sup> *Id.*

<sup>230</sup> *Id.* at 7.

<sup>231</sup> Memo from EC/R Inc. to EPA Re: Control Costs for Existing Stationary SI RICE (June 29, 2010).



## Exhibit 1

technology. E<sup>C</sup>/R Incorporated performed a linear regression analysis<sup>232</sup> 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:

$$2\text{SLB Oxidation Catalyst Total Annual Cost} = \$11.4 \times \text{HP} + \$13,928$$

$$2\text{SLB Oxidation Catalyst Total Capital Cost} = \$47.1 \times \text{HP} + \$41,603$$

$$4\text{SLB Oxidation Catalyst Total Annual Cost} = \$1.81 \times \text{HP} + \$3,442$$

$$4\text{SLB Oxidation Catalyst Total Capital Cost} = \$1.81 \times \text{HP} + \$3,442$$

Where HP equals the engine size in horsepower.

E<sup>C</sup>/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.<sup>233</sup> 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.**<sup>234</sup>

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

<sup>232</sup> *Id.* at 5-6.

<sup>233</sup> *Id.* at 5-6 and Appendix A.

<sup>234</sup> Cost calculations based on E<sup>C</sup>/R equations from above, but assuming a 15-year life and a 5.5% interest rate.

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A 2019 report by SCAQMD indicates that 500 stationary lean-burn engines have been fitted with oxidation catalyst.<sup>235</sup> 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.<sup>236</sup> 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.<sup>237</sup> 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.<sup>238</sup> 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.<sup>239</sup> 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.<sup>240</sup> 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.<sup>241</sup>

In summary, oxidation catalyst is an available control technology that should be considered as a reasonable progress control option to reduce VOC emissions for lean-burn gas-fired RICE.

### **VOC Controls for Rich-Burn RICE**

As discussed in Section II.C. above, NSCR is a three-way catalyst applicable to rich-burn RICE units, which not only removes NOx emissions, but also reduces CO and VOC emissions. In addition to the NSCR catalyst and housing, NSCR requires installation of an oxygen sensor and an AFRC ensure optimum air-to-fuel ratios to ensure conditions are NSCR is the primary VOC control that is implemented for rich-burn gas-fired RICE. Colorado has indicated that an "oxidation catalyst using additional air can be installed downstream of the NSCR catalyst for additional CO and VOC control."<sup>242</sup> The costs for NSCR have been detailed above in Section II.C. NSCR's cost effectiveness for NOx control and its widespread required use, as shown in the state and local air agency rules detailed in Table 15 above, indicates that NSCR must be considered as a reasonable progress control option to reduce VOC emissions from rich-burn RICE.

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<sup>235</sup> 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>.

<sup>236</sup> 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/16qTQLSTX1T49DYWp3voXRNI4\\_g-vbhQT/view](https://drive.google.com/file/d/16qTQLSTX1T49DYWp3voXRNI4_g-vbhQT/view).

<sup>237</sup> Colorado Regulation 7 (5 CCR 1001-9) Part E 1. Control of Emissions from Engines.

<sup>238</sup> *Id.* at Section I.C.4. of Part E.

<sup>239</sup> 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](http://www.kdheks.gov/bar/midkanec/Mid-Kansas_Rubart_Station_PSD_Air_Permit_App_12_19_12.pdf).

<sup>240</sup> 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](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).

<sup>241</sup> *Id.* Table 5-3 at 5-10. Showing sources from Texas, Oregon, Kansas, and Hawaii receiving permits between 2013 and 2016.

<sup>242</sup> CDPHE RP for RICE at 6.

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### IV. CONTROL OF NO<sub>x</sub> 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.<sup>243</sup>

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).<sup>244</sup> 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.<sup>245</sup> 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.<sup>246</sup> 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).<sup>247</sup> Instead, the turbine shaft power is used as mechanical power to drive a compressor. Regardless of the purpose of the gas-fired combustion turbines, the air pollution controls for the associated visibility-impairing pollutants are the same.

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<sup>243</sup> 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 NO<sub>x</sub> 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>.

<sup>244</sup> 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](https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_3_technology_characterization_-_combustion_turbines.pdf).

<sup>245</sup> *Id.* at 3-2.

<sup>246</sup> 40 C.F.R. § 60.331(q).

<sup>247</sup> 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.

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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.<sup>248</sup> That DOE Report, “Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines” dated November 5, 1999 (hereinafter “1999 DOE Report”)<sup>249</sup> 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,<sup>250</sup> 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.<sup>251</sup> 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.<sup>252</sup> In addition, more recent analyses of the costs of NOx controls for gas turbines have been summarized as supporting information for state and local air agency adoption of NOx emission limitations for gas turbines, but those cost analyses are generally not as detailed as the 1999 DOE report. In the discussion below of the NOx pollution control options for gas turbines, we provide information on all of these various cost analyses.

Note that in the following discussion, NOx emission rates are often referred to as parts per million or “ppm.” It should be assumed that such concentration rates are in parts per million by volume or “ppmv” measured on a dry basis and corrected to 15% oxygen unless stated otherwise.

### A. WATER OR STEAM (DILUENT) INJECTION

Water or steam injection has been used for decades to reduce NOx emissions from gas turbines. EPA describes the control in its “AP-42” emission factor documentation for gas turbines as follows:

Water or steam injection is a technology that has been demonstrated to effectively suppress NOx emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Depending on the initial NOx levels, such rates of injection may reduce NOx by 60 percent or higher. Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The increased power output results from the increased mass flow required

<sup>248</sup> See 2012 OTC Report at 66-67.

<sup>249</sup> 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](https://www.energy.gov/sites/prod/files/2013/11/f4/gas_turbines_nox_cost_analysis.pdf).

<sup>250</sup> 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>.

<sup>251</sup> See EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf 12 and 98 (reference 19).

<sup>252</sup> 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.

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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.<sup>253</sup>

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.<sup>254</sup> 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.<sup>255</sup> General Electric also indicates that water injection can reduce NOx emissions to 25 ppm for gas-fired turbines.<sup>256</sup> 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.<sup>257</sup> 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.<sup>258</sup>

The 1999 DOE Report listed the capital and annual operating costs for water injection installed at specific makes/models of combustion turbines, which are reiterated in the table below.

**Table 18. Capital and Operating Costs of Water or Steam Injection for Select Combustion Turbines<sup>259</sup>**

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

<sup>253</sup> EPA, Compilation of Air Pollutant Emission Factors (AP-42), Section 3.1 Gas Turbines, April 2000, at 3.1-6.

<sup>254</sup> 1999 DOE Report, Appendix A at A-5 (Table A-4).

<sup>255</sup> EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.

<sup>256</sup> See GE Power, Water Injection for NOx Reduction, at <https://www.ge.com/power/services/gas-turbines/upgrades/water-injection-for-nox-reduction>.

<sup>257</sup> 2012 OTC Report at 62.

<sup>258</sup> *Id.*

<sup>259</sup> See 1999 DOE Report, Appendix A at A-5 (Table A-4).

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The 1999 DOE report determined the annualized costs of control assuming only a 15-year life of controls and a 10% interest rate.<sup>260</sup> 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.<sup>261</sup> 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.<sup>262</sup> 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.<sup>263</sup> 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,<sup>264</sup> a lower interest rate of 5.5% was assumed.<sup>265</sup> In its 2019 cost calculation spreadsheet for SCR provided with its Control Cost Manual, EPA used an interest rate of 5.5%.<sup>266</sup> 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.<sup>267</sup> 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.<sup>268</sup> In its 2016 TSD for the CSAPR rule, EPA did not escalate the costs of controls from 1999 dollars.<sup>269</sup> As discussed above, lower NOx rates with water or steam injection of 25 ppm are generally achievable. Thus, in Table 19 below, the cost effectiveness of

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<sup>260</sup> *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"].

<sup>261</sup> 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.

<sup>262</sup> 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](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](https://www.solarturbines.com/en_US/products/power-generation-packages/taurus-70.html).

<sup>263</sup> 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.

<sup>264</sup> US EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.

<sup>265</sup> See e.g., <https://fred.stlouisfed.org/series/DPRIME>.

<sup>266</sup> Available at <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution>.

<sup>267</sup> *Id.* at A-3

<sup>268</sup> 2016 EPA CSAPR TSD for Non-EGU Emissions Controls, November 2015, Appendix A at 3-10 through 3-12.

<sup>269</sup> *Id.*

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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<sup>270</sup>**

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.<sup>271</sup> 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%.”<sup>272</sup> This is presumably an average across all compressor engines used in the oil and gas sector, and there are very likely some compressors that do operate at 90% capacity factors. Indeed, the Ozone Transport Commission document indicates that “[f]or many mainline natural gas compressor stations, industry data indicated that the gas compressor stations have compressors in operation 24 hrs/day and 365 days/year, although not all compressors may be operating or may not be operating at high capacity.”<sup>273</sup> 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

<sup>270</sup> See 1999 DOE Report, Appendix A at A-5 (Table A-4). Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in Appendix A of EPA’s 1993 ACT for Stationary Gas Turbines and a 91% operating capacity factor was assumed, reflective of the assumed 8,000 hours of operation per year in the November 1999 DOE Cost Analysis report.

<sup>271</sup> *Id.*, Appendix A at A-5.

<sup>272</sup> 2012 OTC Report at 16.

<sup>273</sup> *Id.*

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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.<sup>274</sup> 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<sup>275</sup>**

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%, but still high compared to today's interest rates.<sup>276</sup> The cost algorithms of EPA's 2016 TSD for the CSAPR Rule are reprinted below.<sup>277</sup>

Water Injection/Gas Turbines:

$$\text{Total Capital Investment (1999 dollars)} = 27665 \times (\text{MMBtu/hr})^{0.69}$$

$$\text{Total Annual Costs (1999 dollars)} = 3700.2 \times (\text{MMBtu/hr})^{0.95}$$

Steam Injection/Gas Turbines:

$$\text{Total Capital Investment (1999 dollars)} = 43092 \times (\text{MMBtu/hr})^{0.82}$$

$$\text{Total Annual Costs (1999 dollars)} = 7282 \times (\text{MMBtu/hr})^{0.76}$$

<sup>274</sup> 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.

<sup>275</sup> See 1999 DOE Report, Appendix A at A-5 (Table A-4). Capital costs in 1999 dollars were updated from 1999 to 2018 dollars based on CEPCI and CPI indices. Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines and a 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.

<sup>276</sup> See 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-11 to 12 and Appendix B at B-2.

<sup>277</sup> *Id.*, Appendix A at 3-12.



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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 NO<sub>x</sub> 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.<sup>278</sup> 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 NO<sub>x</sub> 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<sup>279</sup>

Water use and water availability may be a significant environmental impact for this control technology, especially for locations in the arid West that already have water shortage issues. The 1999 DOE Report included information on expected water usage of water injection at the four turbines evaluated for the cost effectiveness analysis,<sup>280</sup> 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<sup>281</sup>**

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

<sup>278</sup> EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 19.

<sup>279</sup> See, e.g., EPA's 1993 ACT for Stationary Gas Turbines at 2-41.

<sup>280</sup> See 1999 DOE Report, Appendix A at A-5.

<sup>281</sup> *Id.*

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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.”<sup>282</sup> Water quality may be more of an issue for remote sites, especially if surface water or well water is used for the water supply.<sup>283</sup> 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.<sup>284</sup>

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,<sup>285</sup> 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.<sup>286</sup> Dry low NOx combustors are also available for retrofit for several turbine makes and models. This technology to control NOx is discussed in the next section of this report.

### B. DRY LOW NOx COMBUSTION

In the late 1980s, dry low NOx burners (DLNBs) became available on larger turbines<sup>287</sup> 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.”<sup>288</sup> Many DLNBs can achieve reduced NOx rates across the full load range of a gas turbine.<sup>289</sup> DLNBs are also available to retrofit to several types of combustion turbines. General Electric has dry low NOx burner retrofit

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<sup>282</sup> *Id.* at 7-10.

<sup>283</sup> *Id.*

<sup>284</sup> 1999 DOE Report, Appendix A at A-5 (Table A-4).

<sup>285</sup> 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>.

<sup>286</sup> *Id.* at 2-8.

<sup>287</sup> 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](https://www.apti-learn.net/lms/register/display_document.aspx?dID=39).

<sup>288</sup> EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.

<sup>289</sup> As discussed in 2012 OTC Report at 62.

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options for many of its turbine makes and models, and Solar Turbines has an extensive line of retrofit kits including Solar Turbines' SoLoNOx™ technology.<sup>290</sup> To retrofit such DLNBs, the turbines' combustors must be replaced and there may be changes necessary to associated piping and turbine combustion controls.<sup>291</sup>

Based on the range of NOx emission rates that have been reported as achievable with DLNBs, these combustion controls can achieve in the range of 80% to 95% control of NOx emissions.<sup>292</sup> For the turbines for which DLNBs are available, NOx rates have generally ranged from 9–15 ppm.<sup>293</sup> The 1999 DOE Report assumed only a 25 ppmv NOx rate would be achieved at most of the combustion turbines with DLN combustion which reflects approximately 84% NOx reduction, although the DOE report also calculated costs for a larger turbine to meet a 9 ppmv NOx rate which reflects approximately 95% NOx reduction.<sup>294</sup> The 1999 DOE Report indicates that the operation and maintenance costs increase with the lower NOx rate being achieved.<sup>295</sup> 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 ppmv NOx with Solar Turbines' SoLoNOx™ burners, including the Solar Centaur 50L which is rated at 6,276 horsepower (< 5 MW).<sup>296</sup> 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).<sup>297</sup> GE recently announced NOx upgrades completed at 9 GE 9E Gas Turbines (132 145 MW) at a facility in China with its DLN1.0+ with Ultra Low NOx combustors to achieve about 7.5 ppm NOx rates.<sup>298</sup>

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.<sup>299</sup> 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."<sup>300</sup> 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

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<sup>290</sup> *Id.* at 66.

<sup>291</sup> *Id.*

<sup>292</sup> See, e.g., 2015 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12, which indicates that 84% control can be met with DLNB achieving a NOx emission rate of 25 ppmv.

<sup>293</sup> See 1999 DOE Report at 2-10.

<sup>294</sup> *Id.* at 2-10 and at Appendix A at A-3.

<sup>295</sup> *Id.* at 2-9 to 2-10.

<sup>296</sup> 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.

<sup>297</sup> See [https://www.solarturbines.com/en\\_US/services/equipment-optimization/system-upgrades/safety-and-sustainability/solonox-upgrades.html](https://www.solarturbines.com/en_US/services/equipment-optimization/system-upgrades/safety-and-sustainability/solonox-upgrades.html).

<sup>298</sup> See <https://www.genewroom.com/press-releases/ge-completes-worlds-first-dln10-ultra-low-nox-combustion-upgrade-nine-ge-9e-gas>.

<sup>299</sup> 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-12.

<sup>300</sup> 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.

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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<sup>301</sup> (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).<sup>302</sup>

**Table 22. Summary of Cost Effectiveness for DLN Combustion (1999\$) at 91% Capacity Factor<sup>303</sup>**

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.

<sup>301</sup> NESCAUM 2000 Status Report at IV-36.

<sup>302</sup> 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](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](https://www.dec.ny.gov/dardata/boss/afs/permits/929200000800015_r3.pdf).

<sup>303</sup> 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.

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**Table 23. Summary of Cost Effectiveness for DLN Combustion (1999\$) at 40% Annual Capacity Factor<sup>304</sup>**

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

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.<sup>305</sup> The cost algorithms of EPA’s 2016 TSD for the CSAPR Rule for DLN combustion are reprinted below.<sup>306</sup>

$$\text{Total Capital Investment (1999 dollars)} = 2860.6 \times (\text{MMBtu/hr}) + 25427$$

$$\text{Total Annual Costs (1999 dollars)} = 584.5 \times (\text{MMBtu/hr})^{0.96}$$

In its 2000 Status Report, NESCAUM provided information on the capital and operational expenses for two dry low NOx combustor upgrades to a Solar Centaur turbine (4,700 hp) and a Solar Mars turbine (13,000 hp).<sup>307</sup> 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.<sup>308</sup> 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.

<sup>304</sup> 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.

<sup>305</sup> See 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls, Appendix A at 3-11-12, Appendix B at B-2.

<sup>306</sup> See *id.*, Appendix A at 3-13.

<sup>307</sup> See NESCAUM 2000 Status Report at III-16.

<sup>308</sup> *Id.*

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**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<sup>309</sup>**

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 management or other charges associated with the project beyond the equipment and installation.”<sup>310</sup> 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.<sup>311</sup>

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.<sup>312</sup> 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.<sup>313</sup> A non-air quality environmental impact is that DLNBs “tend to create harmonics in the combustor that result in significant vibration and acoustic noise.”<sup>314</sup>

EPA has indicated that the length of time to install DLNBs is 6–12 months.<sup>315</sup>

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.

<sup>309</sup> *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 Appendix A of EPA’s 1993 ACT for Stationary Gas Turbines and both a 91% and a 40% operating capacity factor were assumed.

<sup>310</sup> *Id.*

<sup>311</sup> See EPA Control Cost Manual, Section 1, Chapter 2 at 9.

<sup>312</sup> *Id.* at 2-9 and 3-10.

<sup>313</sup> *Id.*, Appendix A at A-3.

<sup>314</sup> *Id.* at 2-9 and Appendix A at A-3.

<sup>315</sup> See 2016 EPA CSAPR TSD for Non-EGU NOx Emissions Controls at 18.

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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 NO<sub>x</sub> 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 NO<sub>x</sub> rates. Thus, low NO<sub>x</sub> combustion is a preferable combustion-related retrofit option for gas turbines, if a low NO<sub>x</sub> combustion retrofit option is available for the turbine make and model.

### C. SELECTIVE CATALYTIC REDUCTION

SCR is a post-combustion NO<sub>x</sub> reduction control that is commonly applied to gas-fired combustion turbines used for power generation. SCR technology can reduce NO<sub>x</sub> emissions by 80–90% or more and, when used along with water injection or DLNC, it can achieve NO<sub>x</sub> emission rates in the range of 1.5 to 5 ppm.<sup>316</sup> The 1999 DOE Report stated that SCR was the “primary post-combustion NO<sub>x</sub> control method in use” as of 1999.<sup>317</sup>

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 NO<sub>x</sub> to N<sub>2</sub>, H<sub>2</sub>O, and CO<sub>2</sub>. The catalyst selected depends on the temperature range of the flue gas and the size of the catalyst depends on the level of NO<sub>x</sub> 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 NO<sub>x</sub> removal performance.<sup>318</sup> 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.<sup>319</sup> 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.<sup>320</sup> 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% NO<sub>x</sub> reduction.<sup>321</sup> The NOxCat ETZ catalyst is specifically designed for simple-cycle power generating turbines and other high temperature turbine applications.<sup>322</sup> The NOxCat VNX and ZNX catalysts can achieve up to 99%

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<sup>316</sup> 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.

<sup>317</sup> 1999 DOE Report at 1-5.

<sup>318</sup> *Id.*

<sup>319</sup> *Id.*

<sup>320</sup> See EPA, Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, at pdf page 36.

<sup>321</sup> 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>.

<sup>322</sup> 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>.

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NOx reduction and are most effective at a temperature range of 550 to 800 degrees Fahrenheit.<sup>323</sup> 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.<sup>324</sup>

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.<sup>325</sup> Further, aeroderivative turbines typically have somewhat lower exhaust gas temperatures which can work better with conventional SCR systems than frame-type turbines.<sup>326</sup> 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.<sup>327</sup> Conventional catalysts can achieve 80% or greater NOx removal over a wide temperature range of approximately 625 to 900 degrees Fahrenheit.<sup>328</sup> SCR vendors have experience installing SCR to achieve low NOx emission rates on numerous simple cycle turbines of all types and sizes.<sup>329</sup>

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.<sup>330</sup> For these cost ranges, EPA cites to the NESCAUM 2000 Status Report.<sup>331</sup> 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.<sup>332</sup> 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.

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<sup>323</sup> 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>.

<sup>324</sup> *Id.*

<sup>325</sup> See, e.g., Buzanowki, M. and S. McMnamin, 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>.

<sup>326</sup> 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](http://files.brattle.com/files/7644_independent_evaluation_of_scr_systems_for_frame-type_combustion_turbines.pdf).

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

<sup>328</sup> *Id.* at pdf page 20.

<sup>329</sup> 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](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.

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

<sup>331</sup> *Id.* at pdf page 98 (see Reference 19).

<sup>332</sup> NESCAUM 2000 Status Report at III-21 through III-24 and at III-40 (see referenced 11, 16, 9, 14, and 15).



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**Table 25. Cost Effectiveness for High Temperature SCR Retrofit on Simple Cycle Gas Turbines.**<sup>333</sup>

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%
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.

<sup>333</sup> *Id.* at III-24.

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The NESCAUM cost effectiveness numbers in Table 25 above reflect a 15-year equipment life and an interest rate of 7.5%.<sup>334</sup> The NESCAUM cost effectiveness numbers were also primarily based on the 1999 DOE report.<sup>335</sup> 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.<sup>336</sup> Further, as stated above, EPA currently uses a 5.5% interest rate in its cost effectiveness calculations. Tables 26 and 27 below present the cost effectiveness for conventional and high-temperature SCR added to a gas-fired combustion turbine meeting an uncontrolled rate of 42 ppmv, reflective of water or steam injection, to achieve a controlled NOx rate of 9 ppmv, which reflects a 79% reduction in NOx emissions. These cost effectiveness analyses are based on the costs of the 1999 DOE Report, but with the capital cost amortized to reflect a 25-year equipment life and a 5.5% interest rate.<sup>337</sup> 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,<sup>338</sup> 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.<sup>339</sup>

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<sup>334</sup> *Id.* at IV-22.

<sup>335</sup> *Id.* at III-21 through III-24 (see cites to Reference 11, which is the 1999 DOE report).

<sup>336</sup> See EPA Control Cost Manual, Section 4, Chapter 2, at pdf page 80.

<sup>337</sup> 1999 DOE Report at 3-9 to 3-10, Appendix A at A-6 to A-7.

<sup>338</sup> 2012 OTC Report at 16.

<sup>339</sup> 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.

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**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<sup>340</sup>**

<b>Turbine Model</b>	<b>Size, MW</b>	<b>Size, hp</b>	<b>Uncontrolled NOx, ppm at 15% O2</b>	<b>Controlled NOx with SCR, ppm at 15% O2</b>	<b>Annualized Costs of SCR, 1999\$</b>	<b>Cost Effectiveness of Conventional SCR at Stated Capacity Factor, 1999\$</b>	<b>Capacity Factor</b>
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%

<sup>340</sup> 1999 DOE Report, Appendix A at A-6 (Table A-5). Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). To reflect a 40% capacity factor, the annual operating costs due to the fuel penalty and ammonia use were decreased by 56%, to reflect a 40% capacity factor rather than a 91% capacity factor. Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in Appendix A of EPA's 1993 ACT for Stationary Gas Turbines.

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**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<sup>341</sup>**

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.”<sup>342</sup> 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

<sup>341</sup> 1999 DOE Report, Appendix A at A-7 (Table A-6). Annualized costs of control were calculated using a capital recovery factor of 0.074549 (assuming a 25-year life of controls and a 5.5% interest rate). The annual costs due to the fuel penalty and ammonia use were decreased by 56% to reflect a 40% capacity factor, rather than the 91% capacity factor. Uncontrolled and controlled NOx emissions were calculated based on procedures outlined in Appendix A of EPA’s 1993 ACT for Stationary Gas Turbines.

<sup>342</sup> See EPA, Combined Heat and Power Partnership, Catalog of CHP Technologies, Section 3. Technology Characterization-Combustion Turbines, March 2015, at 3-18.

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from \$1.5 million to \$2.9 million with the annual costs ranging from \$63,000 to \$727,000.<sup>343</sup> 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.<sup>344</sup> The cost basis of these costs is not identified, but presumably the costs are from the 2010-2015 timeframe.<sup>345</sup> 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.<sup>346</sup> These limits are required to be met by 2024.<sup>347</sup> 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.<sup>348</sup> 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.<sup>349</sup>

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.<sup>350</sup>
- 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.<sup>351</sup> The use of regenerated catalyst can reduce the amount of spent catalyst that needs to be disposed of.<sup>352</sup>

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<sup>343</sup> 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>.

<sup>344</sup> *Id.* at 182.

<sup>345</sup> 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](https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/regxx/noxreclaimbarct-nonconf-nonrefinery_112614.pdf?sfvrsn=2).

<sup>346</sup> See Rule 1134(d)(4), Table II, available at: <http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1134.pdf>.

<sup>347</sup> *Id.*

<sup>348</sup> 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.

<sup>349</sup> 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/priorito2008/08-08-07/Negative%20Declaration.pdf>.

<sup>350</sup> EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf pages 15-16, and 48.

<sup>351</sup> *Id.* at pdf 18.

<sup>352</sup> *Id.* at pdf 18-19.

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- 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.<sup>353</sup> 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).<sup>354</sup> 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.<sup>355</sup> 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.<sup>356</sup> Clearly, SCR has been considered to be a cost effective NOx reduction technology for combustion turbines, including smaller compressor engines and those that power compressor stations, since at least 2007. Further, SCR is often combined with a combustion control like water injection or dry low NOx combustors, which optimizes the NOx emissions reductions and costs of control.

### D. NOx EMISSION LIMITS THAT HAVE BEEN REQUIRED FOR EXISTING NATURAL GAS-FIRED COMBUSTION TURBINES

In 2005, EPA proposed a new NSPS for gas turbines, which was eventually promulgated at 40 C.F.R. Part 60, Subpart KKKK in 2006.<sup>357</sup> 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.<sup>358</sup> As a starting point for considering the level of control that EPA considered to be cost effective as a retrofit control for existing gas turbines, it is instructive to review what EPA required in the NSPS Subpart KKKK

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<sup>353</sup> 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.

<sup>354</sup> See 1999 DOE Report at 2-11.

<sup>355</sup> 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.

<sup>356</sup> Based on a search on EPA’s Air Markets Program Database, available at: <https://ampd.epa.gov/ampd/>.

<sup>357</sup> 70 Fed. Reg. 8,314-8,332 (Feb. 18, 2005), 71 Fed. Reg. 38,482-38,506 (July 6, 2006).

<sup>358</sup> 44 Fed. Reg. 52,798.

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for existing gas turbines that were modified on or after February 18, 2005. These standards are summarized in the table below. It is important to note that these standards were adopted for gas turbines that generate electricity or that are used for mechanical drive such as at a gas compressor station.

**Table 28. NSPS Subpart KKKK NO<sub>x</sub> Control Requirements for Modifications to Existing Gas Turbines Occurring on or after February 18, 2005.<sup>359</sup>**

Turbine Size/Range	Approximate Turbine size range, hp <sup>360</sup>	Subpart KKKK NO <sub>x</sub> limits for modified sources after 2/2005, ppmv	Control that NO <sub>x</sub> 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 NO<sub>x</sub> 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 NO<sub>x</sub> limits for sources modified in 2005 or later should be considered the “floor” of potential NO<sub>x</sub> controls to consider for an existing gas turbine meaning that, at the very minimum, this level of control should be considered cost effective for NO<sub>x</sub> 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 NO<sub>x</sub> 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,<sup>361</sup> which provided a summary of state NO<sub>x</sub> regulations for gas turbines and other NO<sub>x</sub> sources as of September 2014.<sup>362</sup> 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 NO<sub>x</sub> emissions from existing gas turbines: Alabama, Arkansas, Indiana, Kentucky, Michigan, Mississippi, Oklahoma, South Carolina, and West Virginia.<sup>363</sup> We also reviewed California Air District rules, because several of those air districts have adopted the most stringent NO<sub>x</sub> emission limitations for existing gas turbines. Indeed, several air districts in California have adopted rules necessitating installation of SCR at

<sup>359</sup> See 40 C.F.R. Part 60m Subpart KKKK, Appendix, Table 1.

<sup>360</sup> 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.

<sup>361</sup> See 2016 EPA CSAPR TSD for Non-EGU NO<sub>x</sub> Emissions Controls, Appendix B at 11-13.

<sup>362</sup> *Id.*

<sup>363</sup> *Id.* at 13.

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virtually all simple cycle turbines. We reviewed some of the remaining states' regulations to determine whether there were NOx limitations for existing gas turbines. Specifically, we reviewed air regulations in New Mexico, Colorado, Utah, Montana, North Dakota, South Dakota, and Washington. It appears there are no NOx emission limits required for existing gas turbines in those states aside from what applies to modified gas turbines under the NSPS Subpart KKKK.

Table 29 is a summary of the NOx emission limits required of existing simple cycle gas-fired combustion turbines in state and local air districts across the United States. It is important to note that these are limits that, unless otherwise noted, currently apply to existing gas turbines. Unlike the NSPS standards of 40 C.F.R. Part 60, Subpart KKKK, gas turbines did not have to be modified to trigger applicability to these emission limits. Instead, these emission limits apply to existing gas turbines and generally require an air pollution control retrofit or an outright replacement of the gas turbine with a new turbine with integrated dry low NOx combustors. These state and local NOx limits were most likely adopted to address nonattainment issues with the ozone NAAQS and possibly also the PM<sub>2.5</sub> 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,<sup>364</sup> 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.”<sup>365</sup> 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.”<sup>366</sup> BARCT is similar to a BACT determination under the federal PSD program, but it evaluates controls to be retrofit to existing sources, rather than applying to new or modified sources.

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<sup>364</sup> 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.

<sup>365</sup> 40 C.F.R. § 51.100(o).

<sup>366</sup> HSC Code § 40406 (California Code), *available at*:

[https://leginfo.legislature.ca.gov/faces/codes\\_displaySection.xhtml?sectionNum=40406.&lawCode=HSC](https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=40406.&lawCode=HSC).



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**Table 29. Summary of State/Local Air Agency NOx Emission Limits for Existing Simple Cycle Gas-fired Combustion Turbines that Require NOx Pollution Controls<sup>367</sup>**

State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA – Sacramento Metro AQMD <sup>368</sup>	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 <sup>369</sup> )	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 <sup>370</sup>	Regulation 9-9-301	5-50 MMBtu	42 ppmv or 2.12 lb/MW/hr
	Effective 1/1/2010:	>50-150 MMBtu/hr & no retrofit available	42 ppmv or 1.97 lb/MW/hr
		>5-150 MMBtu/hr & Water/Steam Injection Enhancement available	35 ppmv or 1.64 lb/MW/hr
		>50 150 MMBtu/hr & DLNC available	25 ppmv or 1.17 lb/MW/hr
		>150- 250 MMBtu/hr	15 ppmv or 0.70 lb/MW/hr
		>250-500 MMBtu/hr	9 ppmv or 0.43 lb/MW/hr
		>500 MMBtu/hr	5 ppmv or 0.15 lb/MW/hr
		<877 hrs/yr & 50-250 MMBtu/hr	25 ppmv or 1.97 lb/MW/hr
		250-500+ MMBtu/yr	25 ppmv or 1.17-0.72 lb/MW/hr

<sup>367</sup> This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to RICE units, and in case of any errors in this table.

<sup>368</sup> <http://www.airquality.org/ProgramCoordination/Documents/rule413.pdf>.

<sup>369</sup> Best Available Retrofit Control Technology (BARCT) was to be met by May 31, 1997.

<sup>370</sup> <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>.

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State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA-SCAQMD <sup>371</sup>	Rule 1134  Effective 12/31/95:	>0.3-2.9 MW	25 (reference limit) x EFF/25% <sup>372</sup>
		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 <sup>373</sup>	Rule 4703 Tier 3 limits <sup>374</sup>	>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	5
		and  >10 MW and 200-877 hrs/yr	
		>10 MMW	3-5 <sup>375</sup>
	Rule 74.23	0.3-2.9 MW	42

<sup>371</sup> <http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1134.pdf>.

<sup>372</sup> 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%.

<sup>373</sup> <https://www.valleyair.org/rules/currnrules/r4703.pdf>.

<sup>374</sup> 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.

<sup>375</sup> 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.

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State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
CA – Ventura County APCD <sup>376</sup>	<u>Currently proposed revisions:</u> By 1/1/24:	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
		All turbines	2.5
CA – San Diego APCD <sup>377</sup>	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 <sup>378</sup>	Rule 2.34	0.3-2.9 MW & >877 hrs/yr	42
		AND	
		>4 MW & less than 877 hrs/yr	
		2.9-10 MW	25
		>10.0 MW	9
CA-Imperial County APCD <sup>379</sup>	Rule 400.1	>1 MW & >400 hr/yr	42
CA-Mojave Desert AQMD <sup>380</sup>	Rule 1159	>4MW & >877 hrs/yr	42
CA – Placer County APCD <sup>381</sup>	Rule 250	>0.3-2.9 MW&>877 hrs/yr	42

<sup>376</sup> <http://vcapcd.org/Rulebook/Reg4/RULE%2074.23.pdf>.

<sup>377</sup> <https://ww3.arb.ca.gov/drdb/sd/curhtml/r69-3-1.pdf>.

<sup>378</sup> <https://ww3.arb.ca.gov/drdb/ys/curhtml/r2-34.pdf>.

<sup>379</sup> <https://ww3.arb.ca.gov/drdb/imp/curhtml/r400-1.pdf>.

<sup>380</sup> <https://ww3.arb.ca.gov/drdb/moj/curhtml/r1159.htm>.

<sup>381</sup> <https://ww3.arb.ca.gov/drdb/pla/curhtml/r250.pdf>.

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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 <sup>382</sup>	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 <sup>383</sup>	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 <sup>384</sup>	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 <sup>385</sup>	6
WI (Milwaukee 7 county area) <sup>386</sup>	NR 428.22(1)(g)	>50 MW	25

<sup>382</sup> [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](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).

<sup>383</sup> [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](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).

<sup>384</sup> [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](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).

<sup>385</sup> This appears to be a new source requirement because compliance was required upon startup.

<sup>386</sup> [https://docs.legis.wisconsin.gov/code/admin\\_code/nr/400/428/IV/22](https://docs.legis.wisconsin.gov/code/admin_code/nr/400/428/IV/22).

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State/Local	Regulation	Applicability (Size/Operating Hours if Given)	NOx Limit, ppmv at 15% Oxygen, unless otherwise stated
		25-50 MW	42
NJ <sup>387</sup>	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/MW/hr
	7:27-19.5(g)1 (Table 7)	HEDD Simple Cycle Gas Turbine (Power Generators) >15 MW	1.00 lb/MW/hr
DE <sup>388</sup>	Title 7, §1112.3.5 (Table 3-2)	Gas turbines >15 MMBtu/hr	42
IL (Chicago are and Metro East area) <sup>389</sup>	Title 35 Part 217, §217.388a.1.E.	Gas turbines >2.5 MW (4,694 bhp)	42
PA <sup>390</sup>	Ch. 129.97(g)(2)(iv)	Gas turbines > 6,000bhp	42
MD (certain counties) <sup>391</sup>	COMAR 26.11.09.08G(2)	Turbines with Capacity Factor >15%	42
VA (northern VA) <sup>392</sup>	9VAC5-40-7430 (9VAC5-40-7410 requires compliance with RACT)	Turbines >10 MMBtu/hr RACT Limit	42
OH (Cleveland 8 county area) <sup>393</sup>	3745-110-03(E)(1)	>3.5 MW	42
CT <sup>394</sup>	22a-174-22e	Simple Cycle combustion turbines>5 MMBtu/hr	55

<sup>387</sup> <https://www.nj.gov/dep/aqm/currentrules/Sub19.pdf>.

<sup>388</sup> <http://regulations.delaware.gov/AdminCode/title7/1000/1100/1112.shtml#TopOfPage>.

<sup>389</sup> <http://www.epa.state.il.us/air/rules/rice/217-subpart-g.pdf>.

<sup>390</sup> <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>.

<sup>391</sup> <http://mdrules.elaws.us/comar/26.11.09.08>.

<sup>392</sup> <https://law.lis.virginia.gov/admincode/title9/agency5/chapter40/section7430/>.

<sup>393</sup> [https://www.epa.ohio.gov/portals/27/regs/3745-110/3745-110-03\\_Final.pdf](https://www.epa.ohio.gov/portals/27/regs/3745-110/3745-110-03_Final.pdf).

<sup>394</sup> [https://www.ct.gov/deep/lib/deep/air/regulations/20160114\\_draft\\_sec22e\\_dec2015\(revised\).pdf](https://www.ct.gov/deep/lib/deep/air/regulations/20160114_draft_sec22e_dec2015(revised).pdf).

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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 <sup>395</sup>	310 CMR 7.19:(7)(a)1	>25 MMBtu/hr	65
NY <sup>396</sup>	6CRR-NY 227-2-4(e)	>10 MMBtu/hr	50
	6CRR-NY 227-3.4(a)(2) New Rule – compliance by 5/1/25 <sup>397</sup>	>15 MW	25
LA (Baton Rouge 5 Counties & Region of Influence) <sup>398</sup>	LAC 33.03, Chapter 22, §2201.D.1 (Table D-1A) <sup>399</sup>	≥5-10 MW	0.24 lb/MMBtu (65 ppmv)
		≥10 <MW	0.16 lb/MMBtu (43 ppmv)
MO (St Louis Area) <sup>400</sup>	10 CSR 10-5.510(3)(C)1	>10 MMBtu/hr	75
NC (Charlotte 6 County Area) <sup>401</sup>	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),

<sup>395</sup> <https://www.mass.gov/files/documents/2018/01/05/310cmr7.pdf>.

<sup>396</sup> [https://govt.westlaw.com/nycrr/Document/l4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=\(sc.Default\)](https://govt.westlaw.com/nycrr/Document/l4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default)).

<sup>397</sup> <https://www.dec.ny.gov/regulations/116185.html>.

<sup>398</sup> <https://www.deq.louisiana.gov/resources/category/regulations-lac-title-33>.

<sup>399</sup> These are emission factors, used in setting facility emission caps.

<sup>400</sup> <https://www.sos.mo.gov/cmsimages/adrules/csr/current/10csr/10c10-5.pdf>.

<sup>401</sup> <https://files.nc.gov/ncdeq/Air%20Quality/rules/rules/D1408.pdf>.

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which were adopted in 2007, also reflect application of SCR.<sup>402</sup> 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.<sup>403</sup> In addition, SCR was proposed to be installed at the Charles Compressor Station to be located in Maryland,<sup>404</sup> the Northampton Compressor Station to be located in North Carolina,<sup>405</sup> and the Marts Compressor Station to be located in West Virginia.<sup>406</sup> These draft and final permits provide additional evidence of states and companies finding SCR to not be a cost prohibitive control for a compressor station.

### E. SUMMARY – NOx CONTROLS FOR EXISTING NATURAL GAS-FIRED COMBUSTION TURBINES

The above analyses and state/local rule data demonstrates that numerous state and local air agencies have found water/steam injection, dry low NOx combustors, and SCR as cost effective controls for natural gas-fired combustion turbines, with costs ranging from \$128/ton to \$13,500/ton (1999\$) to

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<sup>402</sup> 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/priorito2008/08-08-07/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](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](http://www.valleyair.org/notices/Docs/2018/2-5-18_(C-1161601)/C-1161601.pdf).

<sup>403</sup> See January 9, 2019 Registration No. 21599, available at: [https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599\\_Signed\\_Permit.pdf](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>.

<sup>404</sup> See Draft Permit for Dominion Energy Cove Point – Charles Station, available at: <https://mde.maryland.gov/programs/Permits/AirManagementPermits/Documents/Dominion%20Charles%20Station%20draft%20optc%20conditions%20for%20compressor%20station2018.pdf>. It is not clear whether the final air permit has been issued yet for this facility.

<sup>405</sup> 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>.

<sup>406</sup> 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](https://dep.wv.gov/daq/Documents/July%202016%20Permits%20and%20Evals/041-00076_PERM_13-3271.pdf).

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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.<sup>407</sup> On the basis of pounds of VOC emission per heat input, EPA's AP-42 emission factors indicate that natural

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<sup>407</sup> 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>.



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gas-fired combustion turbines emit VOCs at a much lower rate than natural gas-fired RICE.<sup>408</sup> However, it must be noted that EPA's uncontrolled VOC emission factor has an emission factor rating of "D," which means tests are based on a generally unaccepted method and/or from a small number of facilities.<sup>409</sup> 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.<sup>410</sup> 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.<sup>411</sup>

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.<sup>412</sup> That said, the data collected by CARB in 2004 indicated 31 natural gas-fired combustion turbines using oxidation catalyst.<sup>413</sup>

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,<sup>414</sup> the Charles Compressor Station to be located in Maryland,<sup>415</sup> the Northampton Compressor Station to be located in North Carolina,<sup>416</sup> and the

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<sup>408</sup> 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.

<sup>409</sup> EPA AP-42, Introduction at 8-10.

<sup>410</sup> EPA, AP-42, Section 3.1, at 3.1-7.

<sup>411</sup> 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>.

<sup>412</sup> 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](http://www.regulations.gov).

<sup>413</sup> See CARB, Report to the Legislature, Gas-Fired Power Plant NOx Emission Controls and Related Environmental Impacts, May 2004, Appendix A.

<sup>414</sup> See January 9, 2019 Registration No. 21599, available at:

[https://www.deq.virginia.gov/Portals/0/DEQ/Air/BuckinghamCompressorStation/21599\\_Signed\\_Permit.pdf](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>.

<sup>415</sup> See Draft Permit for Dominion Energy Cove Point – Charles Station, available at: <https://mde.maryland.gov/programs/Permits/AirManagementPermits/Documents/Dominion%20Charles%20Station%20draft%20optc%20conditions%20for%20compressor%20station2018.pdf>. It is not clear whether the final air permit has been issued yet for this facility.

<sup>416</sup> 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>.

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Marts Compressor Station to be located in West Virginia.<sup>417</sup> These draft and final permits provide evidence of states and companies finding oxidation catalyst to be a cost effective control for a combustion turbine-powered compressor stations.

In summary, oxidation catalyst is an available air pollution control to reduce VOC emissions, as well as to reduce CO and HAP emissions, from natural gas-fired combustion turbines used in the oil and gas industry. States should consider oxidation catalyst when evaluating reasonable progress controls for natural gas-fired combustion turbines used in the oil and gas industry.

## VI. CONTROL OF EMISSIONS FROM DIESEL-FIRED RICE

Compression-ignited (*i.e.*, diesel-fired) RICE units are used in oil and gas exploration, production, and transmission sectors. These types of engines are generally used in the oil and gas industry for on-site power generation, as well as to power or to drive drill rigs, drive hydraulic fracturing pumps, and to power other pumping and compression applications. According to EPA's Alternative Control Techniques Document for Stationary Diesel Engines (2010), many of the "stationary" diesel RICE (meaning engines that are not mobile) are designated for continuous power use or used in standby power applications.<sup>418</sup> Company data suggests that those engines used as standby or emergency generators are generally less than 300 horsepower (hp), and diesel engines used for onsite power generation are typically greater than 300 hp although this is not a firm cutoff for standby diesel generator capacities.<sup>419</sup> The size of diesel engines for drilling rigs are likely much larger. A 2014 drilling rig emission inventory prepared for the state of Texas found that the mechanical drill rig engine sizes ranged from 430 hp for vertical wells less than 7,000 feet deep to 1,094 hp for vertical wells greater than 7,000 feet deep.<sup>420</sup> The study also found that, in Texas, mechanical rigs (diesel engines) were used for 96% of shallow vertical wells (< 7,000 feet) and 80% of deep vertical wells (> 7,000 feet), whereas 86% of horizontal wells are drilled by electric rigs.<sup>421</sup> According to the Texas drilling rig report, the trend in new drilling rigs is mostly electric rigs especially for larger drilling rigs, meaning that diesel-fired electrical generating sets are used to power the drilling engines (rather than diesel engines driving the drilling engines).<sup>422</sup> The electrical rigs typically have three large identical diesel generators, with one of the three units designated for standby

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<sup>417</sup> 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](https://dep.wv.gov/daq/Documents/July%202016%20Permits%20and%20Evals/041-00076_PERM_13-3271.pdf).

<sup>418</sup> EPA, Alternative Control Techniques Document: Stationary Diesel Engines, March 5, 2010, at 13, *available at*: [https://www.epa.gov/sites/production/files/2014-02/documents/3\\_2010\\_diesel\\_eng\\_alternativecontrol.pdf](https://www.epa.gov/sites/production/files/2014-02/documents/3_2010_diesel_eng_alternativecontrol.pdf) [hereinafter referred to as "EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE"]. Note, this ACT document expands upon the 1993 and 2000 ACT documents to address pollutants other than NOx.

<sup>419</sup> *Id.*

<sup>420</sup> Eastern Research Group, Inc., 2014 Statewide Drilling Rig Emissions Inventory with Updated Trends Inventories, Final Report, Prepared for Texas Commission on Environmental Quality, July 31, 2015, at 5-4, *available at*: [https://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5821552832FY1505-20150731-erg-drilling\\_rig\\_2014\\_inventory.pdf](https://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5821552832FY1505-20150731-erg-drilling_rig_2014_inventory.pdf).

<sup>421</sup> *Id.* at 4-1.

<sup>422</sup> *Id.* at 3-1.

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capacity.<sup>423</sup> The Texas inventory report indicates that the typical size of electric generators to power the electric rigs is 1,338 hp.<sup>424</sup> This report was specific to Texas, and other states may have a different mix of size engines used for different types and depth wells. Diesel engine pumps are also used in hydraulic fracturing (“fracking”). In 2016, fracking accounted for 69 percent of all new oil and gas wells, according to the Energy and Information Administration.<sup>425</sup> Diesel engines used to power hydraulic fracturing pumps are generally in the range of 1,000–1,500 hp, with 8 to 12 pumps necessary per well site (total of 20,000+ hp per well site).<sup>426</sup>

### A. CONTROL OPTIONS FOR DIESEL-FIRED RICE

Uncontrolled diesel RICE emit several pollutants that can contribute to regional haze, including NO<sub>x</sub>, particulate matter (PM), SO<sub>2</sub>, and VOCs. In some cases, the pollutant controls used for one pollutant can negatively or positively affect control of another pollutant. For example, combustion modifications employed to reduce NO<sub>x</sub> emissions will tend to increase PM emissions and VOC emissions, and vice versa. Controlling SO<sub>2</sub>, which is achieved by use of ultra-low sulfur diesel (ULSD) fuel, will reduce PM emissions as well. Thus, it can be important to evaluate pollution controls for diesel RICE holistically.

In its 1993 Alternative Control Techniques Document for Stationary RICE, EPA described NO<sub>x</sub> controls for diesel RICE, including combustion modifications (injection timing retard) and add-on controls (SCR), as follows:

Ignition timing retard delays initiation of combustion to later in the power cycle, which increases the volume of the combustion chamber and reduces the residence time of the combustion products. This increased volume and reduced residence time offers the potential for reduced NO<sub>x</sub> formation. ... Achievable NO<sub>x</sub> reductions using IR is engine-specific but generally ranges from 20 to 30 percent. Based on an average uncontrolled NO<sub>x</sub> emission level for diesel engines of 12.0 g/hp-hr (875 ppmv), the expected range of controlled NO<sub>x</sub> emissions is from 8.4 to 9.6 g/hp-hr (610 to 700 ppmv).<sup>427</sup>

Selective catalytic reduction applies to all CI engines and can be retrofit to existing installations except where physical space constraints may exist. ... Based on an average uncontrolled NO<sub>x</sub> emission level of 12.0 g/hp-hr (875 ppmv) for diesel engines, the expected range of controlled NO<sub>x</sub> emissions is from 1.2 to 2.4 g/hp-hr (90 to 175 ppmv). ... Limited emission test data show NO<sub>x</sub> reduction efficiencies of approximately 88 to 95 percent for existing installations, with ammonia slip levels ranging from 5 to 30 ppmv.<sup>428</sup>

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<sup>423</sup> *Id.*

<sup>424</sup> *Id.* at 5-4.

<sup>425</sup> <https://www.eia.gov/todayinenergy/detail.php?id=34732>.

<sup>426</sup> See, e.g., Solar Turbines, Turbomachinery Considerations in Drilling and Fracturing, Gas Electric Partnership 2013, at 7-8, available at: <http://www.gaselectricpartnership.com/hReinerKurzTurboMachinery.pdf>.

<sup>427</sup> EPA 1993 Alternative Control Techniques Document for RICE at 2-5 and 2-22.

<sup>428</sup> *Id.*

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Compression-ignition diesel-fueled engines operate lean, meaning there is excess air during combustion. And while the application of similar control techniques can differ for spark-ignition (gas-fired) and compression-ignition (diesel-fired) engines, according to EPA's 1993 Alternative Control Techniques Document for RICE, the: (1) process; (2) application considerations; (3) performance factors; and (4) potential NOx emissions reductions for SCR applications with diesel engines are similar to those for natural gas applications.<sup>429</sup>

In its 2010 Alternative Control Techniques Document for Stationary Diesel RICE, EPA discusses combining SCR with a particulate filter to reduce both NOx and PM emissions.<sup>430</sup> EPA describes diesel particulate filters (DPF) and catalyzed diesel particulate filters (CDPF) as follows:

[DPF and CDPF] emission control technologies are designed to remove PM from the diesel engine exhaust stream using a wall flow filter material in which the exhaust gas must pass through a ceramic wall. In addition to PM, the catalyst in the CDPF also reduces emissions of [Total Hydrocarbons (THC)] and CO. ... CARB reports PM emission reductions of 85 to 97 percent for various types of verified DPF or CDPFs. The EPA has verified DPF and CDPF systems that achieve up to 90 percent reduction. In addition to the PM reductions, the CDPF filter also reduces emissions of CO and THC by 90 percent but requires sufficient exhaust temperatures to facilitate regeneration by the catalyst. These reductions have been verified by both the CARB and EPA diesel control technology verification programs.<sup>431</sup>

CDPFs are thus a control device for PM and also for VOCs (THC) and CO.

Stationary diesel engine exhaust emissions include SO<sub>2</sub> due to sulfur in fuel, although a smaller percentage of the sulfur in fuel is converted to sulfates (particulate matter). At high temperatures, SO<sub>2</sub> can oxidize to form sulfates, contributing to further increases in PM emissions from engine exhaust. The use of ULSD fuel is essential in conjunction with exhaust treatment control technologies for reducing NOx and PM and is also, by itself, an effective and commonly applied way to reduce SO<sub>2</sub> emissions. Manufacturers require diesel engines equipped with CDPF to use ULSD fuel. EPA, in its 2010 Alternative Control Techniques Document for Stationary Diesel RICE, describes the use of ULSD as follows:

EPA [] finalized NSPS for stationary CI engines that require all new stationary diesel engines to use ULSD in 2010. This ULSD fuel enables the use of aftertreatment technologies for new and existing diesel engines and can also by itself reduce emissions of criteria pollutants. The use of ULSD reduces the formation of sulfur oxides and particulate sulfates from the diesel engine exhaust. The reductions in PM are expected to be approximately 5 to 30 percent depending on the sulfur content of the fuel that is replaced. ... It should be noted that ULSD is prevalent in the fuel pool today, including in some nonroad fuels that may not be labeled as such, and therefore may already be used in many stationary diesel engines.<sup>432</sup>

<sup>429</sup> EPA 1993 Alternative Control Techniques Document for RICE at 5-73.

<sup>430</sup> EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 35.

<sup>431</sup> *Id.* at 32 and 34.

<sup>432</sup> *Id.* at 47 and 48.

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In summary, while any one of these pollution controls can be used at a diesel RICE to control one pollutant, the co-benefits of using all of these controls together (ULSD, CDPF, and SCR) ensure the most effective control of NO<sub>x</sub>, PM, SO<sub>2</sub>, as well as CO and hazardous air pollutants.

### B. EXISTING FEDERAL AIR REGULATIONS FOR DIESEL-FIRED RICE

The diesel engines that power and/or drive drill rigs and wellsite pumping operations may be considered to be nonroad engines (as opposed to stationary engines), if they meet the regulatory criteria to be considered a nonroad engine. According to EPA, a diesel engine is considered a nonroad engine if it is self-propelled or propelled while performing its function or portable or transportable (if it has wheels, skids, carrying handles, a dolly, trailer, or platform), although a nonroad engine becomes a stationary engine if it stays in one location for more than 12 months (or for a full annual operating period of a seasonal source).<sup>433</sup> EPA distinguishes between nonroad diesel engines and stationary diesel engines because the Clean Air Act directs EPA to set emission standards for new nonroad engines and generally does not allow states to set emission standards for nonroad engines except through a specific process outlined in Section 209 of the Clean Air Act.<sup>434</sup>

EPA has established emission limitations to decrease air emissions from nonroad diesel engines using a tiered approach, with the most stringent Tier 4 standards currently in effect for engine manufacturers. See 40 C.F.R. §§89.112, 1039.101, 1039.102. These are emission standards that the manufacturers must meet in their production and sale of diesel engines and for which they demonstrate compliance on a fleetwide basis. There have been four tiers of emission standards applicable to diesel RICE, with Tier 1 standards applying to engines constructed beginning in 1996-1998, Tier 2 standards applying in 2000-2004, Tier 3 standards applying in 2006-2008, and Tier 4 standards applying in approximately 2014 and beyond.<sup>435</sup> The emission standards do not specify any one pollution control technology that needs to be installed to meet the emission limitations. Instead, the standards set limitations on emissions. Generally, the Tier 1, 2, and 3 emission standards were met with advanced engine design, while the Tier 4 emission standards reflect application of CDPF and SCR.<sup>436</sup> These controls reduce PM and NO<sub>x</sub> emissions by over 90% from diesel RICE. In addition, the Tier 4 standards mandate that ULSD be used in Tier 4 engines.<sup>437</sup> This requirement also ensures reduced SO<sub>2</sub> emissions from diesel engines.

EPA has also established NSPS for stationary diesel engines (i.e., those diesel RICE not considered to be nonroad engines) in 40 C.F.R. Part 60, Subpart IIII. Those emission standards generally require engine manufacturers to meet the same emission standards applicable to nonroad diesel engines for the size and model year, beginning in model year 2007, for non-emergency engines of displacement below 10

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<sup>433</sup> See EPA's "Understanding the Stationary Engines Rules," at <https://www.epa.gov/stationary-engines/understanding-stationary-engines-rules>. See also 40 C.F.R. §89.2.

<sup>434</sup> Section 209(e)(2) of the Clean Air Act.

<sup>435</sup> See, e.g., <https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100OA05.pdf>.

<sup>436</sup> See, e.g., EPA's Frequently Asked Questions from Owners and Operators of Nonroad Engines, Vehicles, and Equipment Certified to EPA Standards, available at <https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100U8YP.pdf>.

<sup>437</sup> 40 C.F.R. §1037.501(d)(2)

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liters per cylinder.<sup>438</sup> Non-emergency engines of displacement higher than 10 liters per cylinder must generally meet the applicable emission standards for marine engines in 40 C.F.R. §94.8 which vary based on year of manufacturer and cylinder displacement.<sup>439</sup> Emergency engines that operate in emergency situations (like standby generators) do not have to meet the Tier 4 standards and instead must meet less stringent standards.<sup>440</sup>

The NSPS have separate requirements for owners or operators of stationary diesel engines that are generally not as stringent either in date of applicability or emission limits as the limits applicable to engine manufacturers. As summarized by an industry website, owners or operators of engines of pre-2007 model year must meet Tier 1 nonroad engine standards for engines less than 10 liters per cylinder and must meet Tier 1 marine standards for engines greater than or equal to 10 but less than 30 liters per cylinder.<sup>441</sup> For engines of 2007 model year or later, owners or operators of engines less than 30 liters per cylinder must buy engines that are certified to meet the NSPS standards applicable to manufacturers.<sup>442</sup> Owners or operators of 2007 model or later year engines greater than or equal to 30 liters per cylinder displacement must meet emission standards that vary depending on the year the engine was installed, with installations after January 1, 2016 having to meet emission limits reflective of application of DPF and SCR.<sup>443</sup>

Significantly, the NSPS do not apply to owners or operators of stationary diesel RICE that have been modified or reconstructed, nor do they apply to engines that were removed from one location and reinstalled at a new location.<sup>444</sup> Further, while the NSPS required by October 1, 2010 the use of ULSD fuel for those engines subject to the NSPS that are below 30 liters per cylinder displacement, engines with greater than or equal to 30 liters displacement that are subject to the NSPS are allowed to use 1,000 ppm sulfur content fuel.<sup>445</sup>

EPA has also adopted a National Emission Standard for Hazardous Air Pollutants for Stationary RICE (RICE NESHAP) that requires emission limits on CO that effectively also limit hazardous air pollutants and VOCs.<sup>446</sup>

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<sup>438</sup> 40 C.F.R. §60.4201. Exceptions existing for engines operated in remote areas of Alaska and in marine offshore installations. 40 C.F.R. §60.4201(f).

<sup>439</sup> See 40 C.F.R. §60.4201.

<sup>440</sup> See 40 C.F.R. §60.4202.

<sup>441</sup> See [https://dieselnet.com/standards/us/stationary\\_nsps\\_ci.php](https://dieselnet.com/standards/us/stationary_nsps_ci.php). See also 40 C.F.R. §60.4204(a).

<sup>442</sup> 40 C.F.R. §60.4204(b).

<sup>443</sup> 40 C.F.R. §60.4204(c).

<sup>444</sup> 40 C.F.R. §60.4208(i).

<sup>445</sup> 40 C.F.R. §60.4207.

<sup>446</sup> 40 C.F.R. Part 63, Subpart ZZZZ.

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### C. POLLUTION CONTROL UPGRADES OR RETROFITS FOR DIESEL-FIRED RICE

#### 1. REPLACEMENT OF EXISTING DIESEL-FIRED RICE WITH TIER 4 ENGINES

Given that manufacturers are currently producing diesel RICE with integrated SCR and DPF to meet EPA's Tier 4 emission standards, it is likely the more cost effective option to consider the replacement of existing engines with new Tier 4 engines rather than requiring retrofitting of pollution controls. The emission reduction benefits from replacing existing diesel RICE with Tier 4 diesel RICE can be quite significant. It is difficult to directly compare the regulatory emission standards for Tiers 1–3 to the Tier 4 emission standards because the Tier 2 and 3 emission standards for NO<sub>x</sub> were based on the total of non-methane hydrocarbons (NMHC) plus NO<sub>x</sub>. EPA's 2010 Alternative Control Techniques Document for Stationary Diesel Engines summarized the NO<sub>x</sub> and PM emission rates for various size ranges and for the Tiers 1, 2, and 3, based on EPA's Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling – Compression Ignition (EPA 420-P-04-009), April 2004.<sup>447</sup> In the table below, we compare "Tier 0" (pre-1998) and EPA's Tier 1, 2, and 3 emission factors to the emission standards of the Tier 4 standards promulgated by EPA for specific size engines that fall within the various size ranges of applicability for EPA's nonroad emission standards.<sup>448</sup> The table below shows the NO<sub>x</sub> and PM emission rates expected for each of the four Tiers of diesel RICE rules, as well as NO<sub>x</sub> and PM emissions from diesel RICE manufactured before the EPA emission standards applied (i.e., pre-1998 or "Tier 0").

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<sup>447</sup> See EPA's Alternative Control Techniques Guideline Stationary Diesel Engines, March 5, 2010 at 58 and 61 (Tables 5-2 and 5-3).

<sup>448</sup> See May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1, *available at*: <https://nepis.epa.gov/Exe/ZyPDF.cgi/P10001RN.PDF?Dockey=P10001RN.PDF>.

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**Table 30. Comparison of NOx and PM Emission Rates for Various Engine Sizes and Tier Engines.** <sup>449</sup>

ENGINE SIZE, HP	TIER ENGINE	NOX EMISSIONS, G/HP-HR	PM EMISSIONS, G/HP-HR
75	0	6.89	0.72
	1	5.58	0.47
	2	4.72	0.24
	3	3.00	0.30
	4	3.50 <sup>450</sup>	0.02
174	0	8.39	0.40
	1	5.58	0.25
	2	4.00	0.13
	3	2.50	0.15
	4	0.30	0.01
600	0	8.39	0.40
	1	5.58	0.22
	2	4.10	0.13
	3	2.50	0.15
	4	0.30	0.01
750	0	8.39	0.40
	1	5.58	0.22
	2	4.10	0.13
	3	2.60	0.15
	4	2.60	0.075
1500 GEN SET <sup>451</sup>	0	8.9	0.40
	1	5.58	0.22
	2	4.10	0.13
	3	2.50	0.15
	4	0.5	0.02

As shown in the above table, the Tier 4 NOx limits reflect significant NOx reductions from each prior Tier engine for some engine sizes, except the smallest engines and the non-electrical generating set engines that are greater than 750 hp in size for which there is no difference between Tier 3 and Tier 4 NOx emissions. The PM emissions, on the other hand, get increasingly more stringent with each Tier engine.

To determine the cost effectiveness of replacing an existing engine with a Tier 4 engine, one needs to know the costs of a Tier 4 engine. A 2010 analysis done by CARB collected cost data from equipment manufacturers for Tier 4 compliant Generator-Set Engines (or “Gen Sets”) and determined the average cost per horsepower for a Tier 4 engine equipped with DPF and SCR.<sup>452</sup> Although this CARB analysis was

<sup>449</sup> Data from EPA's Alternative Control Techniques Guideline Stationary Diesel Engines, March 5, 2010 at 58 and 61 (Tables 5-2 and 5-3), and from May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1.

<sup>450</sup> This limit applies to NMHC plus NOx. See

<https://nepis.epa.gov/Exe/ZyPDF.cgi/P10001RN.PDF?DockKey=P10001RN.PDF>.

<sup>451</sup> Generator-set engines or “Gen Sets.” These engines are used to operate an electrical generator or an alternator to produce electric power for other applications.

<sup>452</sup> CARB, Analysis of the Technical Feasibility and Costs of After-Treatment Controls on New Emergency Standby Engines at B-11, available at: <https://ww3.arb.ca.gov/regact/2010/atcm2010/atcmappb.pdf>.



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for emergency standby engines, the cost data can provide a reasonable estimate of the capital costs to purchase diesel RICE meeting Tier 4 standards. This data was collected in 2010, and thus presumably reflects a 2010 \$ cost basis.<sup>453</sup> CARB provided an average cost per horsepower of Tier 4 engines installed with DPF and SCR as follows:

**Table 31. Average Cost Per Horsepower for Diesel RICE Meeting Tier 4 Final Requirements<sup>454</sup>**

HP RANGE	\$/HP FOR NEW ENGINES MEETING TIER 4 FINAL STANDARDS (2010 \$)
50-174	\$250
175-749	\$184
750-1,206	\$160
1,207-2,000	\$155
>2,000	\$125

With this average cost per horsepower data, the average cost effectiveness of replacing an older engine with a Tier 4-compliance diesel engine can be estimated. For the purpose of this cost effectiveness analysis, a 10-year useful life was assumed. The useful life for the emissions warranty guarantee period required in EPA’s nonroad diesel engine rules is only 10 years.<sup>455</sup> While we contend that it is likely a RICE unit including such an engine with SCR installed, can have a useful life of 20 years or more, it is not as clear that the diesel particulate filter would have a life of more than 10 years.<sup>456</sup> Thus, for the purpose of this cost effectiveness analysis, a 10 year life of the new Tier 4 engines was assumed. A 5.5% interest rate was also assumed to be consistent with EPA’s Control Cost Manual which recommends use of the bank prime interest rate.<sup>457</sup> The bank prime rate fluctuates over time, and the highest it has been in the past 5 years is 5.5%.<sup>458</sup> Reductions in NOx and PM emissions with the replacement of existing diesel RICE with Tier 4 engines were based on the emission factors reflected in Table 30 above. Given that the Tier 4 engines have significantly lower emissions of both NOx and PM, the total of NOx plus PM emissions reduced were considered in calculating cost effectiveness. The table below provides the cost effectiveness of replacing either a pre-1998 or a Tier 1, 2, or 3 engine with a Tier 4 engine. Calculations were done assuming that the engines operate at two different levels: 1,000 hours per year and 4,000 hours per year. EPA assumed 1,000 hours per year in cost analyses done for stationary diesel engines in its 2010 Control Techniques Document for Stationary Diesel Engines.<sup>459</sup> However, EPA also presented information from other sources indicating the average operating hours of diesel RICE are as high as 3,790 hours per year.<sup>460</sup> Thus, a 4,000 hour operating level was assumed to capture the upper end capacity factor of diesel RICE.

<sup>453</sup> *Id.* at B-11 and B-20.

<sup>454</sup> *Id.*, Table B-6.

<sup>455</sup> See 40 CFR 89.014.

<sup>456</sup> See, e.g., EPA Technical Bulletin, Diesel Particulate Filter General Information, *available at*: <https://www.epa.gov/sites/production/files/2016-03/documents/420f10029.pdf>.

<sup>457</sup> U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.

<sup>458</sup> See, e.g., <https://fred.stlouisfed.org/series/DPRIME>.

<sup>459</sup> See EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 56.

<sup>460</sup> *Id.* at 56 (Table 5-1).

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**Table 32. COST EFFECTIVENESS OF REPLACING EXISTING DIESEL RICE WITH TIER 4-COMPLIANT DIESEL RICE (2010\$).**

ENGINE SIZE, HP	ANNUALIZED COST OF NEW ENGINE <sup>461</sup>	ENGINE REPLACED WITH TIER 4	COST EFFECTIVENESS OF REPLACEMENT, 1,000 OPERATING HOURS/YR, \$/TON of NOx+PM REMOVED (2010\$)	COST EFFECTIVENESS OF REPLACEMENT, 4,000 OPERATING HOURS/YR, \$/TON of NOx+PM REMOVED (2010\$)
75	\$2,488	Tier 0	\$6,544/TON	\$1,636/TON
		Tier 1	\$9,921/TON	\$2,480/TON
		Tier 2	\$15,517/TON	\$3,879/TON
		Tier 3	\$107,526/TON	\$26,882/TON
174	\$4,247	Tier 0	\$2,610/TON	\$653/TON
		Tier 1	\$4,011/TON	\$1,003/TON
		Tier 2	\$5,794/TON	\$1,448/TON
		Tier 3	\$9,466/TON	\$2,367/TON
600	\$14,647	Tier 0	\$2,610/TON	\$653/TON
		Tier 1	\$4,034/TON	\$1,009/TON
		Tier 2	\$5,646/TON	\$1,412/TON
		Tier 3	\$9,466/TON	\$2,367/TON
750	\$15,920	Tier 0	\$3,147/TON	\$787/TON
		Tier 1	\$6,164/TON	\$1,541/TON
		Tier 2	\$12,368/TON	\$3,092/TON
		Tier 3	\$256,280/TON	\$64,070/TON
1500 GEN SETS <sup>462</sup>	\$30,845	Tier 0	\$2,255/TON	\$564/TON
		Tier 1	\$3,534/TON	\$883/TON
		Tier 2	\$5,026/TON	\$1,256/TON
		Tier 3	\$8,760/TON	\$2,190/TON

Because the NOx emission rates of the various Tier 1–4 standards did not always decrease to the same extent for the smallest and the mid-size to large (non-Gen Set) engines, the cost effectiveness of replacing an existing engine with a Tier 4 engine of 75 hp and of 750 hp increases significantly between installing a Tier 4 engine to replace a Tier 0, 1, or 2 engine as compared to a Tier 3 engine. Also, as would be expected, it is generally more cost effective to replace an engine that operates 4,000 hours per year compared to one that operates 1,000 hours per year. In any event, as Table 32 demonstrates, it should at least be considered cost effective to replace a Tier 0 or Tier 1 engine with a Tier 4 engine of any size or operating hours. For engines in the range of 174 hp to less than 750 hp that operate 4,000 hours or more per year, it is also clearly cost effective to replace any tier engine with a Tier 4 engine, as it also is cost effective for large generator set engines.

<sup>461</sup> Based on the costs per horsepower given in Table 31 above and a capital recovery factor based on a 10-year life and a 5.5% interest rate of 0.132668.

<sup>462</sup> Generator sets > 1,200 hp have more stringent Tier 4 emission standards than other engines that are greater than 750 hp. See May 2004, EPA Regulatory Announcement, Clean Air Nonroad Diesel Rule, Table 1.

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Although the above review focused on the cost effectiveness for the combined reductions of NO<sub>x</sub> plus PM, it is important to note that the EPA nonroad engine requirements also set emission limits on THC. Specifically, the Tier 4 standards set a THC emission limit that reflects an 87% reduction in THC compared to pre-1998 (Tier 0 levels). Further, only ULSD is to be used on Tier 4 engines. That is not only a legal requirement but, as discussed above, it is technically required by the manufacturer to ensure that the CDPF works effectively. The use of ULSD which is 15 ppm sulfur, compared to diesel fuel which may be 500 ppm sulfur, reflects a 97% reduction in SO<sub>2</sub> emissions from diesel RICE. The increased costs for using ULSD are estimated to be \$0.07 more per gallon, but the costs would be reduced to \$0.04 per gallon due to anticipated savings because of decreased RICE maintenance with the use of low sulfur fuel.<sup>463</sup> Some states may already mandate the use of ULSD or it could be that ULSD is the only fuel available in some areas, so installation of a Tier 4 engine may not necessarily reduce SO<sub>2</sub> emissions for all sources.

In terms of the non-air quality environmental and energy impacts associated with the replacement of an older engine with a Tier 4 engine, the impacts associated with the pollution controls could include increased fuel consumption due to reduced efficiency/parasitic load of SCR and CDPF and/or result in reduced power output. However, improvements in combustion efficiency that have been required and engineered into these newer engines also mean fuel savings that will make up for any parasitic loads, particularly for Tier 0 or Tier 1 engines replaced with Tier 4 engines. Other environmental impacts include solid waste disposal issues from spent catalysts. Further, the Tier 4 engines will require operator training and may result in increased maintenance, although the switch from higher sulfur diesel to ULSD which is mandated for use in Tier 4 engines will result in decreased maintenance. One likely benefit regarding maintenance associated with these controls when purchasing an engine with the NO<sub>x</sub> and PM controls built into the design as one package (as compared to retrofitting an existing engine) is that the manufacturers will have a standard set of operating and maintenance procedures for each engine, whereas for a retrofit of SCR and/or CDPF to an existing diesel RICE, the operating and maintenance procedures will presumably need to be tailored to the specific make, model, and condition of the existing engine.

There are also other environmental benefits of replacing existing diesel engines with Tier 4 engines, particularly due to effects that increased engine efficiency and the use of a CDPF will have on reducing black carbon emissions from diesel RICE. Black carbon is very effective at absorbing solar energy. The black carbon particles in the atmosphere absorb solar energy and thus can warm the planet, although black carbon is considered a short-lived climate change pollutant.<sup>464</sup> And when the black carbon particles precipitate to surfaces of snow and ice, it reduces the reflecting power of the snow or ice which results in increased melting of snow and ice. The increased melting of the snow and ice results in a feedback loop with more land exposed to absorb, rather than reflect, solar energy, melting more snow and ice as well as permafrost that releases carbon trapped in the soils which further adds to climate change pollution.<sup>465</sup> Thus, the reduction in black carbon emissions by switching older diesel RICE with Tier 4 engines could have climate change benefits as well as visibility benefits.

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<sup>463</sup> See <https://dieselnet.com/standards/us/nonroad.php>.

<sup>464</sup> See <https://oehha.ca.gov/epic/climate-change-drivers/atmospheric-black-carbon-concentrations>; see also Cho, Renee, The Damaging Effects of Black Carbon, March 22, 2016, Earth Institute, Columbia University, available at: <https://blogs.ei.columbia.edu/2016/03/22/the-damaging-effects-of-black-carbon/>.

<sup>465</sup> *Id.* See also <https://scied.ucar.edu/shortcontent/melting-ice-and-climate-change>.

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Given that manufactures were required to exclusively produce Tier 4 nonroad diesel engines by January 1, 2015, the Tier 4 engines should be readily available for purchase and installation, or be available in fairly short order. Thus, the replacement of an existing diesel RICE with a Tier 4 diesel RICE should presumably be able to be completed within six months to one year.

When EPA adopted the nonroad diesel engine emission standards, EPA envisioned that the nonroad diesel engine fleet would be comprised entirely of Tier 4 engines by 2030.<sup>466</sup> It is not clear whether the diesel RICE used in the oil and gas industry are on track to be operating on Tier 4 engines by 2030. As part of the process of evaluating controls to achieve reasonable progress towards the national visibility goal, States should evaluate the age and EPA emission compliance status (i.e., Tier) of existing diesel RICE operating within the oil and gas industry in the state. If states do not already collect such information, states should gather this information through required source inventory and/or source registration or licensure requirements.

It is clear that requiring replacement of existing diesel RICE with Tier 4 RICE engines is a cost effective control to reduce NO<sub>x</sub> and PM along with VOCs and SO<sub>2</sub> for many size engines in a range of operating hours. Requiring the replacement of existing diesel RICE with new Tier 4 engines along with requiring the use of ULSD fuel is the most readily implementable approach to reducing visibility-impairing emissions from diesel RICE.

It would be most effective to require use of Tier 4-compliant generator sets in conjunction with electric motors for all drilling operations, because large Gen Sets (which would be necessary to power electric drill rigs) are subject to much more stringent NO<sub>x</sub> limits than large diesel RICE (i.e., 0.5 g/hp-hr is the NO<sub>x</sub> limit for Tier 4 engines, compared to the 2.60 g/hp-hr NO<sub>x</sub> limit for large diesel RICE, as shown in Table 30 above). Indeed, the Superintendent of Carlsbad National Park has requested this approach as a mitigation measure for the Chevron U.S.A. Hayhurst Master Development Plan for which the western boundary of the project area was to be located only 17 kilometers from Carlsbad National Park in New Mexico. Specifically, the National Park Service stated that “[i]f this option were implemented, engines would meet the 0.5 g NO<sub>x</sub>/hp-hr [limit] and would reduce drilling and completion emissions by 90%.”<sup>467</sup>

In summary, for stationary diesel RICE units, states should require the replacement of older existing engines with Tier 4 engines. For those diesel RICE that are considered nonroad engines, states should consider adopting emission requirements for diesel nonroad engines if California has adopted emission standards that have been approved by EPA under Section 209(e)(2) of the Clean Air Act, where the state adopts the same standards. Alternatively, a state can incentivize the replacement of existing nonroad engines with Tier 4 engines. Further, the state should otherwise encourage use of electric engines for drill rigs and the use of Tier 4 Gen Sets to power those electric engines, as that will result in the greatest reduction in NO<sub>x</sub> due to the lower emission limits that apply to Tier 4 Generator Set engines. States should evaluate all available options to, at the minimum, encourage replacement of older existing nonroad engines with Tier 4 engines.

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<sup>466</sup> See, e.g., EPA Progress Report on EPA’s Nonroad Mobile Source Emissions Reductions Strategies, September 27, 2006, at 8, available at: <https://www.epa.gov/sites/production/files/2015-11/documents/20060927-2006-p-00039.pdf>.

<sup>467</sup> See August 29, 2016 Memorandum from Doug Neighbor, Superintendent, Carlsbad Caverns National Park, to Paul Murphy, Project Lead, Bureau of Land Management, Carlsbad Field Office, at 6.

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### 2. REPLACEMENT OF EXISTING DIESEL-FIRED RICE WITH NATURAL GAS-FIRED RICE

A second option for reducing emissions from diesel RICE is to replace the engines with natural gas-fired or dual-fuel RICE. This was another mitigation measure recommended by the National Park Service to the Bureau of Land Management for the Chevron U.S.A. Hayhurst Master Development Plan. Specifically, the National Park Service stated: “[b]oth natural gas-fired and dual-fuel engines have proven to be feasible, cost effective options for drilling operations in various basins throughout the United States and Canada [fn omitted].”<sup>468</sup> The National Park Service gave numerous examples of companies employing natural gas-fired or dual-fuel drill rig engines, including “EQT, Apache Corporation, Chesapeake Energy, Statoil, Encana Corporation, Cabot Oil and Gas, Antero Resources, CONSOL Energy and Seneca Resources.”<sup>469</sup> The National Park Service specifically highlighted Chesapeake Energy’s move to “transition all of its hydraulic fracturing equipment to [liquefied natural gas].”<sup>470</sup>

The Four Corners Air Quality Task Force (4CAQTF) also evaluated this option of using natural gas-fired engines on the drill rigs in the Four Corners region.<sup>471</sup> The 4CAQTF found that this switch from diesel RICE to lean burn RICE engines would result in approximately a 91% reduction in NOx from use of Tier 0 diesel engines and approximately an 85% reduction in NOx from use of Tier 1 diesel engines, but this was based on an assumed NOx emission rate from lean burn natural gas-fired RICE of 2 to 3 g/hp-hr.<sup>472</sup> As discussed in Section II.D. and E. of this report, use of LEC or SCR at lean burn engines is cost effective for lean-burn RICE and could achieve NOx emission rates of no higher than 2 g/hp-hr and more likely 1 g/hp-hr or even lower. Use of natural gas-fired RICE instead of diesel RICE would also significantly reduce SO<sub>2</sub> and PM emissions. The 4CAQTF report found that use of natural gas-fired RICE may be less expensive than diesel RICE if natural gas is located within close proximity and able to be piped to the natural gas-fired RICE.<sup>473</sup> Diesel fuel generally needs to be hauled to the drill rig, thus replacement of diesel RICE with natural gas-fired RICE would also reduce mobile source tailpipe and fugitive emissions associated with transporting the diesel fuel. The 4CAQTF report gave one example of a natural gas-fired drill rig being utilized in the Jonah Field in Wyoming to indicate that the use of natural gas-fired drill rigs is a technically feasible option,<sup>474</sup> which is clearly the case given the number of companies cited by the National Park Service that are employing natural gas-fired or dual-fuel drill rig engines.<sup>475</sup> The 4CAQTF indicated a capital cost of up to \$1.2 million dollars per rig for the retrofit.<sup>476</sup> Some of the negative impacts included that the use of natural gas-fired RICE would increase carbon monoxide emissions by

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<sup>468</sup> *Id.* at 7.

<sup>469</sup> *Id.*

<sup>470</sup> *Id.*

<sup>471</sup> See Four Corners Air Quality Task Force, Report of Mitigation Options, November 1, 2007, at 61, *available at*: [https://www.env.nm.gov/wp-content/uploads/sites/2/2016/11/4CAQTF\\_Report\\_FINAL.pdf](https://www.env.nm.gov/wp-content/uploads/sites/2/2016/11/4CAQTF_Report_FINAL.pdf).

<sup>472</sup> *Id.*

<sup>473</sup> *Id.*

<sup>474</sup> *Id.* at 62.

<sup>475</sup> See August 29, 2016 Memorandum from Doug Neighbor, Superintendent, Carlsbad Caverns National Park, to Paul Murphy, Project Lead, Bureau of Land Management, Carlsbad Field Office, at 7.

<sup>476</sup> *Id.*

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approximately 175%, and also that there could be increased land disturbance regarding the installation of natural gas pipelines for delivery of fuel.<sup>477</sup>

In summary, replacement of diesel RICE with natural gas-fired RICE is a viable control option for addressing the visibility-impairing emissions from diesel RICE that states should consider in evaluating reasonable progress measures for diesel RICE units.

### 3. RETROFIT OF DIESEL-FIRED RICE WITH AIR POLLUTION CONTROLS

Another option to control emissions from stationary diesel RICE is to require retrofits of specific pollution controls. Provided below are cost effectiveness analyses for SCR retrofits and for DPF retrofits to diesel RICE.

#### *a) RETROFITTING SCR TO EXISTING DIESEL-FIRED RICE TO REDUCE NO<sub>x</sub>*

EPA's 2010 Alternative Control Techniques Document for Stationary Diesel RICE presented control costs for SCR and for CDPF retrofits at diesel RICE units. For SCR, EPA estimated capital costs at \$98 per hp, based on industry data, and this included costs for the catalyst, reactor housing and ductwork, ammonia injection system, controls, and engineering and installation of the equipment.<sup>478</sup> EPA estimated annualized costs for SCR at \$40 per hp, based on annualized capital costs and costs for operating/supervisory labor, maintenance, ammonia, steam diluent, and fuel penalty calculated using the EPA Control Cost Manual and based on 1,000 hours of operation per year.<sup>479</sup>

EPA's cost data for the 2010 Alternative Control Techniques document for Stationary Diesel RICE assume 90 percent reduction of NO<sub>x</sub> emissions from SCR, which should be readily achievable.<sup>480</sup> EPA estimates uncontrolled NO<sub>x</sub> emissions based on emission factors from modeling for the different tiers of EPA's exhaust emission standards for nonroad engines: (1) Tier 0 Standards (pre-1998); (2) Tier 1 Standards (1998-2003); (3) Tier 2 Standards (2004-2007); and Tier 3 Standards (2006-2010). As discussed above, the Tier 4 standards reflect the NO<sub>x</sub> control levels achievable with SCR, and thus it would not make sense for EPA to evaluate SCR retrofits for a Tier 4 engine.

The following table shows the cost effectiveness, based on EPA's cost data, of retrofitting SCR to an uncontrolled stationary diesel RICE and to a Tier 1, 2, or 3 diesel RICE operating 1,000 hours per year and 4,000 hours per year using EPA uncontrolled NO<sub>x</sub> emissions estimates. EPA assumed 1,000 hours per year in cost analyses done for stationary diesel engines in its 2010 Control Techniques Document for Stationary Diesel Engines.<sup>481</sup> However, EPA also presented information from other sources indicating the average operating hours of diesel RICE as high as 3,790 hours per year.<sup>482</sup> Thus, a 4,000 hour operating level was assumed to capture the upper end capacity factor of diesel RICE. To estimate operating costs for operating at 4,000 hours per year, EPA's annual cost estimates for an engine

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<sup>477</sup> *Id.* at 61-62.

<sup>478</sup> EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 57.

<sup>479</sup> *Id.*

<sup>480</sup> *Id.*

<sup>481</sup> See EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 56.

<sup>482</sup> *Id.* at 56 (Table 5-1).

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operating 1,000 hours per year were multiplied by a factor of four to estimate potential annual costs reflective of engines operating closer to 4,000 hours per year. For the cost effectiveness analysis presented herein, the SCR system was assumed to have a life of 20 years. EPA states that SCR at boilers, refineries, industrial boilers, etc. have a useful life of 20-30 years.<sup>483</sup> To be consistent with EPA's statements on SCR and also considering the useful life of diesel RICE, this analysis will assume a 20-year life of the SCR. A 5.5% interest rate was used to be consistent with EPA's Control Cost Manual which recommends use of the bank prime interest rate.<sup>484</sup>

**Table 33. Cost Effectiveness to Reduce NOx Emissions by 90% from Stationary Diesel RICE with SCR Operating 1,000 Hours per Year and 4,000 Hours per Year<sup>485</sup>**

ENGINE SIZE, hp	ANNUALIZED COSTS OF SCR, 2005\$	EMISSIONS STANDARD	COST EFFECTIVENESS OF SCR, 1,000 HOURS PER YEAR, 2005\$	COST EFFECTIVENESS OF SCR, 4,000 HOURS PER YEAR, 2005\$
75	\$2,808	TIER 0	\$5,474/ton	\$4,575/ton
		TIER 1	\$6,739/ton	\$5,632/ton
		TIER 2	\$8,021/ton	\$6,703/ton
		TIER 3	\$12,581/ton	\$10,514/ton
238	\$8,911	TIER 0	\$4,500/ton	\$3,761/ton
		TIER 1	\$6,781/ton	\$5,667/ton
		TIER 2	\$9,430/ton	\$7,881/ton
		TIER 3	\$15,093/ton	\$12,614/ton
675	\$25,272	TIER 0	\$4,500/ton	\$3,761/ton
		TIER 1	\$6,485/ton	\$5,420/ton
		TIER 2	\$9,207/ton	\$7,694/ton
		TIER 3	\$15,097/ton	\$12,617/ton
1,000	\$37,441	TIER 0	\$4,497/ton	\$3,759/ton
		TIER 1	\$6,500/ton	\$5,432/ton
		TIER 2	\$9,204/ton	\$7,692/ton
		TIER 3	\$15,073/ton	\$12,597/ton

<sup>483</sup> See EPA's Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80.

<sup>484</sup> U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.

<sup>485</sup> See EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 58, Table 5-2. Annualized costs of control were based on a 20-year life and a 5.5% interest rate. NOx emission reductions are based on 90% NOx removal efficiency, with uncontrolled emissions based on EPA estimates (EPA-420/P-04-09, 2004).

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Lower cost data were reported by EPA in its 2000 Updated Information on NOx Emissions and Control Techniques for what it referred to then as 'modern SCR': "The vendor carried out a similar analysis for a 1,000 bhp diesel engine. For an engine operating 200 hours per year, the cost effectiveness was calculated at almost \$4,000 per ton. For an engine operating 2,000 hours per year, the cost effectiveness dropped to less than \$900 per ton."<sup>486</sup>

In its 1993 Alternative Control Techniques Document for RICE, EPA included a cost effectiveness analysis for diesel-fueled RICE with SCR operating 8,000 hours per year with costs as low as \$690/ton for the largest engine sizes (4,000-8,000 hp). EPA noted costs of \$1,000/ton or less for engines larger than 3,200 hp and costs of \$3,000/ton or less for engines larger than 750 hp.<sup>487</sup>

It is clearly cost effective to retrofit SCR to diesel RICE units that emit NOx at levels similar to the older tier nonroad engines (e.g., Tiers 0 or 1) even at low levels of operating hours per year. And, diesel RICE used in the oil and gas industry have been retrofitted with SCR to reduce NOx. For example, the state of Wyoming and the Bureau of Land Management coordinated with companies drilling in the Pinedale Anticline in western Wyoming to reduce NOx emissions from all drill rigs and, as a result, Shell Exploration and Production Company retrofitted 21 drill rigs with SCRs that have achieved 91-99% reduction in NOx emissions with low levels of ammonia slip (averaging 2-3 ppm).<sup>488</sup> There are several examples of successful SCR retrofits to diesel RICE, including for stationary diesel electrical generating sets and backup generators.<sup>489</sup>

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<sup>486</sup> EPA 2000 Updated Information on NOx Emissions and Control Techniques at 5-13 referencing the following document: Manufacturers of Emission Controls Association. *Urea SCR for Stationary IC Engines*. Slides from a presentation to the NESCAUM Stationary Source and Permits Committee. October 6, 1999.

<sup>487</sup> See EPA's 1993 Alternative Control Techniques Document for RICE at 2-38 and Table 2-14 at 2-42.

<sup>488</sup> See Manufacturers of Emission Controls Association, Case Studies of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 7 (Section 2.4), available at: [http://www.meca.org/galleries/files/Stationary\\_Engine\\_Diesel\\_Retrofit\\_Case\\_Studies\\_1109final.pdf](http://www.meca.org/galleries/files/Stationary_Engine_Diesel_Retrofit_Case_Studies_1109final.pdf). See also Johnson Matthey, New system helps control NOx for Shell drill rigs, Pinedale Online, October 28, 2008, available at: <http://www.pinedaleonline.com/news/2008/10/Newsystemhelpscontro.htm>; and Johnson Matthey Catalysts, Application Fact Sheet, Case No. 801: Controlling NOx from Gas Drilling Rig Engines with Johnson Matthey's Urea SCR System, available at: [https://www.jmsec.com/fileadmin/user\\_upload/pdf/application\\_fact\\_sheets/engines/application\\_fact\\_sheet\\_801\\_-\\_shell\\_gas\\_drill\\_rig.pdf](https://www.jmsec.com/fileadmin/user_upload/pdf/application_fact_sheets/engines/application_fact_sheet_801_-_shell_gas_drill_rig.pdf).

<sup>489</sup> See Manufacturers of Emission Controls Association, Case Studies of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 14, 5-7 and 12.



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The environmental and energy impacts of SCR systems for diesel RICE include the following:

- 0.5 percent increase in fuel consumption for SCR and associated air emissions increases<sup>490</sup>
- 1 to 2 percent reduction in power output for SCR<sup>491</sup>
- Increased solid waste disposal from spent catalysts<sup>492</sup>
- 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.<sup>493</sup> If urea or aqueous ammonia is used as the reagent, the hazards from the use of pressurized anhydrous ammonia do not apply. It is likely that urea is the most common reagent used in SCR for diesel RICE

SCR technology is widely used at many industrial sources. There are typically not overarching non-air quality or energy concerns with this technology, and many of the concerns are addressed in the cost analysis.

In terms of length of time to install SCR, EPA has estimated that it takes 28-58 weeks to install SCR at a diesel-fired (lean-burn) RICE unit.<sup>494</sup>

### *b) RETROFITTING CDPF TO DIESEL-FIRED RICE TO REDUCE PM AND VOCS*

For CDPF, EPA estimated capital and annual costs in its 2010 Alternative Control Techniques Document for Stationary Diesel RICE based on cost equations developed for the RICE NESHAP. EPA's analysis was based on 2008 cost data from stationary diesel RICE retrofits. The following linear equation for annual cost includes annual operating and maintenance costs plus annualized capital costs based on a 7% interest rate and 10-year life of controls:

$$\text{CDPF Annual Cost} = 11.6 \times \text{ENGINE HP} + 1,414 \text{ (2008\$)}$$

The capital cost equation for retrofitting a CDPF on a diesel engine was determined by EPA to be:

$$\text{CDPF Capital Cost} = 63.4 \times \text{ENGINE HP} + 5,699 \text{ (2008\$)}$$

These relationships are derived from a data set that includes engines ranging from 40–1,400 hp.<sup>495</sup> EPA's cost estimates are based on 1,000 hours of operation per year.<sup>496</sup>

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<sup>490</sup> See EPA 1993 Alternative Control Techniques Document for RICE, 2-23 (Table 2-11).

<sup>491</sup> *Id.* at 2-23 (Table 2-11).

<sup>492</sup> Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6<sup>th</sup> ed., EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP).

<sup>493</sup> 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.

<sup>494</sup> 2016 EPA CSAPR TSD for Non-EGU NO<sub>x</sub> Emissions Controls at 15.

<sup>495</sup> EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 59.

<sup>496</sup> EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 61.

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EPA's cost data for the 2010 Alternative Control Techniques document for Stationary Diesel RICE assume 90 percent reduction of PM emissions from CDPF.<sup>497</sup> EPA estimates uncontrolled PM emissions based on emission factors from nonroad engine modeling for the different tiers of EPA's exhaust emission standards for nonroad engines: (1) Tier 0 Standards (pre-1998); (2) Tier 1 Standards (1998-2003); (3) Tier 2 Standards (2004-2007); and Tier 3 Standards (2006-2010). In 2004, EPA adopted Tier 4 Standards, which were to be phased-in from 2008 to 2015. The Tier 4 Standards require 90 percent reduction of PM and NOx emissions. According to EPA, "[t]hese emission reductions can be achieved through the use of control technologies, including advanced exhaust gas aftertreatment, similar to those required by the 2007-2010 standards for highway engines."<sup>498</sup>

The following table shows the results of a cost analysis, based on EPA's cost data, of retrofitting CDPF to an uncontrolled stationary diesel RICE operating 1,000 hours per year and 4,000 hours per year using EPA uncontrolled PM emissions estimates. For this cost analysis of CDPF, a 10-year life and 5.5% interest rate. As discussed above, while we contend that it is likely a RICE unit can have a useful life of 20 years, it is not as clear that the diesel particulate filter would have a life of more than 10 years.<sup>499</sup> Therefore, a useful life of a CDPF retrofit was assumed to be 10 years in determining annualized costs of CDPF. A 5.5% interest rate was also assumed to be consistent with EPA's Control Cost Manual which recommends use of the bank prime interest rate.<sup>500</sup> To estimate annual operating costs for operation of CDPF at 4,000 hours per year, EPA's annual cost estimates which were based on 1,000 operating hours per year were multiplied by a factor of four.

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<sup>497</sup> *Id.*

<sup>498</sup> EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 22.

<sup>499</sup> See, e.g., EPA Technical Bulletin, Diesel Particulate Filter General Information, *available at*: <https://www.epa.gov/sites/production/files/2016-03/documents/420f10029.pdf>.

<sup>500</sup> U.S. EPA, Control Cost Manual, Section 1, Chapter 2 (November 2016) at 16.

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**Table 34. Cost Effectiveness to Reduce PM Emissions by 90% from Stationary Diesel RICE with CDPF Operating 1,000 Hours per Year and 4,000 Hours per Year<sup>501</sup>**

ENGINE SIZE, hp	ANNUALIZED COSTS OF CDPF, 2008\$	EMISSIONS STANDARD	COST EFFECTIVENESS OF CDPF, 1,000 HOURS PER YEAR, 2008\$	COST EFFECTIVENESS OF CDPF, 4,000 HOURS PER YEAR, 2008\$
75	\$1,670	TIER 0	\$31,088/ton	\$10,155/ton
		TIER 1	\$47,467/ton	\$15,505/ton
		TIER 2	\$93,735/ton	\$30,619/ton
		TIER 3	\$74,837/ton	\$24,445/ton
238	\$2,955	TIER 0	\$31,265/ton	\$10,510/ton
		TIER 1	\$49,665/ton	\$16,696/ton
		TIER 2	\$95,155/ton	\$31,988/ton
		TIER 3	\$83,321/ton	\$28,010/ton
675	\$6,397	TIER 0	\$23,774/ton	\$8,150/ton
		TIER 1	\$43,343/ton	\$14,860/ton
		TIER 2	\$72,608/ton	\$24,892/ton
		TIER 3	\$63,467/ton	\$21,759/ton
1,000	\$8,958	TIER 0	\$22,468/ton	\$7,740/ton
		TIER 1	\$40,960/ton	\$14,110/ton
		TIER 2	\$68,644/ton	\$23,646/ton
		TIER 3	\$59,960/ton	\$20,654/ton

It must be noted that the higher cost effectiveness values for CDPF in comparison to SCR cost effectiveness values are due to the magnitude of PM emissions from diesel RICE being much lower than the NOx emissions from diesel RICE. The capital costs of CDPF range from \$10,000 to \$70,000, which is somewhat lower than the range of capital costs for SCR (which range from \$7,300 to \$100,000), and the annual operating costs of CDPF are significantly lower than the operating costs of SCR (\$800-\$3,200 per

<sup>501</sup> See EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 58, Table 5-2. Annualized costs of control were calculated assuming a 10-year life of controls and a 5.5% interest rate. NOx emission reductions are based on EPA's assumed 90% removal efficiency. Uncontrolled NOx emissions are based on EPA estimates (EPA-420/P-04-09, 2004).

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year for CDPF compared to \$2,200 to \$29,000 per year for SCR).<sup>502</sup> Although CDPF can achieve greater than 90% reduction of PM, overall the tons of PM reduced with CDPF is an order of magnitude lower than the NOx emissions reduced with SCR, and thus the cost effectiveness of CDPF is much higher than the cost effectiveness of SCR.

To truly understand whether this control is considered cost effective, one has to evaluate whether similar sources have been required to install the control at similar costs. Indeed, there are several examples of diesel particulate filter systems being retrofitted to diesel RICE.<sup>503</sup>

As previously stated, the use of a CDPF requires the use of ULSD fuel. It should be noted that ULSD is prevalent in the fuel pool today, including in some nonroad fuels that may not be labeled as such, and therefore may already be used in many stationary diesel engines.<sup>504</sup> The use of ULSD which is 15 ppm sulfur, compared to higher sulfur diesel fuel which may be of 500 ppm sulfur content, reflects a 97% reduction in SO<sub>2</sub> emissions from diesel RICE. The increased costs for using ULSD are estimated to be \$0.07 more per gallon, but the costs would be reduced to \$0.04 per gallon due to anticipated savings because of decreased RICE maintenance with the use of low sulfur fuel.<sup>505</sup> EPA's 2010 Alternative Control Techniques Document for Stationary Diesel RICE estimated that using ULSD fuel would increase fuel costs by only \$0.03 to \$0.05 per gallon.<sup>506</sup>

The environmental and energy impacts of controls for stationary diesel RICE include the following:

- 1 to 2 percent fuel penalty for CDPF<sup>507</sup>
- Increased solid waste disposal from spent catalysts<sup>508</sup>

The CDPF will have an added benefit of reducing VOCs and associated air toxics. EPA has found that CDPF can reduce THC by 90 percent.<sup>509</sup> Thus, CDPF can be considered a top control technology for both PM and VOCs.

CDPF can be installed fairly quickly. EPA has indicated that diesel particulate filters can be installed in less than a day,<sup>510</sup> although this claim likely pertains to onroad diesel engines (i.e., trucks). Nonetheless, it is the same technology whether applied to a mobile source or a larger generating diesel RICE. It can be assumed that even taking into account time for engineering, design, ordering of parts, etc., the time to install a CDPF is likely under a year.

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<sup>502</sup> These costs reflect the range of capital and operating costs for the engine sizes evaluated in Tables 33 and 34, using EPA's SCR and CDPF cost calculations from its 2010 Alternative Control Techniques Document for Stationary Diesel RICE.

<sup>503</sup> See Manufacturers of Emission Controls Association, Case Study of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 6-14.

<sup>504</sup> EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 47 and 48.

<sup>505</sup> See <https://dieselnet.com/standards/us/nonroad.php>.

<sup>506</sup> EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 71.

<sup>507</sup> EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 35.

<sup>508</sup> Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for RICE Source Category at 10 (citing EPA (2002), EPA Air Pollution Control Cost Manual, 6<sup>th</sup> ed., EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP).

<sup>509</sup> EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 32 and 34.

<sup>510</sup> See <https://www.epa.gov/sites/production/files/2016-03/documents/420f10028.pdf>.

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### D. EXAMPLES OF STATE AND LOCAL AIR AGENCY RULES FOR EXISTING DIESEL-FIRED RICE

States and local air agencies have adopted NOx limits for diesel RICE, some of which have been in place for over 20 years. In Table 35 below, we summarize some of the stronger state and local air pollution requirements. Note that this is not a comprehensive list of state and local air regulations for diesel RICE.

California has adopted fleet-wide emission requirements for existing diesel “off-road” (i.e., non-road) diesel-fueled engines of 25 hp or greater (see Title 13 California Code of Regulations Sections 2449 through 2449.2), and EPA has authorized those rules under Section 209(e) of the Clean Air Act.<sup>511</sup> The goal of this program is to turnover nonroad diesel RICE to Tier 4 engines. The rule established in-use statewide emission performance standards that apply to any person owning and operating a nonroad diesel engine in California of 25 hp or greater. The fleet requirements phase in over time and require that fleets either meet fleet average emission targets or meet best available control technology (BACT). States may be able to adopt requirements like this for nonroad diesel RICE, pursuant to Section 209(e)(2) of the Clean Air Act.

Table 35 is a summary of the stronger NOx emission limits required of diesel RICE in states and local air districts across the United States. It is important to note that these are limits that generally do not apply to portable or nonroad engines, unless clearly stated otherwise. The most broadly applicable NOx limit required is approximately 1.10 g/hp-hr which applies in several air districts in California, although SCAQMD has adopted a more stringent NOx limit of 0.15 g/hp-hr. Those limits all likely reflect application of SCR to diesel RICE. These limits were adopted generally to meet RACT and BARCT (in California) and, as previously discussed, costs are taken into account in making these RACT and BARCT determinations. Thus, the fact that state and local air agencies have adopted emission limits reflective of SCR indicate that these agencies have found SCR to be a cost effective control to retrofit to existing stationary diesel RICE.

**Table 35. State/Local Air Agency Diesel RICE Rules for NOx Emissions<sup>512</sup>**

State/Local	Regulation	Applicability	NOx Limit and units <sup>513</sup> (equivalent g/hp-hr)
CA-Bay Area AQMD <sup>514</sup>	Reg. 9, Rule 8	51 to 275 bhp	180 ppmvd (2.47 g/hp-hr)
	Effective 1/1/2012:  >50 bhp &/or not Low Usage (<100 hrs/yr) &/or not registered as portable:	>175 bhp	110 ppmvd (1.51.g/hp-hr)

<sup>511</sup> 78 Fed. Reg. 58090-58121 (Sept. 20, 2013).

<sup>512</sup> This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules, but the authors recommend that readers check each specific rule for the details of how the rule applies to different units, and in case of any errors in this table.

<sup>513</sup> Emission limits that are in ppmvd are at @ 15% oxygen.

<sup>514</sup> <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>.

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State/Local	Regulation	Applicability	NOx Limit and units <sup>513</sup> (equivalent g/hp-hr)
CA-Mojave Desert APCD <sup>515</sup>	Rule 1160 (Amended 1/22/18)	>50 bhp &/or >100 hours/4 quarters, not portable, not subject to Airborne Toxic Control Measure, and only if located in the Federal Ozone Nonattainment area	80 ppmv (1.09 g/hp-hr)
CA-Sacramento AQMD <sup>516</sup>	Rule 412	>50 bhp with exemptions if portable, or if operated less than certain # of hours which vary based on rating of engine	80 ppmv (1.10 g/hp-hr)  Alt Limit: 90% NOx reduction
CA-San Joaquin Valley APCD <sup>517</sup>	Rule 4702 Exemptions for <50 bhp, portable, or low use engines  Non-EPA certified Compression Ignition Engines installed on or before 6/1/06. -----  Applicable to EPA-certified CI Engines	>50 & ≤ 500 bhp	EPA Tier 3 or Tier 4 by 1/1/2010
		>500 & ≤750 bhp and < 1000 hrs/yr	EPA Tier 3 by 1/1/2010
		>750 bhp & < 1000 hrs/yr	EPA Tier 4 by 7/1/2011
		>500 bhp & ≥1000 hrs/yr	80 ppmv (1.10 g/hp-hr)
		EPA Tier 1 or 2 engine	EPA Tier 4 by 1/1/2015 or 12 years after install date, but no later than 6/1/2018.
		EPA Tier 3 or Tier 4 engine	Meet certified CI engine standard at time of installation
SCAQMD <sup>518</sup>	Rule 1110.2 As amended 11/1/2019	>50 bhp and not nonroad engines or portable (except portable generators that provide primary or supplemental power to a building, facility,	11 ppmvd (0.15 g/hp-hr)

<sup>515</sup> <https://ww3.arb.ca.gov/drdb/moj/curhtml/r1160.pdf>.

<sup>516</sup> <http://www.airquality.org/ProgramCoordination/Documents/rule412.pdf>.

<sup>517</sup> <https://ww3.arb.ca.gov/drdb/sju/curhtml/r4702.pdf>.

<sup>518</sup> <http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf>.

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State/Local	Regulation	Applicability	NOx Limit and units <sup>513</sup> (equivalent g/hp-hr)
		stationary source, or stationary equipment, which are not exempt from the NOx limit)	
CA- Ventura County AQMD <sup>519</sup>	Rule 74.9	>50 bhp & > 200 hrs/yr Does not apply to diesel engines with permitted capacity factor ≤ 15%	80 ppmvd (1.10 g/hp-hr) or 90% NOx reduction
TX- Houston- Galveston-Brazoria Area <sup>520</sup>	30 TAC 117.2010(c)(2) Emission Specs for 8hr ozone demo  The following limits apply to “stationary engines” (stays at same location more than 12 months) operated more than 100 hours per year on average, that were placed into service after 10/1/01, that were installed, modified, reconstructed, or relocated on or after the date specified:	≥50hp & <100 hp, on or after 10/1/2007	3.3 g/hp-hr
		≥100 hp & <750 hp, On or after 10/1/2006	2.8 g/hp-hr
		≥750 hp, On or after 10/1/2005	4.5 g/hp-hr
		≥300 hp & < 600 hp, On or after 10/1/2005	2.8 g/hp-hr
TX- Dallas -Ft. Worth Area <sup>521</sup>	30 TAC 117.2110(3) Emission Specs for 8hr ozone demo  The following limits apply to “stationary” diesel engines (stays at same location more than 12 months) operated more than 100 hours per year on average, that were placed into service after	≥50hp & <100 hp, on or after 3/1/2009	3.3 g/hp-hr
		≥100 hp & <750 hp, On or after 3/1/2009	2.8 g/hp-hr
		≥750 hp, On or after 3/1/2009	4.5 g/hp-hr

<sup>519</sup> <http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.9.pdf>.

<sup>520</sup> [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](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).

<sup>521</sup> [http://txrules.elaws.us/rule/title30\\_chapter117\\_sec.117.2110](http://txrules.elaws.us/rule/title30_chapter117_sec.117.2110).

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State/Local	Regulation	Applicability	NOx Limit and units <sup>513</sup> (equivalent g/hp-hr)
	3/1/09, that were installed, modified, reconstructed, or relocated on or after the date specified:	Alternative limit to above for units with an annual capacity factor of $\leq 0.0383$	0.060 lb/MMBtu
MI <sup>522</sup>	R 336.1818  Applies to stationary engines	>1 ton/day NOx engines per avg ozone control period day in 1995	2.3 g/bhp-hr
NY <sup>523</sup>	6 CCR-NY 227-2.4 (f)(3)  Applies to stationary engines	$\geq 200$ bhp in a severe ozone nonattainment area or $\geq 400$ bhp outside a severe NAA	2.3 g/bhp-hr
WI <sup>524</sup>	NR 428.22(1)(i) Exemptions for low operating unit engines or for engines certified to meet federal nonroad emission standards.	$\geq 500$ hp	2.0 g/bhp-hr
MO <sup>525</sup>	10 CSR 10-5.510(3)(D)3.B.  Applies in St. Louis ozone nonattainment area, to installations with potential to emit $\geq 100$ tpy that operate more than 750 hours annually or more than 400 hours during ozone season	$\geq 1800$ hp	2.5 g/hp-hr
OH <sup>526</sup>	OAC Chapter 3745-110-03(F)(3)  Applies in counties around Cleveland ozone nonattainment	$\geq 2,000$ hp	3.0 g/hp-hr

<sup>522</sup> [https://www.michigan.gov/documents/deq/deq-aqd-air-rules-apc-part8\\_314769\\_7.pdf](https://www.michigan.gov/documents/deq/deq-aqd-air-rules-apc-part8_314769_7.pdf).

<sup>523</sup> [https://govt.westlaw.com/nycrr/Document/l4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originContext=documenttoc&transitionType=CategoryPageItem&contextData=\(sc.Default\)](https://govt.westlaw.com/nycrr/Document/l4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default)).

<sup>524</sup> [http://docs.legis.wisconsin.gov/code/admin\\_code/nr/400/428.pdf](http://docs.legis.wisconsin.gov/code/admin_code/nr/400/428.pdf).

<sup>525</sup> <https://www.sos.mo.gov/cmsimages/adrules/csr/current/10csr/10c10-5.pdf>.

<sup>526</sup> [https://www.epa.ohio.gov/portals/27/regs/3745-110/3745-110-02\\_Final.pdf](https://www.epa.ohio.gov/portals/27/regs/3745-110/3745-110-02_Final.pdf).



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State/Local	Regulation	Applicability	NOx Limit and units <sup>513</sup> (equivalent g/hp-hr)
	area, to stationary engines at a facility with potential to emit ≥100 tpy		

### E. SUMMARY – CONTROL OPTIONS FOR DIESEL-FIRED RICE UNITS

Based on all of the analysis provided above, there are several options for reducing visibility-impairing emissions from diesel-fired RICE units. These options are as follows, in order of most beneficial for reducing visibility-impairing pollutants from this source category:

- 1) Replace existing older diesel-fired engines with Tier 4 engines.

Replacement of existing older diesel-fired RICE with Tier 4 engines is cost effective as shown in Table 32 above, and has the benefit of reducing NOx by 49% to 96% and PM by 81% to 97.5% (with the percentage reduction based on the emission rates the existing engines is complying with). Replacement of older diesel RICE with Tier 4 engines will also result in a reduction in VOC emissions, due to the VOC emission limits required of Tier 4 engines, and it will also reduce SO<sub>2</sub> emissions because ULSD fuel is required for Tier 4 engines.

The cost effectiveness of replacing existing diesel-fired RICE varies based on the size of the engine being replaced (smaller engines and larger engines that are not electrical generating sets have less stringent Tier 4 emission limits, which impacts cost effectiveness for those engines, and also the annual operating hours impact cost effectiveness). In general, as demonstrated in Table 32 above, it is cost effective to replace a Tier 0 or Tier 1 engine with a Tier 4 engine for any size engine including for those engines operating on the lower end of annual operating hours.

For drill rigs, it is most preferable from an air emissions perspective to replace existing older diesel-fired drill rigs with electric-motor drill rigs that are powered by a Tier 4 Electrical Generating Set. Tier 4 Electrical Generating Set engines greater than 1,500 hp are required to meet the lowest NOx and PM emission rates, significantly lower than large non-electrical generating engines (as shown in Table 30 above). Thus, installing electric drill rigs that are powered by Tier 4 electrical generating diesel RICE will result in the greatest reduction in visibility-impairing emissions if the only option is to continue to power the engines with diesel fuel.

- 2) Replace existing diesel-fired RICE with natural gas-fired RICE equipped with LEC or SCR. Replacing existing older diesel-fired RICE with natural gas-fired RICE, particularly those equipped with LEC or SCR, is also a very effective method for reducing NOx emissions by 85% to 95% and also significantly reducing if not eliminating SO<sub>2</sub> and PM emissions. While we did not calculate

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the cost effectiveness of this control option, it is significant to note that the National Park Service has highlighted several companies that employ natural gas-fired or dual fuel drill rig engines,<sup>527</sup> and such engines are also being used in the Jonah Field in Wyoming.<sup>528</sup>

- 3) As a third option, existing diesel RICE can be retrofit with SCR and/or with CDPF. As demonstrated in Table 33, it is most cost effective to retrofit SCR to an existing Tier 0 or Tier 1 engine, and SCR can result in NOx emission reductions of 90% or more. And, as shown in Table 35, several California air districts have adopted NOx emission limitations that would require retrofitting of SCR to diesel RICE.

In addition, CDPF can be retrofit to existing diesel RICE and achieve greater than 90% reduction of PM as well as reductions in VOC emissions. It must be noted that, overall, the tons of PM reduced with CDPF is an order of magnitude lower than the NOx emissions reduced with SCR, and thus the cost effectiveness of CDPF is much higher than the cost effectiveness of SCR- but that does not mean it is has not been considered a cost effective control. There are several examples of diesel particulate filter systems being retrofitted to diesel RICE.<sup>529</sup>

Existing diesel-fired RICE should also be required to use ULSD fuel. EPA estimated that use of ULSD fuel would increase fuel costs by only \$0.03 to \$0.05 per gallon.<sup>530</sup> ULSD fuel is prevalent in the available fuels today and may already be required to be used in some areas/states. It is also required by the CDPF manufacturer to use ULSD fuel.

Thus, there are several options to cost effectively reduce emissions from diesel-fired engines used in the oil and gas industry. States must evaluate all available options for addressing this significant source of NOx, SO<sub>2</sub>, PM and VOC emissions as part of their reasonable progress analysis. The most preferable options are those that address all of the visibility-impairing pollutants from this source category, with replacement of older diesel-fired engines with Tier 4 engines or replacing diesel-fired engines with natural gas-fired RICE equipped with LEC or SCR as the most effective emission limiting options.

## VII. CONTROL OF NOx EMISSIONS FROM NATURAL GAS-FIRED HEATERS AND BOILERS

Natural gas-fired heaters and boilers are used in a variety of applications, including power generation and the production of process heat and steam. Boilers, reboilers, and heaters can be found throughout the production and processing segments of the oil and gas industry.

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<sup>527</sup> See August 29, 2016 Memorandum from Doug Neighbor, Superintendent, Carlsbad Caverns National Park, to Paul Murphy, Project Lead, Bureau of Land Management, Carlsbad Field Office, at 7.

<sup>528</sup> See Four Corners Air Quality Task Force, Report of Mitigation Options, November 1, 2007, at 62.

<sup>529</sup> See Manufacturers of Emission Controls Association, Case Study of Reciprocating Diesel Engine Retrofit Projects, November 2009, at 6-14.

<sup>530</sup> EPA 2010 Alternative Control Techniques Document for Stationary Diesel RICE at 71.

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In oil and gas production and processing, heaters can be used to aid in separation (e.g., heater-treaters, gas production units (GPUs), heated flash separator units),<sup>531</sup> to maintain temperatures within pipes / connectors (e.g., line heaters),<sup>532</sup> to maintain storage tank temperatures (e.g., tank heaters), and as regenerators / reboilers (e.g., glycol dehydrators, desiccant dehydrators).<sup>533,534</sup> These smaller integrated units are generally rated at less than about 2.5 million Btu per hour (MMBtu/hr) heat input.<sup>535</sup> Larger units can be found at gas processing plants, including steam boilers, hot oil heaters, fractionation column heaters, and other process heaters that range in size from a few MMBtu/hr to 100 MMBtu/hr heat input, or more.<sup>536</sup>

There are two basic ways of supplying combustion air to these types of external combustion units (i.e., two draft types): (1) natural draft (i.e., atmospheric units); and (2) mechanical or forced draft. In atmospheric units, the pressure difference between the hot stack gases and the cooler ambient air creates a draft, drawing supply air into the burners. These units are open to the atmosphere (i.e., non-sealed units). Mechanical draft units use a fan to introduce combustion air into the burners. Draft type can affect the level of excess air in the combustion chamber, and the resulting emissions from the unit (e.g., NO<sub>x</sub> emissions are generally lower in mechanical draft units by operating with lower excess air and improved flame characteristics).

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<sup>531</sup> Heater-treaters consist of a heater, free-water knockout, and oil/condensate and gas separator. GPUs consist of a heater and a separator to remove liquid from gas prior to further processing. Heated flash separators are equipped with small boilers to facilitate condensate removal through flashing.

<sup>532</sup> In-line heaters are used to maintain temperatures as pressure decreases, in order to prevent formation of hydrates. Note, in-line heaters can also be used to heat gas transmission lines further downstream in the oil and gas industry.

<sup>533</sup> Glycol dehydrators use glycol to remove water from the gas stream in order to prevent corrosion and freezing; small reboilers are used to regenerate the glycol. Dehydrators can be located at well pads, as well as at centrally-located gathering stations and processing facilities. Solid-desiccant dehydrators are generally used for large volumes of gas, e.g., downstream of a compressor station and use a heater to regenerate the desiccant.

<sup>534</sup> Dehydrator use varies depending on the moisture content of the gas; dry gas requires little dehydration. For example, according to the *Four Corners Air Quality Task Force Report of Mitigations* (Oil and Gas Section), “[i]n the [coal bed methane] areas of Colorado the gas is predominantly methane and the gas is relatively dry gas and requires little dehydration . . . Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required.” See p. 90.

<sup>535</sup> See Colorado Department of Public Health and Environment, Air Pollution Control Division, Reasonable Progress Evaluation for Heater-Treater Source Category, completed for the 1<sup>st</sup> round RH plans [hereinafter referred to as “CDPHE RP for Heater-Treaters”], available at:

[https://www.colorado.gov/pacific/sites/default/files/AP\\_PO\\_Heater-Treaters\\_1.pdf](https://www.colorado.gov/pacific/sites/default/files/AP_PO_Heater-Treaters_1.pdf); also see PA DEP PA TSD for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268) and the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700-PM-BAQ0267), FINAL June 2018. See p.52, available at: <http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=8904>.

<sup>536</sup> Hot oil heaters, or thermal fluid heaters, are used in the oil and gas industry in combination with a heat exchanger to warm up a secondary fluid (gas or liquid). This can be useful in situations with certain temperature limitations (e.g., amine used to remove H<sub>2</sub>S can degrade at high temperatures) or to prevent corrosive fluids from degrading heating coils. Fractionation column heaters are used at natural gas processing plants to separate out natural gas liquids for further use and can be larger than 10 MMBtu/hr.

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Natural gas-fired external combustion units are sources of NO<sub>x</sub>, CO, VOC, and particulate matter emissions, with NO<sub>x</sub> the primary pollutant and the focus of this section. SO<sub>2</sub> emissions may also occur if the field-gas used to fire the heaters contains H<sub>2</sub>S, which converts to SO<sub>2</sub> during combustion. While emissions from natural gas-fired heaters (e.g., heater-treaters, line heaters, tank heaters, and reboilers) may be relatively small on a unit level, compared to other combustion sources at oil and gas production and processing sites, these units may operate continuously throughout the year. And cumulative emissions from all of the heaters in use at an oil and gas production site or processing facility can be significant.

In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the Heater-Treater Source Category, including a NO<sub>x</sub> emission 4-Factor analysis for reasonable progress toward the national visibility goal.<sup>537</sup> In its evaluation, Colorado reported that, “the multitude of gas wells in Colorado (~26,000 by 2018) result in cumulative heater-treater NO<sub>x</sub> emissions that are projected to be the largest single area source category in Colorado by 2018.”<sup>538</sup> Colorado projected NO<sub>x</sub> emissions in 2018 would reach close to 23,000 tons per year.<sup>539</sup>

Federal standards, in the form of NSPS and NESHAP, exist for industrial boilers and process heaters. The NSPS for industrial-commercial-institutional steam generating units are outlined in 40 C.F.R. Part 60, Subparts Db and Dc, and apply to boilers that are capable of combusting over 10 MMBtu/hr of fuel (burning coal, oil, natural gas, or wood). Subpart Db covers industrial-commercial-institutional steam generating units with heat inputs greater than 100 MMBtu/hr and that commenced construction after September 18, 1978. Subpart Dc covers smaller industrial-commercial-institutional steam generating units that commenced constructed after June 9, 1989. These NSPS include emission standards for sulfur oxides (SO<sub>x</sub>) and PM from burning fuels other than natural gas. In addition, there are no performance testing standards for boilers burning only natural gas. EPA also regulates VOC emissions from boilers and process heaters that are used as combustion control devices under Subpart OOOO and OOOOa through VOC emission reduction requirements, operating requirements, performance testing and monitoring requirements.<sup>540</sup> The NESHAP for industrial boilers, commercial and institutional boilers, and process heaters is outlined in 40 C.F.R. Part 63 Subpart DDDDD and controls mercury, hydrogen chloride, particulate matter (as a surrogate for non-mercury metals), and CO (as a surrogate for organic hazardous emissions) from coal-fired, biomass-fired, and liquid-fired major source boilers based on the maximum achievable control technology. However, these requirements will not address NO<sub>x</sub> emissions. In addition, all major source boilers and process heaters are subject to a work practice standard to periodically conduct tune-ups of the boiler or process heater.

When EPA adopts or revises Federal standards for a source category, EPA is establishing an emission standard applicable to all of the source types and variable fuels, operating conditions, etc. that exist for that source category. Thus, the NSPS are generally-applicable emission standards and not a source-specific evaluation of controls. It is necessary to evaluate if more broadly applicable and more stringent requirements and pollution controls are available to achieve reasonable progress towards the national

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<sup>537</sup> See CDPHE RP for Heater-Treaters.

<sup>538</sup> *Id.* at 1.

<sup>539</sup> *Id.*

<sup>540</sup> See, e.g., 40 C.F.R. Part 60 Subpart OOOOa §§ 60.5412, 60.5412a, 60.5413a, 60.5417a.

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visibility goal, especially because the NSPS and NESHAP standards have not been re-evaluated in at least 8 years. Review of state regulations, particularly to address the NAAQS which require reductions in emissions from *existing* sources, is also necessary to fully evaluate controls for emission sources associated with oil and gas development to achieve reasonable progress towards the national visibility goal.

The information provided in this section for heaters and boilers reflects a review of the available pollution controls and techniques and associated emissions levels applicable to these source categories, along with data on cost of controls where available, non-air quality environmental and energy impacts, and the useful life of the emission source being evaluated.

### **Uncontrolled Emission Factors from Natural Gas-Fired External Combustion Units**

NO<sub>x</sub> emissions from natural gas-fired heaters and boilers are generally expressed as emission rates in pounds per million Btu heat input (lb/MMBtu) or pounds per million standard cubic feet of gas (lb/MMscf) or as a concentration in parts per million by dry volume (ppmv or ppmvd). All concentrations expressed in ppmv are on a dry basis and corrected to 3% oxygen. The following emission factors are used in this section:

#### **EPA Emission Factor**

AP-42 Natural Gas Combustion (Section 1.4, last revised 1998)

Small Boilers <100 MMBtu/hr (Uncontrolled).....100 lb/MMscf (0.098 lb/MMBtu)  
*Converted to lb/MMBtu based on fuel heating value of 1,020 Btu/scf*

#### **SCAQMD Emission Factor**

Units ≤2 MMBtu/hr .....110 ppmv (0.136 lb/MMBtu)  
SCAQMD derived an average emission rate to calculate baseline emissions for this size category in its implementation studies for Rule 1146.2 Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers and Process Heaters. This factor accounts for units that are considerably older and also for ones that have not had continual maintenance and upkeep.<sup>541</sup>

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<sup>541</sup> See SJVAPCD Final Draft Staff Report with Appendices For Proposed Amendments to Rule 4308 (November 5, 2009), B-4, available at: [http://www.valleyair.org/board\\_meetings/GB/agenda\\_minutes/Agenda/2009/November/Agenda\\_Item\\_26\\_Nov\\_5\\_2009.pdf](http://www.valleyair.org/board_meetings/GB/agenda_minutes/Agenda/2009/November/Agenda_Item_26_Nov_5_2009.pdf) [hereinafter referred to as "SJVAPCD 2009 Final Draft Staff Report for Rule 4308"].

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### A. COMBUSTION MODIFICATIONS

Combustion modification—such as flue gas recirculation (FGR), low-NOx burners (LNB), and ultra-low NOx burners (ULNB)—reduce NOx formation by controlling the combustion process. The following is EPA’s description of these combustion control techniques:

Staging techniques are usually used by LNB and ULNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNB's create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNB's create a lean primary combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures. The secondary combustion zone is fuel-rich. Ultra-low-NOx burners use staging techniques similar to staged-fuel LNB in addition to internal flue gas recirculation. Flue gas recirculation returns a portion of the flue gas to the combustion zone through ducting external to the firebox that reduces flame temperature and dilutes the combustion air supply with relatively inert flue gas.<sup>542</sup>

Retrofitting natural gas-fired heaters and boilers with LNB was identified by EPA in 1998 as one of the two most prevalent control techniques in its AP-42 Emission Factor documentation, along with FGR.<sup>543</sup> EPA states that, “NOx emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NOx burners.”<sup>544</sup> And EPA further states that, “[w]hen low NOx burners and FGR are used in combination, these techniques are capable of reducing NOx emissions by 60 to 90 percent.”

CARB, in its 1991 RACT and BARCT determinations for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, also identified LNB as one of four control methods (along with FGR, SCR, and selective noncatalytic reduction (SNCR)).<sup>545</sup> CARB concluded that, for units  $\geq 5$  MMBtu/hr (and  $\geq 90,000$  therms annual heat input) a BARCT NOx limit of 30 ppmv (0.036 lbs/MMBtu) could be achieved by installing new burners with FGR, noting that some units would “need to install selective noncatalytic reduction or other emission control technology instead of flue gas recirculation due to particular unit design problems.”<sup>546</sup> However, these determinations were from 1991, and the NOx removal capabilities of low NOx burners and similar combustion controls for NOx has greatly improved over time.

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<sup>542</sup> EPA-453/R-93-034 Alternative Control Techniques Document—NOx Emissions from Process Heaters (Revised), September 1993, p.2-6, *available at*: <https://www3.epa.gov/ttnecatc1/dir1/procheat.pdf> [hereinafter referred to as EPA 1993 ACT for Process Heaters].

<sup>543</sup> EPA, AP-42, Section 1.4.4 (last revised 1998), *available at*: <https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s02.pdf>.

<sup>544</sup> *Id.*

<sup>545</sup> CARB Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, July 18, 1991, p. 7 *available at*: <https://www3.arb.ca.gov/ractbarc/boilers.pdf> [hereinafter referred to as “CARB 1991 Guidance”].

<sup>546</sup> CARB 1991 Guidance at 6.

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For example, in 2018, California’s SCAQMD concluded the following with regard to ULNB technology and its ability to meet very low NOx emission limits across a wide range of unit sizes:

It was noted in the 2008 Rule 1146 and 1146.1 staff reports that there was clear evidence that these types of [ultra-low NOx] burners had been successfully retrofitted on boilers and heaters in the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) in their Rule 4306. Source tests that were conducted in conjunction with Rule 4306 showed a 98% compliance rate with a 9 ppm NOx limits using ultra-low NOx burners. In 2010, staff published a technology assessment report discussing the implementation assessment of ultra-low NOx burners subject to Rules 1146 and 1146.1. **The report concluded that the 9 ppm NOx limit can be achieved by ultra-low NOx burner systems for boilers and process heaters greater than 2 MMBtu/hour.** There were ultra-low NOx burners from 16 different manufacturers that could achieve the 9 ppm NOx compliance limit.<sup>547</sup>

In 2010, California’s Sacramento Metropolitan AQMD (SMAQMD) determined, based on SCAQMD’s rules for similar size sources and models being sold that meet SCAQMD limits, that ULNB technology was available to meet emissions limits for very small units, less than 1 MMBtu/hr.<sup>548</sup> Specifically, SMAQMD found that very small units less than 1 MMBtu/hr could meet a NOx limit equivalent to 20 ppmv:

The proposed standards are technically feasible. The low NOx technology is commercially available and widely used. Additionally, these standards have already been adopted by the South Coast AQMD and the Bay Area AQMD, and except for the limits proposed for 2013 (which take effect for the SCAQMD in 2012), are already in effect in SCAQMD. As documented in the SCAQMD staff report for Rule 1146.2, as of 2006, 18% of the certification tests for units between 75,000–400,000 Btu/hr and 44% of the certification tests for units between 400,000 and 2,000,000 Btu/hr were already meeting the 14 ng/J (20 ppmv) standard. SCAQMD currently keeps a list of well over 100 certified models that are compliant with the standards in Rules 1146.2 and 1121.<sup>549</sup>

SMAQMD concluded that, “[t]he proposed emission limits are readily achievable through the use of low NOx burners.”<sup>550</sup>

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<sup>547</sup> SCAQMD Draft Staff Report Rules 1146, 1146.1, 1146.2, and 1100, p. 2-2 [emphasis added], *available at*: <http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/rule-1146-1146.1-and-1146.2/dsr-1146-final.pdf?sfvrsn=6> [hereinafter referred to as “SCAQMD 2018 Draft Staff Report”].

<sup>548</sup> SMAQMD Staff Report Rule 414 Water Heaters, Boilers and Process Heaters Rated Less Than 1,000,000 Btu Per Hour, January 15, 2010, p. 5, *available at*: <http://www.airquality.org/ProgramCoordination/Documents/Rule414%20StaffReport%20011510.pdf> [hereinafter referred to as “SMAQMD 2010 Rule 414 Staff Report”].

<sup>549</sup> *Id.* at 16.

<sup>550</sup> *Id.* at 13.

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In 2015, a Ventura County Air Pollution Control District (VCAPCD) analysis for amendments to its rules for boilers, steam generators, and process heaters  $\geq 2$  and  $< 5$  MMBtu/hr found:

Ultra-low NOx burner systems can achieve less than 9 ppm NOx for boilers, steam generators, or process heaters without the use of Flue Gas Recirculation (FGR) systems. Source tests performed by the San Joaquin Unified Air Pollution Control District showed a 95 percent compliance rate with 9 ppm limits using ultra-low NOx burners. The average NOx concentration measured was 7 ppm.<sup>551</sup>

And as recently as April 2019, Santa Barbara County APCD concluded the following about the ability of ULNB technology to achieve lower NOx limits of between 9 and 12 ppm for units between 2–5 MMBtu/hr:

The focus of this rule amendment is to lower the emission limits for new and modified natural gas and field gas units from 30 ppm to the 9-12 ppm NOx emission limits, beginning on January 1, 2020. To meet these lower standards, most boilers will have to be equipped with ultra-low NOx burners. Ultra-low NOx burners are designed to achieve low emissions while maintaining good flame stability and heat transfer characteristics. Furthermore, these burners may increase thermal efficiencies by reducing the amount of excess air needed for combustion. This has the added benefit of reducing fuel usage, which results in energy savings.

For most systems, a blower will be required to mix the fuel and air prior to combustion. Even atmospheric boilers, where the burners are not totally enclosed, may still need a blower to pre-mix the fuel and air. Due to the design criteria of these atmospheric boilers, it is only feasible to have them reach the 12 ppm NOx limit, as opposed to the 9 ppm limit for non-atmospheric boilers. It is possible to reach both the 9 and 12 ppm NOx limits without the use of Flue Gas Recirculation (FGR), yet some operators may still choose to use this technology.<sup>552</sup>

Thus, in rulemakings enacted in California air districts from 2015 to 2019, it was essentially deemed reasonable to impose a NOx emission limit of 9 ppm for natural gas-fired heaters and boilers with heat input capacities greater than or equal to 2 ppm. However, as will be discussed in Sections B. and F., even lower NOx limits have been required for heaters and boilers in some California Air Districts.

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<sup>551</sup> VCAPCD Staff Report Amendments to Rule 74.15.1 Boilers, Steam Generators and Process Heaters June 23, 2015, p. 4, available at: <http://www.vcapcd.org/pubs/Rules/74151/201506/Staff-Report-Rule-74-15-JUNE-23-%202015.pdf> [hereinafter referred to as “VCAPCD 2015 Staff Report”].

<sup>552</sup> Santa Barbara County APCD Draft Staff Report for Amended Rule 361. Boilers, Steam Generators, and Process Heaters (Between 2–5 MMBtu/hr); Amended Rule 342. Boilers, Steam Generators, and Process Heaters (5 MMBtu/hr and greater), April 22, 2019, p. 5, available at: <https://www.ourair.org/wp-content/uploads/2019-05cac-r361-r342-att1.pdf> [hereinafter referred to as “Santa Barbara County APCD 2019 Draft Staff Report”].



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There are several emerging combustion technologies that demonstrate the potential for even lower levels of NO<sub>x</sub> without the use of post-combustion controls, such as SCR:

- SOLEX™ Burner is an emerging technology designed to achieve 5 ppm NO<sub>x</sub>.<sup>553</sup> This burner technology is available as a burner-only alternative to SCR for units “with heat releases between 1 MMBtu/hr and +20 MMBtu/hr.”<sup>554</sup> It can be retrofit to existing units and fits traditional ULNB footprints.
- ClearSign Ultra Low NO<sub>x</sub> Technology is designed to achieve sub 5 ppm NO<sub>x</sub>.<sup>555</sup> This technology is reportedly less costly than traditional ultra-low NO<sub>x</sub> controls with no FGR, lower fuel use, and can be retrofit to existing units. This technology has been installed on several units in SJVAPCD with more testing / demonstration needed:
  - Installation at two refinery heaters (burning natural gas, not refinery gas):
    - 15 MMBtu/hr heater
    - 8 MMBtu/hr heater
  - Installation at two natural gas-fired 62.5 MMBtu/hr oil field steam generators
  - Installation at six enclosed flares (thermal oxidizers)
- Altex Technology Corporation Near Zero NO<sub>x</sub> Burner has been applied to an 8 MMBtu/hr unit and is capable of achieving 5 ppm under some operating conditions.<sup>556</sup> This technology is being developed as an alternative to SCR for meeting NO<sub>x</sub> limits as low as 5 ppm for smaller units (e.g., in response to SCAQMD’s consideration of a 5 ppm NO<sub>x</sub> limit for units ≥2 MMBtu/hr).<sup>557</sup>

### 1. COST EFFECTIVENESS EVALUATIONS FOR COMBUSTION MODIFICATION RETROFITS, REPLACEMENTS, AND UPGRADES

California Air Districts have long been regulating NO<sub>x</sub> emissions from boilers and process heaters, with CARB issuing RACT / BARCT guidance to Air Districts in 1991.<sup>558</sup> In its 1991 guidance CARB determined the cost effectiveness of LNB (in 1986\$) for units as small as 3.5 MMBtu/hr and as large as 150 MMBtu/hr, as follows: (1) \$500–\$6,400/ton for units operating at a 50% capacity factor; and (2) \$300–\$4,000/ton for units operating at a 90% capacity factor.<sup>559</sup>

More recent and more detailed cost data are available from California Air Districts that have adopted, and continue to update, regulations for these sources. Based on a review of the various California Air

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<sup>553</sup> John Zink Hamworthy Combustion, SOLEX™ Burner, see: <https://www.johnzinkhamworthy.com/wp-content/uploads/solex-burner.pdf>.

<sup>554</sup> *Id.*

<sup>555</sup> ClearSign <https://clearsign.com/>. Also see SJVAPCD presentation “ClearSign Ultra Low NO<sub>x</sub> Technology” November 7-8, 2017, available at: <https://ww3.arb.ca.gov/enf/training/sympo/ppt2017/0830-b-scandura.pdf>.

<sup>556</sup> California Energy Commission Report, *Near Zero NO<sub>x</sub> Burner*, July 2018, available at: <https://ww2.energy.ca.gov/2018publications/CEC-500-2018-016/CEC-500-2018-016.pdf>.

<sup>557</sup> *Id.*

<sup>558</sup> CARB 1991 Guidance.

<sup>559</sup> CARB 1991 Guidance Table 4. Note, CARB does not identify the underlying assumptions for annualized costs, life of controls, etc.

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District rules and in researching vendor information, the source category of boilers and heaters should be subcategorized into three categories for assessing cost effectiveness and achievable NOx emission rates with combustion modifications: (1) Units > 20 MMBtu/hr (achieving NOx levels as low as 6 ppm); (2) Units >5 MMBtu/hr and ≤20 MMBtu/hr (achieving NOx levels as low as 6 ppm); and (3) Units ≤5 MMBtu/hr (achieving NOx levels of 9–20 ppm). Below, we evaluate cost effectiveness of combustion controls for each of these categories of boilers and heaters, based on cost analyses that local air agencies have relied on for regulating these units.

### *a) Units >20 MMBtu/hr*

SJVAPCD is in the process of reviewing its rules for boilers and process heaters >5 MMBtu/hr and is proposing updates as part of its 2018 PM<sub>2.5</sub> Attainment Plan commitments to reduce NOx emissions.<sup>560</sup> SJVAPCD is considering lowering NOx limits for units >5 MMBtu/hr to levels ranging from 2–3.5 ppm.<sup>561</sup> As part of its control measure analysis, SJVAPCD analyzed the cost effectiveness of retrofitting units of varying sizes with ULNB to achieve a NOx level of 6 ppm, based on vendor cost data. We assume these data are in 2018\$.

The SJVAPCD cost data for retrofitting existing units with ULNB includes detailed direct and indirect capital and operating costs for two unit size categories: (1) units >5 and ≤20 MMBtu/hr; and (2) units >20 MMBtu/hr.<sup>562</sup> For the larger size units (>20 MMBtu/hr), SJVAPCD notes that the retrofit may involve “upgrades to various systems such as fuel train to comply with up to date codes, and may involve upgrades to air intake fans, as these units require more air for the burner to operate at its optimum level.”<sup>563</sup>

Table 36 below summarizes the total costs for retrofitting existing units >20 MMBtu/hr with ULNB, based on SJVAPCD vendor data, along with calculated annualized costs of the control, assuming a 5.5% interest rate and a 25-year life. Low NOx technologies should last the life of the emission unit. SCAQMD is currently assuming a 25-year life for refinery heaters and boilers.<sup>564</sup> And a review of the emission units in New Mexico permitted oil and gas sources such as gas processing plants show average ages of boilers and heaters of 30-35 years. Thus, we used a 25-year life as a minimum life for a heater or boiler controls in the cost effectiveness analysis, which seems more than justified. Table 36 presents the cost effectiveness of applying these low NOx technologies to existing units to reduce NOx emissions from uncontrolled levels to 6 ppm. Uncontrolled emissions are based on the EPA AP-42 uncontrolled

<sup>560</sup> SJVAPCD Rules 4306 and 4320. See: [https://www.valleyair.org/Workshops/public\\_workshops\\_idx.htm#12-05-19\\_ICE](https://www.valleyair.org/Workshops/public_workshops_idx.htm#12-05-19_ICE).

<sup>561</sup> SJVAPCD 2018 Plan for the 1997, 2006, and 2012 PM<sub>2.5</sub> Standards (November 15, 2018), Appendix C: Stationary Source Control Measure Analysis at C-94, available at: <http://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/C.pdf> [hereinafter referred to as “SJVAPCD 2018 PM<sub>2.5</sub> Attainment Plan”].

<sup>562</sup> SJVAPCD 2018 PM<sub>2.5</sub> Attainment Plan pp. C-80–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.

<sup>563</sup> SJVAPCD 2018 PM<sub>2.5</sub> Attainment Plan at C-81.

<sup>564</sup> See, e.g., SCAQMD Presentation for Rule 1109.1 – NO<sub>x</sub> Emission Reduction for Refinery Equipment, Working Group Meeting #9, December 12, 2019, slides 41 and 57, available at: [http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm\\_9\\_final.pdf?sfvrsn=12](http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm_9_final.pdf?sfvrsn=12).

## Exhibit 1

emission rate for small boilers <100 MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting an emission limit of 6 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art ultra-low NOx burner technology of 93%. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

**Table 36. Cost Effectiveness of Retrofitting Existing Units with ULNB to Achieve a NOx Level of 6 ppm at Boilers and Heaters >20 MMBtu/hr Operating at a 50% and 90% Capacity Factor.<sup>565</sup>**

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2018\$)	TOTAL ANNUALIZED COSTS (2018\$)	COST EFFECTIVENESS (\$/TON) 50% CAPACITY FACTOR	COST EFFECTIVENESS (\$/TON) 90% CAPACITY FACTOR
30	\$261,813	\$19,518	\$3,270	\$1,817
40			\$2,452	\$1,362
50			\$1,962	\$1,090
60			\$1,635	\$908
70			\$1,401	\$779
80			\$1,226	\$681
90			\$1,090	\$606
100			\$981	\$545

Based on this analysis of SJVAPCD cost data, it can be cost effective to apply ULNB to existing units >20 MMBtu/hr to reduce NOx emissions to a level of 6 ppm.

SJVAPCD provides separate cost data for oilfield steam generators, noting that most of these units would be 62.5 MMBtu/hr.<sup>566</sup> The SJVAPCD analysis notes that, “[a]s many steam generators are one off built units, they may have different firebox configurations that may not accept the new burner without varying degrees of modification.”<sup>567</sup> However, SJVAPCD analyzed retrofitting these units with new burner technology to achieve a NOx level as low as 5 ppm, based on vendor data. Using this same vendor cost data, the cost effectiveness of retrofitting a 62.5 MMBtu/hr unit to reduce NOx levels to 5 ppm ranges from \$1,664/ton to \$6,656/ton, depending on the extent of the modifications or upgrades that are needed.<sup>568</sup>

<sup>565</sup> Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.

<sup>566</sup> SJVAPCD 2018 PM<sub>2.5</sub> Attainment Plan at C-83.

<sup>567</sup> *Id.*

<sup>568</sup> This range of cost effectiveness is based on retrofit cost data of \$450,000–\$1,800,000 and assumes an 80% capacity factor from SJVAPCD’s analysis. Annualized costs are calculated assuming a 25-year life and a 5.5% interest rate.

## Exhibit 1

### b) Units >5 and ≤20 MMBtu/hr

We also completed a cost effectiveness analysis of retrofitting existing units >5 and ≤20 MMBtu/hr with ULNB based on SJVAPCD vendor cost data for units of this size.<sup>569</sup> Table 37 presents the cost effectiveness of retrofitting existing units >5 and ≤20 MMBtu/hr with ULNB to reduce NOx emissions to 6 ppm from uncontrolled levels based on the EPA AP-42 uncontrolled emission rate for small boilers <100 MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting an emission limit of 6 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art ultra-low NOx burner technology of 93%. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

**Table 37. Cost Effectiveness of Retrofitting Existing Units with ULNB to Achieve a NOx Level of 6 ppm at Boilers and Heaters >5 and ≤20 MMBtu/hr Operating at a 50% and 90% Capacity Factor.<sup>570</sup>**

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2018\$)	TOTAL ANNUALIZED COSTS (2018\$)	COST EFFECTIVENESS (\$/TON) 50% CAPACITY FACTOR	COST EFFECTIVENESS (\$/TON) 90% CAPACITY FACTOR
5	\$69,816	\$5,205	\$5,232	\$2,906
10			\$2,616	\$1,453
15			\$1,744	\$969
20			\$1,308	\$727

Based on this analysis using SJVAPCD cost data, it can be cost effective to apply ULNB to existing units >5 and ≤20 MMBtu/hr to reduce NOx emissions to a level of 6 ppm.

### c) Units ≤5 MMBtu/hr

SMAQMD, in a cost effectiveness analysis for its most recent revision of its rules (in 2005) for boilers and heaters ≥1 MMBtu/hr, noted that, for units ≥1 MMBtu/hr and <5 MMBtu/hr, “[s]ome of these units may not be retrofitted because of equipment age and design and will have to be replaced with new units.”<sup>571</sup>

<sup>569</sup> SJVAPCD 2018 PM<sub>2.5</sub> Attainment Plan pp. C-81–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.

<sup>570</sup> Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.

<sup>571</sup> Sacramento Metropolitan AQMD Staff Report Rules 411 and 301, October 27, 2005, p. 10, available at: <http://www.airquality.org/ProgramCoordination/Documents/Rules411and301%20StaffReport%20102705%20Item11.pdf> [hereinafter referred to as “SMAQMD 2005 Rule 411 Staff Report”].

## Exhibit 1

The SMAQMD cost data included the costs for replacing existing units with new units equipped with “low NOx technologies” in order to meet the District’s emission limits, including costs for equipment, installation, permitting, and source testing for unit sizes ranging from 1–100 MMBtu/hr.<sup>572</sup> Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. Thus, it is assumed that it is more cost effective to replace units that are of a size less than or equal to 5 MMBtu/hr with new units equipped with state-of-the-art combustion controls for NOx.

Table 38 below summarizes cost data for replacing units ≤5 MMBtu/hr with new units with “low NOx technologies.” The costs include costs for equipment, installation, permitting, and source testing, along with calculated annualized costs of the control, and assume a 5.5% interest rate and a 30-year life of the new unit.<sup>573</sup> These low NOx technologies should last the life of the emission unit, and Colorado assumed a 30–40 year life for heater-treater units of this size based on manufacturer data.<sup>574</sup> We used a 30-year life as a minimum useful life for replacement heater or boiler controls in the cost effectiveness analysis, which is justified.

**Table 38. Total and Annualized Costs of Replacement of Boilers and Heaters ≤5 MMBtu/hr with New Units with Low NOx Technologies.**<sup>575</sup>

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2005\$)	TOTAL ANNUALIZED COSTS (2005\$)
1	\$36,284	\$2,551
2	\$52,284	\$3,652
3	\$72,284	\$5,028
4	\$80,284	\$5,579
5	\$135,567	\$9,328

For the units of 5 MMBtu/hr and lower, SMAQMD’s Rule 411 establishes a NOx limit of 30 ppm, but there have been improvements in low NOx technologies demonstrating that units in this size range can meet NOx limits of 20 ppm and even as low as 9 ppm for some applications, based on a review of vendor information.<sup>576</sup> Several California Air Districts require units >2 and <5 to meet a limit of 7–12 MMBtu/hr and units ≤2 MMBtu/hr to meet a limit of 20 ppm. For example, SCAQMD Rule 1146.1 requires units >2 and <5 MMBtu/hr meet limits between 7–12 ppm, depending on the type of unit. And SJVAPCD Rule 4307 requires units >2 and ≤5 MMBtu/hr meet limits of 9 ppm (non-atmospheric units) and 12 ppm

<sup>572</sup> SMAQMD 2005 Rule 411 Staff Report Attachment D-1.

<sup>573</sup> SMAQMD 2005 Rule 411 Staff Report Attachment D-2.

<sup>574</sup> CDPHE RP for Heater-Treaters at 5.

<sup>575</sup> Cost data provided by boiler manufacturers to SMAQMD, annualized costs calculated assuming a 30-year life and a 5.5% interest rate.

<sup>576</sup> See, e.g., Parker Industrial Boiler, offering units <5 MMBtu/hr with Low NOx Power Burners for NOx levels to 9 ppm. Available at: <https://www.parkerboiler.com/products/>.

## Exhibit 1

(atmospheric units). SCAQMD Rule 1146.2 requires units  $\leq 2$  MMBtu/hr be manufactured to meet a NOx limit of 20 ppm and SCAQMD provides a list of numerous units that are pre-certified to meet this limit.<sup>577</sup> SJVAPCD also requires point-of-sale NOx limits for units  $\leq 2$  MMBtu/hr of 20 ppm.<sup>578</sup> And VCAPCD's Rule 74.15.1 currently requires new and replacement units  $\geq 1$  and  $\leq 2$  MMBtu/hr to also meet a 20 ppm NOx limit.<sup>579</sup> See Table 42 for a complete and more detailed list of state and local rules, including many with limits for units in this size range of 9–20 ppm.

While the costs of NOx combustion control technologies to meet NOx limits as low as 9 ppm may be higher than what SMAQMD assumed in its 2005 cost analysis, it is also likely that the costs of low NOx combustion controls have not changed much since then. This is because as air pollution controls are required to be implemented more frequently over time, the cost of the air pollution control often decreases due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc. For example, SCAQMD concluded from its 2008 cost analysis that, “[t]he capital cost for retrofitting a unit has decreased by about 70%....”<sup>580</sup>

Therefore, we calculated the cost effectiveness of retrofitting these size units with low NOx technologies using these cost data based on two emission control scenarios: (1) meeting the SMAQMD limit of 30 ppm; and (2) meeting limits achievable today with low NOx combustion technology.

Table 39 below summarizes the cost effectiveness of replacing existing units  $\leq 5$  MMBtu/hr with new units with low NOx technologies, based on SMAQMD cost data shown above in Table 38. Table 39 below presents the cost effectiveness of replacement units with low NOx technologies to reduce NOx emissions from the uncontrolled emission rate based on EPA for units  $> 2$  MMBtu/hr and the SCAQMD-derived average unit emission rate of 110 ppmv (0.136 lb/MMBtu/hr) for units  $\leq 2$  MMBtu/hr. The SCAQMD-average unit emission rate was, “derived by the SCAQMD to calculate the baseline emissions for this [size] category.”<sup>581</sup> This rate, “accounts for units that are considerably older and also for ones that have not had continual maintenance and upkeep.”<sup>582</sup> Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. For the second scenario, the analysis assumes units  $> 2$  and  $\leq 5$  MMBtu/hr meet a NOx limit of 9 ppm and units  $\leq 2$  MMBtu/hr meet a NOx limit of 20 ppm. Meeting emission limits of 9 ppm and 20 ppm from the estimated uncontrolled levels reflect a control efficiency of 89% and 82%, respectively. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

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<sup>577</sup> See <http://www.riteboiler.com/docs/Rite-Low-NOx-SCAQMD-Precertified-Boilers.pdf>.

<sup>578</sup> SJVAPCD Rule 4308. Available at: [https://www.valleyair.org/rules/currnrules/03-4308\\_CleanRule.pdf](https://www.valleyair.org/rules/currnrules/03-4308_CleanRule.pdf).

<sup>579</sup> VCAPCD Rule 74.15.1. Available at: <http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.15.1.pdf>.

<sup>580</sup> SCAQMD 2018 Draft Staff Report at 4-3. Note, while SCAQMD's analysis specifically applies to retrofitting units  $\geq 20$  and  $< 75$  MMBtu/hr with ULNB it's also possible that these changes in cost would apply to units of other sizes, as well.

<sup>581</sup> SJVAPCD 2009 Final Draft Staff Report for Rule 4308.

<sup>582</sup> *Id.*

## Exhibit 1

**Table 39. Cost Effectiveness of Replacing Existing Boilers and Heaters ≤5 MMBtu/hr with New Units with Low NOx Technologies Operating at a 50% and 90% Capacity Factor.<sup>583</sup>**

UNIT SIZE (MMBtu/hr)	COST EFFECTIVENESS (\$/TON) 50% CAPACITY FACTOR NOx RATE: 30 ppm	COST EFFECTIVENESS (\$/TON) 90% CAPACITY FACTOR NOx RATE: 30 ppm	COST EFFECTIVENESS (\$/TON) 50% CAPACITY FACTOR NOx RATES: 20 ppm (≤2 MMBtu/hr) 9 ppm (>2 MMBtu/hr)	COST EFFECTIVENESS (\$/TON) 90% CAPACITY FACTOR NOx RATES: 20 ppm (≤2 MMBtu/hr) 9 ppm (>2 MMBtu/hr)
1	\$12,160	\$6,756	\$10,809	\$6,005
2	\$8,703	\$4,835	\$7,736	\$4,298
3	\$12,322	\$6,846	\$8,771	\$4,873
4	\$10,254	\$5,696	\$7,298	\$4,055
5	\$13,715	\$7,619	\$9,762	\$5,423

For the smallest units, San Joaquin Valley APCD (SJVAPCD) analyzed the cost of reducing NOx emissions for its point-of-sale rule for boilers and process heaters sized 0.075 to less than 2 MMBtu/hr. Table 40 below shows the differential capital costs (i.e., the difference in cost between a compliant and non-compliant unit), the annualized costs re-calculated using on a 5.5% interest rate (in place of the 10% interest rate assumed by SJVAPCD), and the cost of NOx reduction based on a current unit average emission rate of 110 ppmv meeting a limit of 20 ppmv. For units ≤2 MMBtu/hr uncontrolled emissions are estimated based on the SCAQMD-derived average unit emission rate of 110 ppmv (0.136 lb/MMBtu/hr). Operating and maintenance costs of a new low-NOx unit are assumed to be the same as older units. Cost data were provided to SJVAPCD by stakeholders, retailers, and manufacturers. And again, we used a 30-year life as a minimum life for replacing unit controls with low NOx technologies in the cost effectiveness analysis, as previously discussed. SJVAPCD used a 22% capacity factor in its analysis based on survey data collected by SCAQMD and Bay Area AQMD for “typical usages for these units,” which presumably reflect a wide range of application and do not necessarily reflect how these size units are used in oil and gas applications, where heaters can operate continuously.

<sup>583</sup> Cost data provided by boiler manufacturers to SMAQMD (2005\$), annualized costs calculated assuming a 30-year life and a 5.5% interest rate.

## Exhibit 1

**Table 40. Cost Effectiveness Based on Differential Costs to Reduce NOx Emissions from Replacing Units with Units with Low-NOx Burner Technology to Meet a NOx Limit of 20 ppm, Operating at 22% Capacity<sup>584</sup>**

UNIT SIZE (MMBtu/hr)	DIFFERENTIAL CAPITAL COST (2009\$)	ANNUALIZED COST (2009\$)	COST EFFECTIVENESS (2009\$)
0.75	\$100	\$8	\$883/ton
0.4	\$750	\$63	\$1,242/ton
2.0	\$3,000	\$251	\$994/ton

For units operating at a higher capacity factor, as would likely be the case for many of the units used in the oil and gas production and processing segments, the cost per ton of NOx removal of choosing to replace a unit with a new unit with low NOx technologies over a higher-emitting unit would be even less than what is shown in Table 40. For these type of smaller units, SCAQMD Rule 1146.2 requires units with rated capacities between 400,000 and 2,000,000 Btu/hr (i.e., 0.04 and 2 MMBtu/hr) and more than 15 years old, depending on the original manufacturer date, to meet the same emission standards as new units.<sup>585</sup> Meeting these standards, according to SCAQMD, requires the retrofit, or more likely, replacement of the older units.<sup>586</sup>

In its initial regional haze plan, Colorado completed a Reasonable Progress Evaluation for the heater-treater source category, including a NOx emission 4-Factor analysis for reasonable progress toward the national visibility goal.<sup>587</sup> In its evaluation, Colorado reported that:

The Four Corners Air Quality Task Force considered low NOx burners as a mitigation option for the Four Corners area and had the following finding: “Application not appropriate for the San Juan Basin, because most burners commonly used in the Four Corners Area are smaller than the technology is capable of providing emission reduction.” It appears likely that this technology would also be technically infeasible for the Denver-Julesburg (DJ) Basin considering that low-NO<sub>x</sub> burners are not commercially available for very small combustion sources such as heater-treaters.<sup>588</sup>

<sup>584</sup> See SJVAPCD 2009 Final Draft Staff Report for Rule 4308. Annualized costs of control were calculated using a capital recovery factor of 0.068805 (assuming a 30-year life of controls and a 5.5% interest rate). NOx emission reductions are based on SJAPCD’s assumed unit average emission rate of 110 ppmv meeting an emission limit of 20 ppmv.

<sup>585</sup> SCAQMD Rule 1146.2, available at: <http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1146-2.pdf?sfvrsn=17>.

<sup>586</sup> See SMAQMD 2010 Rule 414 Staff Report at 13 (describing SCAQMD rules).

<sup>587</sup> CDPHE RP for Heater-Treaters.

<sup>588</sup> *Id.* at 3.



## Exhibit 1

The Four Corners Air Quality Task Force report was from 2007 and there have been great improvements since then in low NOx technologies. As shown throughout this section on combustion modifications, however, units around 2 MMBtu/hr, and even smaller, are available with low NOx technologies that can meet very low NOx emission limits and can even, in some cases, be retrofitted with these technologies to achieve emissions reductions from existing units. Note, Colorado's RP for Heater-Treaters indicates that a typical heater-treater design rate is about half of the 5 MMBtu/hr threshold for exemptions from Colorado's permitting requirements.<sup>589</sup> And beyond these very small units, low NOx technologies are widely available and generally cost effective for units  $\geq 5$  MMBtu/hr.

### 2. LOWERING COMBUSTION TEMPERATURES TO REDUCE NOx EMISSIONS

Colorado also considered lowering heater-treater temperatures to reduce NOx emissions and described this combustion modification approach, as follows:

This technology (lowering the heater-treater temperature) was identified by EPA Natural GasSTAR in PRO Fact Sheet No. 906. The fact sheet was written with reduction of methane in mind, although this technology would also reduce combustion emissions because it would reduce fuel use. The following is from the fact sheet: "...heater-treater temperatures at remote sites may be higher than necessary, resulting in increased methane emissions. Commonly, the reason for this is that operators need to reduce the chance of having a high water content in the produced oil and manpower limitations do not allow for constant monitoring at remote sites. Field personnel, consequently, are inclined to operate the equipment at levels that cause the least problems, but also result in higher than necessary emissions."<sup>590</sup>

Estimates for NOx emission reductions from lowering heater-treater temperatures were not provided in EPA's Gas STAR analysis and were not assessed by Colorado. Capital costs were estimated at \$1,000–\$10,000 and annual operating and maintenance costs were estimated to range from \$100–\$1,000.<sup>591</sup> Colorado anticipated that there would be no additional time needed for achieving compliance with this technology, that the lowered heater-treater temperature would reduce fuel use, and that there would be no non-air quality impacts. Further, Colorado concluded that this control technology would not affect the service life of the heater-treater, noting that the typical life of a heater-treater is 30 to 40 years.<sup>592</sup>

There are few energy and non-air environmental impacts of combustion modifications for heaters and boilers. Generally, the combustion practices used to reduce NOx emissions also increase thermal efficiencies by reducing the amount of excess air needed for combustion, which has the added benefit

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<sup>589</sup> *Id.* at 5.

<sup>590</sup> *Id.* at 2.

<sup>591</sup> See EPA Partner Reported Opportunities (PRO) Fact Sheet No. 906 (last updated September 2004), available at: <https://www.globalmethane.org/documents/m2mtool/docs/lowerheatertreatertemp.pdf> and CDPHE RP for Heater-Treaters at 3.

<sup>592</sup> CDPHE RP for Heater-Treaters at 4.

## Exhibit 1

of reducing fuel usage and increasing energy savings. According to EPA, “[r]eductions in NOx formation achieved by reducing flame temperature and oxygen levels can increase CO and HC emissions if NOx reductions by combustion controls are taken to extremes.”<sup>593</sup> And systems where blowers or fans are used, e.g., for LNB plus FGR, will require additional electric energy.

According to EPA, the length of time to install ULNB is 6–8 months (excluding permitting, reporting preparation, and programmatic and administrative considerations).<sup>594</sup>

While the cost estimates in this section on combustion modification are of a cost basis that spans a timeframe from 1986–2018, it is important to note that, beginning in 2006, several state and local air agencies adopted rules to lower NOx emission limits of 30 ppmv to as low as 5–12 ppm for larger units and found it was cost effective to require such a level of control on existing boilers and heating units. This will be discussed further in Section F. below. It is not possible to accurately escalate the older costs to more current dollars. EPA cautions against escalating costs over a period longer than five years because it can lead to inaccuracies in price estimation.<sup>595</sup> Further, the prices of an air pollution control do not always rise at the same level as price inflation rates. In some cases, the cost of the air pollution control decreases over time due to improvements in the manufacturing of the parts used for the control or different, less expensive materials used, etc.<sup>596</sup> In any event, the fact that air agencies have found low NOx combustion technologies to be cost effective to meet NOx emission limits in the range of 5 to 30 ppm indicates that similar sources have had to incur the costs reflected in Tables 36-40 to meet reduced NOx emission limits, and thus the costs of low NOx combustion technology should be considered reasonable for most heaters and boilers.

### B. POST-COMBUSTION CONTROLS: SCR AND SNCR

Post-combustion controls, such as SCR and SNCR, reduce NOx formation in the flue gas. The following is EPA’s description of these add-on control techniques:

These techniques control NOx by using a reactant that reduces NOx to nitrogen (N<sub>2</sub>) and water. The reactant, ammonia (NH<sub>3</sub>) or urea for SNCR, and NH<sub>3</sub> for SCR, is injected into the flue gas stream. Temperature and residence time are the primary factors that influence the reduction reaction. Selective catalytic reduction uses a catalyst to facilitate the reaction.<sup>597</sup>

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<sup>593</sup> EPA 1993 ACT for Process Heaters Section 2.4.

<sup>594</sup> 2016 EPA CSAPR TSD for Non-EGU Emissions Controls at 15.

<sup>595</sup> EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017.

<sup>596</sup> For example, SCAQMD concluded from its 2008 cost analysis that, “[t]he capital cost for retrofitting a unit has decreased by about 70%....” (SCAQMD 2018 Draft Staff Report at 4-3).

<sup>597</sup> EPA 1993 ACT for Process Heaters at 2-6.

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SCR systems on natural gas-fired boilers and heaters should be able to achieve NO<sub>x</sub> removal efficiencies in the range of 80 to 90+%.<sup>598</sup> SNCR systems on natural gas-fired industrial boilers and heaters can achieve NO<sub>x</sub> reductions in the range of 30-75%.<sup>599</sup>

As early as 1991, CARB, in its 1991 RACT / BARCT determination for Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, identified SCR and SNCR as two of four control methods (along with FGR and LNB).<sup>600</sup> CARB concluded that, for units  $\geq 5$  MMBtu/hr (and  $\geq 90,000$  therms annual heat input), a BARCT NO<sub>x</sub> limit of 30 ppmv (0.036 lbs/MMBtu) could be achieved by installing new burners with FGR, noting that some units would “need to install selective noncatalytic reduction or other emission control technology instead of flue gas recirculation due to particular unit design problems.”<sup>601</sup>

EPA provided cost effectiveness data for SNCR at model heaters in its 1993 Alternative Control Techniques document. Specifically, cost effectiveness of SNCR for heaters, at the time, ranged from: (1) \$3,200–\$6,700/ton for a 77 MMBtu/hr heater; (2) \$2,700–\$5,700/ton for a 121 MMBtu/hr heater; and (3) \$2,300–\$4,900/ton for 186 MMBtu/hr heater.<sup>602</sup>

California Air Districts have long been regulating NO<sub>x</sub> emissions from boilers and process heaters, with CARB issuing RACT / BARCT guidance to Air Districts in 1991.<sup>603</sup> In its 1991 guidance, CARB determined the cost effectiveness of SNCR (in 1986\$) for units as small as 50 MMBtu/hr and as large as 375 MMBtu/hr, as follows: (1) \$1,500–\$6,000/ton for units operating at a 50% capacity factor; and (2) \$1,300–\$3,800/ton for units operating at a 90% capacity factor.<sup>604</sup>

More recent and more detailed cost data are available from California Air Districts that have adopted, and continue to update, regulations for these sources. A recent analysis by California’s SCAQMD for revisions to its series of rules for boilers and process heaters (i.e., Rules 1146, 1146.1, and 1146.2) concluded that, “[u]pon reviewing the type of pollution control technologies available to control NO<sub>x</sub> emissions applicable to the boilers, steam generators and process heaters subject to Rule 1146 and 1146.1, SCR and ultra-low NO<sub>x</sub> burners are still the main technologies that can achieve the NO<sub>x</sub> concentration limits specified in these rules.”<sup>605</sup> SCAQMD further determined that, “[b]ased on the 2008 staff reports for Rule 1146 and 1146.1, SCR as applied to Rule 1146 boilers can achieve NO<sub>x</sub>

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<sup>598</sup> See Petroleum Refinery Tier 2 BACT Analysis Report, Prepared for EPA by Eastern Research Group, Inc., January 16, 2001, at 3-11, available at: <https://archive.epa.gov/airquality/ttnnsr01/web/pdf/bactrpt.pdf>. See also NESCAUM 2000 Status Report at II-7. These are both cited by EPA in its Chapter 2, Selective Catalytic Reduction, June 2019, in Section 4 of EPA’s Control Cost Manual (References 19 and 24)

<sup>599</sup> See EPA, Control Cost Manual, Section 4, Chapter 1, Selective Noncatalytic Reduction, at 1-2, available at: <https://www.epa.gov/sites/production/files/2017-12/documents/snrcostmanualchapter7thedition20162017revisions.pdf>.

<sup>600</sup> CARB 1991 Guidance at 8.

<sup>601</sup> CARB 1991 Guidance at 6.

<sup>602</sup> EPA 1993 ACT for Process Heaters Table 2-4. EPA calculates an annualized cost of control assuming a capital recovery factor of 0.131474 (i.e., assuming a 15-year life of controls and a 10% interest rate).

<sup>603</sup> CARB 1991 Guidance.

<sup>604</sup> CARB 1991 Guidance Table 4. Note, CARB does not identify the underlying assumptions for annualized costs, life of controls, etc.

<sup>605</sup> SCAQMD 2018 Draft Staff Report at 2-4.

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concentrations from 5 to 6 ppm for units greater than or equal to 75 MMBtu/hr.”<sup>606</sup> SCAQMD’s revisions to Rule 1146 for Boilers, steam generators, and process heaters  $\geq 5$  MMBtu/hr allow facilities until January 1, 2022 to retrofit all existing units and until January 1, 2023 to replace any existing units to meet a NO<sub>x</sub> emission limit of 5 ppm for units  $\geq 75$  MMBtu/hr burning natural gas.<sup>607</sup> SCAQMD determined that the 1146 rule series are cost effective, including for units  $\geq 75$  MMBtu/hr retrofitted with SCR to meet an emission limit of 5 ppm.<sup>608</sup>

In the SJVAPCD, the District described the following approach to achieving lower NO<sub>x</sub> limits, acknowledging certain technical and cost feasibility considerations with SCR for certain units:

The amendment of Rule 4306 in October 2008 was initially proposed to lower the NO<sub>x</sub> emission limit from 9 ppmv to 6 ppmv for units greater than 20 MMBtu/hr. It was determined that the proposed NO<sub>x</sub> limits could be accomplished by using selective catalytic reduction (SCR) or a combination of SCR and ultra-low NO<sub>x</sub> burners (ULNBs), thus making the lower limits technologically feasible. However, through the public workshop process and additional research it was also determined that most of the units subject to Rule 4306 have undergone several generations of NO<sub>x</sub> controls, and consequently, certain applications of SCR may not be cost effective and/or technological infeasible because of physical limitations. Therefore, the lower NO<sub>x</sub> limits were included in new Rule 4320 and an option was provided in the rule that allows for the payment of an annual emissions fee based on total actual emissions, rather than installation of additional NO<sub>x</sub> controls. These fees are used by the District to achieve cost effective NO<sub>x</sub> reductions through District incentive programs, the District’s Technology Advancement Program, and other routes.<sup>609</sup>

SJVAPCD is in the process of reviewing its rules for boilers and process heaters  $>5$  MMBtu/hr and is proposing updates as part of its 2018 PM<sub>2.5</sub> Attainment Plan commitments to reduce NO<sub>x</sub> emissions.<sup>610</sup> SJVAPCD is considering lowering NO<sub>x</sub> limits for units  $>5$  MMBtu/hr to levels ranging from 2–3.5 ppm.<sup>611</sup> As part of its control measure analysis, SJVAPCD analyzed the cost effectiveness of retrofitting units of varying sizes with SCR to achieve these NO<sub>x</sub> levels, based on information from SCR vendors. We assume these data are in 2018\$.

The SJVAPCD cost data for retrofitting existing units with SCR includes detailed direct and indirect capital, installation, and operating and maintenance costs for two unit size categories: (1) units  $>5$  and  $\leq 20$  MMBtu/hr; and (2) units  $>20$  MMBtu/hr.<sup>612</sup>

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<sup>606</sup> *Id.* at 2-2.

<sup>607</sup> *Id.* at 1-2.

<sup>608</sup> *Id.* at 4-6.

<sup>609</sup> See SJVAPCD 2016 Plan for the 2008 8-Hour Ozone Standard (June 16, 2016), p. C-27, available at: [http://www.valleyair.org/Air\\_Quality\\_Plans/Ozone-Plan-2016/c.pdf](http://www.valleyair.org/Air_Quality_Plans/Ozone-Plan-2016/c.pdf).

<sup>610</sup> SJVAPCD Rules 4306 and 4320. See: [https://www.valleyair.org/Workshops/public\\_workshops\\_idx.htm#12-05-19 ICE](https://www.valleyair.org/Workshops/public_workshops_idx.htm#12-05-19 ICE).

<sup>611</sup> SJVAPCD 2018 PM<sub>2.5</sub> Attainment Plan pp. C-84–C-87.

<sup>612</sup> SJVAPCD 2018 PM<sub>2.5</sub> Attainment Plan pp. C-80–C-82. Note, the cost estimates assume that the existing foundation and supports will not be replaced and that direct and indirect annual costs are presumed to be the same as the existing burner.

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Table 41 below summarizes the total costs for retrofitting existing units  $\geq 5$  MMBtu/hr with SCR, based on SJCAPCD-obtained vendor data, along with calculated annualized costs of the control, assuming a 5.5% interest rate and a 25-year life for SCR. SCAQMD is currently assuming a 25-year life for refinery heaters and boilers.<sup>613</sup> Table 41 also presents the cost effectiveness of applying SCR existing units to reduce NO<sub>x</sub> emissions from uncontrolled levels to levels of: (1) 2.5 ppm for units  $>20$  MMBtu/hr; and (2) 3.5 ppm for units  $>5$  and  $\leq 20$  MMBtu/hr.<sup>614</sup> Uncontrolled emissions are based on the EPA AP-42 uncontrolled emission rate for small boilers  $<100$  MMBtu/hr of 100 lb/MMscf (0.098 lb/MMBtu). Meeting emission limits of 2.5 ppm and 3.5 ppm from this uncontrolled level reflects a control efficiency using state-of-the-art SCR technology of 96% and 97%, respectively. Cost effectiveness is presented for operation at a 50% and 90% capacity factor.

**Table 41. Cost Effectiveness of Retrofitting Existing Units with SCR to Achieve NO<sub>x</sub> Levels of 2.5 ppm for Units  $>20$  MMBtu/hr and 3.5 ppm for Units  $>5$  and  $\leq 20$  MMBtu/hr Operating at a 50% and 90% Capacity Factor.**<sup>615</sup>

UNIT SIZE (MMBtu/hr)	TOTAL CAPITAL COSTS (2018\$)	TOTAL ANNUALIZED COSTS (2018\$)	COST EFFECTIVENESS (\$/TON) 50% CAPACITY FACTOR	COST EFFECTIVENESS (\$/TON) 90% CAPACITY FACTOR
5	\$261,728	\$26,055	\$25,354	\$14,086
10			\$12,677	\$7,043
15			\$8,451	\$4,695
20			\$6,339	\$3,521
30	\$385,705	\$38,397	\$6,149	\$3,416
40			\$4,612	\$2,562
50			\$3,689	\$2,050
60			\$3,074	\$1,708
70			\$2,635	\$1,464
80			\$2,306	\$1,281
90			\$2,050	\$1,139
100			\$1,845	\$1,025

<sup>613</sup> See, e.g., SCAQMD Presentation for Rule 1109.1 – NO<sub>x</sub> Emission Reduction for Refinery Equipment, Working Group Meeting #9, December 12, 2019, slides 41 and 57, available at: [http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm\\_9\\_final.pdf?sfvrsn=12](http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pr1109-1-wgm_9_final.pdf?sfvrsn=12).

<sup>614</sup> See SJVAPCD 2018 PM<sub>2.5</sub> Attainment Plan at C-85 and C-87, stating: “Source test results of various units with SCR systems indicate that an SCR can potentially achieve 3.5 ppmv NO<sub>x</sub> @ 3% O<sub>2</sub> for units rated between 5 to 20 MMBtu/hr.” and “Source test results of various units with SCR system indicate that an SCR can reliably achieve 2.5 ppmv NO<sub>x</sub> @ 3% O<sub>2</sub> (or less) emissions for units greater than 20 MMBtu/hr.”

<sup>615</sup> Cost data provided by vendors to SJVAPCD, annualized costs calculated assuming a 25-year life and a 5.5% interest rate.

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SJVAPCD based its cost analysis on vendor data for the SCR systems and largely on EPA's Air Pollution Control Cost Manual (6<sup>th</sup> Edition) for installation, operating and maintenance costs, etc., for these systems.

This analysis indicates that it is cost effective to retrofit units, especially those >20 MMBtu/hr, with SCR to achieve NO<sub>x</sub> levels as low as 2.5–3.5 ppm.

The energy and non-air environmental impacts of post-combustion control techniques include:

- Parasitic load of operating an SCR system, which requires additional energy (fuel use and electricity) in order to maintain output across the catalyst;
- Solid waste disposal of spent SCR catalyst;
- Ammonia, CO, and nitrous oxide emissions with the use of SNCR;
- Ammonia and sulfite emissions with the use of SCR; and
- Ammonia handling and storage with SNCR and SCR.<sup>616</sup>

According to EPA, the length of time to install SCR is 28–58 weeks (excluding permitting, reporting preparation, and programmatic and administrative considerations).<sup>617</sup> The Institute of Clean Air Companies has stated that SCRs for smaller units (less than 20,000 standard cubic feet per minute gas throughput) are often available in ready-to-install SCR skid packages, and thus SCR for smaller units would take closer to 28 weeks to install.<sup>618</sup> An SNCR would take much less time to install. The Institute of Clean Air Companies states that it takes about 10-13 months to install SNCR, which covers the time from bid evaluations to startup of the SNCR.<sup>619</sup>

### C. NO<sub>x</sub> CONTROLS FOR SEPARATORS

Colorado's Reasonable Progress Evaluation for the heater-treater source category evaluated the installation of insulation on the separator to reduce fuel usage, and resulting combustion emissions (including NO<sub>x</sub>).<sup>620</sup> Installation of insulation on separators was also included in the Four Corners Air Quality Task Force Report of Mitigation Options for the oil and gas industry and determined to be a technically feasible technique for reducing NO<sub>x</sub> emissions.<sup>621</sup> Estimates for NO<sub>x</sub> emission reductions from insulating separators were not provided in the Four Corners Air Quality Task Force report and were not assessed by Colorado. The cost effectiveness of this control will depend on the remaining life of the

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<sup>616</sup> EPA 1993 ACT for Process Heaters Section 2.4.

<sup>617</sup> 2016 EPA CSAPR TSD for Non-EGU Emissions Controls at 15.

<sup>618</sup> See Institute of Clean Air Companies, Typical Installation Timelines for NO<sub>x</sub> Emissions Control Technologies on Industrial Sources, December 4, 2006, at 4-5, *available at*: [https://cdn.ymaws.com/icac.site-ym.com/resource/resmgr/ICAC\\_NOx\\_Control\\_Installatio.pdf](https://cdn.ymaws.com/icac.site-ym.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf).

<sup>619</sup> *Id.* at 7-8.

<sup>620</sup> CDPHE RP for Heater-Treaters.

<sup>621</sup> Four Corners Air Quality Task Force Report of Mitigation Options (November 1, 2007) at 89.

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equipment to which it is applied. Colorado anticipated that there would be no additional time needed for achieving compliance with this technology and that there would be no non-air quality impacts.

### D. NO<sub>x</sub> CONTROLS FOR DEHYDRATORS

Use of a zero emission dehydrator can significantly reduce fuel requirements for a reboiler and therefore reduce combustion emissions (including NO<sub>x</sub>). The Four Corners Air Quality Task Force report identified this type of dehydrator as a mitigation option and described this type of unit and its emissions, as follows:

The zero emissions dehydrator combines several technologies that lower emissions. These technologies eliminate emissions from glycol circulation pumps, gas strippers and the majority of the still column effluent. . . . Benefits of this technology include: . . . Reduces emissions of particulate matter, sulfur dioxide, NO<sub>x</sub> or CO emissions . . . Significantly reduces fuel requirements for glycol reboiler. Natural gas that was used for this purpose can now be sent to market.<sup>622</sup>

The Four Corners Air Quality Task Force report describes how existing dehydrators can be retrofitted to zero emissions dehydrators, “by modifying the gas stream piping and using a 5 kW engine-generator for electricity needs.”<sup>623</sup> The Four Corners Air Quality Task Force reports that operating and maintenance costs are lower than for conventional glycol dehydrators and further reports that EPA estimates the payback for installing a zero emission dehydrator in place of a conventional glycol dehydrator to occur in less than a year.<sup>624</sup>

### E. CENTRAL GATHERING FACILITIES TO REDUCE NO<sub>x</sub> EMISSIONS FROM WELLHEAD SEPARATION SOURCES

Centralization of gas well gathering facilities can be employed to reduce and consolidate wellsite sources, including heaters and separators. Colorado’s Reasonable Progress Evaluation for the heater-treater source category evaluated central gathering facilities to remove wellhead separation.<sup>625</sup> With centralization, emissions from heater-treaters would be reduced because fewer heater-treaters would be needed. Colorado described the effectiveness of this restructuring, as follows:

Removing individual heater-treaters and replacing them with a central gathering facility would eliminate emissions from the heater-treaters. The central gathering facility would be a new source of emissions; however, overall emissions will be reduced. Not only would combustion emissions from the multiple heater-treaters be eliminated, VOC emissions from condensate

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<sup>622</sup> *Id.* at 92.

<sup>623</sup> *Id.* at 93. The report further notes that the electricity needs require a “fuel or power source, for which associated emissions need to be quantified.”

<sup>624</sup> *Id.* at 93.

<sup>625</sup> CDPHE RP for Heater-Treaters.

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tanks (which would also be removed from wellheads if this technology was implemented) would be eliminated. If a vapor recovery unit (VRU) were used at the central gathering facility, VOCs could be compressed back into the gas stream.<sup>626</sup>

Colorado acknowledges that it would be most cost effective to implement a centralized gathering facility on a new field but indicates that retrofitting a field already set up with infrastructure for wellhead separation would be site-specific and depends on several considerations, including the number of heater-treaters being removed, topography, gas composition, mineral rights, etc. Additional benefits of a centralized gathering facility include reduced truck traffic to wellheads (which can be significant sources of fugitive PM emissions) and a reduction in condensate and water tanks (and their associated fugitive emissions). States should consider requiring or otherwise advocating for centralized gathering facilities for new oil and gas development as a measure to prevent future visibility impairment.

Estimates for NOx emission reductions from the centralization of gas well gathering facilities were not assessed by Colorado other than saying that overall emissions will be reduced. Colorado anticipated that additional time needed for achieving centralization would be site-specific, e.g., depending on gas well density and topographical barriers. Finally, Colorado notes that central gathering facilities would be more efficient to operate, reducing overall energy impacts.

### F. NOx EMISSION LIMITS THAT HAVE BEEN REQUIRED FOR HEATERS AND BOILERS

States and local air agencies have adopted NOx limits for existing boilers and heaters, many of which have been in place for more than 20 years and many of which have been strengthened over the years. In Table 42 below, we summarize some of those state and local air pollution requirements. Primarily, a review of California Air District rules was done for this report, because several of those air districts have adopted the most stringent NOx emission limitations.

Table 42 is a summary of the NOx emission limits required of existing boilers and heaters in states and local air districts across the United States. It is important to note that these are limits that, unless otherwise noted, currently apply to existing units and generally required an air pollution control retrofit. These NOx limits were most likely adopted to address nonattainment issues with the ozone and PM<sub>2.5</sub> NAAQS. Regardless of the reason for adopting the NOx emission limits, what becomes clear in this analysis is that governments have adopted NOx limitations that require low NOx technologies at boilers and heaters as small as 0.4 MMBtu/hr and SCR for units  $\geq 75$  MMBtu/hr. The lowest, most broadly applicable NOx limits are those recently adopted by SCAQMD and SJVAPCD. SJVAPCD has a more stringent limit than SCAQMD rules for units between 20 and 75 MMBtu/hr (7 ppm in SJVUAPCD Rule 4320 vs. 9 ppm in SCAQMD Rule 1146), however, it is important to note that for SJVUAPCD's Rules 4306 and 4320, the owner or operator has the option of paying into an annual emissions fee in lieu of

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<sup>626</sup> *Id.* at 3.



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complying with these limits. For units  $\geq 75$  MMBtu/hr, the emission limit in SCAQMD Rule 1146 of 5 ppm is more stringent than SJVAPCD's limit of 7 ppm.

**Table 42. State/Local Air Agency Natural Gas-Fired Boiler and Heater Rules<sup>627</sup>**

State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
CA-SCAQMD	Rule 1146. <sup>628</sup>  Adopted 9/9/98 Last revised 12/7/18	$\geq 5$ MMBtu/hr Effective 9/5/08	30 ppm (0.036 lb/MMBtu)
		$\geq 5$ MMBtu/hr Effective 1/1/14 Atmospheric units	12 ppm (0.015 lb/MMBtu)
		$\geq 75$ MMBtu/hr Effective 1/1/13 Excluding thermal fluid heaters	5 ppm (0.0062 lb/MMBtu)
		$\geq 20$ and $< 75$ MMBtu/hr Effective 12/7/18 Excluding thermal fluid heaters, certain fire-tube boilers, and units with a previous NOx limit $\leq 12$ and $> 5$ ppm prior to 12/7/18	5 ppm (0.0062 lb/MMBtu)
		$\geq 5$ and $< 20$ MMBtu/hr Effective 1/1/15 (or later for units with a previous NOx limit $\leq 12$ ppm prior to 9/5/08) Excluding atmospheric units and thermal fluid heaters	9 ppm (0.011 lb/MMBtu)
		$\geq 5$ and $< 20$ MMBtu/hr Effective 12/7/18 (or later for units with a previous NOx limit $\leq 9$ ppm prior to 12/7/18) Fire-tube boilers excluding units with a previous NOx limit $\leq 12$ and $> 9$ ppm prior to 12/7/18	7 ppm (0.0085 lb/MMBtu)
		$\geq 5$ MMBtu/hr Effective 12/7/18 (or later for certain units at non-RECLAIM facilities) Thermal fluid heaters	12 ppm (0.015 lb/MMBtu)

<sup>627</sup> This table attempts to summarize the requirements and emission limits of State and Local Air Agency rules applicable to the types of units found in the oil and gas industry, but the authors recommend that readers check each specific rule for the details of how the rule applies to different units, and in case of any errors in this table.

<sup>628</sup> <https://ww3.arb.ca.gov/drdb/sc/curhtml/r1146.pdf>.

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State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
CA-SCAQMD	Rule 1146.1 <sup>629</sup>  Adopted 10/5/90 Last revised 12/7/18	>2 and <5 MMBtu/hr Effective 9/5/08	30 ppm (0.036 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 1/1/14 Atmospheric units	12 ppm (0.015 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 1/1/14 (or later for units with a previous NOx limit ≤12 and >9 ppm prior to 9/5/08) Excluding atmospheric units, thermal fluid heaters, and certain fire-tube boilers	9 ppm (0.011 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 12/7/18 (or later for units with a previous NOx limit ≤9 ppm prior to 12/7/18) Fire-tube boilers excluding units with ≤12 and >9 ppm prior to 12/7/18	7 ppm (0.0085 lb/MMBtu)
		>2 and <5 MMBtu/hr Effective 12/7/18 (or later for certain units at non-RECLAIM facilities) Thermal fluid heaters	12 ppm (0.015 lb/MMBtu)
CA-SCAQMD	Rule 1146.2 <sup>630</sup>  Adopted 1/9/98 Last revised 12/7/18	>0.4 and ≤2 MMBtu/hr Effective 1/1/10 Units manufactured or offered for sale	20 ppm (0.024 lb/MMBtu)
		>1 and ≤2 MMBtu/hr Effective 1/1/06 Units more than 15 years old manufactured on or after 1/1/92, except for units at a RECLAIM or former RECLAIM facility	30 ppm (0.037 lb/MMBtu)
		>0.4 and ≤1 MMBtu/hr Effective 1/1/06 Units more than 15 years old manufactured prior to 1/1/00, except for units at a	30 ppm (0.037 lb/MMBtu)

<sup>629</sup> <http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1146-1.pdf>.

<sup>630</sup> <http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1146-2.pdf?sfvrsn=17>.

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State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
		RECLAIM or former RECLAIM facility	
CA-SJVAPCD	Rule 4320 <sup>631</sup>  Adopted 10/16/08	>5 and ≤20 MMBtu/hr Effective 1/1/14 Except for certain other units <sup>632</sup>	6 ppmv (0.007 lb/MMBtu) <sup>633</sup>
		>20 MMBtu/hr Effective 1/1/14 <sup>634</sup> Except for refinery units, <sup>635</sup> and certain other units <sup>636</sup>	5 ppmv (0.0062 lb/MMBtu) <sup>637</sup>
		>5 MMBtu/hr Effective at the next unit replacement but no later than 1/1/14 Certain units <sup>638</sup>	9 ppmv (0.011 lb/MMBtu)
CA-SJVAPCD	Rule 4306 (Phase 3) <sup>639</sup>	>5 and ≤20 MMBtu/hr	9 ppmv (0.011 lb/MMBtu)

<sup>631</sup> <https://www.valleyair.org/rules/currnrules/r4320.pdf>.

<sup>632</sup> These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

<sup>633</sup> Note, the owner or operator has the option of paying into an annual emissions fee based on total actual emissions, rather than installation of additional NOx controls. These fees are used by the District to achieve cost effective NOx reductions through incentives programs, etc.

<sup>634</sup> The rule allows for a “Staged Enhanced Schedule” for oil field steam generators and refinery units as follows: (1) Initial Limit of 9 ppmv (0.011 lb/MMBtu), effective 7/1/12; and (2) Final Limit of 5 ppmv (0.0062 lb/MMBtu), effective 1/1/14.

<sup>635</sup> Note, refinery unit requirements are the same except that these units have a Standard Schedule limit of 6 ppm, effective 7/1/11.

<sup>636</sup> These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

<sup>637</sup> Note, the owner or operator has the option of paying into an annual emissions fee based on total actual emissions, rather than installation of additional NOx controls. These fees are used by the District to achieve cost effective NOx reductions through incentives programs, etc.

<sup>638</sup> These certain other units include: (1) those installed prior to 1/1/09 and limited by a Permit to Operate to an annual heat input >1.8 billion Btu/yr but ≤30 billion Btu/yr; (2) units at a wastewater treatment facility firing on less than 50%, by volume, PUC quality gas; and (3) units operated by a small producer in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is rated between 5 and 20 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

<sup>639</sup> <https://ww3.arb.ca.gov/drdb/sju/curhtml/r4306.pdf>.

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State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
	Adopted 9/18/03 Last revised 10/16/08	Effective 12/1/08 Except for oil field steam generators, refinery units, and certain other units <sup>640</sup>	
		>20 MMBtu/hr Effective 1/1/14 Except for oil field steam generators, refinery units, and certain other units <sup>641</sup>	6 ppmv (0.007 lb/MMBtu)
		>5 MMBtu/hr Effective 6/1/07 Oilfield steam generators Load-following units <sup>642</sup>	15 ppm (0.036 lb/MMBtu)
		>5 MMBtu/hr Effective 6/1/07 Certain other units <sup>643</sup>	30 ppm (0.036 lb/MMBtu)
CA-SJVAPCD	Rule 4307 <sup>644</sup>	>2 and ≤5 MMBtu/hr Existing units	30 ppm (0.036 lb/MMBtu)
	Adopted 12/15/05 Last revised 4/21/16	>2 and ≤5 MMBtu/hr New or replacement units Effective 1/1/16 Atmospheric units Non-atmospheric units	12 ppm (0.014 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA-SJVAPCD	Rule 4308 <sup>645</sup>  Adopted 10/20/05 Last revised 11/14/13	>0.4 and <2 MMBtu/hr Effective 1/1/15 Point-of-sale <sup>646</sup> PUC gas Non-PUC gas	20 ppm (0.024 lb/MMBtu) 30 ppm (0.036 lb/MMBtu)
CA-SMAQMD	Rule 411 <sup>647</sup>	Effective 10/27/09	

<sup>640</sup> These certain other units include: (1) load-following units; (2) units limited by a Permit to Operate to an annual heat input 9–30 billion Btu/yr; and (3) units in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is > 5 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

<sup>641</sup> *Id.*

<sup>642</sup> Load-following units must meet a limit of 9 ppm under the Enhanced Schedule, with a compliance date of 12/1/08.

<sup>643</sup> These certain other units include: (1) refinery units >5 and ≤65 MMBtu/hr (note that units >65 and ≤110 MMBtu/hr are required to meet a limit of 25 ppm (0.031 lb/MMBtu and units >110 MMBtu/hr are required to meet a limit of 5 ppm); (2) units limited by a Permit to Operate to an annual heat input 9–30 billion Btu/yr; and (3) units in which the rated heat input of each burner is ≤5 MMBtu/hr but the total rated heat input of all the burners in a unit is > 5 MMBtu/hr, as specified in the Permit to Operate, and in which products of combustion do not come in contact with the products of combustion of any other burner.

<sup>644</sup> <https://www.valleyair.org/rules/currnrules/Rule4307.pdf>.

<sup>645</sup> [https://www.valleyair.org/rules/currnrules/03-4308\\_CleanRule.pdf](https://www.valleyair.org/rules/currnrules/03-4308_CleanRule.pdf).

<sup>646</sup> This point-of-sale rule covers units supplied, sold, offered for sale, installed, or solicited for installation.

<sup>647</sup> <http://www.airquality.org/ProgramCoordination/Documents/rule411.pdf>.

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State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
	Adopted 2/2/95 Last revised 8/23/07	New and existing units ≥1 and <5 MMBtu/hr ≥5 and ≤20 MMBtu/hr >20 MMBtu/hr	30 ppm (0.036 lb/MMBtu) 15 ppm (0.036 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–SMAQMD	Rule 414 <sup>648</sup> Adopted 8/1/96 Last revised 10/25/18	>0.4 and <1 MMBtu/hr Effective 10/25/18 (date of last revision) Point-of-sale <sup>649</sup>	20 ppm (0.024 lb/MMBtu)
CA–VCAPCD	Rule 74.15.1 <sup>650</sup> Adopted 5/11/93 Last revised 6/23/15	≥1 and <5 MMBtu/hr Effective 1/1/16 Existing units New and Replacement: Atmospheric units Pressurized Units	30 ppm (0.036 lb/MMBtu)  12 ppm (0.014 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–Santa Barbara County APCD	Rule 361 <sup>651</sup> Adopted 1/17/08 Last revised 6/20/19	>2 and <5 MMBtu/hr  Existing units  Installed and modified (after 1/1/20): Atmospheric units Non-atmospheric Units	30 ppm (0.036 lb/MMBtu)   12 ppm (0.014 lb/MMBtu) 9 ppm (0.011 lb/MMBtu)
CA–Santa Barbara County APCD	Rule 342 <sup>652</sup> Adopted 3/10/92 Last revised 6/20/19	≥5 MMBtu/hr  Existing units  Installed and modified (after 1/1/20): ≥5 and ≤20 MMBtu/hr >20 MMBtu/hr	30 ppm (0.036 lb/MMBtu)   9 ppm (0.011 lb/MMBtu) 7 ppm (0.0085 lb/MMBtu)
CA–Feather River AQMD	Rule 3.23 <sup>653</sup> Adopted 10/3/16	>0.4 and <1 MMBtu/hr Effective 1/1/17 Point-of-sale <sup>654</sup>	20 ppm (0.024 lb/MMBtu)
CA–Bay Area AQMD	Regulation 9 Rule 7 <sup>655</sup> Adopted 9/16/92	>2 and ≤5 MMBtu/hr Effective 1/1/15	30 ppm (0.036 lb/MMBtu)

<sup>648</sup> <http://www.airquality.org/ProgramCoordination/Documents/rule414.pdf>.

<sup>649</sup> This point-of-sale rule covers units manufactured, distributed, offered for sale, sold, or installed.

<sup>650</sup> <http://www.vcapcd.org/Rulebook/Reg4/RULE%2074.15.1.pdf>.

<sup>651</sup> <https://www.ourair.org/wp-content/uploads/rule361.pdf>.

<sup>652</sup> <https://www.ourair.org/wp-content/uploads/rule342.pdf>.

<sup>653</sup> <https://www3.arb.ca.gov/drdb/fr/curhtml/r3-23.pdf>.

<sup>654</sup> This point-of-sale rule covers units offered for sale, sold, or installed.

<sup>655</sup> <https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-9-rule-7-nitrogen-oxides-and-carbon-monoxide-from-industrial-institutional-and-commercial-boiler/documents/rg0907.pdf?la=en>.

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State/Local	Regulation	Applicability	NOx Limit and units (equivalent lb/MMBtu)
		>5 and <10 MMBtu/hr Effective 1/1/15	15 ppm (0.036 lb/MMBtu)
		≥10 and <20 MMBtu/hr Effective 1/1/14	15 ppm (0.036 lb/MMBtu)
		≥20 and <75 MMBtu/hr Effective 1/1/14	9 ppm (0.011 lb/MMBtu)
		≥75 MMBtu/hr Effective 1/1/14	5 ppm (0.0062 lb/MMBtu)
		Excluding thermal fluid heaters	
TX- Houston-Galveston-Brazoria Area	30 TAC 117.2010(c)(1) Emission Specs for 8hr ozone demo <sup>656</sup>	Emission specs for mass emission cap and trade	0.036 lb/MMBtu (or, alternatively 30 ppm @ 3% O2)
TX	30 TAC 117.3205(a) <sup>657</sup>	Statewide Point-of-sale <sup>658</sup> Effective 7/1/02 >0.4 and ≤2 MMBtu/hr	30 ppm or 0.037 lb/MMBtu
MA	310 CMR 7.26(30) <sup>659</sup>	≥10 and <40 MMBtu/hr Effective 9/14/01	0.0350 lb/MMBtu
NY	6 CRR-NY 227-2.4 <sup>660</sup>	>25 and ≤100 MMBtu/hr	0.05 lb/MMBtu
GA	Rule 391-3-1-.02.(2)(III)1. <sup>661</sup>	Effective 5/1/00 Fuel-burning equipment 45 county area – ozone May 1 – September 30 each year	30 ppm

<sup>656</sup> [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](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).

<sup>657</sup> [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=3205](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=3205).

<sup>658</sup> Applies to units sold, distributed, installed, or offered for sale.

<sup>659</sup> <https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download>.

<sup>660</sup> RACT for major sources of NOx:

[https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originati onContext=documenttoc&transitionType=CategoryPageItem&contextData=\(sc.Default\)](https://govt.westlaw.com/nycrr/Document/I4e978e48cd1711dda432a117e6e0f345?viewType=FullText&originati onContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default)).

<sup>661</sup> <http://rules.sos.ga.gov/gac/391-3-1>.

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### Most stringent NO<sub>x</sub> Limits of State/Local Rules:

5 ppm (0.0062 lb/MMBtu).....	Units ≥75 MMBtu/hr
5–12 ppm (0.0062–0.015 lb/MMBtu) .....	Units >2 and <75 MMBtu/hr
20 ppm (0.024 lb/MMBtu).....	Units ≤2 MMBtu/hr

As Table 42 shows, several state and local air pollution control agencies have adopted NO<sub>x</sub> emission limits for boilers and heaters that reflect the application of low NO<sub>x</sub> burner technologies, and reflect SCR for units ≥75 MMBtu/hr. These air agencies have thus found that the levels of NO<sub>x</sub> control listed in Table 42, including NO<sub>x</sub> limits as low as 5 ppm for larger units, in the range of 5–12 ppm for smaller units, and as low as 20 ppm for very small units, providing relevant examples for states to consider in their second round haze plans to help make reasonable progress towards remedying existing visibility impairment. The fact that these limits could apply to modified units >2 MMBtu/hr means that the states consider retrofit controls to meet the emission limits in Table 42 above to be cost effective, and should also consider the cost effectiveness of retrofitting units >5 MMBtu/hr to meet NO<sub>x</sub> limits as low as 2–3.5 ppm based on the work being done in the SJVAPCD.

### G. SUMMARY – NO<sub>x</sub> CONTROLS FOR NATURAL GAS-FIRED HEATERS AND BOILERS

The above analyses and rule data demonstrate that numerous state and local air agencies have found that low NO<sub>x</sub> burner technology is a cost effective retrofit NO<sub>x</sub> control for boilers and heaters >5 MMBtu/hr with costs ranging from \$545/ton to \$5,232/ton. Smaller units ≤5 MMBtu/hr can be replaced with new units with low NO<sub>x</sub> burner technology at costs ranging from \$4,055/ton to \$10,809/ton. Low NO<sub>x</sub> burner technologies can generally meet limits down to 5–6 ppm, with the potential for emerging technologies to meet NO<sub>x</sub> levels lower than 5 ppm. For most units, including atmospheric units, a blower may be required to mix the fuel and air prior to combustion. It is possible to reach NO<sub>x</sub> levels of 9 ppm for non-atmospheric units and 12 ppm for atmospheric units without the use of FGR.<sup>662</sup>

Further, SJVAPCD has found that SCR is cost effective for larger units with costs ranging from \$1,025/ton to \$6,149/ton to meet NO<sub>x</sub> levels as low as 2.5 ppm. For the lowest NO<sub>x</sub> limit of 5–6 ppm currently applicable to units under rules adopted by SCAQMD and SJVAPCD, SCR is presumably necessary to meet these limits.

As states evaluate regulation of NO<sub>x</sub> emissions from boilers and heaters, there are several factors to consider, such as draft type (i.e., atmospheric vs. non-atmospheric), operating capacity factor, and size. Nonetheless, given the numerous local NO<sub>x</sub> limits in Table 42 above that reflect operation of low NO<sub>x</sub> burner technology, and SCR for larger units, these controls for units of all sizes should generally be considered as cost effective measures available to make reasonable progress from boilers, reboilers, and

<sup>662</sup> See, e.g., Santa Barbara County APCD 2019 Draft Staff Report.

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heaters, given that similar sources have assumed similar costs of control to meet Clean Air Act requirements.

### VIII. ADDRESSING VISIBILITY-IMPAIRING EMISSIONS FROM FLARING AND THERMAL INCINERATION OF EXCESS GAS AND WASTE GAS

Gas flaring is a process to combust excess or waste gases from oil wells, gas processing plants, or oil refineries. Flaring is intended as a means of disposal of excess gas as a safety measure and is also done to relieve pressure in gas pipelines. Combustion of excess or waste gas can also be accomplished with thermal incinerators rather than flaring.<sup>663</sup> Combustion of excess gas whether done through flaring or thermal incineration is also a VOC control device, as the combustion of the gas destroys most of the VOCs. However, the extent to which VOC emissions are effectively destroyed depends on the design and operation of the combustion device.

There are several processes associated with oil and gas development in which excess gas is flared or combusted, including the following: during testing of a new oil or gas well, when natural gas co-occurs with a new oil well, at gas pipeline headers and at gas processing plants when needed to relieve pressure, at gas compressor stations to combust vapors captured by a dehydrator unit, at gas processing plants and at oil refineries when an upset occurs or to allow maintenance of equipment, and at gas sweetening plants.<sup>664</sup>

A flare system is a thermal oxidation process using an open flame. It consists of an elevated flare stack through which the waste or excess gas stream flows, where it is combusted at the tip of the stack producing a flame. This is sometimes referred to as a “candlestick” flare. A thermal incinerator, which is also called a direct flame incinerator, thermal oxidizer, or an afterburner, is a thermal oxidation process that occurs in an enclosed combustion chamber. The temperature of the waste gas is raised in the combustion chamber in the presence of oxygen above its autoignition point by passing the gas through a flame which is maintained by the waste gas and auxiliary fuel, and combustion of the waste gas occurs. More specific descriptions of these control devices are provided below. The purpose of both a flare and a thermal incinerator is to combust the excess or waste gas and reduce VOC emissions.

#### A. FLARING SYSTEM

EPA describes a flare system as follows:

Flaring is a high-temperature oxidation process used to burn waste gases containing combustible components such as volatile organic compounds (VOCs), natural gas (or

<sup>663</sup> See Alberta Energy Regulator, EnerFAQS, Flaring and Incineration, available at: <https://www.aer.ca/providing-information/news-and-resources/enerfaqs-and-fact-sheets/enerfaqs-flaring>.

<sup>664</sup> See, e.g., Ohio EPA, Understanding the Basics of Gas Flaring, November 2014, available at: <https://www.epa.state.oh.us/portals/27/oil%20and%20gas/basics%20of%20gas%20flaring.pdf>. See also Eman, Eman A., Gas Flaring in Industry: An Overview, Petroleum & Coal 57(5) 532-555, 2015, available at: <http://large.stanford.edu/courses/2016/ph240/miller1/docs/emam.pdf>.



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methane), carbon monoxide (CO), and hydrogen (H<sub>2</sub>). The waste gases are piped to a remote, usually elevated location, and burned in an open flame in ambient air using a specially designed burner tip, auxiliary fuel, and, in some cases, assist gases like steam or air to promote mixing for nearly complete (e.g., ≥ 98%) destruction of the combustible components in the waste gas. Note that destruction efficiency is the percentage of a specific pollutant in the flare vent gas that is converted to a different compound (such as carbon dioxide [CO<sub>2</sub>], carbon monoxide, or another hydrocarbon intermediate), while combustion efficiency is the percentage of hydrocarbon in the flare vent gas that is completely converted to CO<sub>2</sub> and water vapor. . . .

Combustion requires three ingredients: fuel, an oxidizing agent (typically oxygen in the air), and heat (or ignition source). Flares typically operate with pilot flames to provide the ignition sources, and they use ambient air as the oxidizing agent. The waste gases to be flared typically provide the fuel necessary for combustion. Combustible gases generally have an upper and lower flammability limit. The upper flammability limit (UFL) is the highest concentration of a gas in air that is capable of burning. Above this flammability limit, the fuel is too rich to burn. The lower flammability limit (LFL) is the lowest concentration of the gas in air that is capable of burning. Below the LFL, the fuel is too lean to burn. Between the UFL and the UFL, combustion can occur. Completeness of combustion in a flare is governed by flame temperature, residence time and flammability of the gas in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and available oxygen for free radical formation. Combustion is complete if all hydrocarbons and CO are converted to CO<sub>2</sub> and water. Incomplete combustion results in some hydrocarbons or CO discharged to the flare being unaltered or converted to other organic compounds such as aldehydes or acids.<sup>665</sup>

Flares, if operated in a manner to provide for complete combustion, are intended to destroy hydrocarbons and VOCs. Flaring also converts methane to CO<sub>2</sub>. Both are greenhouse gases, but methane is a more powerful greenhouse gas.<sup>666</sup> EPA indicates that properly operated flares should achieve 98% destruction efficiency of VOCs.<sup>667</sup> However, according to EPA studies, flares “can operate at a wide range of Destruction and Removal Efficiency (DRE).” As a result, although flares are a VOC control device, flares are also a source of VOC emissions especially when not designed or operated in a manner to achieve high levels of DRE. Further, “[s]mall amounts of uncombusted vent gas will escape the flare combustion zone along with products of incomplete combustion,”<sup>668</sup> which can add to VOC emissions as well as methane emitted from the flare. Flaring of natural gas also results in emissions of NO<sub>x</sub>, as well as particulate matter emissions of carbon particles (soot) and unburned hydrocarbons.

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<sup>665</sup> EPA, VOC Destruction Controls, Chapter 1 Flares, August 2019, at 1-1, *available at*:

[https://www.epa.gov/sites/production/files/2019-08/documents/flarescostmanualchapter7thedition\\_august2019vff.pdf](https://www.epa.gov/sites/production/files/2019-08/documents/flarescostmanualchapter7thedition_august2019vff.pdf).

<sup>666</sup> See <https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#Learn%20why>

<sup>667</sup> See EPA, Air Pollution Control Fact Sheet, Flare, EPA-452/F-03-019, *available at*:

<https://www3.epa.gov/ttn/catc/dir1/fflare.pdf>.

<sup>668</sup> Shah, Tejas, Ramboll Environ (EPA Contractor), Greg Yarwood (Ramboll Environ), Alison Eyth (EPA), and Madeleine Strum (EPA), Composition of Organic Gas Emissions from Flaring Natural Gas, August 18, 2017, at 6, *available at*: [https://www.epa.gov/sites/production/files/2017-11/documents/organic\\_gas.pdf](https://www.epa.gov/sites/production/files/2017-11/documents/organic_gas.pdf).

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Flaring is also a significant cause of SO<sub>2</sub> emissions when sour gas or acid gas is flared. Although the sulfur content for gas to be considered sour gas can vary by state, gas with a hydrogen sulfide (H<sub>2</sub>S) content of 5.7 milligrams per cubic meter of gas (about 4 ppm) is generally considered to be sour gas.<sup>669</sup> Among other places in the United States, sour gas exists in areas of New Mexico, Texas, Wyoming, and North Dakota.

In terms of air pollution control measures to apply directly to flare design and operation, controls and techniques to ensure or improve DRE are the primary pollution control for natural gas flares. These are discussed further below in Section E.

### B. THERMAL INCINERATION

Thermal incineration of gases is generally able to result in more complete combustion due to the greatly improved ability to control fuel and air flow, temperature, turbulence, and residence time.<sup>670</sup> Thus, incineration of excess gases may result in greater destruction of hydrocarbons and lower VOC emissions than if the same amount of gas was flared. As with flaring, while thermal incineration is a VOC control technology, the incineration of waste gas does result in emissions of NO<sub>x</sub> and some particulate matter as a result of incomplete combustion, along with CO<sub>2</sub>. Further, when sour gas or acid gas is combusted in a thermal incinerator, SO<sub>2</sub> will be emitted. In the absence of SO<sub>2</sub> pollution controls, incineration of waste or excess gases may not be the best choice compared to flaring for gas with sulfur compounds, because the elevated height of the flare can allow for greater dispersion of the SO<sub>2</sub> emissions.<sup>671</sup> On the other hand, use of a thermal incinerator to combust excess or waste gas allows for the addition of an acid gas scrubber to remove SO<sub>2</sub> and also could allow for use of the thermal heat produced by the waste gas combustion, whereas those opportunities for SO<sub>2</sub> control and for getting some energy benefit from the combustion of waste gases do not exist with a flare. Further, low NO<sub>x</sub> combustion controls exist for thermal incinerators. The pollution controls to apply directly to thermal incinerators are discussed further below in Section F.

The best method to reduce/eliminate air emissions from flaring or incineration of excess or waste gas is to avoid the need for combustion of the gases altogether. The options for doing so are discussed further below in Section D.

### C. SO<sub>2</sub> EMISSIONS FROM THE DESTRUCTION OF SOUR GAS WASTE STREAMS

For sour gas, the sulfur compounds must be removed to produce pipeline quality natural gas. H<sub>2</sub>S is the sulfur compound of most concern in sour gas because the majority of sulfur compounds in sour gas are in the form of H<sub>2</sub>S and because it is very poisonous, explosive and corrosive. According to the Occupational Safety and Health Administration (OSHA), exposure to H<sub>2</sub>S can cause significant eye and respiratory irritation and exposure to high concentrations of H<sub>2</sub>S “can cause shock, convulsions, inability

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<sup>669</sup> <http://naturalgas.org/naturalgas/processing-ng/>.

<sup>670</sup> See, e.g., EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022, available at: <https://www3.epa.gov/ttnchie1/mkb/documents/ftthermal.pdf>.

<sup>671</sup> See <https://www.aer.ca/providing-information/news-and-resources/enerfaqs-and-fact-sheets/enerfaqs-flaring#what>.

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to breathe, extremely rapid unconsciousness, coma and death.”<sup>672</sup> It is also very corrosive to gas pipelines and can be explosive. Thus, H<sub>2</sub>S has to be removed from sour gas streams before the gas can be sent into gas pipelines to consumers. H<sub>2</sub>S is removed from the gas in gas sweetening plants, usually via an amine process which separates the H<sub>2</sub>S and also CO<sub>2</sub> from the natural gas.<sup>673</sup> Since 1985, the EPA’s NSPS have required gas sweetening plants with a capacity of more than 2 long tons per day of H<sub>2</sub>S in the acid gas to either 1) completely reinject the acid gas stream into oil- or gas-bearing geologic strata or 2) to use a sulfur reduction and removal technology to reduce SO<sub>2</sub> emissions from the acid gas before it is flared or combusted.<sup>674</sup> Sweetening plants that aren’t subject to such requirements may be allowed to flare the acid gas stream or incinerate the gas stream, either of which could release very significant quantities of SO<sub>2</sub> emissions, although it is not clear that any such plants continue to operate. However, even for gas sweetening plants required to control the H<sub>2</sub>S by reinjecting into the geologic strata or by using a sulfur recovery unit or other control method, SO<sub>2</sub> emissions from flaring or from thermal incineration is of significant concern. For those plants, flaring episodes occur due to malfunctions or due to maintenance or possibly for other reasons.<sup>675</sup> When flared or combusted, the H<sub>2</sub>S in the acid gas stream converts to SO<sub>2</sub>, which is a significant visibility-impairing pollutant. EPA states that “100 tons or more of SO<sub>2</sub> can be released in [a flaring episode] within a 24-hour period.”<sup>676</sup> In the case of flaring of acid gas streams, the only methods to reduce SO<sub>2</sub> emissions directly from flaring acid gas streams at gas sweetening plants are to reduce or eliminate flaring episodes. Methods to reduce such flaring episodes are discussed in the next section.

### D. CONTROL MEASURES, TECHNIQUES, AND OPERATING PRACTICES TO PREVENT FLARING OR INCINERATION OF EXCESS OR WASTE GAS

Prevention of flaring/incineration of excess or waste gases is the best method to reduce the air emissions from this source category. It will also prevent NO<sub>x</sub>, particulate matter, air toxic emissions including formaldehyde, and CO<sub>2</sub> emissions, as well as any VOCs and methane that are not destroyed in the combustion process. Available methods and techniques to reduce flaring or thermal combustion of excess or waste gas are discussed below.

#### 1. REDUCING FLARING AT THE WELL SITE

In 2016, the U.S. Bureau of Land Management (BLM) issued a rule intended “to reduce the waste of natural gas from venting, flaring, and leaks during oil and gas production on onshore Federal and Indian (other than Osage Tribe) leases.”<sup>677</sup> This rule is often referred to as the “BLM Waste Prevention Rule.”

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<sup>672</sup> OSHA Fact Sheet, Hydrogen Sulfide (H<sub>2</sub>S), *available at*: [https://www.osha.gov/OshDoc/data\\_Hurricane\\_Facts/hydrogen\\_sulfide\\_fact.pdf](https://www.osha.gov/OshDoc/data_Hurricane_Facts/hydrogen_sulfide_fact.pdf).

<sup>673</sup> See, e.g., <http://operoenergy.com/gas-sweetening-technologies/>.

<sup>674</sup> See 40 C.F.R. Subparts LLL and OOOO.

<sup>675</sup> See EPA, Enforcement Alert, Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases, October 2000, *available at*: <https://www.epa.gov/sites/production/files/documents/flaring.pdf>.

<sup>676</sup> *Id.*

<sup>677</sup> 81 Fed. Reg. 83,008 (Nov. 18, 2016).

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The fact sheet issued by EPA at the time of the rulemaking stated that the rule would phase in, over several years, a flaring limit per development oil well that ratcheted down over time.<sup>678</sup> There were several options for complying with the flaring limits, including: “expanding gas-capture infrastructure (e.g., installing compressors to increase pipeline capacity, or connecting wells to existing infrastructure through gathering lines); adopting alternative on-site capture technologies (e.g., compressing the natural gas or stripping out natural gas liquids and trucking the product to a gas processing plant); or temporarily slowing production at a well to minimize losses until capture infrastructure is installed.”<sup>679</sup> The rule also required operators to evaluate opportunities for gas capture before drilling a development oil well, which were to be submitted with an Application for a Permit to Drill and which were to be shared with midstream gas capture companies “to facilitate timely pipeline development. . . .”<sup>680</sup> In 2018, the BLM rescinded the gas capture requirements of the 2016 rule “in favor of an approach that relies on State and tribal regulations and reinstates the NTL-4A standard for flaring in the absence of State or tribal regulations.”<sup>681</sup> The 2018 BLM rulemaking describes the NTL-4A standard as the BLM’s existing policy from before the 2016 BLM Waste Prevention Rule, which was published in the Federal Register in 1979 (44 Fed. Reg. 76600, Dec. 27, 1979)<sup>682</sup> and “governed venting and flaring from BLM-administered leases for more than 35 years.”<sup>683</sup> The BLM has clearly indicated that states could regulate flaring. Indeed, development of the BLM Waste Prevention Rule considered “analogous state requirements related to waste of oil and gas resources,” and the BLM “reviewed requirements from Alaska, California, Colorado, Montana, North Dakota, Ohio, Pennsylvania, Utah, and Wyoming.”<sup>684</sup> Further, EPA has been requiring the capture and collection of excess gas from the drilling of natural gas wells under the NSPS since 2012.<sup>685</sup>

Thus, there are example state and federal rules<sup>686</sup> and methods that states should adopt, if not already in place, to reduce flaring of gas associated with oil wells, that would not only reduce visibility-impairing pollution from flaring, but that would also reduce air toxics and greenhouse gases emissions as well as ensure that the natural gas produced along with oil at oil wells is utilized as an energy source rather than just flared or combusted to destroy the VOCs.

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<sup>678</sup> See BLM Fact Sheet on Methane and Waste Prevention Rule, at 3, *available at*:

[https://www.doi.gov/sites/doi.gov/files/uploads/methane\\_waste\\_prevention\\_rule\\_factsheet\\_final.pdf](https://www.doi.gov/sites/doi.gov/files/uploads/methane_waste_prevention_rule_factsheet_final.pdf).

<sup>679</sup> *Id.* See also Clean Air Task Force’s publication entitled “Putting Out the Fire: Reducing Flaring in Tight Oil Fields,” April 2, 2015, for additional discussion of additional alternatives to flaring excess gas, *available at*: <https://www.catf.us/resource/putting-out-the-fire/>; and U.S.DOE, Office of Fossil Energy, Natural Gas Flaring and Venting: State and Federal Regulatory Overview, Trends, and see Impacts, June 2019, at 50-55 *available at*: <https://www.energy.gov/sites/prod/files/2019/08/f65/Natural%20Gas%20Flaring%20and%20Venting%20Report.pdf>.

<sup>680</sup> *Id.*

<sup>681</sup> 83 Fed. Reg. 49,184 at 49,188 (Sept. 28, 2018).

<sup>682</sup> 83 Fed. Reg. 49,184 at 49,185 (Sept. 28, 2018).

<sup>683</sup> 83 Fed. Reg. 49,189 at 49,185 (Sept. 28, 2018).

<sup>684</sup> 81 Fed. Reg. 83,008 at 83,019 (Nov. 18, 2016).

<sup>685</sup> 40 C.F.R. Part 60, Subpart OOOO, §60.5375.

<sup>686</sup> The U.S. Department of Energy has a recent report that summarizes the state and federal rules on flaring. See U.S.DOE, Office of Fossil Energy, Natural Gas Flaring and Venting: State and Federal Regulatory Overview, Trends, and Impacts, June 2019, at 20-48.

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### 2. REDUCING FLARING AT COMPRESSOR STATIONS, GAS PROCESSING PLANTS, AND GAS SWEETENING PLANTS

As discussed above, flaring at compressor stations and gas processing plants including gas sweetening plants, is often due primarily to plant upsets and maintenance. Flaring of sour gas or acid gas streams at gas sweetening plants can be a significant source of visibility-impairing SO<sub>2</sub>, and thus reducing flaring emissions at gas sweetening plants could be an effective reasonable progress measure to address regional haze. Reducing flaring will also reduce the NO<sub>x</sub>, PM, VOCs, and CO<sub>2</sub> emitted from the flares.

EPA listed the following measure to prevent excess flaring at refineries, and this same approach can be used to identify methods and techniques to reduce flaring at natural gas compressor stations and at gas processing facilities:

Conduct a root-cause analysis of each flaring incident to identify if any equipment and/or operational changes are necessary to eliminate or minimize that cause so as to reduce or avoid future flaring events. As appropriate, corrective measures should be taken and implemented. If the analysis shows that the same cause has happened before, the incident should not be considered a malfunction and corrective measures should be taken to prevent future occurrences....<sup>687</sup>

In addition, it is imperative to ensure that there is adequate gas handling capacity at the various processing points in a compressor station, gas processing or gas sweetening plant. EPA states that “[r]edundant units can prevent flaring by allowing one unit to operate if the other needs to be shut down for maintenance or an upset. . . .”<sup>688</sup> Thus, adding excess capacity and/or backup units could be very important in reducing the amount of flaring due to upsets.

As part of their evaluation of measures to provide for reasonable progress towards the national visibility goal, states should evaluate the flaring episodes at the compressor station and at gas processing plants, including the collection of data on the length of time of each flaring episode, frequency, and causes. For plants that have more frequent flaring episodes, and especially for those plants flaring sour gas or acid gas streams from a gas sweetening plant, states should evaluate the root causes of upsets that cause flaring episodes to determine if measures, such as improved maintenance or duplicative parts or processing units, can be employed to reduce flaring episodes.

#### E. POLLUTION CONTROL TECHNIQUES FOR FLARES

EPA has described the control techniques for flares, based on the federal requirements in EPA’s New Source Performance Standards (NSPS) (at 40 C.F.R. §60.8) and EPA’s National Emission Standards for Hazardous Air Pollutants (NESHAPs) (at 40 C.F.R. §63.11) as follows:

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<sup>687</sup> See EPA, Enforcement Alert, Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases, October 2000, at 3 available at: <https://www.epa.gov/sites/production/files/documents/flaring.pdf>.

<sup>687</sup> 81 Fed. Reg. 83,008 (Nov. 18, 2016).

<sup>688</sup> *Id.*

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At a minimum, these [NSPS and NESHAP] rules require flares to be:

- Designed and operated with no visible emissions using EPA [test] Method 22 (except for periods not to exceed 5 minutes in 2 hours);
- Operated with a flame present at all times, confirmed by the use of a thermocouple or equivalent device;
- Used only when the net heating value of the gas to be combusted is 300 BTU per standard cubic foot (BTU/scf) or greater (if the flare is steam- or air-assisted), or 200 BTU/scf or greater (if the flare is nonassisted); and
- Designed for and operated with an exit velocity less than 60 feet per second (f/sec). An exit velocity of greater than 60 ft/sec but less than 400 ft/sec may be used if the net heating value of the gas being combusted is sufficiently high.<sup>689</sup>

Other requirements that must be met include that the flare must be operated at all times in a manner consistent with good air pollution control practices for minimizing emissions, and that flaring operations must be monitored to ensure they are operated and maintained according to their design.<sup>690</sup> EPA has listed several other more detailed guidelines to ensure flares are properly operated.<sup>691</sup> Proper training of employees is also an important part of ensuring the flares are properly operated. States must require documentation of each flaring episode to ensure that the flaring regulations of the NSPS and NESHAPs have been complied with, as well as to ensure that adequate records of the amount of gas flared and causes of flaring are maintained and reported.

The above operating standards are required for all flaring. Alternatives to flaring include 1) gas capture to decrease or eliminate flaring as discussed above, or 2) combusting the gas in a thermal incinerator which can provide for greater destruction of VOC emissions. Also, additional air pollution controls can be used at an incinerator, as is discussed below.

### F. POLLUTION CONTROL TECHNIQUES FOR THERMAL INCINERATION OF EXCESS OR WASTE GAS

As discussed above, waste gases or excess gas can be disposed of via thermal incineration rather than a flare. EPA describes a thermal incinerator, or a thermal oxidizer, as follows:

Incineration, or thermal oxidation is the process of oxidizing combustible materials by raising the temperature of the material above its auto-ignition point in the presence of oxygen, and maintaining it at high temperature for sufficient time to complete combustion to carbon dioxide and water. Time, temperature, turbulence (for mixing), and the availability of oxygen all affect the rate and efficiency of the combustion process. These factors provide the basic design parameters for VOC oxidation systems (ICAC, 1999).

<sup>689</sup> See EPA, Enforcement Alert, EPA Enforcement Targets Flaring Efficiency Violations, August 2012, at 1, *available at*: <https://www.epa.gov/sites/production/files/documents/flaringviolations.pdf>.

<sup>690</sup> *Id.* at 2; see also 40 C.F.R. §63.172(e) and 60.482-10.

<sup>691</sup> See, e.g., EPA, Enforcement Alert, EPA Enforcement Targets Flaring Efficiency Violations, August 2012, at 3.

## Exhibit 1

A straight thermal incinerator is comprised of a combustion chamber and does not include any heat recovery of exhaust air by a heat exchanger (this type of incinerator is referred to as a recuperative incinerator).

The heart of the thermal incinerator is a nozzle-stabilized flame maintained by a combination of auxiliary fuel, waste gas compounds, and supplemental air added when necessary. Upon passing through the flame, the waste gas is heated from its preheated inlet temperature to its ignition temperature. . . The required level of VOC control of the waste gas that must be achieved within the time that it spends in the thermal combustion chamber dictates the reactor temperature. The shorter the residence time, the higher the reactor temperature must be. The nominal residence time of the reacting waste gas in the combustion chamber is defined as the combustion chamber volume divided by the volumetric flow rate of the gas. . . .<sup>692</sup>

EPA indicates that thermal incinerators can achieve 98% to 99.9999% destruction of VOCs.<sup>693</sup> However, thermal incinerators typically require auxiliary fuel to preheat the waste gas and sustain the heat necessary for destruction of VOCs.<sup>694</sup> The high temperature reaction necessary in an incinerator to destroy the VOC and air toxic emissions can result in increased NOx emissions. To limit NOx emissions, low NOx burners or other low NOx processes are available control measures to integrate into the thermal incinerator to limit NOx emissions.<sup>695</sup> Thus, for any thermal incinerators or thermal oxidizers, low NOx burners or other low NOx emission systems should be installed to minimize NOx emissions from the thermal incinerator.

It is important to note that thermal incinerators can be used at gas sweetening plants along with acid gas scrubbers to remove the SO<sub>2</sub> that is formed from combusting the H<sub>2</sub>S in the acid gas. Such a system could potentially be used as an SO<sub>2</sub> control,<sup>696</sup> or it could be used as a backup system for a sulfur recovery unit when it is down due to malfunction, maintenance, or during startup or shutdown.<sup>697</sup> This method of control could greatly reduce if not eliminate the SO<sub>2</sub> emissions that occur at gas sweetening

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<sup>692</sup> EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022, at 4, *available at*: <https://www3.epa.gov/ttnchie1/mkb/documents/ftthermal.pdf>.

<sup>693</sup> *Id.* at 5.

<sup>694</sup> *Id.* See also EPA, Control Cost Manual, Section 3, Chapter 2 – Incinerators and Oxidizers, at 2-3 to 2-4, *available at*: [https://www.epa.gov/sites/production/files/2017-12/documents/oxidizersincinerators\\_chapter2\\_7theditionfinal.pdf](https://www.epa.gov/sites/production/files/2017-12/documents/oxidizersincinerators_chapter2_7theditionfinal.pdf).

<sup>695</sup> See, e.g., Zeeco Products & Applications, Incinerators & Thermal Oxidizers Multi-Stage Low-NOx Incinerator/Thermal Oxidizer, *available at*: <https://www.zeeco.com/incinerators/incinerators-therm-ox-multi-stage.php>. See also AERON, Thermal Oxidation/Incineration Systems, Ultra-Low Emissions Systems, *available at*: <http://www.aereon.com/enclosed-combustion-systems/ultra-low-emissions-systems/certified-ultra-low-emissions-burner-ceb>.

<sup>696</sup> See, e.g., AERON, Thermal Oxidation/Incineration Systems, Tail Gas Incineration Units, which discusses acid flue gas scrubbers as an available option, *available at*: <http://www.aereon.com/enclosed-combustion-systems/thermal-oxidationincineration-systems/tail-gas-incineration-units>.

<sup>697</sup> See Envitech, Industrial Gas Cleaning Systems, Air Pollution Control Innovations, Refinery Sulfur Recovery Unit (SRU) SO<sub>2</sub> Scrubber for Startup, Shutdown, and Malfunctions, *available at*: <https://www.envitechinc.com/air-pollution-control-innovations/refinery-sulfur-recovery-unit-sru-so2-scrubber-for-startup-shutdown-and-malfunctiong-post-title-here>.

## Exhibit 1

facilities when the gas injection well or sulfur recovery unit is not in operation due to malfunctions or maintenance.

In many respects, combusting of waste gases and/or excess gas in a thermal incinerator seems more preferable from an air pollutant perspective than flaring, because thermal incineration will likely result in a greater destruction efficiency of VOCs and because control options exist for limiting emissions of NO<sub>x</sub> and of SO<sub>2</sub> (to the extent that sour gas or an acid gas stream is what was being flared). Further, there could be an option of gathering and routing excess gas emission from multiple points to a centralized thermal incinerator. Moreover, continuous emission monitoring systems (CEMS) could be installed in the thermal oxidizer stack to provide valuable actual emissions data due to the combustion of waste or excess gases, including information to ensure that optimal VOC destruction efficiency is achieved.

However, the need for auxiliary fuel in thermal combustion means more CO<sub>2</sub> will be emitted than if the gas stream was flared. Yet, there are options for thermal incinerators that recover the waste heat, which are called recuperative oxidizers or regenerative oxidizers.<sup>698</sup> The recovered waste heat can be used to preheat the incoming air which would reduce the amount of supplemental fuel required.<sup>699</sup>

To sum up, use of a recuperative or regenerative thermal incinerator (thermal oxidizer) with low NO<sub>x</sub> combustion controls, CEMs, and an acid gas scrubber if necessary, seems to be a preferable alternative to flaring of waste gas streams. Such a system would provide better control of VOCs, reduce NO<sub>x</sub> emissions from combustion of the waste gas via the use of low NO<sub>x</sub> combustion controls, and provide the ability to add an acid gas scrubber to remove SO<sub>2</sub> (which is a control option that does not exist for flares).

### G. SUMMARY – BEST OPTIONS FOR CONTROLLING EMISSIONS DUE TO FLARING OR INCINERATION OF EXCESS OR WASTE GAS

Based on the above analysis, it seems evident that prevention of flaring through the collection of excess gas is the most beneficial option for reducing emissions from flaring. Capturing and using the natural gas that is produced at oil wells would ensure that the energy value of the gas is not wasted by being combusted in a flare or in an incinerator, and it is very likely that the end user of the gas would at least be using some level of NO<sub>x</sub> and VOC control.

Thermal incineration should be considered in lieu of flaring for waste gases due to the pollution controls for NO<sub>x</sub> and SO<sub>2</sub> that are available and because of the improved operation and VOC destruction. Moreover, use of a thermal incinerator provides the opportunity to monitor and accurately track emissions from the combustion of waste or excess gases with the use of CEMS.

At gas processing facilities including gas sweetening plants, it is important that the causes of flaring episodes be documented and assessed to determine any changes in operations, training, and/or in equipment that may be needed to reduce plant upsets and maintenance during which flaring occurs due

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<sup>698</sup> EPA, Air Pollution Control Technology Fact Sheet, Thermal Incinerator, EPA-452/F-03-022, at 5.

<sup>699</sup> *Id.*



## Exhibit 1

to the unavailability of plant equipment to process the gas stream. As stated above, adding excess capacity and/or backup units could be very effective in reducing the amount of flaring due to upsets. Proper maintenance of equipment is also key, as is appropriate training of staff to minimize flaring episodes due to maintenance and upsets.

In general, states should ensure that their rules require companies to document all flaring episodes, including the cause, duration of the flaring, flue gas flow, actions taken to stop the flaring, and emission estimates, and to submit such documentation to the state or local air agency in a timely manner. This data will best enable states to develop appropriate rules and procedures to limit the various causes of flaring emissions within its state.

Overall, the goal of state programs to address flaring emissions should be to minimize flaring to the maximum extent possible. However, for those situations when flaring does occur, it is imperative that the flares be operated in accordance with NSPS and NESHAP requirements, and that the flares are operated and maintained in accordance with their design. Moreover, to ensure these requirements are being met and to ensure that flaring is minimized to the maximum extent possible, the state or local air agencies must conduct thorough oversight into the causes of flaring episodes, to ensure that the facility is being maintained and operated in a manner to minimize all flaring episodes to the extent possible.

Exhibit 2



Hawaii State Department of Health

Regional Haze  
State Implementation Plan

Second Planning Period

Prepared by:  
Clean Air Branch  
Hawaii State Department of Health



David Y. Ige  
Governor of Hawaii

Elizabeth A. Char, M.D.  
Director of Health

## Exhibit 2



Halema'uma'u Crater, from Crater Rim Trail, Hawaii Volcanoes National Park – Courtesy of Janice Wei, National Park Service



Volcanic Landscape, Haleakala National Park - Courtesy of Don Shephard, National Park Service

## Exhibit 2

### Executive Summary

In 1977, Congress amended the Clean Air Act (CAA) to include provisions of a national visibility goal to protect the scenic vistas of the nation's national parks and wilderness areas. In §169A of the CAA, Congress established the following national visibility goal:

“The prevention of any future, and the remedying of any existing impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution.”

On July 1, 1999, the Environmental Protection Agency (EPA) issued the Regional Haze Rule (RHR) to establish goals and emission control strategies that make reasonable progress towards improving visibility in Mandatory Federal Class I areas. The goal of the RHR is to restore natural visibility conditions at all 156 Mandatory Federal Class I areas by 2064. The rule was revised in 2017 to strengthen visibility protection and to emphasize that states reduce man-made emissions of air pollutants that impair visibility. States are required to prepare Regional Haze State Implementation Plans (RH-SIPs) that provide long-term strategies for Class I areas to comply with the RHR. Hawaii's Mandatory Federal Class I areas are Haleakala National Park on Maui Island and Hawaii Volcanoes National Park on the Big Island (Hawaii Island).

The RHR divides the RH-SIP development process into ten-year periods to achieve gradual improvement in visibility. When the final planning period ends in 2064, the goal of the RHR is for visibility to be restored to natural conditions for each Class I area. The first RH-SIPs were due in 2007 and covered the 2008-2018 planning period.

Since Hawaii was unable to submit the initial RH-SIP, the EPA developed a Regional Haze Federal Implementation plan (RH-FIP) that was promulgated on October 9, 2012. The RH-FIP established a total combined SO<sub>2</sub> emissions cap of 3,550 tons per year for three electric power plants in Hilo on the Big Island by December 31, 2018. Since one of these power plants shut down (Shipman Generating Station), the SO<sub>2</sub> emissions cap applies to only two (2) plants (Kanoelehua-Hill and Puna Generating Stations).

The RH-SIP submittal deadline for this second 2018-2028 planning period was updated in the revised RHR from July 31, 2018 to July 31, 2021. The RH-SIP for this planning period establishes new reasonable progress goals (RPGs) for each of Hawaii's two (2) Class I areas.

Initial screening identified seven (7) electric plants with a Q/d threshold greater than ten (10) that were notified to provide a four-factor analysis to evaluate controls. These included three (3) power plants on Oahu, two (2) power plants on the island of Hawaii, and two (2) power plants on Maui. The Q/d surrogate for screening is the annual emissions in tons per year divided by the distance in kilometers between a source and Class I area. The four-factor analysis for selecting control measures considered cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance, and the remaining useful life of the affected anthropogenic source of visibility impairment.

A cost threshold floor of \$5,800 per ton of pollutant was used to determine cost effective controls using the Chemical Engineering Plant Cost Index (CEPCI). The cost for this threshold was escalated from the \$5,000 per ton cost threshold used in the first regional haze planning period.

## Exhibit 2

A more sophisticated weighted emissions potential/area of influence (WEP/AOI) analysis ranked the relative potential of point sources to contribute to haze in Hawaii's Class I areas. The WEP/AOI analysis considered other factors that were not part of the Q/d screening, such as meteorology and light extinction from the specific haze species. Due to the Hawaiian Island chain being subject to predominant North Easterly trade winds, it was found that Oahu-based sources had a very low relative potential to contribute to haze in the national parks. Therefore, only sources on the islands of Hawaii and Maui, where the national parks are located, were evaluated in the process to select controls. Based on the four-factor analysis, WEP/AOI rankings, and source retirement commitments in place of controls selected from the four-factor analysis, the following regional federally enforceable conditions were established in permits for four electric plants:

### Hawaii Island Sources:

- Kanoiehua-Hill Power Plant – Permanent shut down of Boilers Hill 5 and Hill 6 by 2028.
- Puna Power Plant – Fuel switch from fuel oil No. 6 to ULSD for the plant's boiler by four years from permit issuance.

### Maui Island Sources:

- Kahului Power Plant – Permanent shut down of Boilers K-1, K-2, K-3, and K-4 by 2028.
- Maalaea Power Plant – Preliminary evaluation found that fuel injection timing retard (FITR) for Diesel Engine Generators M1, M2, and M3 and selective catalytic reduction (SCR) for Diesel Engine Generator M7 by 2028 are required. After further review, more units from this facility may require controls. Therefore, controls for the Maalaea Generating Station will be addressed in an RH-SIP revision.

Interagency Monitoring of Protected Visual Environments (IMPROVE) data collected at visibility monitors servicing Hawaii's Class I areas was adjusted to screen out impacts from volcanic activity (sulfates) based on EPA's methodology for episodic events. However, not all impacts would be screened out due to the ongoing nature of the Kilauea eruption that releases extremely large amounts of sulfur dioxide (SO<sub>2</sub>).

From 2008 to 2018 eruptive activity was almost continuous along the Kilauea Volcano's East Rift Zone, and the summit vent hosted an active lava lake and significant gas plume. After the eruption ended in 2018, the lava lake drained and a water lake formed in the crater, significantly decreasing the daily SO<sub>2</sub> emissions at the summit.

On December 20, 2020, the volcano started another eruption forming a lava lake in the crater. According to information from United States Geological Survey (USGS) - Hawaii Volcanoes Observatory (HVO) personnel, on the onset of these eruptions, tens of thousands of tons of SO<sub>2</sub> per day is released by the volcano. By February 23, 2020, SO<sub>2</sub> emissions had decreased to about 800 tons per day. These emissions are lower than those from the pre-2018 lava lake that were typically around 5,000 tons per day. This eruption ended on May 26, 2021.

A new eruption started on September 29, 2021. According to information from USGS-HVO personnel, the 2021 Kilauea eruption is characterized by SO<sub>2</sub> emission rates varying by hundreds to thousands of tons per day.

## Exhibit 2

Photochemical modeling was performed by EPA to estimate visibility conditions at the end of the second planning period in 2028 that were compared with the regional haze uniform rate of progress (URP) glidepath. Emissions from EPA's 2016 Hawaii modeling platform were used for the modeling. The modeling assumed no volcanic emissions. The RHR includes a provision that allows states to propose an adjustment to the glidepath to account for impacts from international anthropogenic sources and prescribed fires. Glidepaths in this RH-SIP were not adjusted for international contributions that are beyond the state's authority to control. Prescribed fires were also not considered in the adjustment.

Photochemical model results for 2028 indicate a rate of progress that is slower than the URP for Haleakala National Park and Hawaii Volcanoes National Park (the deciview value is below the glidepath for the most impaired days).

Deciview values based on IMPROVE data for 2019, during a period with significant reduction in SO<sub>2</sub> venting after the Kilauea eruption had ceased, are below the glidepath for the most impaired days and no degradation level on the clearest days for both Haleakala National Park and Hawaii Volcanoes National Park. The 2019 IMPROVE data was adjusted for episodic volcanic events and the change in location of the Haleakala monitor.

The Hawaii Department of Health Clean Air Branch (DOH-CAB) has determined that control strategies in the RH-SIP are adequate for Hawaii to meet the 2028 reasonable progress goals (RPGs) based on four-factor analyses for selecting controls and enforceable commitments to shut down specific units by 2028 if not implementing the controls selected. The RPGs provide an improvement in visibility on the most impaired days for the second implementation period and will help ensure no visibility degradation occurs on the clearest days over this implementation period at Hawaii's two (2) Class I areas. Air permits for the Kahului Generating Station on Maui and the Kanoelehua-Hill and Puna Generating Stations on the Big Island, subject to emission reductions, have been revised to incorporate the federally enforceable regional haze control measures. The permit for the Maalaea Generating Station will be amended to incorporate regional haze controls during an RH-SIP revision.

The WEP/AOI analysis also ranked Mauna Loa Macadamia Nut Corporation Plant on the Big Island as one of the top three contributors to visibility impairment at Hawaii Volcanoes National Park for nitrates. Potential control measures for the Mauna Loa Macadamia Nut Corporation Plant will be addressed in the RH-SIP revision after the four-factor analysis for this facility is completed.

# Exhibit 2

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<b>List of Acronyms and Definitions</b>	
AEO	Annual Energy Outlook
Aerosols	Suspensions of tiny liquid and/or solid particles in the air
AGP	Agricultural Burning Permit
AirSHED	Emissions Inventory System Software from Lakes Environmental
AOI	Area of Influence
Asian Dust	A meteorological phenomenon which affects most of East Asia. The dust originates in the deserts of Mongolia, northern China and Kazakhstan where high winds and intense dust storms kick up dense clouds of fine dry soil particles. The clouds are then carried eastward by prevailing winds.
BART	Best Available Retrofit Technology
b <sub>ext</sub>	Reconstructed Light Extinction
CAA	Clean Air Act
CALPUFF	Transport and Dispersion Model
CDS	Circulating Dry Scrubber
CEPCI	Chemical Engineering Plant Cost Index
CFR	Code of Federal Regulations
CM	Coarse Mass

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<b>List of Acronyms and Definitions</b>	
CMAQ	Community Multiscale Air Quality model
CMV	Commercial Marine Vessel
CO <sub>2</sub>	Carbon Dioxide
CO <sub>2e</sub>	Carbon Dioxide Equivalent
CT	Combustion Turbine
CY	Cubic Yard
DBEDT	Department of Business, Economic Development and Tourism (State of Hawaii)
DEG	Diesel Engine Generator
DLIR	Department of Labor and Industrial Relations (State of Hawaii)
DOE	U.S. Department of Energy
DOH-CAB	Department of Health Clean Air Branch (State of Hawaii)
DOT	Department of Transportation (State of Hawaii)
Dv	Deciview, a measurement of visibility impairment
EC	Elemental Carbon
EEPS	Energy Efficiency Portfolio Standard
EGU	Electric Generating Unit
EIS	EPA's Emissions Inventory System
EPA	US Environmental Protection Agency
ESP	Electrostatic Precipitator for particulate control
EWRT	Extinction Weighted Residence Time
FAA	Federal Aviation Administration
FEMA	Federal Emergency Management Agency
FGR	Flue Gas Recirculation
FIP	Federal Implementation Plan
FITR	Fuel Injection Timing Retard for NO <sub>x</sub> control
Fka	Formerly Known As
FLM	Federal Land Manager
Ft	Feet
Gal	Gallon
GHG	Greenhouse Gas
Glidepath	The linear rate of improvement sufficient to attain natural conditions by 2064.
GWh	Gigawatt Hour (unit of electrical energy)
HACR1	Haleakala Crater Visibility Monitoring Site
HALE1	Haleakala Visibility Monitoring Site Outside Haleakala National Park
HAVO1	Hawaii Volcanoes National Park Visibility Monitoring Site
Hawaiian Electric	Hawaiian Electric Company, Inc.
Hawaii Electric Light	Hawaii Electric Light Company, Inc.
HI	Haze Index
Hr	Hour
HRS	Hawaii Revised Statute
HVO	Hawaii Volcano Observatory
HYSPLIT	Hybrid Single Particle Lagrangian Integrated Trajectory model
IMPROVE	Interagency Monitoring of Protected Visual Environments
IPP	Independent Power Producer
Kw	Kilowatt
Laze	This is a local term that refers to lava haze. When lava flows into the ocean it reacts vigorously with seawater to create large acidic steam plumes, known as 'laze'. These plumes are laden with hydrochloric acid and volcanic glass particles.
LNB	Low NO <sub>x</sub> Burner for NO <sub>x</sub> control
M	Meter

## Exhibit 2

<b>List of Acronyms and Definitions</b>	
Maui Electric	Maui Electric Company, Ltd
MID	Most Impaired Days
MOVES	Motor Vehicle Emissions Simulator
MVA	Megavolt Amp
MW	Megawatt
NA ECA	North American Emissions Control Area
NEI	National Emissions Inventory
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH <sub>3</sub>	Ammonia
NO <sub>x</sub>	Nitrogen Oxides
NP	National Park
NPS	National Park Service
NSPS	New Source Performance Standard
OAQPS	Office of Air Quality Planning and Standards, US EPA
OC	Organic Carbon
OFA	Overfire Air
PBFA	Public Benefits Fee Administrator
PEC	Primary Elemental Carbon
PM <sub>2.5</sub>	Particulate matter less than or equal to 2.5 micrometers in diameter
PMF	Positive Matrix Factorization
POA	Primary Organic Aerosols
POM	Particulate Organic Mass
PSIP	Power Supply Improvement Plan
PUC	State of Hawaii Public Utility Commission
Q/d	A surrogate for screening - annual emissions (in tons per year) divided by the distance in kilometers between a source and the nearest Class I Area.
RICE	Reciprocating Internal Combustion Engine
RH	Regional Haze
RHR	Regional Haze Rule
RPG	Reasonable Progress Goal
RPO	Regional Planning Organization
RPS	Renewable Portfolio Standard
RT	Residence Time
RWC	Residential Wood Combustion
SCR	Selective Catalytic Reduction for NO <sub>x</sub> control
SIP	State Implementation Plan
SLEIS	State and Local Emissions Inventory System Software from Windsor Solutions
SMAT-CE	EPA Software for the Model Attainment Test – Community Edition
SO <sub>2</sub>	Sulfur Dioxide Gas
SNCR	Selective Non-catalytic Reduction for NO <sub>x</sub> control
SUV	Sport Utility Vehicle
TPY	Tons Per Year
TSS	Technical Support System
ULSD	Ultra-Low Sulfur Diesel
URP	Uniform Rate of Progress
USDI	US Department of Interior
USDI-NSP	US Department of Interior – National Park Service
USGS-HVO	United States Geological Survey - Hawaii Volcano Observatory
VMT	Vehicle Miles Traveled
VOC	Volatile organic compound
Vog	This is a local term that refers to “volcanic smog” or a hazy air pollution condition attributed to the active volcano

## Exhibit 2

<b>List of Acronyms and Definitions</b>	
Water Injection System	A system that injects demineralized water into the turbine generator's combustion chamber to reduce the formation of thermal NO <sub>x</sub> .
WESTAR	Western States Air Resources Council
WEPAOI	Weighted Emissions Potential/Area of Influence
WRAP	Western Regional Air Partnership
Yr	Year

## Exhibit 2

### Chapter 1 Overview

#### 1.0 Introduction

Regional haze causes visibility impairment over a large region primarily from sources that emit fine particulate (PM<sub>2.5</sub>) and its precursors into the air. Fine particulate that absorb and scatter light to cause haze include sulfates, nitrates, coarse mass, organic carbon, elemental carbon, soil dust, and sea salt. Sources of particulate can be manmade (anthropogenic) or from natural events. Anthropogenic emissions include primary (directly emitted) PM<sub>2.5</sub> such as fugitive dust (e.g., aggregate processing, vehicle travel on unpaved roads, etc.). Natural emissions of primary PM<sub>2.5</sub> include aerosolized salts from sea spray. Precursors of PM<sub>2.5</sub>, such as SO<sub>2</sub>, NO<sub>x</sub>, NH<sub>3</sub>, and VOCs, can also react to form secondary PM<sub>2.5</sub>. Anthropogenic sources include primary and secondary particulate from combustion (e.g., electric plants, motor vehicles, wildfires, etc.). Kilauea Volcano on the Big Island (Hawaii) is a large source of natural SO<sub>2</sub> that forms secondary PM<sub>2.5</sub>. Volcanic SO<sub>2</sub> emissions create vog when SO<sub>2</sub> reacts with sunlight and air constituents to form sulfate aerosols that cause haze on the Big Island and on other islands hundreds of miles away.

The Kilauea Volcano has erupted almost continuously since 1983 causing considerable property damage and vog from sulfates.<sup>1</sup> On May 3, 2018 volcanic activity started to escalate and continued for about three (3) and a half months before substantially subsiding.<sup>1</sup> This powerful eruptive event destroyed more than 600 homes and made Kilauea the most destructive volcano in the United States since 1980 when Mount St. Helens erupted in Washington State.<sup>2</sup> On December 5, 2018, after ninety (90) days of inactivity from the volcano, the eruption that began in 1983 was declared to have ended.<sup>1</sup> A summary of the 2018 Kilauea eruption event, based on summaries of articles from the Honolulu Star Advertiser and other information from USGS, is provided in Appendix A.

While volcanic SO<sub>2</sub> emissions from Kilauea Volcano typically overwhelmed that from anthropogenic sources, volcanic SO<sub>2</sub> decreased significantly after the eruption ended in 2018. Actual combined SO<sub>2</sub> from power plants alone were higher than that measured from the volcano in 2019. Please refer to Chapter 4. The decrease in volcanic SO<sub>2</sub> made anthropogenic sources a more significant contributor to emissions that can cause haze.

On December 20, 2020, the Kilauea Volcano started another eruption. According to USGS, the SO<sub>2</sub> emission rate measurements from February 23, 2021, were about 800 tons per day. This rate is lower than the emission rates from the pre-2018 lava lake that were typically around 5,000 tons per day of SO<sub>2</sub>. This eruption ended on May 26, 2021.<sup>3</sup>

Pursuant to §169A of the 1977 CAA amendments for addressing regional haze, goals were established to protect visibility from human-made air pollution in 156 National Parks and wilderness areas designated by Congress as Mandatory Federal Class I areas (see Figure 1.1-1).<sup>4</sup> To meet these goals, the Regional Haze Rule (RHR) was established that requires State Implementation Plans (SIPs) to address visibility in Class I areas.

<sup>1</sup> See <https://pubs.usgs.gov/fs/2012/3127/>

<sup>2</sup> See <https://www.popularmechanics.com/science/environment/a25471113/kilauea-hawaiian-volcano-eruption-geology/>

<sup>3</sup> See Appendix A for new eruption that stated on September 29, 2021. See Executive Summary for additional information from phone conversation with HVO personnel.

<sup>4</sup> See <https://www.epa.gov/visibility/visibility-regional-haze-program>.





## Exhibit 2

### 1.1 Regional Haze Rule

The primary purpose of the RHR is to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in Mandatory Federal Class I areas from manmade air pollution.<sup>5</sup> Under the RHR, states develop implementation plans with long-term strategies for protecting visibility in Class I areas. Requirements from the RHR are specified in 40 CFR Part 51, Subpart P, Protection of Visibility.<sup>5</sup> The objective is to improve the visibility on the most impaired days (twenty percent of monitored days in a calendar year with the highest anthropogenic visibility impairment) at each Class I area, and ensure no degradation in visibility in these areas on the clearest days (twenty percent of the monitored days in a calendar year with the lowest values of the deciview index). In accordance with 40 CFR §51.308(f), Hawaii must submit its Regional Haze implementation plan revision by July 31, 2021, July 31, 2028, and every ten (10) years thereafter. Another requirement is that progress reports are due by January 31, 2025, July 31, 2033, and every 10 years thereafter.<sup>6</sup>

### 1.2 Hawaii's Class I Areas

Hawaii's two Mandatory Federal Class I areas are Haleakala National Park on Maui and Hawaii Volcanoes National Park on the Big Island (Hawaii). As indicated in Note 3 on pages 1-3 of Reference 7 below, Class I areas include certain National Parks (over 6,000 acres), wilderness areas and national memorial parks (over 5,000 acres), and international parks which existed as of August 1977.<sup>7</sup> Table 1.2-1 below provides information on the acreage of Hawaii's two National Parks (one on Maui and the other on the Big Island). The National Parks are shaded in green in Figures 1.3-1 and 1.3-2.

Class I Area	Island	Federal Land Manager <sup>8</sup>	Acreage <sup>8</sup>
Haleakala National Park	Maui	NPS	33,265
Hawaii Volcanoes National Park	Hawaii	NPS	229,616

<sup>5</sup> 40 CFR, Part 51, Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Subpart P, Protection of Visibility.

<sup>6</sup> Federal Register, Vol. 82, No. 6, January 10, 2017, 40 CFR Parts 51 and 52, Protection of Visibility: Amendments to Requirements for State Plans, Final Rule.

<sup>7</sup> Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule, U.S. EPA, September 2003.

<sup>8</sup> Federal Land Manager Environmental Database  
<http://views.cira.colostate.edu/fed/DataWizard/Default.aspx>.

## Exhibit 2

### 1.3 Hawaii's IMPROVE Monitoring Sites

Visibility is measured at Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites to measure visibility impairment in mandatory Federal Class I areas throughout the United States. IMPROVE was initially established as a national visibility network in 1985 and consisted of 30 monitoring sites primarily located in national parks.<sup>9</sup> With implementation of the RHR, the IMPROVE network expanded, and 110 monitoring sites were identified that were deemed representative of the regional haze conditions for 155 of the 156 visibility-protected Federal Class I areas.<sup>9</sup> The Bearing Sea Wilderness was the exception.<sup>9</sup> Hawaii has IMPROVE monitors at Haleakala National Park (HACR1 and HALE1) and Hawaii Volcanoes National Park (HAVO1).

For Haleakala National Park, the HALE1 IMPROVE monitor, identified with blue dot in Figure 1.3-1, began operation on Maui in 1990 at a site approximately 3.5 miles outside of this Federal Class I area.<sup>8,10</sup> In 2007 a second IMPROVE monitor (HACR1 identified with pink dot in Figure 1.3-1) was installed at a higher elevation within Haleakala National Park.<sup>10</sup> The HACR1 IMPROVE site was considered more representative of visibility conditions within Haleakala National Park and replaced the HALE1 monitoring station in 2012.<sup>10</sup>

For Hawaii Volcanoes National Park, the HAVO1 IMPROVE monitor started operation on the Big Island in 1988 and is identified with yellow dot in Figure 1.3-2.

Table 1.3-1 below provides additional information on the IMPROVE monitoring sites.

Class I Area	IMPROVE Site	Island	Location <sup>10</sup>		Elevation <sup>10</sup>	
			Latitude	Longitude	M	Ft
Haleakala NP	HACR1*	Maui	20.7585	-156.2479	2,158	7,080
	HALE1**	Maui	20.8086	-156.2823	1,153	3,783
Hawaii Volcanoes NP	HAVO1	Hawaii	19.40309	-155.2579	1,259	4,130

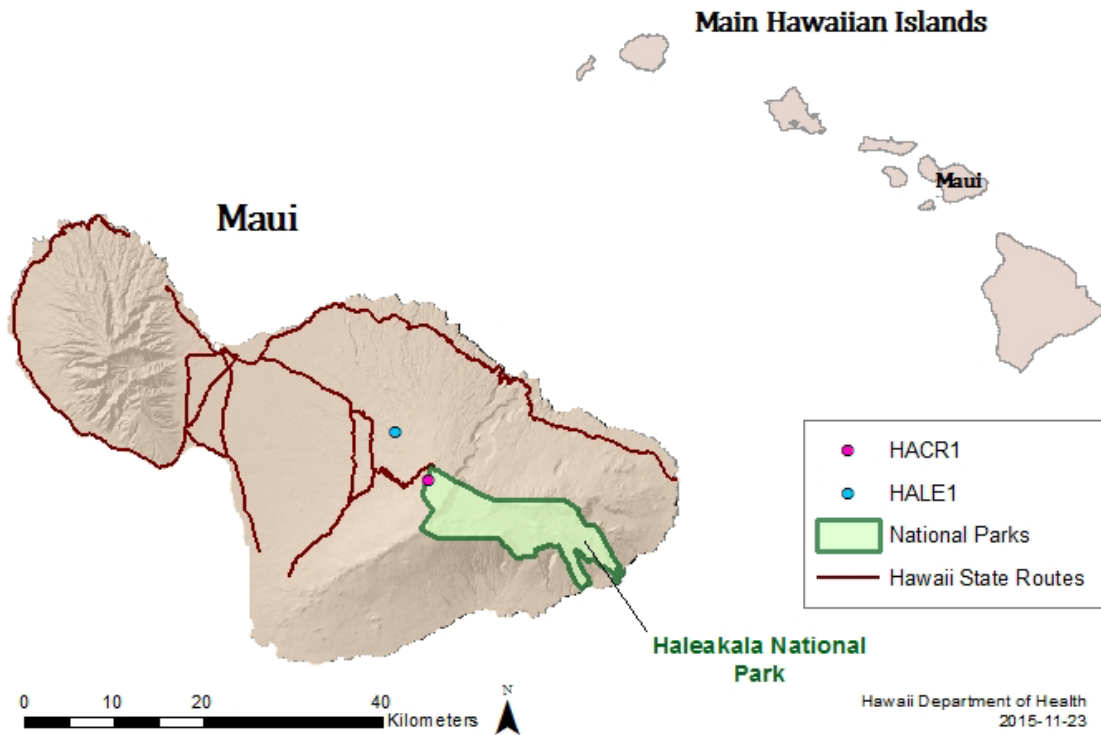
\* Monitoring at HACR1 began in 2007.

\*\*Monitoring at HALE1 site was discontinued in 2012.

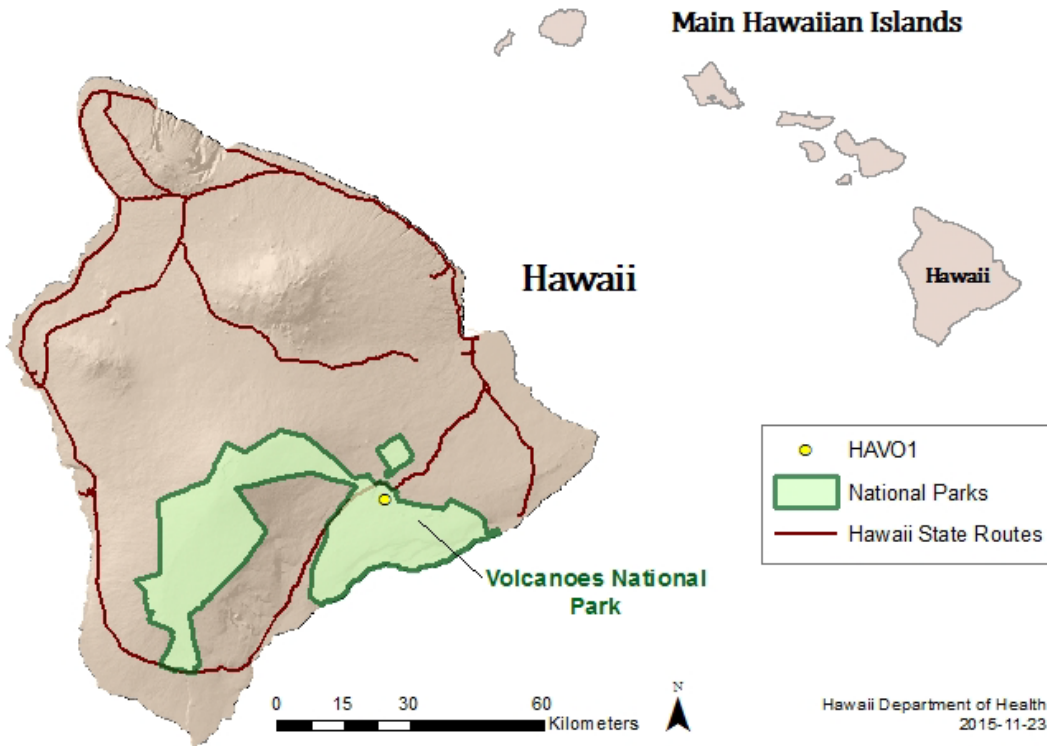
<sup>9</sup> <https://vista.cira.colostate.edu/Improve/improve-program/>

<sup>10</sup> WRAP Regional Haze Rule Reasonable Progress Summary Report, June 28, 2013.

Exhibit 2



**Figure 1.3-1** Haleakala National Park Visibility Monitoring Sites (IMPROVE Sites HALE1 & HACR1)



**Figure 1.3-2** Volcanoes National Park Visibility Monitoring Sites (IMPROVE Site HAVO1)

## Exhibit 2

### 1.4 Estimating Visibility Impairment

Particles and gases in the atmosphere can both absorb and scatter light. The absorption and scattering (i.e., extinguishing) of light result in light extinction (visibility impairment between the viewer and the light source) creating haze. The 2017 Regional Haze Rule defines visibility impairment or anthropogenic visibility impairment as “any humanly perceptible difference due to air pollution from anthropogenic sources between actual visibility and natural visibility on one or more days.”<sup>5</sup>

To determine compliance under the RHR, each IMPROVE monitor collects 24 hour particulate samples every three (3) days on a set of particulate filters to identify the chemical constituents causing visibility impairment at the site.<sup>11</sup> The particulate concentration data is converted into reconstructed light extinction (“ $b_{ext}$ ”) in units of inverse mega meters ( $Mm^{-1}$ ) with the IMPROVE equation.<sup>12</sup> The IMPROVE equation is used to convert the measured or modeled concentrations into extinction for each pollutant chemical species and totals the extinction values accounting for the effect of relative humidity.<sup>12</sup> The equation also accounts for the Rayleigh scattering that occurs in pure air. The IMPROVE equation, revised in December 2005, is listed below in Figure 1.4-1.<sup>12</sup>

$$\begin{aligned} b_{ext} = & 2.2 \times f_s(RH) \times [\text{small sulfate}] + 4.8 \times f_L(RH) \times [\text{large sulfate}] \\ & + 2.4 \times f_s(RH) \times [\text{small nitrate}] + 5.1 \times f_L(RH) \times [\text{large nitrate}] \\ & + 2.8 \times [\text{small organic mass}] + 6.1 \times [\text{large organic mass}] \\ & + 10 \times [\textit{elemental carbon}] \\ & + 1 \times [\textit{fine soil}] \\ & + 1.7 \times f_{ss}(RH) \times [\text{sea salt}] \\ & + 0.6 \times [\textit{coarse mass}] \\ & + \text{Rayleigh scattering (site specific)} \\ & + 0.33 \times [\text{NO}_2 \text{ (ppb)}] \end{aligned}$$

**Figure 1.4-1** Revised IMPROVE Equation<sup>12</sup>

Bracketed items in the IMPROVE equation are the measured concentrations in  $\mu\text{g}/\text{m}^3$  of the particulate constituents collected by the IMPROVE monitoring station.<sup>12</sup> The  $f(RH)$  is a water growth factor for sulfate and nitrate, that are hygroscopic (these particles tend to attract water).<sup>12</sup> The  $f_s$ ,  $f_L$ , and  $f_{ss}$  parameters are water growth factors for small (“s”) and large (“L”) fractions of sulfate and nitrate, and for sea salt (“ss”).<sup>12</sup>

### 1.5 Measures of Visibility

Parameters for evaluating visibility include light extinction -  $b_{ext}$ , haze index (HI) in units of  $\text{dv}$ , and visual range in units of kilometers or miles. Reference 12 disclosed the following information for these parameters:

<sup>11</sup> Guidance for Tracking Progress Under the Regional Haze Rule, U.S. EPA, September 2003.

<sup>12</sup> Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii, U.S. EPA Region 9, May 14, 2012.

## Exhibit 2

Light Extinction ( $b_{ext}$ ) – This parameter is the attenuation of light due to scattering and absorption as it passes through a medium. Light extinction is the most useful parameter for evaluating the relative contributions of pollutants to visibility impairment. Light extinction affects the clarity and color of the object being viewed.

Haze Index (deciview) – This parameter is required by the RHR for tracking visibility conditions. Generally, a one deciview change in the haze index is likely humanly perceptible under ideal conditions. The deciview is a useful measure for tracking progress in improving visibility because each deciview change is an equal incremental change in visibility perceived by the human eye from pristine to highly impaired.

Visual Range – This parameter is the greatest distance, in kilometers or miles, at which a dark object can be viewed against the sky.

Relationships between extinction ( $Mm^{-1}$ ) or ( $10^{-6}m^{-1}$ ), haze index (dv), and visual range (km or mi) are as follows:

1. There is a logarithmic range between the haze index (dv) and reconstructed light extinction ( $Mm^{-1}$ ) expressed by the following equation:

$$HI(\text{deciview}) = 10 \ln(b_{ext}/10)$$

2. The relationship between extinction ( $Mm^{-1}$ ), haze index (dv), and visual range (km) is provided in Figure 1.5-1.

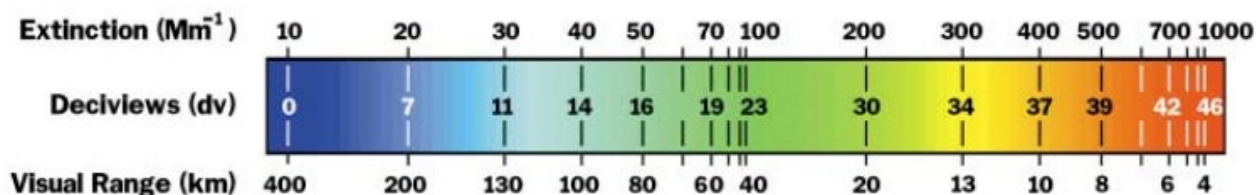


Figure 1.5-1 Comparison of Extinction, Deciview, and Visual Range<sup>13</sup>

### 1.6 Natural, Baseline, and Current Visibility Conditions

For each Class I area, the following definitions apply as part of the determination of reasonable progress:

Natural Visibility – As defined in Reference 5, natural visibility conditions mean visibility (contrast, coloration, and texture) that would have existed under natural conditions. Natural visibility conditions vary with time and location, are estimated or inferred rather than directly measured, and may have long-term trends due to long-term trends in natural conditions. In accordance with the RHR, natural visibility conditions include naturally occurring phenomena that reduce visibility, such as humidity, fire events, dust storms, volcanic activity, and biogenic emissions from soils and trees.

Baseline Visibility – Baseline visibility is the starting point for the improvement of visibility conditions. Pursuant to 40 CFR 51.308(d)(2)(i), the period for establishing

<sup>13</sup> William C. Malm, Introduction to Visibility, May 1999.

## Exhibit 2

baseline visibility conditions is 2000 to 2004.<sup>5</sup> Also, baseline visibility conditions must be calculated, using available monitoring data, by establishing the average degree of visibility impairment for the most and least impaired days for each calendar year from 2000-2004 and the baseline visibility conditions are the average of these annual values.<sup>5</sup>

Current Visibility – Current visibility conditions are assessed for the most impaired and clearest days using the most recent five (5)-year period for which data is available.<sup>5</sup> According to 40 CFR §51.308(f)(1)(iii) in Reference 5, current visibility conditions must be calculated based on the annual average level of visibility impairment for the most impaired and clearest days for each of these five (5) years. The most recent five (5)-year period for which data are available is 2014 through 2018.

Least Impaired Days – Means the twenty (20) percent monitored days in a calendar year with the lowest amounts of visibility impairment.<sup>5</sup>

Most Impaired Days – Means the twenty (20) percent of monitored days in a calendar year with the highest amounts of anthropogenic visibility impairment.<sup>5</sup>

Clearest Days – Means the twenty (20) percent of monitored days in a calendar year with the lowest values on the deciview index.<sup>5</sup>

Deciview Index – Also referred to as haze index (HI), means a value for a day derived from calculated or measured light extinction, such that uniform increments of index correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to very obscured.

Smoke from wildfires and natural dust storms were the major natural contributors to light extinction at many Class I areas in the first planning period (2008–2018), therefore, a new approach was developed by EPA for tracking visibility. The new approach for this second planning period (2018-2028) focuses on the twenty percent (20%) most anthropogenic impaired days and the clearest days at Class I areas.<sup>14</sup> In contrast, for the first regional haze implementation period (2008-2018), states selected the least and most impaired monitored days with the lowest and highest deciview levels irrespective of the source of particulate causing the visibility impairment. The least impaired days for setting the RPGs is now referred to as the twenty percent (20%) clearest days in an effort to be as specific as possible.<sup>15</sup> It is unnecessary to assign extinction on the clearest days to anthropogenic and natural fractions.<sup>15</sup>

The EPA either requires states to use the new second planning period approach for choosing the twenty percent (20%) most impaired visibility days or to allow each state to choose between using the original twenty percent worst overall visibility days and the new approach. Hawaii will use the new approach to track visibility for the twenty percent (20%) most impaired days with additional adjustments for volcanic activity.<sup>15</sup>

<sup>14</sup> Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, U.S. EPA, August 20, 2019.

<sup>15</sup> 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, U.S. EPA, July 2016.

## Exhibit 2

The WRAP TSS<sup>16</sup> provides annual average haze index in deciviews calculated by either the first planning period metric or the second planning period metric including adjustments for volcanic activity.

### 1.7 Uniform Rate of Progress (URP)

Pursuant to Reference 17, the URP is the calculation of the uniform slope, or glide path, of the line between baseline visibility conditions over a 60-year period.<sup>17</sup> By comparing baseline with natural conditions, the uniform rate of visibility improvement, or progress, needed to reach natural conditions by 2064 can be determined for each Class I area.<sup>17</sup> For example, in Figure 1.7-1 below, the 20% worst visibility baseline condition is 29 dv and the natural visibility condition is 11dv. Therefore, the URP is 4.2 dv over the first planning period. This is equivalent to 0.3 dv per year over a 14 year time frame. The 4.2 dv value is determined as follows:  $18 \text{ dv}/60 \text{ yr} = 14\text{yr}/ x \text{ dv}$ ,  $x = 18 \text{ dv}/60 \text{ yr} \times 14 \text{ yr} = 4.2 \text{ dv}$ .

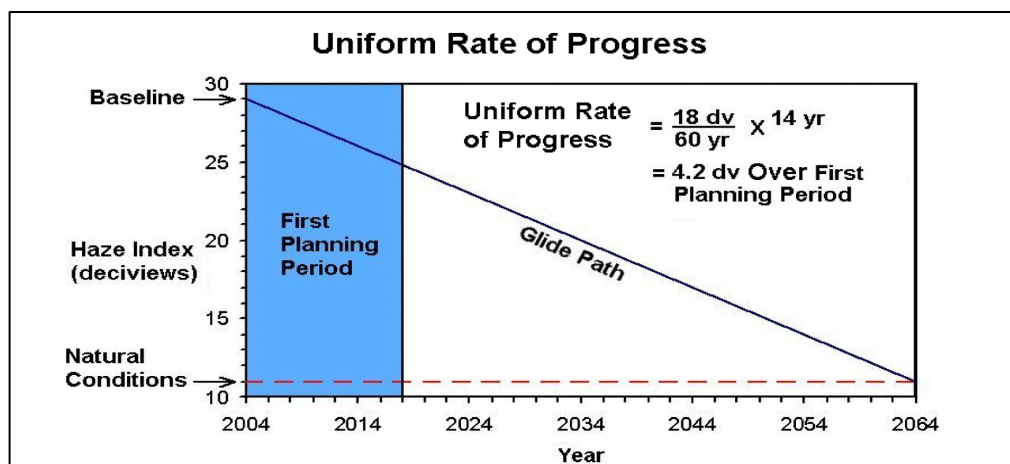


Figure 1.7-1 Uniform Rate of Progress Example<sup>17</sup>

The 2017 Regional Haze Rule:

- (1) Provides a revised approach to tracking visibility improvements over time within the URP framework.<sup>18</sup> Under these rule revisions, in the second and future implementation periods, states must select the "twenty (20) percent most impaired days" each year at each Class I area based on daily anthropogenic impairment.<sup>18</sup>
- (2) Includes a provision that allows states to propose an adjustment to the URP to account for impacts from anthropogenic sources outside the United States, if the adjustment has been developed through scientifically valid data and methods.<sup>18</sup>
- (3) Requires states to determine the baseline (2000-2004) visibility condition for the twenty (20) percent most anthropogenically impaired days and requires that the long-term strategy and reasonable progress goals (RPGs) must provide for improvement of visibility for the most anthropogenically impaired days, relative to baseline period.<sup>18</sup>

<sup>16</sup> WRAP TSS at: <https://views.cira.colostate.edu/tssv2/>

<sup>17</sup> Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, U.S. EPA, June 1, 2007.

<sup>18</sup> Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, U.S. EPA, December 2018.

## Exhibit 2

- (4) Specifies that the URP is calculated according to the following formula:<sup>18</sup>

$$\text{URP} = [(2000-2004 \text{ visibility})_{20\% \text{ most impaired}} - (\text{natural visibility})_{20\% \text{ most impaired}}]/60$$

- (5) Requires states to determine the baseline (2000-2004) visibility conditions for the 20 percent most impaired days and requires that the long-term strategy and RPG ensure no degradation in visibility for the most impaired days, relative to the baseline period.<sup>18</sup>

### 1.8 Regional Haze Rule State Implementation Plan

Core requirements for the implementation plan for regional haze are specified in 40 CFR §51.308(d). For the second planning period, the RH-SIP is due on July 31, 2021 pursuant to 40 CFR §51.308(f). As specified in Reference 5, to meet the core requirements for regional haze in the Class I areas, the State must submit an implementation plan containing the following plan elements and supporting documentation for all required analysis:

- (1) Reasonable progress goals - For each Class I area located within the State, the State must establish goals (expressed in deciviews) that provide for reasonable progress toward achieving natural visibility conditions. The RPGs must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period.

In establishing the RPGs for each Class I Area within the State, the State must consider the cost of compliance, and the remaining useful life or any potentially affected sources and include a demonstration showing how these factors were taken in consideration in selecting the goal.

- (2) Calculations of baseline and natural visibility conditions - For each Class I area, the State must determine the following visibility conditions:
- i. Baseline visibility conditions for the most impaired and clearest days for period 2000 to 2004; and
  - ii. Natural visibility conditions for the most impaired and clearest days.
- (3) Long-term strategy for regional haze - A long-term strategy must be submitted that addresses visibility impairment for each Class I area. The long-term strategy must include enforceable emission limitations, compliance schedules, and other measures as necessary to achieve the RPGs.
- (4) Monitoring strategy and other plan requirements - The state must submit with the implementation plan a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility that is representative of all Class I areas within the state.



## Exhibit 2

The following are regional haze planning steps for completing the RH-SIP:

**STEP 1** – Ambient data analysis to identify baseline, current and natural visibility conditions for the 20% most impaired days and 20% clearest days for each Class I area within the state.

**STEP 2** – Determine which Class I areas in other states may be affected by the state's own emissions. This is not applicable to Hawaii due to its remote location. The closest states to Hawaii with Class I areas are Alaska and California that are over 2,000 miles away.

**STEP 3** – Select the emission sources for which an analysis of emission control measures will be completed in the second implementation period and explain the bases for these selections.

**STEP 4** – Characterize control measure factors for the selected sources pursuant to 40 CFR §51.308(f)(2).

**STEP 5** – Select control measures for reasonable progress.

**STEP 6** – Perform photochemical modeling of the long-term strategy to set reasonable progress goals for 2028.

**STEP 7** – Progress, degradation, and URP glidepath checks to demonstrate that there will be an improvement in the 20% most impaired days in 2028 and there will be no degradation on the 20% clearest days in 2028 at the in-state Class I areas.

**STEP 8** – Additional RH-SIP requirements to ensure the requirements of the Regional Haze Rule are met.

### **1.9 Description of Chapters for Hawaii's Regional Haze Rule State Implementation Plan**

The RHR requires states to periodically submit RH-SIPs every ten (10) years. The first state plans were due in 2007 and covered the 2008 -2018 planning period. For the second 2018-2028 planning period, the due date for submitting the RH-SIP was extended from July 31, 2018 to July 31, 2021.

A brief description of each chapter for Hawaii's second planning period RH-SIP is as follows:

Chapter 1.0 is an overview, which describes the requirements of the RHR; Federal Class I areas located in the State of Hawaii; Hawaii's IMPROVE monitoring sites; measures of visibility including previously established baseline and natural visibility conditions (e.g. volcanic eruption); EPA's new algorithm to separate natural from anthropogenic fractions; uniform rate of progress (URP) or glide path; and brief description of the RH SIP.

Chapter 2.0 covers plan development, which describes RH planning, the Western Regional Air Partnership (WRAP), and consultation with both the Federal Land Manager (FLM) and the Environmental Protection Agency (EPA).

Chapter 3.0 (**STEP 1**) covers visibility conditions, which describes the RH program requirements in Title 40 Code of Federal Regulation (CFR) §51.308(f)(1) for the baseline, natural, and current visibility conditions; and the URP.

## Exhibit 2

Chapter 4.0 (STEP 3) covers emissions inventory requirements in Title 40 CFR §51.308(1)(f)(6)(v) and (g)(4) and (5).

Chapter 5.0 (STEP 3) describes the screening process and criteria used to determine which point sources were included in the long-term strategy pursuant to Title 40 CFR §51.308(f)(2)(i). This chapter also provides the basis for evaluating point and area sources.

Chapter 6.0 (STEPS 4 and 5) evaluates enforceable emission control measures (i.e., emissions limitations, compliance schedules, and other measures) as determined pursuant to Title 40 CFR §51.308(f)(2)(i) through (iv) that provides for reasonable progress in each Federal Class I area. The RPGs, expressed in deciviews, are not directly enforceable and therefore, enforceable emission control measures are necessary to gauge reasonable progress. This section explains how the four-factor analysis takes into consideration selection of measures for inclusion in the State of Hawaii's long-term strategy pursuant to Title 40 CFR §51.308(f)(2)(i). The technical basis (such as documented modeling, monitoring, cost, engineering, and emissions data) that were used as basis for the selection are documented in this section pursuant to Title 40 CFR §51.308(f)(2)(iii).

Chapter 7.0 (STEP 6 and 7) describes the RPG requirements for regional haze in Title 40 CFR §51.308(f)(3), establishes PRGs for 2028 (in deciviews), demonstrates the adequacy of emission control measures to effectively achieve projected natural visibility during both the most impaired and clearest days, and compares improvements in visibility to the URP.

Chapter 8.0 delineates the State of Hawaii's long-term strategy which addresses regional haze visibility impairment for each mandatory Federal Class I area pursuant to Title 40 CFR §51.308(f)(2)(i). Section 8.0 also includes enforceable emission control measures for making reasonable progress pursuant to Title 40 CFR §51.308(f)(2) as documented in Section 6.0 of this state implementation plan and consideration of additional factors as listed in Title 40 CFR §51.308(f)(2)(iv).

Chapter 9.0 (STEP 8) describes the requirements for issuing periodic progress reports to the EPA, updates the status of all measures towards the RPGs, summarizes emissions reductions, assess changes in visibility conditions relative to previously established natural and baseline visibility conditions and any significant changes in anthropogenic emissions since the previous progress report pursuant to Title 40 CFR §51.308(g). In addition, Section 9.0 does the following:

- a. Reviews and assess the Visibility Monitoring Strategy, identifies any planned changes, and provides recommended actions;
- b. Evaluates the adequacy of control strategies in the existing RH plan pursuant to Title 40 CFR §51.308(h); and
- c. Describes the requirements for the State and Federal Land Manager (FLM) coordination in Title 40 CFR §51.308(i) and the interactions that transpired between Hawaii and the EPA and FLMs in consultation with developing this RH-SIP.

## Exhibit 2

### 1.10 Environmental Justice

Mitigating haze-causing pollution is a vital part of our efforts to address environmental justice concerns to reduce visibility impairing emissions from anthropogenic sources that may disproportionately affect those who are socially or economically disadvantaged. The purpose of Hawaii's RH-SIP is for implementing requirements of EPA's Regional Haze Rule by achieving emission reductions to improve visibility in Hawaii's national parks. The permit modifications incorporating regional haze control measures for large sources on Hawaii and Maui Islands are important measures to reduce anthropogenic visibility impacts. The DOH-CAB strongly supports 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. A hard copy of the RH-SIP was provided at designated DOH offices located on all main Hawaiian Islands for personal viewing. The RH-SIP was also posted on DOH-CAB's website for communities to give feedback on the proposed strategy for reducing visibility impairing pollutants.

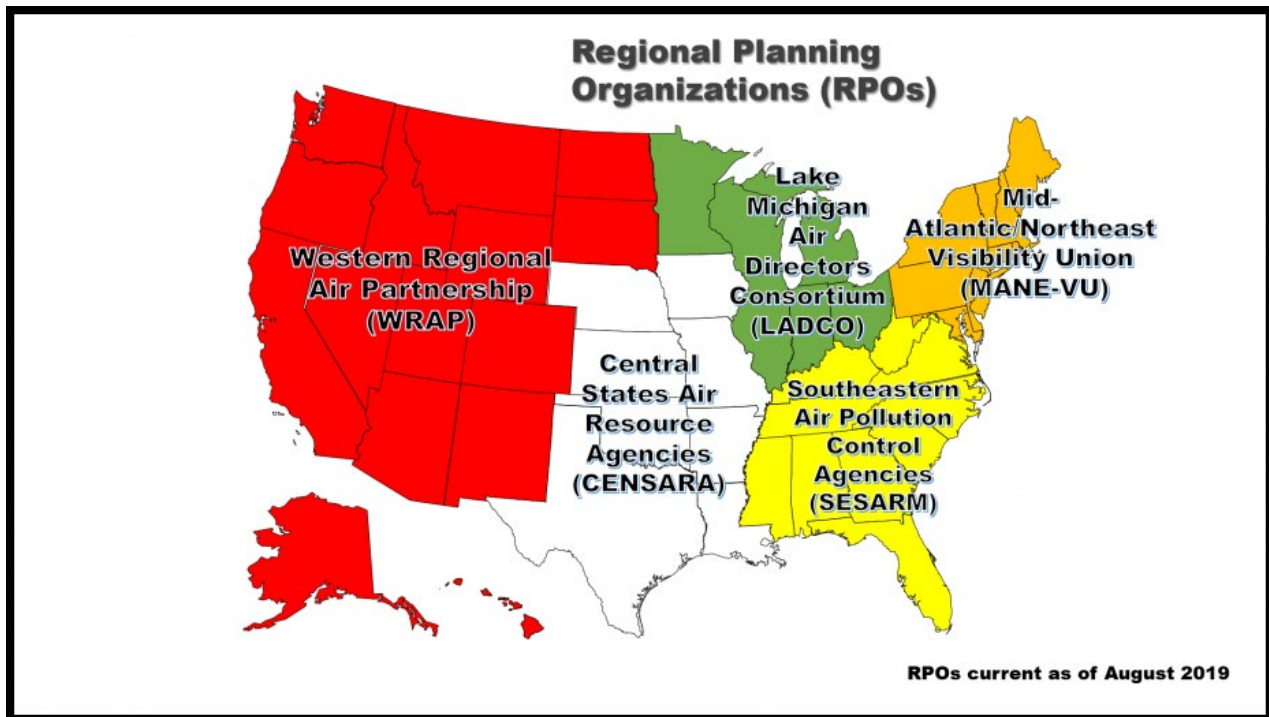
## Chapter 2 Regional Haze State Implementation Plan Development

### 2.0 Regional Haze Planning

There are five regional planning organizations (RPOs) across the United States that include the Western Regional Air Partnership (WRAP), Central States Air Resource Agencies (CENSARA), Lake Michigan Air Directors Consortium (LADCO), Mid-Atlantic/Northeast Visibility Union (MANE-VU), and Southeastern Air Pollution Control Agencies (SESARM). The five (5) RPOs are shown in Figure 2.0-1.<sup>19</sup>

Hawaii is a member of the Western Regional Air Partnership (WRAP) that works in cooperation with the Western States Air Resources Council (WESTAR). Members of WESTAR/WRAP include the states of Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. Federal WRAP/WESTAR partners include the NPS, Fish and Wildlife Service, Bureau of Land Management, and U.S. Forest Service.

<sup>19</sup><https://www.epa.gov/visibility/visibility-regional-planning-organizations>



**Figure 2.0-1** Regional Planning Organizations

## 2.1 Western States Resource Council (WESTAR)/Western Regional Air Partnership (WRAP)

The WESTAR/WRAP is a voluntary partnership of states, tribes, federal land managers, local air agencies and the U.S. EPA whose purpose is to understand current and evolving air quality issues in the West.<sup>20</sup> During this second regional haze planning period, WRAP in cooperation with WESTAR provided the following technical support for developing Hawaii's RH-SIP:

- Planning support and coordination from Regional Haze Planning Work Group (RHPWG) calls and webex recordings. The "Coordination and Glide Path", "Emissions Inventory and Modeling Protocol", and "Control Measures" subcommittees of the RHPWG addressed key technical issues for RH-SIP development. The DOH-CAB attended most of the RHPWG calls/webexs.
- Ramboll US. Corporation, in coordination with WRAP, assisted DOH-CAB with emission inventories of visibility impairing pollutants. Chapter 4 provides additional information on state-wide emissions and trends.
- A screening tool was developed by Ramboll US. Corporation in coordination with WRAP to determine sources with greatest visibility impacts on Hawaii's two (2) Class I areas. Sources selected from this screening step were required to submit a four-factor analysis to evaluate regional haze control measures. Please refer to

<sup>20</sup> <http://www.westar.org/downloads.html>

## Exhibit 2

Chapter 5 for source screening which used a Q/d threshold of ten (10) to select point sources for four-factor analysis.

- A weighted WEP/AOI analysis was provided by Ramboll US. Corporation, in coordination with WRAP, to further screen sources using HYSPLIT back trajectories to regional haze monitoring sites on the most impaired days. An extinction weighted residence time analysis is overlaid with gridded emissions and point source emissions to obtain a WEP that rank source regions and point sources for probability to visibility impairment at Class I areas on the most impaired days.

### **2.2 Federal Land Manger Coordination – 40 CFR §51.308(i)**

The DOH-CAB consulted with FLMs in accordance with the provisions of 40 CFR §51.308(i)(2). These provisions require the State to provide the FLMs with an opportunity for consultation, in person at a point early enough in developing the long-term strategy, but not less than one hundred and twenty (120) days prior to holding a public hearing on the implementation plan. These provisions also require the opportunity for consultation on the implementation plan be provided to the FLMs no less than sixty (60) days prior to a public hearing or public comment opportunity. This consultation must include an opportunity for FLMs to discuss their:

- (1) Assessment of impairment of visibility in any mandatory Class I Federal area; and
- (2) Recommendations on the development and implementation of strategies to address visibility impairment.

Pursuant to 40 CFR §51.308(i)(3), the DOH-CAB provides the following descriptions of how comments from the FLMs were addressed:

- In accordance with 40 CFR §51.308(i)(4), the RH-SIP must provide procedures for continuing consultation between the State and FLMs on the implementation of the visibility protection program, including development and review of implementation plan revisions and progress reports, and on implementation of other programs having the potential to contribute to visibility impairment in Federal Class I areas.
- The DOH-CAB engaged in consultation with FLMs from the National Park Service in developing strategies to address visibility impairment and review of the four-factor analyses provided. Conference calls between DOH-CAB and the National Park Service are documented in Section 9.5, Federal Land Manager Consultation – 40 CFR 51.308(h). The DOH-CAB provided four-factor analyses from the seven (7) power plants and one industrial source screened to evaluate regional haze control measures. Comments from the NPS on the four-factor analyses from the power plants are provided in Appendices D through J. NPS comments on the Mauna Loa Macadamia Nut Corporation Plant analysis were addressed at meetings.
- Hawaii provided the draft RH-SIP to the NPS, U.S. Fish and Wildlife Service, and the U.S. Forest Service on March 24, 2022, for their review and comments prior to initiating the public comment period pursuant to 40 CFR §51.308(i)(2). A regional haze consultation meeting was held on May 19, 2022, to discuss comments from the FLMs on Hawaii's draft RH-SIP. The NPS Air Resources Division, NPS Interior Regions 8, 9, 10, and 12; and several national park units in Hawaii hosted the RH-SIP consultation meeting with DOH-CAB. Representatives from the U.S. Fish and Wildlife Service and EPA (Region 9) also attended the meeting. The FLMs

## Exhibit 2

provided their written comments on May 26, 2022. In accordance with 40 CFR §51.308(i)(3), comments from the FLMs and DOH-CAB's responses to these comments are provided in Section 9.5, Federal Land Manager Consultation– 40 CFR 51.308(h). A summary of the conclusions and recommendations from the FLMS is also provided in the public notice for accepting comments on Hawaii's draft RH-SIP.

- Continued coordination and consultation will occur, as needed, through WRAP/WESTAR business meetings and conference calls that discuss regional haze issues that include FLMs as participants. The DOH-CAB will continue to consult with the FLMs directly.

### **2.3 EPA Guidance, Photochemical Modeling, and IMROVE Data Adjustment**

The DOH-CAB had extensive consultation with EPA for developing the RH-SIP in this second planning period. The EPA provided feedback on four-factor analyses from facilities screened for further evaluation. Conference calls between DOH-CAB and EPA are documented in Section 9.6.

The Office of Air Quality, Permitting and Standards (OAQPS) of EPA conducted photochemical modeling for Hawaii to determine visibility impacts from anthropogenic sources. Emissions for the model were from EPA's 2016 emissions modeling platform. Photochemical modeling was used to determine visibility conditions without SO<sub>2</sub> impacts from the Kilauea Volcano that mask anthropogenic impacts at the IMPROVE monitors since the Kilauea Volcano was erupting in 2016.

The OAQPS adjusted IMPROVE data for Haleakala NP and Hawaii Volcanoes NP to account for visibility impacts from volcanic activity at both Class I areas and the change in location of the visibility monitor servicing Haleakala National Park. A white paper provides the methodology for the adjustments that were made to the IMPROVE data that was use for the photochemical modeling assessment.<sup>21</sup>

## **Chapter 3 Visibility Conditions**

### **3.0 Baseline, Current, and Natural Visibility – 40 CFR §51.308(f)(1)(i-iii)**

40 CFR §51.308(f)(1)(i-iii) requires states to address regional haze in each Mandatory Federal Class I area within the state for the most impaired and clearest days. States must evaluate current visibility conditions relative to a five (5)-year baseline from 2000 to 2004 and natural visibility conditions as they were before human activity in accordance with the RHR. Baseline, natural, and current visibility conditions for Haleakala National Park and Hawaii Volcanoes National Park are based on IMPROVE monitoring station data. IMPROVE monitors collect 24-hour particulate samples every three (3) days to identify haze constituents (e.g., sulfates, nitrates, coarse mass, organic mass, and sea salt) causing visibility impairment. Improve monitors servicing

<sup>21</sup> White paper is at following site:

[https://www.epa.gov/system/files/documents/2021-08/white\\_paper\\_for\\_regional\\_haze\\_hi\\_volcano\\_adjust\\_final.pdf](https://www.epa.gov/system/files/documents/2021-08/white_paper_for_regional_haze_hi_volcano_adjust_final.pdf)

## Exhibit 2

Haleakala National Park and Hawaii Volcanoes National Park are designated HACR1 and HAVO1, respectively. Visibility conditions, based on IMPROVE data, are provided on the WRAP TSS.<sup>16</sup>

On April 13, 2020, EPA issued a memorandum on the use of patched and substituted data and data completeness for tracking visibility with the IMPROVE data.<sup>22</sup> The TSS was updated using IMPROVE data meeting EPA’s recommended completeness criteria for tracking visibility. Adjustments were also made to the IMPROVE data to screen out impacts from natural episodic events with high haze levels related to wildfire (based on organic and elemental carbon) or dust storms (based on fine crustal and coarse mass) that only apply to the most impaired days. In Appendix A of the EPA memorandum, baseline, current, and natural visibility conditions were provided for the most impaired days; however, EPA did not provide results for the clearest days.

On June 3, 2020, EPA issued a memorandum that updated Appendix A of its April 13, 2020 memorandum to include visibility conditions for the clearest days. Tables 3.0-1 and 3.0-2 below provide visibility conditions established by EPA for the HACR1 and HAVO1 monitors based on the technical addendum referenced in EPA’s June 3, 2020 memorandum. Baseline visibility conditions for Haleakala National Park, however, were not adjusted consistently with the methodology established in Hawaii’s Regional Haze Progress Report for incidences when one monitoring station replaces another.

<b>Table 3.0-1</b> Baseline, Current, and Natural Visibility Conditions for Clearest and Most Impaired Days at Haleakala National Park				
20% Days of Calendar Year	Baseline (2000-2004) (dv)	Current (2014-2018) (dv) <sup>a</sup>	Natural (2064) (dv)	
			Clearest Days	Most Impaired Days
Clearest	4.55	0.48	2.66	4.77
Most Impaired	12.67	8.60		

a. HACR1 data combined with HALE1 data starting 01-01-08.

<b>Table 3.0-2</b> Baseline, Current, and Natural Visibility Conditions for Clearest and Most Impaired Days at Hawaii Volcanoes National Park				
20% Days of Calendar Year	Baseline (2000-2004) (dv)	Current (2014-2018) (dv)	Natural (2064) (dv)	
			Clearest Days	Most Impaired Days
Clearest	4.06	3.50	2.20	5.63
Most Impaired	18.66	19.28		

<sup>22</sup> EPA Memorandum, Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, April 13, 2020.

## Exhibit 2

In the July 2020 Technical Support Document for EPA's "Updated 2028 Regional Haze Modeling for Hawaii, Virgin Islands, and Alaska", the IMPROVE data was adjusted to screen out impacts from volcanic activity (sulfates) with the same method used for wildfires and dust storms (episodic threshold determined by the lowest annual 95<sup>th</sup> percentile daily extinction) for the most impaired days only. IMPROVE data was, therefore, adjusted for volcanic activity as well as wildfires and dust storms in the EPA modeling assessment.

The DOH-CAB raised concerns with EPA's methodology to determine baseline visibility conditions for Haleakala National Park because it was inconsistent with the methodology used in Hawaii's Regional Haze Progress Report. An alternative approach for the Haleakala National Park baseline was provided by EPA in discussions with DOH-CAB and WRAP.

On August 5, 2021, EPA issued a white paper titled "Recommendations for the HALE1-HACR1 Site Combination and Volcano Adjustment for Sites Representing Hawaii Class I areas for the Regional Haze Rule".<sup>21</sup> The white paper builds upon the recommendations in the 2018 Technical Guidance and June 2020 Memo with additional recommendations for combining visibility data for IMPROVE sites representing the Haleakala National Park Class I area and an adjustment of visibility data at sites representing Haleakala National Park and Hawaii Volcanoes National Park Class I areas to account for episodic volcanic events.<sup>21</sup>

For the Haleakala National Park combined site (HALE1-HACR1), EPA's calculation methodology to determine visibility conditions was similar to the ratio-based approach used in Hawaii's Regional Haze Progress Report with some major modifications: 1) ratios between the two sites for the same time period were calculated rather than the same site over two time periods, 2) data for all years where both sites were complete during the overlap period (2007-2011) was utilized, 3) the analysis was limited to days where both sites had concentration measurements for all chemical components, and 4) the median rather than the average ratio was used. To screen out volcanic impacts on the most impaired days for the combined HALE1-HACR1 site and the Hawaii Volcanoes National Park monitor (HAVO1), EPA identified the 95<sup>th</sup> percentile 24-hour ammonium sulfate extinction value for each year between 2000 and 2014 and selected the year with the lowest value.

While Hawaii's 2017 Regional Haze Progress Report states that a majority of the visibility degradation in Hawaii's National Parks was due to the ongoing release of SO<sub>2</sub> from the Kilauea Volcano, SO<sub>2</sub> emissions significantly decreased after the Kilauea eruption ended in September 2018. The USGS stated, that in 2019, the Kilauea summit was the only source releasing enough SO<sub>2</sub> emissions to be quantified using ultra-violet spectroscopy. Preliminary USGS results for 2019 indicated an average summit daily SO<sub>2</sub> emission rate of about 43 metric tons per day (47 short tons per day) and an average annual total SO<sub>2</sub> emission rate of about 15,695 metric tons per year (17,301 short tons per year) which is far lower than the SO<sub>2</sub> emissions reported in the progress report of around two (2) million tons per year. The total combined SO<sub>2</sub> emissions from point sources screened for four-factor analysis were estimated to be about 18,058 tons per year in 2017 which is 939 tons higher than preliminary USGS estimates of volcanic SO<sub>2</sub> for 2019. After the Kilauea eruption activity ended in September 2018, point sources played a more significant part in SO<sub>2</sub> visibility impacts.



## Exhibit 2

On December 20, 2020, the Kilauea Volcano started another eruption. According to USGS-HVO personnel, on the onset of these eruptions, tens of thousands of tons of SO<sub>2</sub> per day is released by the volcano. By February 23, 2021, SO<sub>2</sub> emissions had decreased to about 800 tons per day that would correlate to an annual emission rate of 292,000 tons per year. This rate is lower than the emission rates from the pre-2018 lava lake that were typically around 5,000 tons per day of SO<sub>2</sub> or around 1,825,000 tons per year. The December 20, 2020, eruption ended on May 26, 2021. See Page 1 of Chapter 1 for information on new eruption that started on September 29, 2021.

The potential for haze from NO<sub>x</sub> emissions is considered to be low in Hawaii due to warm weather conditions year-round. IMPROVE data for both of Hawaii's national parks indicates that the impact of nitrate is much lower than that at many monitors in other Class I Areas around the country.

A comparison of baseline visibility conditions to the current and natural visibility conditions are shown in Tables 3.0-3 and 3.0-4 for Haleakala National Park and Hawaii Volcanoes National Park, respectively, based on EPA's calculation methodology. IMPROVE data with adjustments for volcanic activity, wildfires, dust storms, and the combined HALE1-HACR1 site was provided to WRAP for updating the TSS.

<b>Table 3.0-3</b> Comparison of Baseline, Current, and Natural Visibility Conditions for Clearest and Most Impaired Days at Haleakala National Park <sup>a</sup>				
20% Days of Calendar Year	Baseline (2000-2004) (dv)	Current (2014-2018) (dv)	Natural (2064) (dv)	
			Clearest Days	Most Impaired Days
Clearest	2.18	0.48	-0.12	4.22
Most Impaired	7.84	7.27		

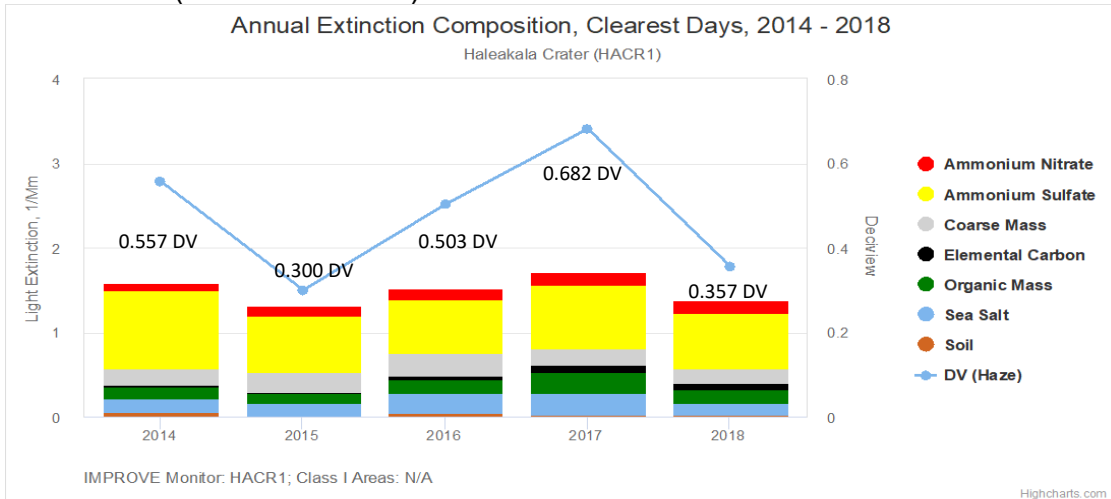
a: IMPROVE data adjusted for HALE1-HACR1 site combination and episodic events that include volcanic activity, wildfires smoke, and dust storms.

<b>Table 3.0-4</b> Comparison of Baseline, Current, and Natural Visibility Conditions for Clearest and Most Impaired Hawaii Volcanoes National Park <sup>a</sup>				
20% Days of Calendar Year	Baseline (2000-2004) (dv)	Current (2014-2018) (dv)	Natural (2064) (dv)	
			Clearest Days	Most Impaired Days
Clearest	4.06	3.50	2.20	6.62
Most Impaired	15.60	16.31		

a: IMPROVE data adjusted for episodic events that include volcanic activity, wildfires smoke, and dust storms.

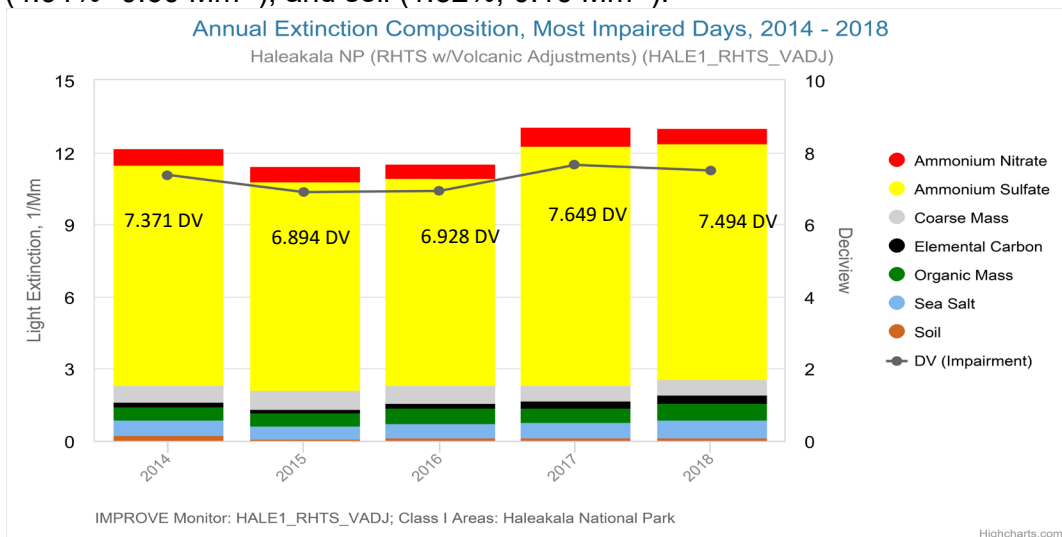
## Exhibit 2

Figure 3.0-1 shows the average annual contributions of haze species to light extinction and average annual deciview index for the clearest days at Haleakala National Park representing current visibility conditions. Most impairment is from sulfates that average (48% -  $0.722 \text{ Mm}^{-1}$ ) of the total light extinction over the five (5) year period (2014-2018) which would be expected since Kilauea Volcano was erupting and emitting extremely large quantities of  $\text{SO}_2$  over this five-year period. The next highest contributor is coarse mass (14% -  $0.215 \text{ Mm}^{-1}$ ). Sea salt is another large contributor after sulfates (12% -  $0.186 \text{ Mm}^{-1}$ ), due to coastal influences, followed by organic mass (11% -  $0.160 \text{ Mm}^{-1}$ ), and nitrates (9% -  $0.129 \text{ Mm}^{-1}$ ).



**Figure 3.0-1** Visibility Conditions at Haleakala NP for Clearest Days

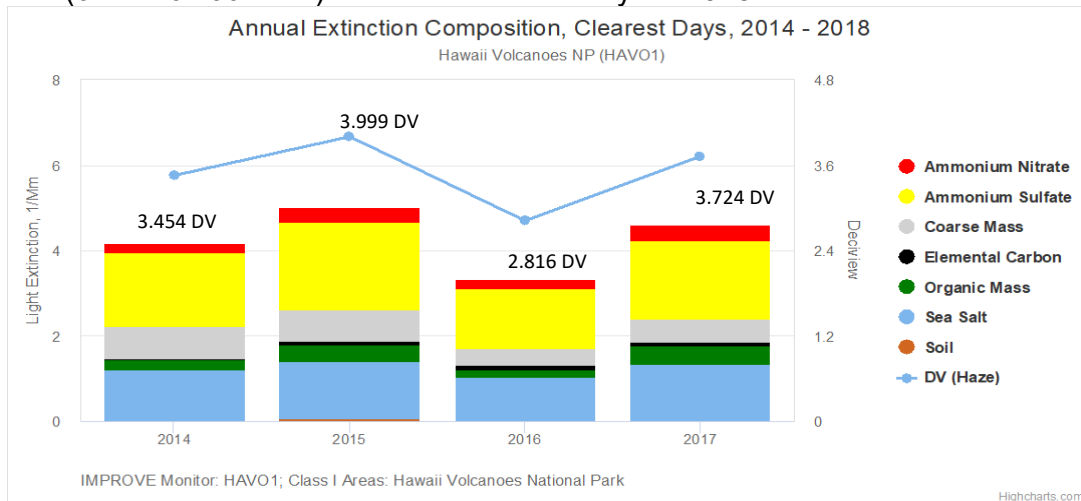
Figure 3.0-2 shows the average annual contributions of haze species to light extinction and average annual deciview index for the most impaired days at Haleakala National Park representing current visibility conditions based on IMPROVE data adjusted to screen sulfates from volcanic activity. Most impairment is from sulfates that average (75.49%;  $9.24 \text{ Mm}^{-1}$ ) of the total light extinction over the five (5) year period (2014-2018). Next highest contributor to light extinction is coarse mass (5.78%;  $0.70 \text{ Mm}^{-1}$ ) followed by nitrates (5.44%;  $0.67 \text{ Mm}^{-1}$ ), sea salt (5.13%;  $0.63 \text{ Mm}^{-1}$ ), organic mass (4.91% -  $0.60 \text{ Mm}^{-1}$ ), and soil (1.32%;  $0.16 \text{ Mm}^{-1}$ ).



**Figure 3.0-2** Visibility Conditions at Haleakala NP for Most Impaired Days

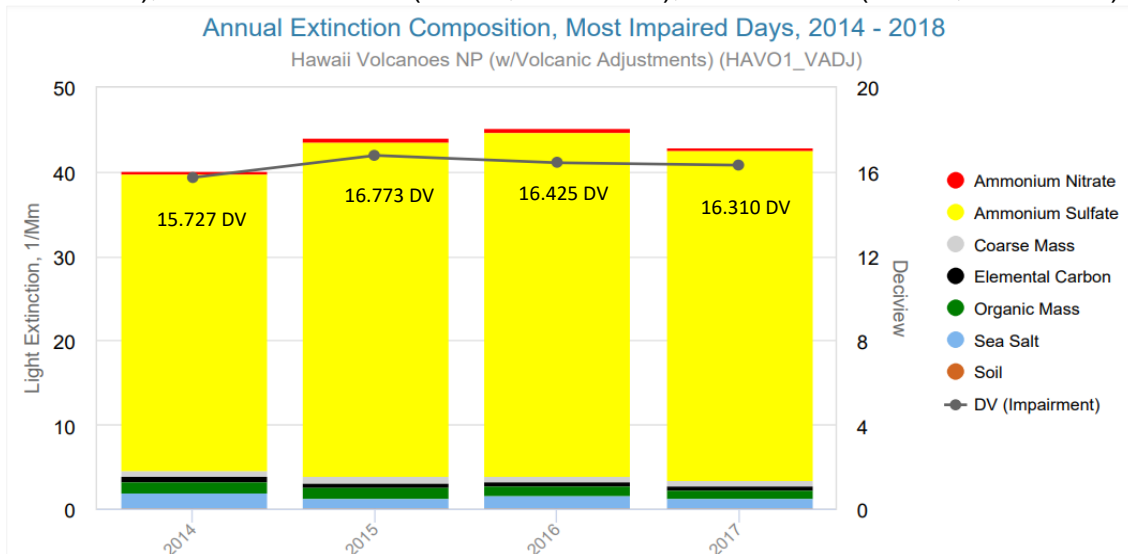
## Exhibit 2

Figure 3.0-3 shows the average annual contributions of haze species to light extinction and average annual deciview index for the clearest days at Hawaii Volcanoes National Park representing current visibility conditions. Most visibility impairment is from sulfates that average (41%; 1.755  $Mm^{-1}$ ) over the most recent 5-year period (2014-2018) of available data. Next highest contributor to light extinction is sea salt (29%; 1.219  $Mm^{-1}$ ) followed by coarse mass (14%; 0.603  $Mm^{-1}$ ), organic mass (6.9% - 0.302  $Mm^{-1}$ ), and nitrates (6.7% - 0.290  $Mm^{-1}$ ). There is no data for year 2018.



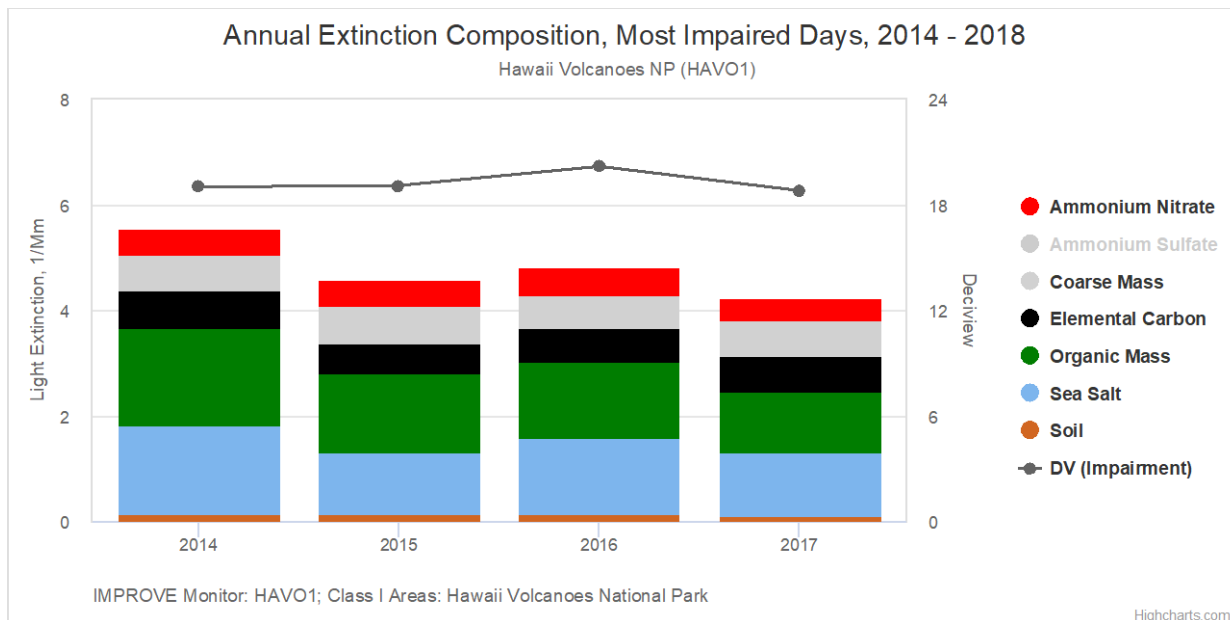
**Figure 3.0-3** Visibility Conditions at Hawaii Volcanoes NP for Clearest Days

Figures 3.0-4 and 3.0-5 show the average contributions of haze species to light extinction and average annual deciview index for the most impaired days at Hawaii Volcanoes National Park representing current visibility conditions based on IMPROVE data adjusted to screen sulfates from volcanic activity. Figure 3.0-5 excludes sulfate to magnify light extinction contributions from other aerosol species. Most impairment is from sulfates that average (86.65%; 32.90  $Mm^{-1}$ ) over the most recent 5-year time frame (2014-2018) of available data. Next highest contributors are sea salt (4.03%; 1.45  $Mm^{-1}$ ) and organic mass (3.57%; 1.21  $Mm^{-1}$ ), followed by coarse mass (2.45%; 0.85  $Mm^{-1}$ ), elemental carbon (1.54%; 0.54  $Mm^{-1}$ ), and nitrates (1.44%; 0.50  $Mm^{-1}$ ).



**Figure 3.0-4** Visibility Conditions at Hawaii Volcanoes NP for Most Impaired Days

## Exhibit 2



**Figure 3.0-5** Visibility Conditions at Hawaii Volcanoes NP for Most Impaired Days

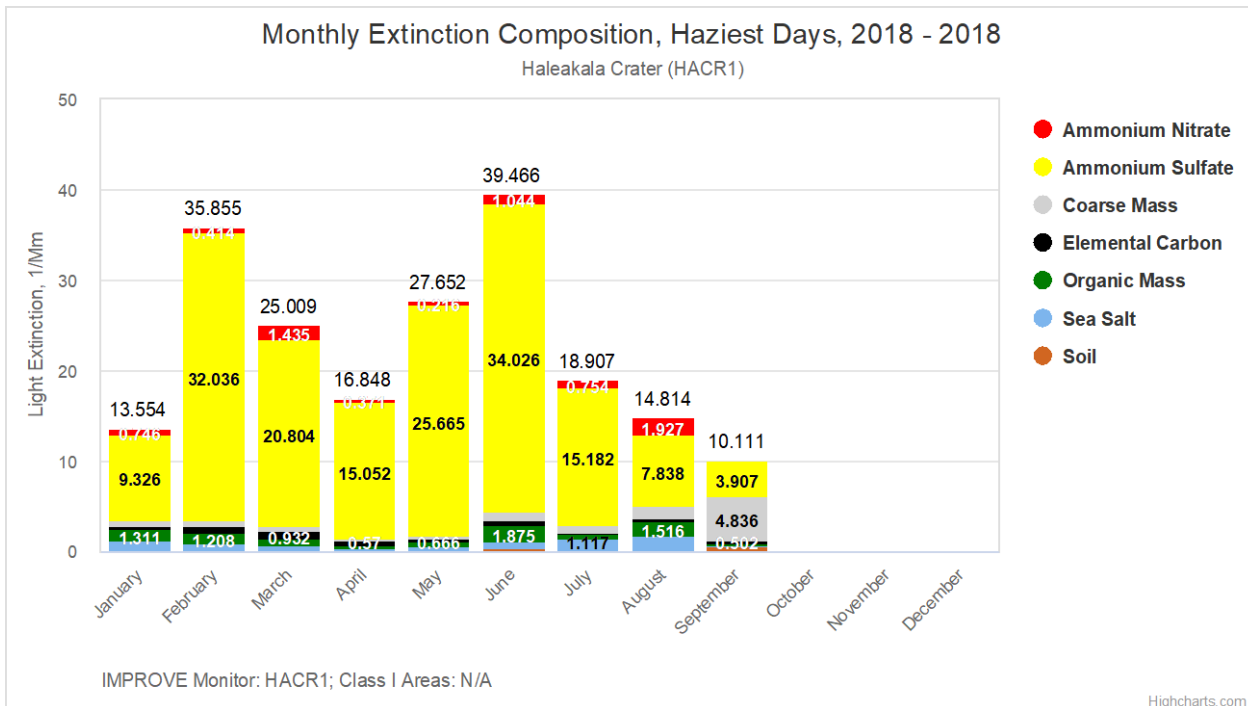
Evaluation of IMPROVE data over the current visibility period from 2014 to 2018 for Haleakala National Park and Hawaii Volcanoes National Park disclosed the following:

Ammonium Sulfate is the largest cause of visibility degradation, contributing from 48%-clearest days to 75%-most impaired days of the light extinction at Haleakala National Park and from 41%-clearest days to 87%-most impaired days of the light extinction at Hawaii Volcanoes National Park.

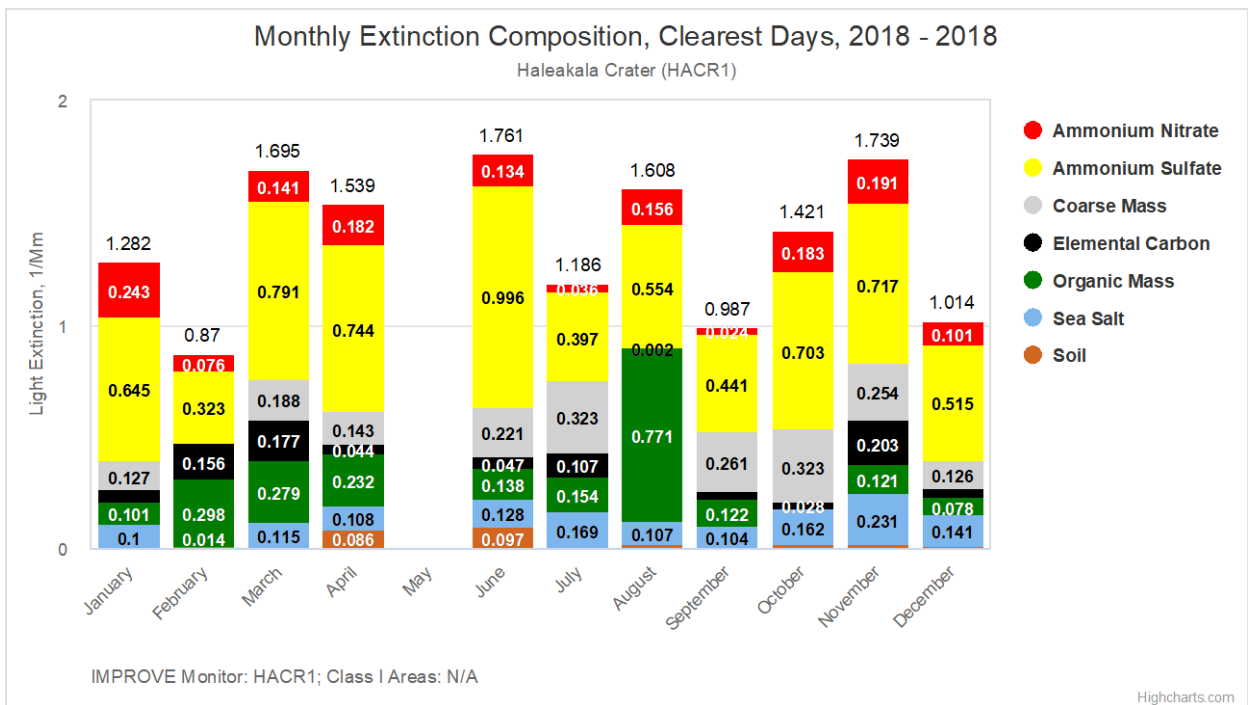
Natural causes of sulfate include  $\text{SO}_2$  from the Kilauea Volcano located in Hawaii Volcanoes National Park.<sup>12</sup> There is significant variability in light extinction from sulfates due to  $\text{SO}_2$  emissions that vary from year to year by hundreds of thousands of tons from the Kilauea eruption. The Kilauea Volcano, however, stopped erupting after the extreme volcanic event from May to September 2018. Figure 3.0-6 shows a significant reduction in light extinction from sulfates on the haziest days in the month of September when the eruption was winding down. The light extinction from sulfates on the haziest days at Haleakala National Park was as high as  $34.026 \text{ Mm}^{-1}$  in June 2018 and decreased to a level of  $3.907 \text{ Mm}^{-1}$  in September 2018. The change in light extinction from sulfates at Haleakala National Park is far less significant for the clearest days in months after the Kilauea eruption. Figure 3.0-7 shows light extinction from sulfates on the clearest days ranging from  $0.323 \text{ Mm}^{-1}$  to  $0.996 \text{ mM}^{-1}$  when the volcano was erupting from January to September 2018. Sulfate light extinction on the clearest days ranged from  $0.515 \text{ Mm}^{-1}$  to  $0.717 \text{ Mm}^{-1}$  between October and December 2018 after the eruption ended in September 2018. Sulfate from volcanic  $\text{SO}_2$  emissions is expected to significantly increase, however, because the Kilauea Volcano started erupting again. Please see Chapter 1, Introduction for details on new eruptions.

Point sources that combust fuel oil are anthropogenic emitters of  $\text{SO}_2$  that cause sulfate. A majority of these sources are power plants on the islands of Oahu, Maui, and Hawaii that combust fuel oil No. 6 with as much as 2.0% sulfur content.

## Exhibit 2



**Figure 3.0-6** Monthly Visibility Conditions at Haleakala NP for Hazeiest Days



**Figure 3.0-7** Monthly Visibility Conditions at Haleakala NP for Clearest Days

## Exhibit 2

Sea salt, due to the natural marine environment, contributes from 5%-most impaired days to 14%-clearest days of the light extinction at Haleakala National Park and from 4%-most impaired days to 29%-clearest days of the light extinction at Hawaii Volcanoes National Park. Sea spray was found to be 90% of total statewide PM<sub>10</sub> emissions (anthropogenic PM<sub>10</sub> + biogenic PM<sub>10</sub>) in Hawaii's 2017 Regional Haze Progress Report.

Coarse mass contributes from 6%-most impaired days to 14%-clearest days of the light extinction at Haleakala National Park and from 3%-most impaired days to 14%-clearest days of the light extinction at Hawaii Volcanoes National Park. Sulfates, ranging from 75% to 87% of the light extinction at the two national parks on the most impaired days, overwhelm light extinction from coarse mass on these days. Anthropogenic sources of coarse mass include fugitive dust from unpaved roads, aggregate processing, and construction activities. Natural sources of coarse mass include windblown dust.

Organic mass contributes from 4.5%-most impaired days to 11%-clearest days of the light extinction at Haleakala National Park and from 2.1%-most impaired days to 6.9%-clearest days of the light extinction at Hawaii Volcanoes National Park. Sources of organic mass include agricultural burning, wildfires, oil combustion, and international transport.<sup>12</sup> Organic mass can also be formed from biogenic plant and soil VOC. Biogenic VOC from plants and soil were found to be 77% of the total statewide VOC emissions (anthropogenic VOC + biogenic VOC) in Hawaii's 2017 Regional Haze Progress Report.

Ammonium Nitrates contribute from 4.0%-most impaired days to 9.0%-clearest days of the light extinction at Haleakala National Park and from 0.8%-most impaired days to 6.7%-clearest days of the light extinction at Hawaii Volcanoes National Park. Point sources that combust fuel oil are major anthropogenic emitters of NO<sub>x</sub> that cause nitrates. A majority of these sources are power plants on the islands of Oahu, Maui, and Hawaii that combust fuel oil No. 6 (residual oil).

Because residual oils are produced from residue remaining after lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur.<sup>23</sup> Fuels that contain nitrogen create "fuel NO<sub>x</sub>".<sup>24</sup>

Elemental Carbon contributes from 1.4%-most impaired days to 3.3%-clearest days of the light extinction at Haleakala National Park and from 1.0%-most impaired days to 1.8%-clearest days of the light extinction at Hawaii Volcanoes National Park. Sources of elemental carbon include fossil fuel combustion and biomass combustion (e.g., wildfires and agricultural burning).

Soil contributes from 1.4%-most impaired days to 3.3%-clearest days of the light extinction at Haleakala National Park and from 1.0%-most impaired days to 1.8%-clearest days at Hawaii Volcanoes National Park. Sources of soil include wind-blown dust, fugitive dust from construction activities, and road dust.

<sup>23</sup> AP-42 VOL1:1.3 Fuel Oil Combustion

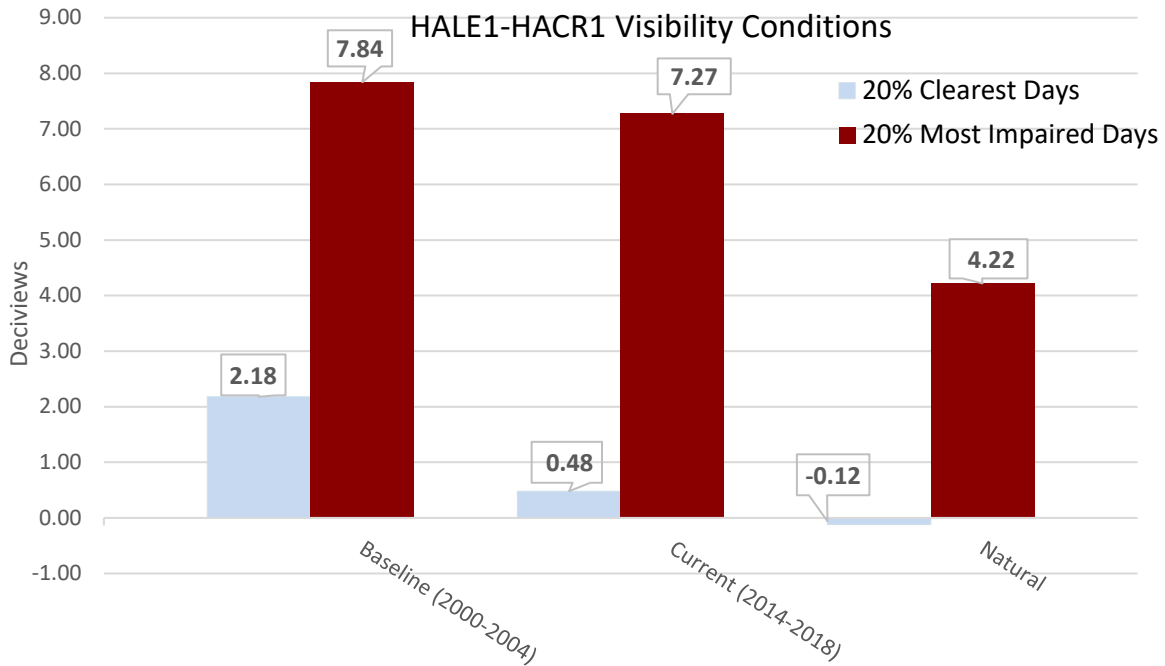
<sup>24</sup> Nitrogen Oxides, Why and How They Are Controlled, U.S. EPA, November 1999

## Exhibit 2

### 3.1 Progress to Date and Visibility Differences for Most Impaired and Clearest Days – 40 CFR §51.308(f)(1)(iv-v)

40 CFR §51.308(f)(1) requires states to address visibility progress and differences between current and natural visibility conditions. 40 CFR §51.308(f)(1)(iv) requires an evaluation of progress to date towards the natural visibility since the baseline period, actual progress made towards the natural visibility condition since the baseline period, and actual progress made during the previous implementation period up to and including the period for calculating current visibility conditions for the most impaired and clearest days. 40 CFR §51.308(f)(1)(v) requires an evaluation of the number of deciviews by which the difference between current visibility conditions exceed the natural visibility conditions, for the clearest and most impaired days.

Figure 3.1-1 compares baseline, current, and natural visibility conditions at Haleakala National Park for the clearest and most impaired days.



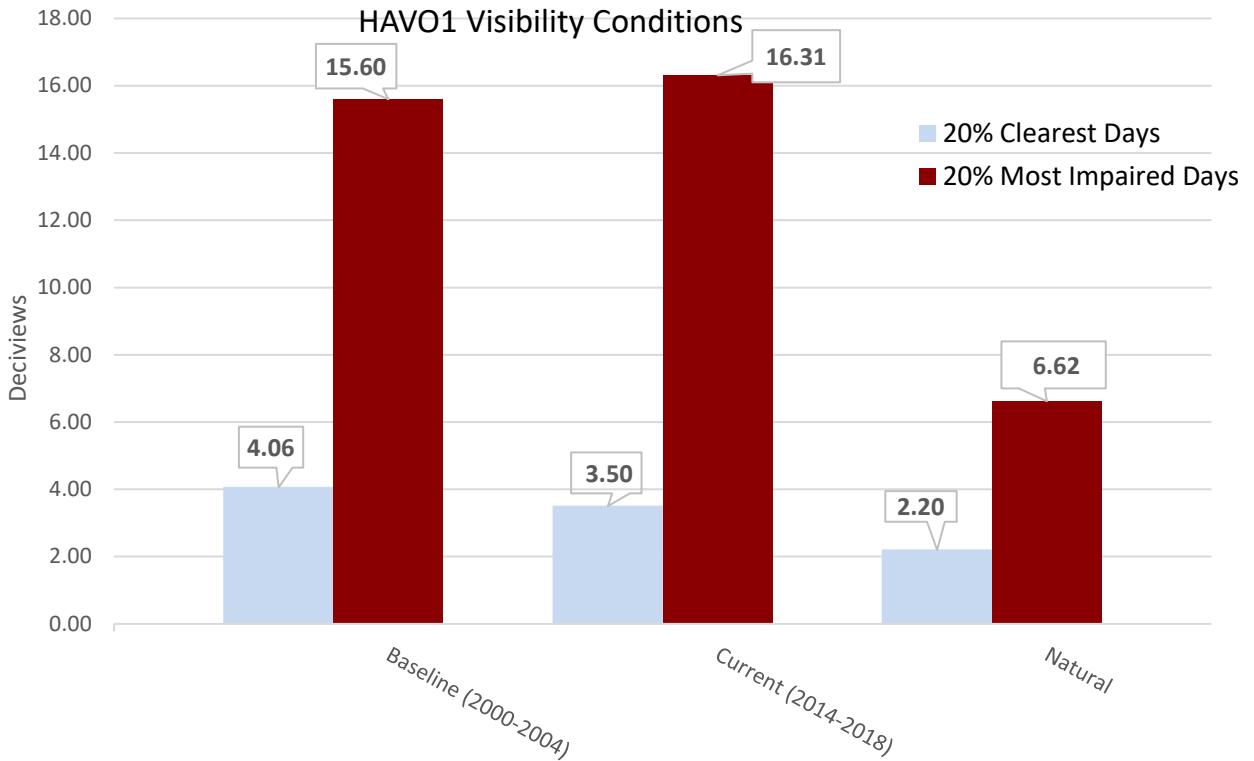
**Figure 3.1-1** Progress for Baseline, Current, and Natural Visibility Conditions at Haleakala NP for Clearest and Most Impaired Days

Table 3.1-1 below provides the difference between current and natural visibility conditions for Haleakala National Park.

Current Visibility (2014-2018)		Natural Visibility (2064)		Difference	
Clearest Days (dv)	Most Impaired Days (dv)	Clearest Days (dv)	Most Impaired Days (dv)	Clearest Days (dv)	Most Impaired Days (dv)
0.48	7.27	-0.12	4.22	0.60	3.05

## Exhibit 2

Figure 3.1-2 compares baseline, current, and natural visibility conditions at Hawaii Volcanoes National Park for the clearest and most impaired days.



**Figure 3.1-2** Progress for Baseline, Current, and Natural Visibility Conditions at Hawaii Volcanoes NP for Clearest and Most Impaired Days

Table 3.1-2 below provides the difference between current and natural visibility conditions for Haleakala National Park.

Current Visibility (2014-2018)		Natural Visibility (2064)		Difference	
Clearest Days (dv)	Most Impaired Days (dv)	Clearest Days (dv)	Most Impaired Days (dv)	Clearest Days (dv)	Most Impaired Days (dv)
3.50	16.31	2.20	6.62	1.30	9.69

### 3.2 Uniform Rate of Progress (URP) – 40 CFR §51.308(f)(1)(vi)

The URP is defined, in deciviews per year, the rate of visibility improvement that would be maintained to reach the natural visibility condition by the end of 2064. The URP or glidepaths are shown in Figures 3.2-1 and 3.2-2 as straight lines between the baseline visibility condition for the 20% most impaired days and natural visibility condition for 2064 based on the 20% most impaired days for Haleakala NP and Hawaii Volcanoes NP, respectively.



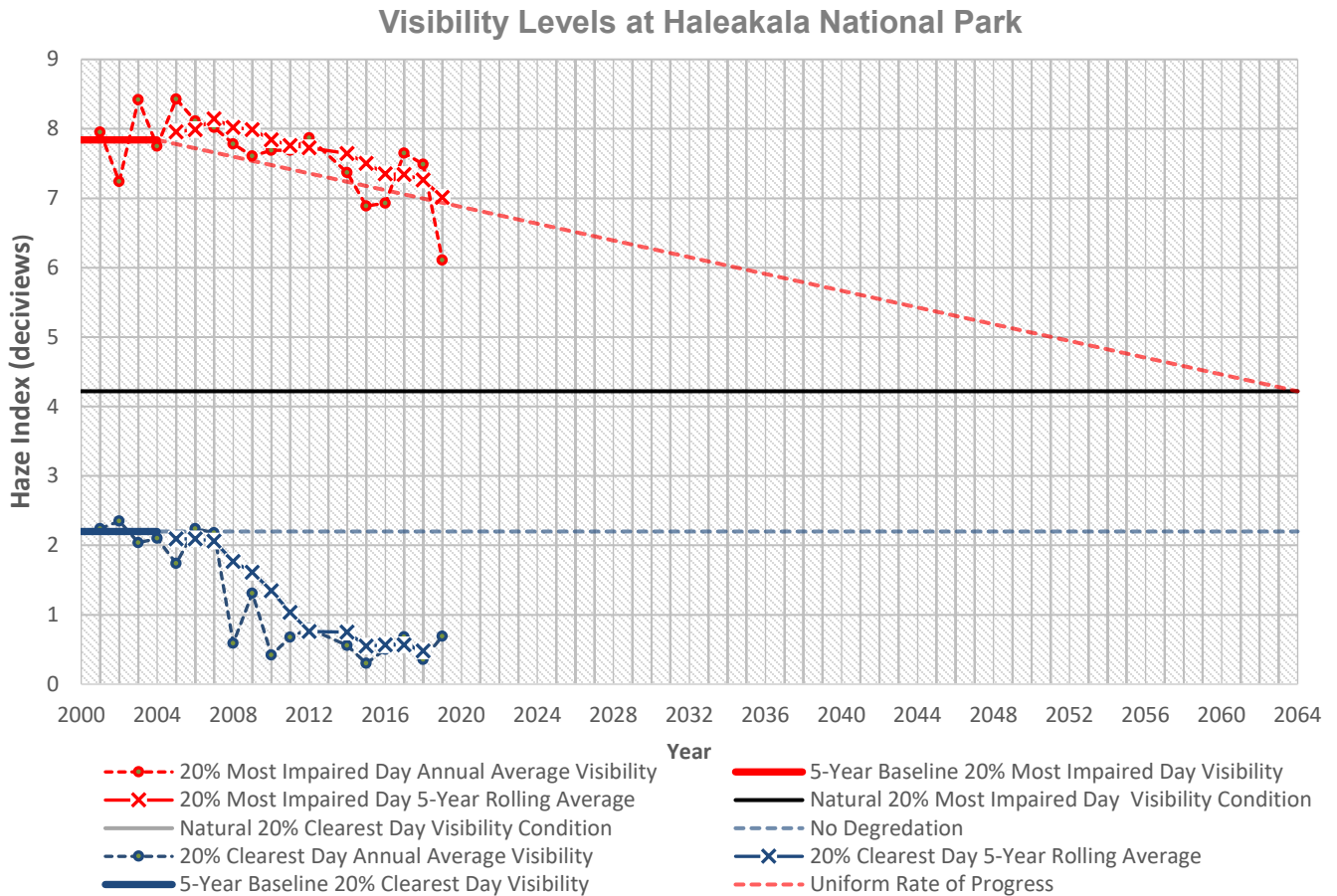
## Exhibit 2

Calculations in Table 3.2-1 show the URP is 0.060 dv/yr for Haleakala National Park.

<b>Table 3.2-1 URP for Haleakala National Park</b>				
2000-2004 Baseline 20% Most Impaired (dv)	2064 Natural 20% Most Impaired (dv)	Total Improvement Needed (dv)		URP (dv/yr) <sup>a</sup>
		2028 <sup>a</sup>	2064 <sup>a</sup>	
7.84	4.22	1.44	3.62	0.060

a.  $7.84 \text{ dv} - 4.22 \text{ dv} = 3.62 \text{ dv}$ ;  $2064 - 2004 = 60 \text{ yrs}$ ;  $3.62 \text{ dv} / 60 \text{ yrs} = 0.060 \text{ dv/yr}$ ;  $2028 - 2004 = 24 \text{ yrs}$ ;  
 $(24 \text{ yrs})(0.060 \text{ dv/yr}) = 1.44 \text{ dv}$  by 2028.

The calculated URP is drawn from the most impaired visibility days only. The value of the 2000-2004 baseline was based on that provided in EPA's white paper "Recommendations for the HALE1-HACR1 Site Combination and Volcano Adjustment for Sites Representing Hawaii Class I areas for Regional Haze Rule".<sup>21</sup> Figure 3.2-1 shows that the most impaired day 5-year rolling average for Haleakala National Park is slightly above the URP level for the first RH-SIP planning period (2001-2018). However, most of the visibility degradation is due to natural sulfates formed from SO<sub>2</sub> as a result of the Kilauea eruption in Hawaii Volcanoes National Park on the Big Island which is uncontrollable and unpreventable.



**Figure 3.2-1** Visibility Levels at Haleakala National Park

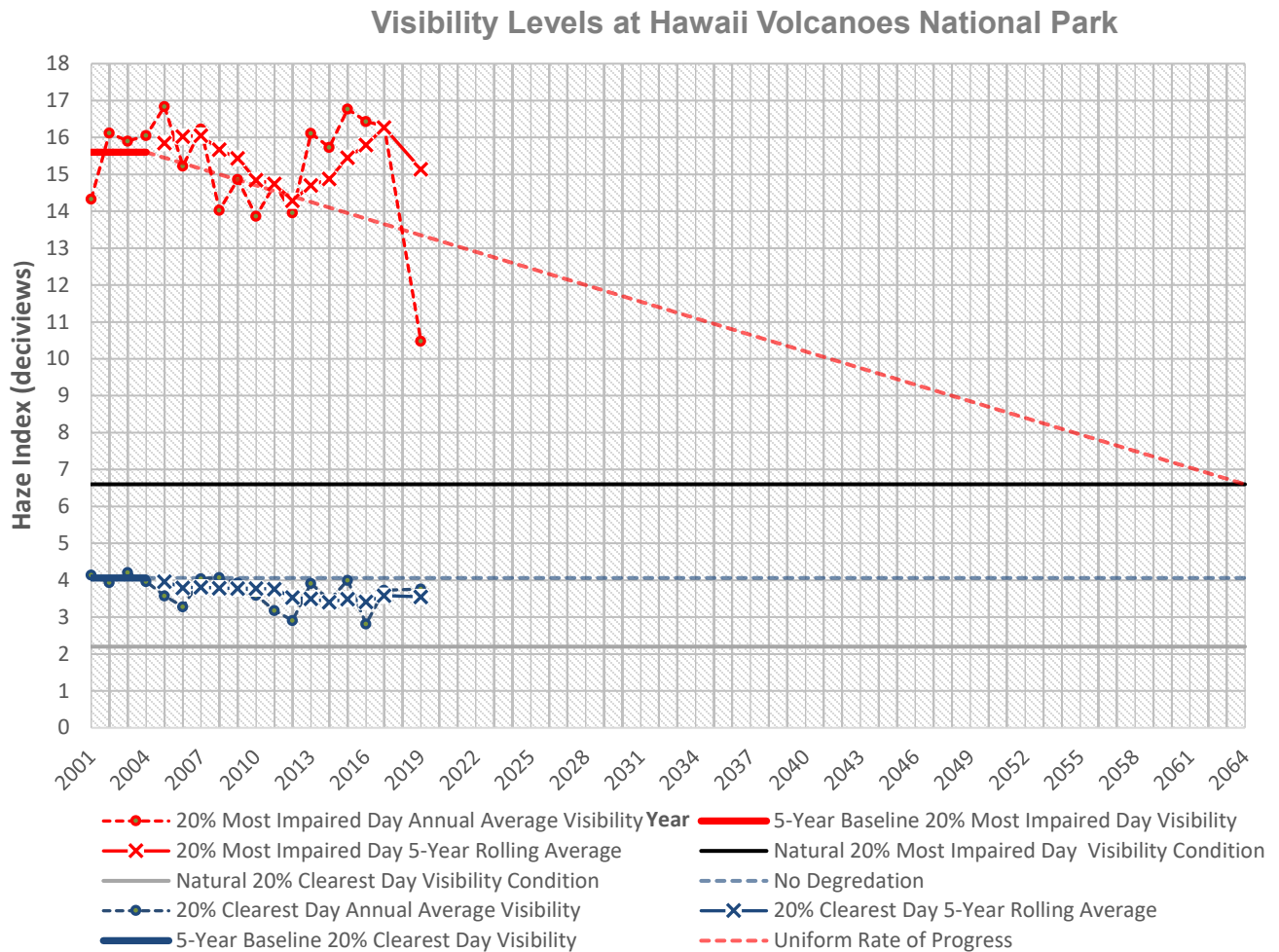
## Exhibit 2

Calculations in Table 3.2-2 show the URP is 0.150 dv/yr for Hawaii Volcanoes National Park.

<b>Table 3.2-2 URP for Hawaii Volcanoes National Park</b>				
2000-2004 Baseline 20% Most Impaired (dv)	2064 Natural 20% Most Impaired (dv)	Total Improvement Needed (dv)		URP (dv/yr)
		2028	2064	
15.60	6.62	3.60	8.98	0.150

a.  $15.60 \text{ dv} - 6.62 \text{ dv} = 8.98 \text{ dv}$ ;  $2064 - 2004 = 60 \text{ yrs}$ ;  $8.98 \text{ dv} / 60 \text{ yrs} = 0.150 \text{ dv/yr}$ ;  $2028 - 2004 = 24 \text{ yrs}$ ,  
 $(24 \text{ yrs})(0.150 \text{ dv/yr}) = 3.60 \text{ dv}$  by 2028.

The calculated URP is drawn from the most impaired visibility days only. Figure 3.2-2 shows that the most impaired day 5-year rolling average for Hawaii Volcanoes National Park is above the URP level for the first RH-SIP planning period (2001-2018). However, most of the visibility degradation is due to natural sulfates formed from SO<sub>2</sub> as a result of the Kilauea eruption in Hawaii Volcanoes National Park on the Big Island which is uncontrollable and unpreventable.



**Figure 3.2-2** Visibility Levels at Hawaii Volcanoes National Park

## Chapter 4 Statewide Emissions Inventory

### 4.0 Statewide Emissions Inventory – 40 CFR §51.308(f)(6)(v)

Section 51.308(f)(6)(v) of EPA's Regional Haze Rule (RHR) requires the establishment of a statewide emission inventory of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area. Hawaii's air emissions inventory includes sulfur dioxide (SO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>), particulate matter less than 10 microns in diameter (PM<sub>10</sub>), volatile organic compounds (VOCs), and ammonia (NH<sub>3</sub>). This section provides information on the development of baseline and future emission inventories that were used in SIP visibility modeling. This section is also intended to satisfy 40 CFR 51.308(g)(4) and 40 CFR 51.308(g)(5) of the RHR.

### 4.1 Trends in Emissions of Visibility Impairing Pollutants – 40 CFR §51.308(g)(4)

40 CFR §51.308(g)(4) of the RHR requires periodic progress towards the reasonable progress goals and must contain:

An analysis tracking the change over the period since the period addressed in the most recent plan in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source or activity. With respect to all sources and activities, the analysis must extend at least through the most recent year for which the state has submitted emission inventory information in accordance with EPA's triennial reporting requirements as of a date six (6) months preceding the required date of the progress report. With respect to sources that report directly to EPA's centralized emissions data system, the analysis must extend through the most recent year for which the Administrator has provided a State-level summary of such reported data or an internet-based tool by which the State may obtain such a summary as of a date six (6) months preceding the required date of the progress report. The State is not required to backcast previously reported emissions to be consistent with more recent emission estimates that may draw attention to actual or possible inconsistencies from changes in estimation procedures.

40 CFR §51.308(g)(5) of the RHR requires period progress towards the reasonable progress goals and must contain:

An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred since the period addressed in the most recent plan required under 40 CFR §51.308(f) including whether or not these changes in anthropogenic emissions were anticipated in that most recent plan and whether they have limited or impeded progress in reducing pollutant emissions and improving visibility.

Chapter 4 of this RH-SIP provides a summary of emissions of visibility impairing pollutants from all sources and activities within the state for the years 2005, 2011, 2014, 2016, & 2017. Data categories are separated into anthropogenic emissions and natural source emissions.

## Exhibit 2

Anthropogenic source categories include point source, area (nonpoint) source, agricultural burning, other fire, nonroad mobile sources, on-road mobile sources, and marine. The natural sources of emissions are from volcanic activity, sea spray, windblown dust, wildfire, and biogenic sources.

Source categories represented in emissions summaries matching EPA's National Emissions Inventory (NEI) are described below:

Point Sources – include emissions estimates for larger sources that are located at a fixed, stationary location. Point sources in the NEI include large industrial facilities and electric power plants, airports, and smaller industrial, non-industrial and commercial facilities. A small number of portable sources such as some asphalt or rock crushing operations are also included. The emissions potential of stationary sources determines whether that facility should be reported as a point source, according to emissions thresholds set in the Air Emissions Reporting Rule (AERR). Emissions are calculated based on source specific factors and are reported to the state and NEI annually. As of 2008, mobile source nonroad emissions from airports, and railroad switch yards are included in the point source category in the NEI.

Area (Nonpoint) Sources – include emissions estimates for sources which individually are too small in magnitude to report as point sources. Examples include residential heating, commercial combustion, asphalt paving, and commercial and consumer solvent use. Beginning in 2008, the NEI includes emissions from the mobile source nonroad categories for commercial marine vessels and underway rail emissions. Prior to 2011, the NEI included vehicle refueling at gasoline service stations in the area sources sector and beginning in 2011 it is included in the on-road sector.

Nonroad Mobile Sources – include off-road mobile sources that use gasoline, diesel, and other fuels (e.g., LPG). Source types include construction equipment, lawn and garden equipment, aircraft ground support equipment, locomotives, and commercial marine vessels. For many nonroad sources, the EPA uses the MOVES-NONROAD model (which assumes that new EPA emissions standards will result in a certain number of off-road sources being replaced every year by new, less polluting off-road sources) and these sources are included in the EIS nonroad Data Category. Starting with the 2008 NEI, some nonpoint sources are included in other EIS Data Categories. Aircraft engine emissions (occurring during landing and takeoff operations) and the ground support and power unit equipment are included in the EIS Point Data Category at airport locations. Locomotive emissions at rail yards are also included in the EIS Point Data Category. Emissions of other locomotive emissions and of commercial marine vessel emissions (both underway and port emissions) are included in the NEI Nonpoint Data Category.

On-road Mobile Sources – include emissions from on-road vehicles that use gasoline, diesel, and other fuels. These sources include light duty and heavy-duty vehicle emissions from operation on roads, highway ramps, and during idling. The MOVES model also computes refueling emissions, which are included in the EIS Nonpoint Data Category. All other on-road source emissions are included in the EIS On-road Data Category.

## Exhibit 2

For Hawaii, year 2005 was selected as the baseline inventory for the first regional haze planning period because it was the most complete inventory at the time technical work commenced for the RH-FIP. The most recent emissions inventory data for tracking the changes in emissions for the second regional haze planning period were obtained from EPA's 2017 NEI. Table 4.1-1 lists the major visibility impairing pollutants inventoried, the related aerosol species, and some of the major sources for each pollutant.

Statewide emissions inventories for SO<sub>2</sub>, NO<sub>x</sub>, NH<sub>3</sub>, VOC, and PM<sub>10</sub> are provided in Tables 4.1-2 through 4.1-6 for the 2005 baseline, 2011, 2014, 2016, and 2017 inventory years. The 2005 emissions inventory, based on data in Reference 25 was derived from a 2010 study conducted by the consulting firm Environ on behalf of the Hawaii DOH-CAB that provided Hawaii's statewide emissions for 2002, 2005, and projected 2018.<sup>25</sup> The emission inventory numbers developed by Environ Corporation were refined, as applicable, by the Hawaii DOH-CAB. The EPA also worked with the University of North Carolina and consulting firm ICF International to develop new emission inventories for on-road vehicles after finalizing a new model MOVES for estimating emissions from on-road vehicles. The Hawaii emission inventories provided by Environ were updated with estimations using the MOVES model.

<b>Table 4.1-1 Hawaii Pollutants, Aerosol Species, and Major Sources <sup>a</sup></b>			
Emitted Pollutant	Related Aerosol	Major Sources	Notes
SO <sub>2</sub>	Ammonium Sulfate	Point Sources; On- and Off-Road Mobile Sources; Volcanic Emissions	SO <sub>2</sub> emissions are generally associated with anthropogenic sources such as fuel oil fired power plants, large commercial operations such as aggregate processing, and both on-road and off-road diesel engines.  In Hawaii, volcanic activity contributes significantly to natural emissions of SO <sub>2</sub> , and it is possible that some of these emissions are transported to the contiguous states. 2019 volcanic activity has significantly decreased and led to significantly reduced volcanic SO <sub>2</sub> emissions after the Kilauea Volcano stopped erupting towards the end of 2018. Volcanic SO <sub>2</sub> emissions, however, are expected to increase significantly as the Kilauea Volcano started erupting again on December 20, 2020.
NO <sub>x</sub>	Ammonium Nitrate	On- and Off-Road Mobile Sources; Point Sources; Area Sources	NO <sub>x</sub> emissions are generally associated with anthropogenic sources. Common sources include virtually all combustion activities, especially those involving cars, trucks, power plants, and other industrial processes.
NH <sub>3</sub>	Ammonium Sulfate & Ammonium Nitrate	Area Sources; On-Road Mobile Sources	Gaseous NH <sub>3</sub> has implications in particulate formation because it can form particulate ammonium. Ammonium is not directly measured by the IMPROVE program but affects formation potential of ammonium sulfate and ammonium nitrate. All measured nitrate and sulfate are assumed to be associated with ammonium for IMPROVE reporting purposes.

<sup>25</sup> Final Emission Inventory Report: Data Population of Air System for Hawaii's Emissions Data (AirSHED), Prepared for Hawaii Department of Health by ENVIRON International Corporation.

## Exhibit 2

Emitted Pollutant	Related Aerosol	Major Sources	Notes
VOCs	Particulate Organic Mass (POM)	Biogenic Emissions; Vehicle Emissions; Area Sources	VOCs are gaseous emissions of carbon compounds, which are often converted to POM through chemical reactions in the atmosphere.  Estimates for biogenic emissions of VOCs have undergone significant updates since 2002, so changes reported here are more reflective of methodology changes than actual changes in emissions (see Section 3.2.1 of Reference 10). <sup>10</sup>
Fine Soil	Soil	Windblown Dust; Fugitive Dust; Road Dust; Area Sources	Fine soil is reported here as the crustal or soil components of PM <sub>2.5</sub> .
Coarse Mass (PMC)	Coarse Mass	Windblown Dust; Fugitive Dust	Coarse mass is reported by the IMPROVE Network as the difference between PM <sub>10</sub> and PM <sub>2.5</sub> mass measurements. Coarse mass is not separated by species in the same way that PM <sub>2.5</sub> is speciated, but these measurements are generally associated with crustal components. Similar to crustal PM <sub>2.5</sub> , natural windblown dust is often the largest contributor to PMC.

a. From Table 6.5-7 on Page 6-131 of Reference 6.

Source Category	SO <sub>2</sub>	NO <sub>x</sub>	VOC	PM <sub>10</sub>	NH <sub>3</sub>
<b>Anthropogenic Sources (TPY)</b>					
Point Sources	27,072	22,745	2,695	3,536	12
Area Sources	3,716	1,509	16,920	33,408	11,136
Agricultural Burning	178	406	535	1,567	60
Other Fire	0	1	7	7	0
On-Road Mobile Sources	321	20,642	12,066	638	1,085
Non-Road Mobile Sources <sup>b</sup>	669	6,296	6,383	649	0
Marine <sup>c</sup>	3,619	5,624	209	398	0
<b>Total Anthropogenic</b>	<b>35,575</b>	<b>57,223</b>	<b>38,815</b>	<b>40,203</b>	<b>12,298</b>
<b>Natural Sources (TPY)</b>					
Volcano	961,366	-	-	-	-
Sea Spray	-	-	-	382,637	-
Windblown Dust	-	-	-	46,808	-
Wildfire	591	2,156	4,729	9,771	540
Biogenic	-	4,617	130,153	-	-
<b>Total Natural</b>	<b>961,957</b>	<b>6,773</b>	<b>134,882</b>	<b>439,216</b>	<b>540</b>
<b>All Sources (TPY)</b>					
<b>Total Overall Emissions</b>	<b>997,532</b>	<b>63,996</b>	<b>173,697</b>	<b>479,419</b>	<b>12,838</b>

a. Based on "Final Emission Inventory Report: Data Population of Air System for Hawaii's Emissions Data (AirSHED), Prepared for Hawaii Department of Health by ENVIRON International Corporation".

b. Non-Road Mobile totals include aircraft and locomotive emissions.

c. Marine totals include in/near/underway emissions.

## Exhibit 2

<b>Table 4.1-3 Statewide Emissions Inventory 2011<sup>a</sup></b>					
Source Category	SO <sub>2</sub>	NO <sub>x</sub>	VOC	PM <sub>10</sub>	NH <sub>3</sub>
<b>Anthropogenic Sources (TPY)</b>					
Point Sources	22,047	28,982	3,059	2,813	1,031
Area Sources <sup>b</sup>	3,331	1,176	18,425	34,803	7,547
Agricultural Burning	178	405	535	1,567	148
Prescribed Burning	36	389	1,672	853	59
On-Road Mobile Sources	102	15,503	11,180	305	412
Non-Road Mobile Sources	7	3,842	5,428	403	6
Marine <sup>c</sup>	2,037	4,895	154	338	3
<b>Total Anthropogenic</b>	<b>27,738</b>	<b>55,192</b>	<b>40,453</b>	<b>41,420</b>	<b>9,749</b>
<b>Natural Sources (TPY)</b>					
Volcano <sup>d</sup>	406,030	-	-	-	-
Sea Spray <sup>e</sup>	-	-	-	382,637	-
Windblown Dust <sup>e</sup>	-	-	-	46,808	-
Wildfire	9	99	390	162	12
Biogenic <sup>e</sup>	-	4,617	130,153	-	-
<b>Total Natural</b>	<b>406,030</b>	<b>4,716</b>	<b>130,543</b>	<b>429,607</b>	<b>12</b>
<b>All Sources (TPY)</b>					
<b>Total Overall Emissions</b>	<b>433,768</b>	<b>59,808</b>	<b>170,996</b>	<b>471,027</b>	<b>9,761</b>

a. Based on 2011 NEI at:

<https://www.epa.gov/air-emissions-inventories/2011-national-emissions-inventory-nei-data>.

b. Area source emissions exclude agricultural burning and marine.

c. Marine totals include diesel port diesel underway, residual port and residual underway.

d. Based on SO<sub>2</sub> emission rates reported by USGS for Kilauea volcano (USGS DailyAves\_720pts.xlsx file provided by Tamar Elias, USGS).

e. Based on emission inventory work from ENVIRON International Corporation for 2002 and 2005 (Reference 25).<sup>25</sup>

<b>Table 4.1-4 Statewide Emissions Inventory 2014<sup>a</sup></b>					
Source Category	SO <sub>2</sub>	NO <sub>x</sub>	VOC	PM <sub>10</sub>	NH <sub>3</sub>
<b>Anthropogenic Sources (TPY)</b>					
Point Sources	19,543	26,163	4,117	2,583	247
Area Sources <sup>b</sup>	98	463	15,162	54,626	3,884
Agricultural Burning	197	359	534	583	2,551
Prescribed Burning	534	6,153	29,665	14,086	951
On-Road Mobile Sources	104	12,077	10,383	770	338
Non-Road Mobile Sources	9	3,228	4,313	356	6
Marine <sup>c</sup>	229	1,131	35	37	0.4
<b>Total Anthropogenic</b>	<b>20,714</b>	<b>49,574</b>	<b>64,209</b>	<b>73,041</b>	<b>7,977</b>
<b>Natural Sources (TPY)</b>					
Volcano <sup>d</sup>	2,062,813	-	-	-	-
Sea Spray <sup>e</sup>	-	-	-	382,637	-
Windblown Dust <sup>e</sup>	-	-	-	46,808	-
Wildfire	258	3,374	14,437	11,340	838
Biogenic <sup>e</sup>	-	237	31,842	-	-
<b>Total Natural</b>	<b>2,063,071</b>	<b>3,611</b>	<b>46,279</b>	<b>440,785</b>	<b>838</b>
<b>All Sources (TPY)</b>					
<b>Total Overall Emissions</b>	<b>2,083,785</b>	<b>53,185</b>	<b>110,489</b>	<b>513,826</b>	<b>8,815</b>

a. Emissions are from the 2014 NEI (<https://www.epa.gov/air-emissions-inventories/2014-national-emissions-inventory-nei-data>) unless noted otherwise below.

## Exhibit 2

- b. Area source emissions include emissions from all sectors in the non-point data category (NP) of 2014 NEI except for agricultural field burning and commercial marine vessels as emissions from these categories are reported separately here (Agricultural Burning and Marine, respectively).
- c. Based on SO<sub>2</sub> emission rates reported by USGS for Kilauea volcano (USGS DailyAves\_720pts.xlsx file provided by Tamar Elias, USGS)
- d. Sea spray and windblown dust emissions were estimated for Hawaii as part of emission inventory work by ENVIRON International Corporation for the years 2002 and 2005 (ENVIRON, 2010). These emissions are reported here and are assumed to be representative of all years.
- e. No wildfire or biogenic emissions were included in the 2014 NEI for Hawaii. Emissions from the EPA's 2016 modeling platform (EPA, 2020) are reported here as 2016 is the closest year with available emissions estimates for these sectors.

<b>Table 4.1-5 Statewide Emissions Inventory 2016<sup>a</sup></b>					
Source Category	SO <sub>2</sub>	NO <sub>x</sub>	VOC	PM <sub>10</sub>	NH <sub>3</sub>
<b>Anthropogenic Sources (TPY)</b>					
Point Sources	19,248	23,585	3,904	2,280	238
Area Sources <sup>b</sup>	98	464	14,556	37,780	1,579
Agricultural Burning <sup>c</sup>	30	55	77	93	391
Prescribed Burning <sup>c</sup>	-	-	-	-	-
On-Road Mobile Sources	63	10,387	9,072	630	316
Non-Road Mobile Sources	8	3,442	4,404	339	7
Marine <sup>d</sup>	267	8,984	443	185	2
<b>Total Anthropogenic</b>	<b>19,715</b>	<b>46,917</b>	<b>32,456</b>	<b>41,307</b>	<b>2,533</b>
<b>Natural Sources (TPY)</b>					
Volcano <sup>e</sup>	2,089,368	-	-	-	-
Sea Spray <sup>f</sup>	-	-	-	382,637	-
Windblown Dust <sup>f</sup>	-	-	-	46,808	-
Wildfire <sup>c</sup>	258	3,374	14,437	11,340	838
Biogenic	-	237	31,842	-	-
<b>Total Natural</b>	<b>2,089,626</b>	<b>3,611</b>	<b>46,279</b>	<b>440,785</b>	<b>838</b>
<b>All Sources (TPY)</b>					
<b>Total Overall Emissions</b>	<b>2,109,341</b>	<b>50,528</b>	<b>78,735</b>	<b>482,091</b>	<b>3,371</b>

- a. Point source emissions are from the 2016 NEI data for Hawaii from the EPA's Emissions Inventory System (EIS) Gateway, which in 2016 only includes point sources. All other emissions are from the EPA 2016 Regional Haze Modeling v1 emissions platform (2016fh) for Hawaii (EPA, 2020) unless otherwise noted below. These emissions were extracted directly from the EPA model-ready emission files for the 3-kilometer resolution HI modeling domain, which were provided by Kirk Baker at the EPA on May 20, 2020.
- b. Area sources include nonpoint sources (nonpt), fugitive dust (afdust\_adj), agricultural ammonia sources (ag), and residential wood combustion (rwc).
- c. The agricultural burning emissions reported here are the point source agricultural fires in the modeling platform (ptagfire). Wildland fire and prescribed burning emissions are provided in a single model emissions file (ptfire) and thus could not be disaggregated. The total wild and prescribed fire emissions are reported as wildfire emissions here.
- d. Marine emissions reported here are the domain-wide total from C1 and C2 (cmv\_c1c2) and C3 (cmv\_c3) commercial marine vessels in the model-ready emission files for the HI 3 km resolution modeling domain, including emissions from outside state waters. This is inconsistent with the emissions reported in the 2014 and 2017 NEI, and thus the 2016 and 2028 marine emissions should not be directly compared to emissions reported for 2014 and 2017.
- e. Based on SO<sub>2</sub> emission rates reported by USGS for Kilauea volcano (USGS DailyAves\_720pts.xlsx file provided by Tamar Elias, USGS).
- f. Sea spray and windblown dust emissions were estimated for Hawaii as part of emission inventory work by ENVIRON International Corporation for the years 2002 and 2005 (ENVIRON, 2010). These emissions are reported here and are assumed to be representative of all years.



## Exhibit 2

<b>Table 4.1-6 Statewide Emissions Inventory 2017<sup>a</sup></b>					
Source Category	SO <sub>2</sub>	NO <sub>x</sub>	VOC	PM <sub>10</sub>	NH <sub>3</sub>
<b>Anthropogenic Sources (TPY)</b>					
Point Sources <sup>b</sup>	17,265	21,596	3,519	2,108	232
Area Sources <sup>c</sup>	1,141	807	14,387	18,908	1,583
Agricultural Burning <sup>d</sup>	-	-	-	-	-
Prescribed Burning	50	90	1,562	673	109
On-Road Mobile Sources	52	9,327	8,109	841	332
Non-Road Mobile Sources	5	3,288	4,454	327	7
Marine	110	4,401	276	102	2
<b>Total Anthropogenic</b>	<b>18,624</b>	<b>39,509</b>	<b>32,307</b>	<b>22,958</b>	<b>2,265</b>
<b>Natural Sources (TPY)</b>					
Volcano <sup>e</sup>	1,925,614	-	-	-	-
Sea Spray <sup>f</sup>	-	-	-	382,637	-
Windblown Dust <sup>f</sup>	-	-	-	46,808	-
Wildfire	43	100	916	432	64
Biogenic	-	1,422	128,061	-	-
<b>Total Natural</b>	<b>1,925,657</b>	<b>1,522</b>	<b>128,977</b>	<b>429,877</b>	<b>64</b>
<b>All Sources (TPY)</b>					
<b>Total Overall Emissions</b>	<b>1,944,281</b>	<b>41,031</b>	<b>161,284</b>	<b>452,835</b>	<b>2,328</b>

a. Emissions are from the 2017 NEI (<https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data>) unless noted otherwise below.

b. Point source emissions are from the June 2020 update to the point sources of the 2017 NEI (2017NEI\_June2020\_PT), which is only available in the EIS gateway.

c. Area source emissions include emissions from all sectors in the non-point data category (NP) of 2017 NEI except for biogenic and commercial marine vessels as emissions from these categories are reported separately here (Biogenic and Marine, respectively).

d. No emissions are reported for the agricultural field burning sector in the 2017 NEI data for HI.

e. Based on SO<sub>2</sub> emission rates reported by USGS for Kilauea volcano (USGS DailyAves\_720pts.xlsx file provided by Tamar Elias, USGS).

f. Sea spray and windblown dust emissions were estimated for Hawaii as part of emission inventory work by ENVIRON International Corporation for the years 2002 and 2005 (ENVIRON, 2010). These emissions are reported here and are assumed to be representative of all years.

## Exhibit 2

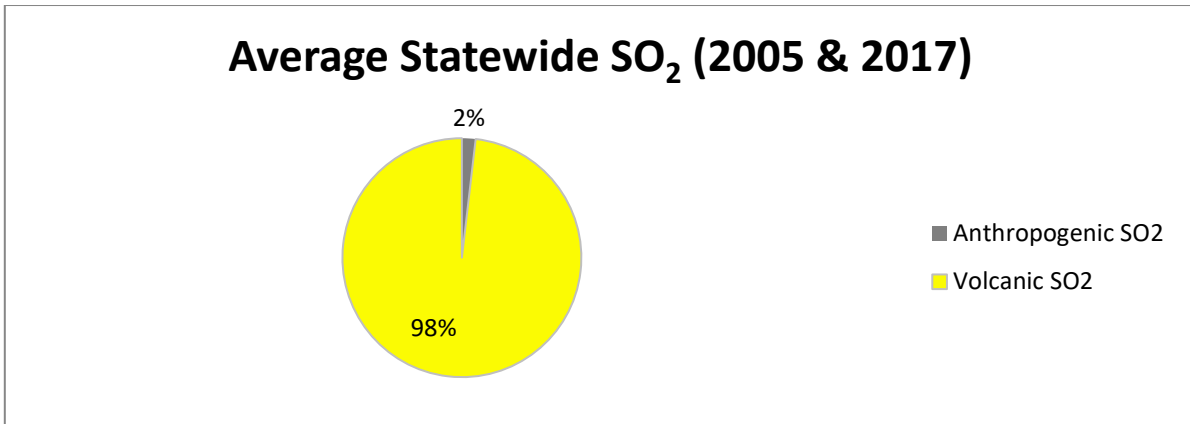
<b>Table 4.1-7 Projected Statewide Emissions Inventory 2028 <sup>a</sup></b>					
Source Category	SO <sub>2</sub>	NO <sub>x</sub>	VOC	PM <sub>10</sub>	NH <sub>3</sub>
<b>Anthropogenic Sources (TPY)</b>					
Point Sources <sup>b</sup>	17,044	22,106	4,153	2,139	218
Area Sources <sup>c</sup>	99	469	13,925	37,950	1,619
Agricultural Burning	30	55	77	93	391
Prescribed Burning	0	0	0	0	0
On-Road Mobile Sources	34	3,221	4,024	527	272
Non-Road Mobile Sources	6	2,086	3,016	212	8
Marine <sup>d</sup>	357	5,658	561	207	3
<b>Total Anthropogenic</b>	<b>17,570</b>	<b>33,595</b>	<b>25,756</b>	<b>41,128</b>	<b>2,511</b>
<b>Natural Sources (TPY)</b>					
Volcano <sup>e</sup>	2,089,368	-	-	-	-
Sea Spray <sup>f</sup>	-	-	-	382,637	-
Windblown Dust <sup>f</sup>	-	-	-	46,808	-
Wildfire <sup>g</sup>	258	3,374	14,437	11,340	838
Biogenic <sup>g</sup>	-	237	31,842	-	-
<b>Total Natural</b>	<b>2,089,626</b>	<b>3,611</b>	<b>46,279</b>	<b>440,785</b>	<b>838</b>
<b>All Sources (TPY)</b>					
<b>Total Overall Emissions</b>	<b>2,107,197</b>	<b>37,206</b>	<b>72,035</b>	<b>481,913</b>	<b>3,349</b>

- a. Emissions are from the EPA 2028 Regional Haze Modeling v1 emissions platform (2028fh) for Hawaii (EPA, 2020) unless otherwise noted below. These emissions were extracted directly from the EPA model-ready emission files for the 3-kilometer resolution HI modeling domain, which were provided by Kirk Baker at the EPA on May 20, 2020. Natural (i.e., biogenic, wildland fire), nonpoint emissions, and agricultural burning emissions were not projected and thus are the same as 2016.
- b. Point source emissions include EGU point sources (ptegu), non-EGU point sources (ptnonipm) and airport sources (airport).
- c. Area sources include nonpoint sources (nonpt), fugitive dust (afdust\_adj), agricultural ammonia sources (ag), and residential wood combustion (rwc).
- d. Marine emissions reported here are the domain-wide total from C1 and C2 (cmv\_c1c2) and C3 (cmv\_c3) commercial marine vessels in the model-ready emission files for the HI 3 km resolution modeling domain, including emissions from outside state waters. This is inconsistent with the emissions reported in the 2014 and 2017 NEI, and thus the 2016 and 2028 marine emissions should not be directly compared to emissions reported for 2014 and 2017.
- e. Volcano emissions were not included in the EPA modeling platform. Emissions from 2016 are reported here to be consistent with the other natural source sectors.
- f. Sea spray and windblown dust emissions were estimated for Hawaii as part of emission inventory work by ENVIRON International Corporation for the years 2002 and 2005 (ENVIRON, 2010). These emissions are reported here and are assumed to be representative of all years.
- g. Wildfire and biogenic emissions were held at 2016 emission levels in the EPA 2028 modeling and so the same emissions are reported here. The agricultural burning emissions reported here are the point source agricultural fires in the modeling platform (ptagfire). Wildland fire and prescribed burning emissions are provided in a single model emissions file (ptfire) and thus could not be disaggregated. The total wild and prescribed fire emissions are reported as wildfire emissions here.

## Exhibit 2

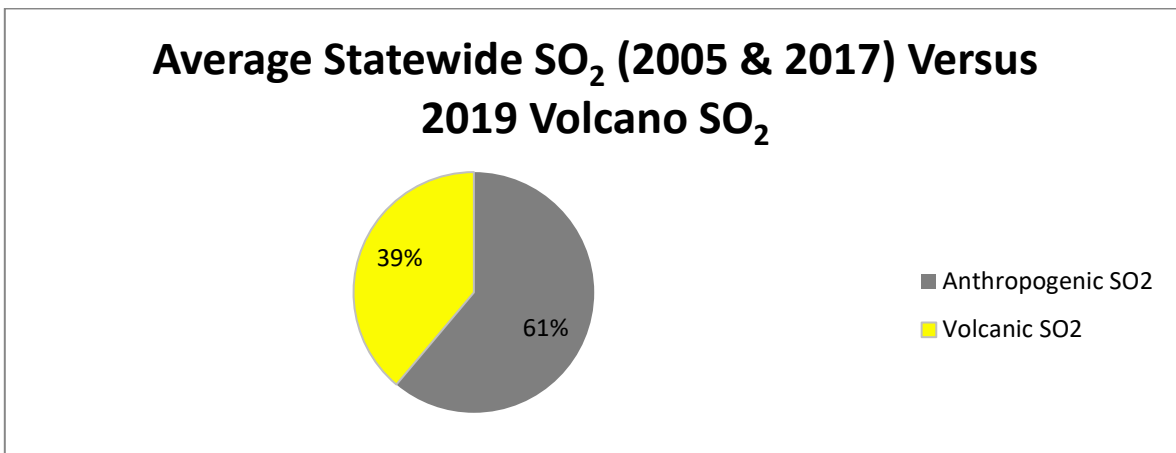
Figures 4.1-1 through 4.1-4, based on emissions inventory data for years 2005 and 2017 from Tables 4.1-2 and 4.1-6, respectively, show that nonanthropogenic (natural) emissions are significant for SO<sub>2</sub>, PM<sub>10</sub>, and VOCs.

As shown in Figure 4.1-1, the average volcanic SO<sub>2</sub> emissions from years 2005 and 2017 dwarf statewide anthropogenic sources of SO<sub>2</sub>. Average of years 2005 and 2017 volcanic SO<sub>2</sub> emissions (1,443,490 tons per year) equate to 98% of total statewide volcanic plus anthropogenic SO<sub>2</sub> emissions (27,099 tons per year) during those same years.



**Figure 4.1-1** Average 2005 & 2017 Statewide Anthropogenic SO<sub>2</sub> Versus Average 2005 & 2017 Volcanic SO<sub>2</sub>

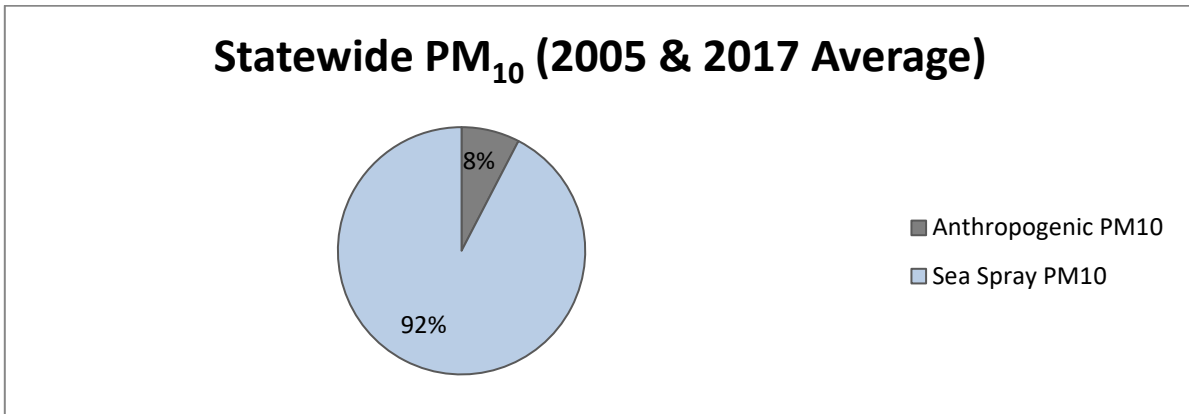
Kilauea Volcano stopped erupting towards the end of 2018 and thus volcanic SO<sub>2</sub> decreased. Figure 4.1-2 shows that in 2019, SO<sub>2</sub> emissions from the volcano significantly decreased (17,301 tons per year) and would only equate to 39% of the total statewide average 2005 and 2017 volcanic SO<sub>2</sub> plus anthropogenic SO<sub>2</sub> (27,099 tons per year) based on USGS preliminary data. However, the volcano started erupting again in December 2020 which increased SO<sub>2</sub> from this uncontrollable source of emissions. This eruption ended on May 26, 2021, and another eruption started on September 29, 2021. According to USGS personnel, the 2021 eruption is characterized by SO<sub>2</sub> emission rates varying by hundreds to thousands of tons per day.



**Figure 4.1-2** Average 2005 & 2017 Statewide Anthropogenic SO<sub>2</sub> Versus 2019 Volcanic SO<sub>2</sub>

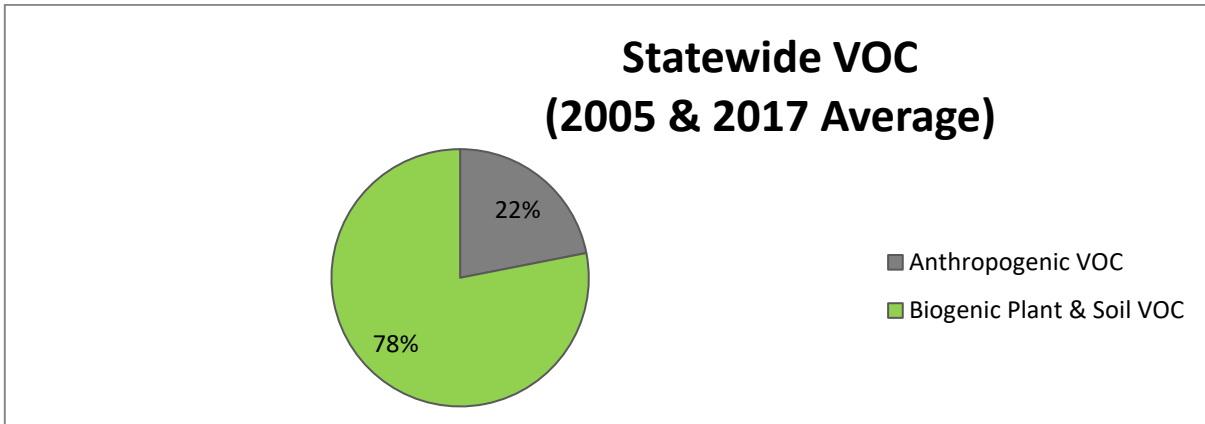
## Exhibit 2

In Figure 4.1-3, statewide PM<sub>10</sub> emissions from sea spray averaged during years 2005 & 2017 (383,120 tons per year) are significant and account for 92% of the total statewide average 2005 and 2017 sea spray PM<sub>10</sub> plus anthropogenic PM<sub>10</sub> emissions (31,581 tons per year).



**Figure 4.1-3** Average 2005 & 2017 Statewide Anthropogenic PM<sub>10</sub> Versus Average 2005 & 2017 Sea Spray PM<sub>10</sub>

Figure 4.1-4 shows that average natural biogenic emissions from plants and soils (129,107 tons per year) are a dominate source of VOC emissions, accounting for 78% of the average total statewide VOC anthropogenic emissions during the same average of years 2005 & 2017 (35,561 tons per year).



**Figure 4.1-4** Average 2005 & 2017 Statewide Anthropogenic VOC Versus Average 2005 & 2017 Biogenic Plant & Soil VOC

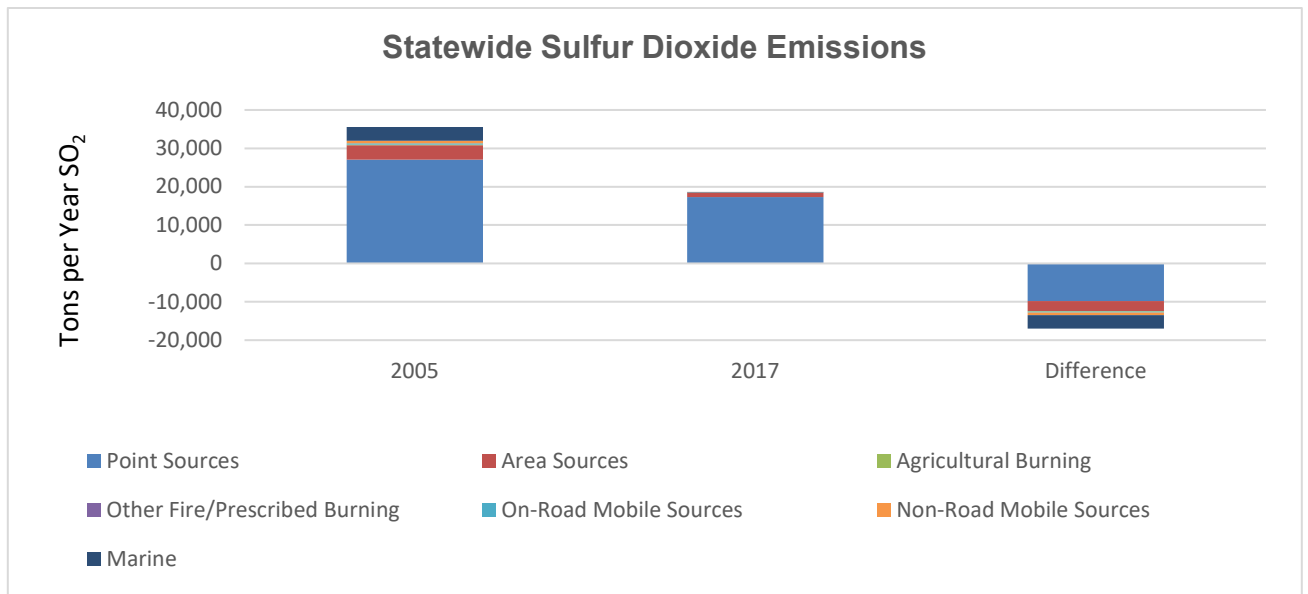
### 4.2 Changes in Emissions – 40 CFR §51.308(g)(5)

This section provides an assessment for any significant changes in anthropogenic emissions in the state that have occurred over the years that have limited or impeded progress in reducing pollutant emissions and improving visibility. Anthropogenic emissions from Tables 4.2-1 to 4.2-5 and Figures 4.2-1 to 4.2-5 show changes in baseline emissions from the first and second planning periods for years 2005 and 2017, respectively. Tables 4.2-6 to 4.2-10 compares 2017 baseline emissions for the second regional haze planning period to projected 2028 emissions.

## Exhibit 2

The difference in statewide SO<sub>2</sub> emission inventory totals from the 2005 and 2017 baselines of the first and second regional haze planning periods, respectively, in Table 4.2-1 and Figure 4.2-1 show an overall forty-eight percent (48%) decrease in SO<sub>2</sub> emissions from 35,575 tons per year in 2005 to 18,623 tons per year in 2017. The only increases in SO<sub>2</sub> is from the other fire/prescribed burning source category. The increase (50 tons per year of SO<sub>2</sub> in 2017 versus 0 tons per year of SO<sub>2</sub> in 2005) is less than one percent (1%) of the total average SO<sub>2</sub> emitted by all anthropogenic sources statewide in the 2005 and 2017 emission years. The largest reductions in terms of tons of SO<sub>2</sub> from 2005 to 2017 came from the point source category (-69%, - 9,807 tons), the commercial marine vessel (marine) category (-97%, - 3,509 tons), and the area source category (-69%, -2,575 tons). Reductions in fuel combustion source's fuel sulfur content have led to lower SO<sub>2</sub> emissions.

<b>Table 4.2-1 Difference in Statewide Anthropogenic SO<sub>2</sub> Emissions</b>							
Source Category	Statewide SO <sub>2</sub> (TPY)						
	2005	2011	2014	2016	2017	Difference	Percent Change
Point Sources	27,072	22,047	19,543	19,248	17,265	-9,807	-36%
Area Sources	3,716	3,331	98	98	1,141	-2,575	-69%
Agricultural Burning	178	178	197	30	-	-178	-100%
Other Fire/Prescribed Burning	-	36	534	-	50	50	
On-Road Mobile Sources	321	102	104	63	52	-269	-84%
Non-Road Mobile Sources	669	7	9	8	5	-664	-99%
Marine	3,619	2,037	229	267	110	-3,509	-97%
<b>Total Anthropogenic</b>	<b>35,575</b>	<b>27,738</b>	<b>20,714</b>	<b>19,715</b>	<b>18,623</b>	<b>-16,952</b>	<b>-48%</b>

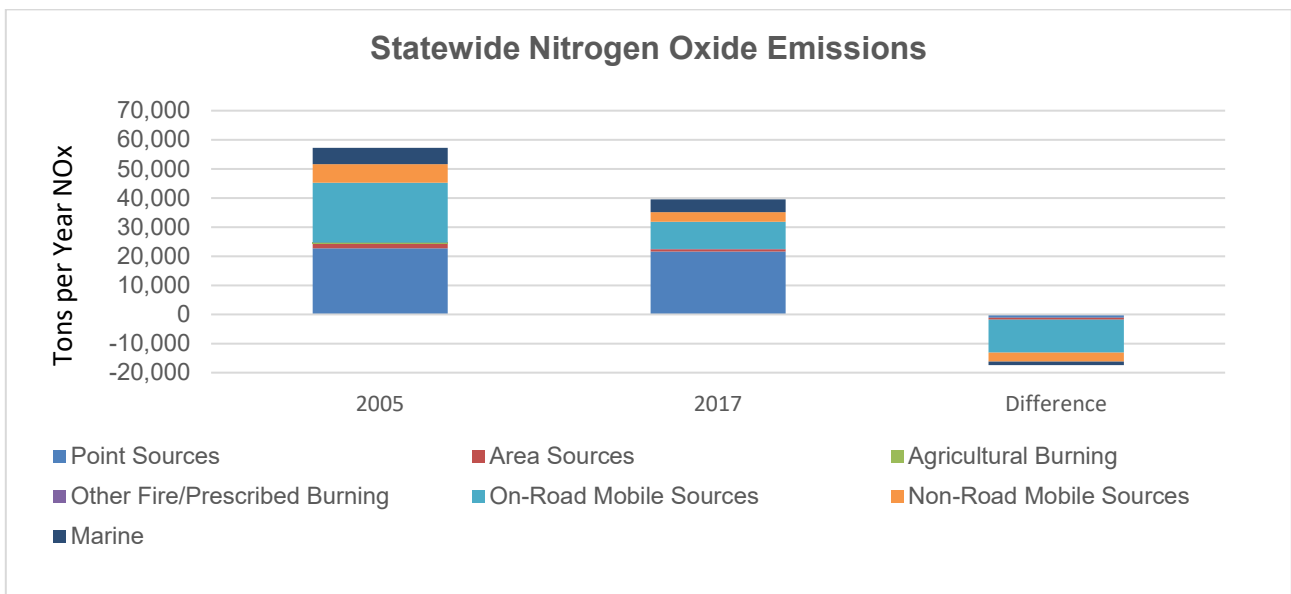


**Figure 4.2-1 2005 & 2017 Statewide SO<sub>2</sub> Emissions and Difference**

## Exhibit 2

The difference in statewide NO<sub>x</sub> emission inventory totals from the 2005 to 2017 baselines of the first and second regional haze planning periods, respectively, in Table 4.2-2 and Figure 4.2-2 show an overall decrease in NO<sub>x</sub> emissions. The only increase in NO<sub>x</sub> is from the other fire/prescribed burning data category. Overall, NO<sub>x</sub> emissions from anthropogenic sources have decreased statewide by thirty-one percent (31%) from 57,223 tons per year in 2005 to 39,509 tons per year in 2017. The increase in NO<sub>x</sub> emissions from 2005 to 2017 for the other fire/prescribed burning source category is less significant, accounting for less than 1% of the total NO<sub>x</sub> emitted by all sources statewide for both the 2005 and 2017 emission years. NO<sub>x</sub> emissions have declined in Hawaii from 2005 to 2017 particularly in the on-road (-55%, -11,315 tons per year) and non-road (-48%, -3,008 tons per year) mobile source categories. Reductions in on-road and non-road emissions are due to federal regulations resulting in emissions reductions from on-road/non-road vehicles and equipment. More efficient on-road/non-road equipment and engines have led to reductions in NO<sub>x</sub> emissions, especially in the on-road source category.

<b>Table 4.2-2</b> Difference in Statewide Anthropogenic NO <sub>x</sub> Emissions							
Source Category	Statewide NO <sub>x</sub> (TPY)						
	2005	2011	2014	2016	2017	Difference	Percent Change
Point Sources	22,745	28,982	26,163	23,585	21,596	-1,149	-5%
Area Sources	1,509	1,176	463	464	807	-702	-46%
Agricultural Burning	406	405	359	55	-	-	
Other Fire/Prescribed Burning	1	389	6,153	-	90	89	>100%
On-Road Mobile Sources	20,642	15,503	12,077	10,387	9,327	-11,315	-55%
Non-Road Mobile Sources	6,296	3,842	3,228	3,442	3,288	-3,008	-48%
Marine	5,624	4,895	1,131	8,984	4,401	-1,223	-22%
<b>Total Anthropogenic</b>	<b>57,223</b>	<b>55,192</b>	<b>49,574</b>	<b>46,917</b>	<b>39,509</b>	<b>-17,714</b>	<b>-31%</b>

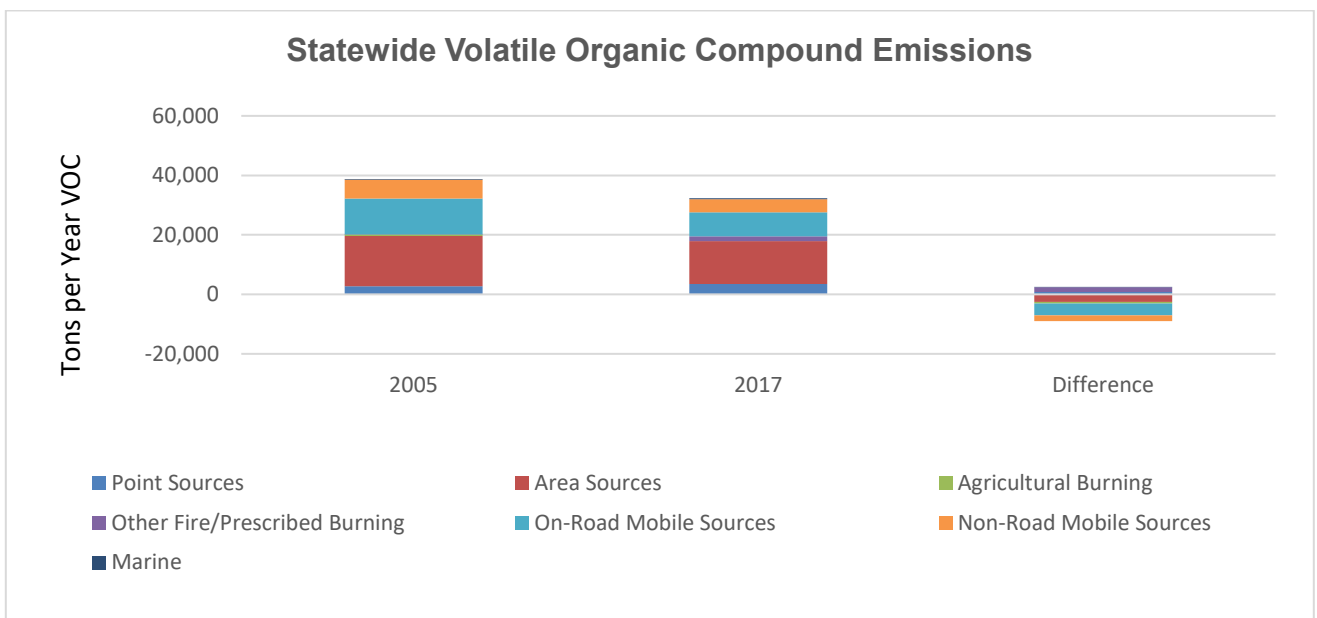


**Figure 4.2-2** 2005 & 2017 Statewide NO<sub>x</sub> Emissions and Difference

## Exhibit 2

The difference in VOC emission inventory totals from 2005 to 2017 baselines of the first and second regional haze planning periods, respectively, in Table 4.2-3 and Figure 4.2-3 show an overall 17% decrease in statewide VOC emissions from 38,815 tons per year in 2005 to 32,307 tons per year in 2017. Increases in VOC emissions from 2005 to 2017 are shown for point, other fire/prescribed fire, and marine source categories. For point and marine source categories, the change is consistent with an Environ 2010 Report that projected an increase in VOCs from these sources from 2005 to 2018. A majority of these point and area source emissions are on the Island of Oahu based on 2017 NEI data. These sources on Oahu would feature prevailing trade winds which would blow pollutants away from the Class I areas a majority of the time. A large increase in VOC emissions from 2005 to 2017 is attributed to the other fire/prescribed burning source category which is about 5% of the total VOCs emitted by all sources statewide for both the 2005 and 2017 emission years.

<b>Table 4.2-3 Difference in Statewide Anthropogenic VOC Emissions</b>							
Source Category	Statewide VOC (TPY)						
	2005	2011	2014	2016	2017	Difference	Percent Change
Point Sources	2,695	3,059	4,117	3,904	3,519	824	31%
Area Sources	16,920	18,425	15,162	14,556	14,387	-2,533	-15%
Agricultural Burning	535	535	534	77	-	-535	-100%
Other Fire/Prescribed Burning	7	1,672	29,665	-	1,562	1,555	>100%
On-Road Mobile Sources	12,066	11,180	10,383	9,072	8,109	-3,957	-33%
Non-Road Mobile Sources	6,383	5,428	4,313	4,404	4,454	-1,929	-30%
Marine	209	154	35	443	276	67	32%
<b>Total Anthropogenic</b>	<b>38,815</b>	<b>40,453</b>	<b>64,209</b>	<b>32,456</b>	<b>32,307</b>	<b>-6,508</b>	<b>-17%</b>

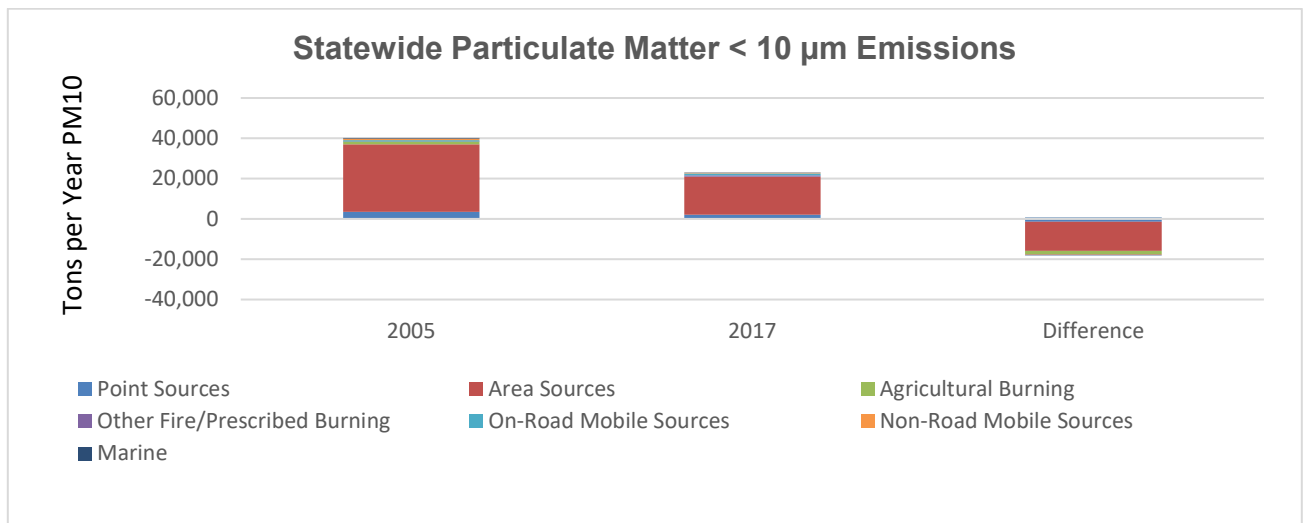


**Figure 4.2-3 2005 & 2017 Statewide VOC Emissions and Difference**

## Exhibit 2

The difference in Particulate Matter less than 10  $\mu\text{m}$  ( $\text{PM}_{10}$ ) emissions inventory totals from the 2005 to 2017 baselines of the first and second regional haze planning periods, respectively, in Table 4.2-4 and Figure 4.2-4 show an overall 43% decrease in statewide  $\text{PM}_{10}$  emissions from 40,203 tons per year in 2005 to 22,958 tons per year in 2017. Increases in  $\text{PM}_{10}$  emissions are shown for other fire/prescribed burning and on-road mobile source categories. For the on-road mobile source category, a majority of the  $\text{PM}_{10}$  emissions are from Oahu where prevailing trade winds would blow pollutants away from the Class I areas a majority of the time. The total combined increase in  $\text{PM}_{10}$  emissions from other fire/prescribed burning and on-road mobile source categories is less than four percent (4%) of the total  $\text{PM}_{10}$  emitted by all sources statewide for both the 2005 and 2017 emission years.

<b>Table 4.2-4 Difference in Statewide Anthropogenic <math>\text{PM}_{10}</math> Emissions</b>							
Source Category	Statewide $\text{PM}_{10}$ (TPY)						
	2005	2011	2014	2016	2017	Difference	Percent Change
Point Sources	3,536	2,813	2,583	2,280	2,108	-1,428	-40%
Area Sources	33,408	34,803	54,626	37,780	18,908	-14,500	-43%
Agricultural Burning	1,567	1,567	583	93	-	-1,567	-100%
Other Fire/Prescribed Burning	7	853	14,086	-	673	666	>100%
On-Road Mobile Sources	638	305	770	630	841	203	32%
Non-Road Mobile Sources	649	403	356	339	327	-322	-50%
Marine	398	338	37	185	102	-296	-74%
<b>Total Anthropogenic</b>	<b>40,203</b>	<b>41,420</b>	<b>73,042</b>	<b>41,307</b>	<b>22,958</b>	<b>-17,245</b>	<b>-43%</b>



**Figure 4.2-4 2005 & 2017 Statewide  $\text{PM}_{10}$  Emissions and Difference**

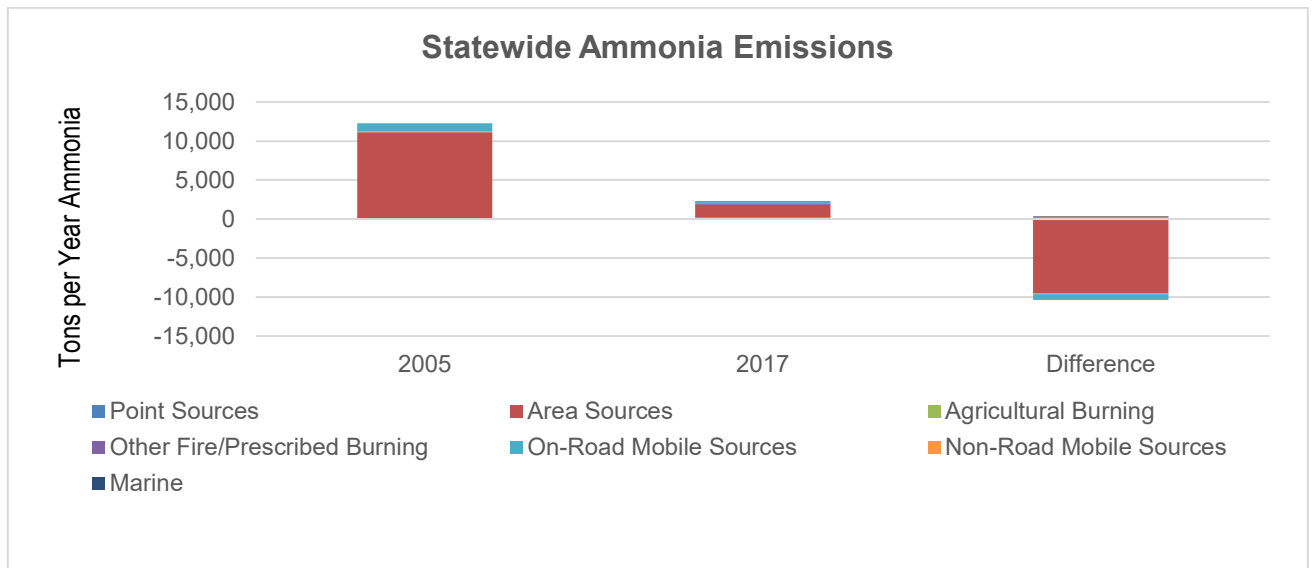
The difference in  $\text{NH}_3$  emissions inventory totals from the 2005 to 2017 baselines of the first and second regional haze planning periods, respectively, in Table 4.2-5 and Figure 4.2-5 show an overall 82% decrease in statewide  $\text{NH}_3$  emissions from 12,293 tons per year in 2005 to 2,265 tons per year in 2017. Increases in  $\text{NH}_3$  emissions are shown for



## Exhibit 2

point, other fire/prescribed burning, non-road mobile, and marine source categories. For point sources, non-road mobile and marine source categories, a majority of the NH<sub>3</sub> emissions are from sources on Oahu where prevailing trade winds would blow pollutants away from the Class I areas a majority of the time. The total combined increase in NH<sub>3</sub> emissions from other fire/prescribed burning, non-road mobile, and marine source categories is less than nine percent (9%) of the total NH<sub>3</sub> emitted by all sources statewide for both the 2005 and 2017 emission years.

<b>Table 4.2-5 Difference in Statewide Anthropogenic NH<sub>3</sub> Emissions</b>								
Source Category	Statewide NH <sub>3</sub> (TPY)						Difference	Percent Change
	2005	2011	2014	2016	2017			
Point Sources	12	1,031	247	238	232	220	>100%	
Area Sources	11,136	7,547	3,884	1,579	1,583	-9,553	-86%	
Agricultural Burning	60	148	2,551	391	-	-60	-100%	
Other Fire/Prescribed Burning	0	59	951	-	109	109		
On-Road Mobile Sources	1,085	412	338	316	332	-753	-69%	
Non-Road Mobile Sources	0	6	6	7	7	7		
Marine	0	3	0	2	2	2		
<b>Total Anthropogenic</b>	<b>12,293</b>	<b>9,206</b>	<b>7,977</b>	<b>2,533</b>	<b>2,265</b>	<b>-10,028</b>	<b>-82%</b>	



**Figure 4.2-5** 2005 & 2017 Statewide Ammonia Emissions and Difference

The change in Hawaii emissions from 2017 to projected 2028, based upon data from Tables 4.1-6 (2017) & 4.1-7 (projected 2028) are shown below in Tables 4.2-6 through 4.2-10.

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<b>Table 4.2-6 Change in Hawaii Sulfur Dioxide Emissions 2017 to 2028 (Percent) <sup>a,b</sup></b>			
Source Category	SO <sub>2</sub>		
	2017	2028	% Change
Point Sources	17,265	17,044	-1%
Area Sources	1,141	99	-91%
Agricultural Burning	-	30	
Other Fire/Prescribed Burning	50	-	-100%
On-Road Mobile Sources	52	34	-35%
Non-Road Mobile Sources	5	6	12%
Marine	110	357	224%
Anthropogenic Total	18,624	17,570	-6%
Natural Sources	1,925,657	2,089,626	9%
<b>Total</b>	<b>1,944,281</b>	<b>2,107,197</b>	<b>8%</b>

- a. Percent change is the emissions percent change from 2017 to projected 2028. A negative % change indicates a projected reduction in emissions in 2028.
- b. Natural sources of emissions include volcano, sea spray, windblown dust, wildfire, and biogenic plant and soil emissions.

<b>Table 4.2-7 Change in Hawaii Nitrogen Oxide Emissions 2017 to 2028 (Percent) <sup>a,b</sup></b>			
Source Category	NO <sub>x</sub>		
	2017	2028	% Change
Point Sources	21,596	22,106	2%
Area Sources	807	469	-42%
Agricultural Burning	-	55	
Other Fire/Prescribed Burning	90	-	-100%
On-Road Mobile Sources	9,327	3,221	-65%
Non-Road Mobile Sources	3,288	2,086	-37%
Marine	4,401	5,658	29%
Anthropogenic Total	39,509	33,595	-15%
Natural Sources	1,522	3,611	137%
<b>Total</b>	<b>41,031</b>	<b>37,206</b>	<b>-9%</b>

- a. Percent change is the emissions percent change from 2017 to projected 2028. A negative % change indicates a projected reduction in emissions in 2028.
- b. Natural sources of emissions include volcano, sea spray, windblown dust, wildfire, and biogenic plant and soil emissions.

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<b>Table 4.2-8 Change in Hawaii VOC Emissions 2017 to 2028 (Percent) <sup>a,b</sup></b>			
Source Category	VOC		
	2017	2028	% Change
Point Sources	3,519	4,153	18%
Area Sources	14,387	13,925	-3%
Agricultural Burning	-	77	
Other Fire/Prescribed Burning	1,562	-	-100%
On-Road Mobile Sources	8,109	4,024	-50%
Non-Road Mobile Sources	4,454	3,016	-32%
Marine	276	561	104%
Anthropogenic Total	32,307	25,756	-20%
Natural Sources	128,977	46,279	-64%
<b>Total</b>	<b>161,284</b>	<b>72,035</b>	<b>-55%</b>

- a. Percent change is the emissions percent change from 2017 to projected 2028. A negative % change indicates a projected reduction in emissions in 2028.
- b. Natural sources emissions include volcano, sea spray, windblown dust, wildfire, and biogenic plant and soil emissions.

<b>Table 4.2-9 Change in Hawaii PM<sub>10</sub> Emissions 2017 to 2028 (Percent) <sup>a,b</sup></b>			
Source Category	PM <sub>10</sub>		
	2017	2028	% Change
Point Sources	2,108	2,139	1%
Area Sources	18,908	37,950	101%
Agricultural Burning	-	93	
Other Fire/Prescribed Burning	673	-	-100%
On-Road Mobile Sources	841	527	-37%
Non-Road Mobile Sources	327	212	-35%
Marine	102	207	103%
Anthropogenic Total	22,958	41,128	79%
Natural Sources	429,877	440,785	3%
<b>Total</b>	<b>452,835</b>	<b>481,913</b>	<b>6%</b>

- a. Percent change is the emissions percent change from 2017 to projected 2028. A negative % change indicates a projected reduction in emissions in 2028.
- b. Natural sources of emissions include volcano, sea spray, windblown dust, wildfire, and biogenic plant and soil emissions.

## Exhibit 2

<b>Table 4.2-10 Change in Hawaii Ammonia Emissions 2017 to 2028 (Percent) <sup>a,b</sup></b>			
Source Category	NH <sub>3</sub>		
	2017	2028	% Change
Point Sources	232	218	-6%
Area Sources	1,583	1,619	2%
Agricultural Burning	-	391	
Other Fire/Prescribed Burning	109	-	-100%
On-Road Mobile Sources	332	272	-18%
Non-Road Mobile Sources	7	8	12%
Marine	2	3	41%
Anthropogenic Total	2,265	2,511	11%
Natural Sources	64	838	1215%
<b>Total</b>	<b>2,328</b>	<b>3,349</b>	<b>44%</b>

a. Percent change is the emissions percent change from 2017 to projected 2028. A negative % change indicates a projected reduction in emissions in 2028.

b. Natural sources of emissions include volcano, sea spray, windblown dust, wildfire, and biogenic plant and soil emissions.

## Chapter 5 Source Screening

### 5.0 Screening - 40 CFR §51.308(f)(2)(i)

Hawaii first used a Q/d screening tool developed from work led by WRAP with Ramboll US Corporation (Ramboll) to determine which sources required a four-factor analysis. The “Q/d” surrogate for screening is the annual emissions in tons per year (tpy) divided by the distance in kilometers (km) between a source and the nearest Class I area. This surrogate is correlated to a certain degree with visibility impacts as would be estimated with modeling.<sup>26</sup> Electric plants on Oahu, Maui, and the Big Island, identified with Q/d to significantly affected visibility, were notified to provide a four-factor analysis. Please note that the Q/d metric is only a rough indicator of actual visibility impact because it does not consider transport, dispersion, and photochemical processes.<sup>26</sup>

After reviewing four-factor analyses for the seven facilities screened with Q/d, WRAP/Ramboll provided a more sophisticated weighted emissions potential/area of influence (WEP/AOI) analysis to screen facilities. There are differences between the Q/d source screening assessment and the WEP/AOI analysis completed early in February 2021. The Q/d screening provided an assessment of SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub>, while the WEP/AOI analysis provided an individual Q/d assessment for SO<sub>2</sub> and NO<sub>x</sub>. The WEP/AOI also accounted for meteorological data such as wind patterns and the specific light extinction contribution of the particle species (nitrates and sulfates).

<sup>26</sup> Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for Second Implementation Period, U.S. EPA, July 2016. Available at:

[https://www.epa.gov/sites/production/files/2016-07/documents/draft\\_regional\\_haze\\_guidance\\_july\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf)

## Exhibit 2

Based on WEP/AOI rankings, sources selected with Q/d on Oahu which did not rank high in their potential to affect visibility in the national parks were excluded from requiring a four-factor analysis. The WEP/AOI analysis; however, determined that the Mauna Loa Macadamia Nut Corporation plant on the Big Island required a four-factor analysis for regional haze control measures.

### 5.1 Emissions Inventory and Sources

For the Q/d analysis, draft EPA Guidance in 2016 recommended evaluating eighty percent (80%) of the emissions impact at each Class I area from major and minor stationary sources and area sources to ensure a reasonably large fraction of emissions affecting visibility in the Class I areas on the twenty percent (20%) most impaired days are assessed.<sup>26</sup> As stated in the draft guidance, the eighty percent (80%) threshold, however, may not be fully applicable when Q/d is used as a surrogate for visibility impacts.<sup>26</sup> The 80% threshold was removed from final EPA guidance issued on August 20, 2019.<sup>14</sup> The draft EPA guidance recommended that major sources be compared to the threshold individually, but that minor sources of a similar type be grouped. Except when sources are clustered geographically near a Class I area, all sources including major sources should be grouped and aggregated. Mobile sources were excluded from the screening analysis because the state does not have regulatory authority to control emissions from these sources. The Hawaii Administrative Rules exempt mobile sources from air permitting requirements.

### 5.2 Haleakala National Park

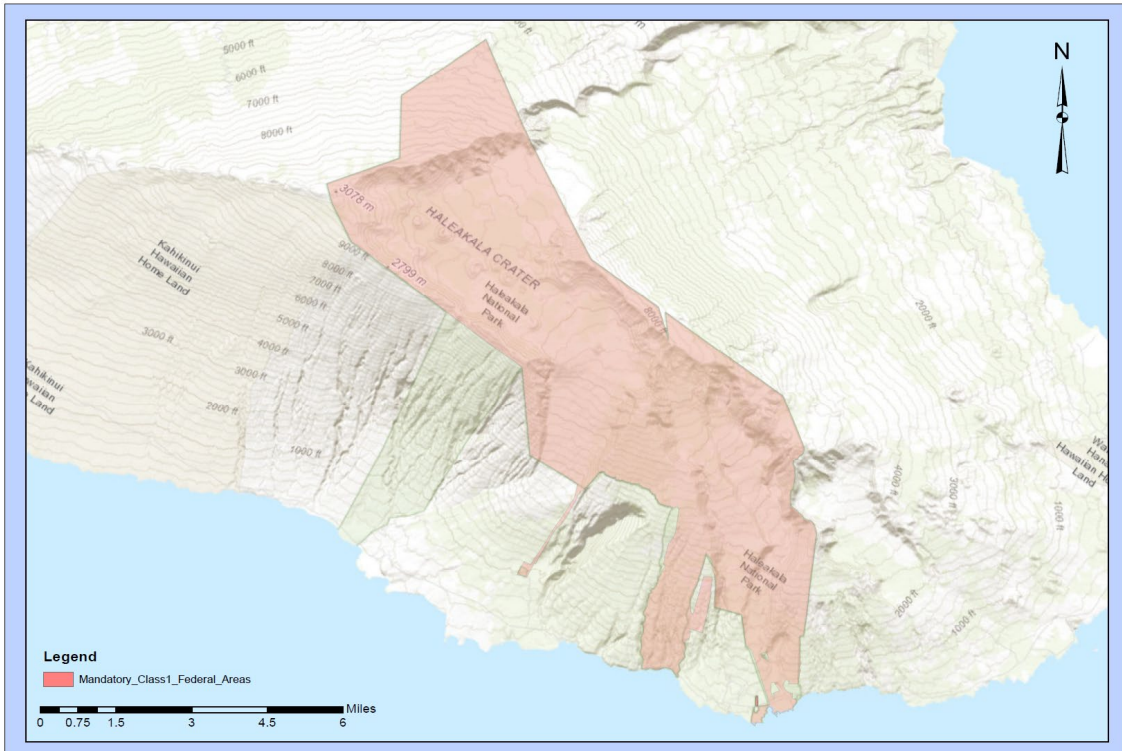
Haleakala National Park is shown in Figure 5.2-1 shaded in pink. Two (2) noncontiguous regions of the National Park are identified in Figure 5.2-2. These regions are labeled “Haleakala NP: big island” and “Haleakala NP: small island”. For the Q/d analysis, a Q/d value is provided based on the emissions and distance between the source and the national park for each noncontiguous region.

### 5.3 Hawaii Volcanoes National Park

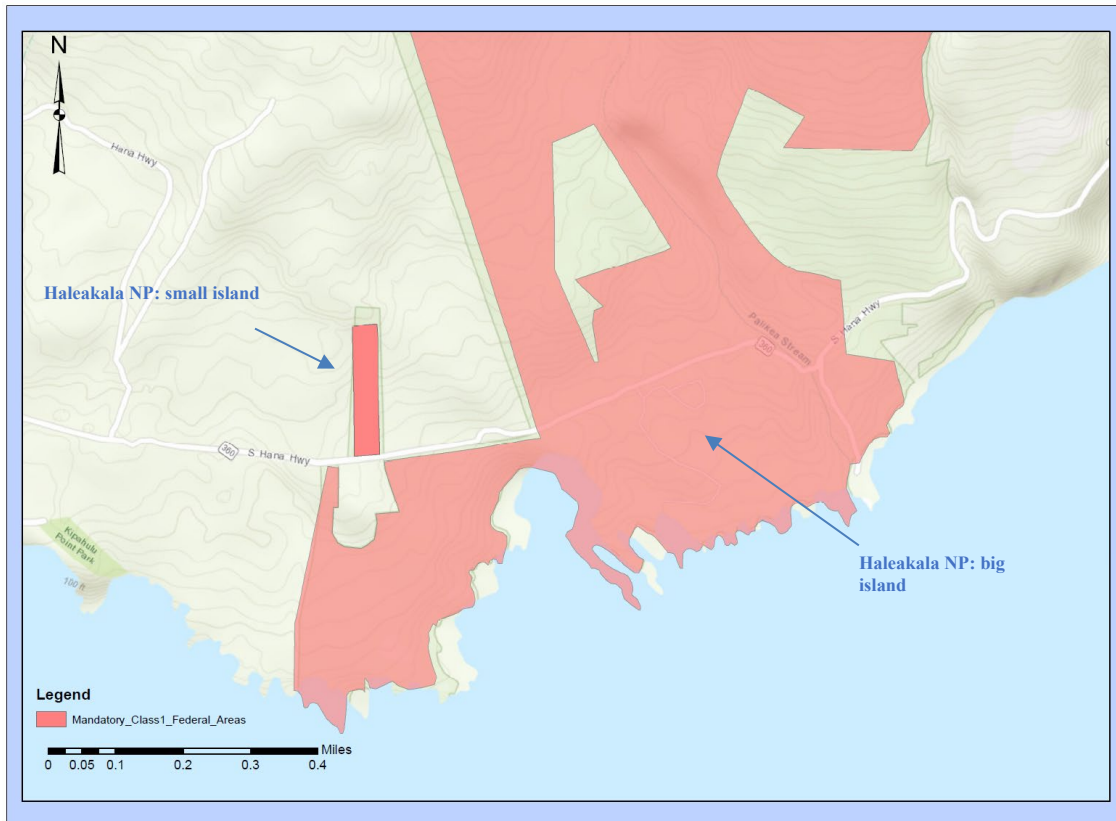
Hawaii Volcanoes National Park is shown in Figure 5.3-1 shaded in pink. Two (2) noncontiguous regions of the National Park are identified. These regions are labeled “Hawaii Volcanoes National Park” and “Hawaii Volcanoes National Park: Oloa Tract”. For the Q/d analysis, a Q/d value is provided based on the emissions and distance between the source and the national park for each noncontiguous region.

# Exhibit 2

## Haleakala National Park



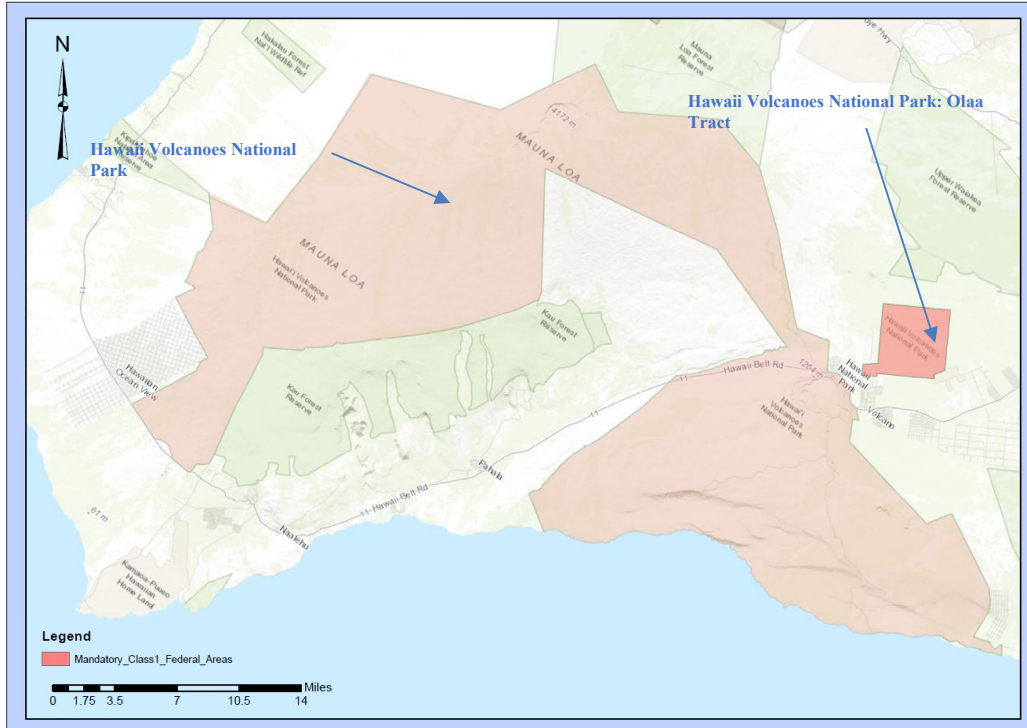
**Figure 5.2-1** Map of Haleakala National Park  
Haleakala National Park



**Figure 5.2-2** Map Closeup of Haleakala National Park

## Exhibit 2

### Hawaii Volcanoes National Park



**Figure 5.3-1** Map of Hawaii Volcanoes National Park

### 5.4 Point Source Q/d Screening Methodology

The following were assumed for the Q/d screening analysis using the screening tool developed by Ramboll to assist states with the Q/d screening process:

- The visibility facility-level emissions are the total combined emissions of nitrogen oxide (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter less than 10 microns in diameter (PM<sub>10</sub>) - facility level emission  $Q = Q_{NOX} + Q_{SO2} + Q_{PM10}$ .
- Distance (d) from the Class I area in kilometers, includes only facilities within 400 km (250 miles) of a Class I area. When evaluating sources for impacts the larger of the two (2) Q/d values were used for noncontiguous regions of each National Park.
- Emissions were from the 2014 National Emissions Inventory (NEI)v2.
- For facilities with multiple emission units/processes, facility location was based on the emission unit/process with the highest Q.
- Screening thresholds were set at  $Q = 25$  TPY and  $Q/d = 10$  tpy/km to pre-screen sources for Four-Factor Analysis.

### 5.5 Point Source Q/d Screening Results

Table 5.5-1 through 5.5-4 below provide a list of point sources identified by the screening analysis with Q greater than 25 and a Q/d greater than 10. The analysis is for each noncontiguous National Park region is sorted by Q/d in descending order. These sources combined account for 79% to 91% of the total point source Q (91% Haleakala National Park: big, 88% Haleakala National Park: small island, 79% Hawaii Volcanoes National Park, and 79% Hawaii Volcanoes National Park: Olaa Track).

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<b>Table 5.5-1 Haleakala NP: big island</b>					
Source <sup>27</sup>	d (km)	Q/d (TPY/km) NO <sub>x</sub> + SO <sub>2</sub> + PM <sub>10</sub>	Q (TPY)		
			NO <sub>x</sub>	SO <sub>2</sub>	PM <sub>10</sub>
MECO – Maalaea Generating Station	25.52	110.18	2,114	549	148
MECO – Kahului Power Plant	26.49	82.20	483	1,634	60
HECO – Kahe Power Plant	206.11	67.77	7,858	5,555	556
HC & S – Puunene Sugar Mill	23.94	46.77	692	219	209
Kalaeloa Cogeneration Plant	201.09	30.91	2,628	2,917	671
HECO – Waiau Power Plant	190.89	30.53	2,844	2,784	200
Kahului Airport	24.41	20.45	438	47	15
HELCO – Kanoiehua-Hill Power Plant	147.01	17.13	611	1,852	56
AES Hawaii, LLC Cogeneration Plant	201.95	16.01	915	2,243	75
Honolulu International Airport	186.72	11.45	1,903	182	54

<b>Table 5.5-2 Haleakala NP: small island</b>					
Source	d (km)	Q/d (TPY/km) NO <sub>x</sub> + SO <sub>2</sub> + PM <sub>10</sub>	Q (TPY)		
			NO <sub>x</sub>	SO <sub>2</sub>	PM <sub>10</sub>
HECO – Kahe Power Plant	229.2	60.94	7,858	5,555	556
MECO – Maalaea Generating Station	48.49	57.98	2,114	549	148
MECO – Kahului Power Plant	50.16	43.41	483	1,634	60
Kalaeloa Cogeneration Plant	224.13	27.74	2,628	2,917	671
HECO – Waiau Power Plant	214.19	27.21	2,844	2,784	200
HC&S – Puunene Sugar Mill	47.55	23.54	692	219	209
HELCO – Kanoiehua-Hill Power Plant	147.66	17.06	611	1,852	56
AES Hawaii, LLC Cogeneration Plant	224.98	14.37	915	2,243	75
Kahului Airport	48.06	10.39	438	47	15
Honolulu International Airport	209.88	10.19	1,903	182	54

<b>Table 5.5-3 Hawaii Volcanoes National Park</b>					
Source	d (km)	Q/d Value (TPY/km) NO <sub>x</sub> + SO <sub>2</sub> + PM <sub>10</sub>	Q (TPY)		
			NO <sub>x</sub>	SO <sub>2</sub>	PM <sub>10</sub>
HELCO – Kanoiehua-Hill Power Plant	34.53	72.94	611	1,852	56
HECO – Kahe Power Plant	328.98	42.46	7,858	5,555	556
HELCO – Puna Power Plant	27.46	22.70	70	524	29
Kalaeloa Cogeneration Plant	322.50	19.28	2,628	2,917	671
HECO – Waiau Power Plant	318.39	18.31	2,844	2,784	200
MECO – Maalaea Generating Station	169.61	16.57	2,114	549	148
MECO – Kahului Power Plant	176.82	12.31	483	1,634	60
AES Hawaii, LLC Cogeneration Plant	323.26	10.00	915	2,243	75

<sup>27</sup> Hawaiian Electric Company, Inc. (HECO), Hawaiian Electric Light Company, Inc. (HELCO), Maui Electric Company, Limited (MECO).



## Exhibit 2

Source	d (km)	Q/d (TPY/km) NO <sub>x</sub> + SO <sub>2</sub> + PM <sub>10</sub>	Q (TPY)		
			NO <sub>x</sub>	SO <sub>2</sub>	PM <sub>10</sub>
HELCO – Kanoelehua-Hill Power Plant	25.69	98.07	611	1,852	56
HECO – Kahe Power Plant	361.50	38.64	7,858	5,555	556
HELCO – Puna Power Plant	23.01	27.09	70	524	29
Kalaeloa Cogeneration Plant	355.36	17.49	2,628	2,917	671
HECO – Waiiau Power Plant	349.32	16.68	2,844	2,784	200
MECO – Maalaea Generating Station	191.85	14.65	2,114	549	148
MECO – Kahului Power Plant	197.82	11.01	483	1,634	60

### 5.6 Point Sources Considered with Q/d

Table 5.6.1 describes point sources considered for four-factor analysis using the Q/d methodology. The HC&S Puunene Sugar Mill on the island of Maui permanently shut down on December 16, 2016 and was, therefore, removed from the list of sources considered for further evaluation. Listed sources include two (2) independent power producers (IPPs), six (6) plants from the four Hawaiian Electric Utility Companies, and two (2) airports.

<b>IPP Plants</b>			
Facility	Permit No.	Description	Island
AES Hawaii, LLC Cogeneration Plant	CSP No. 0087-02-C	203 MW Coal Fired Generation Plant Consisting of Two (2) CFB Boilers and Two Limestone Dryers. The Boilers are Each Equipped with Lime Injection, SNCR, and a Baghouse.	Oahu
Kalaeloa Partners, L.P. Cogeneration Plant	CSP No. 0214-01-C	Two (2) 86 MW CTs with Steam Injection, Two (2) HRSGs, and 51 MW Steam Turbine.	Oahu
<b>Hawaiian Electric Plants</b>			
Facility	Permit No.	Description	Island
Kahe Power Plant	CSP No. 0240-01-C	Six (6) Boilers (92 MW to 142 MW) and Two (2) 2.5 MW Black Start DEGs.	Oahu
Waiiau Power Plant	CSP No. 0239-01-C	Six (6) Boilers (49 MW to 92 MW), 50 MW CT and 52 MW CT.	Oahu
<b>Hawaii Electric Light Plants</b>			
Facility	Permit No.	Description	Island
Kanoelehua-Hill Power Plant <sup>b</sup>	CSP No. 0234-01-C	14.1 MW Boiler, 23 MW Boiler, 11.6 MW CT, 2.0 MW DEG with Oxidation Catalyst, and Three (3) 2.75 MW DEGs with Oxidation Catalyst.	Hawaii
Puna Power Plant <sup>b</sup>	CSP No. 0235-01-C	20 MW CT with water injection, 1,250 hp Black Start DEG, and 15.5 MW Boiler with Multicyclone Dust Collector.	Hawaii
<b>Maui Electric Company, Limited Plants</b>			
Facility	Permit No.	Description	Island
Kahului Power Plant	CSP No. 0232-01-C	Two (2) 5.0 MW Boilers, One (1) 11.5 MW Boiler, and 12.5 MW Boiler.	Maui

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<b>Table 5.6-1 Point Sources Considered for Four-Factor Analysis <sup>a</sup></b>			
Maalaea Generating Station	CSP No. 0067-01-C	Three (3) 2.5 MW DEGs with Oxidation Catalyst and Lube Oil Separator, Six (6) 5.6 MW DEGs with Oxidation Catalyst and Open Crankcase Filtration System, Two (2) 12.5 MW DEGs with Oxidation Catalyst and Open Crankcase Filtration System, Two (2) 12.5 MW DEGs with Oxidation Catalyst, Crankcase Filtration System, and FITR, Two (2) 20 MW CTs with Water Injection, Two (2) HRSGs, 18 MW Steam Turbine, Two (2) 20 MW CTs with Water Injection, HRSG, Two (2) 2.5 MW DEGs with Oxidation Catalyst, Lube Oil Separator, and FITR, and 600 kW Black Start DEG.	Maui
<b>Airports</b>			
Facility	Permit No.	Description	Island
Kahului Airport	-----	Emissions include those from the landing and take-off portion of aircraft operations and from the ground support equipment at airports.	Maui
Honolulu International Airport	-----		Oahu

a: CFB-circulating fluidized bed, NO<sub>x</sub>-nitrogen oxide, CT- combustion turbine, DEG-diesel engine generator, FITR-fuel injection timing retard, HRSG-heat recovery steam generator, kW-kilowatt, MW-megawatt, SCR-selective catalytic reduction, and SNCR-selective non-catalytic reduction.

b: Boilers at the Kanoelehua-Hill Power Plant and Puna Power Plant in Hilo on the Big Island are subject to a total combined 3,550 ton per year SO<sub>2</sub> emissions cap based on the reasonable progress goal established in the first regional haze implementation period.

### 5.7 Point Source Selection with Q/d

The following were determined in selecting point sources for the four-factor analysis with Q/d:

- Airports - The airports listed in the Table 5.6-1 were excluded from the list of point sources requiring a four-factor analysis because the state does not have authority to regulate emissions from these sources. Pursuant to HAR §11-60.1-62(d)(21), internal combustion engines propelling mobile sources, such as airplanes, are exempt from permitting. In accordance with HAR §11-60.1-62(d), diesel fired portable ground support equipment used exclusively to start aircraft or provide temporary power or support service to aircraft prior to start-up are also exempt from permitting.
- AES Hawaii, LLC - The two (2) coal fired boilers at this cogeneration plant are each equipped with state-of-the-art air pollution controls. These controls include SNCR with ammonia/urea injection, low temperature-staged combustion, limestone injection, and baghouses as part of PSD/BACT determinations. The permit application review to renew the permit for this plant indicates a 70% NO<sub>x</sub> reduction for SNCR, a 75% to 90% SO<sub>2</sub> reduction for limestone injection, and 99.99% PM/PM<sub>10</sub> reduction for particulate control with the baghouses.

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Based on review of the RACT/BACT/LEAR Clearinghouse<sup>28</sup> for coal burning plants over the past ten (10) years, emission controls for the AES Hawaii, LLC facility were consistent with those determined to be BACT for other coal fired plants. Therefore, a four-factor analysis would likely result in the conclusion that no further controls would be reasonable. In addition, the permit for this facility was amended to comply with Hawaii Act 023 (September 14, 2020) for the cessation of coal burning. There is a federally enforceable emission limit specified in the permit for this cogeneration plant to cease all coal burning or consumption of coal by December 31, 2022. Please see amended permit to incorporate a GHG emission cap for partnering facilities at:

[https://health.hawaii.gov/cab/files/2020/10/2020\\_10\\_28\\_DFileNo\\_20-439E\\_0087-02-C.pdf](https://health.hawaii.gov/cab/files/2020/10/2020_10_28_DFileNo_20-439E_0087-02-C.pdf). Also, the AES Hawaii, LLC facility, located on Oahu, did not rank high in its potential to impair visibility when considering meteorology, haze species, emissions, and distance from the national parks using the WEP/AOI analysis.

The WEP point source contribution potential of nitrates and sulfates for the AES Hawaii, LLC cogeneration plant was 0.01% for Haleakala National Park and 0.10% and 0.01%, respectively, for Hawaii Volcanoes National Park. Therefore, the AES Hawaii, LLC facility was screened out of requiring further analysis.

- Table 5.7-1 shows point sources selected for four-factor analysis using Q/d methodology:

<b>Table 5.7-1 Point Sources Selected for Four-Factor Analysis</b>				
Source	Q (TPY)	d (km)	Q/d	Class I Area
Kalaeloa Partners, L.P. Plant	6,216	201.9	30.91	1) Haleakala NP
HECO - Kahe Power Plant	13,968	206.11	67.77	1) Haleakala NP
		328.98	42.46	2) Hawaii Volcanoes NP
HECO - Waiiau Power Plant	5,828	190.89	30.53	1) Haleakala NP
		318.39	18.31	2) Hawaii Volcanoes NP
HELCO - Kanoiehua-Hill Power Plant	2,519	147.01	17.13	1) Haleakala NP
		25.69	98.07	2) Hawaii Volcanoes NP
HELCO - Puna Power Plant	623	23.01	27.09	1) Hawaii Volcanoes NP
MECO - Kahului Power Plant	2,177	26.49	82.20	1) Haleakala NP
		176.82	12.31	2) Hawaii Volcanoes NP
MECO - Maalaea Generating Station	3,508	25.52	110.18	1) Haleakala NP
		169.61	16.57	2) Hawaii Volcanoes NP

- Point Sources are shown on map in Figure 5.7-1. Letters notifying facilities selected in the Q/d analysis to provide a four-factor analysis are shown in Appendix B.

<sup>28</sup> USEPA. 2017. RACT/BACT/LAER Clearinghouse (RBLC). Available at: <https://cfpub.epa.gov/RBLC/index.cfm?action=Home.Home&lang=en> .Accessed: June 2019.

Exhibit 2

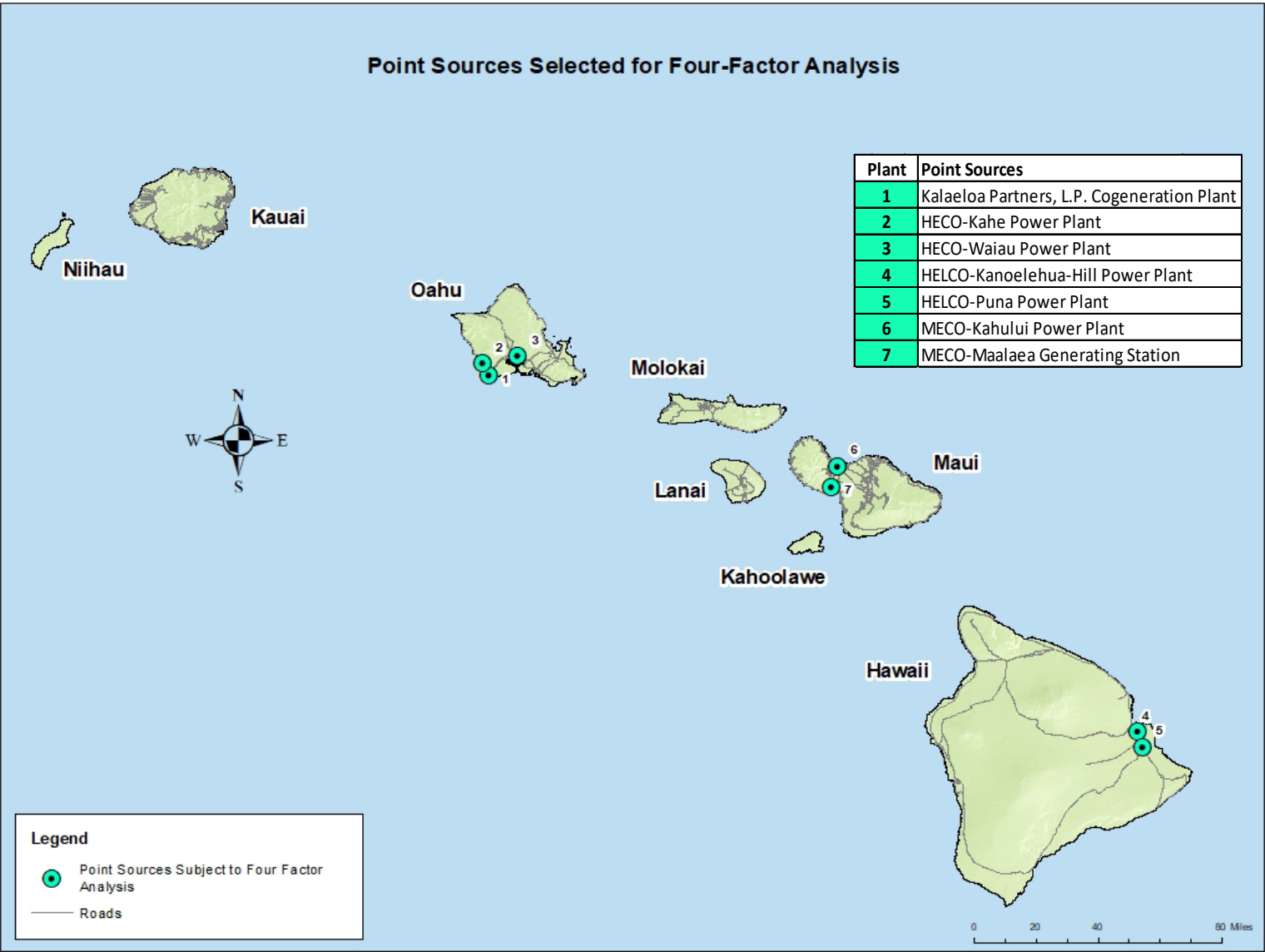


Figure 5.7-1 Point Sources Selected for Four-Factor Analysis

## Exhibit 2

### 5.8 2017 Point Source Emissions – 40 CFR §51.308(f)(2)(iii)

The 2014 v2 national emissions inventory (NEI) data (available September 2017) was used for baseline Q/d screening. Since 2017 NEI data was not available in a finalized form until February 2020, the DOH-CAB did not believe it practicable to revise the Q/d screening using 2017 NEI data after WRAP already used the 2014 NEI data to determine the applicable Q/d facilities subject to requirements to submit a four-factor analysis.

Nonetheless, 2017 SLEIS emissions were checked to determine if any additional point source facilities would have been pulled into the four-factor analysis. Results showed that no additional 2017 facilities would have exceeded  $Q/d \geq 10$ , and further that the HELCO Puna facility would have been screened out ( $Q/d = 9.88$ ). Since HELCO Puna Q/d is so close to ten (10) and no permit limitations were included to ensure that future Q/d will not exceed 10 in the future, Puna Generating Station was assumed to be screened into the four-factor analysis based upon the 2014 NEI data.

### 5.9 Other Considerations

The following are two key issues in screening facilities for four-factor analysis that were not covered by the Q/d screening analysis:

#### Trade Winds

For Hawaii, prevailing trade winds from the northeast transport pollutants from point sources on Oahu located down-wind of the Class I areas away from the Class I areas a majority of the time. Please refer to Figure 5.9-1 with wind data from Honolulu International Airport, Molokai Airport, and Kahului International Airport showing predominate northeast trade winds for these islands between years 2015 and 2019. Wind roses with the wind data are shown in Appendix C.

#### Meteorology

A more sophisticated WEP/AOI analysis, using meteorology and grided emissions from EPA's photochemical modeling, was performed to determine the potential of sources to contribute to visibility impairment at the national parks for the most impaired days. This methodology to screen sources for four-factor analysis would be more representative than screening with Q/d; especially for sources in Hawaii with prevailing trade winds and sources on the Oahu down-wind and hundreds of miles away from the national parks. The WEP/AOI analysis is detailed in Section 5.10 of this RH-SIP.



## Exhibit 2

### 5.10 WEP/AOI Analysis

A WEP/AOI analysis was conducted by WRAP/Ramboll with hybrid single-particle lagrangian integrated trajectory (HYSPLIT) back trajectories to regional haze IMPROVE monitoring sites on the most impaired days. The WEP/AOI analysis was performed using both gridded emissions from the EPA's 2016 Hawaii modeling platform and 2017 and 2028 facility-level emissions data provided by Hawaii's Clean Air Branch. The 2028 emission reductions were used in conjunction with the 2017 NEI data to arrive at 2028 facility-level emissions based on information from Hawaiian Electric's PSIP. Plots of gridded emissions of NO<sub>x</sub>, SO<sub>x</sub>, PEC (primary elemental carbon), and POA (primary organic aerosols) from EPA's 2016 Hawaii modeling platform were used for the HYSPLIT model for the analysis of Ammonium Nitrate (Amm\_NO<sub>3</sub>), Ammonium Sulfate (Amm\_SO<sub>4</sub>), organic aerosol (OA), and elemental carbon (EC). The residence time (RT) of the most impaired day back trajectories was calculated for grid cells of EPA's 27-km modeling domains. The RT analysis provides an area of influence or frequency of occurrence that back trajectories passing over a grid cell arrive at the Class I area on the most impaired days. The RT analysis was expanded to an extinction weighted residence time (EWRT) analysis by weighting the HYSPLIT back trajectories by the daily light extinction on the most impaired days at the Class I areas for specific particulate species. Major point source emissions were overlaid with the EWRT to provide a ranking of the facility's visibility precursor emissions potential to contribute to visibility impairment at the national parks for the most impaired days.

HYSPLIT calculated back trajectories to arrive at the IMPROVE sites on the most impaired days from 2014 to 2018. The HYSPLIT model simulated 72-hour (3-day) back trajectories arriving at each of the sites on the most impaired days at four (4) times a day local standard time (06:00, 12:00, 18:00, and 24:00). The back trajectories were calculated to arrive at the IMPROVE sites on the most impaired days at four (4) different heights above ground level (100 m, 200 m, 500 m, and 1,000 m). The WEP/AOI plots represent the potential 2016 emissions to Haleakala NP and Hawaii Volcanoes NP.

Figures 5.10-1 and 5.10-2 provide RT plots aggregated from all four (4) trajectory heights for Haleakala National Park and Hawaii Volcanoes National Park, respectively. The RT plots of individual trajectory heights (100 m, 200 m, 500 m, and 1,000 m) can be obtained by accessing the WRAP TSS. The RT is the frequency that air masses passed over a location prior to arriving at a specific Class I area, as defined by HYSPLIT back trajectories.

HALE1\_RHTS\_VADJ - 20% Most Impaired Days - All  
Residence Time (%)

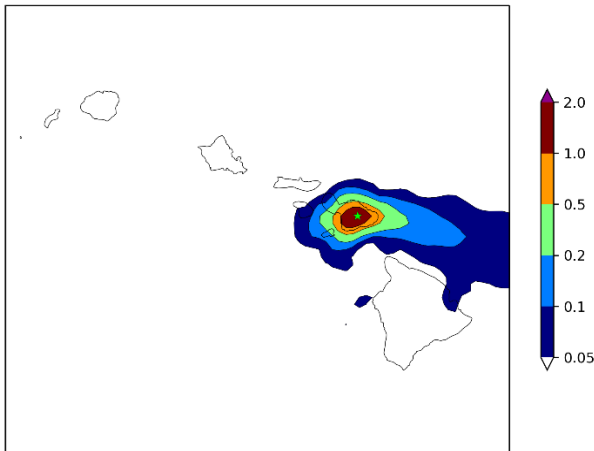


Figure 5.10-1 Haleakala NP, RT

HAVO1\_VADJ - 20% Most Impaired Days - All  
Residence Time (%)

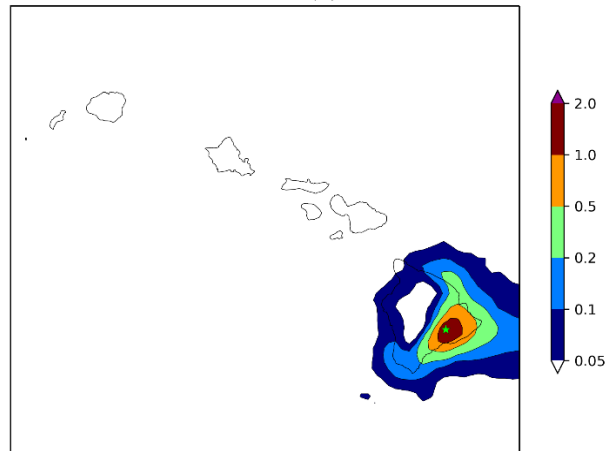
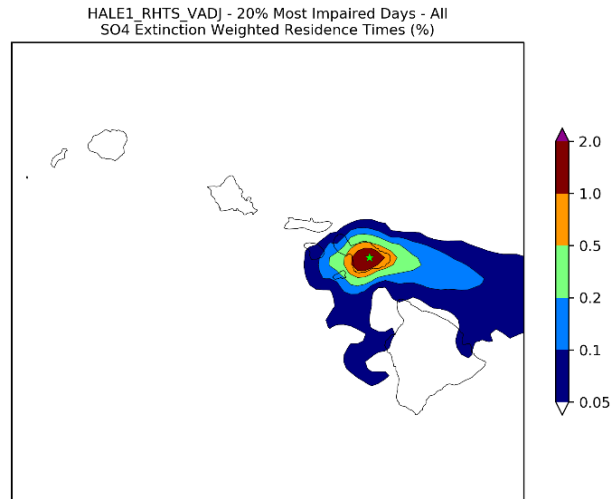
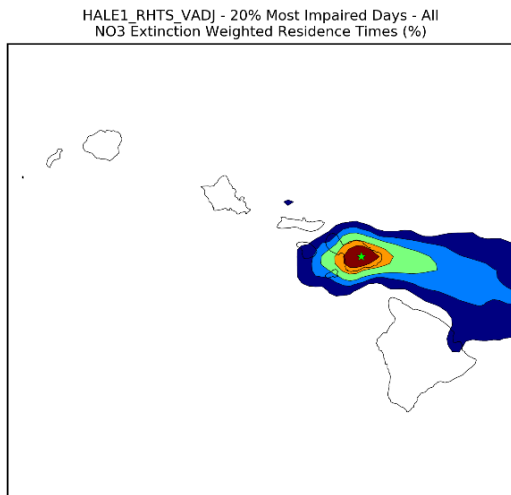


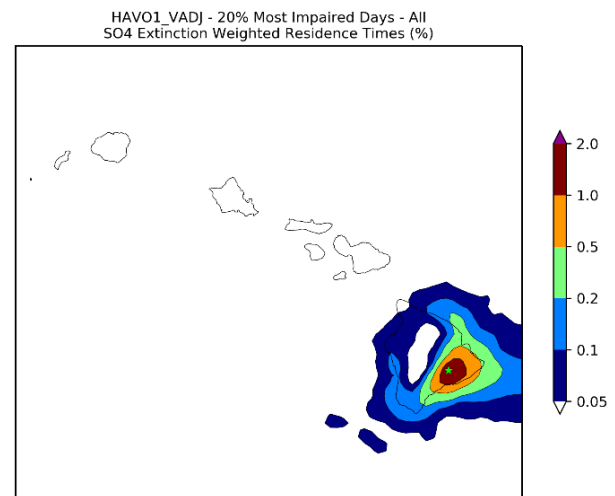
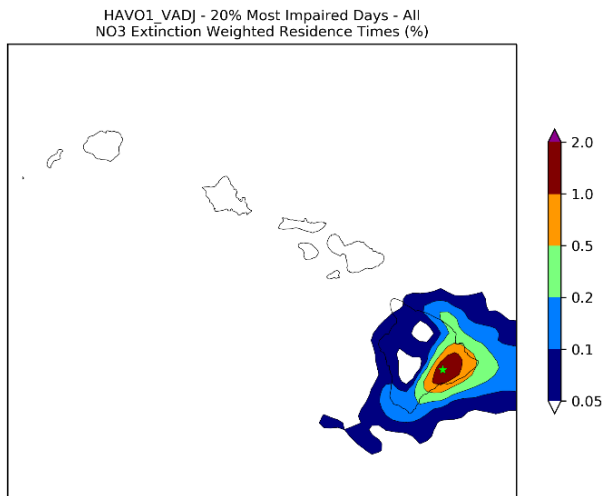
Figure 5.10-2 Hawaii Volcanoes NP, RT

## Exhibit 2

Figures 5.10-3 through 5.10-6 provide EWRT plots (all heights) for Haleakala National Park and Hawaii Volcanoes National Park. The EWRT provides the relative probability that sources of the visibility precursor in the grid cell contributed to the extinction at the national park on the most impaired days.



**Figure 5.10-3** Haleakala NP, EWRT Amm\_NO<sub>3</sub> **Figure 5.10-4:** Haleakala NP, EWRT Amm\_SO<sub>4</sub>

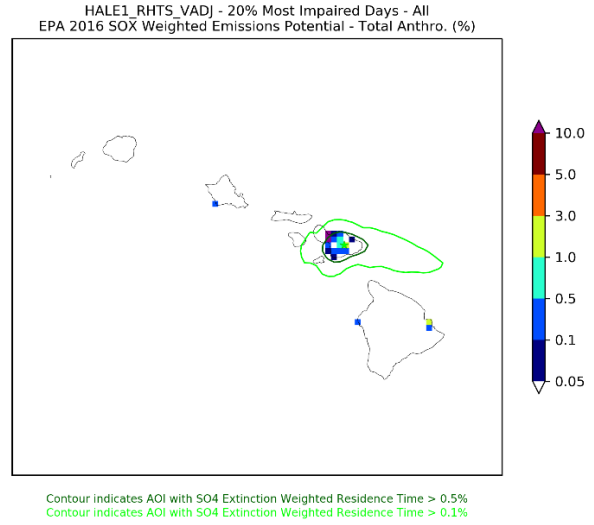
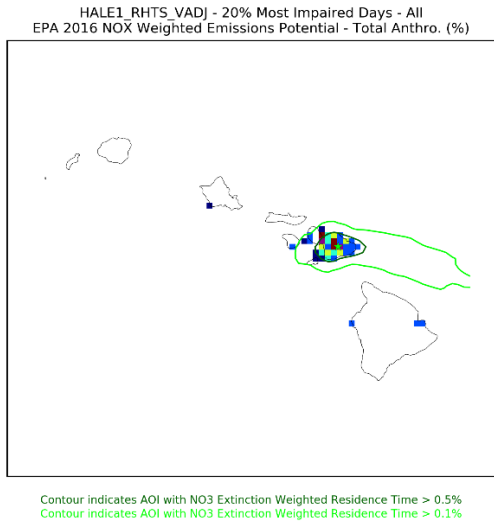


**Figure 5.10-5** HAVO1 NP, EWRT Amm\_NO<sub>3</sub> **Figure 5.10-6** HAVO1 NP, EWRT Amm\_SO<sub>4</sub>

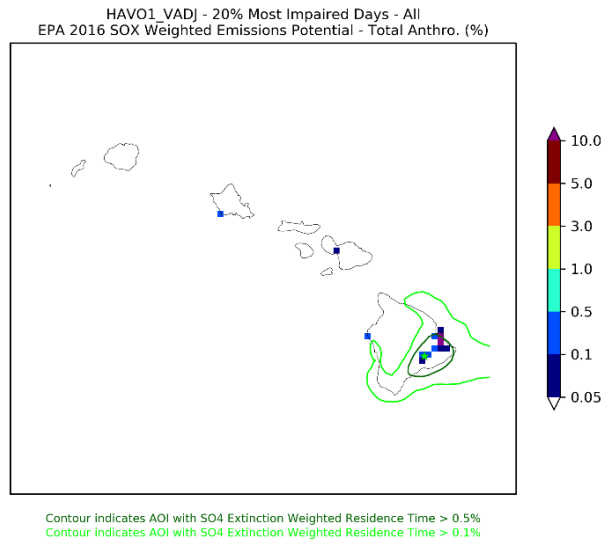
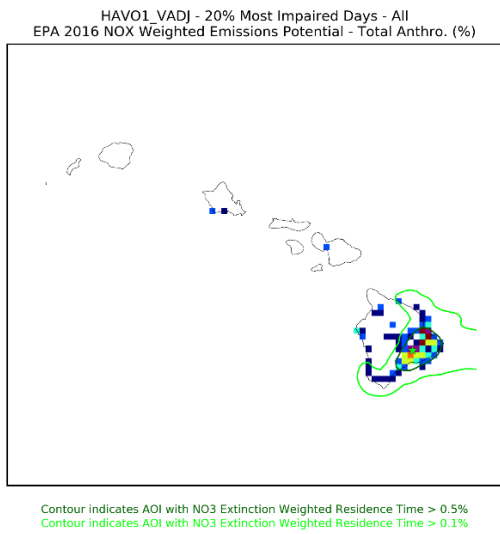
Figures 5.10-7 through 5.10-10 are WEP plots (all heights) that combine emissions and AOIs. The WEP is calculated by overlaying the EWRT results with emissions of light extinction precursors (e.g., NO<sub>x</sub> emissions for ammonium nitrate extinction). The results are normalized by the sum of the WEP for total anthropogenic emissions. The dark and light green isopleths in the WEP plots that correspond to the 0.5 and 0.1 percent frequency from the corresponding EWRT are the AOIs. The AOIs indicate geographic areas where the haze species are coming from. Source grids within the light green, 0.5 percent frequency range are more likely to contribute to haze than those within the dark blue 0.1 percent frequency range. Each grid location contains at least one point source but may contain more than one point source. Grids that show up far away from the isopleths, such as the South-West corner of Oahu, contribute less than sources within the 0.5 and 0.1 isopleths.



## Exhibit 2



**Figure 5.10-7** Haleakala NP, WEP Amm\_NO<sub>3</sub>    **Figure 5.10-8** Haleakala NP, WEP Amm\_SO<sub>4</sub>



**Figure 5.10-9:** HAVO1 NP, WEP Amm\_NO<sub>3</sub>    **Figure 5.10-10:** HAVO1 NP, WEP Amm\_SO<sub>4</sub>

## Exhibit 2

The WEP/AOI ranking provides the relative potential of a point source to contribute to visibility impairment for each national park. The ten (10) facilities that have the highest WEP/AOI values include some facilities that were not selected as part of the initial Q/d screening assessment.

Tables 5.10-1 and 5.10-2 provide the point source ranking of the WEP/AOI for ammonium nitrate at Haleakala National Park and Hawaii Volcanoes National Park, respectively. These tables are based on the RANK\_POINT spreadsheets that consist of facility level emissions of NO<sub>x</sub> overlaid with the corresponding EWRT for Amm\_NO<sub>3</sub> for the 2017 emissions scenario. Emissions from airports were excluded for the point source ranking.

<b>Table 5.10-1 Haleakala NP, Facility Contribution Ranking for NO<sub>3</sub></b>			
Facility Rank	Facility Name	WEP Amm_NO <sub>3</sub>	Amm_NO <sub>3</sub> % Contribution
1	MECO - Maalaea Generating Station	91,737.709	86.91%
2	MECO - Kahului Power Plant	11,524.123	10.92%
3	HC&D Camp 10 Quarry	1,154.769	1.09%
4	MECO - Miki Basin Power Plant	416.505	0.39%
5	HELCO - Kanoiehua Power Plant/ HILL	268.138	0.25%
6	HECO - Kahe Power Plant	105.440	0.10%
7	MECO - Palaau Power Plant	85.497	0.08%
8	HELCO - Keahole Power Plant	70.778	0.07%
9	Kalaeloa Cogeneration Plant	45.052	0.04%
10	Mauna Loa Macadamia Nut Plant	29.166	0.03%

<b>Table 5.10-2 Hawaii Volcanoes NP, Facility Contribution Ranking for NO<sub>3</sub></b>			
Facility Rank	Facility Name	WEP Amm_NO <sub>3</sub>	NO <sub>3</sub> % Contribution
1	HELCO - Kanoiehua Power Plant/ HILL	11,579.191	79.63%
2	Mauna Loa Macadamia Nut Plant	1,331.709	9.16%
3	HELCO - Puna Power Plant	1,047.520	7.20%
4	MECO - Maalaea Generating Station	128.522	0.88%
5	HECO - Kahe Power Plant	124.804	0.86%
6	HELCO - Keahole Power Plant	87.640	0.60%
7	Hamakua Energy, LLC - Hamakua Energy Plant	53.656	0.37%
8	Kalaeloa Cogeneration Plant	52.923	0.36%
9	HELCO - Waimea Power Plant	28.156	0.19%
10	HPOWER	18.282	0.13%

## Exhibit 2

Tables 5.10-3 and 5.10-4 show the point source ranking of the WEP/AOI for ammonium sulfate at Haleakala National Park and Hawaii Volcanoes National Park, respectively. These tables are based on the RANK\_POINT spreadsheets that consist of facility level emissions of SO<sub>2</sub> overlaid with the corresponding EWRT for Amm\_SO for the 2017 emissions scenario. Emissions from airports were excluded for the point source ranking.

<b>Table 5.10-3 Haleakala NP, Facility Contribution Ranking for SO<sub>4</sub></b>			
Facility Rank	Facility Name	WEP Amm SO <sub>4</sub>	SO <sub>4</sub> % Contribution
1	MECO - Kahului Power Plant	640,503.639	83.78%
2	MECO - Maalaea Generating Station	102,281.522	13.38%
3	HELCO - Kanoelehua Power Plant/ HILL	15,591.339	2.04%
4	HELCO - Puna Power Plant	2,388.154	0.31%
5	HELCO - Keahole Power Plant	1,699.209	0.22%
6	HECO - Kahe Power Plant	1,121.539	0.15%
7	Kalaeloa Cogeneration Plant	559.328	0.07%
8	Kapolei Refinery (IES Downstream, LLC)	102.500	0.01%
9	AES Hawaii, LLC	85.362	0.01%
10	HC&D Camp 10 Quarry	42.288	0.01%

<b>Table 5.10-4 Hawaii Volcanoes NP, Facility Contribution Ranking for SO<sub>4</sub></b>			
Facility Rank	Facility Name	WEP Amm SO <sub>4</sub>	SO <sub>4</sub> % Contribution
1	HELCO - Kanoelehua Power Plant/HILL	2,342,219.833	84.06%
2	HELCO - Puna Power Plant	425,758.317	15.28%
3	HELCO - Keahole Power Plant	7,303.296	0.26%
4	Mauna Loa Macadamia Nut Plant	3,211.788	0.12%
5	HECO - Kahe Power Plant	2,856.909	0.10%
6	Kalaeloa Cogeneration Plant	1,414.019	0.05%
7	MECO - Kahului Power Plant	1,233.516	0.04%
8	MECO - Maalaea Generating Station	666.451	0.02%
9	HECO - Waiiau Power Plant	450.037	0.02%
10	Kapolei Refinery (IES Downstream, LLC)	260.055	0.01%

The Kahului, Maalaea, and Kanoelehua-Hill power plants along with the HC&D Camp 10 Quarry were facilities with the greatest potential to contribute to visibility impairment at Haleakala National Park. The percentage of contribution potential, based on WEP/AOI point source rankings for ammonium nitrate after excluding airports, ranged from 1.09% to 10.92% to 86.91% for the Camp 10 Quarry, Kahului Power Plant, and Maalaea Power Plant, respectively. The percentage contribution potential, based on WEP/AOI rankings for ammonium sulfate after excluding airports, ranged from 2.04% to 13.38% to 83.78% for the Kanoelehua-Hill, Maalaea, and Kahului power plants, respectively.

The Kanoelehua-Hill, Mauna Loa Macadamia Nut Corporation, and Puna plants had the greatest potential to contribute to visibility impairment at Hawaii Volcanoes National Park. The percentage of contribution potential, based on WEP/AOI rankings for ammonium nitrate after excluding airports, ranged from 7.20% to 9.16% to 79.63% for the Puna, Mauna Loa, and Kanoelehua-Hill facilities, respectively. The percentage of contribution potential, based on WEP/AOI rankings for ammonium sulfate after excluding airports, ranged from 15.26% to 84.06% for the Puna and Kanoelehua-Hill power plants, respectively.

## Exhibit 2

The Mauna Loa Macadamia Nut Corporation Plant and HC&D Camp 10 Quarry were among the top three (3) facilities with the highest potential to contribute to haze for ammonium nitrates in Hawaii's Class I areas based on WEP/AOI rankings but were not selected for control evaluation after initial Q/d screening. These facilities were below a Q/d threshold of ten (10).

Based on the WEP/AOI analysis, the DOH-CAB decided to require a four-factor analysis for the Mauna Loa Macadamia Nut Corporation plant since its ranking for ammonium nitrate of 9.16% as a contributor to visibility impairment at Hawaii Volcanoes National Park was relatively high. The total combined ammonium nitrate contribution for Hawaii Volcanoes National Park from the top three (3) facilities, that included the Mauna Loa Macadamia Nut Corporation plant, accounted for approximately 96% of the ranking. The Mauna Loa Macadamia Nut Corporation plant is evaluated further in Chapter 7. The four-factor analyses for the Mauna Loa Macadamia Nut Corporation Plant on Hawaii Island was determined to be incomplete and is still being worked on. Potential control measures for this plant will be provided in supplemental documents as an RH-SIP revision.

For the HC&D Camp 10 Quarry, the WEP/AOI ranking of 1.09% for ammonium nitrate as a contributor to visibility impairment at Haleakala National Park was relatively low. The total combined ammonium nitrate contribution for Haleakala National Park from the top two (2) facilities, with the HC&D Camp 10 Quarry excluded, accounted for approximately 98% of the ranking. Therefore, HC&D Camp 10 Quarry was excluded from further evaluation.

### 5.11 Sources Selected With WEP/AOI Analysis

The WEP/AOI analysis showed that sources nearby the Class I areas had the greatest potential to contribute to visibility impairment in Hawaii's national parks on the most impaired days from 2014 to 2018. The Kalaeloa Partners L.P., Kahe, and Waiiau Power Plants on the island of Oahu, initially screened with Q/d, did not rank high in their potential to impair visibility when considering meteorology, haze species, emissions, and distance using the WEP/AOI analysis. The WEP point source contribution potential for these facilities ranged from 0.04% to 0.86% and 0.02% to 0.15% for nitrates and sulfates, respectively. Therefore, Kalaeloa, Kahe, and Waiiau Power Plants were excluded from requiring controls in this second regional haze planning period.

The WEP/AOI analysis showed that sources on the islands of Maui and Hawaii, where the national parks are located, had the greatest potential to impair visibility. Control measures were selected for the Kanoelehua-Hill and Puna Power Plants on the island of Hawaii and the Kahului and Maalaea Power Plants on the island of Maui. Control measures selected were those below the \$5,800/ton of total combined pollutant ( $\text{SO}_2$ ,  $\text{NO}_x$ , and  $\text{PM}_{10}$ ) removed cost threshold. Please refer to Appendix K.

Additionally, as illustrated in Figure 5.9-1, from 2015 to 2019, Oahu was influenced by winds from the northeast direction 58.7% of the time. In addition, higher wind speeds, in the range of 7.00 knots to 21.58 knots occur 77.0% from the northeast direction. These northeast trade winds blow emissions from Kalaeloa Partners L.P., Kahe and Waiiau power plants away from Hawaii's Class I areas. Generally, in order for these emissions to significantly influence Hawaii's Class I areas, sustained winds from the west-northwest direction are needed. As Figure 5.9-1 shows, winds from this direction are virtually non-existent.

## Exhibit 2

An analysis of the 2015 to 2019 raw wind rose data illustrated in Figure 5.9-1, for the Honolulu International Airport (now Daniel K. Inouye International Airport) was conducted to demonstrate the significantly low number of hours that winds with the appropriate direction, speed, and duration could impact Hawaii's Class I areas. The raw wind rose data consisted of 43,824 hourly wind speed and wind direction measurements. The scope of the analysis demonstrated that winds with the necessary direction, wind speed magnitude, and duration to blow emissions from the Kalaeloa Partners L.P., Kahe, and Waiau power plants toward, and reach Hawaii's Class I areas is extremely rare. Within the analysis, straight-line distances are defined as the shortest distance between the specified emission source and the Class I area. This analysis did not attempt to demonstrate the deciview impacts from the emission sources on Hawaii's Class I areas.

As stated in Section 5.10, The WEP/AOI analysis was performed using gridded emissions data and incorporating the residence time (RT) of back trajectories for the most impaired days calculated for grid cells of modeling domains. The RT analysis provides an area of influence or frequency of occurrence of back trajectories passing over a grid cell that arrive at the Class I area.

Our analysis focuses on evaluating both the frequency and duration that emissions from the Oahu facilities (i.e., Kalaeloa Partners L.P., Kahe, and Waiau power plants) could impact visibility by traveling to and passing over the Class I areas based on wind direction and speed.

A subset of the 2015 to 2019 raw wind rose data was evaluated in detail with focus on occurrences with sustained winds from the west-northwest directions or 275 to 315 degrees. These are time periods when the Oahu facilities potentially could influence visibility at Hawaii's Class I areas. The number of occurrences provides an indication of the potential weighted residence time or frequency that a back trajectory could pass over Hawaii's Class I areas once it arrives.

With time of travel being excluded, there were two days within the 2015 to 2019 data set where emissions from the Oahu facilities potentially could have arrived at the HALEOBS Class I area. On February 13, 2015, and February 10, 2019, there were one (1) and three (3) occurrences, respectively, where emissions from the Oahu facilities potentially could have impacted the HALEOBS Class I area (Haleakala NP).

Since each occurrence measures one-hour intervals, the maximum duration of each occurrence is not expected to exceed one hour for a total of four (4) hours from 2015 to 2019. The total number of measured data or occurrences is 43,824, of which four (4) was determined to have the potential to impact the HALEOBS Class I area based on of wind direction and speed. This represents less than 0.01% of the total time, which demonstrates the rarity of occurrences that potentially could have an influence on Hawaii's Class I area.

The required wind magnitude and duration for emissions to impact HVNP Class I area (Hawaii Volcanoes NP) did not occur at any time from 2015 to 2019.

## Exhibit 2

Table 5.11-1 below shows:

1. The locations of the Kalaeloa Partner L.P., Kahe and Waiau Power Plants and also representative locations of Haleakala NP and Hawaii Volcanoes NP;
2. The straight-line distances from each power plant to Haleakala NP and Hawaii Volcanoes NP, respectively; and
3. The straight-line wind direction from each power plant that is needed for emissions to impact Haleakala NP and Hawaii Volcanoes NP, respectively.

<b>Table 5.11-1 Oahu Sources Impact on HALEOBS and HVNP</b>						
Location	Latitude (°)	Longitude (°)	Distance to HALEOBS (mi.)	Wind Direction to HALEOBS (°)	Distance to HVNP (mi.)	Wind Direction to HVNP (°)
Kalaeloa	21.301803	-158.096257	125	289	224	305
Kahe	21.356642	-158.128566	128	290	227	306
Waiau	21.388572	-158.960798	120	293	220	308
Haleakala Observatory (HALEOBS)	20.708102	-156.256688				
Hawaii Volcanoes NP Visitor Center (HVNP)	19.429561	-155.257165				

The straight-line wind directions needed for emissions to impact Haleakala NP and Hawaii Volcanoes NP range from 289° to 308°. A conservative range of wind directions from 275° to 315° was chosen for the purpose of this analysis. The raw wind rose data shows that winds within this range occur a total of 848 hours or 1.93% of the 43,824 hours. The data also shows that the magnitude and duration necessary for emissions to impact Haleakala NP occurs conservatively on only two (2) occasions: six (6) hours from 14:00 to 19:00 on February 13, 2015, and four (4) hours from 14:00 to 17:00 on February 10, 2019. The required wind magnitude and duration for emissions to impact Hawaii Volcanoes NP did not occur at any time from 2015 to 2019. Therefore, as the data demonstrates, winds with the necessary direction, magnitude, and duration to blow emissions from the Kalaeloa Partners, L.P., Kahe, and Waiau power plants toward, and reach Hawaii's Class I areas are extremely rare. Therefore, Kalaeloa Partners, L.P., Kahe, and Waiau power plants on Oahu were excluded from requiring controls in this second regional haze planning period. Controls were only selected for sources on Hawaii and Maui Islands that ranked high in their potential to affect visibility in the national parks based on results from the WEP/AOI analysis.

## Exhibit 2

### 5.12 Area Source Screening Methodology

The following were assumed for the area source screening analysis:

- a. Gather 2014 EPA NEIv2 emissions data across the state for Kauai, Honolulu, Maui, and Hawaii Counties.
- b. Visibility emissions were total combined emissions of NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>10</sub> (facility level emission  $Q = Q_{NOx} + Q_{SO2} + Q_{PM10}$ ).
- c. Remove, PM<sub>10</sub> primary area source emissions from Honolulu and Kauai Counties since PM<sub>10</sub> does not generally experience high transport distances.
- d. Determine the Q threshold which achieves inclusion of SCCs with the largest Qs until at least 80% of total Q emissions across all SCCs throughout the state are accounted for (i.e.,  $Q > 1,139$  tons per year includes three (3) sectors which account for 85% of the total nonpoint Q).<sup>29</sup>

### 5.13 Area Source Screening Results

Tables 5.13-1 and 5.13-2 below show a list of the larger area sources sorted by Q in descending order for Maui and Hawaii Counties, respectively.

<b>Table 5.13-1 Maui County Area Sources<sup>a</sup></b>					
Sector	Description	Q (tpy)	Q (tpy)		
		NO <sub>x</sub> + SO <sub>2</sub> + PM <sub>10</sub>	NO <sub>x</sub>	SO <sub>2</sub>	PM <sub>10</sub>
Dust-Unpaved Road Dust	Fugitive Dust, Unpaved Roads	8,011	-----	-----	8,011
Fires-Agricultural Field Burning	Sugarcane Burning Emissions. <sup>b</sup>	1,139	359	197	583
Dust-Construction Dust	Fugitive Dust: Road, Residential, and Nonresidential Construction.	786	-----	-----	786
Mobile-Commercial Marine Vessels	Port and Underway Emissions.	354	317	28	9
Agricultural-Crops & Livestock Dust	Fugitive Dust: Dust Kicked up by Hooves and Tilling.	221	-----	-----	221
Dust-Paved Road Dust	Fugitive Dust: Paved Roads	177	-----	-----	177
Waste Disposal	Open Burning: Land Clearing Debris, Yard Waste-Leaves & Brush, Household Waste,	126	25	7	94
Fuel Combustion-Residential-Wood	Wood Stove, Wood Fireplace Insert, Outdoor Wood Burning, and Fireplace.	89	9	1	79

- a. Maui County includes Kahoolawe, Lanai, Maui, and Molokai Islands.
- b. HC&S transitioned out of farming sugar on the island of Maui and shut down in 2016. This was the only facility in Hawaii that processed sugar. Currently, there is no sugar cane burning in Hawaii.

<sup>29</sup> <https://ofmpub.epa.gov/sccwebservices/sccsearch/>

## Exhibit 2

<b>Table 5.13-2 Hawaii County Area Sources<sup>a</sup></b>					
Sector	Description	Q (tpy)	Q (tpy)		
		NO <sub>x</sub> +SO <sub>2</sub> + PM <sub>10</sub>	NO <sub>x</sub>	SO <sub>2</sub>	PM <sub>10</sub>
Dust-Unpaved Road Dust	Fugitive Dust: Unpaved Roads.	24,856	-----	-----	24,856
Agricultural-Crops & Livestock Dust	Fugitive Dust: Dust Kicked up by Hooves and Tilling.	1,130	-----	-----	1,130
Dust-Construction Dust	Fugitive Dust: Road, Residential, and Nonresidential Construction.	563	-----	-----	563
Dust-Paved Road Dust	Fugitive Dust: Paved Roads.	354	-----	-----	354
Waste Disposal	Open Burning: Land Clearing Debris, Yard Waste-Leaves & Brush, Household Waste.	244	46	11	187
Fuel Combustion-Residential-Wood	Wood Stove, Wood Fireplace Inserts, Outdoor Wood Burning, and Fireplaces.	237	25	4	208
Mobile-Commercial Marine Vessels	Port Emissions. <sup>b</sup>	191	143	43	5

a. Hawaii County includes Hawaii Island only.

b. No underway emissions were provided for Mobile-Commercial Marine Vessels for Hawaii County.

Table 5.13-3 on the next page shows the results of the screening analysis for area sources with a Q value of greater than 1,139 tons per year for the largest SCCs which are at least 80% of the total statewide area source emissions. The total Q for all of Hawaii's area sources is 39,967 tons per year. For the screening analysis, area sources are ranked from highest to lowest Q statewide. In Table 5.13-3, the top three (3) area source emitters among those evaluated statewide account for 85% of the statewide area source emissions.



## Exhibit 2

<b>Table 5.13-3 Top Three (3) Area Source Emitters <sup>a</sup></b>							
Sector	Description	County <sup>a,b</sup>	% Statewide Q (39,967 tpy) <sup>c</sup>	Q (tpy)		Q (tpy)	
				NO <sub>x</sub> +SO <sub>2</sub> + PM <sub>10</sub>	NO <sub>x</sub>	SO <sub>2</sub>	PM <sub>10</sub>
Dust-Unpaved Road Dust	Fugitive Dust, Unpaved Roads	Hawaii	62% See Note c	24,886	-----	-----	24,886
Dust-Unpaved Road Dust	Fugitive Dust, Unpaved Roads	Maui	20% See Note d	8,011	-----	-----	8,011
Fires-Agricultural Field Burning	Sugarcane Burning Emissions <sup>f</sup>	Maui	3% See Note e	1,139	-----	-----	1,139
<b>Total→</b>			<b>85% See Note e</b>	<b>34,036</b>	<b>-----</b>	<b>-----</b>	<b>34,036</b>

a. Hawaii County includes Hawaii Island only.

b. Maui County includes Kahoolawe, Lanai, Maui, and Molokai Islands.

c.  $(24,886 \text{ tpy}/39,967 \text{ tpy}) \times 100\% = 62\%$

d.  $[(8,011 \text{ tpy})/39,967 \text{ tpy}] \times 100\% = 20\%$

e.  $[(1,139 \text{ tpy})/39,967 \text{ tpy}] \times 100\% = 20\%$

f.  $[(24,886 \text{ tpy} + 8,011 \text{ tpy} + 1,139 \text{ tpy}) \times 100\% = 85\%$

f. HC&S transitioned out of farming sugar and the plant on the island of Maui shut down in 2016. This was the only facility in Hawaii that processed sugar. Currently, there is no sugar cane burning in Hawaii.

## Exhibit 2

### 5.14 Area Source Selection

In selecting area sources for further evaluation:

- Since the HC&S plant permanently shut down on the island of Maui in 2016, there is no more sugar cane burning in the state of Hawaii. Therefore, this area source was screened out from requiring further analysis.
- Fugitive dust from unpaved roads on Hawaii Island was selected for its potential to affect visibility in Hawaii Volcanoes National Park.
- Fugitive dust from unpaved roads on Maui Island was selected for its potential to affect visibility in Haleakala National Park.

Further evaluation of area sources for potential controls was not performed in this second regional haze planning period since the focus was on point sources. The review of the four-factor analyses to determine potential control measures for the facilities screened involved a considerable amount of time and effort. As such, area source screening is for information only. Please refer to Section 6.3 in Chapter 6 for additional information regarding the evaluation of area sources.

## Chapter 6 Emission Control Measures

### 6.0 Introduction

Hawaii is required to identify potential controls for sources screened in Chapter 5 to determine what measures are necessary to make reasonable progress towards natural visibility by 2064. Most units at point sources screened for further evaluation operate with minimal or no emission controls. Examples of control measures to consider for regional haze include control device retrofits; fuel switches/mixing with inherently lower SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub> emissions; operating restrictions on hours and fuel input; emission limits; and plant shut downs.

In the first regional haze planning period (2001-2018), the emphasis was on Best Available Retrofit Technology (BART) to address reasonable progress that included a 0.5 deciview threshold. In this second planning period (2018-2028), there is no BART or deciview threshold. The focus in the second planning period is on determining reasonable progress through analysis of the four factors identified in §169A(g)(1) of the Clean Air Act.

EPA guidance notes that because regional haze results from a multitude of sources over a broad geographic area, progress may require addressing many relatively small contributions to impairment. Thus, a measure may be necessary for reasonable progress even if that measure in isolation does not result in perceptible visibility impairment.

Initial Q/d screening identified seven (7) power plants that required a four-factor analysis. The four-factor analyses, comments on the analyses, report revisions, and changes to worksheets are shown in Appendices D through I for all facilities screened with the Q/d methodology.

## Exhibit 2

Following initial Q/d screening, the WEP/AOI analysis conducted by WRAP/Ramboll identified three Oahu power plants with low relative potential for contributing to visibility impairment at the Class I areas. Therefore, control measures identified in the four-factor analyses of Appendices D through F were excluded from consideration for additional controls in this planning period for the Kalaeloa Partners, L.P. and Hawaiian Electric Kahe and Waiiau power plants, respectively, that were located on Oahu. The WEP/AOI ranked remaining plants selected with Q/d high in their potential to affect visibility in the national parks. Therefore, controls selected in the four-factor analyses of Appendices G through J were considered for the Hawaii Electric Light Kanoelehua-Hill and Puna power plants and Maui Electric Kahului and Maalaea power plants, respectively.

The WEP/AOI also ranked the Mauna Loa Macadamia Nut Corporation plant on the Big Island high in its potential to affect visibility at Hawaii Volcanoes National Park. The four-factor analysis for the Mauna Loa Macadamia Nut Corporation plant is evaluated in Chapter 7.

### 6.1 Four-Factor Analysis (Point Sources)

Potential control measures that could be implemented by 2028 were determined based on four-factor analyses from facilities identified in the screening process. The four-factor analysis considers cost of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of the affected anthropogenic source of visibility impairment.

#### Cost of Compliance

A driving factor in selecting controls is the cost based on assumptions used in calculations to determine the cost per tons of pollutant removed by the control measure. Calculation methodologies to determine the control measure cost are provided in EPA's Air Pollution Control Cost Manual. Since facilities did not incorporate relevant changes requested in comments on the analyses (e.g., those pertaining to current prime interest rate of 3.25% versus 7% interest rate, cost/total combined tons of pollutant removed, estimated equipment life, retrofit factor, Hawaii Island construction cost multiplier, Maui Island construction cost multiplier, etc.), the DOH-CAB requested the original control cost worksheets and made the appropriate changes as part of its review.

Control costs are summarized in Tables 6.1-1 through 6.1-4 for the Hawaii Electric Light Kanoelehua-Hill, Hawaii Electric Light Puna, Maui Electric Kahului, and Maui Electric Maalaea power plants based on the factor analysis provided for these facilities. The cost per ton of pollutant removed, highlighted in green, are costs after changes were made to worksheets by DOH-CAB to align with EPA guidance and the comments provided by EPA and the National Park Service. For costs highlighted in green, the DOH-CAB assumed a remaining useful life thirty (30) years for SCR and twenty (20) years for all other controls. Costs for scrubbers that are highlighted in blue were based on a remaining useful life of thirty (30) years.

## Exhibit 2

### Four-Factor Analysis for Hawaii Electric Light Kanoelehua-Hill Power Plant (Hawaii)

For Boilers Hill 5 and Hill 6, a fuel switch to ULSD with 0.0015% sulfur content was determined to be cost effective at \$4,319/ton and \$4,684/ton respectively for SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub> combined. SCR and combustion controls after the fuel switch to ULSD were also determined to be cost effective for these same units at \$4,242/ton and \$4,326/ton respectively. The cost per ton of pollutant removed, highlighted in green, are costs after changes were made to worksheets by DOH-CAB to align with EPA guidance and comments provided by EPA and the FLMs. For costs highlighted in green, the DOH-CAB assumed a remaining useful life thirty (30) years for SCR and twenty (20) years for all other controls. Costs for scrubbers that are highlighted in blue were based on a remaining useful life of thirty (30) years. An SCR construction cost multiplier of 1.0 was used instead of 1.840. A 3.25% prime interest rate was used versus a 7% interest rate. A retrofit factor of 1.0 was used for SNCR. Please refer to Appendix G.

CT-1 and Diesel Engine Generators D-11, D-15, D-16, and D-17 operate on a limited basis. Therefore, a four-factor analysis was not conducted for these units for NO<sub>x</sub>.

<b>Table 6.1-1 Four-Factor Analysis for Hawaii Electric Light Kanoelehua-Hill Power Plant Hawaii</b>			
Unit	Description	Primary Fuel	Control Measure & Cost per Ton <sup>a,b,c,d,e</sup>
Hill 5	14 MW Boiler	Fuel Oil No. 6 with 2.0% maximum sulfur content	Fuel switch to residual/distillate fuel blend with 1.0% maximum sulfur content - \$6,559/ton SO <sub>2</sub> for Hill 5 and 6 Fuel switch to distillate fuel with 0.4% maximum sulfur content - \$6,119/ton SO <sub>2</sub> for Hill 5 and 6 Fuel switch to residual/ULSD fuel blend with 1.0% maximum sulfur content - \$5,682/ton SO <sub>2</sub> for Hill 5 and 6 Fuel switch to ULSD with 0.0015% maximum sulfur content - \$5,026/ton SO <sub>2</sub> for Hill 5 and 6
Hill 6	23 MW Boiler	Fuel Oil No. 6 with 2.0% maximum sulfur content	Fuel switch to ULSD with 0.0015% sulfur content - <b>\$4,319/ton</b> SO <sub>2</sub> , NO <sub>x</sub> , and PM <sub>10</sub> combined for Hill 5 Fuel switch to ULSD with 0.0015% sulfur content - <b>\$4,684/ton</b> SO <sub>2</sub> , NO <sub>x</sub> , and PM <sub>10</sub> combined for Hill 6 LNB w/OFA/FGR for Hill 5 - \$1,188 ( <b>\$1,051</b> )/ton NO <sub>x</sub> LNB w/OFA/FGR for Hill 6 - \$678 ( <b>\$598</b> )/ton NO <sub>x</sub>
CT-1	11.6 MW Combustion Turbine	Fuel Oil No. 2 with 0.4% maximum sulfur content	SCR for Hill 5 - \$3,873 ( <b>\$1,733</b> )/ton NO <sub>x</sub> SCR for Hill 6 - \$4,021 ( <b>\$1,858</b> )/ton NO <sub>x</sub> SCR + Combustion Controls for Hill 5 - \$4,122 ( <b>\$2,116</b> )/ton NO <sub>x</sub> SCR + Combustion Controls for Hill 6 - \$4,011 ( <b>\$2,041</b> )/ton NO <sub>x</sub> SNCR for Hill 5 - \$2,322 ( <b>\$1,884</b> )/ton NO <sub>x</sub> SNCR for Hill 6 - \$1,552 ( <b>\$1,274</b> )/ton NO <sub>x</sub> SNCR + Combustion Controls for Hill 5 - \$2,568 ( <b>\$2,147</b> )/ton NO <sub>x</sub> SNCR + Combustion Controls for Hill 6 - \$1,903 ( <b>\$1,597</b> )/ton NO <sub>x</sub>
D-11	2.75 MW DEG	ULSD	Wet Scrubber for Hill 5 – \$11,128 ( <b>\$10,836</b> ) ( <b>\$10,438</b> )/ton PM <sub>10</sub> Wet Scrubber for Hill 6 – \$9,728 ( <b>\$9,389</b> ) ( <b>\$8,914</b> )/ton PM <sub>10</sub>
D-15	2.75 MW DEG	ULSD	Wet ESP for Hill 5 - \$67,514 ( <b>\$61,169</b> )/ton PM <sub>10</sub> Wet ESP for Hill 6 – \$91,694 ( <b>\$82,918</b> )/ton PM <sub>10</sub>
D-16	2.75 MW DEG	ULSD	

## Exhibit 2

<b>Table 6.1-1 Four-Factor Analysis for Hawaii Electric Light Kanoelehua-Hill Power Plant Hawaii</b>			
Unit	Description	Primary Fuel	Control Measure & Cost per Ton <sup>a,b,c,d,e</sup>
D-17	2.75 MW DEG	ULSD	

- a. CDS-circulating dry scrubber, DEG-diesel engine generator, ESP-electrostatic precipitator, FGR-flue gas recirculation, LNB-low NO<sub>x</sub> burner, MW-megawatt, OFA-overfire air, SCR-selective catalytic reduction, ULSD-ultra-low sulfur diesel, and combustion controls are LNB with OFA and/or FGR.
- b. Combustion turbine CT-1 is considered a limited use unit.
- c. As per EPA guidance, fuel combustion units that are restricted to using only ULSD or distillate fuel with a sulfur content of no more than 0.0015 percent, per enforceable requirements, do not need further evaluation of SO<sub>2</sub> and particulate matter (PM) control measures.
- d. CT-1, D-11, D-15, D-16, and D-17 operate on a limited basis. Therefore, a four-factor analysis was not conducted for these units for NO<sub>x</sub>.
- e. According to the four-factor analysis, it is unknown if LNB alone can achieve a controlled NO<sub>x</sub> emission level of 0.30 lb/MMBtu and 0.20 lb/MMBtu for Hill 5 and Hill 6, respectively. Therefore, costing is based on a range of costs cost for LNB with OFA. The cost of FGR and LNB with FGR are expected to be covered by this range and have similar NO<sub>x</sub> control.

### Four-Factor Analysis for Hawaii Electric Light Puna Power Plant (Hawaii)

For the boiler, a fuel switch to ULSD with 0.0015% sulfur content was determined to be cost effective at \$4,690/ton SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub> combined. CT-3 operates on a limited basis. Therefore, a four-factor analysis was not conducted for this unit for NO<sub>x</sub>. The cost per ton of pollutant removed, highlighted in green, are costs after changes were made to worksheets by DOH-CAB to align with EPA guidance and comments provided by EPA and the FLMs. For costs highlighted in green, the DOH-CAB assumed a remaining useful life thirty (30) years for SCR and twenty (20) years for all other controls. Costs for scrubbers that are highlighted in blue were based on a remaining useful life of thirty (30) years. A construction cost multiplier of 1.0 was used instead of 1.840 for SCR. A 3.25% prime interest rate was used versus a 7% interest rate. An SNCR retrofit factor of 1. Please refer to Appendix H.

<b>Table 6.1-2 Four-Factor Analysis for Hawaii Electric Light Puna Power Plant Hawaii</b>			
Unit	Description	Primary Fuel	Control Measure & Cost per Ton <sup>a, b, c</sup>
CT-3	20 MW Combustion Turbine	Fuel Oil No. 2 with 0.4% maximum sulfur content	Fuel switch to residual/distillate fuel blend with 1.0% maximum sulfur content - \$7,422/ton SO <sub>2</sub> for Boiler Fuel switch to residual/distillate fuel blend with 0.4% maximum sulfur content - \$6,921/ton SO <sub>2</sub> for Boiler Fuel switch to ULSD with 0.0015% sulfur content - \$4,690/ton SO <sub>2</sub> , NO <sub>x</sub> , and PM <sub>10</sub> for Boiler SCR for Boiler - \$59,655 ( <b>\$23,478</b> )/ton NO <sub>x</sub> SCR + Combustion Control for Boiler - \$49,119 ( <b>\$22,229</b> )/ton NO <sub>x</sub> SNCR for Boiler - \$29,311 ( <b>\$22,621</b> )/ton NO <sub>x</sub> SNCR + Combustion Controls -Boiler - \$34,235 ( <b>\$27,558</b> )/ton NO <sub>x</sub> LNB w/OFA/FGR for Boiler - \$13,431 ( <b>\$11,785</b> )/ton NO <sub>x</sub> Wet Scrubber for Boiler - \$35,648 ( <b>\$34,168</b> ) ( <b>\$32,150</b> )/ton PM <sub>10</sub>

## Exhibit 2

<b>Table 6.1-2 Four-Factor Analysis for Hawaii Electric Light Puna Power Plant Hawaii</b>			
Unit	Description	Primary Fuel	Control Measure & Cost per Ton <sup>a, b, c</sup>
Boiler	15.5 MW Boiler	Fuel Oil No. 6 with 2.0% maximum sulfur content	Wet ESP for Boiler - \$496,875 ( <span style="color: green;">\$448,892</span> )/ton PM <sub>10</sub>

- a. CDS-circulating dry scrubber, ESP-electrostatic precipitator, FGR-flue gas recirculation, LNB-low NO<sub>x</sub> burner, MW-megawatt, OFA-overfire air, SCR-selective catalytic reduction, ULSD-ultra-low sulfur diesel, and combustion controls are LNB with OFA and/or FGR.
- b. Combustion turbine CT-3 is considered a limited use unit.
- c. Wet ESP was assumed to be 90% efficient at removing particulate. A wet scrubber was assumed to be 50% efficient at removing particulate.

### Four-Factor Analysis for Maui Electric Kahului Power Plant (Maui)

For all boilers, fuel switch to ULSD with 0.0015% sulfur content with SCR and combustion controls is determined to be cost effective the combined cost controls for each boiler are less than at \$5,800/ton SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub> combined. The cost per ton of pollutant removed, highlighted in green, are costs after changes were made to worksheets by DOH-CAB to align with EPA guidance and comments provided by EPA and the FLMS. For costs highlighted in green, the DOH-CAB assumed a remaining useful life thirty (30) years for SCR and twenty (20) years for all other controls. Costs for scrubbers that are highlighted in blue were based on a remaining useful life of thirty (30) years. A construction cost multiplier of 1.0 was used instead of 1.938 for SCR. A 3.25% prime interest rate was used versus a 7% interest rate. Please see Appendix I.

<b>Table 6.1-3 Four-Factor Analysis for Maui Electric Kahului Power Plant Maui</b>			
Unit	Description	Primary Fuel	Control Measure & Cost per Ton <sup>a,b,c,d</sup>
K-1	5.0 MW Boiler	Fuel Oil No. 6 with 2.0% maximum sulfur content	Fuel switch to residual/distillate fuel blend with 1.0% maximum sulfur content - \$7,548/ton SO <sub>2</sub> for K1 through K-4 Fuel switch to residual/ULSD fuel blend with 1.0% maximum sulfur content - \$6,535/ton SO <sub>2</sub> for K1 through K-4 Fuel switch to ULSD with 0.0015% maximum sulfur content - \$5,820/ton SO <sub>2</sub> for K1 through K-4 Fuel switch to ULSD with 0.0015% sulfur content - \$4,935/ton SO <sub>2</sub> , NO <sub>x</sub> , and PM <sub>10</sub> combined for K1 Fuel switch to ULSD with 0.0015% sulfur content - \$4,910/ton SO <sub>2</sub> , NO <sub>x</sub> , and PM <sub>10</sub> combined for K2 Fuel switch to ULSD with 0.0015% sulfur content - \$4,920/ton SO <sub>2</sub> , NO <sub>x</sub> , and PM <sub>10</sub> combined for K3 Fuel switch to ULSD with 0.0015% sulfur content - \$5,156/ton SO <sub>2</sub> , NO <sub>x</sub> , and PM <sub>10</sub> combined for K4

Exhibit 2

Table 6.1-3 Four-Factor Analysis for Maui Electric Kahului Power Plant Maui			
Unit	Description	Primary Fuel	Control Measure & Cost per Ton <sup>a,b,c,d</sup>
K-2	5.0 MW Boiler	Fuel Oil No. 6 with 2.0% maximum sulfur content	LNB w/OFA/FGR for K-1 - \$4,222 (\$3,723)/ton NO <sub>x</sub> LNB w/OFA/FGR for K-2 - \$3,676 (\$3,239)/ton NO <sub>x</sub> LNB w/OFA/FGR for K-3 - \$906 (\$803)/ton NO <sub>x</sub> LNB w/OFA/FGR for K-4 - \$2,317 (\$2,050)/ton NO <sub>x</sub> SCR for K-1 - \$9,135 (\$3,719)/ton NO <sub>x</sub> SCR for K-2 - \$9,433 (\$3,795)/ton NO <sub>x</sub> SCR for K-3 - \$3,295 (\$1,456)/ton NO <sub>x</sub> SCR for K-4 - \$5,596 (\$2,381)/ton NO <sub>x</sub> SCR + Combustion Controls for K-1 - \$9,268 (\$4,422)/ton NO <sub>x</sub> SCR + Combustion Controls for K-2 - \$9,717 (\$4,595)/ton NO <sub>x</sub> SCR + Combustion Controls for K-3 - \$3,501 (\$1,769)/ton NO <sub>x</sub> SCR + Combustion Controls for K-4 - \$5,713 (\$2,813)/ton NO <sub>x</sub> SNCR for K-1 - \$8,934 (\$6,359)/ton NO <sub>x</sub> SNCR for K-2 - \$7,858 (\$6,178)/ton NO <sub>x</sub> SNCR for K-3 - \$1,885 (\$1,549)/ton NO <sub>x</sub> SNCR for K-4 - \$4,245 (\$3,420)/ton NO <sub>x</sub>
K-3	11.5 MW Boiler	Fuel Oil No. 6 with 2.0% maximum sulfur content	SNCR + Combustion Controls for K-1 - \$7,171 (\$5,495)/ton NO <sub>x</sub> SNCR + Combustion Controls for K-2 - \$7,097 (\$5,794)/ton NO <sub>x</sub> SNCR + Combustion Controls for K-3 - \$2,109 (\$1,777)/ton NO <sub>x</sub> SNCR + Combustion Controls for K-4 - \$3,832 (\$3,195)/ton NO <sub>x</sub> Wet Scrubber for K-1 - \$17,310 (\$16,965) (\$16,494)/ton PM <sub>10</sub> Wet Scrubber for K-2 - \$24,223 (\$23,728) (\$23,052)/ton PM <sub>10</sub> Wet Scrubber for K-3 - \$7,091 (\$6,910) (\$6,663)/ton PM <sub>10</sub> Wet Scrubber for K-4 - \$13,647 (\$13,262) (\$12,738)/ton PM <sub>10</sub> Wet ESP for K-1 - \$56,071 (\$51,030)/ton PM <sub>10</sub> Wet ESP for K-2 - \$77,314 (\$70,369)/ton PM <sub>10</sub> Wet ESP for K-3 - \$35,665 (\$32,343)/ton PM <sub>10</sub> Wet ESP for K-4 - \$86,708 (\$78,535)/ton PM <sub>10</sub>
K-4	11.5 MW Boiler	Fuel Oil No. 6 with 2.0% maximum sulfur content	

- a. CDS-circulating dry scrubber, ESP-electrostatic precipitator, FGR-flue gas recirculation, LNB-low NO<sub>x</sub> burner, MW-megawatt, OFA-overfire air, SCR-selective catalytic reduction, ULSD-ultra-low sulfur diesel, and combustion controls are LNB with OFA and/or FGR.
- b. For particulate control the Kahe boilers are subject to a filterable PM standard of 0.030 lb/MMBtu on a thirty-boiler operating day rolling average for non-continental liquid oil-fired units in accordance with EGU MACT.
- c. Dry ESPs, cyclones, and fabric filters are not good technical matches since particulate emissions from residual oil-fired boilers tend to be sticky and small.
- d. According to the four-factor analysis, LNB and possibly LNB in combination with OFA and FGR can achieve a NO<sub>x</sub> emission level of 0.15 lb/MMBtu.

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### Four-Factor Analysis for Maui Electric Maalaea Power Plant (Maui)

For DEG units M1, M2, and M3, fuel ignition timing retard (FITR) is determined to be cost effective as the cost controls for each unit are less than \$5,800/ton NO<sub>x</sub>.

For DEG unit M7, is determined to be cost effective as the cost controls for this unit is less than \$5,530/ton NO<sub>x</sub>.

The cost per ton of pollutant removed, highlighted in green, are costs after changes were made to worksheets by DOH-CAB to align with EPA guidance and comments provided by EPA and the FLMs. For costs highlighted in green, the DOH-CAB assumed a remaining useful life thirty (30) years for SCR and twenty (20) years for all other controls. An SCR construction cost multiplier of 1.0 was used instead of 1.938. A 3.25% prime interest rate was used versus a 7% interest rate. Please see Appendix J.

<b>Table 6.1-4 Four-Factor Analysis for Maui Electric Maalaea Power Plant Maui</b>			
Unit	Description	Primary Fuel	Control Measure & Cost per Ton <sup>a</sup>
M1	2.5 MW DEG	ULSD	Fuel switch to ULSD with 0.0015% maximum sulfur content - \$10,347/ton SO <sub>2</sub> (PM <sub>10</sub> and NO <sub>x</sub> emissions for ULSD and F.O. #2 are considered to be similar) FITR for M1 - \$4,159 ( <b>\$3,030</b> )/ton NO <sub>x</sub> FITR for M2 - \$7,173 ( <b>\$5,225</b> )/ton NO <sub>x</sub> FITR for M3 - \$4,159 ( <b>\$3,030</b> )/ton NO <sub>x</sub> SCR for M1 - \$19,383 ( <b>\$13,996</b> )/ton NO <sub>x</sub> SCR for M2 - \$29,578 ( <b>\$19,778</b> )/ton NO <sub>x</sub> SCR for M3 - \$19,295 ( <b>\$13,896</b> )/ton NO <sub>x</sub> SCR for M4 - \$11,072 ( <b>\$10,336</b> )/ton NO <sub>x</sub> SCR for M5 - \$8,371 ( <b>\$7,327</b> )/ton NO <sub>x</sub> SCR for M6 - \$12,130 ( <b>\$10,823</b> )/ton NO <sub>x</sub> SCR for M7 - \$6,162 ( <b>\$5,530</b> )/ton NO <sub>x</sub> SCR for M8 - \$12,151 ( <b>\$10,857</b> )/ton NO <sub>x</sub> SCR for M9 - \$9,562 ( <b>\$9,087</b> )/ton NO <sub>x</sub> SCR for M10 - \$8,335 ( <b>\$8,757</b> )/ton NO <sub>x</sub> SCR for M11 - \$8,546 ( <b>\$8,859</b> )/ton NO <sub>x</sub> SCR for M12 - \$11,832 ( <b>\$12,423</b> )/ton NO <sub>x</sub> SCR for M13 - \$10,805 ( <b>\$11,292</b> )/ton NO <sub>x</sub> SCR for X1 - \$33,856 ( <b>\$23,041</b> )/ton NO <sub>x</sub> SCR for X2 - \$33,024 ( <b>\$22,388</b> )/ton NO <sub>x</sub> SCR for M14 - \$60,413 ( <b>\$23,854</b> )/ton NO <sub>x</sub> SCR for M16 - \$52,326 ( <b>\$20,660</b> )/ton NO <sub>x</sub> SCR for M17 - \$67,266 ( <b>\$26,559</b> )/ton NO <sub>x</sub> SCR for M19 - \$77,700 ( <b>\$30,679</b> )/ton NO <sub>x</sub> DPF for M4 - \$41,214 ( <b>\$30,031</b> )/ton PM <sub>10</sub> DPF for M5 - \$52,455 ( <b>\$38,221</b> )/ton PM <sub>10</sub> DPF for M6 - \$52,455 ( <b>\$38,221</b> )/ton PM <sub>10</sub> DPF for M7 - \$48,084 ( <b>\$35,036</b> )/ton PM <sub>10</sub>
M2	2.5 MW DEG	ULSD	
M3	2.5 MW DEG	ULSD	
M4	5.6 MW DEG	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content	
M5	5.6 MW DEG	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content	
M6	5.6 MW DEG	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content	
M7	5.6 MW DEG	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content	
M8	5.6 MW DEG	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content	
M9	5.6 MW DEG	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content	
M10	12.5 MW DEG	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content	
M11	12.5 MW DEG	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content	
M12	12.5 MW DEG	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content	
M13	12.5 MW DEG	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content	
X1	2.5 MW DEG	ULSD	
X2	2.5 MW DEG	ULSD	



## Exhibit 2

<b>Table 6.1-4 Four-Factor Analysis for Maui Electric Maalaea Power Plant Maui</b>			
Unit	Description	Primary Fuel	Control Measure & Cost per Ton <sup>a</sup>
M14	20 MW Combustion Turbine	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content and 0.015% average nitrogen content	
M16	20 MW Combustion Turbine	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content and 0.015% average nitrogen content	
M17	20 MW Combustion Turbine	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content and 0.015% average Ce nitrogen content	
M19	20 MW Combustion Turbine	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content and 0.015% average nitrogen content	

a. DPF-diesel particulate filters, FITR-fuel ignition timing retard, LNB-low NO<sub>x</sub> burner, MW-megawatt, OFA-overfire air, SCR-selective catalytic reduction, ULSD-ultra-low sulfur diesel.

### Remaining Useful Life

In accordance with EPA's control cost manual and comments provided, the DOH-CAB used thirty (30) years for the remaining useful life of SCR at power plants. The DOH-CAB used twenty (20) years for the remaining useful life for all other control equipment. Trinity Consultants used a remaining useful life of thirty (30) years for SCR, combustion controls, and post combustion controls. Trinity Consultants used a twenty (20) year remaining useful life for SNCR. The DOH-CAB also determined costs for scrubber systems assuming a remaining useful life of thirty (30) years after additional feedback from the EPA and the FLMs. For fuel switching, the remaining useful life does not impact the annualized costs since fuel switching will not require capital investments in new equipment. It was indicated that fuel switching would require changes to the injectors and fuel system; however, these expenses were not included in the analysis. Although some Hawaiian Electric units are planned to be retired, since there are no commitments to retire plant equipment through federally enforceable emission limits, the remaining useful life is the useful life of the control equipment rather than the source.

### Time Necessary for Compliance

According to information from the four-factor analyses provided, the time necessary to implement control measures is as follows:

- Fuel switching - Two (2) to three (3) years for Hawaiian Electric units and one (1) year for units at the Kalaeloa Partners, L.P. Power Plant.
- CDS - Two (2) to three (3) years.
- FITR – Three (3) to five (5) years.

## Exhibit 2

- SCR, SNCR, and combustion controls (LNB, OFA, and FGR) - Three (3) to five (5) years.
- Water injection – Three (3) to five (5) years.
- Wet ESPs and wet scrubbers - Three (3) to five (5) years.

### Energy and Non-air Environmental Impacts

The following information for the energy and non-air environmental impact factor was provided in the four factor analyses:

- Fuel Switching - There are no energy and non-air quality environmental impacts of compliance for fuel switching.
- CDS - CDS systems require electricity to operate the ancillary equipment. In addition, solid waste streams are generated that require disposal.
- DPF – There are no energy and non-air quality environmental impacts of compliance for adding diesel particulate filters.
- SCR and SNCR - These control systems require electricity to operate the ancillary equipment. SCR and SNCR can potentially cause environmental impacts related to storage of ammonia. These control systems can also release unreacted ammonia referred to as ammonia slip.
- Wet ESPs - ESPs apply energy for removing particulate from the exhaust stream of the emissions source. Wet ESPs generate wastewater streams that must be treated onsite or sent to a wastewater treatment plant. The wastewater treatment process will generate filter cake that would likely require landfilling.
- Wet Scrubbers - Wet scrubbers require energy to force exhaust gases through the scrubber and generate wastewater streams that would need to be treated.

### **6.2 Control Cost Threshold**

To remain consistent to the current value of the dollar, the control cost threshold of \$5,000/ton of pollutant removed in 2009 dollars (one year into the first regional haze planning period) should be subject to escalation to 2019 dollars (one year into the second regional haze planning period). One cost index that has been used extensively by EPA for escalation purposes is the Chemical Engineering Plant Cost Index (CEPCI).

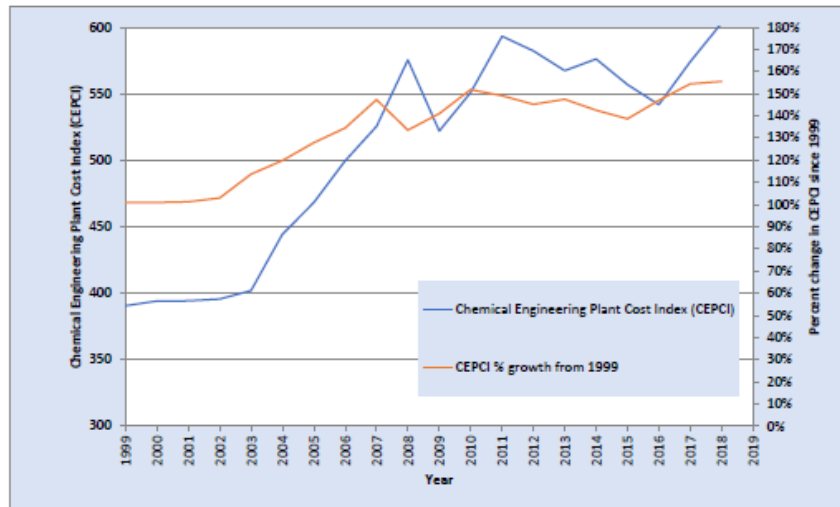
The CEPCI tracks costs of equipment, construction labor, buildings, and supervision in chemical process industries. A chart showing the history of the CEPCI is provided below as Figure 6.2-1.

Since the first planning period, when less than \$5,000/ton of pollutant removed was generally considered reasonable in accepting a control measure as economically feasible, there has been a 16% increase in the CEPCI. Therefore, since there was a 16% increase to the CEPCI between 2009 and 2019, there should also be a 16% increase to the control cost threshold. Proceeding with this methodology would result in an updated control cost threshold of \$5,800/ton of pollutant removed, 16% higher than the \$5,000/ton of pollutant removed threshold. It is important to note that the control cost threshold is a guideline for evaluating cost effective controls and is not considered a definitive line. Control measures that are above the control cost threshold may still be considered reasonable.

## Exhibit 2

### Chemical Engineering Plant Cost Index (CEPCI)

Year	Index	CEPCI % growth from 1999	CEPCI % growth from 2000	CEPCI % growth from 2001	CEPCI % growth from 2002	CEPCI % growth from 2003	CEPCI % growth from 2004	CEPCI % growth from 2005	CEPCI % growth from 2006	CEPCI % growth from 2007	CEPCI % growth from 2008	CEPCI % growth from 2009	CEPCI % growth from 2010	CEPCI % growth from 2011	CEPCI % growth from 2012	CEPCI % growth from 2013	CEPCI % growth from 2014	CEPCI % growth from 2015	CEPCI % growth from 2016	CEPCI % growth from 2017	CEPCI % growth from 2018	
1999	390.6																					
2000	394.1	101%																				
2001	394.3	101%	100%																			
2002	395.6	101%	100%	100%																		
2003	402.0	103%	102%	102%	102%																	
2004	444.2	114%	113%	113%	112%	110%																
2005	468.2	120%	119%	119%	118%	116%	105%															
2006	499.6	128%	127%	127%	126%	124%	112%	107%														
2007	525.4	135%	133%	133%	133%	131%	118%	112%	105%													
2008	575.4	147%	146%	146%	145%	143%	130%	123%	115%	110%												
2009	521.9	134%	132%	132%	130%	130%	117%	111%	104%	99%	91%											
2010	550.8	141%	140%	140%	139%	137%	124%	118%	110%	105%	96%	106%										
2011	593.2	152%	151%	150%	150%	148%	134%	127%	119%	113%	103%	114%	108%									
2012	582.2	149%	148%	148%	147%	145%	131%	124%	117%	111%	101%	112%	106%	98%								
2013	567.3	145%	144%	144%	143%	141%	128%	121%	114%	108%	99%	109%	103%	96%	97%							
2014	576.1	147%	146%	146%	146%	143%	130%	123%	115%	110%	100%	110%	105%	97%	99%	102%						
2015	566.8	143%	141%	141%	141%	139%	125%	119%	111%	106%	97%	107%	101%	94%	96%	98%	97%					
2016	541.7	139%	137%	137%	137%	135%	122%	116%	108%	103%	94%	104%	98%	91%	93%	95%	94%	97%				
2017	574.0	147%	146%	146%	145%	143%	129%	123%	115%	109%	100%	110%	104%	97%	99%	101%	100%	103%	106%			
2018	603.1	154%	153%	153%	152%	150%	136%	129%	121%	115%	105%	116%	109%	102%	104%	106%	105%	108%	111%	105%		
2019	607.5	156%	154%	154%	154%	151%	137%	130%	122%	116%	106%	116%	110%	102%	104%	107%	105%	109%	112%	106%	101%	



**Figure 6.2-1** 1999-2019 Chemical Engineering Plant Cost Index (CEPCI)

## Exhibit 2

### 6.3 Controls Selected

The WEP/AOI analysis showed that sources nearby the Class I areas had the greatest potential to contribute to visibility impairment in Hawaii’s national parks on the most impaired days (2014-2018). The Kalaheo Partners L.P., Kahe, and Waiuu Power Plants on the island of Oahu, initially screened with Q/d, did not rank high in their potential to impair visibility when considering meteorology, haze species, emissions, and distance using the WEP/AOI analysis. Control measures selected were those below the \$5,800/ton of pollutant removed cost threshold with the greatest reductions in visibility impairing pollutants (SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub>). Please refer to Appendix K.

Tables 6.3-1 and 6.3-2 provide a summary of the control measures selected, emission reductions, and compliance times based on a four-factor analysis for Hawaii and Maui Island sources, respectively. These sources ranked high in the WEP/AOI analysis in their potential to affect visibility in the national parks.

<b>Table 6.3-1 Controls Selected for Hawaii Island Sources</b>						
Power Plant	Controls Selected	Emission Reductions (Tons)				Compliance Time after RH-SIP Approval
		NO <sub>x</sub>	SO <sub>2</sub>	PM <sub>10</sub>	Total	
Kanoelehua-Hill	SCR + Combustion Controls + ULSD for Boilers Hill 5 and Hill 6	585	2,165	49	2,799	2 years – ULSD 3 years – SCR and combustion controls
Puna	ULSD for Boiler	18	184	8	210	2 years – ULSD
Total →		603	2,349	56	3,009	See note a

a: Pursuant to 2016 Updates to the Assessment of Reasonable Progress for Regional Haze in Mane-VU Class I areas, two (2) year period after SIP approval is adequate for pre-combustion controls and three (3) year period for installation of post combustion controls.

<b>Table 6.3-2 Controls Selected for Maui Island Sources</b>						
Power Plant	Controls Selected	Emission Reductions (Tons)				Compliance Time after RH-SIP Submittal <sup>a</sup>
		NO <sub>x</sub>	SO <sub>2</sub>	PM <sub>10</sub>	Total	
Kahului	SCR + Combustion Controls + ULSD for Boilers K-1, K-2, K-3, and K-4	588	2,219	72	2,879	2 years – ULSD 3 years – SCR and combustion controls
Maalaea	FITR for Diesel Engine Generators M1, M2, and M3 SCR for Diesel Engine Generator M7	124	-----	-----	124	2 years for FITR 3 years - SCR
Total →		712	2,219	72	3,003	See note a

a: Pursuant to 2016 Updates to the Assessment of Reasonable Progress for Regional Haze in Mane-VU Class I areas, two (2) year period after SIP approval is adequate for pre-combustion controls and three (3) year period for installation of post combustion controls.

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Table 6.3-3 below shows Q/d values based on actual emissions from facilities for years 2014 and 2017 and reductions from actual 2017 baseline emissions after control measures from Tables 5.11-1 and 5.11-2 are accounted for in the emission estimates.

<b>Table 6.3-3 Q/d Values Before and After Controls</b>				
Source	Q/d			Class I Area
	2014	2017	2017	
	Before Controls <sup>a</sup>	Before Controls <sup>b</sup>	After Controls <sup>c</sup>	
HELCO - Kanoelehua-Hill Power Plant	17	19	0.2	1) Haleakala NP
	98	110	1.0	2) Hawaii Volcanoes NP
HELCO - Puna Power Plant	27	10	0.3	1) Hawaii Volcanoes NP
MECO - Kahului Power Plant	82	110	1.1	1) Haleakala NP
	12	16	0.2	2) Hawaii Volcanoes NP
MECO - Maalaea Generating Station	110	124	104	1) Haleakala NP
	17	19	15.7	2) Hawaii Volcanoes NP

a. Worst case Q/d values based on 2014 actual emissions before controls selected in Tables 6.6-2 and 6.6-3.

b. Worst case Q/d values based on 2017 actual emissions before controls selected in Tables 6.6-2 and 6.6-3.

c. Worst case Q/d values based on 2017 baseline emissions after controls selected in Tables 6.6-2 and 6.6-3.

The DOH-CAB sent letters to Hawaiian Electric requesting permit applications to incorporate the regional haze control measures selected for the Kahului, Kanoelehua-Hill, Maalaea, and Puna power plants. Hawaiian Electric responded with new information that was not provided in Hawaiian Electric's four-factor analyses for these facilities. This included the need to install secondary tank containment liners and fuel atomization systems for the fuel switches, a claim that 7% is the nominal interest rate, new remaining useful life assumptions, and revised construction cost multiplier for SCR of 1.2. Please see Chapter 7 of this RH-SIP for additional evaluation and permit amendments to incorporate the federally enforceable regional haze control measures.

### 6.4 Four-Factor Analysis (Area Sources)

A four-factor analysis was not performed for fugitive dust from unpaved roads identified as a potential source for controls in Chapter 5. In accordance with EPA guidance, a state is not required to evaluate all sources of emissions in each implementation period. A four-factor analysis for fugitive dust may be considered in future implementation periods as more guidance becomes available for evaluating area sources.

The DOH-CAB is preparing rules with amended provisions for regulating fugitive dust emissions. Please refer to Sections 7.3 and 7.5.b in Chapter 7 for Hawaii's fugitive dust requirements.

## Chapter 7 Long Term Strategy

### 7.0 Description – 40 CFR §51.308(f)(2)

- a. 40 CFR §51.308(f)(2): 40 CFR §51.308(f)(2)<sup>5</sup> states that the long-term strategy must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress. This includes actions to:

## Exhibit 2

- i. 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, which are discussed further in Chapters 6 and 8;
  - ii. Consult with those States that have emissions that are reasonably anticipated to contribute to visibility impairment in the mandatory Class I Federal area to develop coordinated emission management strategies, which does not apply to Hawaii; and
  - iii. Document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, to determine the emission reduction measures that are necessary to make reasonable progress as discussed in Chapter 6.
- b. 40 CFR §51.308(f)(2)(iv): 40 CFR §51.308(f)(2)(iv) further requires States to consider the following factors when determining their long-term strategy:
- i. Emissions reductions due to ongoing air pollution control programs including measures to address reasonably attributable visibility impairment;
  - ii. Measures to mitigate construction activities;
  - iii. Source retirement and replacement schedules;
  - iv. Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs; and
  - v. The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the planning period.

### 7.1 Ongoing Air Pollution Control Programs Under State Regulations – 40 CFR §51.308(f)(2)(iv)(A)

- a. Renewable Portfolio Standards (RPSs): The main focus of the State of Hawaii’s RPS is on transitioning companies that generate and sell electricity for consumption from using fossil fuels to renewable sources. These standards are codified in Hawaii Revised Statute (HRS) §269-92 (refer to Appendix L) which establishes a percentage of net electricity each company sells for consumption that must be generated from renewable energy by the end of identified years as shown in Table 7.1-1.

<b>Table 7.1-1 HRS §269-92 Renewable Portfolio Standards</b>	
Dates	Net Electricity Sold Using Renewable Energy
December 31, 2010	10%
December 31, 2015	15%
December 31, 2020	30%
December 31, 2030	40%
December 31, 2040	70%
December 31, 2045	100%

The State of Hawaii Public Utilities Commission (PUC) is required by HRS §269-95 to evaluate the RPS every five (5) years, beginning in 2013 and may revise the standards based on the best information available at the time to determine if the standards established by HRS §269-92 remain effective and achievable; and report its findings and RPS revisions based on its own studies and other information, twenty (20) days prior to the Hawaii State’s Legislature every five (5) years. The latest PUC Report to the

## Exhibit 2

2019 Hawaii State's Legislature on RPS (refer to Appendix M) indicates that while there is some uncertainty regarding the more distant future RPS benchmarks, the existing RPS benchmarks remain appropriate and effective and are sufficiently achievable based on best currently available information. Findings include:

- i. The RPS remains effective in helping the State of Hawaii achieve its policies and objectives with respect to developing renewable energy resources.
- ii. Achievement of the 2020 RPS requirement of 30% is highly likely for both the Hawaiian Electric (including its subsidiaries Maui Electric Company and Hawai'i Electric Light Company) and Kaua'i Island Utility Cooperative (KIUC). KIUC has already achieved the 2020 requirement.
- iii. It appears likely that the 2030 RPS requirement of 40% is achievable for both Hawaiian Electric and KIUC, provided that reasonably expected amounts of utility-scale renewable energy projects and distributed renewable generation are successfully developed and integrated on the utility systems. KIUC has already achieved the 2030 requirement.
- iv. The cost of renewable projects under development and recently proposed are below recent costs of most fossil fuel generation, making renewable projects cost competitive alternatives to continuing to utilize fossil fuel generation resources.
- v. Reliability events that occurred on Kauai and Maui in 2017 and 2018, both islands with high levels of inverter-based renewable generation, suggest that continued research and development of grid integration technologies and grid management solutions will be necessary for reliable operation of the grid as the State progresses towards the longer term RPS goals.

40 CFR 51.308(f)(2)(iv)(A) requires states to consider emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment. To characterize the impact of the RPS, sale of electricity data from Section 5 of the PUC RPS Report to the 2019 Legislature (refer to Appendix M) was compiled to provide an estimate of the statewide impact of the RPS on visibility impairment. The report presented sales of electricity data for 2017 and projected data for 2020 and 2030 in units of gigawatt-hours (GWh). A breakdown of the sales data was made between sales from all fuel sources and renewable sources. The renewable sales data were further broken down to establish a sub-group consisting of sales from biomass and biofuel sources, which were excluded from the estimates. The percentage of renewables less biofuels and biomass relative to the statewide total sales from all fuel sources were calculated and subtracted from 100% to provide a reasonable measure of the impact the RPS will have on visibility impairment. As illustrated in the following tables, the percentage of sales of electricity from renewables less biofuels and biomass sources are projected to increase from 2017 to 2030, therefore as the RPS progresses, the impact of fuel-fired electric plants on visibility impairment is expected to decline.

## Exhibit 2

<b>Table 7.1-1a Sales of Electricity (GWh)</b>	
Annual Sales by Hawaiian Electric <sup>a</sup>	8,690
Annual Sales by KIUC <sup>a</sup>	445
Statewide Total Sales from all Fuel Sources <sup>a</sup>	9,135

<b>Table 7.1-1b Statewide<sup>b</sup> Sales from Renewables Less Sales from Biofuel &amp; Biomass</b>			
Calendar Year (P=Projected)	2017	2020P	2030P
Sales of Renewables (GWh)	1,465.7	1,926.7	3,333.5
Sales from Biofuels & Biomass (GWh)	483.3	704.3	773.3
Renewables less Biofuels & Biomass (GWh)	982.4	1222.4	2560.2
Statewide Total Sales from all Fuel Sources <sup>a</sup> (GWh)	9,135	9,135	9,135
Renewables less Biofuels & Biomass (%)	11%	13%	28%
Estimated Impact to Visibility Impairment (%) – Fuel Sources	89%	87%	72%

a. Data Source: Footnote 10 in the PUC RPS Report to the 2019 Legislature

b. Data Source: Tables 3 & 4 in the PUC RPS Report to the 2019 Legislature

- b. **Energy Efficiency Portfolio Standard (EEPS):** The main focus of the State of Hawaii’s EEPS is on reducing consumption (or demand) of electricity by improving efficiency. These standards are codified in HRS §269-96 (see Appendix L), which is designed to achieve a reduction in the consumption of 4,300 gigawatt hours (GWh) of electricity statewide by 2030. The HRS tasks PUC with establishing interim goals for 2015, 2020, and 2025; and authorizes the PUC to adjust the 2030 standard and to establish incentives and penalties based on performance in achieving the standards. The HRS further tasks the PUC to determine if the EEPS remains effective and achievable and report findings and revisions of the EEPS to the Hawaii State’s Legislature every five (5) years.

Unlike the RPS, the PUC lacks jurisdiction over many large consumers of electricity. Therefore, the PUC contracts with a Public Benefits Fee Administrator (“PBFA”) to design and implement the Hawaii Energy program where at least 70% of the PBFA budget is designated for direct incentives in the form of cash rebates or services for customers. The latest PUC’s report to the 2019 Hawaii State’s Legislature on EEPS (refer to Appendix N) identified a savings of 2,030 GWh for the first interim period ending in 2015, which exceeded its goal of 1,375 GWh of energy savings by nearly 50%. Saving for the second interim period is 530 GWh as of the end of 2017, which exceeds half the interim goal of 980 GWh. An annual target of approximately 196 GWh is used to established interim goals as shown in Table 7.1-2.

<b>Table 7.1-2 Hawaii’s Interim Goals for the Energy Efficiency Portfolio Standard</b>			
Calendar Year	Interim Savings Goal (GWh)	Actual Savings Achieved (GWh)	Notes
2015	1,375	2,030	See note <sup>a</sup>
2020	980	530	Data for 2016 and 2017
2025	980		
2030	980		
Total	4,315	2,560	

a. Customer solar panel photovoltaic installations after 2014 no longer count towards the EEPS goal.



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However, the PUC's report also stated that maintaining the past level of savings is becoming more difficult. Preliminary findings suggest that the EEPS goal is achievable, but requires strategic adaptation, possible increases in energy efficiency program budgets, continued innovation in program design, and a more aggressive approach by Hawaii Energy to maintain future saving levels. In addition, savings from customer solar photovoltaic (PV) installations accrued prior to 2015 counted towards the EEPS goal; however, these installations are now counted to the RPS.

- c. Greenhouse Gas (GHG) Rules: The GHG rules were enacted to further implement the goals of Act 234, 2007 Hawaii Session Laws to effect policies on climate change by imposing a carbon dioxide equivalent (CO<sub>2</sub>e) emissions cap to reduce GHGs in the State of Hawaii. By January 1, 2020, the State of Hawaii's goal was a reduction in statewide GHG emissions to levels at or below the best estimates of statewide GHG emissions for 1990. The GHG cap, as a measure for meeting the statewide GHG emission reduction goals, applies to facilities, except for municipal waste combustion operations, with the potential to emit GHG emissions (biogenic plus nonbiogenic) equal to or above 100,000 short tons of CO<sub>2</sub>e per year.

Actions taken to reduce GHG emissions will also reduce emissions of other air pollutants as a co-benefit of implementing the GHG rules. As an example, thirteen (13) electric plants shown on the map in Figure 7.1-1 and listed in Table 7.1-3 by facility name and number, are partnering to meet the emission cap specified in the GHG rules. As illustrated in Table 7.1-4, by implementing the GHG rules, statewide estimated reductions in maximum potential NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>10</sub> are 23,058 TPY, 26,456 TPY, and 4,865 TPY, respectively. By partnering, facilities are allowed to exceed the individual emission cap of at least 16% below a facility's established GHG baseline level as long as the total combined cap for all facilities is at least 16% below the total combined baseline emission level. The baseline is set at the 2010 GHG emission level for each facility unless another year or an average of other years between 2006 and 2010 is more representative of normal operations. Permits for these partnering facilities are available on the Clean Air Branch GHG Program website.<sup>30</sup> All point sources screened in Chapter 5 for requiring a four-factor analysis are among facilities listed in Table 7.1-3 that are subject to GHG emission caps.

Annual GHG emissions and projections for facilities subject to the CO<sub>2</sub>e emission caps are provided in the Hawaii greenhouse gas inventory reports posted on the Clean Air Branch GHG Program website.<sup>31</sup> These include stationary combustion emissions from electric plants and petroleum refineries, as well as fugitive emissions from the petroleum refineries. Biogenic carbon dioxide (CO<sub>2</sub>) emissions are not presented, as these emissions are excluded from the annual facility-wide GHG emission cap. Based on the final Hawaii GHG Emission Report for 2017 dated April 2021, compared to 1990, total emissions in Hawaii in 2017 were roughly 6 percent lower, while net emissions were lower by roughly 8 percent. This report further states that the total GHG emissions are projected to be 16.32 million metric-tons (MMT) CO<sub>2</sub>e in 2020, 17.80 MMT CO<sub>2</sub>e in 2025, and 16.03 MMT CO<sub>2</sub>e in 2030.

<sup>30</sup> <https://health.hawaii.gov/cab/ghg-permits/>

<sup>31</sup> <https://health.hawaii.gov/cab/hawaii-greenhouse-gas-program/>

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As stated in the report, net emissions which considers carbon sinks, are projected to be 13.64 MMT CO<sub>2</sub>e in 2020, 15.17 MMT CO<sub>2</sub>e in 2025, and 13.44 MMT CO<sub>2</sub>e in 2030. Also, relative to 2017, total emissions under the baseline scenario are projected to decrease by 21% by 2020, 13% by 2025, and 22% by 2030.

<b>Table 7.1-3 Point Sources from Figure 7.1-1</b>				
Plant	Partnering Facilities <sup>a</sup>	CO <sub>2</sub> e Baseline Emissions (TPY)	CO <sub>2</sub> e Cap (TPY)	CO <sub>2</sub> e Reduction (TPY) <sup>b,c</sup>
<b>1</b>	AES Hawaii, LLC Cogeneration Plant	1,681,605	1,412,548	269,057
<b>2</b>	Hamakua Energy, LLC Cogeneration Plant	182,975	153,699	29,276
<b>3</b>	Kalaeloa Partners, L.P. Cogeneration Plant	1,094,813	1,164,577	-69,764
	<b>Hawaiian Electric Company, Inc.:</b>			
<b>4</b>	Campbell Industrial Park Power Plant	14,946	123,504	-108,558
<b>5</b>	Kahe Power Plant	2,776,073	2,203,516	572,556
<b>6</b>	Honolulu Power Plant	133,609	0	133,609
<b>7</b>	Waiau Power Plant	1,074,359	878,050	196,309
	<b>Hawaii Electric Light Company, Inc.:</b>			
<b>8</b>	Kanoiehua-Hill Power Plant	222,784	172,456	50,328
<b>9</b>	Keahole Power Plant	191,387	242,208	-50,821
<b>10</b>	Puna Power Plant	99,691	31,747	67,944
	<b>Maui Electric Company, Ltd.:</b>			
<b>11</b>	Kahului Power Plant	230,839	154,633	76,206
<b>12</b>	Maalaea Generating Station	619,512	459,864	159,448
<b>13</b>	Palaau Power Plant	28,236	26,454	1,783

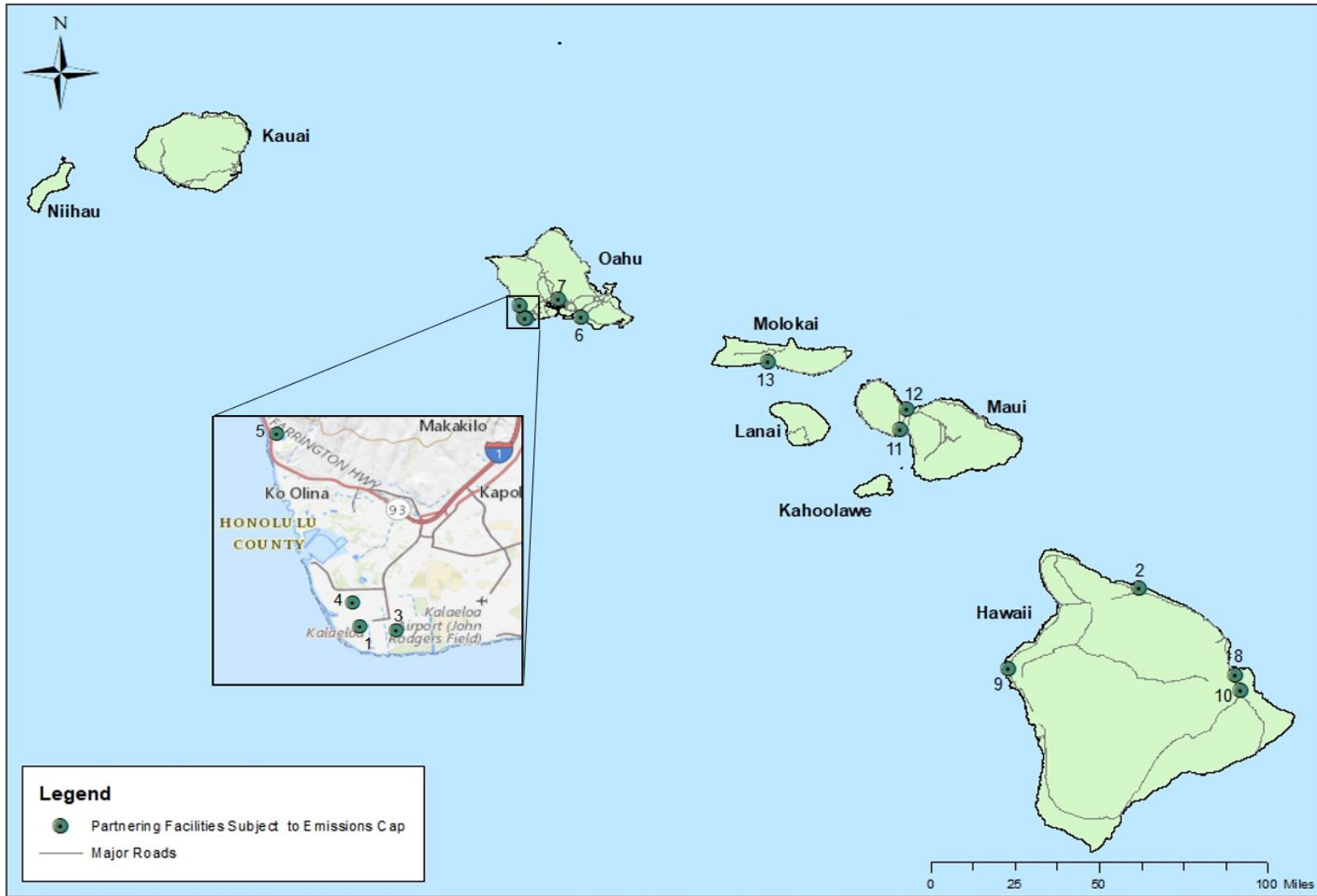
a. Based on Hawaiian Electric's proposed plan, revision date May 19, 2020.

b. A negative number for the reduction is an increase in emissions from the baseline level.

c. Total combined reduction for the facilities is a 16% reduction from the total combined baseline emissions.

<b>Table 7.1-4 Reductions in Visibility Impairing Pollutants after Capping GHGs from Thirteen (13) Partnering Facilities as a Co-benefit</b>				
Pollutant	Maximum Potential Emissions			
	Uncapped	Capped	Reduction	Reduction
	(TPY)	(TPY)	(TPY)	(%)
NO <sub>x</sub>	83,239	60,181	23,058	28%
SO <sub>2</sub>	58,029	31,573	26,456	46%
PM <sub>10</sub>	13,066	8,381	4,685	36%
Combined	154,334	100,135	54,199	35%

# Exhibit 2



**Figure 7.1-1** Partnering Facilities Subject to GHG Emission Reductions

## Exhibit 2

- d. Open Burning – 40 CFR 51.308(f)(2)(iv)(D): The State of Hawaii does not have a smoke management plan. Instead, planned open burning is regulated as codified in Hawaii Administrative Rules (HAR) §11-60.1 Subchapter 3 (Refer to Appendix O, Existing Requirements). Open burning includes agricultural, residential, and prescribed burning, and is prohibited with a few exceptions such as cooking, fire training, and agricultural burning with a valid permit. Other types of open burning require approval from DOH-CAB. Since January 2012, “backyard” burning of garbage and yard waste has been prohibited on all islands.

An Agricultural Burning Permit (AGP) program is administered for legitimate agricultural businesses to burn green waste (Refer to Appendix O, Existing Requirements, Subchapter 3, §11-60.1-54 to §11-60.1-58). For these businesses to burn green waste, they must obtain an AGP, which imposes conditions (e.g., notification requirements, location where burning is allowed, when burning may occur, what materials can be burned, and other limitations) to minimize visible smoke impacts to schools, highways, airports, and other sensitive areas. Further restrictions such as “No-Burn” periods may be imposed as deemed prudent in times of drought, or where other concerns may be prevalent.

Tables 7.1-5a and 7.1-5b summarize emissions from open burning and wildfires for the major islands in the state. Emissions were based on the National Emissions Inventory (NEI) for years 2014 and 2017 and emissions inventory data from the Hawaii State Department of Health Regional Haze Progress Report dated October 2017.<sup>32</sup> An NEI report is prepared and posted on EPA’s Air Emissions Inventories website on a three-year basis. The emissions inventory data for 2020 has not been released yet.

On Maui, Hawaiian Commercial and Sugar Company (HC&S) was the last sugar cane plantation in the state where AGPs were issued to burn cane. With the shut down of HC&S in 2016, no agricultural burning emissions have been reported in the 2017 NEI. However, an increase in wildfire events in 2019 and 2020, attributable primarily to dryer weather conditions, are a growing concern for all islands.

<b>Table 7.1-5a Emissions (TPY) from Open Burning and Wildfires</b>							
Year	County→	Maui Island			Hawaii Island		
	Source↓ Pollutant→	SO <sub>2</sub>	NO <sub>x</sub>	PM <sub>10</sub>	SO <sub>2</sub>	NO <sub>x</sub>	PM <sub>10</sub>
2005	Agricultural Burning	132	298	---	0	2	---
	Prescribed Burning	---	---	---	---	---	---
	Wildfires	14	52	---	469	1,712	---
	Sub – Total	146	350		469	1,714	
2008	Agricultural Burning	132	298	1,154	---	2	3
	Prescribed Burning	---	---	---	---	---	---
	Wildfires	---	---	---	---	---	---
	Sub – Total	132	298	1,154		2	3
2011	Agricultural Burning	132	298	1,154	---	2	3
	Prescribed Burning	10	88	219	26	297	630
	Wildfires	---	---	---	9	99	162
	Sub – Total	132	386	1,373	35	398	795

<sup>32</sup> <https://health.hawaii.gov/cab/files/2020/04/2017-Progress-Report.pdf>

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<b>Table 7.1-5a Emissions (TPY) from Open Burning and Wildfires (Continued)</b>							
Year	County→	Maui Island			Hawaii Island		
	Source↓ Pollutant→	SO <sub>2</sub>	NO <sub>x</sub>	PM <sub>10</sub>	SO <sub>2</sub>	NO <sub>x</sub>	PM <sub>10</sub>
2014	Agricultural Burning	197	359	583	---	---	---
	Prescribed Burning	42	560	872	487	5,529	13,096
	Wildfires	---	---	---	---	---	---
	Sub – Total	239	919	1,455	487	5,529	13,096
2017	Agricultural Burning	---	---	---	---	---	---
	Prescribed Burning	31	51	462	4	10	42
	Wildfires	---	---	---	35	79	350
	Sub – Total	31	51	462	39	89	392

<b>Table 7.1-5b Emissions (TPY) from Open Burning and Wildfires</b>							
	County→	Honolulu			Kauai		
	Source↓ Pollutant→	SO <sub>2</sub>	NO <sub>x</sub>	PM <sub>10</sub>	SO <sub>2</sub>	NO <sub>x</sub>	PM <sub>10</sub>
2005 NEI Report	Agricultural Burning	---	---	---	---	---	---
	Prescribed Burning	---	---	---	---	---	---
	Wildfires	---	---	---	---	---	---
	Sub – Total	---	---	---	---	---	---
2008 NEI Report	Agricultural Burning	---	---	---	---	---	---
	Prescribed Burning	---	---	---	---	---	---
	Wildfires	---	---	---	---	---	---
	Sub – Total	---	---	---	---	---	---
2011 NEI Report	Agricultural Burning	---	---	---	---	---	---
	Prescribed Burning	---	---	---	---	---	---
	Wildfires	---	---	---	---	---	---
	Sub – Total	---	---	---	---	---	---
2014 NEI Report	Agricultural Burning	---	---	---	---	---	---
	Prescribed Burning	5	65	119	---	---	---
	Wildfires	---	---	---	---	---	---
	Sub – Total	5	65	119	---	---	---
2017 NEI Report	Agricultural Burning	---	---	---	---	---	---
	Prescribed Burning	12	23	147	2	6	22
	Wildfires	4	9	37	5	11	46
	Sub – Total	16	32	184	7	17	68

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- e. **Sulfur Dioxide (SO<sub>2</sub>) Emission Caps:** The Hawaii's Regional Haze Federal Implementation Plan (RH-FIP) imposed a 3,550 TPY SO<sub>2</sub> combined emissions cap on five (5) boilers at three (3) of the Hawaii Electric Light Company, Inc.'s power plants located on the island of Hawaii. This combined emissions cap was incorporated into the air permits for two of the three power plants and two boilers located at the third power plant were retired prior to implementation of the combined emissions cap. The impact of implementing the combined SO<sub>2</sub> emissions cap on the five (5) boilers is illustrated in Table 7.1-6 that shows maximum potential SO<sub>2</sub> emissions in comparison to the cap.

<b>Table 7.1-6 Boilers Subject to the SO<sub>2</sub> Total Emissions Cap</b>			
Plant	CSP No.	Emission Unit	SO <sub>2</sub> Emissions (TPY)
Kanoelehua-Hill	0234-01-C	14.1 MW Boiler Hill 5	1,899
		23 MW Boiler Hill 6	2,400
Puna	0235-01-C	15.5 MW Boiler	2,399
Shipman <sup>a</sup>	0236-01-C	7.5 MW Boiler	1,118
		7.7 MW Boiler	1,134
Total Potential SO <sub>2</sub> Emissions from five (5) Boilers Without Cap			8,950
Total SO <sub>2</sub> Emissions with Cap			3,550
Total Reduction in Potential SO <sub>2</sub> Emissions			5,400

a. Boilers are now retired.

- f. **Motor Vehicle Regulations:** HAR §11-60.1-34 prohibits motor vehicles from discharging visible smoke while in operation (operating while the vehicle is stationary or moving) and removing or failing to maintain air pollution devices of a motor vehicle, subject to certain exceptions and conditions.

### **7.2 Ongoing Air Pollution Control Programs under Federal Regulations – 40 CFR §51.308(f)(2)(iv)(A)**

- a. **Volkswagen (VW) Settlement:** VW was charged with selling approximately 590,000 model year 2009 to 2016 diesel motor vehicles equipped with computer “defeat devices”. This enabled falsified emissions testing results thus causing these vehicles to be non-compliant with the Clean Air Act (CAA) emission limits, with a primary concern for emissions of NO<sub>x</sub>. Under the settlements, VW agreed to establish a \$2.925 billion Environmental Mitigation Trust for its beneficiaries to pursue alternative transportation projects intended to fully mitigate the total excess NO<sub>x</sub> emitted by the non-compliant VW vehicles. As an eligible beneficiary, the State of Hawaii has been allocated \$8.125 million, which in part, is helping the Hawaii State Energy Office (HSEO) in developing the following<sup>33</sup>:
- i. A statewide Vehicle Assistance Program (VAP) for the purpose of offering financial assistance to private and/or public vehicle owners looking to medium/heavy duty vehicle or engine with clean alternative. HSEO plans to initially focus the VAP on rebates for medium and heavy-duty buses and trucks,

<sup>33</sup> <https://energy.hawaii.gov/vw-settlement/vw>

## Exhibit 2

- while recognizing that the program may need to evolve in response to market demand and economic conditions including disruptions such as COVID-19.
- ii. Solicitations were opened by the City and County of Honolulu for two heavy duty low floor battery electric buses to replace two older diesel buses for city transit services dedicated to a loop of downtown medical facilities. These buses will service an area that could benefit roughly 20,000 residents and are estimated to reduce 0.997 tons of NO<sub>x</sub> emissions annually.
  - ii. In addition, VW will pay for penalties, customer vehicle buyback, modification programs and invest \$2 billion over the next 10 years in zero emission vehicle infrastructure and education projects across the United States, which could possibly include Hawaii. Washington and Hawaii both earned a top-of-the-class A+ for spending as much as the settlement allowed on electric vehicle charging infrastructure and electrified mass transit buses and ferries.<sup>34</sup>
- b. Federal Regulations: The following existing federal regulations were previously implemented to control emissions of air pollutants that adversely impacts visibility and were determined to be applicable to one (1) or more of the seven (7) point sources initially selected for conducting a four-factor analysis:
- i. 40 CFR Part 50: Establishes the National Primary Ambient Air Quality Standards for NO<sub>x</sub>, SO<sub>2</sub>, PM<sub>10</sub>, PM<sub>2.5</sub>, and lead (Pb). An 8,610 gallon per hour consumption limit for Boiler K-6 was imposed onto the Kahe Generating Station to comply with the ambient air quality standards for SO<sub>2</sub>.
  - ii. 40 CFR Part 52.21(b): Establishes provisions for the Prevention of Significant Deterioration (PSD) of Air Quality. The requirements apply to the construction of any new major stationary source or any major modification at an existing major stationary source in an area designated as attainment or unclassifiable. The following control measures at the respective facilities were imposed by PSD permits:
    - Boiler K-6 at the Kahe Generating Station is subject a limit on its heat input rate of 433.5 MMBtu/hr, together with a 600 hr/yr operating limit, to keep NO<sub>x</sub> below the 40 ton per year PSD emissions threshold for BACT review. Also, PSD conditions in the permit imposes a 0.30 lb/MMBtu limit for controlling NO<sub>x</sub> during startup and 0.23, 0.53, and 0.10 lb/MMBtu limits during normal operations to control NO<sub>x</sub> (for other than startup), SO<sub>2</sub>, and PM, respectively.
    - Combustion turbines CT1 and CT2 at Kalaeloa Cogeneration Plant are subject to this same regulation, which imposes a NO<sub>x</sub> emissions limit of 130 ppmvd (483 lbs/hr), a fuel sulfur content limit of 0.5 percent maximum by weight, and a sulfur dioxide emission limit of 98 ppmvd.
  - iii. 40 CFR Part 60, Subpart D Standards of Performance for New Stationary Sources (NSPS) for Fossil-Fuel-Fired Steam Generators with capacity greater than 73 MW (250 MMBtu/hr) and the unit commenced construction after August 17, 1971: Boiler K-6 at the Kahe Generating Station is subject to this federal regulation, however, the PSD emission limits are either equivalent or more stringent and therefore no added benefit to visible impairment is expected.

<sup>34</sup> Volkswagen Settlement State Scorecard dated May 2019 at <https://uspirg.org/reports/usp/volkswagen-settlement-state-scorecard>.

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- iv. 40 CFR Part 60, Subpart GG NSPS for Stationary Gas Turbines is applicable to stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules/hr (10 MMBtu/hr), but less than or equal to 107.2 gigajoules/hr (100 MMBtu/hr), based on the lower heating value of the fuel fired and any facility which commences construction, modification, or reconstruction after October 3, 1977. The combustion turbines, CT1 and CT2, at Kalaeloa Cogeneration Plant are subject to this this federal regulation, however, since the PSD NO<sub>x</sub> emissions limit of 130 ppmvd (483 lbs/hr) is more stringent, no added benefit to visible impairment is expected.
- v. 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants (NESHAP) is applicable to stationary reciprocating internal combustion engines (RICE) at a major or area source of hazardous air pollutant (HAP) emissions. 40 CFR §63.6604(a) requires all existing non-emergency, non-black start stationary RICE at Kanoelehua-Hill and Maalaea Generating Stations, with a site rating of more than 300 brake hp and a displacement of less than 30 liters per cylinder, to operate on ultra-low sulfur diesel (ULSD) in accordance with 40 CFR §80.510(c). Emergency stationary RICE at area sources of HAP are not subject to this federal regulation if equipment meets 40 CFR §63.6585(f). However, 40 CFR §63.6603(a) requires that the air cleaner for the black start stationary compression ignited RICE at the Puna Generating Station, be inspected every 1,000 hours of operation or annually, whichever comes first, and replaced as necessary to comply with the requirements in Table 2d to Subpart ZZZZ.
- vi. 40 CFR Part 63, Subpart JJJJJJ, NESHAP applies to Industrial, Commercial, and Institutional Boilers at Area Sources of HAP. The following control measures at the respective facilities are required by Subpart JJJJJJ:
  - At the Kahului Generating Station, the 11.5 MW, 12.5 MW boilers, and the two (2) 5.0 MW boilers are subject to ongoing tune-ups every 5 years as specified in 40 CFR §63.11223;
  - At the Kanoelehua-Hill Generating Station, the 14.1 MW & 23 MW boilers are equipped with oxygen trim systems and are subject to ongoing tune-ups every five (5) years as specified in 40 CFR §63.11223.
  - At the Puna Generating Station, the 15.5 MW boiler is equipped with an oxygen trim system and is subject to ongoing tune-ups every five (5) years as specified in 40 CFR §63.11223.
- vii. 40 CFR Part 63, Subpart UUUUUU, NESHAPs: Coal- and Oil-Fired Electric Utility Steam Generating Units is applicable to boiler units that meet the definition of an electric utility steam generating unit (EGU). An EGU means any fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. Pursuant to 40 CFR §63.999, the following boilers were required to meet the emission limits for filterable PM or HAP metals (total combined or individual limits) and the work practice standards by April 16, 2015:
  - Kahe Generating Station – Boilers K-1 through K-6; and
  - Waiau Generating Station – Boilers 3 through 8.



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### 7.3 Construction Activity Mitigation – 40 CFR 51.308(f)(2)(iv)(B)

- a. Rules of General Conformity: HAR §11-60.1-33(a) and §11-60.1-192(a) establishes rules and citations that prohibits and enforces any person(s) from causing visible fugitive dust to become airborne when engaged in activities such as construction without taking reasonable precaution. Examples of reasonable precautions are:
- i. Use of water or suitable chemicals for control of fugitive dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of land;
  - ii. Application of asphalt, water, or suitable chemicals on roads, material stockpiles, and other surfaces which may result in fugitive dust;
  - iii. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials. Reasonable containment methods shall be employed during sandblasting or other similar operations;
  - iv. Covering all moving, open-bodied trucks transporting materials which may result in fugitive dust;
  - v. Maintenance of roadways in a clean manner; and
  - vi. Prompt removal of earth or other materials from paved streets which have been transported there by trucking, earth-moving equipment, erosion, or other means.

HAR §11-60.1-33(b) and §11-60.1-192(a) further prohibits and enforces any person from discharging visible fugitive dust beyond the property lot line on which the fugitive dust originates. Exceptions from this rule are persons engaged in agricultural operations or persons who can demonstrate to the director that the best practical operation or treatment is being implemented. HAR §11-60.1-34(c) prohibits any person(s) from exhausting emissions from idling vehicles and equipment in operation while the motor vehicle is stationary. Exception to this rule is equipment being operated as originally designed and intended, however, no visible discharge of smoke is allowed. Examples of this includes operation of ready-mix trucks, cranes, hoists, and certain bulk carriers, or other auxiliary equipment built onto the vehicle or equipment that require power take-off from the engine.

- b. Rules Specific to Persons Requiring a Permit: HAR §11-60.1-62 and 11-60.1-82 implement rules that determine which person(s) and activities are required to obtain a state or federally enforceable permit. Construction activities requiring to be permitted are subject to additional state and federal requirements that are beyond the general rules of conformity. Person(s) or activities not in compliance shall be subject to enforcement action(s) pursuant to HAR f§11-60.1-192(a) for operating without a permit.

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### 7.4 Source Retirements – 40 CFR 51.308(f)(2)(iv)(C)

- a. Hawaiian Electric: Hawaiian Electric's Power Supply Improvement Plan (PSIP) of 2016 <sup>35</sup> was developed with the support of the Energy + Environment Economics (E3) to meet the 100% renewable portfolio standard (RPS) goal by 2045. The E3 used a renewable energy solutions model (RESOLVE) to develop several least cost expansion plans for the islands of Oahu, Maui and Hawai'i.

As the State of Hawaii moves toward meeting the 100% RPS goal, conventional generating units are being replaced with sources of renewable energy. Historically, steam units provided the bulk of the energy needs. Gas turbines and combined cycle resources were incorporated into the system, which are more flexible and efficient than steam units. The operational flexibility of gas turbines makes it better suited for supporting renewable sources with high variable energy production rates, such as solar PV systems and wind. As opposed to steam units, gas turbines are able to start quickly, ramp up and down at high rates, and start and stop multiple times a day. Due to its higher efficiency, gas turbines potentially can offset higher fuel cost and reduce overall production cost and emissions of air pollutants. However, gas turbines can also increase production cost depending on the difference in fuel and maintenance cost between steam units and gas turbines.

At the time the Hawaiian Electric's 2016 PSIP was issued, steam units remained in active operation because the cost of the fuel used in the steam units resulted in lower production cost. However, if and when the fuel economics change to where it is no longer cost-effective to operate, the steam units will be removed from service. Therefore, the scheduled removal dates of these fossil fuel units may be adjusted based on further optimization taking into account actual fuel costs and resource availability at the time of the decision, and on the timing of proposed renewable energy and firm dispatchable additions. A case-by-case evaluation will determine whether an existing unit will be immediately retired, deactivated, used for seasonal cycling, or kept operational. The goal is to manage these assets in a manner that provides maximum value for customers.

Table 7.4-1 on the next page shows schedules of fossil fuel units that have been and are under consideration for removal from service on the islands of Oahu, Hawaii, and Maui according to Hawaiian Electric's PSIP. However, according to Hawaiian Electric, the actual schedules for retiring these units have not been firmly established.

<sup>35</sup> <https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/power-supply-improvement-plan>

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Table 7.4-1 Hawaiian Electric Emission Reductions from Unit Shut Downs				
Year	Facility	Description of Unit(s) Planned to be Removed from Service	Total Combined Emissions Reduced 2017 Inventory (TPY) <sup>a</sup>	
			NO <sub>x</sub>	SO <sub>2</sub>
2020	HECO Waiiau Generating Station	49 MW Boiler Unit 3	64.85	89.92
		49 MW Boiler Unit 4	95.51	92.84
		57 MW Boiler Unit 5	366.70	280.51
		Total→	<b>527.06</b>	<b>463.27</b>
2022	AES Hawaii, LLC Cogeneration Plant <sup>b</sup>	Boiler A	331.22	199.72
		Boiler B	363.36	230.52
		Limestone Dryer A	<0.001	<0.001
		Limestone Dryer B	<0.11	<0.001
		Total→	<b>694.69</b>	<b>430.24</b>
2022	HECO Kahe Generating Station	92 MW Boiler Unit 1	932.72	841.79
		90 MW Boiler Unit 2	962.95	659.5
		92 MW Boiler Unit 3	661.7	836.26
		93 MW Boiler Unit 4	732.18	859.83
		Total→	<b>3,289.55</b>	<b>3,197.38</b>
2020	HELCO Kanoelehua - Hill Generating Station	14 MW Boiler Unit 5	251.54	820.55
		23 MW Boiler Unit 6	353.62	1,346.62
		Total→	<b>605.16</b>	<b>2,167.17</b>
2020	HELCO Puna Generating Station	20 MW Unit CT-3	6.82	2.88
		15.5 MW Boiler Unit Boiler	22.71	183.96
		Blackstart Generator	0.008	0.0001
		Total→	<b>29.54</b>	<b>186.84</b>
2022	HECO Waiiau Generating Station	58 MW Boiler Unit 6	340.49	344.14
		92 MW Boiler Unit 7	839.47	814.35
		92 MW Boiler Unit 8	491.02	672.45
		Total→	<b>1,670.98</b>	<b>1,830.94</b>
2024	MEGO Kahului Generating Station	5.0 MW Boiler Unit 1	65.83	293.14
		5.0 MW Boiler Unit 2	62.30	253.29
		11.5 MW Boiler Unit 3	292.63	898.54
		12.5 MW Boiler Unit 4	182.68	775.81
		Total→	<b>603.44</b>	<b>2,220.78</b>

a. Emissions reported for units in the State and Local Emissions Inventory System (SLEIS) for operating year 2017.

b. AES Hawaii LLC permit was amended on October 27, 2020, to incorporate GHG emission cap and provision to cease the burning of coal by December 31, 2022 in accordance with Hawaii Act 023 (September 15, 2020).

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- b. Kaua'i Island Utility Cooperative (KIUC): KICU did not include any plans for retiring fossil fuel units in their 2018 annual RPS Status Report to the PUC. However KIUC's 2019 Annual Report<sup>36</sup> stated that a diesel generator, located at the Kapaia Power Station, was upgraded to run as a synchronous condenser. That means the engine can run with little or no fuel to provide inertia, fault current, voltage support and frequency stabilization to the grid. This is especially important given the intermittent nature of solar PV systems and hydro power sources.

In addition, more than 56 percent of the electricity generated in 2019 on Kauai came from a mix of renewable resources, such as solar, hydropower and biomass, which exceeds the State's RPS 2020 target of thirty percent (30%). KIUC's progress towards 100% renewable energy as evidenced from its initial unveiling of the world's first utility-scale solar plus battery storage generation facility in March 2017 to other renewable projects is illustrated in Figure 7.4-1 taken from KIUC's 2019 Annual Report. Based on KIUC's current rate of progress and potential renewal energy projects planned towards meeting the State's energy goal, it is anticipated that existing fossil fueled units will inevitably be retired and/or upgraded.

<sup>36</sup> [https://website.kiuc.coop/sites/kiuc/files/documents/annualreport/AnnualReport19\\_web.pdf](https://website.kiuc.coop/sites/kiuc/files/documents/annualreport/AnnualReport19_web.pdf)

# Exhibit 2



**Figure 7.4-1** KIUC Total Renewable Energy in Service in 2019 and Potential Renewable Energy in Service in 2025

## Exhibit 2

### 7.5 Further Controls on Sources (Permitting for 2018 - 2028 Planning Period)

a. Projected Changes in Point Source Emissions – 40 CFR 51.308(f)(2)(iv)(E): Section II.B.3 of EPA’s Guidance on Regional Haze State Implementation Plans states, “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.”<sup>14</sup> This section describes the process and criteria used to select point sources of anthropogenic emissions of NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>10</sub> with the greatest potential impact on visibility impairment on Class I areas in the State of Hawaii for analysis of additional emission control measures. This section further describes how point sources are evaluated using statutory factors to characterize and determine what control measures are necessary to make reasonable progress over the 2018 - 2028 planning period.

1. Initial Source Screening: The initial screening method used to identify point sources with reasonably large potential for contributing to visibility impairment at each Class I area was based on the total combined ton per year emissions (Q) of nitrogen oxide (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), and particulate matter less than ten (10) microns (PM<sub>10</sub>) divided by the distance (d) from the Class I area in kilometers or Q/d. Point sources with Q/d exceeding 10 tpy/km were requested to perform a four-factor analysis. The following facilities were identified to have exceeded this threshold:

- Kalaeloa Partners, L.P. Power Plant (Island of Oahu)
- Kahe Power Plant (Island of Oahu)
- Waiau Power Plant (Island of Oahu)
- Kanoelehua-Hill Power Plant (Island of Hawaii)
- Puna Power Plant (Island of Hawaii)
- Kahului Power Plant (Island of Maui)
- Maalaea Power Plant Island of Maui)

A full description of the method used, and the sources selected during the initial screening process is covered in Chapter 5.

2. Four-Factor Analysis: The first step in characterizing was to identify technically feasible control measures for pollutants that contribute to visibility impairment, i.e., NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>10</sub>. Technically feasible control measures were further characterized and evaluated using the following four regulatory factors pursuant to 40 CFR §51.308(f)(2)(i):

- The cost of compliance;
- The time necessary to achieve compliance;
- The energy and non-air quality environmental impacts of compliance; and
- The remaining useful life of any existing source subject to such requirements.

*Cost of Compliance*: A driving factor in selecting reasonable control measures is the facility’s cost of compliance, which is the “cost effectiveness” or the dollar cost per tons of pollutant removed. Where a control measure, such as fuel switch, impacted multiple pollutants, emissions were combined in performing these calculations.

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Capital cost or capital investment associated with a technically feasible control measure is annualized by amortization or is converted to an equivalent uniform annual cost (EUAC) using the nominal interest rate and the useful life of the equipment as described in EPA's Air Pollution Control Cost Manual and in Chapter 6. The facility's annualized capital cost is then combined with the increase in the facility's annual operating and maintenance cost associated with the control measure under evaluation. This includes differences in fuel cost, and additional cost to inspect, test, and repair equipment needed for implementing the control measure. The combined annual cost is then divided by the estimated tons of pollutants removed per year.

*Time necessary to achieve compliance:* Compliance schedules may be used as a measure for making reasonable progress pursuant to Section II.B.5.e) of EPA's Guidance on Regional Haze State Implementation Plans.<sup>14</sup> Characterizing the time necessary for compliance involves estimating the time needed for a source to comply with a potential control measure, which may be based on prior experiences with planning and installation of new emission controls. However, Section II.B.4. d) of EPA's Guidance also recommends that states consider source specific factors where appropriate and states, "there is no requirement in the Regional Haze Rule that emission control measures that have been determined to be necessary to make reasonable progress must be installed as expeditiously as practicable or within 5 years of EPA's approval of the SIP revision." Section II.B.5. e) of the EPA's Guidance further states, "The state may establish a compliance deadline that provides reasonable time for an affected source to come into compliance in an efficient manner, without unusual amounts of overtime, above-market wages and prices, or premium charges for expedited delivery of control equipment".<sup>14</sup> An appropriate source specific factor to consider is the State of Hawaii's RPS which mandates the transitioning of companies that generate and sell electricity for consumption from using fossil fuels to renewable sources. Hawaiian Electric's PSIP provides a tentative schedule to retire specific point sources, however, past experience has demonstrated unexpected delays for some of the past renewable projects, which are attributable to factors that are not completely within Hawaiian Electric's control, including the PUC approvals. Therefore, extending the time of compliance provides a more flexible schedule to proceed in an efficient manner by aligning Hawaiian Electric's current efforts with realizing the RPS goal, including the retirement and lower utilization of some of these facilities' commitment without incurring unreasonable additional cost.

*Energy and Non-Air Quality Environmental Impacts of Compliance:* Section II.B.5. c) of the EPA's Guidance, EPA recommends that states consider energy impacts by accounting for any increase or decrease in energy use at the source as part of the costs of compliance.<sup>14</sup> EPA also recommends that states consider relevant non-air quality environmental impacts, such as water usage or waste disposal of spent catalyst or reagent, by accounting for them as part of the costs of compliance. Fuel switching from residual oil to ULSD may have an energy impact in both the fuel refining and fuel combustion processes, however, Section II.B.4. e) of EPA's Guidance recommends that states focus their analysis on direct energy consumption at the source rather than indirect energy inputs needed to produce raw materials.<sup>14</sup>

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Therefore, energy impacts are accounted for by including the annual fuel cost difference and the annualized capital cost of atomization to improve fuel combustion efficiency within the cost of compliance. The lower viscosity of ULSD can have non-air quality environmental impacts in the event of inadvertent or accidental spills and therefore, the capital cost of installing secondary containments to comply with EPA's Spill Prevention, Controls, and Countermeasures (SPCC) requirements is also included as an annualized cost of compliance.

Combustion controls do not have non-air quality environment impacts; however, improper feed rate of OFA can result in heat loss and decreased boiler efficiency.

*Remaining useful life of equipment:* In the situation of an enforceable requirement for the source to cease operation before the end of the useful life of the controls under consideration, EPA guidance allows the use of an enforceable shut down date as the end of the remaining useful life. If no enforceable shut down date exists for units requiring controls, the remaining useful life is the full useful life of the control under consideration. Useful life of the equipment with the nominal interest rate are used to convert capital cost or capital investment associated with a technically feasible control measure as an annualized cost used in determining the cost of compliance and is described further in Chapter 6 of this RH-SIP

3. Photochemical Modeling: EPA's photochemical modeling platform, incorporates meteorology, emissions, and air quality modeling, and is used to further develop the photochemical grid modeling or the Comprehensive Air quality model with extensions (CAMx). The CAMx provides the 2016 baseline and 2028 emission projections which enables users to evaluate reasonable progress goals at IMPROVE sites representing individual Class I areas for regional haze. These modeling programs are also capable of estimating contributions of anthropogenic emissions from international sources thus providing a means for comparing projections to both the unadjusted and adjusted reasonable progress goals. A description of this is covered in Chapter 8.
4. Weighted emissions potential (WEP)/Area of Influence (AOI): Western Regional Air Partnership (WRAP) with RAMBOLL developed this modeling platform by incorporating Residence Time (RT), Area of Influence (AOI), and Extinction Weighted Residence Time (EWRT) analysis, with back trajectories generated from the HYSPLIT modeling program. The HYSPLIT simulates 72-hour (3-day) back trajectories, which are the wind travel paths arriving at the IMPROVE monitoring sites on the Most Impaired Days (MID) at four different times a day and at four (4) different elevations. IMPROVE observations that represent Class I areas in Hawaii for the 5-year period of 2014 to 2018 were used for this analysis. The RT analysis provides an Area of Influence (AOI) or amount of time a back trajectory to a Class I area on the MIDs passes over a grid cell. The EWRT is developed from the RT weighted by the measured extinction by species (i.e., pollutant). For each point source, the Rank Point files are developed to show the WEP of each facility using facility-specific Emissions (Q) with the EWRT for each species divided by the Distance (d) between the point source and the IMPROVE monitoring site. The WEP data is used to determine the potential contributions of each point source to visibility impairment at each Class I area based on the MIDs. The WEP ranking, which is based on a more



## Exhibit 2

sophisticated and refined analysis for selecting facilities, shows a combined contribution of less than 1.5% of the total contributions of all Oahu facilities excluding airports. Therefore, the Oahu facilities identified on the initial screening were removed, however, Mauna Loa Macadamia Nut Corporation Plant with contribution as high as 9.16% was added to the list. Since the WEP/AOI analysis focus is on the MIDs, a supplemental analysis was conducted to examine all potential back trajectories from the 2015 to 2019 raw wind rose data for the Daniel K. Inouye International Airport (fka Honolulu International Airport). Due to the predominant trade wind patterns that exist in the State of Hawaii and the location of the Oahu facilities relative to the Class I areas, contributions from these facilities were estimated to be 0.06% of the total occurrences to the daily light extinction. A full description of the WEP analysis and refinements made from the initial screening and source selection are covered in Chapter 5 of this RH-SIP.

5. Establish a Reasonable Cost Threshold: A control cost threshold of \$5,800/ton of pollutant removed was established and used as guidance for the selection of cost-effective control measures for establishing the reasonable progress goals. A full description of relevant factors used to develop this threshold is covered in Chapter 6 of this RH-SIP.

In letters dated March 30, 2021 and June 16, 2021, new information was provided by Hawaiian Electric that was not included in four-factor analyses from Chapter 6. This included the need to install secondary containment liners and fuel atomization systems to accomplish boiler fuel switches to ULSD, documentation to support Hawaiian Electric's claim that 7% is the nominal interest rate, new remaining useful life assumptions, and revised construction cost multiplier of 1.2. Please refer to Appendix P for additional details. DOH-CAB reviewed the information and revised assumptions, as applicable, to align with EPA and NPS guidance for performing the cost analysis. Changes included an interest rate of 6.56% for Hawaii Island sources, interest rate of 5.31% for Maui Island sources, a 25-year life for fuel atomization systems and tank containment liners instead of a 20-year life, and a construction cost multiplier of 1 instead of 1.2.

Regional haze control measures that are necessary to make reasonable progress, as well as the associated monitoring, recordkeeping and reporting requirements, are made practically and federally enforceable by being incorporated into the facilities air permits, using a Significant Modification to Incorporate Regional Haze Controls. Hawaiian Electric committed to an enforceable shut down of boilers at the Kahului and Kanoiehua-Hill Generating Stations by 2028. Covered Source Permit (CSP) 0232-01-C, provided in Appendix P, was amended to incorporate regional haze controls for Kahului Generating Station. CSP No. 0234-01-C, provided in Appendix P, was amended to incorporate regional haze controls for the Kanoiehua-Hill Generating Station. EPA regional haze guidance dated August 20, 2019, Section II.B.3.e allows states to consider one or more of five additional factors when it selects sources for analysis.

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The Puna and Maalaea Generating Stations were re-evaluated to determine reasonable control measures based on new information provided by Hawaiian Electric. CSP 0235-01-C, provided in Appendix P, was amended to incorporate regional haze controls and associated monitoring, recordkeeping and reporting requirements for Puna Generating Station. Due to the greater complexity of determining regional haze controls for Maalaea Generating Station, federally enforceable limits will be provided in supplemental documents as an RH-SIP revision for this facility.

Emission control measures were found to be infeasible for some units. EPA's August 2019 Regional Haze Guidance requires emission limits to be included for sources for which added emission controls are not feasible due to a four-factor analysis. However, the guidance further states that if a source that has been selected for analysis of emission control measures has recent actual emissions below its permitted levels, for example due to voluntary operation restrictions, and the state reasonably projects that this situation will continue through 2028 based on the best available information, a state can reasonably conclude based on appropriate considerations that requiring the source to abide by an emission limit is not a measure that is necessary to make reasonable progress. Historical data on these units from 2011 to 2020 show that they have consistently operated below their potential to emit (PTE) emissions listed in their air permits and will emit even less in future years to comply with Hawaii's Renewable Portfolio Standard (RPS) requirements. Hawaiian Electric's RPS commitment is to reach 70 percent electricity generation from renewable sources by 2030. In 2020, Hawaiian Electric produced 36 percent of their electricity from renewable sources, providing the reasonable assumption that they will need to restrict unit operating hours even more to attain their 2030 commitment. Historical emissions for the selected Hawaiian Electric facilities are provided in Appendix Q.

Appendix P also provides details of the revised cost analyses for the facilities screened in Chapter 5. Tables 7.5-1 and 7.5-2 provide revised costs for the control measures selected in Chapter 6 that are shown in Table 6.1-2 for the Puna Generating Station and Table 6.1-4 for the Maalaea Generating Station. The cost per ton of pollutant removed, highlighted in green in Tables 7.5-1 and 7.5-2, are the costs after changes were made to worksheets by DOH-CAB to align with EPA and NPS guidance.

<b>Table 7.5-1 Four-Factor Analysis for Hawaii Electric Light Puna Power Plant Hawaii</b>			
Unit	Description	Primary Fuel	Control Measure & Cost per Ton <sup>a</sup>
Boiler	15.5 MW Boiler	Fuel Oil No. 6 with 2.0% maximum sulfur content	Fuel switch to ULSD with 0.0015% sulfur content + ULSD atomization + secondary tank containment liners - \$5,983 (\$5,804)/ton SO <sub>2</sub> , NO <sub>x</sub> , and PM <sub>10</sub> for Boiler

- a. Hawaiian Electric assumed a 7% interest rate and 20-year life for atomization and tank containment liners. DOH-CAB assumed a 6.56% interest rate and 25-year life for atomization and tank containment liners. DOH-CAB assumed a construction cost multiplier (retrofit factor) of 1 instead of 1.2.

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<b>Table 7.5-2 Four-Factor Analysis for Maui Electric Maalaea Power Plant Maui</b>			
Unit	Description	Primary Fuel	Control Measure & Cost per Ton <sup>a</sup>
M1	2.5 MW DEG	ULSD	FITR for M1 - \$4,159 (\$3,629)/ton NO <sub>x</sub> FITR for M2 - \$7,173 (\$6,257)/ton NO <sub>x</sub> FITR for M3 - \$4,159 (\$3,629)/ton NO <sub>x</sub> SCR for M7 - \$6,162 (\$5,977)/ton NO <sub>x</sub>
M2	2.5 MW DEG	ULSD	
M3	5.6 MW DEG	ULSD	
M7	5.6 MW DEG	Diesel Fuel Oil No. 2 with 0.4% maximum sulfur content	

a. Hawaiian Electric assumed a 7% interest rate for FITR and SCR. DOH-CAB assumed a 5.31% interest rate for controls.

The cost of installing FITR for M1, M2, and M3 at the Maalaea Generating station ranges from \$3,629/ton for M1 and M3 to \$6,257/ton for M2. The cost of FITR for M1 and M3 is below the \$5,800/ton threshold. The cost of FITR is above the threshold for M2; however, this cost is close to the \$5,800/ton threshold floor. Therefore, the DOH-CAB considers the installation of FITR for M1, M2, and M3 a cost-effective control measure.

The cost of installing SCR for M7 of \$5,977/ton is close to the \$5,800/ton threshold floor. Therefore DOH-CAB considers installation of SCR for M7 at Maalaea Generating Station a cost-effective control measure.

On January 14, 2022, Hawaiian Electric provided information that the proposed monitoring of NO<sub>x</sub> with a continuous emissions monitoring system (CEMS) for Maalaea Generating Station M1, M2, and M3 will result in a high cost for these units that run very little. It was indicated that the units are used as quick response during wind variability and are therefore kept offline as much as possible. Total hours of operation between January 2020 and December 2020 ranged from 121 hours for M2, to 177 hours for M3, to 194 hours for M1.

On January 25, 2022, Hawaiian Electric provided information that the estimated capital expense of a CEMS for M1, M2, and M3 is \$235,000 for each unit and the estimated annual operation and maintenance expense is \$43,000 per unit.

The DOH-CAB randomly contacted CEMS manufactures to determine the typical price for installing and operating a CEMS (e.g., \$5,000 for sample probe + \$5,000 for sample line (100 ft at \$50/ft) + \$10,000 for sample conditioning system + \$13,000 for NO<sub>x</sub> analyzer + \$7,000 for O<sub>2</sub> analyzer + \$10,000 for rack + \$50,000 for shelter + \$20,000 for programable logic controller in rack + (\$15,000 + \$5,000 + \$5,000)/3 for initial RATA testing + (\$15,000 + \$5,000 + \$5,000)/3 for technician to start up = \$136,667). Operation and maintenance expenses were also checked (e.g., (\$15,000 + \$5,000 + \$5,000)/3 for RATA testing + (\$15,000 + \$5,000 + \$5,000)/3 for startup + (20% x \$70,000/3) for technician to calibrate = \$21,334).

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Hawaiian Electric’s control cost worksheets were updated to account for the additional costs to install and operate a CEMS for M1, M2, and M3 at Maalaea Generating Station. A capital cost of \$235,000 for installing a CEMS was added to the existing capital cost of FITR for each unit based on Hawaiian Electric’s numbers. An additional \$43,000 was added to the annualized capital cost for yearly operation and maintenance of each CEMS based on numbers from Hawaiian Electric. DOH-CAB’s costs were based on a \$136,667 capital cost of installing a CEMS and \$21,334 cost for operation and maintenance. Costs estimated by DOH-CAB are highlighted in green in Table 7.5-3 for installing and operating a CEMS for M1, M2, and M3.

<b>Table 7.5-3 Four-Factor Analysis for Maui Electric Maalaea Power Plant Maui</b>			
Unit	Description	Primary Fuel	Control Measure & Cost per Ton <sup>a,b</sup>
M1	2.5 MW DEG	ULSD	FITR + CEMS for M1 - \$16,100 (\$10,147)/ton NO <sub>x</sub>
M2	2.5 MW DEG	ULSD	FITR + CEMS for M2 - \$27,759 (\$17,495)/ton NO <sub>x</sub>
M3	5.6 MW DEG	ULSD	FITR + CEMS for M3 - \$16,100 (\$10,147)/ton NO <sub>x</sub>

a. Hawaiian Electric assumed a capital cost of \$235,000 and an operation and maintenance cost of \$43,000.

b. DOH-CAB assumed a capital cost of \$136,667 and an operation and maintenance cost of \$21,334.

The cost of installing FITR plus CEMS for M1, M2, and M3 at the Maalaea Generating Station ranges from \$10,147/ton for M1 and M3 to \$17,495/ton for M2. The cost of FITR plus CEMS is considered to be too far above the \$5,800/ton threshold. Therefore, installing a CEMS is not cost-effective. As such, DOH-CAB will specify annual source testing to determine compliance with the NO<sub>x</sub> emissions limit for FITR servicing M1, M2, and M3.

After further review of the four-factor analysis for the Maalaea Generating Station to address comments from the FLMs, the DOH-CAB determined that the four-factor analysis for this facility is incomplete. Therefore, additional review to determine potential control measures for the Maalaea Generating Station will be addressed in an RH-SIP revision.

As part of the long-term strategy, 40 CFR §51.308(f)(2) requires enforceable emission limitations, compliance schedules, and other measures necessary to make reasonable progress be clearly stated. Point sources re-evaluated based on the new information are identified with cost effective control measures (based on the four-factor analyses) and compliance schedule dates are stated in Table 7.5-4. DOH-CAB will incorporate the regional haze provisions into permits for these sources as follows (please refer to Appendix P for details):

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<b>Table 7.5-4 Cost Effective Control Measures and Compliance Schedules</b>							
Facility <sup>a</sup>	Unit	Unit Nos.	Shut Down	Fuel Switch	SCR	LNB w/ OFA/FGR	FITR
Kanoelehua-Hill	Boilers	Hill 5&6	12/31/27	--	--	--	--
Puna	Boiler	--	--	See note <sup>b</sup>	--	--	--
Kahului	Boilers	K1, K2, K3, & K4	12/31/27	--	--	--	--
Maalaea	DEGs	M1, M2, & M3	--	--	--	--	12/31/27 See note <sup>c</sup>
		M7	--	--	12/31/27 See note <sup>d</sup>	--	--

a. Potential control measures for Mauna Loa Macadamia Nut Corporation Plant, not listed in the table as a facility evaluated, will be provided in supplemental documents as indicated in Chapter 6.

b. Fuel switch to ULSD by four (4) years from permit issuance.

c. Compliance with the NO<sub>x</sub> emissions limit for FITR will be verified with annual source testing.

d. Compliance with the NO<sub>x</sub> emissions limit for SCR will be verified with a CEMS.

6. WRAP Technical Support System (TSS): Pursuant to 40 CFR §51.308(d)(1), States are required to include as reasonable progress goals, metrics to ensure there is no degradation in visibility for the least impaired days (now referred to as clearest days) over the same period of the implementation plan.

7. Hawaii Administrative Rules (HAR): The anticipated net effect on visibility impairment due to projected changes in point source emissions of anthropogenic particulate matter and SO<sub>2</sub> for this planning period is addressed by the following proposed revisions to HAR Chapter 11-60.1, upon being enacted:

- Proposed revision to §11-60.1-35(b), §11-60.1-36(b), and §11-60.1-37(b) for incinerations, biomass fuel burning boilers, and process industries, respectively to add enforceable compliance standards to emissions of particulate matter pursuant to 40 CFR Part 60, Appendix A-3, Method 5 or other EPA approved methods.
- Proposed revision to §11-60.1-38(c) will add enforceable compliance standards to the sulfur content by weight in liquid and gaseous fuel used for combustion using the American Society for Testing and Materials (ASTM) Methods

b. Projected Changes in Area Sources (40 CFR 51.308(f)(2)(iv)(E)): The anticipated net effect on visibility impairment due to area source emissions of anthropogenic fugitive particles for this planning period is addressed by the following proposed revisions to HAR Title 11, Chapter 60.1, upon being enacted:

1. Proposed revision to §11-60.1-33 adds enforceable standards that prohibits emissions of visible fugitive dust that exceeds 20% opacity, as determined by using EPA 40 CFR 51 Appendix M, Method 203C (Refer to Appendix P, Propose Revisions, Subchapter 2).
2. Proposed revision to §11-60.1-55 for agricultural burning expands and refines the criteria for declaring “no burn” periods (Refer to Appendix O, Propose Revisions, Subchapter 3).

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### c. Projected Changes in Mobile Sources (40 CFR 51.308(f)(2)(iv)(E)):

In October 2017, by way of Act 32, Session Laws of Hawaii 2017, the Hawaii Climate Change Mitigation and Adaptation Commission (Commission) was formally established. As highlighted in its 2018 annual report, the Commission established two main focuses; one of which is the reduction of emissions from ground transportation. The second main focus is on emissions from the power sector, however, since goals have already been established by the Hawaii Clean Energy Initiative through the RPS and EEPS, the Commission decided to mainstream its attention to reducing emissions from ground transportation: The Commission recognizes that ground transportation contributes significantly to Hawaii's share of greenhouse gas emissions. It supports a price on carbon, and mechanisms to reduce overall vehicle miles traveled, as well as converting all remaining vehicle-based ground transportation to renewable, zero-emission fuels and technologies. Under the Climate Ready Hawaii framework, the Commission is formulating policy tools for use by all departments, such as strategies for reducing GHG emissions from mobile sources that would also reduce visibility impairing pollutants as a co-benefit.<sup>37</sup>

1. Social Cost of Carbon: In an attempt to assist the State of Hawai'i to move its economy to a low/zero-carbon growth path, the Commission, with the leadership of the Hawaii Department of Transportation, has initiated research on how to assess, incorporate and measure the carbon footprint of projects and programs in all state departments. By properly accounting for the full cost of carbon emissions, a more accurate benefit-cost assessment will allow agencies to properly evaluate projects and associated policies. While it is a positive step for departments to consider how to reduce emissions from fuel use through fuel switching and efficiency measures, these efforts are not enough to bring about the reduction needed. On November 28, 2018, the Commission issued a release stating that putting a price on carbon is the most effective single action that will achieve Hawaii's ambitious and necessary emissions reduction goals (refer to Appendix R). Since releasing this statement, the Hawaii Senate had passed a carbon emission pricing bill in two consecutive years, but in both instances, the Senate has not yet managed to enact this bill. Currently, multiple carbon tax and pricing bills, such as HB134, HB460, & SB311, are again under review by the 2022 State Legislature.
2. Multi-Modal Mobility Hub: A Climate Ready Hawaii also supports mitigation efforts to reduce Hawaii's dependence on imported fossil fuels. To this end, the Commission's work is focused on active transportation and multi-modal mobility, which includes the full gamut of strategies from telework, transit, bicycling, pedestrian and other modes to reduce vehicle miles traveled, thereby averting emissions. Specifically, this entails initiating collaborative work with the Hawaii Energy Policy Forum, counties, metropolitan planning organizations, and federal and private partners to develop plans for innovative concepts of multi-modal mobility hubs statewide.
  - Renewable Bus: Refer to Sections 7.2.a and 7.5.c.iii.

<sup>37</sup> <https://climate.hawaii.gov/wp-content/uploads/2020/11/HI-Climate-Annual-Report-V8.pdf>

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- **Bicycling and Walking:** Senate bill (refer to Appendix S) S.B. NO. 574 is again under review by the 2022 Hawaii State Legislature to develop a plan to widen shoulders on state highways with designated bike lanes to at least three feet in width, with exceptions. Senate Bill No.1402 was passed by the 2021 Hawaii State Legislature as Act 131, 06/30/2021 (Gov. Msg. No. 1233), which requires the DOT to create motor vehicle, bicycle, and pedestrian highway and pathway networks. These initiatives will encourage use of alternate means to reduce vehicle miles traveled.
  - **Income Taxation of Nonresidents Working Remotely:** Hawaii joined more than a dozen states in filing a brief petition with the U.S. Supreme Court to take up an October 2020 lawsuit filed by the state of New Hampshire (refer to Appendix T) that seeks to block Massachusetts from taxing its residents who no longer commute across state lines for work. The lawsuit claims that it is unconstitutional for Massachusetts to tax income “earned entirely outside its borders.” A ruling by the U.S. Supreme Court that favors the petitioners will encourage working remotely out of state to reduce vehicle miles traveled.
  - **Telework:** Teleworking lessens traffic congestion and reduces emissions of pollutants, provides job flexibility to improve the quality of work-life of employees, and enables employers to expand their ability to recruit and retain a skilled work force. Current technology in broadband telecommunication provides the infrastructure necessary to make this a viable option. To promote teleworking, a State of Hawaii’s “*Remote Work Pilot Project*”<sup>38</sup> was initiated by the Department of Business, Economic Development and Tourism (DBEDT) and Department of Labor and Industrial Relations (DLIR). This program focuses on enabling Hawaii’s unemployed workforce, especially those affected by the pandemic, to work remotely and encourages work flexibility as a means to retain and attract local residents currently working out of state to return home. The success of this pilot project will reduce the need for commuting to and from work thus reducing the overall vehicle miles traveled. In addition, a number of bills are again under review by the 2022 Hawaii State Legislature that if enacted, will encourage teleworking. HB567 and SB1252 requires each department to conduct a study on best practices for teleworking and establish a telework and alternative work schedule policy for state employees as an integral part of the employer's normal business operations. It also establishes a minimum percentage of eligible employees who are required to telework or use an alternative work schedule policy. HB836, which is also under review by the 2022 Hawaii State Legislature (refer to Appendix U), establishes a telework tax credit to encourage employers to allow their employees to telework.
3. **Fleet Tools:** One of the critical components of reducing ground transportation emissions is the conversion of public fleets to clean, renewable fuels, and more efficient vehicles. A key is assessing lifecycle costs, benefits, and emissions. Such tools will assist in making the best low/zero carbon decisions. The Commission is working with the University of Hawaii and the U.S. DOE’s Clean Cities Coalition to develop cost and emission tools.

<sup>38</sup> <https://governor.hawaii.gov/newsroom/dbedt-news-release-hawaii-remote-work-pilot-project-remote-ready-hawaii/>

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### Chapter 8 Reasonable Progress Goals for Regional Haze

#### 8.0 Reasonable Progress - 40 CFR §51.308(f)(2) and (f)(3)

Hawaii is required to determine reasonable progress goals (RPGs) for long term strategy to achieve natural visibility conditions for Haleakala National Park and Hawaii Volcanoes National Park by 2064. The RPGs are required to provide improvement in visibility on the most impaired days and no degradation in visibility on the clearest days. The reasonable progress goals required by 40 CFR §51.308(f)(3) must be expressed in deciviews that reflect the visibility conditions that are projected to be achieved by the end of the second implementation period (2028) as a result of the enforceable emission limitations, compliance schedules, and other measures required by 40 CFR §51.308(f)(2). State-to-state consultation pursuant to 40 CFR §51.308(f)(ii) and (iii) is not applicable since emissions from anthropogenic sources in another state are not reasonably anticipated to contribute to visibility impairment in Hawaii's Class I areas. The closest states to Hawaii are Alaska and California that are about 2,500 miles away.

For establishing reasonable progress goals, potential control measures that could be implemented by 2028 were determined in Chapter 6 of the RH-SIP based on a four-factor analysis from sources screened for further evaluation. Chapter 7 of this RH-SIP provides the final control measures selected for sources and permit amendments to incorporate the federally enforceable regional haze rule limits.

#### 8.1 Photochemical Modeling

To determine visibility conditions in deciviews for 2028 reasonable progress goals, EPA performed photochemical modeling to assess visibility impacts using the Community Multiscale Air Quality (CMAQ) model.<sup>39</sup> Input files for the CMAQ model included hourly emission estimates, meteorological data, and boundary concentrations. Emissions, meteorology, and other inputs were from a 2016 base year. For the modeling assessment, 2016 emissions were projected to future 2028 emissions. Emission plots of gridded emissions of NO<sub>x</sub>, SO<sub>x</sub>, PEC (elemental carbon), and POA (organic aerosol) from EPA's 2016 HI modeling platform were used.

40 CFR §51.308(f)(3)(i) requires that states establish reasonable progress goals (expressed in deciviews) that reflect visibility conditions that are projected to be achieved by the end of the implementation period as a result of the enforceable emission limitations. Hawaii therefore adjusted the RPG for Haleakala NP and Hawaii Volcanoes NP based on the proportion of emissions from all source categories with point source emission reductions over emissions from all source categories without enforceable emission reductions to determine scaling factors. Emissions were based on those from EPA's 2016 modeling platform. These scaling factors were then used to scale down average light extinction for sulfate, nitrates, and elemental carbon based on point source reductions in SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub> emissions, respectively. Emissions reductions were from the shut down of boilers Hill 5 and Hill 6 at the Kanoelehua - Hill Generating Station, shut down of Boilers K-1 through K-4 at the Kahului Generating Station, a fuel switch to USLD for the Puna Generating Station boiler, installation of FITR for Maalaea Generating Station M1, M2, and M3, and SCR for Maalaea M7.

<sup>39</sup> <https://www.epa.gov/system/files/documents/2021-08/epa-454-r-21-007.pdf>



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Three (3) modeling domains were used in the model consisting of 27 km, 9 km, and 3 km cell sizes over the Hawaii Island chain from the Big Island (Hawaii) to Kauai. The modeling domain contained 35 vertical layers with the top layer at 17,550 meters. The model provided hourly concentrations for each cell across the modeling domain.

Table 8.1-1 below shows each of the CMAQ model runs performed for the analysis.

<b>Table 8.1-1 CMAQ Model Runs</b>	
<b>Scenario Name</b>	<b>Description</b>
2016fh_16j	Historical 2016 base case
2028fh_16j	Future year 2028 “on the books” scenario
2028fh_16j_zeroanth	Future year 2028 “on the books scenario, with U.S. anthropogenic emissions zeroed out.

Meteorological inputs for the model were generated with a Weather Research and Forecasting (WRF) model for year 2016. The WRF model was applied with the settings in Table 8.1-1 above.

Regional hemispheric inventories over North America from the Inventory Collaborative 2016 modeling platform were used in the assessment. There were thirty (30) anthropogenic emission sectors including nine (9) sectors based on the Hemispheric Transport of Air Pollution inventory and fifteen (15) sectors representing emissions in China for anthropogenic emissions outside of North America. The inventories included biogenic VOCs and NO<sub>x</sub> emissions. Wildland fire emissions were based on SmartFire2/BlueSky. Emissions from agricultural burning were based on the Hazardous Mapping System (HMS). Sea-salt and halogen emissions from the ocean were also included. Lightning, wind-blown dust, and volcanic emissions were excluded from the modeling assessment. Anthropogenic emissions were used in the CMAQ modeling. Emission sources and key assumptions from EPA’s regional haze modeling TSD are summarized as follows:

- (1) Electric generating unit (EGU) emissions were based on 2016 state submitted data and held constant at the 2016 level for the 2028 projections.
- (2) Non-EGU point source emissions were from the 2014 NEI. Industrial emissions were grown to 2028 based on information from the 2019 Annual Energy Outlook (AEO). Controls were incorporated to reflect relevant NSPS (e.g., reciprocating internal combustion engines (RICE), process heaters, etc.).
- (3) Airport point source emissions were from the 2017 NEI that were back projected to 2016 using FAA data. Airport emissions were projected to 2028 using FAA’s Terminal Area Forecast (TAF) data.
- (4) On-road mobile source emissions were generated with MOVES.
- (5) On-road and non-road were created for 2028 with activity data projected from 2016 to 2028 based on the 2018 AEO and state provided data where available.
- (6) Commercial marine vessel (CMV) emissions, modeled as point sources, were based on AIS hourly ship data for 2017 that were adjusted to 2016 based on national adjustment factors. CMV emissions were projected to 2028 using region-specific emission factors for NO<sub>x</sub>, SO<sub>2</sub>, and other pollutants.

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- (7) Nonpoint emissions were held constant from 2014 NEI for the 2016 inventory. Portions of nonpoint emissions were grown to 2028 based on expected growth in human population. Nonpoint agricultural emissions, including NH<sub>3</sub> and VOC from livestock and fertilizer sources, were not included due to lack of data.
- (8) Nonpoint fugitive dust consisted of emissions from the 2014 NEI. Emissions from paved roads were projected from 2014 to 2016 based on county total vehicle miles traveled (VMT), but emissions from all other sources, including unpaved roads, were held constant. Paved road dust was grown to 2028 based on the growth in VMT from 2016 to 2028. The remainder of the fugitive dust sector including building construction, road construction, agricultural dust, and road dust was held constant.
- (9) Residential wood combustion (RWC) emissions were projected from the 2014 NEI to represent 2016 and 2028 inventories using EPA's 2011v6.3 emissions modeling platform. Projected emissions account for growth, retirements, and NSPS.
- (10) Point oil and gas emissions were based on the 2016 point source modeling platform. Oil and gas emissions were not projected to year 2028.

EPA used the 2016 and 2028 CMAQ model predictions for the components of particulate matter to project 2014-2017 IMPROVE visibility data from the national parks to 2028. The EPA Software for the Model Attainment Test – Community Edition (SMAT-CE) tool was applied to determine 2028 deciview values on the most impaired and clearest days at each Class I area using the 2028 emissions with “on the books” controls. IMPROVE data was used between 2014-2017, which included adjustments for wild-fire (organic and elemental carbon), dust storm impacts (fine crustal and coarse mass), and adjustments for volcanic emissions (sulfates).

For visibility projections, the observed baseline visibility data from 2014 to 2017 was linked to the 2016 modeling year. The baseline ambient IMPROVE monitoring should be for five (5) years from 2014 to 2018. However, since 2018 IMPROVE data was not available, the average 2014-2017 base period was used. Future year 2028 visibility on the most impaired and clearest days in each Class I area was estimated using the 2014-2017 IMPROVE data and relative percent modeled change in particulate matter species between 2016 and 2028. Table 8.1-2 provides EPA's modeling results.

<b>Table 8.1-2 Base and Future Year Class I Area Deciview Values</b>					
Class I Area	IMPROVE Monitor	Base Year (2014-2017) Clearest Days (dv)	Future Year (2028) Clearest Days (dv)	Base Year (2014-2017) Most Impaired Days (dv)	Future Year (2028) Most Impaired Days (dv)
Haleakala NP <sup>a,b</sup>	HACR1	0.51	0.50	7.70	7.55
Hawaii Volcanoes NP <sup>a</sup>	HAVO1	3.50	3.49	16.31	16.03

a. 2014-2017 in SMAT.

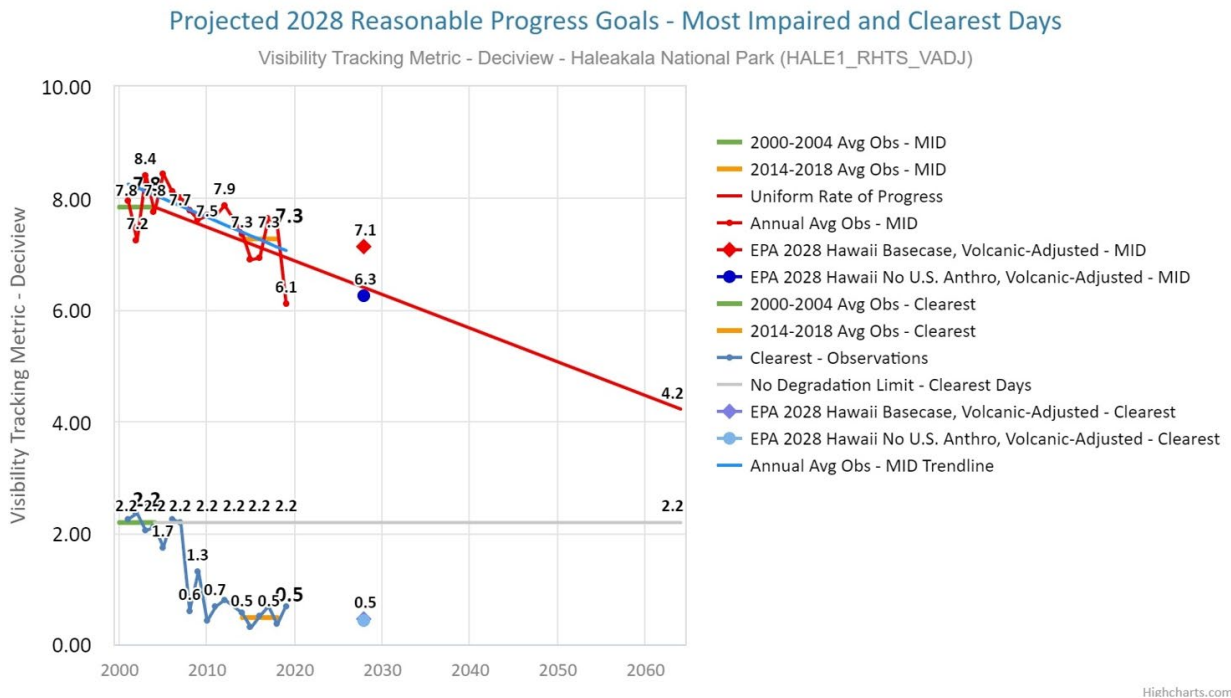
b. 2001-2007 HALE1, 2008-2018 HACRA with volcano adjustment per EPA white paper.

## Exhibit 2

### 8.2 Haleakala National Park Visibility Goals

Visibility conditions and visibility goals for Haleakala National Park are provided in the Figure 8.2-1 glidepath graph from the WRAP TSS. The Figure includes EPA’s photochemical modeling results and adjustments to the IMROVE monitoring data for volcanic activity and the change in location of the monitor for Haleakala National Park.

Table 8.2-1 summarizes visibility conditions shown in Figure 8.2-1 and described in Chapter 3 (see Section 3.2). EPA’s photochemical modeling results that exclude SO<sub>2</sub> emissions from the Kilauea Volcano are provided in Table 8.1-2 and updated in Table 8.2-1 based on numbers from the WRAP TSS in the modeling Express tools under Hawaii Volcanic – Adjusted EPA Modeling Results, Hawaii – URP Glidepath with Visibility Projections.



**Figure 8.2-1** Reasonable Progress Goals for Haleakala National Park

<b>Table 8.2-1</b> Visibility Goals for Haleakala National Park	
Conditions <sup>a,b</sup>	Deciview
Natural Visibility on 20% Most Impaired Days (Goal in 2064)	4.2
Average Baseline Visibility on 20% Clearest Days (2000-2004)	2.2
Average Baseline Visibility on 20% Most Impaired Days (2000-2004)	7.8
Uniform Rate of Progress in 2028 on the 20% Most Impaired Days	6.4
Modeled 2028 Visibility Projection for Most Impaired Days <sup>c</sup>	7.1
Modeled 2028 Visibility Projection for Most Impaired Days – Zero-Out <sup>d</sup>	6.3

a. 2014-2018 in SMAT.

b. 2001-2018 HALE-RHTS combined and volcano adjustment per EPA white paper.

c: Model results in WRAP TSS account for updated IMPROVE data adjustments by EPA for combining visibility monitoring data for IMPROVE sites representing Haleakala National Park and volcanic activity.

d: Zero-Out – All U.S. anthropogenic emissions set to zero in the photochemical modeling assessment.

## Exhibit 2

The uniform rate of improvement needed to achieve the 2028 reasonable progress goal is 1.4 dv (0.06 dv x 24 yrs) on the most impaired days for Haleakala National Park, or an average of 0.06 deciviews per year on the most impaired days based on the glidepath (7.8 dv - 4.2 dv = 3.6 dv; 3.6 dv/60 yrs = 0.060 dv/yr).

The URP for 2028 at Haleakala National Park of 6.4 dv (7.8 dv - 1.4 dv), no degradation limit, and visibility conditions for the most impaired and clearest days were evaluated with the photochemical modeling results. The 2028 modeled deciview projections for both the most impaired and clearest days assumes 2016 EGU emissions are constant from 2016 to 2028 and excludes volcanic SO<sub>2</sub> emissions. The glidepath was not adjusted to account for international anthropogenic emissions and wildland prescribed fires. The 2028 modeled deciview projection – zero out sets all U.S. anthropogenic emissions to zero and excludes volcanic SO<sub>2</sub> emissions. Therefore, regional haze control measures would provide a deciview level somewhere between the 2028 base case and no U.S. anthropogenic modeling scenarios. A modeled result above 6.4 would indicate a rate of progress that is slower than the URP on the most impaired days. If the modeled result is below 6.4, it would indicate a rate of progress that is greater than the URP.

Based on the scaling factors established for point source emission reductions in Appendix V, the RPGs for 2028 are 7.08 dv and 0.50 dv for the most impaired and clearest days, respectively. For the most impaired days, this would be a 0.03 dv/yr reduction (7.8 dv – 7.08 dv)/24 yrs = 0.03 dv/yr) that is slower than the URP. At this rate it would take about 102 years (2028-2022 + (7.08dv - 4.2dv)/0.03) to reach the 4.2 dv natural visibility level from year 2022. Although the anticipated rate of progress, based on modeling, may be slower than the URP for Haleakala National Park, the state has demonstrated that control measures ultimately selected in Chapter 7 are reasonable in accordance with the applicable provisions of 40 CFR §51.308(d)(1) and §51.308(f)(2)(iv)(C). For the clearest days, the RPG of 0.5 dv is below the no degradation level of 2.2 dv.

The modeled projections for the most impaired days are as high as levels at the IMPROVE monitor for Haleakala National Park measuring actual visibility impacts from both the volcano and anthropogenic sources. This is evident even for the projection assuming all anthropogenic and volcanic emissions set to zero. Note that the volcano was erupting continuously from 2014 to most of 2018 emitting extremely high amounts of SO<sub>2</sub>. For example, in 2016 SO<sub>2</sub> emissions from the Kilauea summit, based on USGS information, ranged from approximately 1,000 tons per day to about 9,000 tons per day. It would be expected that the model, assuming no volcanic or anthropogenic emissions, would project a visibility level that is much lower than the observed level.

Note that volcanic impacts would not be completely screened out after adjusting the IMPROVE data for episodic events due to the continuous nature of the Kilauea eruption. Therefore, projections from scaling 2028 modeling results with the observed 2014 to 2018 IMPROVE data on the most impaired days would still be influenced by sulfates from volcanic activity.

The observed visibility conditions measured by the HACR1 monitor at Haleakala National Park in 2019 in Figure 8.2-1, during a period with significant decrease in SO<sub>2</sub> venting after the Kilauea eruption had ceased, shows the following deciview values:

- a. 6.1 dv for the most impaired days which is below the URP (glidepath); and

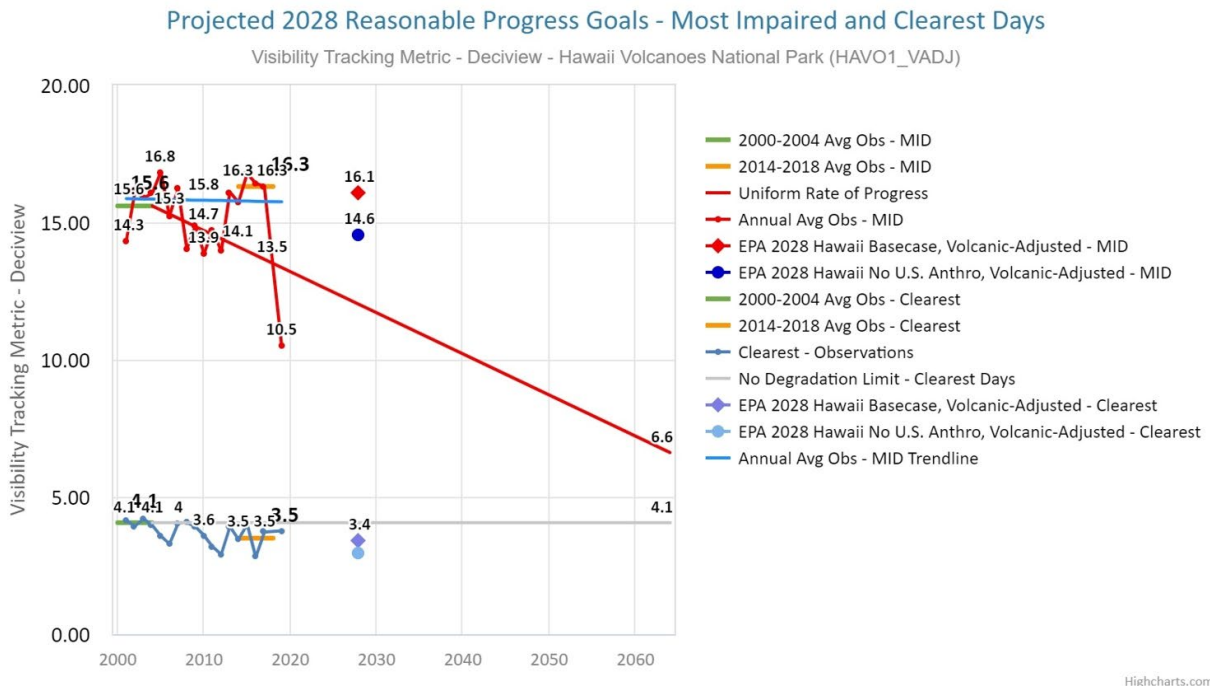
## Exhibit 2

b. 0.7 dv for the clearest days which is below the no degradation level of 2.2 dv.

### 8.3 Hawaii Volcanoes National Park Visibility Goals

Visibility conditions and visibility goals for Hawaii Volcanoes National Park are shown in the Figure 8.3-1 glidepath graph from the WRAP TSS. The Figure includes EPA’s photochemical modeling results and adjustments to the IMPROVE data for volcanic activity.

Table 8.3-1 summarizes visibility conditions shown in Figure 8.3-1 and described in Chapter 3 (see Section 3.2) of the RH-SIP. Photochemical modeling results are provided in Table 8.1-2 and updated in Table 8.3-1 based on numbers from WRAP TSS in the modeling express tools under Hawaii Volcanic – Adjusted EPA Modeling Results, Hawaii – URP Glidepath with Visibility Projections.



**Figure 8.3-1** Reasonable Progress Goals for Hawaii Volcanoes National Park

<b>Table 8.3-1</b> Visibility Goals for Hawaii Volcanoes National Park	
Conditions <sup>a</sup>	Deciview
Natural Visibility on 20% Most Impaired Days (Goal in 2064)	6.6
Average Baseline Visibility on 20% Clearest Days (2000-2004)	4.1
Average Baseline Visibility on 20% Most Impaired Days (2000-2004)	15.6
Uniform Rate of Progress in 2028 on the 20% Most Impaired Days	12.0
Modeled 2028 Visibility Projections for Most Impaired Days <sup>b</sup>	16.1
Modeled 2028 Visibility Projection for Most Impaired Days – Zero-Out <sup>c</sup>	14.6

a. 2014-2018 in SMAT.

b. Model results in WRAP TSS account for updated IMPROVE data adjustments by EPA at the IMPROVE site representing Hawaii Volcanoes National Park for volcanic activity.

c: Zero-Out – All U.S. anthropogenic emissions set to zero in the photochemical modeling assessment.

## Exhibit 2

The uniform rate of improvement needed to achieve the 2028 reasonable progress goal is 3.60 dv ( $0.150 \text{ dv} \times 24 \text{ yrs}$ ) on the most impaired days for Hawaii Volcanoes National Park, or an average of 0.150 dv/yr on the most impaired days ( $15.6 \text{ dv} - 6.6 \text{ dv} = 8.98 \text{ dv}$ ;  $9.0 \text{ dv}/60 \text{ yrs} = 0.150 \text{ dv/yr}$ ).

The URP for 2028 at Hawaii Volcanoes National Park of 12.0 dv of ( $15.6 \text{ dv} - 3.6 \text{ dv}$ ), no degradation limit, and visibility conditions for the most impaired and clearest days were evaluated with photochemical modeling results. The 2028 modeled deciview projections for both the most impaired and clearest days assumes 2016 EGU emissions are constant from 2016 to 2028 and excludes volcanic SO<sub>2</sub> emissions. The glidepath was not adjusted to account for international emissions and wildland prescribed fires. The 2028 modeled deciview projection – zero sets all U.S. anthropogenic emissions to zero and excludes volcanic SO<sub>2</sub> emissions. Therefore, regional haze control measures would provide a deciview level somewhere between the 2028 base case and no U.S. anthropogenic modeling scenarios. A modeled result above 12.0 would indicate a rate of progress that is slower than the URP

Based on scaling factors established for point source emission reductions in Appendix V, the RPGs for 2028 of 16.08dv and 3.39 dv for the most impaired and clearest days, respectively. For the most impaired days, this would be an increase in visibility impairment of 0.008 dv/yr ( $15.6 \text{ dv} - 16.08 \text{ dv}/24 \text{ yrs} = -0.008 \text{ dv/yr}$ ). At this rate the natural visibility condition of 6.6 dv would never be reached. Although modeling indicates a rate of progress that is slower than the URP for Hawaii Volcanoes National Park, the state has demonstrated that the control measures ultimately selected in Chapter 7 are reasonable in accordance with applicable provisions of 40 CFR §51.308(d)(1) and §51.308(f)(2)(iv)(C). For the clearest days, the RPG of 3.39 dv is below the no degradation level of 4.1 dv.

The modeled projections are as high as levels at the IMPROVE monitor for Hawaii Volcanoes National Park measuring visibility impacts from both the volcano and anthropogenic sources. Even if all anthropogenic sources are zeroed out, modeling projections show a level of visibility that is above the glidepath. Note that the volcano was erupting continuously from 2014 to most of 2018 emitting extremely high SO<sub>2</sub> emissions. For example, in 2016 SO<sub>2</sub> emissions from the Kilauea summit vent, based on USGS information, ranged from approximately 1,000 tons per day to about 9,000 tons per day. It would be expected that the model, assuming no volcanic emissions, would project a visibility level that is much lower than the observed level.

As stated above for Haleakala National Park, volcanic impacts would not be completely screened out after adjusting the IMPROVE data for episodic events due to the continuous nature of the Kilauea eruption. Therefore, projections from scaling 2028 modeling results with the observed 2014 to 2017 or 2014 to 2018 IMPROVE data on the most impaired days would still be influenced by volcanic activity.

The observed visibility conditions measured by the HAVO1 monitor at Hawaii Volcanoes National Park in 2019 (See Figure 8.3-1), during a period with significant decrease in SO<sub>2</sub> venting after the Kilauea eruption ceased, shows deciview values of:

- a. 10.5 dv for the most impaired days which is below the URP (glidepath); and
- b. 3.8 dv for the clearest days which is below the no degradation level of 4.1 dv.

## Chapter 9 Consultation and Future Planning Commitments

### 9.0 Consultation and Future Planning Commitments – 40 CFR §51.102, §51.103, §51.308(d), §51.308(f), §51.308(g), §51.308(h)

The RHR requires states to commit to future planning that includes a visibility data monitoring strategy, updates to statewide emission inventories of pollutants that impair visibility, periodic RH-SIP revisions and progress reports, and continued consultation with the Federal Land Managers. Each comprehensive RH-SIP submittal must provide a determination of the adequacy of the existing plan. Procedural requirements are followed for RH-SIP revisions in accordance with RHR for the public participation process.

### 9.1 Monitoring Strategy – 40 CFR §51.308(f)(6)

40 CFR §51.308(f)(6) requires states to develop a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment that is representative of all Class I areas within the state. Hawaii is relying on the continued availability of the Inter-Agency Monitoring of Protective Visual Environments (IMPROVE) program in meeting the monitoring operation, collection, and reporting requirements for measuring visibility impairment in its mandatory Class I areas. Other associated monitoring strategy requirements include:

1. 40 CFR §51.308 (f)(6)(i) - Establishment of any additional monitoring sites or equipment needed to assess whether reasonable progress goals are being achieved as follows:
  - a. Hawaii will work with IMPROVE, EPA, and the FLMs to ensure that representative monitoring continues for its Class I areas.
  - b. Visibility data for Haleakala National Park collected by the IMPROVE monitor (HACR1) operated and maintained by the National Park Service is considered adequate. The HACR1 site is considered adequate for assessing the reasonable progress goals for Haleakala National Park and no additional monitoring sites are necessary at this time. Hawaii worked with WRAP, TSS, and EPA representatives during this planning period to adjust IMPROVE data for the monitor relocation and to screen out episodic events related to volcanic activity (sulfates).
  - c. Visibility data for Hawaii Volcanoes National Park collected by the IMPROVE monitor (HAVO1) is operated and maintained by the National Park Service is considered adequate. The HAVO1 site is considered adequate for assessing the reasonable progress goals for Hawaii Volcanoes National Park and no additional monitoring sites are necessary at this time. Hawaii worked with WRAP, TSS, and EPA representatives during this planning period to adjust IMPROVE data to screen out episodic events related to volcanic activity (sulfates).
2. 40 CFR §51.308 (f)(6)(ii) – Procedures by which monitoring data and other information are used in determining the contribution of emissions from within the state to regional haze visibility impairment within the Class I areas are as follows:
  - a. Chapter 3 - *Visibility Conditions*, Chapter 5 - *Source Screening*, Chapter 6 - *Emission Control Measures*, Chapter 7: - *Reasonable Progress Goals*, and Chapter 8 - *Long Term Strategy*, describe the procedures used in developing this

## Exhibit 2

SIP revision. These chapters assess the relative impact of emissions on Hawaii's Class I areas.

- b. Chapter 4 - *Emissions Inventory* describes the procedures used for this RH-SIP revision to produce the statewide emissions inventory of pollutants reasonably anticipated to cause or contribute to visibility impairment in Hawaii's Class I areas.
3. 40 CFR §51.308(f)(6)(iii) – This provision is for states with no mandatory Class I area and does not apply to Hawaii.
4. 40 CFR §51.308(f)(6)(iv) – Reporting of all visibility monitoring data to EPA at least annually for each Class I area. The DOH-CAB does not directly collect, or handle IMPROVE data. The DOH-CAB will continue to participate in the exchange of IMPROVE information for developing and updating the WRAP TSS. The DOH-CAB considers the WRAP TSS to be a core part of the IMPROVE program. The DOH-CAB will report data from its two (2) Class I areas at least annually to EPA using the WRAP TSS and recommends that EPA continue to adjust future visibility data collected at Hawaii's IMPROVE monitors.
5. 40 CFR §51.308(f)(6)(v) – Hawaii with support from WRAP shows a statewide inventory of emissions that can be reasonably expected to cause or contribute to visibility impairment in Class I areas. Chapter 4 of this RH-SIP summarizes the emissions by pollutant and source category.

Hawaii commits to updating statewide emissions periodically. The updates will be used for Hawaii's tracking of emission changes, trends, and evaluation of whether reasonable progress goals are being achieved along with other regional analyses. The inventories will be updated every three years on the same schedule as the triennial reporting required by EPA's Air Emissions Reporting Requirements.

As a member of the WRAP, the state will utilize WRAP sponsored Emissions Data Management System and Fire Emissions Tracking System to store and access emission inventory data for the region. Hawaii will also depend upon and participate in additional periodic collective emissions inventory efforts by the WRAP. Further, Hawaii will continue to depend on and use the capabilities of the WRAP's regional modeling to simulate the visibility impacts of emissions for haze and other related air quality planning purposes. Hawaii State will collaborate with WRAP members (EPA, states, and FLMs) to ensure the continued operation of these technical support analysis tools and systems.

6. 40 CFR §51.308(f)(6)(vi) – Other elements, including reporting, recordkeeping, and other measures, necessary to assess and report visibility are as follows:
  - a. EPA provides guidance for states to follow to establish baseline visibility and track visibility from baseline. The EPA guidance also outlines an adjustment process to distinguish the relative contributions from U.S. anthropogenic and natural sources.
  - b. There are no other elements, including reporting, recordkeeping, or other measures necessary to address and report visibility in Hawaii's Class I areas.



## Exhibit 2

### 9.2 Periodic Regional Haze Progress Reports

In accordance with 40 CFR §51.308(g), states are required to submit periodic regional haze progress reports. The first progress report is due five (5) years from submittal of the initial implementation plan. Subsequent progress reports are due by January 1, 2025, July 31, 2033, and every ten (10) years thereafter. Subsequent progress reports must be made available for public inspection and comment for at least thirty (30) days prior to submitting to EPA and all comments must be submitted to EPA, along with an explanation of any changes to the progress report made in response to comments. The progress reports must include the following:

1. Description of the implementation status;
2. Summary of the emission reductions achieved;
3. Assessments of changes in visibility conditions for most impaired and clearest days;
4. Analysis of emission changes over the applicable five (5) year period;
5. Assessment of any significant changes in anthropogenic emissions that have occurred since the most recent RH-SIP submittal including whether the changes were anticipated and whether the changes limited progress in improving visibility; and
6. Assessment of whether the current plan elements and strategies are sufficient to meet the regional haze reasonable progress goals.

Hawaii commits to submitting regional haze progress reports for evaluating progress made towards the reasonable progress goals for Haleakala National Park and Hawaii Volcanoes National Park as required by 40 CFR §51.308(f) and 40 CFR §51.308(g).

### 9.3 Determination of Adequacy – 40 CFR §51.308(h)

In accordance with 40 CFR §51.308(h), states are required to determine the adequacy of the existing RH-SIP based on the findings of the periodic progress reports that will be based on consultation with the FLMs and EPA.

Hawaii commits to make adequacy determinations of the existing RH-SIP at the time regional haze progress reports are due in accordance with 40 CFR §51.308(h). Hawaii, in consultation with the FLMs and EPA, will determine what actions are necessary for the adequacy determination.

### 9.4 Comprehensive RH-SIP Revisions

Pursuant to 40 CFR §51.308(f), states must revise and submit RH-SIP revisions by July 31, 2021, July 31, 2028, and every ten (10) years thereafter. In accordance with 40 CFR §51.308(f), the State of Hawaii commits to revising and submitting its RH-SIP by July 31, 2028 and every ten (10) years thereafter. The plan will contain elements and supporting documentations required by 40 CFR §51.308(f) to meet the core requirements for the regional haze specified in 40 CFR §51.308(d).

## Exhibit 2

### 9.5 Federal Land Manager Consultation – 40 CFR §51.308(i)(2)

Hawaii provided the Federal Land Managers (FLMs) opportunities for consultation at least 120 days prior to holding a public hearing or any other public comment opportunity on the RH-SIP in accordance with 40 CFR §51.308(i)(2). Discussions from conference calls are provided in Appendix P.

Hawaii provided an opportunity for consultation with the Federal Land Managers (FLMs) at least sixty (60) days prior to initiating the public comment period and providing the public the opportunity to request a public hearing on the RH-SIP. The RH-SIP was submitted to the NPS, U.S. Fish and Wildlife Service, and the U.S. Forest Service on March 24, 2022, for review and comments. The EPA was also notified on March 24, 2022 and provided a copy of the RH-SIP during the FLM review and comment period. A regional haze consultation meeting was held on May 19, 2022, to discuss comments from the FLMs on Hawaii's draft RH-SIP. The NPS Air Resources Division, NPS Interior Regions 8, 9, 10, and 12; and several national park units in Hawaii hosted the RH-SIP consultation meeting with DOH-CAB. Representatives from the U.S. Fish and Wildlife Service and EPA (Region 9) also attended the meeting. The FLMs provided written comments on May 26, 2022. In accordance with 40 CFR §51.308(i)(3), comments from the FLMs are provided in Appendix P.

From their review, the FLMs concluded that there may be additional cost-effective opportunities to control nitrogen oxide (NO<sub>x</sub>) emissions from four (4) larger diesel engines (M10–M13) at the Maalaea Generating Station on Maui. As indicated at the consultation meeting, these engines are responsible for 69% of the facility's total NO<sub>x</sub> emissions. The FLMs stated that the draft RH-SIP could be improved by more robust justification for the cost of emission controls for these engines. The NPS analysis of selective catalytic reduction (SCR) control costs for these engines, found that they may be below the cost-effectiveness threshold established by the state. The FLMs requested that DOH staff consider their cost estimates for Maalaea engines M10–M13 and update cost estimates for the facility if appropriate. The FLMs further recommend that Hawaii DOH staff require SCR for these engines as a technically feasible cost-effective control to reduce NO<sub>x</sub> emissions if revised cost-effectiveness estimates are below the established threshold. The NPS supports Hawaii DOH-CAB's request for a vendor quote as this would provide the highest level of certainty for evaluating the cost-effectiveness of SCR for these engines.

After further review of the four-factor analysis for the Maalaea Generating Station to address comments from the FLMs, the DOH-CAB determined that the four-factor analysis for Maalaea Generating Station is incomplete. Therefore, additional review to determine potential control measures for the Maalaea Generating Station will be addressed in a\* SIP revision.

The four-factor analyses for the Mauna Loa Macadamia Nut Corporation Plant on Hawaii Island was also determined to be incomplete and is still being worked on. Potential control measures for the Mauna Loa Macadamia Nut Corporation Plant will be address in the SIP revision.

## Exhibit 2

### 9.6 Procedural Requirements – 40 CFR §51.102

Pursuant to Hawaii Revised Statutes (HRS) Section 342B-13, a public notice for the RH-SIP revision was published on June 24, 2022, with the public comment period commencing on June 24, 2022, and ending on July 24, 2022. The public notice provided the opportunity for the public to request a public hearing. If requested, the hearing was scheduled to be held on August 2, 2022. The FLMs and EPA were notified on June 24, 2022 that the DOH-CAB was accepting comments and would hold a public hearing, if requested, on the draft RH-SIP revision. A hard-copy of the draft RH-SIP was provided on all the main islands for personnel viewing. The DOH-CAB also posted the draft RH-SIP on its website at: <https://health.hawaii.gov/cab/public-notices/>. Copies of the notice sent to the Star Advertiser, Hawaii Tribune-Herald, West Hawaii Today, The Garden Island, and Maui News are provided in Appendix W.

Prior to the close of the public comment period, representatives provided comments on Hawaii's draft RH-SIP. Comments received, the DOH-CAB's responses to the comments, and final permit amendments are provided in Appendix X.

The DOH-CAB has the legal authority to adopt Hawaii's RH-SIP and has adopted the revision in accordance with State statutory and regulatory rules. Please see Appendix Y.

## Exhibit 3



June 30, 2022

*Via electronic mail*

Michael Madsen  
Clean Air Branch  
Department of Health  
2827 Waimano Home Road  
Suite #130  
Pearl City, Oahu 96872  
[michael.madsen@doh.hawaii.gov](mailto:michael.madsen@doh.hawaii.gov)

**Re: Requesting Extension of Comment Period for Hawaii's Draft Regional Haze State Implementation Plan for the Second Implementation Period**

Dear Mr. Madsen,

On behalf of Coalition to Protect America's National Parks and National Parks Conservation Association, (the "Conservation Organizations"), we request that the Hawaii Department of Health Clean Air Branch ("CAB") grant an extension of the public comment deadline for Hawaii's Draft Regional Haze State Implementation Plan for the Second Implementation Period ("SIP"), currently noticed for public comment.<sup>1</sup> Specifically, we ask that the current deadline for comments, Sunday, July 24, 2022, be extended to Friday, August 5, 2022.

For review of the proposed SIP, CAB provided interested stakeholders with just 31 days to evaluate and provide comment regarding over a hundred pages of legal and technical analysis, as well as hundreds of pages in additional appendices and consultation documents.<sup>2</sup> Given the scope, volume, and complexity of this information, the Conservation Organizations believe that the current comment period is not sufficient to fully analyze the potential impacts of the proposed SIP and provide meaningful comment. Reviewing CAB's legal and technical analysis along with its modeling, conducting any analysis of our own, and developing comments requires more time than allowed by the current comment period, which ends on July 24, 2022.

<sup>1</sup> See Hawaii's public notice: <https://health.hawaii.gov/cab/files/2022/06/22-CA-PA-08.pdf>.

<sup>2</sup> See Hawaii's Proposed SIP and appendices: <https://health.hawaii.gov/cab/public-notice/>.

### Exhibit 3

A modest extension of the public comment period will not adversely impact any other party. We understand and appreciate that CAB has provided periodic stakeholder updates throughout the planning process, but we have not had access to the proposed SIP before its release on June 24. A 12-day extension of the deadline will not prejudice any regulated entity and will not materially affect CAB's ability to submit its SIP to EPA within a reasonable time.

Conversely, given the scope and complexity of the proposed SIP, the current July 24 deadline for comments will effectively preclude the Conservation Organizations from reviewing all of the relevant technical data supporting the rule, fully analyzing those voluminous files, and providing meaningful legal and technical comments. We previously requested, and were granted, regional haze SIP comment period extensions by the states of Arkansas, Indiana, Montana, Ohio and Texas. Additionally, the state of Alaska initially provided over 50 days for their public comment period.

Additionally, we request an avenue to submit comments electronically. Printing and shipping our comments and supporting exhibits is unnecessary in the days of electronic delivery. Moreover, the comment deadline falls on a Sunday which eliminates one more day from the comment period as many USPS locations are closed on Sundays so therefore, we would not be able to get anything postmarked that day.

Furthermore, we note that CAB recently published a "NOTICE OF PUBLIC HEARING ON PROPOSED AMENDMENTS TO THE HAWAII ADMINISTRATIVE RULES TITLE 11, CHAPTER 60.1 AIR POLLUTION CONTROL DEPARTMENT OF HEALTH STATE OF HAWAII Docket No. 11-60.1-03-21 (CAB Docket No. 21-CA-PA-21)" and in that notice explained that it will accept written comments on those SIP amendments:

[T]hrough e-mail at CAB@doh.hawaii.gov, by delivery, or by postal mail to the address listed above.<sup>3</sup>

It appears to be the State's practice to accept comments electronically. Thus, we ask that the State provide the same opportunity here with its Draft Regional Haze SIP and accept comments from the Conservation Organizations electronically.

If the State insists on receiving public comments, including those from the Conservation Organizations via postal mail delivery to Hawaii, we request confirmation that it will accept our comments and supporting exhibits *both* electronically via electronic mail (to CAB@doh.hawaii.gov or to your email address) and via postal mail delivery using electronic media device (device type coordinated with your office (*e.g.*, flash drive, etc.)) rather than paper copies.

Finally, we appreciate that you let Natalie Levine know via email on June 29<sup>th</sup> that additional information on the permits for this proposed action will be posted on your website on

<sup>3</sup> NOTICE OF PUBLIC HEARING ON PROPOSED AMENDMENTS TO THE HAWAII ADMINISTRATIVE RULES TITLE 11, CHAPTER 60.1 AIR POLLUTION CONTROL DEPARTMENT OF HEALTH STATE OF HAWAII Docket No. 11-60.1-03-21 (CAB Docket No. 21-CA-PA-21), at 1, 2, <https://health.hawaii.gov/cab/proposed-amendments-to-hawaii-administrative-rules/>.

## Exhibit 3

Friday July 1, 2022. As this is information that was not available at the start of the comment period, and consistent with EPA's regulations that require a minimum 30-day public comment period, we look forward to seeing the new public notice and extension of the public comment period.

Ultimately, if finalized as currently proposed, the SIP would adversely affect the Conservation Organizations' interests in pollution reduction, the environment, as well the health and welfare of our members and their use and enjoyment of Haleakala and Hawaii Volcanoes National Parks. We respectfully ask that you grant our request by Thursday, July 7, 2022, so that we can plan our comments most efficiently.

Respectfully submitted,

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**Exhibit 4**  
**REQUEST FOR PUBLIC COMMENTS ON**  
**HAWAII'S DRAFT REGIONAL HAZE STATE IMPLEMENTATION PLAN (RH-SIP)**  
**FOR THE SECOND IMPLEMENTATION PERIOD (2018-2028)**  
**(Docket No. 22-CA-PA-08)**

In accordance with 40 Code of Federal Regulations (CFR) §51.102 and Hawaii Administrative Rules §11-60.1-10, the Department of Health, State of Hawaii (DOH) is accepting comments on the subject draft RH-SIP for the second implementation period of the U.S. Environmental Protection Agency's (EPA's) Regional Haze Rule (RHR).

The proposed RH-SIP revision contains federally enforceable permit limits to address requirements of the RHR to 1) improve visibility on the most impaired days and 2) ensure no visibility degradation occurs on the clearest days for each Class I area in the state (Haleakala National Park on Maui Island and Hawaii Volcanoes National Park on Hawaii Island). These goals and long-term strategies for achieving the goals are included in RH-SIPs covering each ten-year period up to 2064. Hawaii has committed to implement its long-term strategy to improve visibility including fuel switching to ultra-low sulfur diesel and other requirements to shut down units within this second regional haze planning period. Pursuant to 40 CFR §51.308(f) of the RHR, Hawaii's RH-SIP includes the following key elements:

- Calculations of baseline, current, and natural visibility conditions; progress to date; and the uniform rate of progress for each Class I area – Chapter 3;
- Statewide emission inventories of visibility impairing pollutants – Chapter 4;
- Source screening including an analysis with Q/d, a more sophisticated weighted emissions potential/area of influence (WEP/AOI) analysis, and supplemental analysis – Chapter 5;
- Source specific four-factor analyses of facilities screened – Chapters 6 and 7;
- Long-term strategy for regional haze including federally enforceable emission limitations and compliance schedules - Chapter 7 and Appendix P with draft permits;
- Reasonable progress goals based on the regional haze controls selected – Chapter 8;
- A progress report addressing the requirements of 40 CFR §51.308(g)(1) through (5) – Chapter 9;
- Monitoring strategy and other implementation plan requirements – Chapter 9; and
- Documentation of consultation with EPA, Federal Land Managers (FLMs), and the regulated industry – Chapter 9.

A regional haze consultation meeting was held on May 19, 2022, to discuss comments from the FLMs on Hawaii's draft RH-SIP pursuant to 40 CFR §51.308(i)(2). The National Park Service (NPS) Air Resources Division; NPS Interior Regions 8, 9, 10, and 12; and several national park units in Hawaii hosted the RH-SIP consultation meeting with the Hawaii Department of Health Clean Air Branch (DOH-CAB). Representatives from the U.S. Fish and Wildlife Service and the EPA (Region 9) also attended the meeting.

From their review, the FLMs concluded that there may be additional cost-effective opportunities to control nitrogen oxide (NO<sub>x</sub>) emissions from four (4) larger diesel engines (M10–M13) at the Maalaea Generating Station on Maui. As indicated at the consultation meeting, these engines are responsible for 69% of the facility's total NO<sub>x</sub> emissions. The FLMs stated that the draft RH-SIP could be improved by more robust justification for the cost of emission controls for these engines. The NPS analysis of selective catalytic reduction (SCR) control costs for these engines, found that they may be below the cost-effectiveness threshold established by the state. The FLMs requested that DOH staff consider their cost estimates for Maalaea engines M10–M13 and update cost estimates for the facility if appropriate. The FLMs further recommend that Hawaii DOH staff require SCR for these engines as a technically feasible cost-effective control to reduce NO<sub>x</sub> emissions if revised cost-effectiveness estimates are below the established threshold. The NPS supports Hawaii DOH-CAB's request for a vendor quote as this would provide the highest level of certainty for evaluating the cost-effectiveness of SCR for these engines.

After further review of the four-factor analysis for the Maalaea Generating Station to address comments from the FLMs, the DOH-CAB determined that the four-factor analysis for Maalaea Generating Station is incomplete. Therefore, additional review to determine potential control measures for the Maalaea Generating Station will be addressed in a SIP revision.

## Exhibit 4

The four-factor analyses for the Mauna Loa Macadamia Nut Corporation Plant on Hawaii Island was also determined to be incomplete and is still being worked on. Potential control measures for the Mauna Loa Macadamia Nut Corporation Plant will be address in the SIP revision.

The following is a link to Hawaii's draft RH-SIP for the second planning period (2018-2028):

<https://health.hawaii.gov/cab/public-notice/>

The documents can be viewed in person at the following locations, Mon-Fri, 8 a.m.-4 p.m. (except on state holidays):

### Oahu:

- Clean Air Branch, Department of Health  
2827 Waimano Home Road, Suite #130, Pearl City, Oahu 96872

### Hawaii:

- Hawaii District Health Office, Department of Health  
1582 Kamehameha Ave., Hilo, Hawaii 96720
- Clean Air Branch – Kona, Keakealani Building, Department of Health  
79-1020 Haukapila Street, Room 113, Kealahou, Hawaii 96750

### Kauai:

- Kauai District Health Office, Department of Health  
3040 Umi St., Lihue, Kauai 96766

### Maui:

- Maui District Health Office, Department of Health  
54 High St., Room 300, Wailuku, Maui 96793

Copies may be requested for a fee of five (5) cents/page plus postage. Please send written requests to the Clean Air Branch listed above or call Mr. Michael Madsen at the Clean Air Branch at (808) 586-4200 to request a copy.

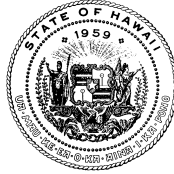
All written comments on Hawaii's draft RH-SIP must be addressed to the Clean Air Branch at the above address on Oahu and must be postmarked or received by July 24, 2022. Any person may request a public hearing by submitting a written request to the above address on Oahu that explains the person's interest and reasons why a hearing is warranted. If requested, a virtual public hearing will be held at 9:00 a.m. on August 2, 2022. Information on the public hearing will be posted on the Department of Health's website at: <https://health.hawaii.gov/cab/public-notice/> at least thirty (30) days in advance of the scheduled hearing date. If no request for a public hearing is received, we will post a cancellation notice on the Department of Health's website on July 25, 2022. Please contact Mr. Madsen to find out if the hearing has been cancelled.

DOH will make a final decision on the RH-SIP after considering all comments and will send notice of the final decision to each person who has submitted comments or requested such notice.

The DOH will initiate another public comment period at a later date after completing Hawaii's RH-SIP revision to address potential regional haze control measures for the Mauna Loa Macadamia Nut Corporation Plant and Maalaea Generating Station.

Elizabeth A. Char, M.D.  
Director of Health





STATE OF HAWAII  
DEPARTMENT OF HEALTH

P.O. Box 3378  
HONOLULU, HAWAII 96801-3378

In reply, please refer to:  
File:

22-286E CAB

July 8, 2022

Ms. Natalie Levine  
Climate and Conservation Program Manager  
National Parks Conservation Association  
Novato, California  
[nlevine@npca.org](mailto:nlevine@npca.org)

Dear Ms. Levine:

**SUBJECT: Response to Request for an Extension of the Comment Period for Hawaii's Draft Regional Haze State Implementation Plan for the Second Implementation Period**

The Department of Health, Clean Air Branch (CAB), acknowledges receipt of your letter dated June 30, 2022, requesting to extend the public comment period for Hawaii's Regional Haze State Implementation Plan (RH-SIP) for the second implementation period from July 24, 2022, to August 5, 2022. In addition, you also requested for an avenue to submit comments electronically.

We have reviewed your request and determined that extending the deadline of the public comment period will compromise the CAB's ability to meet the August 15, 2022, deadline for submitting Hawaii's RH-SIP to the U.S. Environmental Protection Agency (EPA). This deadline was announced by EPA on April 7, 2022, of issuing Findings of Failure to Submit to states that do not submit their RH-SIPs for the second planning period by August 15, 2022.<sup>1</sup> Therefore, due to the tight schedule for submitting the RH-SIP by EPA's deadline, the CAB is unable to accommodate your request for an extension.

The CAB, however, will accept comments received by July 24, 2022, on the draft RH-SIP from you electronically at: [CAB@doh.hawaii.gov](mailto:CAB@doh.hawaii.gov). As stated in your letter, the electronic avenue should expedite the process for submitting comments to the CAB. While we support and welcome all public participation, we do ask that you kindly make your comments as concise as possible and reduce the amount of duplicative and/or repetitive material you submit electronically.

If there are any questions regarding this matter, please contact Mr. Dale Hamamoto of my staff at (808) 586-4200. Thank you for your interest in clean air quality matters.

Sincerely,

A handwritten signature in blue ink that reads "Marianne Rossio".

MARIANNE ROSSIO, P.E.  
Manager, Clean Air Branch

DH:tkg

c: Michael B. Murray, Chair, Coalition to Protect America's National Parks  
Sara L. Laumann, Principal, Laumann Legal, LLC, Counsel for National Parks Conservation Association

Exhibit 5

## Exhibit 6

# National Park Service (NPS) Regional Haze SIP feedback for the Hawaii State Department of Health Clean Air Branch

May 26, 2022

### 1. Executive Summary

The National Park Service (NPS) appreciates the opportunity to review the draft Hawaii Regional Haze State Implementation Plan (SIP) for the second planning period. On May 19, 2022, staff from the NPS Air Resources Division; NPS Interior Regions 8, 9, 10, and 12; and several national park units in Hawai'i hosted a regional haze SIP review consultation meeting with the Hawaii State Department of Health Clean Air Branch (DOH-CAB) staff. During the meeting, NPS staff shared input on the draft Hawaii Regional Haze SIP.

As discussed during the consultation meeting, NPS review of the draft SIP supports the control determinations identified by Hawaii DOH-CAB and finds that there may be additional reasonable emission reduction opportunities for one of the facilities considered. Specifically, for the Maalaea Power Plant on Maui there may be additional cost-effective opportunities to control NO<sub>x</sub> emissions from the facility's four larger diesel engines (M10–M13). Section 2 of this technical feedback document provides facility-specific feedback, analyses, and recommendations. Section 3 provides some editorial suggestions.

Hawai'i is home to two NPS-managed Class I areas—Haleakalā National Park on Maui and Hawai'i Volcanoes National Park on Hawai'i. The NPS values clean air and clear views and recognizes these as essential to our visitor experience and the very purpose of our Class I areas. The NPS appreciates the steps Hawaii DOH-CAB is taking to reduce haze causing pollution and address regional haze in our national parks in this planning period. The NPS welcomes future opportunities to engage with Hawaii DOH-CAB and work together as we strive toward the goal of unimpaired visibility.

## Exhibit 6

### 2. Four-factor Analyses

Hawaii DOH-CAB selected eight facilities for four-factor analysis:

Table 1. Facilities selected for four-factor analysis.

Facility	Location
1. Kalaeloa Partners, L.P. Plant	Oahu
2. Kahe Power Plant	Oahu
3. Waiau Power Plant	Oahu
4. Kanoiehua-Hill Power Plant	Hawai'i
5. Puna Power Plant	Hawai'i
6. Kahului Power Plant	Maui
7. Maalaea Generating Station	Maui
8. Mauna Loa Macadamia Nut Corporation Plant	Hawai'i

In evaluating the first seven facilities identified for potential emission controls, the state reviewed a weighted emissions potential and area of influence (WEP/AOI) analysis described in Section 6.5 of the draft SIP. This analysis helps define the relative contributions of emissions from point sources to haze-causing particulates at the two Class I areas, Hawai'i Volcanoes and Haleakalā National Parks. The results of this analysis led the state to conclude that the three facilities located on Oahu (Kalaeloa, Kahe, and Waiau) have relatively little impact to haze in Class I areas in Hawai'i. In addition, an analysis of surface wind patterns on Oahu shows that winds are predominantly from the northeast and thus tend to blow pollutants away from the parks, which are located on the islands of Maui and Hawai'i. As a result, the three Oahu facilities were excluded from consideration for additional controls in this planning period.

The same WEP/AOI analysis identified the Mauna Loa plant as a potential source of haze causing emissions for Hawai'i Volcanoes National Park. Hawaii DOH-CAB therefore added this source to the list for consideration in this planning period and will provide a four-factor analysis for the Mauna Loa Macadamia Nut Corporation Plant in supplementary documents.

The NPS agrees with the refinement of facility selection for reasonable progress analysis and requests an opportunity to review and provide feedback on the Mauna Loa Macadamia Nut Corporation analysis when it becomes available. NPS comments on the Hawai'i four-factor analyses from the draft SIP therefore are focused on: Kanoiehua-Hill Power Plant, Puna Power Plant, Kahului Power Plant, and the Maalaea Generating Station.

## Exhibit 6

### 2.1. Kanoelehua-Hill Power Plant

The Kanoelehua-Hill Power Plant, located on Hawai'i, consists of two boilers combusting No. 6 fuel oil (Hill 5 and Hill 6), one combustion turbine, and four diesel generators. Baseline sulfur dioxide (SO<sub>2</sub>) and nitrogen oxide (NO<sub>x</sub>) emissions given in the four-factor analysis are shown in the following table.

Table 2. Kanoelehua-Hill baseline emissions.

Kanoelehua-Hill Emissions		
Source	SO <sub>2</sub> (tons/year)	NO <sub>x</sub> (tons/year)
Hill 5	821	252
Hill 6	1,347	354
D-11	< 0.1	0.4
D-15	< 0.1	1.9
D-16	< 0.1	0.7
D-17	< 0.1	1
CT-1	< 0.1	0.3

Hawaii DOH-CAB reviewed the four-factor analysis submitted by the company and determined that Hill 5 and Hill 6 would be required to switch to ultra-low sulfur diesel and to install selective catalytic reduction (SCR) and combustion controls. In lieu of installing these controls, Hawaiian Electric has committed to an enforceable shutdown of the Hill 5 and Hill 6 boilers by 2028. The NPS supports the state's control determination for this facility.

### 2.2. Puna Power Plant

The Puna plant sources consist of one boiler combusting No. 6 fuel oil and one combustion turbine using No. 2 fuel oil. Baseline SO<sub>2</sub> and nitrogen oxide NO<sub>x</sub> emissions given in the four-factor analysis are shown in the following table.

Table 3. Puna baseline emissions.

Puna Emissions		
Source	SO <sub>2</sub> (tons/year)	NO <sub>x</sub> (tons/year)
Boiler	184	22.7
CT-3	2.9	6.8

Hawaii DOH-CAB reviewed the four-factor analysis submitted by the company and determined that the boiler would be required to switch from No. 6 fuel oil to ultra-low sulfur diesel by four years from the issuance of a new permit. The NPS supports the state's control determination for this facility.

## Exhibit 6

### 2.3. Kahului Power Plant

The Kahului power plant includes two 5.0 MW boilers, one 11.5 MW boiler, and one 12.5 MW boiler. Baseline SO<sub>2</sub> and NO<sub>x</sub> emissions for the facility are shown in the following table. All four boilers are currently combusting No. 6 fuel oil. Kahului baseline emissions are shown in the following table.

Table 4. Kahului baseline emissions.

Kahului Emissions		
Source	SO <sub>2</sub> (tons/year)	NO <sub>x</sub> (tons/year)
K1	293	66
K2	253	62
K3	899	293
K4	776	183

Hawaii DOH-CAB reviewed the four-factor analysis submitted by the company and determined that all four boilers would be required to switch to ultra-low sulfur diesel and to install SCR and combustion controls. Hawaiian Electric has committed to an enforceable shutdown of boilers K1–K4 by 2028 instead of adopting the required control measures. The NPS supports the state’s control determination for this facility.

### 2.4. Maalaea Power Plant

The Maalaea power plant includes 19 emissions sources:

- Five 2.5 megawatt (MW) diesel engine generators (M1, M2, M3, X1, and X2) currently firing ultra-low sulfur diesel (ULSD);
- Six 5.9 MW diesel engine generators (M4, M5, M6, M7, M8, and M9) currently firing diesel with a maximum sulfur content of 0.4 percent by weight;
- Four 12.5 MW diesel engine generators (M10, M11, M12, and M13) currently firing diesel with a maximum sulfur content of 0.4 percent by weight; and
- Four 20 MW combustion turbine generators (M14, M16, M17, and M19) currently firing diesel with a maximum sulfur content of 0.4 percent by weight.

## Exhibit 6

Baseline emissions for these sources are shown in the following table:

Table 5. Maalaea baseline emissions.

Maalaea Emissions		
Source	SO <sub>2</sub> (tons/year)	NO <sub>x</sub> (tons/year)
M1	0.001	10
M2	0.001	6
M3	0.001	10
M4	2	81
M5	2	83
M6	1	61
M7	2	123
M8	1	61
M9	2	102
M10	12	580
M11	10	506
M12	11	406
M13	11	420
X1	0.002	5
X2	0.002	5
M14	32	85
M16	37	99
M17	59	77
M19	54	66

Based on the results of the four-factor analysis, Hawaii DOH-CAB determined that fuel injection timing retard (FITR) would be required for diesel engine generators M1, M2, and M3 and SCR would be required for diesel engine generator M7 by 2028. No controls were determined to be cost-effective for the other 15 emissions sources at the facility.

As shown in Table 5, engines M10–M13 together account for 1,912 tons/year of NO<sub>x</sub> emissions, this is approximately 69% of the total NO<sub>x</sub> emissions at the facility. These four engines are rated at 17,520 hp each. Appendix I, Rev 1 of the SIP contains the four-factor analysis for Maalaea. Hawaii DOH-CAB’s estimated costs for SCR on the 15 diesel engine generators are presented in Table 4-3 on page 147. The cost-effectiveness for SCR on the four largest engines, M10–M13, are:

- \$8,757/ton NO<sub>x</sub> removed for M10,
- \$8,895/ton NO<sub>x</sub> removed for M11,
- \$12,423/ton NO<sub>x</sub> removed for M12, and
- \$11,292/ton NO<sub>x</sub> removed for M13.

## Exhibit 6

These costs are all above the Hawaii DOH-CAB cost-effectiveness threshold of \$5,800/ton and were therefore not considered cost effective.

### M10–M13 NO<sub>x</sub> control cost estimates

#### *Draft SIP analysis*

The total annualized cost estimates for controls are the sum of estimated annualized capital recovery costs and annual operating costs. According to the notes in Table 4-3, the capital recovery costs were determined using a cost factor of \$27,837 per MW, based on a 2012 internal engineering report for units M5–M9. The internal report that this cost factor was based upon is not included in the draft SIP and has not been provided for NPS review. Therefore, the NPS is unable to directly evaluate the capital recovery cost estimates for the diesel engine generators.

Available information indicates that the annual operating costs were determined using a cost factor \$0.0452 per engine horsepower per operating hour. As detailed in Appendix A, Table A-1 on page 153 of the four-factor analysis, the annual operating cost factor was determined using information in an EPA document titled *Assessment of Non-EGU NO<sub>x</sub> Emission Controls, Cost of Controls, and Time for Compliance, Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS*, Docket ID No. EPA-HQ-OAR-2015-0500, November 2015. Table 5-6 of the TSD, [SCR for Diesel Lean Burn Engines—Assumptions](#), page 5–13, presents cost factors of \$98/hp for capital costs and annual costs of \$40/hp (including capital recovery). These figures are use in the SIP’s Appendix A, Table A-1 to derive the annual operating cost factor.

According to the EPA TSD, “The costs and cost effectiveness for applying SCR to diesel lean burn engines is provided in *Alternative Control Techniques Document: Stationary Diesel Engines* (EPA 2010).” According to this 2010 report, the source for capital cost estimates for diesel engine SCR applications is a 2006 memorandum titled “Memorandum from Brenda Riddle, AGTI to Jaime Pagán, EPA Energy Strategies Group, Control Technologies for Internal Combustion Engines, May 22, 2006.” The cost methodology used to estimate the costs for operating/supervisory labor, maintenance, ammonia, steam diluent, and fuel penalty were calculated using the EPA Control Cost Manual; this methodology was used to derive the annual operating cost factor. The source documents for the SIP’s annual operating cost factor thus appear to be from 2010 and 2006.

#### *Control cost reference*

EPA’s 2017 update to the Control Cost Manual, Section 1, Introduction, Chapter 2, Cost Estimation: Concepts and Methodology, p. 19, says: “*It should be noted that the accuracy associated with escalation (and its reverse, de-escalation) declines the longer the time period over which this is done. Escalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate. [9] Thus, obtaining new price quotes for cost items is advisable beyond five years.*”

#### *NPS analysis*

To estimate SCR costs for engines M10–M13, the NPS used the SCR cost estimation Excel worksheet provided with the 7<sup>th</sup> edition of the Control Cost Manual, available online at <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual>. This resulted in cost-effectiveness estimates of \$931–\$1,240/ton NO<sub>x</sub> removed (see attached calculation workbooks).

## Exhibit 6

NPS analyses assumed:

- a retrofit factor of 1,
- a remaining useful life of 20 years,
- a NO<sub>x</sub> removal efficiency of 90%, and
- an interest rate of 5.31% for Maui as specified by Hawaii DOH-CAB in the draft SIP.

This is a preliminary analysis because information was not available for all input parameters. As a result, some values required by the worksheet (e.g., annual MW-hours) have been estimated and others (such as net plant heat rate, electricity and labor costs, etc.) were left at their default values. The results suggest that SCR may be significantly more cost-effective than the estimates provided in the four-factor analysis.

The NPS recommends that Hawaii DOH-CAB reconsider the cost factors and methodology used for the Maalaea diesel engines M10–M13 and update the cost-effectiveness estimates if needed. Further, the NPS recommends that Hawaii DOH-CAB require SCR for these engines as a technically feasible cost-effective control to reduce NO<sub>x</sub> emissions if cost-effectiveness is found to be within the established threshold. The NPS supports Hawaii DOH-CAB's request for a vendor quote as this would provide the highest level of certainty for evaluating the cost-effectiveness of SCR for these engines.

### 3. Editorial recommendations

In some locations in the text of the draft SIP, the name of Hawai'i Volcanoes National Park is incorrectly given as "Volcanoes National Park." These locations include the list of figures (for Figure 1.3–2), in Table 1.2–1 page 3, and in the title of Figure 1.3–2 on page 5. Please correct these with the full park name "Hawai'i Volcanoes National Park."



# Section 1

## Introduction

## Chapter 2

# Cost Estimation: Concepts and Methodology

John L. Sorrels  
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Air Economics Group  
Health and Environmental Impacts Division  
Office of Air Quality Planning and Standards  
U.S. Environmental Protection Agency  
Research Triangle Park, NC 27711

November 2017

# Exhibit 7

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## Exhibit 7

### 2.1 Introduction

This chapter presents a methodology that will enable the user, having knowledge of the source being controlled, to produce study-level estimates of the costs incurred by regulated entities for a control system applied to that source. The methodology, which applies to each of the control systems included in this Manual, is general enough to be used with other “add-on” systems as well. Further, the methodology can apply to estimating the costs of fugitive emission controls and other non-stack abatement methods.

There are several types of users for this Manual. Industrial users are the most common, but State, local, other officials, and other environmental stakeholders (e.g., environmental groups) are other users of the Manual. EPA strongly recommends that the methodology in this Manual be followed as part of compliance with various Clean Air Act programs.

The cost estimation methodology can be used in the development of assessing private compliance decisions/strategies or effects of permits as various alternatives are considered. If the regulation or permit prescribes a particular control technology (e.g., installation of a scrubber), then the costs of individual controls can be estimated for affected entities. If the regulation or permit establishes performance standards, with flexibility as to how the standards can be achieved, then the cost estimation methods can be used to estimate the costs of various options for achieving the standards.

We note that these cost estimation procedures are meant to support the calculation of the costs of purchasing and installing pollution control equipment, and then operating and maintaining this equipment, at a facility. Such costs are private costs because they reflect the private choices and decisions of the owners and operators of the facilities. Broader costs associated with the installation and operation of pollution control equipment, such as impacts on society (e.g., changes in prices to consumers due to the impact on a producer from additional pollution control) are analyzed using methods that assess the social costs of regulatory intervention.

Again, the methods provided in this Manual is to aid in assessing private choices that regulated entities may undertake in complying with regulation. Analyzing private decisions and the associated costs are important in and of itself and can be used as inputs to assessing the likely effects of regulations. In other words, the cost estimation methodology in this Manual is meant for private cost estimation, not social cost estimation. Information on social cost estimation can be found in the EPA Economic Guidelines and the U.S. Office of Management and Budget’s Circular A-4. This Manual is not intended to assess the likely effects of federal regulations to society, but is intended to provide assessment of private actions which can be inputs to social impacts analysis.

Users with the role of developing or reviewing compliance plans can use this Manual to estimate private costs of installing and operating control equipment. Regulated entities facing regulation can use this Manual to help decide how to comply with the requirements they are facing.

## Exhibit 7

### 2.2 Private Versus Social Costs

Before delving deeper into a discussion on estimating private costs, identifying the differences between private and social costs is important. The Manual focuses on private cost, which refers to the costs borne by a private entity for an action the private entity decides. For example, if the private entity pays for the cost of installing and operating pollution control equipment, among many options available to the entity, the entirety of these costs would be considered private costs.

The EPA's Guidelines for Preparing Economic Analysis define social cost as follows: "Social cost represents the total burden a regulation will impose on the economy; it can be defined as the sum of all opportunity costs incurred as a result of a regulation. These opportunity costs consist of the value lost to society of all the goods and services that will not be produced and consumed if firms comply with the regulation and reallocate resources away from production activities and towards pollution abatement. To be complete, an estimate of social cost should include both the opportunity costs of current consumption that will be forgone as a result of the regulation, and the losses that may result if the regulation reduces capital investment and thus future consumption."<sup>1</sup>

The term social cost refers to the overall cost of an action to society, not just to the private entity that incurs the expense to control pollution. Social cost is based on the concept of opportunity cost, the value associated with production and consumption that are reduced or changed as a result of reallocating resources to reduce pollution.

Assessing private cost is more straightforward because it attempts to tally up expenses that individual entities or facilities incur to purchase, finance, and operate pollution abatement equipment or strategies. Suppose a state government wanted to encourage pollution control for a certain industry and provided grants to pay half of the costs of a scrubber. The private cost for the industry would be 50% of the cost of a scrubber. Using another example, suppose a firm purchases equipment, pays sales tax on the item, and receives an immediate tax rebate. The private cost to the firm is the sum of the equipment price plus the sales tax amount minus the excise tax amount.

The estimation of private costs is the focus of the cost estimation procedures and data in this Manual. Both EPA and OMB have developed guidance on methods appropriate for use in estimating social costs for regulatory impact analysis or economic impact analysis where the social costs of government interventions are assessed. The guidelines presented in this Manual are not suitable in conducting regulatory impact analysis or economic impact analysis where the social costs of government interventions are assessed. Because this Manual focuses on private costs to facilities of installing and operating pollution control equipment, we will not present the

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<sup>1</sup> U.S. Environmental Protection Agency, Office of Policy, National Center for Environmental Economics. Guidelines for Preparing Analysis. May 2014. Pp. 8-1 – 8-2.

## Exhibit 7

methodologies for social cost calculations. For more information on social cost estimation methods, please see EPA's Economics Guidelines [5] and OMB Circular A-4 [6].

### 2.3 Types of Cost Estimates

As mentioned in Chapter 1.1, the costs and estimating methodology in this Manual are directed toward the "study" estimate with a probable error of 30% percent. According to Perry's Chemical Engineer's Handbook, a study estimate is "... used to estimate the economic feasibility of a project before expending significant funds for piloting, marketing, land surveys, and acquisition ... [I]t can be prepared at relatively low cost with minimum data." [1] The accuracy of the study-level estimate is consistent with that for a Class 4 cost estimate as defined by the Association for Advancement of Cost Engineering International (ACEI), which ACEI defines as a "study or feasibility"-level estimate. [2]

Specifically, to develop a study estimate, the following must be known:

- Location of the plant;
- Location of the source within the plant;
- Design parameters, such as source size or capacity rating, uncontrolled pollutant concentrations, pollutant removal requirements, etc.
- Rough sketch of the process flow sheet (i.e., the relative locations of the equipment in the system);
- Preliminary sizes of, and material specifications for, the system equipment items;
- Approximate sizes and types of construction of any buildings required to house the control system;
- Rough estimates of utility requirements (e.g. electricity, steam, water, and waste disposal);
- Quantity and cost materials consumed in the process (e.g., water, reagents, and catalyst);
- Preliminary flow sheet and specifications for ducts and piping; Approximate sizes of motors required;
- Economic parameters (e.g. annual interest rate, equipment life, cost year, and taxes.) [1]

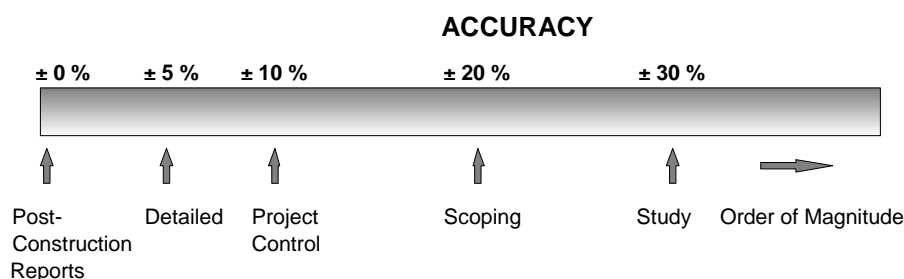
Besides the labor requirements for construction and operation of a project, the user will need an estimate of the labor hours required for engineering and drafting activities because the accuracy of an estimate (study or otherwise) depends on the amount of engineering work expended on the project. There are four other types of estimates, three of which are more accurate than the study estimate. Figure 2.1 below displays the relative accuracy of each type of cost estimation process. The other processes are: [1]

- Order-of-magnitude. This estimate provides "a rule-of-thumb procedure applied only to repetitive types of plant installations for which there exists good cost history." Its

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probable error bounds are greater than 30%. (However, according to Perry's, "... no limits of accuracy can safely be applied to it.") The sole input required for making this level of estimate is the control system's capacity (often measured by the maximum volumetric flow rate of the gas passing through the system).

- Scope, Budget Authorization, or Preliminary. This estimate, with probable error of 20%, requires more detailed knowledge than the study estimate regarding the site, flow sheet, equipment, buildings, etc. In addition, rough specifications for the insulation and instrumentation are also needed.
- Project Control or Definitive. This estimate, with a probable error of 10%, requires yet more information than the scope estimates, especially concerning the site, equipment, and electrical requirements.
- Firm, Contractor's, or Detailed. This is the most accurate (probable error of 5%) of the estimate types, requiring complete drawings, specifications, and site surveys. Consequently, detailed cost estimates are typically not available until right before construction, since "time seldom permits the preparation of such estimates prior to an approval to proceed with the project." [1]



**Figure 2.1:** The Continuum of Accuracy for Cost Analyses

These error bands are attempts at assessing the probable errors associated with each estimation method based on past practices of the engineering cost-estimation discipline. However, the error bands do not shed any light on the distribution of the likely errors. The users of this Manual should not draw conclusions about probable errors that this Manual does not intend.

Study-level estimates represent a compromise between the less accurate order-of-magnitude estimates and the more accurate estimate types. The former is too imprecise to be of much value in the context of pollution control installation and operation, while the latter are very expensive for an entity to prepare, and require detailed site- and process-specific knowledge that some Manual users are unlikely to have. Over time, this Manual has become the standard for air pollution control costing methodologies for many State regulatory agencies. For example, Virginia requires that the Manual be used in making cost estimates for BACT and other permit applications, unless the permit applicant can provide convincing proof that another cost reference should be

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used.<sup>2</sup> Texas accepts the Manual methodology “as a sound source for the quantitative cost analysis” for BACT analyses it reviews.<sup>3</sup>

The industrial user is more likely to have site-specific and detailed information than the average cost and sizing information used in a study estimate. The methodology laid out in this Manual can provide cost estimates that are more accurate when using detailed site-specific information. The anecdotal evidence from most testimonials volunteered by industrial users indicates that much greater accuracy than 30 percent probable error can be attained. However, this Manual does not assume that detailed site-specific information will always be available to estimate costs associated with installing and operating pollution abatement equipment at a much higher accuracy level. This Manual retains the conclusion that the cost methodology laid out in this chapter and information in each control measure chapter with 30% probable error is relevant to be used in air pollution control cost estimation for permitting actions. It is the affected industry source that bears the burden of providing information of sufficient quality that will yield cost estimates of at least a study-level estimate for permitting decisions pertaining to their facilities.

### 2.4 Cost Categories Defined

The terminology addressing cost categories used in the earlier editions of this Manual was adapted from the AACEI. [2]. However, different disciplines give different names to the same cost components, and the objective of this edition is to reach out to a broader scientific audience. For example, engineers determine a series of equal payments over a long period of time that fully funds a capital project (and its operations and maintenance) by multiplying the present value of those costs by a capital recovery factor, which produces an Equivalent Uniform Annual Cost (EUAC) value. This is identical to the process used by accountants and financial analysts, who adjust the present value of the project’s cash flows to derive an annualized cost number.

#### 2.4.1 Elements of Total Capital Investment

In assessing the total capital investment, this Manual takes the viewpoint of an owner, the firms making the investment, or those who have material interest in the project. Total capital investment (TCI) includes all costs required to purchase equipment needed for the control system (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings, and certain other costs (indirect installation costs). TCI also includes costs for land, working capital, and off-site facilities.<sup>4</sup> Taxes, permitting costs, and other administrative costs are covered in Section 2.6.5.8. Financing costs

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<sup>2</sup> State of Virginia, Department of Environmental Quality. Draft PSD Guidelines, August 4, 2011. Pp. 4-4 to 4-5.

<sup>3</sup> Texas Commission on Environmental Quality. Air Permits Division. Air Permit Reviewer Reference Guide, APDG 6110. Appendix G. p. 45. January 2011.

<sup>4</sup> Estimates of TCI for some control measures may not necessarily be calculated in this way due to availability of public information on capital investment costs and equations for those measures, such as the SNCR and SCR chapters in this Manual.



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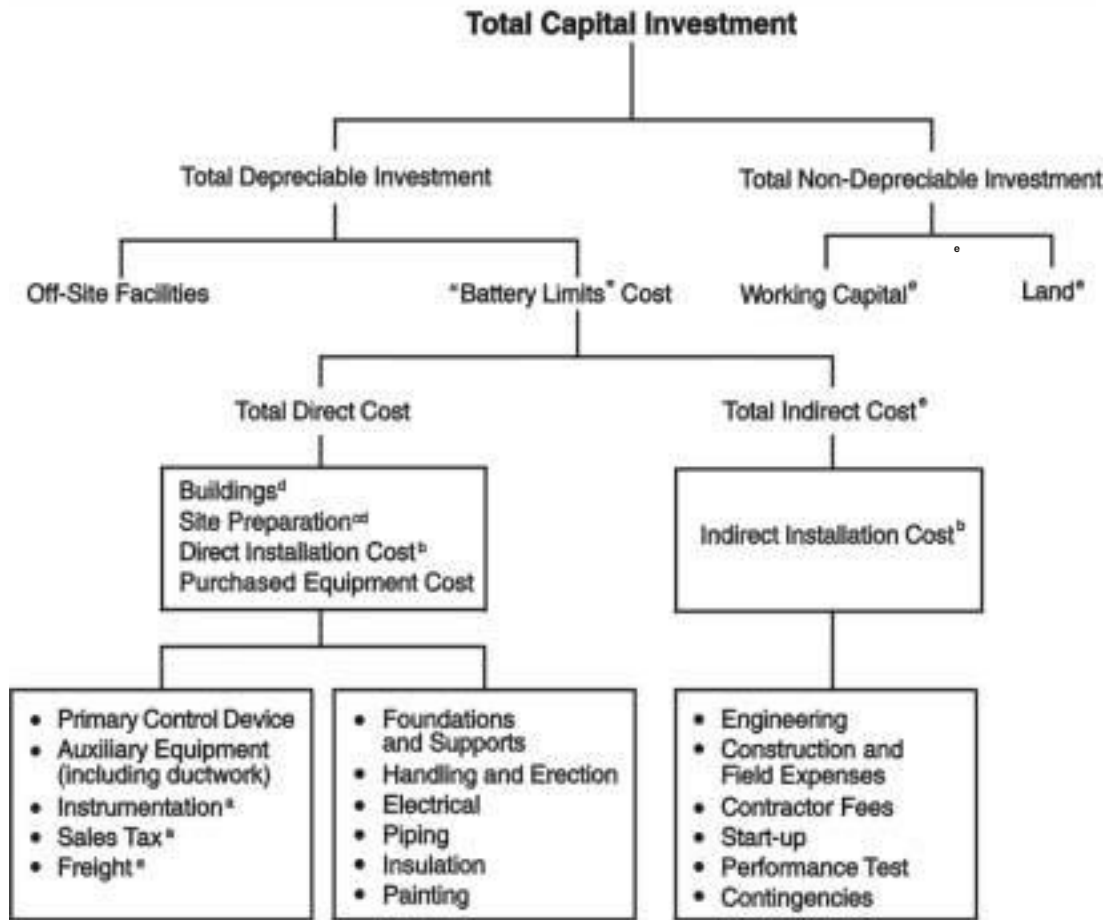
are covered in Sections 2.5.3 and 2.5.4. Foregone revenue associated with facility shut downs are covered in Section 2.6.4.2.

Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation, and painting. Indirect installation costs include such costs as engineering costs; construction and field expenses (i.e., costs for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies. Another item within owner's costs, technology royalties, is not separately included with the Manual's methodology because technology royalties are assumed to be reflected within the purchased equipment costs. Contingencies is a catch-all category that covers unforeseen costs that may arise, such as "... possible redesign and modification of equipment, escalation increases in cost of equipment, increases in field labor costs, and delays encountered in start-up." [2] Contingencies are discussed in more detail later in this chapter. Contingencies are not the same thing as uncertainty and retrofit factor costs, which are treated separately in this chapter. Escalation is not treated as part of contingencies. Please refer to section 2.6.4 for further discussion.

The elements of TCI are displayed in Figure 2.2. Note that the sum of the purchased equipment cost, direct and indirect installation costs, site preparation, and buildings costs comprises the battery limits estimate. A battery limit is the geographic boundary defining the coverage of a specific project [3]. Usually this encompasses all equipment of interest (in this case, the pollution control equipment), but excluding provision of storage, utilities, administrative buildings, or auxiliary facilities unless so specified [3]. This estimate would mainly apply to control systems installed in existing plants, though it could also apply to those systems installed in new plants when no special facilities for supporting the control system (i.e., off-site facilities) would be required. Off-site facilities include units to produce steam, electricity, and treated water; laboratory buildings; and railroad spurs, roads, and other transportation infrastructure items. Some pollution control systems do not generally have off-site capital units dedicated to them since these pollution control devices rarely consume energy at that level. However, it may be necessary—especially in the case of control systems installed in new or “grass roots” plants—for extra capacity to be built into the site generating plant to service the system. For example, installation of a venturi scrubber, which often requires large amounts of electricity, would require including costs associated with off-site facilities.

Note, however, that the capital cost of a device does not include routine utility costs (which can include the cost of steam, electricity, process and cooling water, compressed air, refrigeration, waste treatment and disposal, and fuel), even if the device were to require an offsite facility. Utility costs are categorized as operating costs that covers both the investment and operating and maintenance costs for the utility. The utility costs associated with start-up operations are included in the “Start-Up” component of the indirect installation costs. Operating costs are discussed in greater detail below. In addition, not every air pollution control system installation will have all of the elements for its TCI that are listed below (e.g., buildings).

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<sup>a</sup>Typically factored from the sum of the primary control device and auxiliary equipment costs.

<sup>b</sup>Typically factored from the purchased equipment cost.

<sup>c</sup>Usually required only at “grass roots” installations.

<sup>d</sup>Unlike the other direct and indirect costs, costs for these items usually are not factored from the purchased equipment cost. Rather, they are sized and costed separately.

<sup>e</sup>Normally not required with add-on control systems.

**Figure 2.2: Elements of Total Capital Investment**

As Figure 2.2 shows, the installation of pollution control equipment may also require land, but since some add-on control systems take up very little space (often a quarter-acre or less), this cost may be relatively small. Certain control systems, such as those used for flue gas desulfurization (FGD) or selective catalytic reduction (SCR), require larger quantities of land for the equipment, chemicals storage, and waste disposal. In these cases, especially when performing a retrofit installation, space constraints can significantly influence the cost of installation, and the purchase of additional land and remediation of existing land and property may be a significant factor in the development of the project’s capital costs.

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However, land is not treated the same as other capital investments, since it is not depreciated for accounting purposes. The value of the land may fluctuate depending on the market conditions, but for accounting purposes and assessing private costs, land is not depreciated. The purchase price of new land needed for siting a pollution control device can be added to the TCI, but it must not be depreciated. If the firm plans on dismantling the device at some future time, the value of the land should be included at the disposal point as an “income” to the project to net it out of the cash flow analysis (more on cash flow analysis later, in section 2.5.4).

One might expect initial operational costs (the initial costs of fuel, chemicals, and other materials, as well as labor and maintenance related to start-up) to be included in the operating cost section of the cost analysis instead of in the capital component, but such an allocation would be inappropriate. Routine operation of the control does not begin until the system has been tested, balanced, and adjusted to work within its design parameters. Until then, all utilities consumed, all labor expended, and all maintenance and repairs performed are a part of the construction phase of the project and are included in the TCI in the “Start-Up” component of the indirect installation costs.

In addition, the TCI of controls for sources that affect fan capacity (e.g., FGD scrubbers, SCRs) may be impacted by the unit’s elevation with respect to sea level. Cost calculations for the control measures within the Manual have typically been developed for systems located at sea level. For systems located at higher elevations (generally over 500 feet above sea level), the purchased equipment cost and balance of plant cost should be increased based on the ratio of the atmospheric pressure between sea level and the location of the system, i.e., atmospheric pressure at sea level divided by atmospheric pressure at the elevation of the unit.<sup>5</sup>

The method for estimating TCI in this Manual is an “overnight” estimation method. This method estimates capital cost as if no interest was incurred during construction and therefore estimates capital cost as if the project is completed “overnight.” An alternate way of describing this method is the present value cost that would have to be paid as a lump sum up front to completely pay for a construction project. Cost items such as Allowance for Funds Used During Construction (AFUDC), which is defined as the costs of debt and equity funds used to finance plant construction, and is an amount credited on the firm’s statement of income and charged to construction in progress on the firm’s balance sheet, is treated separately in Section 2.5.3 in this Manual. This item is an estimate that is incurred over the timespan of construction. For example, this is considered as a cost item within the electric power industry.<sup>6</sup> [15] Other cost items similarly treated separately include escalation of costs to a future year due to inflation in Section 2.5.4. We provide more discussion later in this chapter on these cost items that are not included in this section.

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<sup>5</sup> One instance of this is the estimates of costs for the recently revised SNCR and SCR Control Cost Manual chapters, which are available at <http://www.epa.gov/ttn/ecas/costmodels.html>.

<sup>6</sup> See the National Energy Technology Laboratory’s “Quality Guidelines for Energy System Studies: Cost Estimation Methodology for NETL Assessments of Power Plant Performance.”

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### 2.4.2 Elements of Total Cost

Total Cost (TC) refers to costs that are incurred yearly. TC has three elements: direct costs (DC), indirect costs (IC), and recovery credits (RC), which are related by the following equation:

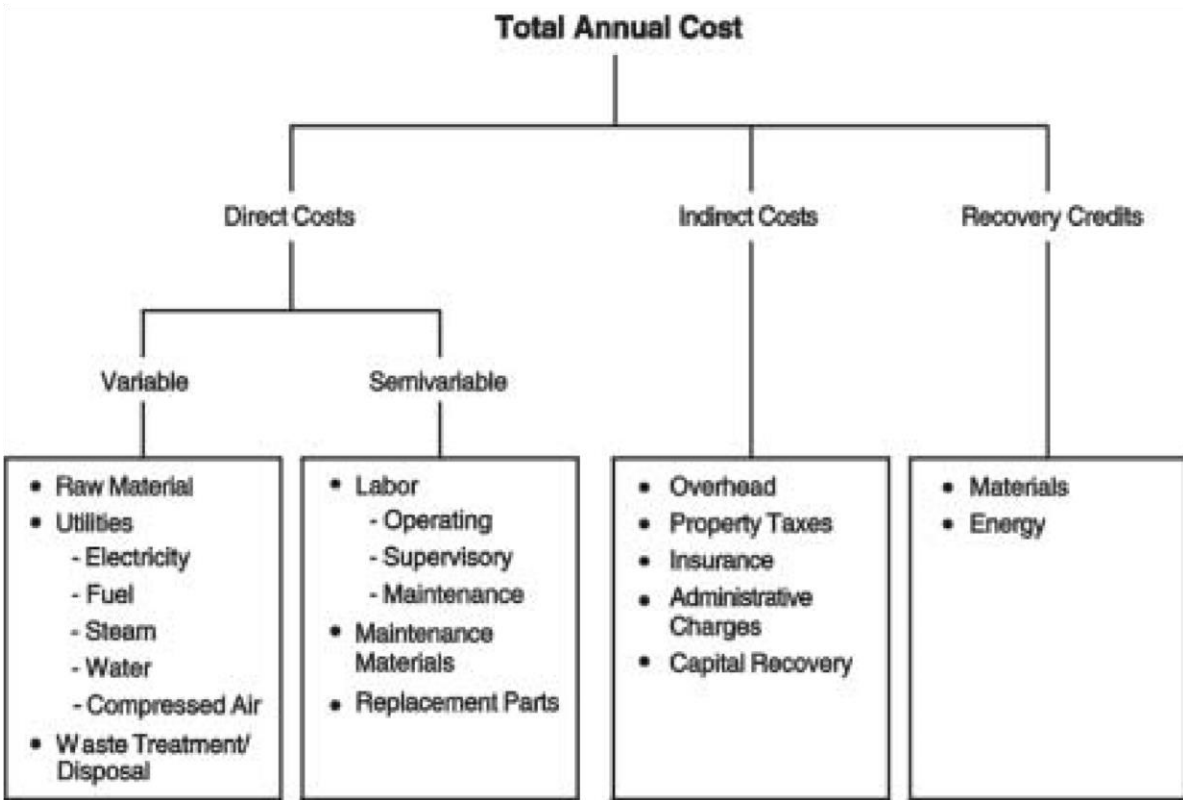
$$TC = DC + IC - RC \quad (2.1)$$

The basis of direct costs and recovery credits is one year, as this period allows for seasonal variations in production (and emissions generation) and is directly usable in financial analyses. (See Section 2.3.) [4] The various annual costs and their interrelationships are displayed in Figure 2.3. Some indirect costs are not incurred on an annual basis. Purchase, installation, and start-up of pollution abatement capital equipment often take multiple years. To incorporate these multi-year costs with other annual costs, the capital costs are amortized and converted into capital recovery. If the timing between direct costs and indirect costs are different, then an alternative approach for estimating total cost is to calculate the present value of these costs before summing them.

Variable costs are those that vary with some measure of productivity - generally the company's productive output. But for our purposes, the proper metric may be the quantity of exhaust gas processed by the control system per unit time. Semi-variable costs also vary with some measure of production, but have a positive cost even when production is zero.

An example would be a boiler producing process steam for only sixteen hours a day. During the time the boiler is idle, it costs less to keep the boiler running at some idle level than to re-heat it at the beginning of the next shift. Consequently, that idle level operation cannot be attributed to production and should be considered the fixed component of the semi-variable fuel cost of the boiler. Direct costs include costs for raw materials (reagents or adsorbers), utilities (steam, electricity, process and cooling water), waste treatment and disposal, maintenance materials (greases and other lubricants, gaskets, and seals), replacement parts, and operating, supervisory, and maintenance labor. Generally, raw materials, utilities, and waste treatment and disposal are variable costs, but there is no hard and fast rule concerning any of the direct cost components. Each situation requires a certain level of insight and expertise on the part of the analyst to present the cost components accurately

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**Figure 2.3:** Elements of Total Annual Cost

Indirect, or “fixed” annual costs are independent of the level of production (or whatever unit of measure serves as the analytical metric) and, in fact, would be incurred even if the control system were shut down. Indirect costs include such categories as administrative charges, property taxes, insurance, administrative charges including permitting costs and capital cost amortized into capital recovery.

Capital is depreciable, indicating that, as the capital is used, it wears out and that lost value cannot be recovered. Economic depreciation, which is the lost value due to wear and tear, is different than accounting depreciation, the declared lost value, that is usually used in a cost analysis. Depreciation costs are a variable or semi-variable cost that is also included in the calculation of tax credits (if any) and depreciation allowances whenever taxes are considered in a cost analysis. However, taxes are not uniformly applied, and subsidies, tax moratoriums, and deferred tax opportunities distort how the direct application of a tax works.

Finally, direct and indirect annual costs can be offset by recovery credits, taken for materials or energy recovered by the control system, which may be sold, recycled to the process, or reused elsewhere at the site. An example of such credits is the by-product of controlling sulfur with a FGD scrubber. As the lime or limestone reagent reacts with the sulfur in the exhaust gas stream, it becomes transformed into CaSO<sub>4</sub> - gypsum - which can be landfilled inexpensively (a direct cost) or collected and sold to wallboard manufacturers (a recovery credit). These credits,

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must be calculated as net of any associated processing, storage, transportation, and any other costs required to make the recovered materials or energy reusable or resalable. Great care and judgment must be exercised in assigning values to recovery credits, since materials recovered may be of small quantity or of doubtful purity, resulting in their having less value than virgin material. Like direct annual costs, recovery credits are variable, in that their magnitude is directly proportional to level of production.

A more thorough description of these costs and how they may be estimated is provided in Section 2.6

### **2.5 Financial Concepts**

Firms have latitude in developing compliance strategies. For standards that are performance oriented, firms have great latitude. Even for standards that are fairly prescriptive and technical in nature, firms still have to make some choices on how to comply. How do they compare these choices or alternatives?

Alternatives will usually have expenditures at multiple times. Not only may the expenditures be different but the timing of expenditures may also be different. When comparing two different investment opportunities, how do you distill all of these data into one comprehensive and coherent form so that an informed decision can be made? This section deals with a number of the concepts and operations that are needed to make a meaningful comparison. They include: selection of an appropriate timeframe, addressing the time value of money, adjusting for prices over time, and selection of the appropriate measure of cost.

#### **2.5.1 Time Frame**

To compare two alternatives in a meaningful way, the comparison is more meaningful when the alternatives are examined over the same time frame or calculate the net present value of the alternatives. For example, if one alternative uses a control device that lasts two years and another alternative uses a device that lasts three years, the alternatives may be difficult to compare directly because of the inconsistent lifetimes of the devices. One approach to developing a more meaningful comparison would be to assume a common time frame by using each type of device for six years, with the two-year alternative being replaced two times and the three-year alternative being replaced once. Another approach is to calculate the net present value of the two alternatives. Amortization or the EUAC method also can be helpful in comparing alternatives with different lifetimes.

#### **2.5.2 Interest Rates**

Firms may borrow to finance the expenses associated with their compliance strategies. The interest rate at which a firm borrows is a key component in estimating the total costs of compliance. Financial markets set different interest rates for different activities depending on many factors.

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The three factors that are relevant to this Manual are: time value of money, inflation risk, and credit risk of borrowers.

Time value of money reflects the timing aspect of borrowing money—a firm would like to borrow now and pay back later and a financial institution would like to lend now and collect later. The time value of money is also known as the real interest rate. Financial institutions know that the price of goods and services will probably increase in the future, but they don't know by how much. So they hedge against this risk by building in a premium for this risk. The credit risk of borrowers refers to the risk associated with whether the loan will be paid back. The credit risk premium will depend on the credit rating of the borrowing firms.

The interest rates that firms face are nominal interest rates. For the rest of the discussion, this Manual assumes that the credit risk of borrowers is essentially zero. Removing the inflation adjustment from the nominal interest rate yields the real rate of interest - the actual cost of borrowing from a societal perspective. In equation form, the nominal interest rate ( $i$ ) equals the ex ante real interest rate ( $i_r$ ) plus the expected rate of inflation ( $p^e$ ) plus the product of the expected inflation rate and the real interest rate as seen in Equation 2.3.

$$i = i_r + p^e + i_r p^e \quad (2.3)$$

This is the well-known Fisher Equation. Since the product of the ex ante real interest rate and expected inflation is small, Equation 2.3 simplifies to:

$$i = i_r + p^e$$

When performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face. Accounting for inflation should be done separately rather than using the real interest rate.

The determination of appropriate private nominal interest rates is important for analyses of private costs done for permit applications where the costs assessed are for the permitted source. Different firms may structure how they finance their purchases differently. Some may choose to finance their purchases through cash holding or other means of equity; some may choose to borrow to finance their investment. When firms choose to borrow, depending on the size of the investment, borrowing could be structured very differently at very different interest rates given the choices firms have for financing an investment. For permit applications, if firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates given the potential difficulties in eliciting accurate private nominal interest rates since these rates may be regarded as confidential business information or difficult to verify. The bank prime rate is published by the Board of Governors of the Federal Reserve

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System.<sup>7</sup> The bank prime rate is the “rate posted by a majority of the top 25 (by assets in domestic offices) insured U.S. chartered commercial banks. The bank prime rate is one of several base rates used by banks to price short-term business loans.”<sup>8</sup> Analysts should use the bank prime rate with caution as these base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers.

For input to analysis of rulemakings, assessments of private cost should be prepared using firm-specific nominal interest rates if possible, or the bank prime rate if firm-specific interest rates cannot be estimated or verified. If neither of these types of private nominal rates are available, then the cost analysis should use 3% or 7%, rates that are used for social cost estimation as discussed later in this section, as a default. Analysts should be especially cautious using 3% and 7% rates in assessing cost of short term assets or projects. These rates represent long-run, real interest rates as described later in this section. Conflating real and nominal interest rates may lead to different conclusions than using consistent interest rates throughout the analysis. Private interest rates are but one component of the overall cost analysis, which will include social cost estimation to reflect relevant guidance from OMB.

To clarify potential confusion that might arise, this Manual discusses the difference between private interest rate and social discount rate. If capital markets are perfect with no distortions (e.g., no taxes, no risk), then the return to savings (the consumption rate of interest) equals the return on private sector investments. Therefore, when the government needs to convert future costs and benefits into present value terms in the same way as the affected individuals would do so, it should also discount using this single market rate of interest. In other words, in this “first best” world, the private market interest rate would be an unambiguous choice for the social discount rate. However, ‘real-world’ issues make the issue much more complicated. For example, private sector investment returns are taxed (often at multiple levels), capital markets are not perfect, and capital investments often involve risks reflected in market interest rates (i.e., lenders charge riskier projects higher rates of interest to compensate for lenders’ risk). All of these factors drive a wedge between the social rate at which consumption can be traded through time (the pre-tax rate of return to private investments) and the rate at which individuals can trade consumption over time (the post-tax consumption rate of interest).

As stated earlier, interest rate accounts for the time value of money, inflation, and other premiums, including risks, faced by lenders. The social discount rate is the rate at which society can trade consumption through time (i.e., the time value of money). When assessing the societal effect of regulations, such as for EPA rulemakings that are economically significant according to Executive Order 12866, analysts should use the 3% and 7% real discount rates as specified in the U.S. Office of Management and Budget (OMB)’s Circular A-4 [6]. The 3% discount rate represents the social discount rate when consumption is displaced by regulation and the 7% rate

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<sup>7</sup> Board of Governors of the Federal Reserve System. “Selected Interest Rate (Daily) – H.15.” Available at: <https://www.federalreserve.gov/releases/h15/> (Accessed August 4, 2017).

<sup>8</sup> Board of Governors of the Federal Reserve System. “Selected Interest Rate (Daily) – H.15.” Available at: <https://www.federalreserve.gov/releases/h15/> (Accessed August 4, 2017).



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represents the social discount rate when capital investment is displaced. Regardless, these are real social discount rates that are riskless. Therefore, they are not appropriate to use to assess private costs that will be incurred by firms in making their investment decisions. In assessing these private decisions, interest rates that face firms must be used, not social rates.

### 2.5.3 Prices and Inflation

With changes in prices over time for all relevant goods and services such as capital equipment, engineering services, other materials and reagents used in the construction and operation of control equipment, inflation's impacts on prices and their effect on cost estimates is of concern to Manual users. The prices in the Manual were not standardized. Some chapters had prices for materials and reagents developed in the late 1990s, and other chapters had prices developed from as far back as 1985. Because these differences were not explicitly discussed in these earlier additions, the Agency attempted to standardize all prices into a particular base year's dollar in subsequent editions of the Manual to reduce the chance for analytical error. In the sixth edition of the Manual, EPA updated all the costs to at least 1990. For the seventh edition of the Manual, EPA will update the costs to at least 2012.

Updating costs for this Manual is an effort with a goal of standardizing all costs to one base year for a particular analysis. Each chapter of the Manual fully discloses the limitations of the costing information found in that chapter. This allows the analyst to make any adjustment they deem necessary, provided sufficient basis exists, and assuming the approval of the appropriate regulatory agency.

To develop the costs used in each of the chapters of this Manual, we attempted to survey the largest possible group of vendors and collected information from industry literature and other technical reports to determine an industry average price for each cost component. In many cases, this involved contact with a number of vendors, including trade associations, and the assimilation of large amounts of data. In other cases, the pollution control equipment was supplied by only a few vendors, which limited the robustness of our models. And, in still other cases, the number of existing manufacturers or the highly site-specific nature of their installation made it difficult for us to develop robust prices for some components. While recognizing the difficulties in providing manufacturer-specific or site-specific information, this Manual also acknowledges that timeliness of such information is important. If the survey information is not timely, errors to the cost estimation would be introduced in unknown ways. Thus, every effort is made to update the information in as timely a manner as possible.

In collecting and using prices in estimating pollution control costs, one should be cognizant of the effect of inflation. We can define prices in "real" and "nominal" terms. Real and nominal prices act in the same way as real and nominal interest rates. Nominal prices are actual prices (i.e., the sticker or spot price) and represent the value of a particular good at a particular point in time. Real prices remove the effect of inflation. The reason for using real price is that purchases may happen over several years especially for projects that invest heavily in capital. Because purchasing

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power in any given year may be different than other years, combining nominal prices is like mixing apples and oranges.

This Manual uses real prices for estimation of capital costs (in this case, an older capital cost to a more recent year), and other costs for any given cost analysis, not nominal prices. Using a price of reagent, catalyst, or other cost input to reflect possible price changes over the equipment lifetime is not correct in adjusting for inflation. Hence, the inclusion of price inflation via escalation estimates or having input prices reflect price changes over time as part of capital cost estimation is not allowed under the Control Cost Manual Methodology. The capital cost should be estimated for the time that the cost estimate is prepared, and should not be escalated to some future year, such as an anticipated date that construction will be completed or some other future year unless the analyst has a robust method to forecast future inflation. A linear extrapolation of past inflation is not a robust method of forecasting future inflation.

Adjusting nominal prices to real prices involves establishing a base year for comparison purposes and then creating an adjustment factor for each year's prices relative to those in the base period. This adjustment factor is a price index (PI) that can then be used to adjust nominal prices to an equivalent base year value; derived through the following formula:

$$PI = \frac{\text{price in given year}}{\text{price in base year}} \quad (2.5)$$

For example, if the price of a reagent in 2010 is 100, and we want a reagent price for 2012, then an index value of 1.2 for that reagent price between 2012 and 2010 will yield a 2012 price of 120. The Federal government and industry develop a variety of indexes tailored to the analysis of specific price issues. The most recognizable of these indexes are the Consumer Price Index (CPI), the Producer Price Index (PPI) and Gross Domestic Price (GDP) implicit deflator, which investigate the change in prices across the entire economy. The most relevant price index for private cost estimation is PPI, and PPI is provided at the 6-digit North American Industry Classification System (NAICS) level. However, for some equipment and materials, even a 6-digit NAICS code level PPI may be too general for the specific needs of industry in the course of an analysis and should only be used if other indexes, particularly well-documented indexes for specific industries, materials, or uses, are not available.

The CPI is not recommended because the price change of interest is among consumer goods and services which have little relevance to capital project spending or industrial intermediate goods such as raw materials such as reagents [8]. The Gross Domestic Product (GDP) implicit price deflator measures broad price changes in the economy rather than CPI, which is a measure of only goods bought by consumers. PPI is a measure of inflation faced by

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industries.<sup>9</sup> Other indexes are also available from industry and academic sources through the Internet, industry publications, trade journals, and financial institutions. One index that has been used extensively by EPA for escalation purposes is the Chemical Engineering Plant Cost Index (CEPCI), an index that tracks costs of equipment, construction labor, buildings, and supervision in chemical process industries.<sup>10</sup> Other cost indexes exist, such as Marshall & Swift (M&S), another equipment cost index that is widely used.<sup>11</sup>

It should be noted that the accuracy associated with escalation (and its reverse, de-escalation) declines the longer the time period over which this is done. Escalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate. [9] Thus, obtaining new price quotes for cost items is advisable beyond five years. If longer escalation periods are unavoidable due to limited recent cost data that is reasonably available, then the analysis should use the principles in this Manual chapter to provide as accurate an escalation as possible consistent with the Manual given the limitations of the cost analysis. The appropriate length of time for escalation can vary as a result of significant changes in the cost of major production inputs (e.g., energy, steel, chemical reagents, etc.) and technological changes in control measures, particularly if these changes occur in an unusually short period of time. Hence, shorter time periods for escalation and de-escalation are clearly preferred over longer ones.

### 2.5.4 Financial Analysis

Firms make purchase decisions that occur at different times for different durations and schedule paybacks which also occur at different times as well. Because of these reasons, the following financial analysis tools are necessary because they allow firms, state regulators, and other users of the Manual to be able to compare the costs of different compliance strategies.

#### 2.5.4.1 Net Present Value

The process through which future cash flows are translated into current dollars is called present value analysis. When the cash flows involve income and expenses, it is also commonly referred to as net present value (NPV) analysis. In either case, the calculation is the same: adjust the value of future money to values based on the same year (generally year zero of the project), employing an appropriate interest (discount) rate and then add them together, after all income and expenses have been converted into the same year dollar using appropriate price indices.

Derivation of a cash flow's net present value involves the following steps:

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<sup>9</sup> U.S. Bureau of Labor Statistics. "Comparing the Consumer Price Index with the gross domestic product price index and gross domestic product implicit price deflator." Monthly Labor Review. March 2016.

<sup>10</sup> This index is available at <http://www.chemengonline.com/pci>. It is also available in Chemical Engineering magazine. Mention of this index is not meant to offer commercial endorsement by EPA.

<sup>11</sup> More information on this cost index can be found at <http://www.corelogic.com/products/marshall-swift-valuation-service.aspx>.

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- Identification of alternatives. For example, the choice between a fabric filter/baghouse and an electrostatic precipitator (ESP) for removing particulate matter (PM) from a flue gas stream.
  - Determination of costs and cash flows over the life of each alternative. Each of the subsequent chapters of this Manual offers detailed costing information on specific air pollution control devices and equipment.
  - Determination of an appropriate real interest or discount rate(s). The appropriate interest rate in private cost assessment is the private interest rate for each firm affected. Determining private interest rates may be difficult due to the firm-specific nature of the private nominal interest rates faced by firms. If firm-specific private nominal interest rates are available, then the appropriate rates are simply the difference between the nominal interest rate minus the prevailing inflation in the industry. Industrial and other users of this Manual should consult with their financial officers and/or trade associations for input regarding such rates. More extensive discussion of interest rates can be found earlier in this Manual in Section 2.5.2. If discounting is performed using the same rate across all alternatives, ranking of alternatives by cost will always yield the same order, no matter which rate is used.
  - For each alternative: Calculate a discounting factor for each year over the life of the equipment. The discount factor formula is:  $DF_t = \{1/(1+i)^t\}$  where  $i$  is the discount rate and  $t$  is the number of years. For example, using a seven percent discount rate produces discount factors of: 0.9346, 0.8734, 0.8163, 0.7629, and 0.7130 for the 1<sup>st</sup>, 2<sup>nd</sup>, 3<sup>rd</sup>, 4<sup>th</sup>, and 5<sup>th</sup> years of a piece of equipment's life, respectively. Table A.1 in Appendix A displays discount factors for interest rates from 5.5 to 15 percent, in half-percent increments for 25 years.
  - For each year's cash flows, sum all incomes and expenses to determine the net cash flow for that year in nominal terms.
  - Multiply each year's net cash flow by the appropriate discount factor.
  - Sum the discounted net cash flows to derive the net present value.
- Compare the net present values from each alternative. The net present value of a stream of cash flows over the life of an investment can be calculated using equation 2.6:

$$NPV = \sum NCF_t * [i/(1-(1+i)^t)] \quad (2.6)$$

where  $NCF_t$  represents the net cash flow for year  $t$ , and  $i$  is the interest rate.

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If discounting is performed using a uniform rate across different mutually exclusive alternatives, ranking of alternatives by cost or net cash flow will always yield the same order, no matter which rate is used or cost approach is employed.

### 2.5.4.2 Amortization: Equivalent Uniform Annual Cost and Annualization

Net present value (NPV) analysis allows us to evaluate between investments by summing the present value of all future incomes and expenses, but that does not give us an insight into the expected cash flows that will actually occur. NPV allows for comparison of alternatives by compressing the value of cost streams or return on investments over same or different time horizons to a single point in time. It's as though regulated entities are paying up front for all the future costs of installation, maintenance, and operation of a pollution control device. However, firms may want to pay back their expenses in equal sums over the life of the control. A common engineering cost tool for this sort of evaluation is called the equivalent uniform annual cash flow (EUAC) approach. [4] In the finance literature, this approach is called amortization.

EPA uses the EUAC approach as the basis for the Control Cost Methodology for the following reason:

- The methodology is general enough to be used for estimating costs for any pollution control measure applied to any industry. In this respect, the EUAC is different from the levelized cost method (LCM), which is a method specific to the electric power industry and requires relatively extensive information to be applied properly as compared to application of the EUAC. The EUAC thus provides consistency in cost analysis of pollution control measures for sources in all industries as part of actions for which the Control Cost Manual is applicable. [7]

Annualization is a process similar to EUAC but is not limited to constant cash flows. It involves determining the NPV of each alternative equipment investment and then determining the equal payment that would have to be made at the end of each year to attain the same level of expenditure. In essence, annualization involves establishing an annual "payment" sufficient to finance the investment for its entire life, using the formula:

$$PMT = NPV * (i / (1 - (1 + i)^{-n})) \quad (2.7)$$

where  $PMT$  is the equivalent uniform payment amount over the life of the control equipment,  $n$ , at an interest rate,  $i$ .  $NPV$  indicates the present value of the investment as defined above in equation 2.6.

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This payment is the capital recovery cost (*CRC*), which is calculated by multiplying the *NPV* of the investment by the capital recovery factor (*CRF*):

$$CRC = NPV \times CRF \quad (2.8)$$

where *CRF* is defined according to the formula:

$$CRF = i(1+i)^n / ((1+i)^n - 1) \quad (2.8a)$$

The *CRF* equation is a transformation of the *PMT* form in equation 2.7 and returns the same information. Table A.2 in Appendix A lists the *CRF* for interest rates between 5.5 percent and 15 percent for annualization periods from one to 25 years.

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

The life of the control is appropriate to use when the analytic timeline or the length of the analysis is longer than the useful life of the control equipment. If the analytic timeline is shorter than the useful life of the control equipment, use the analytic timeline to annualize the capital cost.

It is crucial that the analyst use the same interest or discount rate to estimate costs using *NPV* and when amortizing (i.e., *EUAC*).

## 2.6 Estimating Procedure

The estimating procedure used in the Manual consists of five steps: (1) obtaining the facility parameters and compliance options for a given facility; (2) preparing the control system design; (3) sizing the control system components; (4) estimating the costs of these individual components; and (5) estimating the costs (capital and annual) of the entire system.

### 2.6.1 Facility Parameters and Regulatory Options

Obtaining the facility parameters and regulatory options involves not only assembling the parameters of the air pollution source (i.e., the quantity, temperature, and composition of the emission stream(s)), but also compiling data for the facility's operation. (Table 2.2 lists examples of these.) We identify two facility parameters: intensive (with values independent of quantity or dimensions) and extensive (size-dependent variables, such as the gas volumetric flow rate).

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Compliance options are usually specified by others (generally a regulatory authority) and are often technology driven, typically defining allowable ways to achieve a predetermined emission limit. These options range from “no control” to a requirement for the system to reach the maximum control technically achievable. The options allowed will depend, firstly, on whether the emission source is a point source (a stack or other identifiable primary source of pollution), a fugitive source (a process leak or other source of pollution that could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening) or an area fugitive source (an unenclosed or partly enclosed area, such as a storage pile or a construction site). Stacks are normally controlled by “add-on” devices - the primary focus of this Manual. (However, some of these devices can be used to control process fugitive emissions in certain cases, such as a fabric filter used in conjunction with a building evacuation system.) Add-on or end-of-pipe pollution controls are normally used to meet a specified emission limit, although in the case of particulate emissions, they may also be required to meet an opacity level.

**Table 2.2: Facility Parameters and Compliance Options**

<b>Facility Parameters</b>	<b>Compliance Options</b>
<b>Intensive</b> Facility status (new or existing, location) Gas Characteristics (temperature, pressure, moisture control) Pollutant concentration(s) and/or particle size distribution	<b>No control</b>  <b>Add-on devices</b> Emission limits Opacity limits
<b>Extensive</b> Facility capacity Facility life Exhaust gas flow rate Pollutant emission rate(s)	<b>Process modification</b> Raw material changes Fuel substitution  <b>Source/Feedstock pretreatment</b> Coal desulfurization Wet dust suppression

### 2.6.2 Control System Design

Preparing the control system design for an end of pipe device at a plant involves deciding what kinds of systems will be priced (a decision that will depend on the pollutants to be controlled, exhaust gas stream conditions, and other factors), and what auxiliary equipment will be needed. When specifying the auxiliary equipment for a typical add-on control device (e.g., a coal fired FGD scrubber), several questions may need to be answered, among others, depending on the specific control device:

- What is the fuel’s (in this case, coal’s) sulfur content? What is the content of other toxic substances in the fuel (heavy metals, mercury)?

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- How many absorber modules will be needed?
- Does the exhaust stream pose any hazard to the materials of the hoods, ducts, fans, and other auxiliary equipment? Is the exhaust caustic or acidic? Is it abrasive? Does the treatment of the exhaust render it caustic or acidic?
- Does the exhaust stream require any pre-treatment (e.g., particulate control equipment, which will likely be in operation at the source) before it enters the control device?
- Will the captured pollutants be disposed of or recycled? How will this be done? Will a salable byproduct be produced (e.g., gypsum for drywall)?
- Can the on-site capacity (e.g., utilities, stockpiling space) accommodate the added requirements of the control system? Is additional wastewater and solid waste disposal capacity needed?

### 2.6.3 Sizing the Control System

Once the system components have been selected, they must be sized (i.e., the correct size of components must be determined). Sizing is probably the most critical step because the assumptions made in this step will more heavily influence capital investment than any other. Table 2.3 lists examples of these parameters. Also listed in Table 2.3 are general parameters which must be specified before the purchased cost of the system equipment can be estimated. Note that, unlike the control device parameters, these parameters may apply to any kind of control system. They include materials of construction (which may range from carbon steel to various stainless steels to fiberglass-reinforced plastic), presence or absence of insulation, and the equipment or useful life of the system. As indicated in Section 2.4.2, this last parameter is required for estimating the annual capital recovery costs as long as the analytic length exceeds the useful life of the equipment. The lifetime not only varies according to the type of the control system, but with the severity of the environment in which it is installed. Each of the control-specific chapters of this Manual include a comprehensive list of the specific parameters that must be considered for each device.

**Table 2.3:** Examples of Typical Control Device Parameters [3]

General	Device-Specific
Material of construction: carbon steel	Gas-to-cloth ratio (critical parameter): 3.0 to 1
Insulated? Yes	Pressure drop: 6.0 in w.c. (inches water column)
Equipment life: 30 years	Construction: standard (vs. custom)



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Redundancy<sup>a</sup>: none

Duty: continuous (vs. intermittent)

Filter type: shaker

Bag material: polyester, 16-oz.

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<sup>a</sup> Refers to whether there are any extra equipment items installed (e.g., fans) to function in case the basic items become inoperative, so as to avoid shutting down the entire system. Please note that values in this table are shown only for illustrative purposes.

### 2.6.4 Estimating Total Capital Investment

#### 2.6.4.1 General Considerations

The fourth step is estimating the purchased equipment cost of the control system equipment. As discussed in Section 2.2, total direct cost includes purchased equipment cost, which in turn, is the sum of the base equipment cost (control device plus auxiliaries), freight, instrumentation, and sales tax. The values of these installation factors depend on the type of the control system installed and are, therefore, listed in the individual Manual chapters dedicated to them. These costs are available from this Manual for the most commonly used add-on control devices and auxiliary equipment, with each type of equipment covered in a separate chapter (see Table of Contents and the discussion in Chapter 1). Total Direct Cost also includes Direct Installation Cost, which contains many of the cost categories included in Section 2 of this Manual, Generic Equipment and Devices.<sup>12</sup>

As mentioned previously, most of the costs in each of the subsequent sections of this Manual were derived from data obtained from reputable control equipment vendors. For many control devices there are many vendors, which allowed us to offer robust average costs of components submitted by large samples of vendors in response to Agency survey efforts. [10] For items that are mass produced or “off-the-shelf” equipment, vendors provided a written quotation listing their costs, model designations, date of quotation, estimated shipment date, and other information. For other equipment there are not as many vendors or we did not receive sufficient number of responses to our inquiries, resulting in small samples. Thus, there could be a limited number of observations in the data sets available for estimation of average costs. In these cases, we offer these average costs and the cost discussion in that control’s particular chapter offers appropriate caveats to the analyst.

For some controls, no amount of vendor data would have made our cost numbers more accurate because the control in question is either so large or so site-specific in design that suppliers design, fabricate, and construct each control according to the specific needs of the facility. For these kinds of controls, the vendor may still give quotations, but will likely take much longer to do so and may even charge for this service, to recoup the labor and overhead expenses of his estimating department. When performing a cost analysis, the cost of the quotation is a part of the TCI.

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<sup>12</sup> Estimates of TCI for some control measures may not necessarily be calculated in this way due to availability of public information on capital investment costs and equations for those measures, such as the SNCR and SCR chapters in this Manual.

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Generally, vendor quotes are “F.O.B.” (free-on-board) for the vendor, meaning that no taxes, freight, or other charges are included. For these equipment, the analyst must take care to identify and include the cost of transportation, taxes, and other necessary charges in the TCI (see Figure 2.1). The costs of freight, instrumentation, and sales tax are calculated differently from the direct and indirect installation costs. These items are developed by multiplying the base equipment cost (F.O.B. the vendor) by an industry-accepted factor. Unlike other estimating factors that differ from system to system, installation factors are essentially equal for all control systems. [10] Table 2.4, below, displays values for these factors.

**Table 2.4:** Cost Ranges for Freight, Sales Tax, and Instrumentation

% of Total Equipment Cost, FOB		
Cost	Range	Typical
Freight	0.01 - 0.10	0.05
Sales Tax	0 - 0.08	0.03
Instrumentation	0.05- 0.30	0.10

To some extent, the application of an appropriate factor requires the subjective application of the analyst’s best judgment. For example, the range in freight costs is, in part, a function of the distance between the vendor and the site. The lower end of the factor range represents shorter distance deliveries, while the upper end of the range would reflect freight charges to remote locations such as Alaska and Hawaii. [10] The sales tax factors simply reflect the range of local and state tax rates currently in effect in the United States. [10] In some locations, and for many institutional and governmental purchases, sales taxes do not apply; (hence the zero value at the low end of the sales tax factor range). The range of instrumentation factors is also quite large. For systems requiring only simple continuous or manual control, the lower factor would apply. However, if the control is intermittent and/or requires safety backup instrumentation, the higher end of the range would be applicable. [10] Finally, some “package” control systems (e.g., incinerators covered in Chapter 3) have built-in controls, with instrumentation costs included in the base equipment cost. In those cases, the instrumentation factor to use would, of course, be zero.

Regarding the amount of labor for construction and installation of a control device, EPA has prepared a number of analyses that include estimates for power plants in particular. These analyses are extensive in nature, and we refer readers wanting more information to appendixes in several recent Regulatory Impact Analyses (RIAs) that include employment data for various add-on control devices, including some of the control devices found in the Control Cost Manual.<sup>13</sup>

<sup>13</sup> One example of this is Appendix 6A in the RIA for the Mercury and Air Toxics Standards (MATS), which provides an estimate of the labor necessary to construct and install an FGD scrubber on a coal-fired power plant

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### 2.6.4.2 Retrofit Cost Considerations

Probably the most subjective part of a cost estimate occurs when the control system is to be installed on an existing facility. Unless the original designers had the foresight to include additional floor space and room between components for new equipment, the installation of retrofitted pollution control devices can impose an additional expense to “shoe-horn” the equipment into the right locations. For example, an SCR reactor can occupy thousands of square feet and may be installed directly behind a boiler’s combustion chamber to offer the best environment for NO<sub>x</sub> removal. Many of the utility boilers currently considering or have installed an SCR reactor to meet Federal or other NO<sub>x</sub> limits are over thirty years old - designed and constructed before SCR was a proven technology in the United States. For these boilers, there is often little room for the reactor to fit in the existing space and additional ductwork, fans, and flue gas heaters may be needed to make the system work properly.

To quantify the additional costs of installation not directly related to the capital cost of the controls themselves, engineers and cost analysts typically multiply the cost of the system by a retrofit factor. The proper application of a retrofit factor is as much an art as it is a science, in that it requires a good deal of insight, experience, and intuition on the part of the analyst. The key behind a good cost estimate using a retrofit factor is to make the factor no larger than is necessary to cover the occurrence of expected (but reasonable) extra costs for demolition and installation. Such expected but extra costs include - but are certainly not limited to - the unexpected magnitude of anticipated cost elements; the costs of unexpected delays; the cost of re-engineering and re-fabrication; and the cost of correcting design errors.

The magnitude of the retrofit factor varies across the kinds of estimates made as well as across the spectrum of control devices. The retrofit factor is calculated as a multiplier applied to the TCI. For instance, if a retrofit factor of as much as 50 percent can be justified, then the retrofit factor in the cost estimate is 1.5. For systems installed at the end of the stack, such as flares, retrofit uncertainty is typically a factor. In these cases, an appropriate retrofit factor may be as little as one or two percent of the TCI. In complicated systems requiring many pieces of auxiliary equipment, it is not uncommon to see retrofit factors of much greater magnitude being used.

Since each retrofit installation is unique, no general factors can be developed. Nonetheless, if necessary, some general information can be given concerning the kinds of system modifications one might expect to be considered in developing a retrofit factor:

1. Handling and erection. Because of a “tight fit,” special care may need to be taken when unloading, transporting, and placing the equipment. This cost could increase

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boiler. This RIA can be found at <http://www.epa.gov/ttn/ecas/regdata/RIAs/matsriafinal.pdf>. In addition, the RIA for the Cross-State Air Pollution Rule (CSAPR) provides estimates of the labor necessary to construct and install an SCR, dry sorbent injection (DSI) and FGD scrubber on coal-fired power plant boilers. The CSAPR RIA can be found at <http://www.epa.gov/airtransport/pdfs/FinalRIA.pdf>.

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significantly if special means (e.g., helicopters) are needed to get the equipment on roofs or to other inaccessible places.

2. Site Preparation. Site preparation includes the surveying, clearing, leveling, grading, and other civil engineering tasks involved in preparing the site for construction. Unlike the other categories, this cost may be zero or decreases, since most of this work would have been done when the original facility was built [11]. However, if the site is crowded and the control device is large, the size of the site may need to be increased and then site preparation may prove to be a major source of retrofit related costs. As mentioned earlier in the chapter, if additional land is purchased to accommodate the installation of the control equipment, this cost needs to be added in as well. If other production related equipment must be relocated to allow for the installation of the control equipment, the cost associated with the relocation needs to be included.
3. Off-Site Facilities. Off-site facilities should not be a major source of retrofit costs, since they are typically used for well-planned activities, such as the delivery of utilities, transportation, or storage.
4. Limited Space for Staging Equipment. During construction, materials and equipment are transported, received, and stored on site. These commodities are marked, arranged, and placed in a sequence for retrieval by construction crews prior to final installation. In many ways, the storage yard on a construction site represents a depot with shipments being received from vendors and commodities being constantly repositioned to facilitate retrieval to meet a scheduled installation sequence. For large sites, repositioning becomes less of an issue; however, for small limited area sites, repositioning items in the construction queue becomes a major logistical effort, and in some cases, requires JIT (just-in-time) delivery to allow for direct off-loading from carrier and then straight to installation. To allow schedule flexibility (for the unseen), equipment can be stored off-site (for a fee) or at the fabricator's shop (once again, for a space rental fee).
5. Transportation. The delivery of equipment is more than the arrival of commodities at plant site. It is the examination of the destination route from shop to plant site with all special aspects taken into consideration, such as: road bearing limitations, bridge overpass height restrictions, permits for oversized shipments (extra wide loads), required special escorts, time-of-day transit limitations (non-traffic hour, weekends only), railway restrictions, waterway provisions (locks, docking, piloting), tunnel limitations. Depending on the site's location in relationship to the origin point, the typical transit route for normal cargo shipments yields to alternate routes and times for large special shop fabricated assemblies.

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6. Lost Production. The shut-down for installation of a control device into the system should be a well-planned and anticipated event, and typically occurs during routine, scheduled outages. As such, its cost should be considered a part of the indirect installation cost (start-up). However, unanticipated problems with the installation due to retrofit-related conditions if they happen could impose significant costs on the system. Retrofit factors should be reserved for those items directly related to the demolition, fabrication, and installation of the control system. A contingency factor should be reserved (and applied to) only those items that could incur a reasonable but unanticipated increase but are not directly related to the demolition, fabrication, and installation of the system. For example, a hundred year flood may postpone delivery of materials, but their arrival at the job site is not a problem unique to a retrofit situation. If the shut-downs do not occur in a well planned and routine manner, any additional foregone production of goods and products would need to be included as a private cost attributable to the retrofit cost.

It is important to consider the type of contract and its influence on contingency factors. The two types of major contract vehicles that exist for the buyer (owner) to issue to a seller (vendor) are: lump-sum / fixed price and cost-plus. Between these extremes, a myriad of hybrids exists. The lump-sum contract vehicle stipulates a fixed price for delivery of a product performing to specified conditions set by the buyer with all materials, services, engineering/ design, installation, and commissioning supplied by the seller. Under this fixed price, the seller is at financial risk for delivering a conforming product at the contracted price; corrections to attain conformance and cost overruns are at the seller's expense; however, realized savings are solely to the seller's benefit. The buyer's risk involves changes to the supplied product outside of contractually agreed upon conditions due to unforeseen events or issues. Under such contracts, the engineering contractor assumes the majority of the risk. A cost-plus vehicle allows the buyer to pay for actual expenses incurred by the vendor (materials, labor, engineering / design, etc.) without mark-up plus an agreed upon surcharge to cover the vendor's overhead and profit. The owner is at risk because this type of contract can become open-ended; however, the buyer has extreme control over the cost process and can terminate the project at any time without penalty. The seller settles for minor risk while forgoing the chance to realize cost efficient savings; however, an assured profit margin exists. This is also known as a "time and materials" contract. In between these two extreme contract vehicles, a multitude of blended hybrids exist to suit both buyer and seller and blend the likenesses of each; for example: lump sum + fee, cost-plus + award with shared savings / overruns, lump sum on materials / cost plus on labor, and many more. Contingency cost placement differs between the two vehicles. For cost-plus contracts, the owner determines the contingency amount set aside; for lump-sum / fixed price contracts, the seller determines contingency allowances, (which is reflected in the price).

Project execution typically follows one of two forms: Design-Build (DB) or Design, Bid, Build (DBB) [12]. A contract issued under Design-Build conditions allows the buyer to have a single entity contact (supplier) which performs the engineering, design, purchasing and installation for the vended product plus retains responsibility for that product. DB project execution operates under shorter time schedule since the single entity can design, procure, and construct

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simultaneously from commencement through completion. The owner's main disadvantage becomes losing control over the design process and selection of equipment, which consequently affects cost. While DB is a common term, it is better known as EPC (engineer, procure, construct), EPCM (engineer, procure, construct, manage), and EPM (engineer, procure, manage with construction under separate contract). DBB project execution follows a more deliberate path with each phase completed before the next. The design phase involves hiring an architect/engineering firm (via contract vehicle) create a complete documentation package for a product. This involves specifications, drawings, fabrication drawings, construction drawings, and all documentation necessary for competitive bid to supply materials, commodities, and construction services for installation. General contractors bid on this design package and a bid is selected. This type of project execution distinctly separates the design/engineering phase from the procurement and installation phase, but takes longer to implement. The method's main advantage allows revising design before equipment and services are procured.

Regardless of execution form selected (DB or DBB), the buyer tends to become involved with the vendor's process (to varying degrees) to coordinate activities between the owner's staff and the supplier's personnel. There is one exception to this case, and it is termed the "turnkey" project. In its purest sense, the buyer's involvement on a turnkey project is negligible; the owner meets the supplier on the first day to award the contract and returns on the final day to receive ownership. In reality, the buyer exercises minor involvement to ensure ongoing progress.

Lump-sum or EPC contracts are generally awarded on the basis of a competitive tender and often lead to the lowest direct cost compared to other type of contracts. These contracts are often turnkey in nature. Thus, these contracts will have larger contingencies than engineer, procure, construction, and management (EPCM) contracts. EPCM contractors are paid when their costs are incurred (cost-reimbursable contracts) and the owner assumes more of the risk (though the owner has more flexibility to specify changes during construction). Most contracts awarded to pollution control vendors are EPC or turnkey due to their shorter time schedules.

Contingency also accounts for inadequacies in cost estimating methods and for expected unknowns that may arise during project execution. The contingency funds are born by the owner or by the supplier, depending on contract vehicle issued. In any case, it is reflected in the TCI. Contingency is inversely proportional to the level of accuracy for a cost estimate. A study-level cost estimate, which is the level of analysis accuracy for estimates arrived at using the Control Cost Methodology, will have a higher contingency as compared for a more accurate (20% probable error) cost estimate that was arrived at with a greater amount of data and effort. Contingency can also vary depending primarily on the age of the technology. For mature control technologies, which reflect the control technologies covered in the other chapters of this Manual, the contingency can range from 5 to 15% of the TCI [3] This contingency is quite consistent with

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general cost guidance for mature or well-known technologies.<sup>14</sup> Finally, contingency should not account for events such as price escalation, work stoppages, and disasters. [13]

### 2.6.5 Estimating Annual Costs

Determining the total annual cost is the last step in the estimating procedure. As mentioned in Section 2.3 the total annual cost is comprised of three components—direct and indirect costs and recovery credits. Some cost items are annual; others are multi-year. Unlike the installation costs, which are factored from the purchased equipment cost, annual cost items are usually computed from known data on the system size and operating mode, as well as from the facility and control device parameters.

Following is a more detailed discussion of the items comprising the total cost. (Values/factors for these costs are given in the chapters for individual devices.)

#### 2.6.5.1 Raw Materials

Raw materials may be needed with control systems. Examples would be chemicals used in gas absorbers or venturi scrubbers as absorbents or to neutralize acidic exhaust gases (e.g., hydrochloric acid). Chemicals may also be required to treat wastewater discharged by scrubbers or absorbers before releasing it to surface waters. If the source uses the same raw materials for production, the analyst must be careful to include only those costs that are attributable to the raw materials needed by the control device. Quantities of chemicals required are calculated via material balances, with an extra 10 to 20% added for miscellaneous losses on average. Specifying one or several sources for a recent reagent cost should be sufficient for cost estimation that is consistent with the Control Cost Methodology. Costs for chemicals are available from vendors, governmental sources such as the U.S. Geological Survey (USGS), and from ICIS Chemical Business, IHS Chemical Week, and similar well-recognized business publications.<sup>15</sup> A list of well-regarded sources for chemicals used as reagents in pollution control operations and other industrial chemical operations and processes can be found at university library web sites, with one maintained by Texas A&M's University Library being a particularly good example.<sup>16</sup> If the price of these reagents and raw materials become more volatile and deviate significantly from historical price trends, then the analyst is advised to take this into account in assessing the cost of material.

#### 2.6.5.2 Labor

This section discusses the amount of labor required to operate and maintain a pollution control system. The necessary labor depends on the system's size, complexity, level of automation,

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<sup>14</sup> Hollman, John K. "Improving Your Contingency Estimates for More Realistic Project Budgets." *Chemical Engineering*, December 2014. Available at [http://www.chemengonline.com/improve-your-contingency-estimates-for-more-realistic-project-budgets/?printmode=1#disqus\\_thread](http://www.chemengonline.com/improve-your-contingency-estimates-for-more-realistic-project-budgets/?printmode=1#disqus_thread).

<sup>15</sup> No endorsement by US EPA is made or implied of any publication that is named here, or anywhere else in the Manual.

<sup>16</sup> The link is at <http://guides.library.tamu.edu/chemicalengineering>. Click on "Chemical Prices" for industrial chemical data sites and publications.

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and operating mode (i.e., batch or continuous). The labor is usually estimated on an hours-per-shift basis. As a rule, though, data showing explicit correlations between the labor requirement and capacity are often hard to obtain. One non-linear correlation found in the literature is shown below: [3]

$$L_2/L_1 = (V_2/V_1)^y \quad (2.9)$$

where

$L_1, L_2$	=	labor requirements for systems 1 and 2
$V_1, V_2$	=	capacities of systems 1 and 2 (as measured by the gas flow rate, for instance)
$y$	=	0.2 to 0.25 (typically)

The exponent in Equation 2.9 can vary considerably. Conversely, in many cases, the amount of operator labor required for a system will be approximately the same regardless of its size.

Maintenance labor is calculated in the same way as operating labor and is influenced by the same variables. The maintenance labor rate, however, is normally higher than the operating labor rate, mainly because more skilled personnel are required. Many cost studies use a flat ten percent premium over the operations labor wage rate for maintenance labor costs. [13] A certain amount must also be added to operating labor to cover supervisory requirements. Generally, cost estimates include supervisory labor as a flat fifteen per cent of the operating labor requirement. [13] To obtain the annual labor cost, multiply the operating and supervisory labor requirements (labor-hr/operating-hr) by the respective wage rates (in \$/labor-hr) and the system operating factor (number of hours per year the system is in operation). Wage rates also vary widely, depending upon the source category, geographical location, etc. These data are tabulated and periodically updated by the U.S. Department of Labor, Bureau of Labor Statistics, in its Monthly Labor Review and in other publications. This Manual uses labor rates that are representative of industries at the national level. For cost assessments, these wages (adjusted for inflation through an appropriate cost index) should be adequate for study level purposes.

Finally, please note that the wage rates used by the Manual and its supplemental programs are base labor rates, which do not include payroll and plant overhead. Wages found in reports from the Bureau of Labor Statistics or some other reliable source may or may not include overhead. The analyst must be careful to apply overhead and other wage adjustment factors uniformly. (See the discussion on Overhead, below.)

### 2.6.5.3 Maintenance Materials

Maintenance also requires maintenance materials—oil, other lubricants, duct tape, etc., and a host of small tools. The costs for these items can be figured individually, but since they are normally so small, they are usually factored from the maintenance labor. Reference [3] suggests a factor of 100% of the maintenance labor to cover the maintenance materials cost.



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### 2.6.5.4 Utilities

This cost category covers many different items, ranging from electricity to compressed air. Of these, only electricity is common to all control devices, where fuel oil and natural gas are generally used only by incinerators; water and water treatment, by venturi scrubbers, quenchers, and spray chambers; steam, by carbon adsorbers; and compressed air, by pulse-jet fabric filters. Techniques and factors for estimating utility costs for specific devices are presented in their respective sections. However, because nearly every system requires a fan to convey the exhaust gases to and through it, a general expression for computing the fan electricity cost ( $C_e$ ) is given here: [10]

$$C_e = 0.746 Q \Delta P s \Theta p_e / 6356 \eta \quad (2.10)$$

Where

- $Q$  = gas flow rate (actual ft<sup>3</sup> /min, acfm)
- $P$  = pressure drop through system (inches of water, column) (Values for P are given in the chapters covering the equipment items.)
- $s$  = specific gravity of gas relative to air (1.000, for all practical purposes)
- $\Theta$  = operating factor (hr/yr)
- $\eta$  = combined fan and motor efficiency (usually 0.60 to 0.70)
- $p_e$  = electricity cost<sup>17</sup> (\$/kw-hr)

A similar expression can be developed for calculating pump motor electricity requirements.

### 2.6.5.5 Waste Treatment and Disposal

Though often overlooked, there can be a significant cost associated with treating and/or disposing of waste material captured by a control system that neither can be sold nor recycled to the process. Liquid waste streams, such as the effluent from a gas absorber, are usually processed before being released to surface waters. The type and extent of this processing will, of course, depend on the characteristics of the effluent. For example, the waste can first be sent to one (or more) clarifiers, for coagulation and removal of suspended solids. The precipitate from the clarifier is then conveyed to a rotary filter, where most of the liquid is removed. The resulting filter cake is then disposed of, via landfilling, for example. The costs of waste treatment and disposal should be estimated where appropriate and consistent with the Control Cost Methodology. If installation of control equipment is expected to increase the waste generation from the current level, the difference between the expected level and the current level is attributable to the control equipment and should be accounted for in the cost estimate. Estimation of costs is accounted for in the chapters for specific control measures where waste treatment and disposal is a concern (e.g., gas absorbers, carbon adsorbers).

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<sup>17</sup> The electricity cost in this equation is the cost to the power plant to generate its electricity, or busbar cost. Data on busbar costs is collected in Form 1 of the Federal Energy Regulatory Commission (FERC). Information on Form 1 can be found at <http://www.ferc.gov/docs-filing/forms/form-1/data.asp>.

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### 2.6.5.6 Replacement Materials

The cost of maintenance materials is a component of the operations and maintenance function of the system and is not the same thing as the system's replacement materials cost, which is the cost of such items as carbon (for carbon absorbers), bags (for fabric filters) and catalyst (for catalytic incinerators), along with the labor for their installation. Because replacement materials last for more than a year but are consumed by the system, they cannot be included in the general maintenance and operations costs, which are annual in nature. Instead, these the present value of these costs in constant dollar must be calculated before being annualized by taking into account the life of the material (see section 2.5.5.3, above). The annual cost of the replacement materials is a function of the initial parts cost, the parts replacement labor cost, the life of the parts, and the interest rate, as follows:

$$CRC_p = (C_p + C_{pl}) CRF_p \quad (2.11)$$

Where

- $CRC_p$  = capital recovery cost of replacement parts (\$/yr)
- $C_p$  = initial cost of replacement parts, including sales taxes and freight (\$)
- $C_{pl}$  = cost of parts-replacement labor (\$)
- $CRF_p$  = capital recovery factor for replacement parts (defined in Section 2.3).

The useful life of replacement materials is generally less than the useful life of the rest of the control system - typically two to five years. Consequently, the analyst can choose to keep the length of the analysis as same as the life of the control system, and input the cost of the replacement materials accordingly before annualizing or annualize the replacement material cost stream separately from the control system. Furthermore, the annualized cost of the pollution control system should be performed net of the cost of the replacement materials needed at the beginning of operations to prevent double counting. Replacement materials labor will vary, depending upon the amount of the material, its workability, accessibility of the control device, and other factors. The cost of replacement materials labor should be included in the cost of the materials before annualization. Either way, this approach is appropriate when only the cost is under consideration in the overall analysis.

### 2.6.5.7 Overhead

This cost is easy to calculate, but often difficult to comprehend. Much of the confusion surrounding overhead is due to the many different ways it is computed and to the several costs it includes, some of which may appear to be duplicative.

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There are, generally, two categories of overhead: payroll and plant. Payroll overhead includes expenses directly associated with operating, supervisory, and maintenance labor, such as: workmen's compensation, Social Security and pension fund contributions, vacations, group insurance, and other fringe benefits. Some of these are fixed costs (i.e., they must be paid regardless of how many hours per year an employee works). Payroll overhead is traditionally computed as a percentage of the total annual labor cost (operating, supervisory, and maintenance).

Conversely, plant (or "factory") overhead accounts for expenses not necessarily tied to the operation and maintenance of the control system, including: plant protection, control laboratories, employee amenities, plant lighting, parking areas, and landscaping. Some estimators compute plant overhead by taking a percentage of all labor plus maintenance materials [3], while others factor it from the total labor costs alone. [3]

For study estimates, it is sufficiently accurate to combine payroll and plant overhead into a single indirect cost. This is done in this Manual. Also, overhead is factored from the sum of all labor (operating, supervisory, and maintenance) plus maintenance materials, the approach recommended in reference [3]. The factors recommended therein range from 50 to 70% [3]. An average value of 60% is used in this Manual.

### 2.6.5.8 Property Taxes, Insurance, Administrative Charges and Permitting Costs

The first three indirect operating costs are factored from the system total capital investment, at 1, 1, and 2%, respectively. Property taxes and insurance are self-explanatory. Administrative charges cover sales, research and development, accounting, and other home office expenses. (It should not be confused with plant overhead, however.) For simplicity, the three items are usually combined into a single, 4% factor. These estimates can serve for cost estimates if sources do not have any reliable and accurate information on these indirect operating costs. This is the standard approach used in actions for which the cost methodology in this Cost Manual is a basis.

The permitting costs are costs borne by the facilities to get the necessary approval to design and install the control equipment. This is a site-specific cost where the costs borne by one facility may not translate well into another facility. However, because of potentials for delays, re-design and other considerations, permitting costs should be included in the overall cost assessment. While the cost of re-design and lost production are explicitly taken into account, analysts should carefully the effects of permitting process and their associated costs on the overall cost assessment.

## 2.7 Example

As an illustrative example of applying the cost methodology discussed in this chapter, consider the hypothetical All-American Electrical (AAE) <sup>1</sup> that operates a single 600 MWe tangentially fired high sulfur bituminous coal-fired boiler to produce steam to power its generators.

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It emits an uncontrolled 50,000 tons of sulfur dioxide per year, and because it is planning on a major renovation, it must install devices to reduce its sulfur emissions to less than 1,000 tons per year (98 percent removal efficiency). After careful study of the available technologies, AAE has determined that either a wet limestone flue gas desulfurization (FGD) scrubber or a wet buffered lime FGD would be the most logical choice to achieve such a high removal rate. For simplification purposes we will assume either device would have an operating life of thirty years, after which the scrubbers could be sold as scrap for a salvage value of about \$500,000. We also provide an estimate of annual gypsum sales in the overall calculation given that gypsum can be a by-product of FGD scrubber operation. Table 2.5, below, displays the capital and annual costs associated with each of the alternative devices.

**Table 2.5:** Capital, O&M, and Parasitic Energy Costs (Including Revenue Streams) of Alternative FGD Controls

	Wet Limestone FGD	Wet Buffered Lime FGD
Capital Cost	\$200,000,000	\$180,000,000
Annual O&M Costs		
Fixed O&M Costs <sup>a</sup>	\$2,000,000	\$1,800,000
Reagent	\$1,200,000	\$3,750,000
Auxiliary Power	\$1,300,000	\$1,150,000
Annual Gypsum Sales	\$1,200,000	\$600,000
Parasitic Power <sup>b</sup>	\$950,000	\$375,000

<sup>a</sup> Estimated at 1% of capital cost

<sup>b</sup> In many systems, the insertion of a pollution control device causes the system to lose productive capacity. This can be caused by the device creating obstructions in the flue, temperature losses that create imbalances, or other physical changes that affect performance. These losses are collectively termed “parasitic power” losses.

From the information in Table 2.5, neither device can be shown to be superior to the other. It costs \$20 million less to install a wet buffered lime scrubber, but a buffered lime FGD would cost over three times as much each year for the purchase of the lime, relative to the cost of the reagent in a limestone FGD. Each FGD has similar fixed O&M costs, but because a buffered lime FGD uses much less reagent, it requires less power to run - about half the power demand and about 40 percent of the productive loss of the limestone FGD. While these factors indicate the wet buffered lime FGD may be a better alternative, the use of less reagent also means the production of less gypsum by-product - for about half the expected revenue generating capability of a limestone system. To make our selection, we must rely upon our financial tools.

The exercise does not lend itself to a payback analysis, even though there are revenues to be generated from the sale of the scrubber’s byproduct. So long as annual costs exceed annual

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revenues, payback will not be an alternative because there will be no net revenue to help offset the capital costs of the project. Furthermore, even if one were to ignore the cost component of the cash flow, the revenues from most pollution control devices are so low that their payback values are meaningless. For instance, the limestone and buffered lime scrubbers in this exercise have a simple payback (without considering costs) of 167 and 300 years, respectively. Consequently, the analyst must look to the more sophisticated tools available: cash flow analysis and net present value.

Table 2.6 shows the hypothetical cash flows from each alternative control in nominal dollars. You will notice that the cost for O&M and the revenues from selling the gypsum by-product are constant over time. That is because we have ignored any inflation rate change in prices and have created our cash flow analysis in real dollars. This is the preferred way to approach this kind of analysis, since it relies on the most accurate information available (current prices) and does not try to extrapolate those prices into the future. Because we will perform our cash flow analysis in real dollars, we must use the real interest rate to determine net present values. We will assume AAE can borrow funds at will at a nominal interest rate of nine percent and sources the company consults expect the inflation rate over the relevant range to be, on average, two percent. Consequently, the real rate of interest is (nine percent minus two percent) seven percent. Using real dollars for revenues and costs and then using nominal interest rates for our discounting factors (nine percent) would have led to an understatement of the net present value of the projects, making them appear less beneficial to AAE.

Translating the costs in each future year to year zero values means applying the factors found in Table A.1 from Appendix A. From the 10 percent column, we applied the factors 0.90909, 0.82645, 0.75131, 0.68301, and 0.62092, respectively, to the net costs of years 1, 2, 3, 4, and 5 to determine the year zero costs, and then sum all of the values to derive the net present value for each control alternative. Based upon the information developed in the cash flow analysis and the NPV calculation, which control device is the best one for AAE to install? The answer is still not evident! Even with a twenty million dollar capital cost savings, the net present value of the wet buffered lime FGD is only about a half million dollars more expensive than the wet limestone FGD! This is a function of the other cash flow components - the higher operating cost of the buffered lime system versus the higher revenue generating capacity of the limestone FGD, both of which work to almost completely eliminate the capital cost advantage of the buffered lime scrubber. Clearly, relying on just the sticker price of the two units could have driven us to a potentially bad decision. So now what? Payback analysis does not offer any help, (nor will internal rate of return (IRR), which also relies upon a positive net cash flow to work). Cash flow analysis tells us that, within our study-level estimation range, the two devices are almost identical. That in and of itself is important information, because the environmental engineer can be fairly certain that whichever device they choose, the effect of that choice on his company will be about the same. That leaves them free to look at other considerations that are not accounted for easily within this cost analysis: Twice as much limestone means twice as much storage and twice as much stockpiling of the gypsum by-product. Is that an important factor? Limestone is more caustic than buffered lime, but it takes less equipment to operate the system. Should the engineer opt for simplicity in design or potentially higher rates of repair? These are the sort of considerations, some

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numerical and can be accounted for in the cost analysis, and some not, that can now come into play in making a decision, now that the relative values of each device has been determined.

This does not mean that our process has failed. Far from it. If our input assumptions have been made correctly, then we have determined that from a cost standpoint, there does not seem to be an appreciably different risk to choosing one device over the other. However, other considerations may play a role in making the choice clearer. For instance, the limestone scrubber will produce about twice as much gypsum as the wet buffered lime scrubber. Does the storage, transportation, or marketability of that amount of gypsum create a problem? Likewise, it takes about three times as much limestone to remove the same amount of sulfur, relative to the amount of lime needed, but the lime costs between five and seven times as much as the limestone. Do these considerations clarify the choice? Finally, the power demands for each device differ significantly, both in terms of operation and in lost productive capacity. Perhaps these considerations will make one device more attractive to the firm. The bottom line is that there is no clear-cut “cookbook” process through which the analyst will be able to make the right informed decision each time, and the formalized costing methodology employed by the Manual is only a part of that process. However, if the Manual’s methodology is followed rigorously and in an unbiased manner, then the analyst can feel safe about the study-level cost of his alternative projects and can then move on to a more formal cost determination with the help of an engineering or consulting firm.

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**Table 2.6:** Cash Flow Analyses Exercise (in thousands of dollars)

Years	0	1	2	3	4	5	6	7	8	9	10
<b>Limestone Scrubber</b>											
Income											
Gypsum Sales	0	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Salvage Value	0	0	0	0	0	0	0	0	0	0	500
Expenses											
Capital Investment	200,000	0	0	0	0	0	0	0	0	0	0
Annual O&M Costs	0	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500
Parasitic Power	0	950	950	950	950	950	950	950	950	950	950
Net Annual Cost	-200,000	-4,250	-4,250	-4,250	-4,250	-4,250	-4,250	-4,250	-4,250	-4,250	-3,750
Present Value	-200,000	-4,048	-3,855	-3,671	-3,496	-3,330	-3,171	-3,020	-2,877	-2,740	-2,302
NPV	-232,510										
<b>Buffered Lime Scrubber</b>											
Income											
Gypsum Sales	0	600	600	600	600	600	600	600	600	600	600
Salvage Value	0	0	0	0	0	0	0	0	0	0	500
Expenses											
Capital Investment	180,000	0	0	0	0	0	0	0	0	0	0
Annual O&M Costs	0	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000
Parasitic Power	0	375	375	375	375	375	375	375	375	375	375
Net Annual Cost	-180,000	-6,775	-6,775	-6,775	-6,775	-6,775	-6,775	-6,775	-6,775	-6,775	-6,275
Present Value	-180,000	-6,452	-6,145	-5,852	-5,574	-5,308	-5,056	-4,815	-4,586	-4,367	-3,852
NPV	-232,008										

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### APPENDIX A

#### Net Present Value and Capital Recovery Factor Tables

Table A.1 shows an example of present value calculations that includes illustrative discount rates and illustrative investment lifespans.<sup>18</sup> The table displays the amount an individual would be willing to accept today for a dollar promised in the future assuming the illustrative discount rates and investment lifespans. Select the year in which the dollar is supposed to be paid from the leftmost column and the discount rate from the top row. The value where the column and row intersect is the present value of that future dollar. For instance, if you were promised a dollar twelve years from now, and you believed the interest rate over that period would be 9.5 percent, then you would be willing to accept 33.7 cents for that dollar today.

**Table A.1:** Present Value Factors for a Dollar to Be Paid Now Instead of in a Future Year

	5.50%	6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	9.00%	9.50%	10.00%
1	0.94787	0.9434	0.93897	0.93458	0.93023	0.92593	0.92166	0.91743	0.91324	0.90909
2	0.89845	0.89	0.88166	0.87344	0.86533	0.85734	0.84946	0.84168	0.83401	0.82645
3	0.85161	0.83962	0.82785	0.8163	0.80496	0.79383	0.78291	0.77218	0.76165	0.75131
4	0.80722	0.79209	0.77732	0.7629	0.7488	0.73503	0.72157	0.70843	0.69557	0.68301
5	0.76513	0.74726	0.72988	0.71299	0.69656	0.68058	0.66505	0.64993	0.63523	0.62092
6	0.72525	0.70496	0.68533	0.66634	0.64796	0.63017	0.61295	0.59627	0.58012	0.56447
7	0.68744	0.66506	0.64351	0.62275	0.60275	0.58349	0.56493	0.54703	0.52979	0.51316
8	0.6516	0.62741	0.60423	0.58201	0.5607	0.54027	0.52067	0.50187	0.48382	0.46651
9	0.61763	0.5919	0.56735	0.54393	0.52158	0.50025	0.47988	0.46043	0.44185	0.4241
10	0.58543	0.55839	0.53273	0.50835	0.48519	0.46319	0.44229	0.42241	0.40351	0.38554
11	0.55491	0.52679	0.50021	0.47509	0.45134	0.42888	0.40764	0.38753	0.36851	0.35049
12	0.52598	0.49697	0.46968	0.44401	0.41985	0.39711	0.3757	0.35553	0.33654	0.31863
13	0.49856	0.46884	0.44102	0.41496	0.39056	0.3677	0.34627	0.32618	0.30734	0.28966
14	0.47257	0.4423	0.4141	0.38782	0.36331	0.34046	0.31914	0.29925	0.28067	0.26333
15	0.44793	0.41727	0.38883	0.36245	0.33797	0.31524	0.29414	0.27454	0.25632	0.23939
16	0.42458	0.39365	0.3651	0.33873	0.31439	0.29189	0.2711	0.25187	0.23409	0.21763
17	0.40245	0.37136	0.34281	0.31657	0.29245	0.27027	0.24986	0.23107	0.21378	0.19784
18	0.38147	0.35034	0.32189	0.29586	0.27205	0.25025	0.23028	0.21199	0.19523	0.17986
19	0.36158	0.33051	0.30224	0.27651	0.25307	0.23171	0.21224	0.19449	0.17829	0.16351
20	0.34273	0.3118	0.2838	0.25842	0.23541	0.21455	0.19562	0.17843	0.16282	0.14864
21	0.32486	0.29416	0.26648	0.24151	0.21899	0.19866	0.18029	0.1637	0.1487	0.13513
22	0.30793	0.27751	0.25021	0.22571	0.20371	0.18394	0.16617	0.15018	0.1358	0.12285
23	0.29187	0.2618	0.23494	0.21095	0.1895	0.17032	0.15315	0.13778	0.12402	0.11168
24	0.27666	0.24698	0.2206	0.19715	0.17628	0.1577	0.14115	0.1264	0.11326	0.10153
25	0.26223	0.233	0.20714	0.18425	0.16398	0.14602	0.13009	0.11597	0.10343	0.0923

<sup>18</sup> The example calculations in Table A.1 are all illustrative in nature. Nothing in this example is meant to contradict language earlier in this chapter concerning the appropriate use of interest rates, equipment life, and the EUAC in cost analysis to which the Control Cost Methodology is a basis.

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**Table A.1: Continued**

	10.50%	11.00%	11.50%	12.00%	12.50%	13.00%	13.50%	14.00%	14.50%	15.00%
1	0.90498	0.9009	0.89686	0.89286	0.88889	0.88496	0.88106	0.87719	0.87336	0.86957
2	0.81898	0.81162	0.80436	0.79719	0.79012	0.78315	0.77626	0.76947	0.76276	0.75614
3	0.74116	0.73119	0.7214	0.71178	0.70233	0.69305	0.68393	0.67497	0.66617	0.65752
4	0.67073	0.65873	0.64699	0.63552	0.6243	0.61332	0.60258	0.59208	0.58181	0.57175
5	0.607	0.59345	0.58026	0.56743	0.55493	0.54276	0.53091	0.51937	0.50813	0.49718
6	0.54932	0.53464	0.52042	0.50663	0.49327	0.48032	0.46776	0.45559	0.44378	0.43233
7	0.49712	0.48166	0.46674	0.45235	0.43846	0.42506	0.41213	0.39964	0.38758	0.37594
8	0.44989	0.43393	0.4186	0.40388	0.38974	0.37616	0.36311	0.35056	0.3385	0.3269
9	0.40714	0.39092	0.37543	0.36061	0.34644	0.33288	0.31992	0.30751	0.29563	0.28426
10	0.36845	0.35218	0.33671	0.32197	0.30795	0.29459	0.28187	0.26974	0.25819	0.24718
11	0.33344	0.31728	0.30198	0.28748	0.27373	0.2607	0.24834	0.23662	0.2255	0.21494
12	0.30175	0.28584	0.27083	0.25668	0.24332	0.23071	0.2188	0.20756	0.19694	0.18691
13	0.27308	0.25751	0.2429	0.22917	0.21628	0.20416	0.19278	0.18207	0.172	0.16253
14	0.24713	0.23199	0.21785	0.20462	0.19225	0.18068	0.16985	0.15971	0.15022	0.14133
15	0.22365	0.209	0.19538	0.1827	0.17089	0.15989	0.14964	0.1401	0.1312	0.12289
16	0.2024	0.18829	0.17523	0.16312	0.1519	0.1415	0.13185	0.12289	0.11458	0.10686
17	0.18316	0.16963	0.15715	0.14564	0.13502	0.12522	0.11616	0.1078	0.10007	0.09293
18	0.16576	0.15282	0.14095	0.13004	0.12002	0.11081	0.10235	0.09456	0.0874	0.08081
19	0.15001	0.13768	0.12641	0.11611	0.10668	0.09806	0.09017	0.08295	0.07633	0.07027
20	0.13575	0.12403	0.11337	0.10367	0.09483	0.08678	0.07945	0.07276	0.06666	0.0611
21	0.12285	0.11174	0.10168	0.09256	0.08429	0.0768	0.07	0.06383	0.05822	0.05313
22	0.11118	0.10067	0.09119	0.08264	0.07493	0.06796	0.06167	0.05599	0.05085	0.0462
23	0.10062	0.09069	0.08179	0.07379	0.0666	0.06014	0.05434	0.04911	0.04441	0.04017
24	0.09106	0.0817	0.07335	0.06588	0.0592	0.05323	0.04787	0.04308	0.03879	0.03493
25	0.0824	0.07361	0.06579	0.05882	0.05262	0.0471	0.04218	0.03779	0.03387	0.03038

## Exhibit 7

Table A.2 displays the annual payment you would have to make for a specific number of years to equal the present value of a single dollar borrowed today. Select the number of years you will make payments from the leftmost column and the discount rate from the top row. The value where the column and row intersect is annual payment on that borrowed dollar. For example, if you plan on making equal payments for twelve years at 9.5 percent interest to repay a dollar borrowed today, you would make annual payments of 14.3 cents.

**Table A.2:** Capital Recovery Factors for Equal Payments on a Dollar over a Number of Years

	5.50%	6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	9.00%	9.50%	10.00%
1	1.055	1.06	1.065	1.07	1.075	1.08	1.085	1.09	1.095	1.1
2	0.54162	0.54544	0.54926	0.55309	0.55693	0.56077	0.56462	0.56847	0.57233	0.57619
3	0.37065	0.37411	0.37758	0.38105	0.38454	0.38803	0.39154	0.39505	0.39858	0.40211
4	0.28529	0.28859	0.2919	0.29523	0.29857	0.30192	0.30529	0.30867	0.31206	0.31547
5	0.23418	0.2374	0.24063	0.24389	0.24716	0.25046	0.25377	0.25709	0.26044	0.2638
6	0.20018	0.20336	0.20657	0.2098	0.21304	0.21632	0.21961	0.22292	0.22625	0.22961
7	0.17596	0.17914	0.18233	0.18555	0.1888	0.19207	0.19537	0.19869	0.20204	0.20541
8	0.15786	0.16104	0.16424	0.16747	0.17073	0.17401	0.17733	0.18067	0.18405	0.18744
9	0.14384	0.14702	0.15024	0.15349	0.15677	0.16008	0.16342	0.1668	0.1702	0.17364
10	0.13267	0.13587	0.1391	0.14238	0.14569	0.14903	0.15241	0.15582	0.15927	0.16275
11	0.12357	0.12679	0.13006	0.13336	0.1367	0.14008	0.14349	0.14695	0.15044	0.15396
12	0.11603	0.11928	0.12257	0.1259	0.12928	0.1327	0.13615	0.13965	0.14319	0.14676
13	0.10968	0.11296	0.11628	0.11965	0.12306	0.12652	0.13002	0.13357	0.13715	0.14078
14	0.10428	0.10758	0.11094	0.11434	0.1178	0.1213	0.12484	0.12843	0.13207	0.13575
15	0.09963	0.10296	0.10635	0.10979	0.11329	0.11683	0.12042	0.12406	0.12774	0.13147
16	0.09558	0.09895	0.10238	0.10586	0.10939	0.11298	0.11661	0.1203	0.12403	0.12782
17	0.09204	0.09544	0.09891	0.10243	0.106	0.10963	0.11331	0.11705	0.12083	0.12466
18	0.08892	0.09236	0.09585	0.09941	0.10303	0.1067	0.11043	0.11421	0.11805	0.12193
19	0.08615	0.08962	0.09316	0.09675	0.10041	0.10413	0.1079	0.11173	0.11561	0.11955
20	0.08368	0.08718	0.09076	0.09439	0.09809	0.10185	0.10567	0.10955	0.11348	0.11746
21	0.08146	0.085	0.08861	0.09229	0.09603	0.09983	0.1037	0.10762	0.11159	0.11562
22	0.07947	0.08305	0.08669	0.09041	0.09419	0.09803	0.10194	0.1059	0.10993	0.11401
23	0.07767	0.08128	0.08496	0.08871	0.09254	0.09642	0.10037	0.10438	0.10845	0.11257
24	0.07604	0.07968	0.0834	0.08719	0.09105	0.09498	0.09897	0.10302	0.10713	0.1113
25	0.07455	0.07823	0.08198	0.08581	0.08971	0.09368	0.09771	0.10181	0.10596	0.11017

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**Table A.2: Continued**

	10.50%	11.00%	11.50%	12.00%	12.50%	13.00%	13.50%	14.00%	14.50%	15.00%
1	1.105	1.11	1.115	1.12	1.125	1.13	1.135	1.14	1.145	1.15
2	0.58006	0.58393	0.58781	0.5917	0.59559	0.59948	0.60338	0.60729	0.6112	0.61512
3	0.40566	0.40921	0.41278	0.41635	0.41993	0.42352	0.42712	0.43073	0.43435	0.43798
4	0.31889	0.32233	0.32577	0.32923	0.33271	0.33619	0.33969	0.3432	0.34673	0.35027
5	0.26718	0.27057	0.27398	0.27741	0.28085	0.28431	0.28779	0.29128	0.29479	0.29832
6	0.23298	0.23638	0.23979	0.24323	0.24668	0.25015	0.25365	0.25716	0.26069	0.26424
7	0.2088	0.21222	0.21566	0.21912	0.2226	0.22611	0.22964	0.23319	0.23677	0.24036
8	0.19087	0.19432	0.1978	0.2013	0.20483	0.20839	0.21197	0.21557	0.2192	0.22285
9	0.17711	0.1806	0.18413	0.18768	0.19126	0.19487	0.19851	0.20217	0.20586	0.20957
10	0.16626	0.1698	0.17338	0.17698	0.18062	0.18429	0.18799	0.19171	0.19547	0.19925
11	0.15752	0.16112	0.16475	0.16842	0.17211	0.17584	0.1796	0.18339	0.18722	0.19107
12	0.15038	0.15403	0.15771	0.16144	0.16519	0.16899	0.17281	0.17667	0.18056	0.18448
13	0.14445	0.14815	0.1519	0.15568	0.1595	0.16335	0.16724	0.17116	0.17512	0.17911
14	0.13947	0.14323	0.14703	0.15087	0.15475	0.15867	0.16262	0.16661	0.17063	0.17469
15	0.13525	0.13907	0.14292	0.14682	0.15076	0.15474	0.15876	0.16281	0.1669	0.17102
16	0.13164	0.13552	0.13943	0.14339	0.14739	0.15143	0.1555	0.15962	0.16376	0.16795
17	0.12854	0.13247	0.13644	0.14046	0.14451	0.14861	0.15274	0.15692	0.16112	0.16537
18	0.12586	0.12984	0.13387	0.13794	0.14205	0.1462	0.15039	0.15462	0.15889	0.16319
19	0.12353	0.12756	0.13164	0.13576	0.13993	0.14413	0.14838	0.15266	0.15698	0.16134
20	0.12149	0.12558	0.1297	0.13388	0.1381	0.14235	0.14665	0.15099	0.15536	0.15976
21	0.11971	0.12384	0.12802	0.13224	0.13651	0.14081	0.14516	0.14954	0.15396	0.15842
22	0.11813	0.12231	0.12654	0.13081	0.13512	0.13948	0.14387	0.1483	0.15277	0.15727
23	0.11675	0.12097	0.12524	0.12956	0.13392	0.13832	0.14276	0.14723	0.15174	0.15628
24	0.11552	0.11979	0.1241	0.12846	0.13287	0.13731	0.14179	0.1463	0.15085	0.15543
25	0.11443	0.11874	0.1231	0.1275	0.13194	0.13643	0.14095	0.1455	0.15008	0.1547



## 2021 Regional Haze Four Factor Initial Control Determination

Facility: Tucson Electric Power  
Springerville Generating Station

*Air Quality Division*  
*April 13, 2021*

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# 1 ADEQ Initial Regional Haze Four Factor Control Determination

## 1.1 ADEQ Initial Control Determination for TEP Springerville

ADEQ’s initial decision is to find that it is reasonable to require additional controls on TEP Springerville during this planning period in order to make reasonable progress toward natural visibility conditions. ADEQ proposes, as reasonable controls, additional sulfur dioxide (SO<sub>2</sub>) controls for Unit 1 and Unit 2 by upgrading the current spray dry absorbers (SDA) or equivalent SO<sub>2</sub> emission reductions from Units 1 and 2 achieved through other means. ADEQ additionally proposes that no new emission reductions are reasonable for Units 3 and 4.

## 1.2 ADEQ Control Determination Finalization Timeline

In order to meet the State rulemaking and Regional Haze state implementation plan (SIP) timeline, ADEQ must finalize all four factor analyses as expeditiously as possible. To provide an opportunity for interested stakeholders to review and comment on ADEQ’s initial decision prior to finalization, the department intends to post initial decisions on the agency webpage along with the original source submitted four factor analyses. Once ADEQ has reviewed relevant stakeholder comments, the agency will revise its initial decisions if necessary and post final decisions (see Figure 1). ADEQ welcomes feedback on these initial decisions and invites any interested party to send their comments by **May 14, 2021** to:

**Ryan Templeton, P.E.**  
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[Templeton.Ryan@azdeq.gov](mailto:Templeton.Ryan@azdeq.gov)

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Please note that this review and feedback opportunity does not constitute an official state implementation plan or state rulemaking comment period. The agency intends to provide an official 30 day comment period on any proposed SIP or rulemaking action in accordance with Arizona Revised Statutes §§ 41-1023, 49-425, and 49-444.

**Figure 1: Four Factor Control Determination Process Map**



## 2 ADEQ Four Factor Analysis

### 2.1 Summary

ADEQ is proposing additional sulfur dioxide (SO<sub>2</sub>) emission limitations for Unit 1 and Unit 2 based on updating the current spray dry absorbers (SDA). TEP contracted Sargent and Lundy (S&L) to evaluate potential upgrades for the units, which concluded updating the SDA could result in emissions reductions of 36%. Based on S&L's analysis, ADEQ is proposing the following combined emission limitations for Unit 1 and Unit 2:

**Table 1: Proposed Emission Limits**

Unit	Pollutant	Limit	Averaging Period	Corresponding Control Technology
Unit 1 & Unit 2	SO <sub>2</sub>	17.1 tpd	30-day rolling average	Upgraded spray dry absorber (SDA)
Unit 1 & Unit 2	SO <sub>2</sub>	3,729 tpy	12-month rolling average	Upgraded spray dry absorber (SDA)

TEP completed and submitted separate four factor analysis reports for SGS Units 1, SGS Unit 2, and another for Unit 3 and 4, to the Department on March 31, 2020. TEP supplied supplemental submittals on November 6, 2020 and December 18, 2020. The four factor analyses considered emissions of nitrogen oxides (NO<sub>x</sub>), SO<sub>2</sub>, and particulate matter less than 10 microns (PM<sub>10</sub>) and associated control technologies. The controls were evaluated for technical feasibility, cost of compliance, time necessary for compliance, energy and non-air environmental impacts, and the remaining useful life of the source. In addition to the four factors, the TEP reports assess the visibility impacts of SGS and the visibility benefits of feasible control options.

ADEQ reviewed TEP's four factor analysis report for completeness and accuracy and noted some assumptions which have been updated in subsequent submittals or in this document. These changes included the life expectancy for SCR and SO<sub>2</sub> controls, the interest rate used in the cost calculations, and a more thorough review of Wet Flue Gas Desulfurization (wet FGD) and Circulating Dry Scrubbers (CDS). TEP proposed a life expectancy of 20 years for an SCR on Unit 1 and 2, however the EPA Cost Control Manual recommends a life expectancy of at least 30 years for SCRs installed at electricity generating units and 20 to 30 years for SO<sub>2</sub> controls<sup>1</sup>. The cost calculations submitted by TEP utilized an interest rate of 5.25%, which was lowered to 4.75% (the approximate average bank prime interest rate for the last 3 years) to recalculate the control costs

<sup>1</sup> EPA Cost Manual Section 4, Chapter 2 and EPA Cost control Manual Section 5, Chapter 1.

submitted in the four-factor analysis.<sup>2</sup> In their initial four-factor analysis TEP inadvertently included the sales tax for the pollution control devices, which is exempt under Arizona Revised Statute (ARS) 43-1081.B. This was corrected in a supplemental submittal to ADEQ.

## 2.2 Facility Overview

### 2.2.1 Process Description

Springerville Generating Station (SGS) comprises four coal-fired electric generating units with a combined, nominal, net generating capacity of 1,620 megawatts (MWe). Units 1 and 2 at SGS are owned and operated by Tucson Electric Power Company (TEP). Unit 3 is owned by Tri-State Generation and Transmission Association, Inc., and Unit 4 is owned by the Salt River Project Agricultural Improvement and Power District (SRP). All units are operated by TEP.

Unit 1 and Unit 2 boilers are tangentially-fired units, each with a nameplate capacity of 424.8 megawatts. Units 1 and 2 combust subbituminous coal from El Segundo mine, which has a sulfur content of approximately 1% by weight<sup>3</sup>. Unit 3 and Unit 4 boilers are dry bottom wall-fired units each with a nameplate capacity of 458.1 MWe and primarily fire Powder River basin (PRB) coal and other low-sulfur coals which have a typical sulfur content of about 0.2% by weight<sup>4</sup>.

In addition to controls in place to meet the requirements of other programs such as Mercury and Air Toxics Standards (MATS) and new source performance standards (NSPS), all four units at SGS are equipped with pollution control devices to control emissions of particulate matter less than 10 microns (PM<sub>10</sub>), nitrogen oxides (NO<sub>x</sub>), and SO<sub>2</sub>, which have been summarized in Table 2 below.

<sup>2</sup> ADEQ calculated the three-year average monthly bank prime rate for 2017-2019 and 2018-2020 as 4.83% and 4.78%, respectively. Based on these averages, ADEQ finds that 4.75% is a representative interest rate.

<sup>3</sup> US Energy Information Administration. Coal shipment sulfur content: El Segundo (2902257) to Springerville (8223): Subbituminous : quarterly.

[https://www.eia.gov/opendata/qb.php?category=773545&sid=COAL.SHIPMENT\\_SULFUR.2902257-8223-SUB.Q](https://www.eia.gov/opendata/qb.php?category=773545&sid=COAL.SHIPMENT_SULFUR.2902257-8223-SUB.Q)

<sup>4</sup> US Energy Information Administration. Coal shipment sulfur content: North Antelope Rochelle Mine (4801353) to Springerville (8223) : Subbituminous : quarterly.

[https://www.eia.gov/opendata/qb.php?category=773545&sid=COAL.SHIPMENT\\_SULFUR.4801353-8223-SUB.Q](https://www.eia.gov/opendata/qb.php?category=773545&sid=COAL.SHIPMENT_SULFUR.4801353-8223-SUB.Q)

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**Table 2 Pollution Control Devices at SGS<sup>5</sup>**

	<b>Units 1 and 2</b>	<b>Units 3 and 4</b>
PM <sub>10</sub>	Baghouse	Baghouse
NO <sub>x</sub>	Low NO <sub>x</sub> burners and overfire air (OFA)	Low NO <sub>x</sub> burners, OFA, and selective catalytic reduction (SCR)
SO <sub>2</sub>	Spray dry absorbers (SDA)	Spray dry absorbers (SDA)

Unit 1 and Unit 2 began construction in 1978 and commenced operations in 1985 and 1990, respectively. The boilers are subject to NSPS Subpart D since the capacity of each is greater than 25 MW and commenced construction after 1971. EPA issued an approval to construct with emission limits more stringent than the federal standards; therefore, these limits have been incorporated into the permit.

A prevention of significant deterioration (PSD) permit for the construction and operation of Unit 3 and Unit 4 was issued in 2002. During the permitting action, TEP accepted combined emission limits for SO<sub>2</sub> and NO<sub>x</sub> for all four units as well as limits for particulate matter (PM) for Units 3 and 4. Because the units are greater than 73 MW and commenced construction after 1978, both units are subject to NSPS Subpart Da. All four units are subject to the MATS rule for coal-fired boilers, thus the emission limits from this subpart are also listed in the air quality permit. A summary of NO<sub>x</sub>, SO<sub>2</sub>, and PM emission limits for Units 1-4 can be found in Table 3 below.

**Table 3 Current Emission Limits**

<b>Emission Source</b>	<b>Pollutant</b>	<b>Emission Limits</b>
<b>Unit 1 &amp; Unit 2</b>	NO <sub>x</sub>	0.22 lb/MMBtu (12-month rolling average); and 0.697 lb/MMBtu (avg. of three 1-hr tests)
<b>Unit 1 &amp; Unit 2</b>	SO <sub>2</sub>	0.27 lb/MMBtu (12-month rolling average); 0.690 lb/MMBtu (average of three 1-hr tests); 85% reduction (90-day rolling average); and 0.2 lb/MMBtu or 1.5 lb/MWh (optional MATS limit)
<b>Unit 1 &amp; Unit 2</b>	PM/PM <sub>10</sub>	0.034 lb/MMBtu (avg of three 1-hr tests); 0.03 lb/MMBtu; and 0.3 lb/MWh or 0.03 lb/MMBtu (total PM)
<b>Unit 3</b>	NO <sub>x</sub>	1.6 lb/MWh (30-day rolling average)

<sup>5</sup> This list is not inclusive of all controls at SGS. Given that ADEQ is targeting NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>10</sub> pollution controls, we have chosen to exclude controls required for programs such as the Mercury Air Toxics Standards (MATS).

## Exhibit 8

Emission Source	Pollutant	Emission Limits
Unit 3	SO <sub>2</sub>	1.2 lb/MMBtu and a 90% reduction; Or 70% reduction when emissions are <0.6 lb/MMBtu; and 0.2 lb/MMBtu or 1.5 lb/MWh (optional MATS limit)
Unit 3 & Unit 4	PM	0.015 lb/MMBtu (excludes condensable PM); and 0.3 lb/MWh or 0.03 lb/MMBtu (total PM)
Unit 3 & Unit 4	PM <sub>10</sub>	0.055 lb/MMBtu (includes filterable and condensable PM <sub>10</sub> )
Unit 4	NO <sub>x</sub>	1.0 lb/MWh (30-day rolling average)
Unit 4	SO <sub>2</sub>	1.4 lb/MWh or 95% reduction; and 0.2 lb/MMBtu or 1.5 lb/MWh (optional MATS limit)
Unit 4	PM	0.14 lb/MWh or 0.15 lb/MMBtu; Or 0.03 lb/MMBtu and 99.9% reduction
Combined emission limit	NO <sub>x</sub>	9,600 tpy (calendar year and rolling 12-month total)
Combined emission limit	SO <sub>2</sub>	10,800 tpy (calendar year and rolling 12-month total); and 8,448 lb/hr (3-hr rolling basis)

### 2.2.2 Affected Class I Area(s)

There are five Class I areas within 200 km of TEP Springerville. These areas from nearest to furthest are Mount Baldy Wilderness, Petrified National Forest Park, Gila Wilderness, Sierra Ancha Wilderness and Tonto National Forest Wilderness.

### 2.2.3 Baseline Emission Calculations

ADEQ generally established baseline emissions for all sources using emissions from 2016-2018. TEP SGS Unit 1, however, was shut down for four months in 2017 resulting in a lower throughput that year than in normal years. Therefore, baseline emissions were from years 2016, 2018 and 2019 for TEP SGS Units 1 and 2, to ensure that the baseline emissions were representative of normal operations. Table 4 below shows the heat inputs, coal throughputs, and annual emissions of NO<sub>x</sub>, SO<sub>2</sub> and PM<sub>10</sub> from 2016, 2018 and 2019 for Unit 1 and Unit 2, and 2016-2018 for Units 3 and 4.

**Table 4 Historical Emissions**

Year	Heat Input (MMBtu/yr)	Coal Throughput (tpy)	NO <sub>x</sub> (tpy)	SO <sub>2</sub> (tpy)	PM <sub>10</sub> (tpy)
<b>Unit 1</b>					
<b>2016</b>	21,012,116	1,202,152	1,864	2,207	65
<b>2018</b>	26,071,321	1,448,446	2,188	3,494	112
<b>2019</b>	25,275,437	1,343,462	2,235	2,979	103
<b>Unit 2</b>					
<b>2016</b>	26,982,858	1,503,358	2,341	2,516	127
<b>2018</b>	26,403,872	1,497,576	2,406	3,632	104

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Year	Heat Input (MMBtu/yr)	Coal Throughput (tpy)	NO <sub>x</sub> (tpy)	SO <sub>2</sub> (tpy)	PM <sub>10</sub> (tpy)
2019	23,417,570	1,349,140	2,100	2,777	92
<b>Unit 3</b>					
2016	22,646,321	1,222,173	852	851	32
2017	25,715,188	1,432,627	1,122	1,163	101
2018	26,938,375	1,480,843	1,092	1,106	366
<b>Unit 4</b>					
2016	23,845,639	1,326,676	912	1,038	18
2017	21,565,128	1,196,220	878	915	14
2018	23,281,713	1,229,277	996	1,167	60

### 2.3 ADEQ Screening Methodology

ADEQ considered unit processes that underwent evaluation in regional haze round 1, BACT analysis post 2014 or other SIP actions to achieve compliance with the NAAQS post 2014 as effectively controlled for the purposes of this regional haze analysis.

Unit Processes that emit PM<sub>10</sub>, SO<sub>2</sub> and NO<sub>x</sub> that were not considered effectively controlled were summed to determine the ton per year emissions (Q) for the facility. If the Q value exceeded 10, ADEQ determined the distance (d) of the facility to the border of the nearest Class I area and calculated the ratio of emissions to distance (Q/d). If the Q/d value exceeded 10, then the source was subject to four factor review. The Q/d value for SGS was determined to have a Q/d of over 300 for Mount Baldy Wilderness, making the facility subject to four-factor review.

ADEQ's default methodology for conducting a four-factor analysis was to limit the number of processes considered to only those processes that make up the top 80% of emissions at the source. Prior to providing TEP with the result of the screening analysis, discussions with TEP revealed that their reported PM emissions for the cooling towers assumed PM=PM<sub>10</sub>. TEP provided a speciation analysis on particulate matter from cooling towers to demonstrate that PM<sub>10</sub> was significantly lower than PM and should not be included in the four factor analysis. ADEQ reviewed this analysis and agreed with results of TEP's speciation report. Table 5 shows the top 80% of emissions at SGS after the cooling tower adjustment.

**Table 5 Top 80% of emissions at SGS based on 2018 emissions**

Emission Unit	Process	Pollutant	Emissions (tpy)	Cumulative % of Emissions
Unit 2 Boiler	Coal Combustion	SO <sub>2</sub>	3632	21%
Unit 1 Boiler	Coal Combustion	SO <sub>2</sub>	3494	40%
Unit 2 Boiler	Coal Combustion	NO <sub>x</sub>	2406	54%
Unit 1 Boiler	Coal Combustion	NO <sub>x</sub>	2188	66%

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<b>Emission Unit</b>	<b>Process</b>	<b>Pollutant</b>	<b>Emissions (tpy)</b>	<b>Cumulative % of Emissions</b>
<b>Unit 4 Boiler</b>	Coal Combustion	SO <sub>2</sub>	1167	73%
<b>Unit 3 Boiler</b>	Coal Combustion	SO <sub>2</sub>	1106	79%
<b>Unit 3 Boiler</b>	Coal Combustion	NO <sub>x</sub>	1092	85%

After identifying the top 80% of emissions at SGS, ADEQ considered the unit process emissions that were not included and identified potential emissions that should be added to the four factor analysis. The most significant exclusion was 996 tons per year of NO<sub>x</sub> from coal combustion at the Unit 4 boiler, which if added to the screening analysis would represent the top 91% of emissions at SGS. Additionally, based on the magnitude of emissions, ADEQ determined that PM<sub>10</sub> emissions from coal combustion at all four boilers should also be included in the four factor analysis. This addition resulted in 95% of emissions at SGS being included in the four factor analysis. Table 6 shows the final screening results. All unit process emissions that were not from coal combustion at the boilers were excluded from the four factor analysis.

**Table 6 Processes included in SGS 4FA based on 2018 emissions**

<b>Emission Unit</b>	<b>Process</b>	<b>Pollutant</b>	<b>Emissions (tpy)</b>
<b>Unit 2 Boiler</b>	Coal Combustion	SO <sub>2</sub>	3,632
<b>Unit 1 Boiler</b>	Coal Combustion	SO <sub>2</sub>	3,494
<b>Unit 2 Boiler</b>	Coal Combustion	NO <sub>x</sub>	2,406
<b>Unit 1 Boiler</b>	Coal Combustion	NO <sub>x</sub>	2,188
<b>Unit 4 Boiler</b>	Coal Combustion	SO <sub>2</sub>	1,167
<b>Unit 3 Boiler</b>	Coal Combustion	SO <sub>2</sub>	1,106
<b>Unit 3 Boiler</b>	Coal Combustion	NO <sub>x</sub>	1,092
<b>Unit 4 Boiler</b>	Coal Combustion	NO <sub>x</sub>	996
<b>Unit 3 Boiler</b>	Coal Combustion	PM <sub>10</sub>	366
<b>Unit 1 Boiler</b>	Coal Combustion	PM <sub>10</sub>	112
<b>Unit 2 Boiler</b>	Coal Combustion	PM <sub>10</sub>	104
<b>Unit 4 Boiler</b>	Coal Combustion	PM <sub>10</sub>	60

## 2.4 Proposed Control Methodology

### 2.4.1 Baseline Control Scenario (Projected 2028 Emissions Profile)

To calculate the 2028 projected emissions profile, ADEQ relied on the emissions inventory data that was submitted to the Clean Air Markets Division (CAMD) which is summarized in Table 4 above. The 2028 emissions projections for Unit 1 and Unit 2 used emissions and throughput data for 2016, 2018 and 2019. ADEQ determined that 2017 was not a representative year for Unit 1 since it was not operating for several months of the year. The 2028 emissions profile for Unit 3 and Unit 4 were based on the emissions and

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throughput data from 2016 through 2018. The projected air pollutants include PM<sub>10</sub>, SO<sub>2</sub>, and NO<sub>x</sub>.

ADEQ calculated a scaling factor for each emission unit by dividing the annual emissions by the heat input for SO<sub>2</sub> and NO<sub>x</sub> and dividing the annual emissions by the throughput of coal combusted for PM<sub>10</sub>. Next, ADEQ calculated the average throughput and scaling factor for each unit and pollutant, and then multiplied these values to determine the 2028 emissions projections. Table 7 below summarizes the average scaling factors and process throughputs, and the resulting projected 2028 emissions profile.

**Table 7: TEP Springerville 2028 Projections**

	Average Scaling factor			Average Throughput			2028 Emission Projections (tpy)		
	PM <sub>10</sub> (ton/ton coal)	NO <sub>x</sub> (ton/MMBtu)	SO <sub>2</sub> (ton/MMBtu)	PM <sub>10</sub> (ton coal/yr)	NO <sub>x</sub> (MMBtu/yr)	SO <sub>2</sub> (MMBtu/yr)	PM <sub>10</sub>	NO <sub>x</sub>	SO <sub>2</sub>
<b>Unit 1 Boiler</b>	6.92E-05	8.70E-05	1.19E-04	1,331,353	24,119,624	24,119,624	92	2,099	2,869
<b>Unit 2 Boiler</b>	7.40E-05	8.92E-05	1.16E-04	1,450,025	25,601,433	25,601,433	107	2,283	2,982
<b>Unit 3 Boiler</b>	1.15E-04	4.06E-05	4.13E-05	1,378,548	25,099,962	25,099,962	158	1,019	1,036
<b>Unit 4 Boiler</b>	2.45E-05	4.06E-05	4.54E-05	1,250,724	22,897,493	22,897,493	31	929	1,039

## 2.4.2 Evaluated Controls and Emission Estimates

### 2.4.2.1 Particulate Matter Emission Controls

Particulate matter emissions from pulverized coal-fired boilers are typically comprised of fly ash and incomplete combustion material. Subbituminous coals have an ash content of less than or equal to 10%<sup>6</sup>. Particulates are also formed as an unwanted byproduct as a result of ammonia injection for control technologies such as a selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR). The following devices can be used to control particulate matter emissions from coal-fired power plants:

- Baghouse – currently installed Units 1-4
- Wet Electrostatic Precipitator (Wet ESP)
- Dry Electrostatic Precipitator (ESP)
- Wet Scrubber
- Cyclones

<sup>6</sup> Bowen, B, Irwin, M. (October 2008). Coal Characteristics CCTR Basic Facts File #8. West Lafayette, IN: The Energy Center at Discovery Park Purdue University.  
<https://www.purdue.edu/discoverypark/energy/assets/pdfs/cctr/outreach/Basics8-CoalCharacteristics-Oct08.pdf>



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### 2.4.2.2 NO<sub>x</sub> Emission Controls:

Coal combustion results in the formation of both fuel and thermal NO<sub>x</sub>. The production of NO<sub>x</sub> depends heavily on the nitrogen content of the fuel and the combustion process of the boiler. TEP combusts subbituminous coal in all four units which has a typical nitrogen content of 0.5 to 2 percent by weight and can result in up to 80% of the total NO<sub>x</sub> emissions<sup>7</sup> from these types of facilities.

Emission reductions for coal-fired boilers can be accomplished by two general methodologies: combustion controls and add-on pollution control devices. Combustion controls include technologies such as low-NO<sub>x</sub> burners, burners out of service (BOOS) and over fire air (OFA). These techniques reduce the combustion temperature and oxygen concentration which prevent the formation of both thermal and fuel NO<sub>x</sub> generated during the combustion process.

#### Combustion Control Options:

- Low-NO<sub>x</sub> burners, OFA or other combustion controls – currently installed on all four units

#### Post-Combustion Control Options:

- Selective catalytic reduction (SCR) – installed on Unit 3 and 4
- Selective non-catalytic reduction (SNCR)

### 2.4.2.3 SO<sub>2</sub> Emissions:

Sulfur oxides are formed during the combustion process of sulfur containing coal. Subbituminous coals, which contain less than 2% sulfur by weight<sup>8</sup> are combusted in all four units. Similarly to NO<sub>x</sub> emissions controls, coal fired electric steam generating units can reduce SO<sub>2</sub> emissions using post-combustion control technologies.

#### Post combustion control technologies include:

- Spray Dry Absorber (SDA) – Installed on all four units
- Dry Sorbent Injection (DSI)
- Circulating Dry Scrubber (CDS)
- Wet Flue Gas Desulfurization (FGD)

<sup>7</sup> Environmental Protection Agency. September 1998. AP-42, Fifth Edition, Volume I, Chapter I Section 1: Bituminous and Subbituminous Coal Combustion. <https://www3.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf>  
<https://www3.epa.gov/ttn/chie1/ap42/ch01/final/c01s01.pdf>

<sup>8</sup> <https://www.purdue.edu/discoverypark/energy/assets/pdfs/cctr/outreach/Basics8-CoalCharacteristics-Oct08.pdf>

## 2.5 Four Factor Analysis Review for PM<sub>10</sub> Emissions

### 2.5.1 Technical Feasibility

Particulate matter controls discussed above were evaluated for technical feasibility. A summary of the control technologies and technical feasibility of the devices can be found in Table 8 below. While wet scrubbers and cyclones also represent technically feasible control options for PM<sub>10</sub> emissions reduction, their control efficiencies range from 95-99% and 90-95% respectively.<sup>9</sup> As such, these control technologies are less effective than the currently installed baghouses and will not be considered further in this evaluation.

**Table 8 Evaluated PM<sub>10</sub> Controls**

Emission Unit	Control Option	Technically Feasible (Y/N)	Additional Control Effectiveness (%)
Unit 1-4	Baghouse	Y	0%
Unit 1-4	Wet ESP	Y	0%
Unit 1-4	ESP	Y	0%

#### **Baghouses:**

Baghouses control particulate matter emissions by utilizing fabric filtration and have a control efficiency up to 99.9%<sup>10</sup>. Units 1-4 are each equipped with baghouses to control particulate matter emissions. Therefore, baghouses are not considered further in this analysis.

#### **ESP and West ESP:**

Electrostatic precipitators are typically separated into two groups: dry ESPs and wet ESPs. The primary difference between the two is the method used to remove particulates from the electrodes. Wet ESPs utilize water sprays to remove particulates from the electrodes and collect the slurry material in a sump while particulate matter from dry ESPs is removed using mechanical methods, such as rapping or vibrating and collected in a hopper below the electrode. ESPs use an electrical charge to separate the particles in the flue gas stream under the influence of an electric field. The collection efficiency of an ESP depends on the resistance of the particles in the flue gas. ESPs have typical collection efficiencies greater than 99% for fine (less than 0.1 micrometer) and coarse particles (greater than 10 micrometers)<sup>10</sup>. Because ESP collection efficiency is comparable to or less than that of the current baghouses installed on the units, ADEQ determined replacing

<sup>9</sup> Environmental Protection Agency. September 1998. AP-42, Fifth Edition, Volume I, Chapter I Section 1: Bituminous and Subbituminous Coal Combustion. <https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>

<sup>10</sup> *ibid*

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the control device with an ESP, while technically feasible, should not be considered further.

### ADEQ Determination:

ADEQ has determined that the baghouses currently installed on all four units adequately control particulate matter emissions from the boilers and therefore, no additional controls are necessary.

## 2.6 Four Factor Analysis Review for NO<sub>x</sub> Emissions

### 2.6.1 Technical Feasibility

A summary of the technical feasibility of the pollution control devices for NO<sub>x</sub> can be found in Table 9 below.

**Table 9 Evaluated NO<sub>x</sub> Controls**

Control Option	Technically Feasible (Y/N)	Additional Control Effectiveness (%)	Emission Factor (lb/MMBtu)	Heat Input Rate (MMBtu/hr)	NO <sub>x</sub> Emission Rate (lb/hr)	NO <sub>x</sub> Emissions (tpy)
<b>Unit 1<sup>1</sup></b>						
LNB and OFA	Y	0%	0.17	2753	479	2,099
SNCR	Y	14%	0.15	2753	413	1,809
SCR	Y	66%	0.06	2753	165	724
<b>Unit 2<sup>2</sup></b>						
LNB and OFA	Y	0%	0.18	2923	521	2,283
SNCR	Y	16%	0.15	2923	438	1,920
SCR	Y	66%	0.06	2923	175	768
<b>Unit 3</b>						
LNB, OFA and SCR <sup>3</sup>	Y	0%	0.081	2865	233	1,019
<b>Unit 4</b>						
LNB, OFA and SCR <sup>3</sup>	Y	0%	0.081	2,614	212	929

<sup>1</sup> Capacity factor Unit 1: 65%

<sup>2</sup> Capacity factor Unit 2: 69%

<sup>3</sup> The combination of combustion controls (LNB+SOFA) and SCR is the existing configuration of Units 3 and 4 at SGS. Since this combination represents the most effective control technologies available for NO<sub>x</sub> for coal fired EGUs, no further analysis for other control technologies is needed.

### Selective Non-Catalytic Reduction (SNCR):

SNCR is a selective non-catalytic processes that uses an ammonia type reagent, such as urea or ammonia to reduce NO<sub>x</sub> to water and elemental nitrogen. The removal efficiency of NO<sub>x</sub> utilizing SNCR technologies for coal fire boilers ranges from 20-83%. For boilers above 400 MW most SNCR removal efficiencies are between 20 and 30% with a maximum

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of ~55%.<sup>11</sup> Another potential reaction of concern is the reaction of ammonia with sulfur trioxide. The resulting ammonia sulfates can deposit on equipment surfaces and fly ash requiring increased acid washing to preserve equipment and fly ash treatment. These additional considerations result in increased chemical consumption for treatment, and waste water generation.

### **Selective Catalytic Reduction (SCR):**

The removal mechanism for SCR is similar to SNCR with the addition of a metal based catalyst with activated sites to increase removal rate. In addition to the faster reaction rate, NO<sub>x</sub> removal with SCR requires a lower operating temperature however, the temperature range is catalyst dependent. The removal of NO<sub>x</sub> can in theory be as high as over 99% but is dependent on the inlet concentration. In practice outlet NO<sub>x</sub> emissions are rarely below 0.04 lb/MMBTU.<sup>12</sup>

### Unit 1 and Unit 2

Units 1 and 2 currently operate low NO<sub>x</sub> burners with OFA to control NO<sub>x</sub> emissions. Additional potential controls include SCR and SNCR. SNCR and SCR offer respective 14-16% and 66% emission reductions over LNB with OFA controls currently installed on Units 1 and 2. The outlet emissions for SNCR are expected to be 0.15 lb/MMBTU. This is consistent with 20% efficiency for units starting with 0.2 lb/MMBTU NO<sub>x</sub> emissions that has been observed for utility boilers<sup>13</sup>. The expected SCR emissions are consistent with the EPA's RACT/BACT/LAER Clearinghouse (RBLC) emissions. Both of these controls are technically feasible.

### Unit 3 and Unit 4

Retrofitting Unit 3 and Unit 4 with SNCR was not considered as a potential NO<sub>x</sub> emissions control because the removal efficiency of the control technology is estimated to be between 25-50%.<sup>14,15</sup> for coal fired EGUs with nameplate capacities between 400 and 500 MWe. The current controls (LNB, OFA with SCR) represent the most effective NO<sub>x</sub> control technologies for coal fired EGUs and are estimated to achieve 85-95%.<sup>15</sup> removal efficiency. In addition, ADEQ evaluated the current controls on these units with the RBLC and determined the current controls installed on Unit 3 and Unit 4 constitute best available control technology (BACT) for coal-fired EGUs.

<sup>11</sup> EPA SNCR Cost Manual – Revised April, 2019

<sup>12</sup> EPA SCR Cost Manual – Revised June, 2019

<sup>13</sup> EPA SNCR Cost Manual – Revised April, 2019

<sup>14</sup> See Figure 1.1a in EPA SNCR Cost Manual – Revised April, 2019.

<sup>15</sup> See Table 1.1-2 AP-42 Section 1.1 <https://www3.epa.gov/ttnca1/dir1/cs4-2ch2.pdf>

## 2.6.2 Cost of Compliance

The cost of both the SCR and the SNCR control technologies were calculated using the EPA cost calculation spreadsheets<sup>16</sup>. The estimated life for SCR and SNCR were set at 30 and 20 years respectively to match current EPA guidance for these control technologies on utility boilers<sup>17</sup>. TEP’s analysis used 20 years based on previous Regional Haze guidance, however, EPA has since reviewed multiple utility boilers and determined 30 years was the appropriate estimated life to use for utility boilers equipped with SCR. ADEQ selected an interest rate of 4.75%.

**Table 10 NO<sub>x</sub> Control Option Cost Effectiveness**

Control option	Capital cost	Annualized Capital Cost	Annual O&M Cost	Total annual cost (\$/yr)	Emission reduction (tpy)	Average Cost-effectiveness (\$/ton)
<b>Unit 1</b>						
SNCR	\$11,422,587	\$897,815	\$1,361,453	\$2,259,269	290	\$7,791
SCR	\$169,483,516	\$10,711,358	\$1,849,205	\$12,560,563	1,375	\$9,133
<b>Unit 2</b>						
SNCR	\$11,541,710	\$907,178	\$1,467,335	\$2,374,514	363	\$6,539
SCR	\$169,907,018	\$10,738,124	\$1,900,270	12,638,394	1,515	\$8,341

## 2.6.3 Visibility Impact

TEP provided a visibility modeling analysis to determine the potential visibility improvements at Class I areas resulting from a hypothetical emission control. TEP modeled a hypothetical NO<sub>x</sub> emission reduction of 2,118 tpy, which is approximately equivalent to 0.08 lb/MMBtu for both units when a control measure is implemented. This emission reduction results in a cumulative visibility improvement of 0.028 Mm<sup>-1</sup> and an average visibility improvement of 0.0005 Mm<sup>-1</sup> across 65 Class I areas on the 20% anthropogenically most impaired days (MIDs). The highest visibility improvement at a single Class I area on the MIDs, 0.00414 Mm<sup>-1</sup>, was realized at the Salt Creek Wilderness. The visibility improvement at Mount Baldy Wilderness Area, the nearest Class I area to SGS, was 0.00227 Mm<sup>-1</sup> on the MIDs. For seven Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors within 300-km of the SGS, the average visibility improvement is 0.00078 Mm<sup>-1</sup> on the MIDs. ADEQ further reviewed the aerosol light extinction (haze budgets) data for these monitors on the MIDs over 2014-2018<sup>18</sup>. ADEQ estimated that the visibility improvements resulted from the hypothetical NO<sub>x</sub> emission

<sup>16</sup> <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution> Accessed: April 15, 2020

<sup>17</sup> EPA SCR Cost manual updated June, 2019

<sup>18</sup> [http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF\\_VisSum](http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF_VisSum)

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reduction account for less than 0.02% of the aerosol light extinction for any Class I areas (see Table 11).

**Table 11 Visibility Improvements from NO<sub>x</sub> Emission Control and Aerosol Light Extinction on the MIDs over 2014-2018**

IMPROVE Site	Distance to SGS (km)	5-Year Average Aerosol Light Extinction <sup>1</sup> on MIDs over 2014-2018 (Mm <sup>-1</sup> )	Modeled Visibility Improvement on MIDs (Mm <sup>-1</sup> )	Percentage of Visibility Improvement to Aerosol Light Extinction (%)
Mount Baldy	38	12.06	0.00227	0.0188
Petrified Forest National Park	101	13.82	0.00071	0.0051
Gila Wilderness	149	12.50	0.0003	0.0024
Bosque del Apache Wilderness	218	19.00	0.00234	0.0123
Chiricahua National Monument	257	15.86	-0.00003 <sup>2</sup>	-0.0002 <sup>2</sup>
Saguaro National Park	279	19.78	0.00048	0.0024
San Pedro Parks Wilderness	282	11.48	-0.00062 <sup>2</sup>	-0.0054 <sup>2</sup>
Salt Creek Wilderness <sup>3</sup>	449	36.40	0.00414	0.0114

<sup>1</sup>Aerosol light extinction includes contributions from seven species (ammonium nitrate, ammonium sulfate, coarse mass, elemental carbon, organic mass, sea salt, and fine soil).

<sup>2</sup>The modeled results indicate that the hypothetical NO<sub>x</sub> control slightly degrades the visibility at the two Class I areas.

<sup>3</sup>Although Salt Creek Wilderness is beyond 300 km from SGS, it has the highest visibility improvement in term of light extinction among 65 Class I areas modeled. The visibility improvements are less than 0.002 Mm<sup>-1</sup> for any other Class I areas that are beyond 300 km from SGS.

By examining a variety of metrics for visibility improvements (cumulative and average for all Class I areas, maximum at a single Class I area), ADEQ concludes that the predicted visibility improvements resulted from the emission reduction of 2,118 tpy are small.

### 2.6.4 Determining Control Measures that are Necessary to Make Reasonable Progress

A state must consider the four statutory factors to determine what control measures are necessary to make reasonable progress. A state also has the flexibility to select or not select to take the visibility impacts of a source and the visibility benefits of feasible control options into account. To make a determination, ADEQ considers the balance between the cost of compliance and the visibility benefits.

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ADEQ has reviewed Best Available Retrofit Technology (BART) and Reasonable Progress (RP) determinations during the first regional haze second planning period. In particular, ADEQ examined how EPA accepted or rejected SCR. EPA heavily weighed two factors for their determinations: cost-effectiveness (average and incremental) in conjunction with visibility improvements in Class I areas (maximum visibility improvement at a single Class Area and total visibility improvements for all Class I Areas). While EPA did not explicitly state whether they used cost/visibility thresholds or not for their determinations, it appears that EPA would accept SCR if the cost-effectiveness was less than 5,000 \$/ton and the control achieved a visibility improvement of 0.5 deciviews (dv) or above. A visibility improvement of 0.5 dv is in line with previous EPA regional haze BART determination guidelines. EPA rejected SCR with a cost-effectiveness of greater than 5,000 \$/ton regardless of whether a visibility benefit was significant or not.

Considering the EPA's decisions during the first implementation period and adjusting the costs with an inflation rate, ADEQ is using an average cost-effectiveness of 6,500 \$/ton as a reasonable threshold to assess whether a control option is cost excessive or not. Any controls having an average cost-effectiveness of 6,500 \$/ton are cost excessive unless there are compelling evidence that the controls would result in a significant visibility improvement at Class I areas. Additionally, ADEQ determines that any controls having an average cost-effectiveness of 4,000 \$/ton or lower are deemed to be cost effective unless there are compelling or extraordinary circumstances. Controls with an average cost-effectiveness between 4,000 \$/ton and 6,500 \$/ton are further considered based on additional cost metrics, the remaining three statutory factors, and visibility modeling, if appropriate.

### 2.6.4.1 SNCR

The SNCR-based control options have an average cost effectiveness of 7,791 \$/ton and 6,539 \$/ton for Unit 1 and Unit 2, respectively, which are higher than the threshold of 6,500 \$/ton ADEQ has established. The SNCR option results in a combined emission reduction of 653 tpy, significantly lower than the modeled emission reduction of 2,118 tpy. Since the modeled visibility improvements are small, it is expected that the visibility improvements from SNCR are marginal. By weighting the factors of cost of compliance and the visibility benefits, ADEQ rejects SNCR as the control to make reasonable progress.

### 2.6.4.2 SCR

The SCR-based control options have an average cost effectiveness of 9,133 \$/ton and 8,341 \$/ton for Unit 1 and Unit 2, respectively, which are higher than the threshold of 6,500 \$/ton ADEQ has established. It should be addressed that the average cost-effectiveness are estimated using a remaining useful life of 30 years for the control device. However, it is expected that the remaining useful life for Unit 1 and Unit 2 would be much shorter than 30 years. As laid out in its 2020 Integrated Resource Plan (IRP), TEP is planning to retire Unit 1 in 2027 and Unit 2 in 2032. The average cost-effectiveness would be higher if using a shorter remaining useful life as opposed to a 30-year remaining useful

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life. However, given that a shut-down is not enforceable through rule or permit, ADEQ continues to rely on a 30 year useful life for this determination.

The SCR option results in a combined emission reduction of 2,890 tpy, higher than the modeled emission reduction of 2,118 tpy. However, considering the magnitude of modeled emission reductions and corresponding the visibility improvement, ADEQ determines that SCR is unlikely to achieve a significant visibility improvement at Class I areas. By weighting the factors of cost of compliance and the visibility benefits, ADEQ also rejects SCR as the control to make reasonable progress.

## 2.7 Four Factor Analysis Review for SO<sub>2</sub> Emissions

### 2.7.1 Technical Feasibility

A summary of the technical feasibility of the pollution control devices for SO<sub>2</sub> can be found in Table 12 below.

**Table 12 Evaluated SO<sub>2</sub> Controls**

Control Option	Technically Feasible (Y/N)	Additional Control Effectiveness (%)	Emission Factor (lb/MMBtu)	Heat Rate (MMBtu/hr)	SO <sub>2</sub> Emission Rate (lb/hr)	SO <sub>2</sub> Emission Rate (tpy)
<b>Unit 1<sup>1</sup></b>						
Current SDA	N/A	0%	0.24	2,753	655	2869
Upgraded SDA	Y	37%	0.15	2,753	413	1809
DSI	Y	24%	0.18	2,753	496	2171
CDS	Y	71%	0.07	2,753	193	844
Wet FGD	Y	87%	0.03	2,753	83	362
<b>Unit 2<sup>2</sup></b>						
Current SDA	N/A	0%	0.23	2,923	681	2982
Upgraded SDA	Y	36%	0.15	2,923	438	1920
DSI	Y	23%	0.18	2,923	526	2304
CDS	Y	70%	0.07	2,923	205	896
Wet FGD	Y	87%	0.03	2,923	88	384
<b>Unit 3<sup>3</sup></b>						
Low sulfur coal and SDA	N/A	0%	0.083	2,865	237	1,036
<b>Unit 4<sup>3</sup></b>						
Low sulfur coal and SDA	N/A	0%	0.091	2,614	237	1,039

<sup>1</sup> Capacity factor Unit 1: 65%

<sup>2</sup> Capacity factor Unit 2: 69%

<sup>3</sup>As will be discussed in Section 2.7.1.1, ADEQ determines that the additional controls for Unit 3 and Unit 4 are not reasonable for this implementation period and no further analysis is needed.



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### 2.7.1.1 Unit 3 and Unit 4

Per Guidance on Regional Haze State Implementation Plans for the Second Implementation Period<sup>19</sup>, a state may select to not perform further analysis for a particular unit that already has an effective emission control technology in place. Specifically, the Guidance states:

*“For the purpose of SO<sub>2</sub> control measures, an EGU that has add-on flue gas desulfurization (FGD) and that meets the applicable alternative SO<sub>2</sub> emission limit of the 2012 Mercury Air Toxics Standards (MATS) rule for power plants. The two limits in the rule (0.2 lb/MMBtu for coal-fired EGUs or 0.3 lb/MMBtu for EGUs fired with oil-derived solid fuel) are low enough that it is unlikely that an analysis of control measures for a source already equipped with a scrubber and meeting one of these limits would conclude that even more stringent control of SO<sub>2</sub> is necessary to make reasonable progress.”*

Units 3 and 4 are equipped with SDA systems, one of the flue gas desulfurization technologies. Both units are subject to the 2012 Mercury Air Toxics Standards (MATS) rule. The rule promulgated a single acid gas Hazardous Air Pollutant (HAP) emissions standard for all coal-fired EGUs using hydrochloric acid (HCl) as a surrogate for all acid gas HAP, as well as an alternative emissions standard for sulfur dioxide (SO<sub>2</sub>) as a surrogate for the acid gas HAP that may be used if a coal-fired EGU is operating some form of flue gas desulfurization (FGD) system and an SO<sub>2</sub> continuous emissions monitoring system (CEMS). In the permit issued to TEP, all four units must meet the following emission limits as specified in Table 2 to 40 CFR part 63, subpart UUUUU:

- Total HCl emissions of 0.002 lb/MMBtu or 0.02 lb/MWh; or
- SO<sub>2</sub> emissions in excess of 0.2 lb/MMBtu or 1.5 lb/MWh.

ADEQ reviewed the most recent 5 years (2016-2020) of the SO<sub>2</sub> emissions data for SGS. The SO<sub>2</sub> emission rates for Unit 3 and Unit 4 range from 0.069 to 0.090 lb/MMBtu and from 0.076 to 0.010 lb/MMBtu on an annual basis, respectively. This clearly demonstrates that Unit 3 and Unit 4 have continuously complied with the applicable SO<sub>2</sub> emission standard of 0.20 lb/MMBtu.

Based on the above discussions, ADEQ determines that the current SO<sub>2</sub> emission control systems are efficient and additional controls on Unit 3 and Unit 4 are not reasonable for this implementation period.

### 2.7.1.2 Unit 1 and Unit 2

Although both Unit 1 and Unit 2 have SDA systems installed and are also subject to the MATS rule, they are not able to continuously comply with the alternative SO<sub>2</sub> emission standard of 0.20 lb/MMBtu. During 2016-2020, the SO<sub>2</sub> emission rates for Unit 1 and Unit

<sup>19</sup> [https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019\\_-\\_haze\\_guidance\\_final\\_guidance.pdf](https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_haze_guidance_final_guidance.pdf)  
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2 range from 0.210 to 0.268 lb/MMBtu and from 0.186 to 0.275 lb/MMBtu on an annual basis, respectively. Therefore, ADEQ performed further analysis for the two units.

### 2.7.1.2.1 Spray Dry Absorber (SDA)<sup>20</sup>:

SDA works by mixing SO<sub>2</sub> containing gases with an alkaline solution to cause a reaction that will remove the SO<sub>2</sub> from the gas stream. The alkaline solution is introduced to a large vessel via spray nozzles where it can react with the gases for sufficient time to allow the SO<sub>2</sub> to be absorbed and react with the alkaline solution. While the reaction is taking place, heat and the gas stream dry the reaction products which can then be captured via particulate capture mechanism such as a fabric filter. The desired operating temperature range is 20 to 50°F below saturation temperature of the gas stream. The efficiency of these systems is a function of temperature, pH and gas liquid contact.

The following operational upgrades were evaluated to determine which improvements could be made to the SDA installed on Unit 1 and 2 to reduce SO<sub>2</sub> emissions:

- Lime (CaO) quality
- Improved flue gas distribution
- Increase calcium to sulfur stoichiometric ratio
- Approach to saturation temperature
- Atomizer upgrades
- Adding an absorber vessel

#### 2.7.1.2.1.1 Lime Quality

Sargent and Lundy evaluated the current SDA system at SGS and concluded the scrubber uses high quality lime (90% CaO) and there are no technically feasible improvements to the quality that can be made.

#### 2.7.1.2.1.2 Improved Flue Gas Distribution

S&L's analysis also indicated there was a flue gas imbalance in the four SDA vessels currently used to control emissions from Unit 1 and Unit 2. The 4<sup>th</sup> vessel is currently receiving approximately 25% more flue gas than the other three vessels. It is believed that the current lime supply to the unit is insufficient to control the additional SO<sub>2</sub> intake into the unit and therefore the SO<sub>2</sub> emissions from the unit are 15-20% higher than the other three vessels. The report proposes enhancements such as adding perforated plates as well as a balancing damper on the flue gas inlets to each damper to remove the imbalance. Correcting the maldistribution of the flow will allow for greater residence time and proper reactant injection for each of the vessels.

<sup>20</sup> EPA Air Pollution Control Fact Sheet: Flue Gas Desulfurization (FGD) – Wet, Spray Dry, and Dry Scrubbers

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### 2.7.1.2.1.3 *Increased Ca:S Stoichiometric Ratio*

The Ca:S ratio is important in controlling SO<sub>2</sub> emissions from the vessels. The ratio can be changed by adjusting the recycle rate of the lime or the rate of fresh lime injection. Currently, TEP recycles approximately 20-55% solids<sup>21</sup>. A further increase in recycle rate is not considered technically feasible. Increasing the fresh lime rate would result in a decrease of SO<sub>2</sub> emissions and is considered a technically feasible option.

### 2.7.1.2.1.4 *Approach to Saturation Temperature*

Vessels A-C currently operate 25-30 degrees above the adiabatic saturation temperature. Vessel D, which currently receives 25% more flue gas than the others operates 50 degrees above the saturation temperature. Operating at the proper saturation temperature is critical for removing SO<sub>2</sub> as it allows for the correct residence time for SO<sub>2</sub> removal. Correcting the flue gas maldistribution is expected to correct the temperature of Vessel D such that it mimics Vessels A-C.

### 2.7.1.2.1.5 *Atomizer Upgrades*

The atomizers in all four units are considered modern, thus, no additional improvements are expected if the atomizers are replaced.

### 2.7.1.2.1.6 *Additional Absorber Vessel*

S&L also considered the addition of a new absorber vessel to increase the residence time and the Ca:S ratio of the scrubbers, however it was determined that an additional unit would not result in any further SO<sub>2</sub> reductions.

The specific upgrades being proposed by TEP are to lower the stack emissions set point in order to increase the sorbent injection rate and to balance the distribution of gas in the four current SDA vessels to maximize renewal efficiency.

The current SDA system has a control efficiency of approximately 90%. Upgrading the current SDA for Unit 1 and 2 is considered technically feasible.

### 2.7.1.2.2 *Dry Sorbent Injection (DSI)<sup>20</sup>:*

DSI injects dry sorbent into the system to react with the gas stream. The resulting dry waste after SO<sub>2</sub> removal is captured using standard PM capturing mechanisms and typically involves cooling the gas before it enters the PM control device. The operating temperature depends on where the sorbent is injected into the system, and is as high as 1000°F if injected into the furnace and as low as 150°F when injected into the duct. Removal efficiencies of DSI systems depends heavily on an even distribution of sorbent injection and ample residence time for the removal reaction to take place. Typical DSI

<sup>21</sup> S&L Report pg. 6

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efficiencies range from 50 to 90% depending on the sorbent used and the size of the boiler with small and medium sized boilers having higher efficiencies. Because DSI technology is commercially available for installation on coal-fired EGUs, DSI is considered technically feasible for Unit 1 and 2.

### 2.7.1.2.3 Circulating Dry Scrubber (CDS):

CDS works by using a fluidized bed reactor to mix the sorbent agent with the flue gas stream to promote the removal reaction. The resulting mixture containing solid reaction products and other solid material is sent to a standard PM control device where a small portion of the waste product is disposed of while the remaining mixture is recycled, mixed with fresh reagent and reintroduced to the CDS system. Larger units such as utility boilers may require more than one CDS to treat the flue gas. CDS technology has been implemented on coal-fired power plants, therefore the installation of this technology is considered technically feasible.

### 2.7.1.2.4 Wet Flue Gas Desulfurization (Wet FGD)<sup>20</sup>:

In a wet FGD system the flue gas is mixed with an aqueous solution of sorbent. SO<sub>2</sub> dissolves into droplets formed during the mixing process to allow it to react with the sorbent reagent. The slurry falls and is sent to a reaction vessel to complete the removal reactions and the treated gas passes through a mist eliminator. Lime and limestone are the typical reagents, with lime providing greater efficiency but a higher cost. TEP proposes wet FGD systems are commonly installed on coal fired power plants, therefore the replacement of the current SDA with a wet FGD is considered technically feasible.

## 2.7.2 Cost of Compliance

ADEQ calculated the cost effectiveness of the four SO<sub>2</sub> control methods that were deemed technically feasible. Table 13 and table 14 show the results of the cost analysis and indicate that the upgraded SDA is the most cost effective control at 20 and 30 years useful life. The following steps were used to calculate the cost of all four control options:

1. Determine the capital cost
2. Determine the annualized capital cost based on a 20 and 30 year life and 4.75% interest (same as NO<sub>x</sub>)
3. Estimate the annual O&M cost
4. Estimate the potential emissions reductions
5. Use the total annual cost (TAC) and emissions reductions to calculate the cost effectiveness in \$/ton

The cost of SDA upgrades was proposed by Sargent & Lundy (S&L) on TEP's behalf. ADEQ accepted Sargent & Lundy's estimates. The capital cost is based off of vendor quotes. Equipment and materials were approximately \$2 million. Material taxes was set at 0% and freight was 5%. Labor costs were based on \$60 per hour which is consistent with

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Bureau of Labor Statistics for employees in the electrical generation field which includes, engineers, managers and legal. The remaining capital costs are based on Sargent & Lundy's estimates of a certain percentage of labor and total direct costs. The direct operating and maintenance costs were based on the cost of waste disposal, lime reagent, and additional power and water requirements. The waste disposal cost was compared to the EPA cost manual for particulate matter where the cost of disposal was \$1.50 per ton. The cost of the additional power was compared to Energy Information Administration (EIA) wholesale power prices. These costs were comparable to the estimates provided by S&L. Indirect operating costs were a percentage of the total capital investment (TCI) and were taken from the EPA cost manual.

DSI is less effective than the SDA upgrades removing about 300 less tons of SO<sub>2</sub> per year. S&L calculated the cost effectiveness of DSI in a similar fashion to SDA. The equipment cost was over \$9 million and total direct costs of \$12 million. ADEQ compared this to the total capital cost of DSI for a 1,300 MW boiler controlled by DSI from EIA which was ~\$34/kW and would equate to over \$14 million for TEP units 1 and 2 each. ADEQ calculated labor in the same manner as for the SDA upgrades. ADEQ calculated the waste disposal, lime cost, auxiliary power, insurance, property taxes and administration in the same manner as the SDA upgrades Table 13 and Table 14 show that DSI is not cost effective at 20 or 30 years of useful life.

Wet FGD capital costs were based on the EPA retrofit cost analyzer. The result is the total capital cost for Wet FGD is \$250 million. The CDS capital cost was based on controls identified by the EIA using EIA form 860<sup>22</sup> for generators above 400 MW that were retrofitted with CDS. The EPA retrofit cost calculator was used to estimate the operating costs for CDS and Wet FGD. The operating costs are the difference between the operating costs of using an SDA (current controls) and retrofitting the units with CDS or Wet FGD. Operating costs of wet FGD are lower than the operating costs of the SDA resulting in a negative value for the annual O&M costs for wet FGD. Table 13 shows that CDS and wet FGD are not cost effective at 20 years life, with average cost-effectiveness approximately or exceeding \$6,500 /ton. Table 14 shows that CDS is not cost effective at 30 years but wet FGD requires further consideration at about \$5000/ton for each unit.

Incremental cost effectiveness for wet FGD ranges from approximately \$7,800 /ton up to just over \$11,100 /ton depending on the useful life of the equipment and the unit in question. The exact useful life of wet FGD is unknown (resulting in a range of average and incremental cost-effective values between \$4,900 - \$6,900 /ton and \$7,800 - \$11,200 /ton, respectively) and the resulting range of costs are either on the high side or outside of what ADEQ would consider cost-effective. Additionally, while wet FGD provides a larger SO<sub>2</sub> emission reduction as compared to upgrading the SDA, ADEQ finds the large capital and annualized costs associated with this technology excessive given the determination that another viable reasonable control exists to reduce SO<sub>2</sub> emissions from Units 1 & 2

<sup>22</sup> <https://www.eia.gov/electricity/data/eia860/>

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(upgraded SDA). Therefore, ADEQ finds that wet FGD is not a cost-effective SO<sub>2</sub> control. Similarly, CDS also exceeds ADEQ's cost-effectiveness threshold for reasonable controls.

**Table 13 SO<sub>2</sub> Control Option Cost Effectiveness for 20 Years**

Control option	Capital cost	Annualized capital cost	Annual O&M cost	Total annual cost (\$/yr)	Emission reduction (tpy)	Cost Effectiveness(\$/ton)	
						Average	Incremental
<b>Unit 1</b>							
Upgraded SDA	\$3,709,228	\$291,362	\$627,207	\$918,569	1,060	\$867	n/a
DSI	\$19,287,201	\$1,515,019	\$6,700,270	\$8,215,289	699	\$11,753	n/a <sup>1</sup>
CDS <sup>2</sup>	\$205,962,996	\$16,178,490	\$695,000	\$16,873,490	2,025	\$8,332	\$16,534
Wet FGD <sup>2</sup>	\$250,000,000	\$19,637,617	-\$2,544,000	\$17,093,617	2,508	\$6,817	\$11,171
<b>Unit 2</b>							
Upgraded SDA	\$3,709,228	\$291,362	\$654,667	\$946,029	1,062	\$891	n/a
DSI	\$19,287,201	\$1,515,019	\$7,030,712	\$8,545,731	678	\$12,604	n/a <sup>1</sup>
CDS <sup>2</sup>	\$205,962,996	\$16,178,490	\$638,000	\$16,816,490	2,086	\$8,063	\$15,498
Wet FGD <sup>2</sup>	\$250,000,000	\$19,637,617	-\$2,850,000	\$16,787,617	2,598	\$6,463	\$10,314

<sup>1</sup> DSI is less effective and more expensive than SDA and so no incremental cost effectiveness was calculated.

<sup>2</sup> The operating costs are the difference between the operating costs of using an SDA (current controls) and retrofitting the units with CDS or Wet FGD. Operating costs of wet FGD are lower than the operating costs of the SDA resulting in a negative value for the annual O&M costs for wet FGD.

**Table 14 SO<sub>2</sub> Control Option Cost Effectiveness for 30 Years**

Control option	Capital cost	Annualized capital cost	Annual O&M cost	Total annual cost (\$/yr)	Emission reduction (tpy)	Cost Effectiveness(\$/ton)	
						Average	Incremental
<b>Unit 1</b>							
Upgraded SDA	\$3,709,228	\$234,458	\$627,207	\$861,665	1,060	\$813	n/a
DSI	\$19,287,201	\$1,219,133	\$6,700,270	\$7,919,403	699	\$11,330	n/a <sup>1</sup>
CDS <sup>2</sup>	\$205,962,996	13,018,808	\$695,000	\$13,713,808	2,025	\$6,772	\$13,318
Wet FGD <sup>2</sup>	\$250,000,000	\$15,802,363	-\$2,544,000	13,258,363	2,508	\$5,287	\$8,561
<b>Unit 2</b>							
Upgraded SDA	\$3,709,228	\$234,458	\$654,667	\$889,125	1,062	\$837	n/a
DSI	\$19,287,201	\$1,219,133	\$7,030,712	\$8,249,845	678	\$12,168	n/a <sup>1</sup>
CDS <sup>2</sup>	\$205,962,996	\$13,018,808	\$638,000	\$13,656,808	2,086	\$6,548	\$12,468
Wet FGD <sup>2</sup>	\$250,000,000	\$15,802,363	-\$2,850,000	\$12,952,363	2,598	\$4,986	\$7,854

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<sup>1</sup> DSI is less effective and more expensive than SDA and so no incremental cost effectiveness was calculated.

<sup>2</sup> The operating costs are the difference between the operating costs of using an SDA (current controls) and retrofitting the units with CDS or Wet FGD. Operating costs of wet FGD are lower than the operating costs of the SDA resulting in a negative value for the annual O&M costs for wet FGD.

### 2.7.3 Time Necessary for Compliance

The only cost effective control option at 20 and 30 years for SO<sub>2</sub> is upgrading the current SDA system. ADEQ proposes the compliance deadline should be three years after EPA approval of the control into the Arizona State Implementation Plan.

### 2.7.4 Energy and Non-Air Quality Impacts

Upgrading the SDA will lead to additional solid waste from increased lime consumption, additional water consumption and increased energy consumption from handling a higher amount of lime.

### 2.7.5 Remaining Useful Life of Source

The remaining useful life for Units 1 and 2 was estimated at a maximum of 30 years based on the maximum useful life (30 years) used in the four factor analysis for installing an SCR.

### 2.7.6 Visibility Impact

TEP provided a visibility modeling analysis to determine the potential visibility improvements at Class I areas resulting from a hypothetical emission control. TEP modeled a hypothetical SO<sub>2</sub> emission reduction of 3,236 tpy, which is approximately equivalent to 0.08 lb/MMBtu for both units when a control measure is implemented. This emission reduction results in a cumulative visibility improvement of 0.625 Mm<sup>-1</sup> and an average visibility improvement of 0.00962 Mm<sup>-1</sup> across 65 Class I areas on the MIDs. The highest visibility improvement at a single Class I area on the MIDs, 0.05598 Mm<sup>-1</sup>, was realized at San Pedro Parks Wilderness. The visibility improvement at Mt. Mount Baldy Wilderness Area, the nearest Class I area to SGS, was 0.0357 Mm<sup>-1</sup> on the MIDs. For seven IMPROVE monitors within 300-km of the SGS, the average visibility improvement is 0.02833 Mm<sup>-1</sup>. ADEQ further reviewed the aerosol light extinction (haze budgets) data for these monitors on the MIDs over 2014-2018. ADEQ estimated that the visibility improvements resulted from the hypothetical SO<sub>2</sub> emission reduction account for less than 0.5% of the aerosol light extinction for any Class I areas (see Table 15).

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**Table 15 Visibility Improvements from SO<sub>2</sub> Emission Control and Aerosol Light Extinction on the MIDs over 2014-2018**

IMPROVE Site	Distance to SGS (km)	5-year Average of Aerosol Light Extinction on MIDs over 2014-2018 (Mm <sup>-1</sup> )	Modeled Visibility Improvement on MIDs (Mm <sup>-1</sup> )	Percentage of Visibility Improvement to Aerosol Light Extinction (%)
Mount Baldy	38	12.06	0.0257	0.2131
Petrified Forest National Park	101	13.82	0.0304	0.2200
Gila Wilderness	149	12.50	0.04629	0.3703
Bosque del Apache Wilderness	218	19.00	0.01999	0.1052
Chiricahua National Monument	257	15.86	0.00855	0.0539
Saguaro National Park	279	19.78	0.0114	0.0576
San Pedro Parks Wilderness	282	11.48	0.05598	0.4876

While the modeled visibility improvements from the SO<sub>2</sub> emission control scenario are greater than the NO<sub>x</sub> emission control scenario (see section 2.6.3), ADEQ determines that the predicted visibility improvements resulted from the SO<sub>2</sub> emission reduction of 3,236 tpy are not large enough to necessitate ADEQ reconsider the determinations previously made based on control cost-effectiveness.

### 2.7.7 Determining Control Measures that are Necessary to Make Reasonable Progress

#### 2.7.7.1 Upgraded SDA

As shown in Table 13, the upgraded SDA control option has an average cost-effectiveness at 20 years of 867 \$/ton and 891 \$/ton for Unit 1 and Unit 2, respectively. Although the visibility benefits from this control option are likely to be small, it is more compelling to conclude that the control is cost effective because the average cost-effectiveness number is well within the range ADEQ considers reasonable. Therefore, it is reasonable to require TEP to upgrade the current SDA systems to further reduce the SO<sub>2</sub> emissions at Unit 1 and Unit 2 or an equivalent SO<sub>2</sub> emission reductions from Units 1 and 2 achieved through other means.

#### 2.7.7.2 CDS and Wet FGD

As shown in Table 13 and Table 14, the average cost-effective values for CDS are higher than the ADEQ's cost-effectiveness threshold of 6,500 \$/ton. Additionally, the incremental cost-effective values for CDS are above 12,000 \$/ton, which is cost excessive.

Incremental cost effectiveness for wet FGD ranges from approximately \$7,800 /ton up to just over \$11,100 /ton depending on the useful life of the equipment and the unit in question. The exact useful life of wet FGD is unknown (resulting in a range of average and



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incremental cost-effective values between \$4,900 - \$6,900 /ton and \$7,800 - \$11,200 /ton, respectively) and the resulting range of costs are either on the high side or outside of what ADEQ would consider cost-effective. Additionally, while wet FGD provides a larger SO<sub>2</sub> emission reduction as compared to upgrading the SDA, ADEQ finds the large capital and annualized costs associated with this technology excessive given the determination that another viable reasonable control exists to reduce SO<sub>2</sub> emissions from Units 1 & 2 (upgraded SDA). Therefore, ADEQ finds that wet FGD is not a cost-effective SO<sub>2</sub> control. Similarly, CDS also exceeds ADEQ's cost-effectiveness threshold for reasonable controls.

The CDS and wet FGD control options result in an emission reduction of 4,111 tpy and 5,106 tpy, respectively, higher than the modeled emission reduction of 3,236 tpy. However, considering the magnitude of modeled emission reductions and the corresponding visibility improvements, ADEQ determines that the two control options are unlikely to achieve a significant visibility improvement at Class I areas.

ADEQ also reviewed the source apportionment results of the 2028 emissions scenario (2028OTBa2) from the Western Regional Air Partnership (WRAP)/Western Air Quality Study (WAQS) Regional Haze photochemical grid modeling platform<sup>23</sup>. As shown in Table 15, the SO<sub>2</sub>-attributed ammonium sulfate extinction due to U.S. anthropogenic sources accounts for less than 10% of the aerosol light extinction on the MIDs at seven Class I areas within 300 km of SGS. Comparatively, the international anthropogenic sources accounts for up to 25% of the aerosol light extinction (data not shown). In general, the SO<sub>2</sub> anthropogenic sources from U.S. are not the major contributor to the visibility impairment at Class I areas of interest.

**Table 16 Ammonium Sulfate Extinction from U.S. Anthropogenic Sources**

IMPROVE Site	Distance to SGS (km)	Modeled Ammonium Sulfate Extinction from US Anthropogenic Sources (Mm <sup>-1</sup> )	Modeled Aerosol Light Extinction on MIDs (Mm <sup>-1</sup> )	Percentage of Ammonium Sulfate Extinction from US Anthropogenic Sources to Aerosol Light Extinction (%)
Mount Baldy	38	0.365	8.375	4.4
Petrified Forest National Park	101	0.602	10.622	5.7
Gila Wilderness	149	0.508	10.099	5.0
Bosque del Apache Wilderness	218	1.265	12.912	9.8
Chiricahua National Monument	257	0.277	7.069	3.9
Saguaro National Park	279	0.401	19.292	2.1
San Pedro Parks Wilderness	282	0.88	10.176	8.6

Based on the above discussions, the visibility benefits resulted from the two control options are not compelling when considering a relatively high average cost-effectiveness,

<sup>23</sup> <https://views.cira.colostate.edu/tssv2/Express/ModelingTools.aspx>

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an excessive incremental cost-effectiveness, and an excessive capital cost of the controls. Therefore, by weighting the factors of cost of compliance and the visibility benefits, ADEQ rejects CDS and wet FGD as the control to make reasonable progress in the second implementation period.

This determination is also consistent with the EPA's BART Guidelines, which recommend States to evaluate upgrade options for scrubbers currently achieving at least 50 percent removal efficiencies<sup>24</sup>. For existing SO<sub>2</sub> controls achieving removal efficiencies of less than 50 percent, the BART Guidelines require States to consider constructing a new FGD system. While these guidelines are for BART sources, ADEQ believes that the same principles are applicable to the RP sources. Since the current SDA systems at Unit 1 and Unit 2 are effective with a control efficiency more than 85%, ADEQ concludes that it is more reasonable to upgrade the SDA systems rather than replacing the systems with a CDS or wet FGD.

### 2.7.8 Emission Limits

Based on the four-factor analysis as discussed above, ADEQ determines that emission reductions equivalent to SDA upgrades at Unit 1 and Unit 2 are necessary to make reasonable progress. Therefore, ADEQ establishes the SO<sub>2</sub> emission limits for the two units in lieu of updating the current SDA systems. However, TEP is not required to upgrade the SDA systems to demonstrate compliance with the limits, and may pursue other means of meeting the limits. This is consistent with the EPA's RP determination on Phoenix Cement Company (PCC) in the first implementation period. The EPA established an annual emission limit for PCC Clarkdale Kiln 4 based on SNCR but allowed PCC to comply with the limit using other means such as a reduction of production levels<sup>25</sup>.

The form of pounds per MMBtu on a 30-operating day rolling average is most common for EGUs equipped with a CEMs. As stated in the EPA's Guidance<sup>26</sup>, the Regional Haze Rule also allows SIPs to contain mass-based emission limits for circumstances under which the state had determined to be reasonable. To support a more responsive and sustainable resource portfolio for power production, TEP may significantly reduce the operating hours and throughputs for Unit 1 and Unit 2 in the future. As discussed in TEP's 2020 Integrated Resource Plan (IRP)<sup>27</sup>, Units 1 will transition to seasonal operation in 2023 and Unit 2 in 2024. TEP is planning to retire Unit 1 in 2027 and Unit 2 in 2032. TEP will be very likely to manage its operating level strategically instead of the upgrades of the SDA systems for meeting the RP requirements. Therefore, ADEQ determines that a mass-based emission limit is reasonable.

<sup>24</sup> 70 Fed. Reg. 39171

<sup>25</sup> 79 FR 52460

<sup>26</sup> [https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019-regional\\_haze\\_guidance\\_final\\_guidance.pdf](https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019-regional_haze_guidance_final_guidance.pdf) Pg. 44

<sup>27</sup> <https://www.tep.com/wp-content/uploads/TEP-2020-Integrated-Resource-Plan-Lo-Res.pdf>

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To establish emission limits for Unit 1 and Unit 2, ADEQ considers three key factors: visibility protection, equivalent to upgraded SDA, and compliance flexibility:

- Because the two emission units are identical (capacity, coal-fired method, coal source, and control systems) and have similar emission temporal profiles and stack parameters, it is expected that a unit emission rate (such as 1 ton) from the two emission units would have an identical modeled visibility impact at Class I areas. Therefore, ADEQ is proposing capped emission limits for the two units rather than establishing an individual emission limit for each unit.
- ADEQ is proposing a capped annual emission limit of 3,729 tons per year for the units. This emission limit is derived from an emission rate of 0.15 lb/MMBtu, which is consistent with upgraded SDA as a control technology, and an average annual heat input of 49,721,058 MMBtu over the baseline years (2016, 2018 and 2019). For details, see Table 17.

**Table 17 Annual Capped Emissions Limit for Unit 1 and Unit 2**

Units	2016 Heat Input (MMBtu)	2018 Heat Input (MMBtu)	2019 Heat Input (MMBtu)	Average Heat Input (MMBtu/year)	Emission Rate Factor (lb/MMBtu)	Emission Limit (tpy)
<b>Unit 1</b>	21,012,116	26,071,321	25,275,437	24,119,624		
<b>Unit 2</b>	26,982,858	26,403,872	23,417,570	25,601,433		
<b>Combined</b>	47,994,974	52,475,193	48,693,007	49,721,058	0.15	3,729

- To ensure short-term visibility protection, ADEQ has also explored a mass-based emission limit expressed in terms of tons per day on 30-calendar-day rolling average. ADEQ reviewed the daily SO<sub>2</sub> emissions for Unit 1 and Unit 2 over the baseline years (2016, 2018 and 2019), and obtained the maximum combined 30-calendar-day rolling average of 26.8 tons per day over the two units. ADEQ then applied a control efficiency of 36% (which is consistent with the upgraded SDA) and calculated an emission limit of 17.1 tons per day on a 30-calendar-day rolling average.

In summary, ADEQ is proposing the following two capped combined emission limits for Unit 1 and Unit 2:

- 3,729 tons per year on 12-month rolling average; and
- 17.1 tons per day on a 30-calendar-day rolling average.

## Exhibit 8

ADEQ believes that establishing the two capped emission limits within the two emission units can provide compliance flexibility yet still guarantee that each unit is well controlled to protect and improve the visibility in Class I areas. TEP must comply with the emission limits no later three years after the SIP approval.



Exhibit 9



# Regional Haze

## Stakeholder Outreach Webinar #2

Mark Jones, Michael Baca, Neal Butt, Rhett Zyla - New Mexico Environment  
Department Air Quality Bureau

Ed Merta, Andrew Daffern - City of Albuquerque Environmental Health Department



Photo credit Rhett Zyla #IamNMED



Exhibit 9

# What we will cover today





Exhibit 9

# WRAP Regional Planning

- ▣ Provides data/technical services for Western states
- ▣ Forum for consultation to develop consensus
  - States, Tribes, EPA, & Federal Land Managers
  
- ▣ Overview of Western perspective on Regional Haze
- ▣ Accessible content, abundant visuals
- ▣ [https://views.cira.colostate.edu/wrap\\_rhpwg\\_Storyboard\\_draftNov20\\_2019/](https://views.cira.colostate.edu/wrap_rhpwg_Storyboard_draftNov20_2019/)
- ▣ Let's take a (brief) look!



3



## Exhibit 9







Exhibit 9

# WRAP Stages of Planning Process

<b>Step 1</b>	<b>Ambient data analysis</b>
<b>Step 2</b>	<b>Determination of affected Class I Areas in other states</b>
<b>Step 3</b>	<b>Selection of emission sources for control measure analysis</b>
<b>Step 4</b>	<b>Characterization of four factors for control measures analysis</b>
<b>Step 5</b>	<b>Decisions on control measures necessary for reasonable progress</b>
<b>Step 6</b>	<b>Regional modeling to project 2028 reasonable progress goals (RPGs)</b>
<b>Step 7</b>	<b>Compare RPGs to baseline conditions and uniform rate of progress</b>
<b>Step 8</b>	<b>Additional requirements: emissions, monitoring, reporting, etc.</b>



Exhibit 9

# Regional Haze Info and Resources

<https://www.env.nm.gov/air-quality/reg-haze/>

- ▣ Regional Haze background information
- ▣ View fall 2019 webinar/sign up for listserv
- ▣ List of sources subject to four factor analysis
- ▣ Drafts of four factor analyses submitted by facilities
- ▣ Regional Haze planning schedule

<https://www.wrapair2.org/RHPWG.aspx>

<https://views.cira.colostate.edu/tssv2/>





Exhibit 9

# Ambient Monitor Data

Visibility Progress Summary: New Mexico

New Mexico - Class I Area Visibility Trends Summary Most Impaired Days (defined by EPA guidance <sup>1</sup> )					
Class I Area	Representative IMPROVE Monitor	IMPROVE 2000-2004	IMPROVE 2008-2012	IMPROVE 2014-2018	Estimated Natural Conditions 2064
Bandelier National Monument	BAND1	9.7 <i>dv</i>	9.3 <i>dv</i>	8.4 <i>dv</i>	4.6 <i>dv</i>
Bosque del Apache National Wildlife Refuge Wilderness	BOAP1	11.6 <i>dv</i>	11.2 <i>dv</i>	10.5 <i>dv</i>	5.4 <i>dv</i>
Carlsbad Caverns National Park	GUMO1	14.6 <i>dv</i>	12.9 <i>dv</i>	12.6 <i>dv</i>	4.8 <i>dv</i>
Gila Wilderness Area	GICL1	9 <i>dv</i>	8.3 <i>dv</i>	7.6 <i>dv</i>	4.2 <i>dv</i>
Pecos Wilderness Area	WHPE1	7.3 <i>dv</i>	6.7 <i>dv</i>	6 <i>dv</i>	3.5 <i>dv</i>
Salt Creek National Wildlife Refuge Wilderness	SACR1	16.5 <i>dv</i>	15.3 <i>dv</i>	15 <i>dv</i>	5.5 <i>dv</i>
San Pedro Parks Wilderness Area	SAPE1	7.7 <i>dv</i>	7 <i>dv</i>	6.4 <i>dv</i>	3.3 <i>dv</i>
Wheeler Peak Wilderness Area	WHPE1	7.3 <i>dv</i>	6.7 <i>dv</i>	6 <i>dv</i>	3.5 <i>dv</i>
White Mountain Wilderness Area	WHIT1	11.3 <i>dv</i>	10.5 <i>dv</i>	10 <i>dv</i>	4.9 <i>dv</i>

1) U.S. EPA. December 2018. [Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program](#). EPA-454/R-18-010

<https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx>

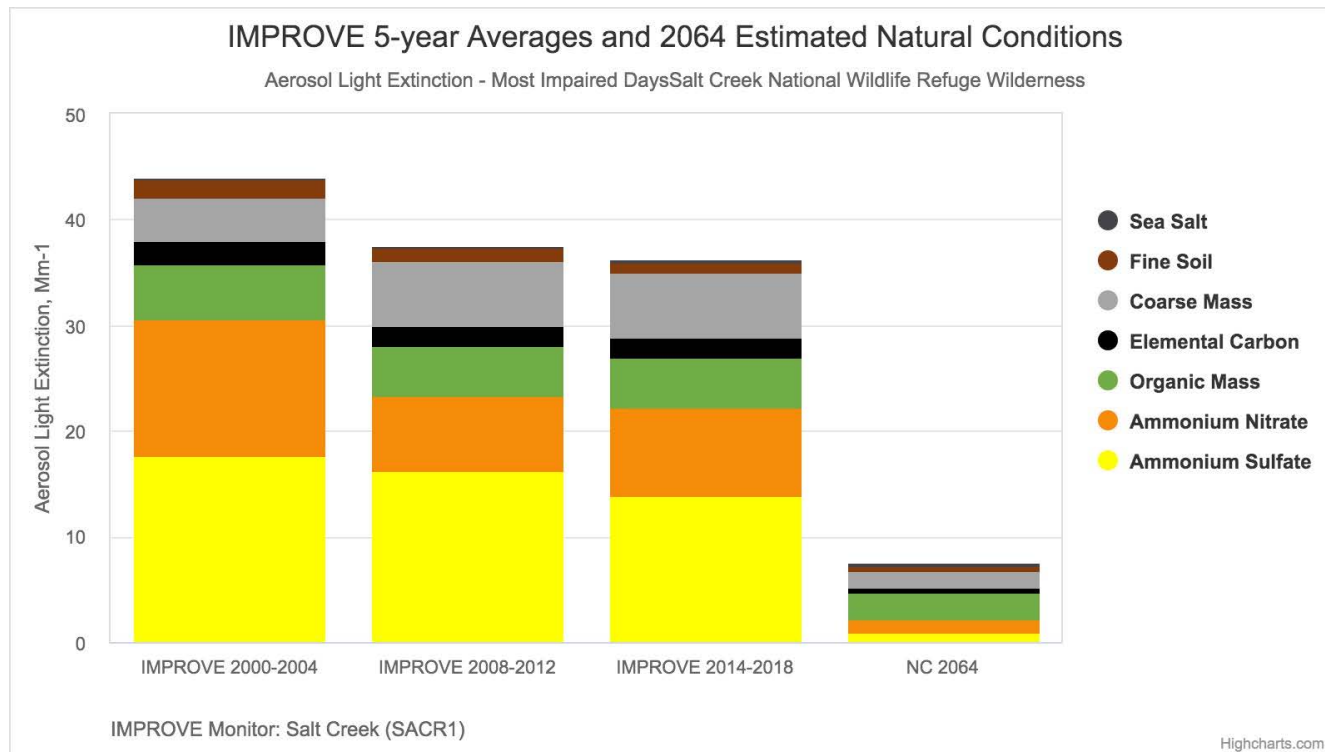
**Requirement:**

**40 CFR § 51.308(f)(1)(i) to (v)**



Exhibit 9

# Ambient Monitor Data



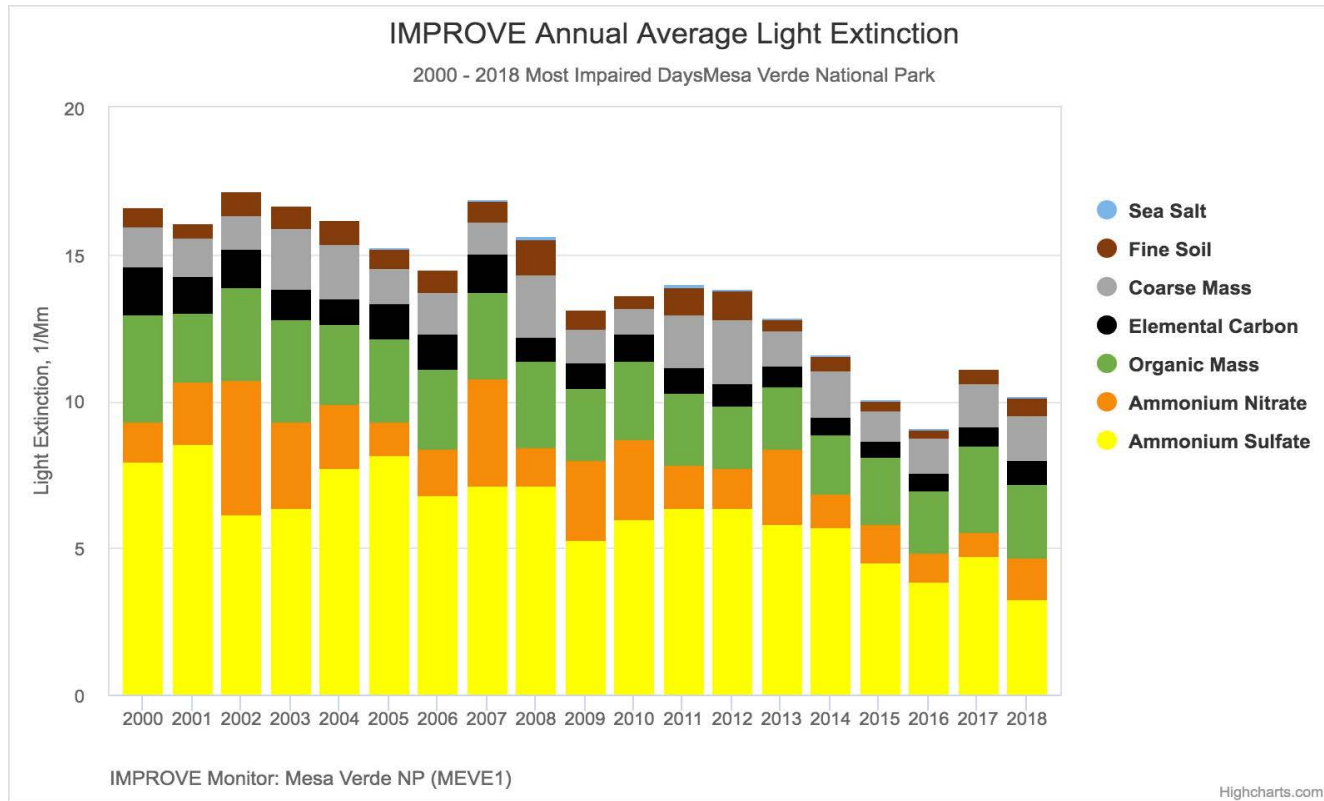
<https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx>

**Requirement:  
 40 CFR § 51.308(f)(2)(iii)**



Exhibit 9

# Ambient Monitor Data



<https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx>

**Requirement:**  
**40 CFR § 51.308(f)(2)(ii)**



- **“Source selection”**
  - ▣ Determine which facilities will be subject to analysis of potential new control measures (Four-Factor Analysis)
- **NMED/EHD process based on WRAP guidance**
  - ▣ Target key drivers of visibility impairment: SO<sub>2</sub> and NO<sub>x</sub>
  - ▣ For each Title V facility, calculate the following:
    - Q = reported SO<sub>2</sub> + NO<sub>x</sub> emissions (tons, 2016)
    - d = distance (kilometers) to nearest Class I Area
    - Q/d = potential visibility impact of facility
  - ▣ Rank all facilities highest to lowest Q/d
  - ▣ Identify facilities accounting for 80% of SO<sub>2</sub> + NO<sub>x</sub>
  - ▣ These facilities are subject to Four-Factor Analysis
  - ▣ Minor & Area sources not considered for evaluation



## Exhibit 9

Title V Facilities w/ Q/d > 5.5	Q/d	Class I area	Company Name
Cunningham Station	7.72	Carlsbad NP	Xcel Energy
Prewitt Escalante Generating Station	26.1	San Pedro Parks WA	Tri-State Generation and Transmission Association
Roswell Compressor Station No9	7.6	Salt Creek WA	Transwestern Pipeline
Mountainair No7 Compressor Station	5.7	Bosque del Apache WA	
Monument Gas Plant	20.4	Carlsbad NP	Targa Midstream Services
Eunice Gas Processing Plant	13.0	Carlsbad NP	
Saunders Gas Plant	11.7	Salt Creek WA	
San Juan Generating Station	461.0	Mesa Verde NP	Public Service Co. of New Mexico
Indian Basin Gas Plant	9.4	Carlsbad NP	Oxy USA
Bitter Lake Compressor Station	50.2	Salt Creek WA	IACX Roswell, LLC
Kutz Canyon Processing Plant	10.3	Mesa Verde NP	Harvest Four Corners, LLC
Harvest Pipeline - San Juan Gas Plant	8.3	Mesa Verde NP	
Jal No3 Gas Plant	20.5	Carlsbad NP	ETC Texas Pipeline, Ltd.
Chaco Gas Plant	28.2	Mesa Verde NP	Enterprise Field Services
Blanco Compressor C & D Station	7.8	Mesa Verde NP	
South Carlsbad Compressor Station	5.9	Carlsbad NP	
Washington Ranch Storage Facility	23.5	Carlsbad NP	El Paso Natural Gas Company
Pecos River Compressor Station	13.9	Carlsbad NP	
Blanco Compressor Station A	5.6	Mesa Verde NP	
Eunice Gas Plant	18.4	Carlsbad NP	DCP Operating Company, LP
Linam Ranch Gas Plant	7.6	Carlsbad NP	DCP Midstream
Artesia Gas Plant	5.7	Carlsbad NP	
Denton Gas Plant	7.6	Salt Creek WA	Davis Gas Processing
Rio Grande Portland Cement Plant*	16.0	Bandelier WA	

\*Located in Bernalillo County outside of NMED Jurisdiction.

Four-factor analysis documentation available at:

<https://www.env.nm.gov/air-quality/four-factor-analysis-reports/>



## Exhibit 9

- Identify additional controls that are technically feasible for equipment that emits  $\geq 5$  tpy  $\text{SO}_2/\text{NO}_x$
- Assess the four factors for feasible controls:
  - ▣ Cost of compliance
  - ▣ Time necessary for compliance
  - ▣ Energy & non-air environmental impacts
  - ▣ Remaining useful life of the source
- Calculate cost effectiveness of each control
  - ▣ Expressed as \$ per ton of annual emission reduction achieved
  - ▣ Anticipated cost effective threshold:  $\leq$  \$7,000 per ton/year
  - ▣ Case by case basis for final determination





Exhibit 9

# Equipment Under Evaluation

- ▣ Reciprocating internal combustion engines (RICE)
- ▣ Turbines & boilers
- ▣ Amine units & sulfur recovery units
- ▣ Flares
  
- ▣ Boilers & turbines
  
- ▣ Kilns



Exhibit 9

# Example of Potential Controls

- ▣ Low emissions combustion, including the Cooper Bessemer Clean Burn Technology™
- ▣ Selective catalytic reduction
- ▣ Replace internal combustion engines with electric utility powered compressors
- ▣ Reduce capacity and/or operating hours



## Exhibit 9

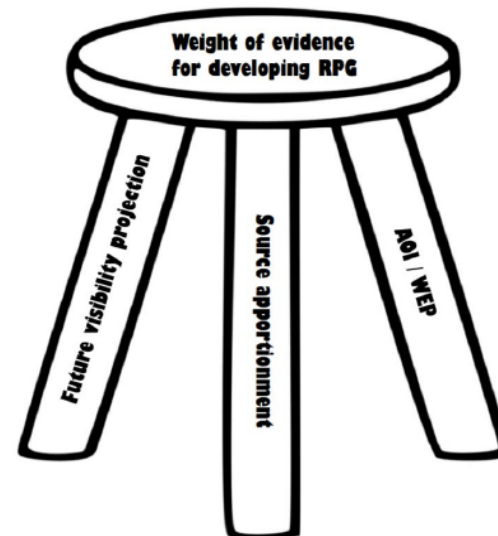
- Spring 2019:
  - ▣ Q/d to identify facilities subject to four-factor analysis
  - ▣ Consultation with EPA & federal land managers
- Summer 2019:
  - ▣ Request four-factor analyses from facilities
- Fall 2019:
  - ▣ Facilities submit four-factor analyses
  - ▣ Initial NMED/EHD review and requests for additional information
- Spring 2020:
  - ▣ NMED/EHD continue analysis
- Summer 2020
  - ▣ Begin determination of cost effective controls



Exhibit 9

# Regional Modeling

- ▣ Future visibility projections
- ▣ Source apportionment
- ▣ Weighted emissions potential





## Exhibit 9

<https://www.wrapair2.org/rtowg.aspx>



### Regional Technical Operations Work Group



### Regional Technical Operations Work Group

**Overview**

- Regional analyses in support of planning activities related to emissions and modeling for regional haze, ozone, PM, and other indicators.
- Evaluation of background and regional transport, international transport, sensitivity and other analyses of emissions data focused on the western U.S.
- Perform and leverage modeling, data analysis, and contribution assessment studies.
- Investigation of "background ozone" impacts to western U.S. locations.
- Coordination and collaboration with other WRAP member-sponsored regional air quality modeling groups including IWDW, NW-AIRQUEST, EPA-OAQPS, BAAQMD, and otherstate and local agencies performing regional ozone modeling.
- Provide guidance on more complete and uniform model performance evaluations (MPES).
- Develop and implement a protocol to use the IWDW-WAQS capabilities as the WRAP Regional Technical Center.

**Guidance Documents** (final and draft as noted)

[Procedures for Making 2028 Visibility Projections using the WRAP-WAQS 2014 Modeling Platform](#) (July 24, 2020 draft)

[Adjusting the URP Glidepath Accounting for International Anthropogenic Emissions and Prescribed Fires using the WRAP 2014/2028 Modeling Platform Results](#) (July 24, 2020 draft)

June 2020 Regional Haze Modeling Plan Schedule update ([PDF](#)) (final)

March 2020 Regional Haze Modeling Plan update ([PDF](#)) (final)

January 2020 Regional Haze Modeling Plan update ([PDF](#)) (final)



# Modeling Products

## EPA Uniform Rate of Progress Glidepath for the Visibility Tracking Metric – Deciview

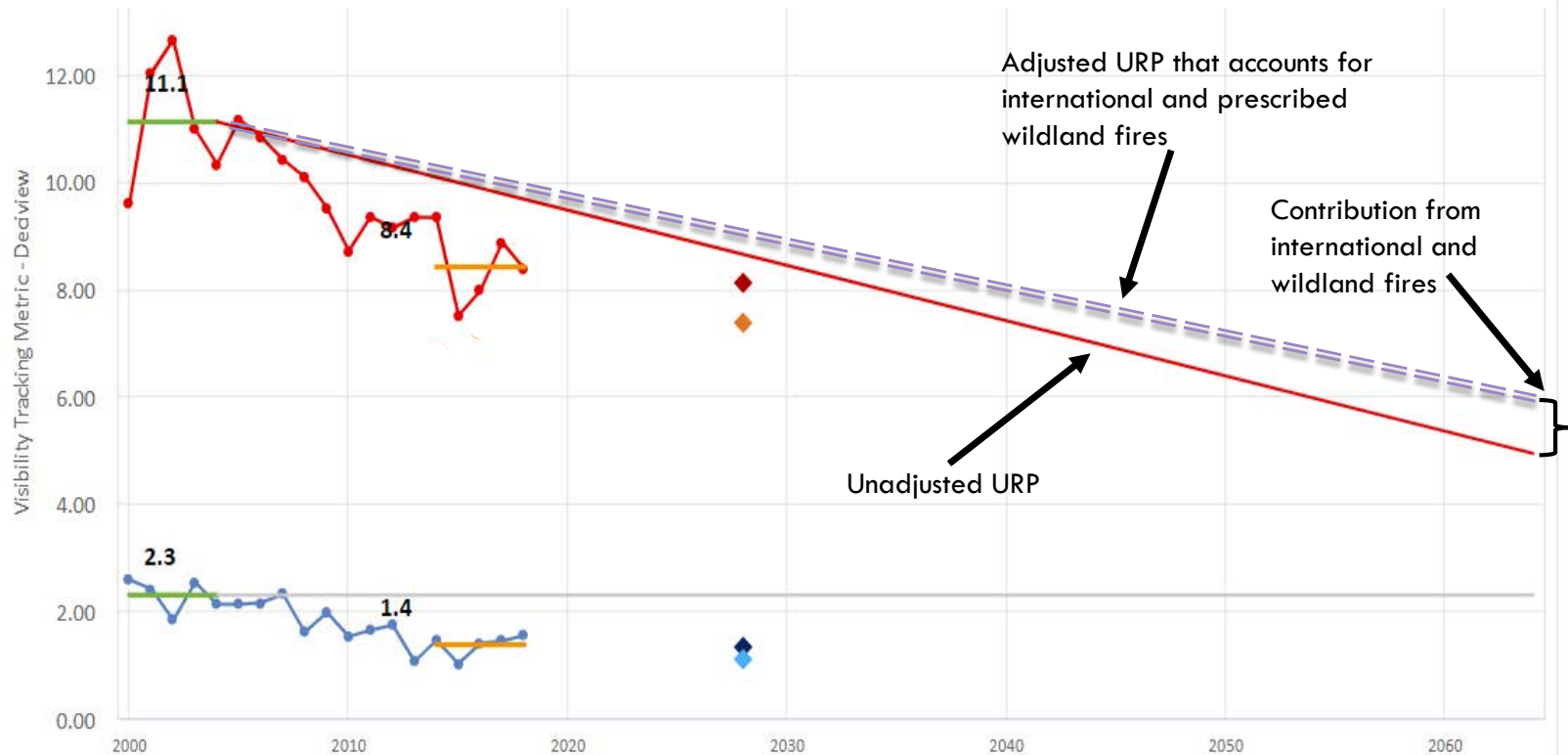




Exhibit 9

# Potential Additional Controls Modeling

- Submittal to WRAP due September 10<sup>th</sup>



Exhibit 9

# Continuing EPA Steps 4 & 5







Exhibit 9

# EPA Steps 6 & 7

<https://www.env.nm.gov/air-quality/reg-haze/>



Exhibit 9

# Next Steps in Stakeholder Process

- ▣ <https://www.env.nm.gov/air-quality/reg-haze/>
- ▣ [nm.regionalhaze@state.nm.us](mailto:nm.regionalhaze@state.nm.us) or
- ▣ Mark Jones [mark.jones@state.nm.us](mailto:mark.jones@state.nm.us) (505) 566-9746
- ▣ Ed Merta [emerta@cabq.gov](mailto:emerta@cabq.gov) (505) 768-2660





# Oregon

September 9, 2020

Howard Hughes  
Corporate Environmental Manager  
Collins Forest Products  
[hhughes@collinsco.com](mailto:hhughes@collinsco.com)

Sent via EMAIL

Re: Round 2 Regional Haze Program, Four Factor Analysis  
Collins Forest Products Co – 18-0013

Dear Howard Hughes,

Thank you for submitting the four-factor analysis for your facility for Round 2 of the Regional Haze Program.

As you know, the Regional Haze Rule (40 CFR 51.308) was issued as part of the Clean Air Act on July 1, 1999. The goal of the Regional Haze program is to improve visibility conditions in Class I Areas back to natural conditions by 2064. Regional Haze is a long-term program that sets goals for visibility improvement in 10-year periods of time from 2004 through to 2064, with interim checks on visibility conditions every 5 years.

The letter DEQ sent to you regarding four factor analysis on December 23, 2019, is part of Oregon's requirements for Round 2 of the Regional Haze program, as detailed in 40 CFR 51.308(f), for the period from 2021 to 2028. DEQ used the 2017 PSELS to screen Oregon Title V and ACDP facilities for applicability to conduct four factor analyses for the 2018-2028 time period. DEQ requested the four-factor analysis under OAR 340-214-0110.

DEQ reviewed the submitted four-factor analysis, and consulted with other states to strive for consistency, where appropriate, in identifying criteria and screening levels used in assessing presumed cost-effectiveness of pollution controls. The criteria that DEQ staff used to identify the emission units that require additional review and information were the following:

- Step 1: Divide emissions units for each facility into three bins:
  - Bin 1. Likely cost-effective candidates. Control devices with cost less than \$10,000/ton, or those that appear to be technically feasible but for which no cost analysis was provided.
  - Bin 2. Retain for further analysis. Control devices with cost more than \$10,000/ton but less than \$30,000/ton.
  - Bin 3. Cost is unlikely to be reasonable. Above \$30,000/ton.
- Step 2: Adjust cost estimates to get close to an apples-to-apples comparison for EUs.
  - Bins 1 & 2. Adjust for basic factors (PSEL, interest rate, useful life).
  - Bin 3. No further analysis. Unlikely to be cost effective.

After initial review, DEQ ruled out control devices that:

## Exhibit 10

- a) Cost of control was greater than \$10,000 per ton, after adjustment to current prime rate (3.25%),<sup>1</sup> 30 year lifetime, and emissions at PSEL, or
- b) Provided an emissions reduction (using emissions at PSEL) of less than 20 tons/year.

DEQ staff selected 43 emissions units at 17 facilities for additional review for a total of 62 control devices.

DEQ found no emissions units and control devices at your facility met the criteria for further analysis as outlined above.

DEQ appreciates your commitment to protecting air quality and improving visibility in Oregon's National Parks and Wilderness Areas. If you have any questions about the content of this letter or need technical assistance, please feel free to contact D Pei Wu, PhD, at [wu.d@deq.state.or.us](mailto:wu.d@deq.state.or.us) or 503-229-5269.

Sincerely,



Ali Mirzakhali  
Air Quality Division Administrator  
Oregon Department of Environmental Quality

Cc: Karen Williams  
D Pei Wu, PhD  
Joe Westersund  
Michael Orman  
Walt West  
Mark Bailey

<sup>1</sup> Per EPA Cost Control Manual, pages 14-17: [https://www.epa.gov/sites/production/files/2017-12/documents/epacmcostestimationmethodchapter\\_7thedition\\_2017.pdf](https://www.epa.gov/sites/production/files/2017-12/documents/epacmcostestimationmethodchapter_7thedition_2017.pdf)



**Draft Federal Land Manager Comments  
and Ecology Responses to  
Draft Regional Haze State  
Implementation Plan Revision**

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Air Quality Program

Washington State Department of Ecology  
Olympia, Washington

January 2021

Exhibit 11

## Federal Land Manager Comments for Chemical Pulp and Paper Mills and Ecology's Responses

#	Federal Land Manager Comment	Ecology Response
1	<p>Following is my initial feedback on the four-factor analyses conducted on the pulp &amp; paper mills in WA. The overarching issues are the costs of potential controls and the visibility improvements that could result from cost-effective emission reductions. While I appreciate that Ecology has adjusted the costs presented by All4 (the consultant for the Washington Pulp &amp; Paper Mills) to correct for All4's incorrect interest rate, All4's application of a 1.5 retrofit factor without adequate justification leads me to believe that even the adjusted costs may be overestimated and the cost-effective emission reductions underestimated. Also, All4 has not provided the data inputs to the SNCR and SCR workbooks it used to generate its cost estimates--without those inputs, I cannot properly evaluate its cost estimates.</p>	<p>Thank you for your feedback. These comments are addressed as they are raised individually below.</p>

## Exhibit 11

#	Federal Land Manager Comment	Ecology Response
2	<p>Regarding the potential visibility improvements, it appears that Ecology is relying upon its 2016 RACT analysis and associated visibility modeling to conclude that the visibility improvements that could result from cost-effective emission reductions are not significant. However, as noted above, if the amount of emission reductions is underestimated due to overestimated costs, then the resulting visibility improvements would also be underestimated. And, although we believe we have seen the 2016 RACT analysis, or, at least, part of it, Ecology should provide this analysis in its entirety because it is such a critical component of Ecology's current analysis.</p>	<p>Specific comments about cost are addressed as they are raised below. The 2016 Washington Regional Haze Reasonably Available Control Technology Analysis for Pulp and Paper Mills (2016 RACT Analysis) was provided to Don Shepherd on 10/27/2020 in its entirety.</p>

Exhibit 11

#	Federal Land Manager Comment	Ecology Response
3	<p>(Note: Under the Reasonable Progress provisions of the Clean Air Act, visibility improvement is not a fifth-factor "off-ramp" for emission controls. EPA guidance has placed certain constraints on its use and we need to be sure we understand how Ecology is applying this "fifth-factor.").</p>	<p>Washington has a Reasonably Available Control Technology (RACT) provision that can be applied to attainment areas (unlike some other states and EPA, which generally apply RACT exclusively to non-attainment areas). The five factors of Washington’s RACT rule are listed on page 4 of the 2016 RACT Analysis. Two of the factors (impact of source on air quality, and impact of additional controls on air quality) are described in Chapter 5 of the 2016 RACT Analysis. Two other factors (available controls; and cost) have an entire chapter devoted to each factor. Chapters 3 and 4 of the 2016 RACT Analysis describe in depth a fifth factor in the Washington RACT process (emission reductions to be achieved by additional controls).</p> <p>According to Washington State University, which prepared Appendix C of the 2016 RACT Analysis, “Results from this modeling study show that RACT implementation in the pulp and paper industry does little to improve visibility in Class I areas.” They found that “the 8th highest deciview change was less than 0.05 dv at all of the IMPROVE sites.” This is a valid off-ramp for using the Washington RACT provisions to address regional haze.</p> <p>In terms of 4-factor analyses, the pulp mill information presented to Ecology fully satisfies the current EPA requirements for regional haze 4-factor analysis as specified in the August 20, 2019 EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (2019 EPA Guidance). Based on the current 2019 EPA Guidance, and confirmed on November 3, 2020 in consultation with EPA, Ecology is in full compliance with the regional haze rule by deciding to not pursue controls for pulp mills at this time.</p> <p>In terms of Reasonable Progress provisions of the Clean Air Act, Washington is successfully navigating regional progress goals and will continue to do so as we will also re-evaluate these sources during the next implementation period.</p>



## Exhibit 11

#	Federal Land Manager Comment	Ecology Response
4	<p>I am very pleased to read that the mills have mostly eliminated use of #6 fuel oil (some have eliminated all fuel oil firing) and that some mills have installed additional emission controls during the last planning period. However, according to the All4 report, "Most of the recovery furnaces in this analysis fire either natural gas or No. 2 fuel oil as auxiliary fuel, with two recovery furnaces firing No. 6 fuel oil." Which two furnaces are still firing #6 oil? All4 goes on to say, "The cost of switching to low-sulfur No. 2 fuel oil for the remaining two recovery furnaces is approximately \$12,000/ton SO<sub>2</sub> removed based on fuel prices from the U.S. Energy Information Administration and using a 10% capacity factor." Please provide supporting documentation and calculations.</p> <p>I agree that adding NO<sub>x</sub> and PM emission controls to the recovery furnaces and lime kilns is probably not practical. The best NO<sub>x</sub> control strategy we have seen for recovery furnaces is quaternary combustion controls (which would be very difficult to retrofit).</p>	<p>The two recovery furnaces that use No. 6 fuel oil are Nippon RB#10 and WestRock (WR) Tacoma RF#4. [Note: the terms recovery boiler (RB) and recovery furnace (RF) are used interchangeably by the chemical pulp mills.]</p> <p>At the Nippon RB#10 unit, supplementary No. 6 fuel oil is used very rarely; primarily during startup, shutdown, and malfunction events. In 2018, it only used #6 fuel oil about 4% of the year.</p> <p>At WR Tacoma RF#4 unit, they only use supplemental oil during startups, shutdowns, and to help stabilize combustion of black liquor. The mill provided the following information to clarify:</p> <p>"We expounded on the use and purpose of a Kraft Mill's Recovery Boiler/Furnace and the fuels it burns to provide additional information/ understanding for the FLMs. The primary purpose of the recovery boiler is to recover inorganic cooking chemicals from the pulping process so they can be reused. The spent pulp cooking chemicals are called black liquor, and black liquor is the primary fuel for the recovery boiler. When fired in the recovery boiler, the organic portion of the black liquor burns and the resulting heat is used to make steam (which is used in the pulping and papermaking processes) and the inorganic portion is recovered in the form of smelt (which is dissolved to regenerate the pulp cooking chemicals and used to make pulp). Oil is a purchased fuel and is used only as a supplemental fuel. The mill typically burns oil during RB4 startups, shutdowns, and to help stabilize combustion of black liquor. The boiler is limited in the amount of oil it can burn to a 10 percent annual capacity factor (40 CFR 60.44b(c) and Condition A.4 of the AOP). This usage is tracked to ensure that compliance with the capacity factor is met."</p>

## Exhibit 11

#	Federal Land Manager Comment	Ecology Response
5	<p>All4 has proposed a retrofit factor of 1.5 for several of the emission units for which it conducted a cost analysis. Not only is it highly unlikely that all of these emission units would experience the maximum degree of difficulty recommended by the EPA Control Cost Manual (CCM), these broad assertions are unsubstantiated and undocumented. Instead, we recommend that consultants and states itemize costs or show how they derived their retrofit factors as discussed in <u>Estimating Costs of Air Pollution Control</u>, by William M. Vatauvak, Lewis Publishers, 1990, pp. 60-62.</p>	<p>Cost factors. The chemical pulp mills in Washington are among the oldest major industrial facilities in the Pacific Northwest (GP Camas dates back to 1885). Applying a 1.5 retrofit factor is reasonable.</p>
6	<p>All4 states: "Based on a review of recent information on the effectiveness of applying SNCR to industrial boilers, including recent WestRock experience at multiple locations, our analyses assumed SNCR would achieve 35% control on a solid fuel-fired boiler and 45% control efficiency on a gas-fired boiler." According to the CCM, the effectiveness of SNCR is typically a function of the NOx emission rate--the higher the NOx rate, the more efficient SNCR is likely to be. All4 should provide those NOx emission rates and document and justify its assumptions about SNCR efficiency.</p>	<p>Control efficiencies. The mills used the cost manual estimates except where they have actual information from their emission units. Efficiency rates are what the mills have actually experienced. Emission rates are provided in annual emission inventories, which the FLMs already have access to.</p>

Exhibit 11

#	Federal Land Manager Comment	Ecology Response
7	<p>All4 states that, "The costs of installing and operating an SNCR on mill boilers was estimated using U.S. EPA's "Air Pollution Control Cost Estimation Spreadsheet for Selective Non-Catalytic Reduction (SNCR)" (June 2019)." However, All4 has not provided the inputs to that process, making it impossible for us to evaluate its accuracy.</p> <p>All4 states that, "The costs of installing and operating an SCR on mill boilers were estimated using U.S. EPA's "Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction (SCR)" (June 2019)." However, All4 has not provided the data inputs to that process, making it impossible for us to evaluate its accuracy.</p> <p>In its section 3.3.3 "Energy and Non-Air Related Impacts," All4 has raised additional impacts cost issues that should have already been included in the cost analyses. All4 also raises issue of safety and environmental impacts associated with SCR that are common to all SCR installations and can be addressed by proper safety, operation, and maintenance measures.</p> <p>All4 included sales taxes in its analyses.</p> <p>All4 used a 4.8% interest rate in many of its analyses. The CCM recommends use of the current prime = 3.25%.</p>	<p>Ecology agrees that All4 interest rates were out of date. Ecology adjusted the interest rates from All4 to 3.25%. Our work is shown in the spreadsheet called "all controls" sent to Don Shepherd on 10/9/2020. This spreadsheet contains the data inputs used to arrive at the All4 cost estimates.</p>

## Exhibit 11

#	Federal Land Manager Comment	Ecology Response
8	Do any of the mills generate a waste caustic solution that could be used to scrub SO <sub>2</sub> ?	According to the Ecology's Industrial Section: "Kraft pulp mills generates process-related caustic solutions which are an inherent part of the pulp making process. These caustic solutions are white liquor and weak wash (a dilute solution of white liquor). Weak wash is already commonly used at smelt dissolver tanks as a scrubbing solution. Smelt dissolver tanks are not significant sources of SO <sub>2</sub> emissions. The recovery furnaces at the pulp mills do not have scrubbers installed as emission control devices, instead relying on precipitators."
9	All4 included used a 7% interest rate with a 10-year life in its analyses of adding Low-NOx Burners. The CCM recommends use of the current prime = 3.25%.	Ecology agrees that All4 interest rates were out of date and that a 10-year life for low-NOx burners was inappropriate. Ecology adjusted the interest rates from All4 to 3.25% and the 10-year life value to 20 years. Our work is shown in the spreadsheet called "all controls" sent to Don Shepherd on 10/9/2020. This spreadsheet contains the data inputs used to arrive at the All4 cost estimates.
10	I have attached an annotated excerpt from Ecology's four-factor analyses for the Pulp & Paper industry that contains our feedback on that document. Please provide the Ecology 2016 RACT analysis for pulp/paper mills	The 2016 RACT Analysis (in its entirety) was provided to Don Shepherd on 10/27/2020.
11	"Was this a BACT determination?" (RE: WR Tacoma PB #6 low NOx burner).	It was not a direct BACT determination. The facility installed them on their own. However, the fact that they installed them on their own for reasons other than non-attainment (or similar reasons such as MACT considerations), makes it a relevant cost incurred for BACT considerations.

## Exhibit 11

#	Federal Land Manager Comment	Ecology Response
12	<p>“What is the basis for this assumption?” (RE: RACT cost of 50% of BACT cost)</p>	<p>When not being applied to address non-attainment area concerns, RACT in Washington is understood by at least three agencies (NWCAA, PSCAA, and Ecology) to be a C-grade level control or emission limit. There is a precedent threshold in a previous Washington RACT determination from p. 77 of 107 of the combined (Ecology/ NWCAA/ PSCAA) Washington Oil Refinery RACT – TSD FINAL – 11/25/2013: “The proposed RACT defines a reasonably efficient refinery... comparable to or above the 50% percentile of similar-sized US refineries...”</p> <p>Ecology used its discretion to also apply a similar type of 50% factor to BACT costs to arrive at a RACT cost. In a December 5, 2019 conversation between Ecology and EPA, EPA agreed that this was a reasonable approach.</p>
13	<p>“Please show your math. Please update” (RE: proposed RACT costs)</p>	<p>Our work is shown in the spreadsheet called “all controls” sent to Don Shepherd on 10/9/2020. This spreadsheet contains the data inputs used to arrive at the All4 cost estimates, as well as the costs Ecology arrived at. Ecology’s listed cost threshold values are reasonable and defensible and it is therefore unnecessary to update them.</p>
14	<p>Nippon Boiler #7 @ \$6441/ton and WestRock Tacoma Boiler #6 @ \$6302/ton are not significantly higher and could result in an additional 97 tons/yr. NO<sub>x</sub> removed.</p>	<p>A low NO<sub>x</sub> burner at WestRock Tacoma is already installed. This was the unit from which Ecology used their actual costs for this analysis. Adding a Low-NO<sub>x</sub> burner to Nippon boiler #7 would reduce NO<sub>x</sub> by 28 tpy not 97 tpy. The reasoning behind the suggestion to raise the cost threshold is not supported. If removing more regional haze pollutants were the only criteria, there would be no upper limit for a cost threshold. Whereas Ecology’s cost threshold value of \$6,300/ton value (rounded down from \$6,302/ton) for low NO<sub>x</sub> burners is reasonable and defensible.</p>

## Exhibit 11

#	Federal Land Manager Comment	Ecology Response
15	SCR on WestRock Tacoma HFBoiler #7 @ \$6508/ton and SNCR on WestRock Longview HFBoiler 20 @ \$6245/ton are not significantly higher and could result in an additional 646 tons/yr. NO <sub>x</sub> removed.	An SNCR at WestRock Longview is already installed. This was the unit from which Ecology used their actual costs for this analysis. Adding an SCR WR Tacoma HF Boiler #7 could potentially reduce NO <sub>x</sub> by 457 tpy not 646 tpy. The reasoning behind the suggestion to raise the cost threshold is not supported. If removing more regional haze pollutants were the only criteria, there would be no upper limit for a cost threshold. Whereas Ecology's cost threshold value of \$6,250/ton value (rounded up from \$6,245/ton) for SNCR/SCR is reasonable and defensible.
16	An additional 743 tons of NO <sub>x</sub> could be removed by slightly raising your cost-effectiveness thresholds (or reducing the costs).	If Ecology raised the NO <sub>x</sub> cost threshold, the additional amount of NO <sub>x</sub> removed would potentially be 485 tpy not 743 tpy. The reasoning behind the suggestion to raise the cost threshold is not supported. If removing more regional haze pollutants were the only criteria, there would be no upper limit for a cost threshold. Whereas Ecology's cost threshold value of \$6,250/ton value (rounded up from \$6,245/ton) for SNCR/SCR and the \$6,300/ton value (rounded down from \$6,302/ton) for low NO <sub>x</sub> burners are reasonable and defensible.
17	Please provide this analysis. (RE: 2016 Ecology RACT analysis).	The 2016 RACT Analysis (in its entirety) was provided to Don Shepherd on 10/27/2020.

## Exhibit 11

#	Federal Land Manager Comment	Ecology Response
18	<p>This is irrelevant. The potential for an adverse impact determination only occurs when new emissions from a major source or major modification rise to the level that the FLM has no other recourse. Instead of these rare instances, the facilities under review here are already in existence and have much greater emissions. Due to such congoing emissions, the Dol made a determination in 1985 that all Class I areas it administered were experiencing impaired visibility—that determination has not been changes and is supported by current visibility monitoring data. For example, our monitoring data indicates that visibility in Mount Rainer, North Cascades, and Olympic national parks is “fair” and unchanging.</p>	<p>Pointing out that the FLMs have not issued an adverse impact to the chemical pulp mills in Washington is relevant. In consultation with the FLMs, Ecology wishes to focus its resources on areas that the FLMs consider the greatest concern to regional haze. Because the FLMs issued a recent adverse impact determination to the Washington refinery sector, Ecology is focusing its resources on refineries during this round of regional haze. Ecology acknowledges that an adverse impact determination is not required to address regional haze. However, due to the recent adverse impact determination issued for the refinery sector, as well as recent Washington State University modeling showing that controls on chemical pulp mills “does little to improve visibility in Class I areas” (see response to comment No. 3 above), Ecology is focusing its resources on refineries more than chemical pulp mills during this current regional haze implementation period. Even so, Ecology has included other industries besides refineries in its Q/D analysis and required them to submit 4-factor analysis just like the refineries. All of them have done so in accordance with the 2019 EPA Guidance.</p>
19	<p>Please describe emission reductions that have occurred or will occur during this planning period.</p>	<p>As noted in Ecology’s analysis, the GP Camas facility is no longer operating as a chemical pulp mill. In addition, there are now enforceable conditions that would prevent GP Camas from operating as a chemical pulp mill during this planning period. If GP Camas pursues operation as a chemical pulp mill in the future, they will need to go through new source review.</p>

## Exhibit 11

#	Federal Land Manager Comment	Ecology Response
20	<p>If the cost-effective controls evaluated in the Initial Review were implemented, emission reductions and visibility improvements would be even greater.</p>	<p>It is very unlikely that emission reductions would be greater. The controls considered in the 2016 RACT Analysis were primarily wet heat recovery as was used at the GP Camas mills. Unless the other mills needed wet heat recovery, it would be very difficult to force them to modify their facilities for this reason. In the 2016 RACT Analysis, Washington State University modeling shows that even if the highest standard of SO<sub>2</sub> control (the GP Camas SO<sub>2</sub> limit is as stringent as anywhere in the world), were applied to the other mills in the state, it would do “little to improve visibility in Class I areas.”</p>
21	<p>As Ecology noted above, perceptibility is not an acceptable criterion. Please provide the information on which Ecology made its “demonstration.” Ecology should also consider the cumulative impacts and benefits on all of the Class I areas evaluated.</p>	<p>Ecology did not state that “perceptibility is not an acceptable criterion.” But rather, Ecology quotes the 2019 EPA Guidance directly, and therefore more accurately as follows: “a measure may be necessary for reasonable progress even if that measure in isolation does not result in perceptible visibility improvement.”</p> <p>The actual quote clearly states that “a measure may be necessary for reasonable progress.” It does not state that a measure is necessary in all circumstances for reasonable progress. Based on the circumstances in Washington as described in Chapter 11 of Ecology’s analysis, Ecology appropriately considered this information from the 2019 EPA Guidance for 4 factor analyses. The information presented in Chapter 11 (including but not limited reference to the 2016 RACT Analysis), supports Ecology’s conclusions. The 2016 RACT Analysis (in its entirety) was provided to Don Shepherd on 10/27/2020. Ecology’s analyses of all of its Class I areas shows that Washington is meeting and addressing the 2064 glide path goals appropriately.</p>



## Exhibit 11

#	Federal Land Manager Comment	Ecology Response
22	That cost-effectiveness value would be \$6,350 in 2019\$ based upon the CEPCI.	<p>As WestRock Tacoma noted in its response to Ecology’s follow-up requests regarding cost for the low NOx burners, they were already using “actual capital costs in 2019 dollars.” Therefore, the suggested cost conversion is not necessary.</p> <p>It would also not make any difference because Ecology’s adjusted threshold of \$6,300/ton for low NOx burners (after accounting for 20 years useful life and a 3.25% interest rate, as described in comment 9), is almost identical to what is being suggested in the comment.</p> <p>It would not pull in any additional units for consideration. A low NOx burner at WestRock Tacoma is already installed (see response to comment No. 14).</p>
23	That cost-effectiveness value would be \$6,520 in 2019\$ based upon the CEPCI.	<p>As WestRock Longview noted in its response to Ecology’s follow-up requests regarding cost for the SNCR, they were already using “actual capital costs in 2019 dollar’s.” Therefore, the suggested cost conversion is not necessary.</p>
24	We are aware of cost-effectiveness thresholds of \$4400 - \$7600/ton among the WRAP states.	<p>Ecology’s cost thresholds for chemical pulp mills (~\$6300 - \$7,800) are mostly within this range, except for Ecology’s particulate matter threshold, which is slightly above this range (\$7,800). Each state is able to determine their own cost threshold independently. The costs incurred by one industry for a control technology may vary from the costs incurred by another industry. Cost incurred for control technologies could also vary from state to state. Ecology’s cost threshold values are well reasoned and defensible.</p>
25	Perceptibility is not an acceptable criterion. Please provide the information on which Ecology based this conclusion. Please provide the information on which Ecology based its conclusion.	<p>See Ecology’s responses to Comment No. 3 and Comment No. 21 above.</p>

## Federal Land Manager Comments for Petroleum Refineries and Ecology's Responses

#	Federal Land Manager Comment	Ecology Response
1	<p>First, some general feedback on the "Refineries" section of your draft chapter 11 (see attachment):</p> <ul style="list-style-type: none"> <li>• I really like the comparison of emissions/bbl among the US refineries--I had not seen that sort of thing before and it will be helpful to us as we look at other refineries across the nation.</li> <li>• While we bureaucrats understand acronyms like "AO" and "FFA", it would probably be a good idea to define them for the public.</li> <li>• It was not until I had reviewed multiple refinery reports that I began to realize how Ecology selected emission units within a refinery for review. I found your approach to evaluate "each fluid catalytic cracking unit (FCCU), boiler greater than 40 MMBtu/hr., and heater greater than 40 MMBtu/hr." makes sense in dealing with facilities with so many emission units and I recommend that you state that explicitly in your draft SIP. I also appreciate that you are willing to add the calciners at BP-Cherry Point.</li> <li>• I recommend that you explain why Ecology is only evaluating NOX emissions and not SO2.</li> <li>• Although I know of no regulatory basis for exempting emission units modified after 2005, I am K with the results of applying that filter.</li> </ul>	<ul style="list-style-type: none"> <li>• First bullet – no response required</li> <li>• Second bullet – Ecology will review the document to ensure that the initial use of an acronym is spelled out.</li> <li>• Third bullet – Ecology will make will add in the refinery sections introduction language that states what equipment is being evaluated.</li> <li>• Fourth bullet – an explanation on what equipment was selected for further evaluation will be added</li> <li>• Fifth bullet – this will be part of the explanation on the fourth bullet</li> </ul> <p>It is Ecology's intention to start a RACT process for the refineries. The RACT process requires rule making and will not be completed before the draft Regional Haze State Implementation Plan is submitted to EPA. The rule making itself will be open to the public and it is encouraged for all stake holders (which include the FLMs) to participate.</p>

## Exhibit 11

#	Federal Land Manager Comment	Ecology Response
	<p>It is my understanding that you intend to address RP for the refinery sector via a RACT action--is that correct? What is your timeline for that--can you complete that action in time to allow us to review it and for Ecology to include it in your SIP submittal?</p>	
2	<p>I agree that BP has overestimated costs of NOx controls and commend Ecology for using the Control Cost Manual (CCM) to conduct its independent analysis. I offer these observations in support of your approach. (Please see the attachment for more specifics.):</p> <ul style="list-style-type: none"> <li>• The "Jacobs" report upon which BP based its analysis is too old (per the CCM). The method BP used to escalate costs from the Jacobs report were not adequately explained.</li> <li>• BP appears to have included costs of lost production without explaining how they relate to conducting modifications during turnarounds.</li> <li>• BP has overestimated Capital Recovery Costs and reagent costs.</li> </ul> <p>NPS's comments:</p> <ul style="list-style-type: none"> <li>• The adverse impact determination was dated December 15, 2016 and was never withdrawn.(Ecology will change)</li> <li>• The NPS identify various flaws in BPs cost analysis</li> </ul>	<p>The observation supports Ecology's planned approach. For this reason no responses are required.</p>
3	<p>I agree that Phillips 66 (P66) has overestimated costs of NOx controls and commend Ecology for using the Control Cost Manual (CCM) to conduct its independent analysis. I offer these</p>	<p>The observation supports Ecology's planned approach. For this reason no responses are required.</p>

## Exhibit 11

#	Federal Land Manager Comment	Ecology Response
	<p>observations in support of your approach. (Please see the attachment for more specifics.)</p> <ul style="list-style-type: none"> <li>• The report upon which Phillips 66 based its analysis is too old (per the CCM).</li> <li>• P66 has overestimated Capital Recovery Costs.</li> </ul> <p>NPS's comments:</p> <ul style="list-style-type: none"> <li>• The NPS identify various flaws in Phillip 66's cost analysis</li> </ul>	
4	<p>I agree that Marathon has overestimated costs of NOx controls and commend Ecology for using the Control Cost Manual (CCM) to conduct its independent analysis. I offer these observations in support of your approach. (Please see the attachment for more specifics.)</p> <ul style="list-style-type: none"> <li>• Marathon has overestimated Capital Recovery Costs and reagent costs.</li> </ul> <p>NPS's comments:</p> <ul style="list-style-type: none"> <li>• The NPS identify various flaws in Tesoro's cost analysis</li> </ul>	<p>The observation supports Ecology's planned approach. For this reason no responses are required.</p>
5	<p>I agree that Shell has overestimated costs of NOx controls and commend Ecology for using the Control Cost Manual (CCM) to conduct its independent analysis. I offer these observations in support of your approach. (Please see the attachment for more specifics.)</p> <ul style="list-style-type: none"> <li>• Shell's cost analyses are unsupported.</li> <li>• Shell has overestimated Capital Recovery Costs.</li> </ul>	<p>The observation supports Ecology's planned approach. For this reason, no responses are required for the first section. Open bullets responses are given below.</p> <ul style="list-style-type: none"> <li>• 2019 emission inventory with Shell and Ecology's reviews highlighted in yellow</li> <li>• Ecology plans to perform an engineering study on the three turbines and may set lower limit based on RACT</li> <li>• Ecology: FLM's comments will be included in appendix.</li> </ul>

## Exhibit 11

#	Federal Land Manager Comment	Ecology Response
	<p>I have attached a workbook that includes data from the 2019 emission inventory provided by NWCAA.</p> <p>Don's comments:</p> <ul style="list-style-type: none"> <li>• Need copies of support data from Shell</li> <li>• Retrofit Factor justification needed</li> <li>• Should use current interest rate of 3.25%</li> <li>• Need federally enforceable limit on equipment life (Erie City Boiler)</li> <li>• Noted FCCU SO2 of 142 tpy</li> </ul>	
6	<p>Finally, we have a question regarding Chapter 10 of the draft SIP. On page 5, the SIP refers to "state oil and gas emissions control programs". Can you explain what this is referring to?</p>	<p>This is actually 40 CFR 60, subpart OOOO requirements. This does contain transportation requirements for movement of natural gas. Also some information is provided by the Western Regional Air Partnership and it may be more relevant to other western states.</p> <p>It is Ecology's intent to clarify this point and correct any inconsistencies.</p>

## Federal Land Manager Comments for Cement Industry and Ecology’s Responses

#	Federal Land Manager Comment	Ecology Response
1	<p>In Chapter 11, page 16, the discussion on potential NO<sub>x</sub> controls at Ash Grove says:</p> <p>Selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) emission control systems are two potentially viable methods of reducing NO<sub>x</sub> emissions. The exit stack temperature at the facility is typically around 350°F. This stack temperature is less than the typical SCR operation temperature and requires additional heating to 650°F. The temperature is significantly lower than optimal SNCR temperatures and requires heating, which generates more NO<sub>x</sub>.</p> <p>We note that SNCR would not be located at the exit stack, so the temperature at that point would not preclude SNCR. Typically on a cement kiln the reagent would be injected into the kiln, not downstream at the exit stack.</p>	<p>Ecology acknowledges this comment and is working with the facility to gather additional information. The original analysis was for a SCR system and not for a SCR <b>and</b> SNCR system. Resolution of this issue will be added to the proposed Regional Haze State Implementation Plan when opened for formal public comment.</p>
2	<p>On page 17, the discussion says: “The facility is located on a confined property with very little available area to install new equipment. The facility would need to move and relocate existing facilities in a vertical fashion to free up space. Another option would be to reduce the space allowed for stockpiles, but this would result in potential operational impacts and increased vessel traffic to deliver materials more frequently.”</p> <p>We have not previously encountered a cement plant that did not have sufficient space for an SNCR system. The primary components of an SNCR system are reagent tanks and an injection system. The analysis should include an evaluation from</p>	<p>Ecology acknowledges this comment and is working with the facility to gather additional information. The original analysis was for a SCR system and not for a SCR <b>and</b> SNCR system. Resolution of this issue will be added to the proposed Regional Haze State Implementation Plan when opened for formal public comment.</p>

Exhibit 11

#	Federal Land Manager Comment	Ecology Response
	an SNCR vendor to determine whether installation of a system is physically feasible.	

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## Federal Land Manager Comments for the Glass Industry and Ecology's Responses

#	Federal Land Manager Comment	Ecology Response
1	<p>I also have a question regarding the Cardinal FG Company glass facility. Chapter 11 of the draft SIP indicates that the company has submitted an application to modify the facility's permit and will install an SCR system. According to the SIP, NOX at the SCR inlet will be 437.5 lbs./hr. and 49.1 lb./hr. at the SCR outlet, for an emissions reduction of 88%. According to the permit technical support document, Tech Support Doc 20-3409TSD.pdf page 8, the SCR will have a "minimum" efficiency of 80%, and the emissions rate will be 1.63 lb./ton glass and 101.1 lb./hr. (24-hour average). Maybe I am misunderstanding this, but it seems like there is some inconsistency here. Can you clarify what the NOx removal efficiency will be with SCR? Also, we are aware of a glass facility in New Jersey that was required to install an SCR system and achieve an emissions rate of 1.2 lb./ton of glass with a 90% control efficiency. I have attached a copy of the settlement announcement for your reference.</p>	<p>The facility has requested the permit modification numbers in order to keep the facility below PSD permit levels. This will allow for the recension of the current PSD permit. This permit modification was on a voluntary basis, so the permittee established the technical requirements.</p> <p>The facility will operate the SCR system in the manner required by the newly modified permit and the manufacturer's operating requirements.</p> <p>It is expected that the efficiency of the system will be greater than 80%, but the permitted levels will be at 80%.</p> <p>Ecology does acknowledge that higher efficiency can be achieved. With the facility doing this change on a voluntary basis, Ecology is accepting this change in regards to regional haze emission reductions.</p>



## Exhibit 12

BEFORE THE AIR QUALITY CONTROL COMMISSION  
STATE OF COLORADO

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IN THE MATTER OF PROPOSED REVISIONS TO REGULATION NUMBER 23  
NOVEMBER 17 to 19, 2021 HEARING

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### PREHEARING STATEMENT OF THE COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT, AIR POLLUTION CONTROL DIVISION

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The Colorado Department of Public Health and Environment, Air Pollution Control Division (“Division”) hereby submits its Prehearing Statement (“PHS”) in this matter, discussing the policy, factual, and legal grounds for the proposed revisions to Regulation Number 23 which addresses Colorado’s obligations related to regional haze.

#### I. EXECUTIVE SUMMARY

##### A. Summary of Proposal

The Division is proposing revisions to Regulation Number 23 to address Colorado’s obligations related to Regional Haze, as directed by § 25-7-211, C.R.S. These revisions are expected to also achieve the co-benefit of reducing greenhouse gases (“GHGs”) contingent upon Public Utility Commission (“PUC”) approval of electric generating unit (“EGU”) closures and generator fuel switching proposed in pending resource plans, as directed by SB 19-096,<sup>1</sup> HB 19-1261,<sup>2</sup> and HB 21-1266,<sup>3</sup> and are consistent with SB 19-236.<sup>4</sup> The proposed revisions complete the second phase of the Regional Haze rulemaking process for those sources identified during the initial screening process that were not addressed during the phase 1 rulemaking conducted in 2020.

The U.S. Environmental Protection Agency (“EPA”) promulgated the Regional Haze rule in 1999, and subsequently revised it in 2017, which requires each state to reduce

<sup>1</sup> SB 19-096, Concerning the Collection of Greenhouse Gas Emissions Data to Facilitate the Implementation of Measures that Would Most Cost-Effectively Allow the State to Meet Its Greenhouse Gas Emissions Reduction Goals, and, in Connection Therewith, Making an Appropriation, 72nd Gen. Assemb., 1st Reg. Sess. (Colo. 2019) (codified as § 25-7-140 C.R.S.).

<sup>2</sup> HB 19-1261, Concerning the Reduction of Greenhouse Gas Pollution, and, in Connection Therewith, Establishing Statewide Greenhouse Gas Pollution Reduction Goals and Making an Appropriation, 72nd Gen. Assemb., 1st Reg. Sess. (Colo. 2019) (codified as §§ 25-7-102, -103, -105, C.R.S.).

<sup>3</sup> HB 21-1266, Concerning Efforts to Redress the Effects of Environmental Injustice on Disproportionately Impacted Communities, and, in Connection Therewith, Making an Appropriation, 73rd Gen. Assemb., 1st Reg. Sess. (Colo. 2021) (relevant portions codified as §§ 24-4-109, 25-7-105, C.R.S.) (“HB 21-1266”).

<sup>4</sup> SB 19-236, Concerning the Continuation of the Public Utilities Commission, and, in Connection Therewith, Implementing the Recommendations Contained in the 2018 Sunset Report by the Department of Regulatory Agencies and Making an Appropriation, 72nd Gen. Assemb., 1st Reg. Sess. (Colo. 2019) (relevant portions codified as §§ 40-2-124, -125.5) (“SB 19-236”).

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emissions of visibility impairing pollutants that negatively impact class I areas and incorporate any necessary emission reductions in a state implementation plan (SIP) to address Regional Haze.<sup>5</sup> Regional haze is visibility impairment caused by multiple emission sources over a broad geographic area. The Regional Haze Rule aims to continue progress towards improving visibility at the 156 mandatory class I areas nationwide for the most impaired days and maintain the best visibility for the clearest days. Colorado has twelve class I areas (four national parks and eight wilderness areas) at which visibility must be evaluated. EPA intended that the Regional Haze rule be evaluated periodically over a period of 60 years with a goal of achieving natural visibility conditions by 2064.

During the first implementation period, often referred to as round 1, states were required to establish Best Available Retrofit Technology (“BART”) and Reasonable Progress (“RP”) requirements. Colorado accomplished this with two separate SIP submittals to EPA in 2008 and 2009, and subsequently adopted revisions in 2011, 2014, and 2016. EPA approved Colorado’s Regional Haze SIP in several actions, last approved on July 5, 2018.<sup>6</sup>

During this second implementation period (aka round 2), states must evaluate their progress in meeting natural visibility conditions in class I areas and submit a SIP revision to EPA by July 31, 2021. Colorado has historically, and continues, to collaborate with other western states and EPA through the Western Regional Air Partnership (“WRAP”) to develop the necessary data products to support the second 10-year planning period Regional Haze SIP, including emission inventories, meteorological weighted emission impact analyses, particulate matter (“PM”) source apportionment, and visibility modeling. During round 2, however, the complexity of the Regional Haze technical analysis coupled with coordination among so many states, tribes, federal land managers (“FLMs”), and EPA has produced delays in the release of some of the data products that are instrumental to completing the Regional Haze SIP. Final data products were just recently completed from this coordinated process.

The delay in necessary data and modeling products has significant implications for several states, including Colorado, in meeting the round 2 SIP submittal due date. While Colorado has actively worked to timely evaluate potential emission reduction strategies for stationary sources, Colorado could not fully evaluate progress against the visibility goals without all of the modeling and data analysis products. This delay also created challenges for Colorado to satisfy FLM consultation directives, provide information to stakeholders, and finalize the analyses to be included in the SIP. Further, Colorado’s rulemaking process itself demands at least a three-month timeframe in addition to a required legislative review process for any SIP submittal. All of this means that Colorado was not able to fully address all SIP requirements and submit the round 2 SIP to EPA by the July 31, 2021 due date. EPA is aware of these challenges and has been notified of the delay in submittal.

<sup>5</sup> See 40 CFR §§ 51.300-51.309.

<sup>6</sup> Approval and Promulgation of Air Quality Implementation Plans; Colorado; Regional Haze State Implementation Plan, 83 Fed. Reg. 31332 (July 5, 2018).

## Exhibit 12

Additionally, EPA issued a Regional Haze clarification memo on July 8, 2021,<sup>7</sup> only 23 days before the due date for the round 2 SIP submissions. While Colorado believes that the technical analyses, rule proposal, and SIP revisions are aligned with the EPA Regional Haze clarification memo, the timing of its release does not allow for substantial changes in the planning process or SIP adoption proposed for consideration before the Air Quality Control Commission without creating significant delays (well beyond the SIP due date of July 31, 2021), requiring additional or new analyses, and elevating the risk of a Federal Implementation Plan being imposed upon Colorado.

The Division has not proposed any unit retirements, fuel switching, or changes to permitted fuel consumption limits as a RP control strategy. Therefore, no proposed control strategies for this Regional Haze SIP revision can be stated to directly reduce GHG emissions. However, the proposed revisions are expected to achieve the additional co-benefit of reducing GHG emissions contingent upon PUC approval of the proposed EGU closure and fuel switching dates in Public Service Company of Colorado's ("PSCo") pending Electric Resource Plan/Clean Energy Plan, docket number 21A-0141E. In HB 19-1261, the General Assembly declared that "[c]limate change adversely affects Colorado's economy, air quality and public health, ecosystems, natural resources, and quality of life[,]” acknowledged that “Colorado is already experiencing harmful climate impacts[,]” and that “[m]any of these impacts disproportionately affect” certain disadvantaged communities.<sup>8</sup> Colorado's statewide GHG reduction goals require the Commission to implement regulations to achieve a 26% reduction of statewide GHG emissions by 2025; 50% reduction by 2030; and 90% reduction by 2050 as compared to 2005 levels.<sup>9</sup> HB 21-1266 further clarified timelines for electric generating utilities to submit Clean Energy Plans and placed additional GHG reduction requirements on the industrial sector, which also affects sources subject to this phase 2 rulemaking. To clarify, this phase 2 rulemaking addresses Regional Haze SIP requirements under the Clean Air Act, while achieving GHG co-benefits. The data collection, development, and evaluation of the first Clean Energy Plan is currently underway.<sup>10</sup> The development of rules to achieve industrial GHG reductions is being conducted simultaneously with this regional haze rulemaking process and emissions reductions are quantified in the Final Economic Impact Analysis.

Colorado continues to separately develop GHG emission reduction strategies to address these objectives and statutorily mandated reduction goals. The potential EGU

<sup>7</sup> APCD\_PHS\_EX-012 (Memorandum from Peter Tsirigotis, Director, EPA, to Regional Air Division Directors, Regions 1-10 (July 8, 2021)).

<sup>8</sup> § 25-7-102, C.R.S.

<sup>9</sup> § 25-7-102(g), C.R.S.

<sup>10</sup> See SB 19-236. Section 40-2-125.5(4)(a) requires PSCo, a “qualifying retail utility” as defined in statute, to file the first electric resource plan that includes a clean energy plan outlining how PSCo intends to achieve the clean energy targets established in § 40-2-125.5(3). This is currently under review at the PUC in Docket No. 21A-0141E. Other utilities have announced their intent to voluntarily submit Clean Energy Plans in the near future.

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retirements and fuel switching aid in securing timely and significant GHG reductions and require an analysis of the social cost of greenhouse gases pursuant to § 25-7-105(1)(e), C.R.S.

In HB 21-1266, signed into law on July 2, 2021, the General Assembly, determined that “[s]tate action to correct environmental injustice is imperative, and state policy can and should improve public health and the environment and improve the overall well-being of all communities... [and that e]fforts to right past wrongs and move toward environmental justice must focus on disproportionately impacted communities and the voices of their residents.”<sup>11</sup> Thus, the state must meaningfully engage disproportionately impacted communities as partners and stakeholders in government decision-making, especially when evaluating potential environmental and climate threats to these communities. The Division has endeavored to meaningfully engage with these communities even though the vast majority of outreach and planning for this rule began more than two years ago, long before the establishment of HB 21-1266 just three months ago.

### **B. History of Rulemaking Stakeholder Process**

The Division held six regional haze public meetings on June 10, August 1, October 3, 2019, January 9, March 27, and July 28, 2020. The Division also met with the FLM agencies in June 2019 and in August and October 2020 in preparation for the phase 1 hearing.

Specific to its August 2021 rulemaking proposal for this universe of regulated sources being considered in phase 2, the Division held public listening sessions on January 7 and February 10, 2021 with the North Denver area communities; March 4 and March 11, 2021 with the Pueblo area communities; and August 10 via Zoom platform to discuss the upcoming proposal. The Division has also participated in ongoing WRAP meetings, held meetings with FLM agencies in April, May, and June 2021 to discuss SIP progress and technical analyses, and also met with other state agencies, EPA Region 8 staff, and stakeholders subject to this rulemaking.

Since submitting its request for hearing to the Commission, the Division has met regularly and often with stakeholders, which has resulted in identifying primary issues as well as changes to the Request Proposal as described in this Prehearing Statement and as included in the PHS Proposal. The Division will further continue its efforts in coordinating with stakeholders to narrow the contested issues to be heard by the Commission in November.

<sup>11</sup> HB 21-1266, § 2(IV).

## Exhibit 12

### C. Contents of Prehearing Statement

This Prehearing Statement contains the following:

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### D. Summary of Exhibits

On the APCD PHS Exhibit List enclosed with this Prehearing Statement, the Division has identified potential exhibits in support of its petition for rulemaking in addition to citations provided in this Prehearing Statement. The Division's exhibits include documents and data used to support its compliance with federal and state regulations, data submitted to or collected by the Division to administer its air quality program, and studies and reports relating to the proposed rules. The Division is also submitting the current proposed revisions to Regulation Number 23, along with a revised Statement of Basis and Purpose and Final Economic Impact Analysis.

Many of the Division's exhibits are cited in this Prehearing Statement as support for specific positions; however, a citation to one exhibit is not intended to preclude the Division's reliance on another exhibit for the same position. Further, not all exhibits are cited specifically in this Prehearing Statement but represent the collection of studies and data relied upon to prepare this proposal. The Division will supplement its exhibits to respond to other Parties' prehearing statements, as necessary.

### E. Estimate of Time Necessary for Presentation

The Division estimates that it will require approximately 3.5 hours during the hearing to: present its case in chief (90 minutes), cross-examine witnesses (45 minutes), and

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present its rebuttal (75 minutes).

### II. DISCUSSION OF PROPOSED REVISIONS AND BRIEFING OF LEGAL AND FACTUAL ISSUES BEFORE THE COMMISSION

#### A. Proposed Requirements for Regional Haze Limits - Reasonable Progress

The Division requests that the Air Quality Control Commission consider adopting new requirements within Regulation Number 23 and the Round 2 Regional Haze SIP.

The new Regulation Number 23 requirements will further reduce emissions of visibility impairing pollutants from stationary sources to improve visibility in Colorado's twelve class I areas and assure achievement of Regional Haze RP goals.

For the second implementation period, phase 2 hearing, the Division evaluated units at 17 facilities:

- Colorado Springs Utilities (“Utilities”) Nixon Power Plant Coal Handling;
- Utilities Front Range Power Plant (“FRPP”) Turbines 1 and 2;
- Utilities Clear Spring Ranch Sludge Handling and Disposal Facility, 4 digester gas-fired boilers and 2 flares;
- PSCo Comanche Station Unit 3;
- PSCo Hayden Station Units 1 and 2, coal ash and sorbent handling and disposal, and fugitive dust from unpaved roads;
- PSCo Cherokee Station Turbines 5 and 6;
- PSCo Pawnee Station Unit 1 and the cooling tower;
- Manchief Generating Station Turbines 1 and 2, co-located with PSCo Pawnee Station;
- CEMEX Lyons Portland cement manufacturing facility in Lyons, CO plant Kiln, Quarries, and Raw Materials Grinding;
- Holcim Florence Portland cement manufacturing facility in Florence, CO plant Kiln, Quarry, and Finish Mills;
- GCC Pueblo Portland cement manufacturing facility plant Kiln and Clinker Cooler;
- MillerMolson Coors Boiler Support Facility Boilers 1, 2, 4, & 5;
- Evraz Rocky Mountain Steel Mill Electric Arc Furnace (“EAF”), Ladle Metallurgy Station (“LMS”), Ladle Preheaters, Round Caster, Rotary Furnace, Quench Furnace, Tempering Furnace, Rod/Bar Mill Furnace, Rail Mill Furnace, Vacuum Tank Degasser (“VTD”) Boiler, Haul Roads;
- Rocky Mountain Bottle Company Furnaces B+ and C;
- Suncor Energy Denver Refinery Plant 1 and 2 Fluid Catalytic Cracking Units (“FCCU”), Plant 1 and 2 Sulfur Recovery Complexes (SRCs), Plant 1 Main Plant Flare, Process Heaters H-11, H-17, H-27, H-28/29/30, H-37, H-101, H-401/402, and H-2101, and Boilers 4 and 505;
- Denver International Airport (“DIA”) Boilers, Cooling Tower, Emergency

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- Generators, and Miscellaneous Engines; and
- Craig Cooling Towers 1, 2, and 3.

As part of this process, the Division reviewed and conducted analyses of the projected costs of RP controls, as well as additional information regarding the four factors for RP, which includes documentation provided by the sources and other stakeholders. Through a combination of emission limit tightening, work practice and control requirements, the Division projects total emission reductions of up to 3,986 TPY for visibility impairing pollutants (NO<sub>x</sub>, SO<sub>2</sub>, PM) from additional control strategies and proposed EGU retirements and repowering in phase 2 that are currently being considered by the PUC. The Division also anticipates GHG co-benefits from the EGU retirements and repowering.

Highlighted issues and proposed revisions are described briefly below.

### 1. Proposed EGU Closure Dates

A potential issue was raised during the request for party status with how the Division has applied proposed closure dates for electric generating units in the 4-factor analyses and how proposed retirement dates and fuel conversion dates have been included in the proposed regulation, which are subject to PUC approval.<sup>12</sup> This has been raised by the party that includes Sierra Club, who the Division notes is already an intervening party in the proceeding currently in progress before the PUC. The Division will continue to work with the parties to this rulemaking in an attempt to resolve this concern.

### 2. Cost Considerations in 4-factor Analyses

The Division anticipates that cost considerations and cost effectiveness of control strategies will be issues to be discussed among parties leading up to and during the rulemaking hearing.

The Division is using \$10,000 per ton of regional haze pollutant as the nominal cost threshold to determine cost effective control strategies for Round 2 RP. This threshold is applied to the individual pollutants in the control strategy analyses, specifically NO<sub>x</sub>, PM, and SO<sub>2</sub>. This threshold value is an increase from Round 1 and reflects the fact that with each successive round of planning, less costly and easier to implement strategies have already been adopted. Colorado has maintained this threshold throughout the planning process despite the fact that each of the Class I areas in Colorado is below the URP for 2028. We believe that this is consistent with the discussion in the July 8, 2021 EPA Regional Haze clarification memo.<sup>13</sup>

The Division also expects questions and additional discussion with parties regarding interest rates and cost estimates used in the 4-factor analyses. The Division hopes to

<sup>12</sup> NPCA-Sierra's Petition for Party Status, at 3-5.

<sup>13</sup> See APCD\_PHS\_EX-012 (Memorandum from Peter Tsirigotis, Director, EPA, to Regional Air Division Directors, Regions 1-10 (July 8, 2021)).

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resolve many of these questions through ongoing collaborative conversations and review of any additional technical information that may be supplied by the parties.

### **3. Fuel Conversions Occurring Between Round 1 and Round 2**

The Division is including additional revisions to Regulation 23 and the associated SBAP language with this PHS Proposal to identify and clarify fuel conversions that occurred after Round 1, but were not required by the Round 1 planning process. Specifically, the boilers at the Miller MolsonCoors Boiler Support Facility, formerly CENC, were converted from coal to gas-fired operation. Round 1 evaluated control strategies for the boilers while operating on coal and the Round 2 Technical Support Document (“TSD”) evaluated potential control strategies after the units were converted to gas-fired operation. Fuel conversion dates, and the Boiler 3 retirement date, have been included in the rule as well as clarification of monitoring and recordkeeping requirements associated with gas-fired operation.

### **4. Alternate Proposals for Additional Control Strategies**

Based on the information supplied when party status was requested, the Division is anticipating alternate proposals that may impact up to three (3) facilities included in the scope of this rulemaking hearing. Specifically, Suncor, GCC Pueblo, and Holcim Florence have been identified as facilities where a possible alternate proposal is being explored by Sierra Club and National Parks Conservation Association.<sup>14</sup> Because the proposal(s) have not yet been submitted, the Division cannot take a position at this time regarding the merits of the potential proposal(s). Upon submission of any alternate proposal in this hearing, the Division will review the proposal, and the supporting information on which it was developed, for completeness with respect to technical information, feasibility and cost analysis, and any emissions reduction strategies and regulatory requirements that may be proposed.

### **5. Uniform Rate of Progress (“URP”)**

As stated in EPA’s 2017 Regional Haze Rule, “[t]he rate of progress in some Class I areas may be meeting or exceeding the [URP] that would lead to natural visibility conditions by 2064, but this does not excuse [Colorado] from conducting the required analysis and determining whether additional progress would be reasonable based on the four factors.”<sup>15</sup> This was further clarified in the memorandum issued by EPA on July 8, 2021.<sup>16</sup> Colorado has performed a detailed analysis for each of the facilities identified for Round 2 RP review even after the modeling results indicated that all of Colorado’s

<sup>14</sup> NPCA-Sierra’s Petition for Party Status, at 5.

<sup>15</sup> Protection of Visibility: Amendments to Requirements for State Plans, 40 Fed. Reg. 3,078, 3080 (Jan 10, 2017).

<sup>16</sup> See APCD\_PHS\_EX-012 (Memorandum from Peter Tsigotis, Director, EPA, to Regional Air Division Directors, Regions 1-10 (July 8, 2021)).



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class 1 areas are below the URP for 2028. The rule and SIP proposal use the detailed analysis performed for each facility as the basis for the development of the requirements and do not rely on the URP for determining cost effective RP control strategies.

### **6. EPA Startup, Shutdown, and Malfunction Memorandum**

On September 30, 2021, EPA issued a new memorandum that withdrew a previous 2020 memorandum by the prior administration.<sup>17</sup> The September 30th memorandum references 2015 requirements associated with the use of Startup, Shutdown, and Malfunction (“SSM”) provisions in SIPs. The Division is currently reviewing the memorandum and the newly reinstated 2015 requirements as they pertain to this rulemaking and SIP approval, specifically analyzing the use of EPA-approved consent decree requirements within the SIP. The Division acknowledges that several consent decrees, which are issued and enforced by the EPA, are the source of emissions limits and SSM conditions incorporated into this proposed revision to Regulation 23. Additional revisions to Regulation 23 and the SIP may be necessary as a result of this review and forthcoming discussions with EPA.

### **7. Consistency**

The Division updated the SIP, proposed language in Regulation 23, and the SBAP for consistency and clarity. In particular, through preliminary conversations with EPA Region 8 staff, the Division determined it had incorrectly highlighted portions of section 7.3 in the SIP. Highlighted portions were meant to denote sources that had been acted on by the Commission in the phase 1 hearing in November 2020, but all of this section was inadvertently highlighted. This has been corrected in the revised SIP document. The Division will continue to make revisions to the appropriate documents to ensure consistency as issues are resolved during the rulemaking process.

### **III. LIST OF ISSUES TO BE RESOLVED BY THE COMMISSION**

1. Whether the proposed rules are consistent with the provisions of the Clean Air Act and implementing regulations regarding regional haze and SIP revisions, 42 U.S.C §§ 7410 and 7491 and 40 C.F.R § 51.300, *et seq.*
2. Whether the proposed rules and revisions are consistent with the legislative purpose of the Air Pollution Prevention and Control Act, as stated in § 25-7-102, C.R.S.
3. Whether the proposed rules and revisions comply with the requirements of

<sup>17</sup> APCD\_PHS\_EX-013 (Memorandum from Janet McCabe, Deputy Administrator, EPA, to Regional Administrators (Sept. 30, 2021)).

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- the State Administrative Procedure Act, §§ 24-4-101, C.R.S. et seq., the Commission's Procedural Rules, and other applicable law.
4. Whether the proposed rules and revisions comply with the requirements of the Air Pollution Prevention and Control Act, §§ 25-7-101, C.R.S. *et seq.*, including the new requirements added by Senate Bill 19-181.
  5. Whether the proposed rules and revisions are consistent with the scope of the Notice of Rulemaking Hearing issued by the Commission on August 26, 2021.
  6. Whether there is justification for the adoption of the proposed rules and revisions in accordance with §§ 25-7-110.5 and -110.8, C.R.S.
  7. Whether the proposed revisions are cost-effective and technically feasible.
  8. Whether the submitted alternative proposals comply with applicable state and federal law, and whether any portions thereof should be adopted.
  9. Whether the proposed revisions comply with all other relevant requirements of state and federal law.

### IV. EXHIBIT LIST

The Exhibits submitted by the Division are listed on the enclosed APCD PHS Exhibit List. The Final Economic Impact Analysis includes cost updates for Rocky Mountain Bottle Company and Miller MolsonCoors Boiler Support Facility and have been incorporated into the revised TSDs. A Cost Benefit Analysis has been requested for this rulemaking. It has not been completed at this time and will be submitted at least 10 days prior to the hearing date.

The Division may also utilize exhibits identified by other parties.

### V. WITNESS LIST

The following potential witnesses are employees of the Colorado Department of Public Health and Environment, Air Pollution Control Division and should be contacted only through undersigned counsel.

1. Joshua Korth - Technical Support and SIP Unit Supervisor. Mr. Korth may testify regarding the development, meaning, and implementation of the proposed revisions and documents on which they are based. Mr. Korth may provide information about how the PUC process relates to this rule proposal. Mr. Korth may also testify regarding any alternative proposals submitted by other parties.
2. Sara Heald - Technical Planner. Ms. Heald may testify regarding the development, meaning, and implementation of the proposed revisions and documents on which they are based. Ms. Heald may also testify regarding any alternative proposals submitted by other parties.

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3. Weston Carloss - Technical Planner. Mr. Carloss may testify regarding the development, meaning, and implementation of the proposed revisions and documents on which they are based. Mr. Carloss may also testify regarding any alternative proposals submitted by other parties.
4. Richard Coffin - Planner. Mr. Coffin may testify regarding stakeholder outreach and agency coordination related to the proposed revisions.
5. Dena Wojtach - Manager, Planning & Policy Program. Ms. Wojtach may testify regarding the development, meaning, and implementation of the proposed revisions and documents on which they are based. Ms. Wojtach may also testify regarding any alternative proposals submitted by other parties.
6. Garry Kaufman - Director. Mr. Kaufman may testify regarding the development, meaning, and implementation of the proposed revisions, as well as the Economic Impact Analysis and documents on which they are based. Mr. Kaufman may also testify regarding any alternative proposals submitted by other parties.
7. Blue Parish - Title V Operating Permits Unit Supervisor. Ms. Parish may testify regarding the netting, offset, and permitting-related issues for the proposed revisions.

The Division may also call the following potential witnesses:

8. Parties to this rulemaking, their representatives, or witnesses identified by those Parties.

### VI. IDENTIFICATION OF WRITTEN TESTIMONY

The Division does not, at this time, intend to submit any written testimony.

Respectfully submitted this 7<sup>th</sup> day of October, 2021.

By: /s/ Josh Korth  
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### CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing Prehearing Statement of the Colorado Department of Public Health and Environment, Air Pollution Control Division was served on the Parties listed below on October 7, 2021.

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*/s/ John Watson*

John Watson

# Maalaea M10 SCR

## Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency  
Air Economics Group  
Health and Environmental Impacts Division  
Office of Air Quality Planning and Standards  
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO<sub>x</sub> emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO<sub>x</sub> within a specific temperature range to produce N<sub>2</sub> and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#ccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NO<sub>x</sub> reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

### Instructions

**Step 1:** Please select on the *Data Inputs* tab and click on the *Reset Form* button. This will clear many of the input cells and reset others to default values.

**Step 2:** Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

**Step 3:** Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

**Step 4:** Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ( $Vol_{catalyst}$ ) or flue gas flow rate ( $Q_{flue\ gas}$ ), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

**Step 5:** Once all of the data fields are complete, select the *SCR Design Parameters* tab to see the calculated design parameters and the *Cost Estimate* tab to view the calculated cost data for the installation and operation of the SCR.

## Maalaea M10 SCR

	NOx (lb/MMBtu)	NOx (tons/year)	Annual heat input MMBtu/year	Fuel heating value (Btu/gal)	gal/year	gal/year (calculated)	Operating hours (hrs/yr)	Estimated annual MWhs	estimated days/year
M10	2.884	580.3	402,410	137169	2,933,686	2,933,680	5,336	66,698	222
M11	2.877	506.2	351,916	137169	2,565,572	2,565,565	4,678	58,471	195
M12	2.027	405.9	395,391	137169	2,882,514	2,882,510	5,291	66,143	220
M13	2.171	419.5	381,950	137169	2,784,528	2,784,521	4,944	61,803	206

# Maalaea M10 SCR

## Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?    
 What type of fuel does the unit burn?    
 Is the SCR for a new boiler or retrofit of an existing boiler?    
 Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?    
 What is the higher heating value (HHV) of the fuel?    
 What is the estimated annual MWh output?    
 Enter the net plant heat input rate (NPHR)    
 If the NPHR is not known, use the default NPHR value:   

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

  
 Plant Elevation

Not applicable to units burning fuel oil or natural gas   
 Type of coal burned:    
 Enter the sulfur content (%S) =    
 Not applicable to units burning fuel oil or natural gas   
 Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.   

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.38	11,243
Sub-Bituminous	0	0.41	9,823
Lignite	0	0.82	6,688

  
 Please click the calculate button to calculate weighted average values based on the data in the table above.   
 For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method.   
 Method 1   
 Method 2   
 Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates ( $t_{scr}$ )    
 Number of days the boiler operates ( $t_{boiler}$ )    
 Inlet NO<sub>x</sub> Emissions (NO<sub>x,i</sub>) to SCR    
 Outlet NO<sub>x</sub> Emissions (NO<sub>x,o</sub>) from SCR    
 Stoichiometric Ratio Factor (SRF)    
\*The SRF value of 1.05 is a default value. User should enter actual value, if known.   
 Estimated operating life of the catalyst ( $H_{catalyst}$ )    
 Estimated SCR equipment life    
\* For utility boilers, the typical equipment life of an SCR is at least 30 years.   
 Concentration of reagent as stored ( $C_{stored}$ )    
 Density of reagent as stored ( $\rho_{stored}$ )    
 Number of days reagent is stored ( $t_{stored}$ )    
\*The reagent concentration of 29% and density of 56 lb/cf are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.   
 Number of SCR reactor chambers ( $n_{scr}$ )    
 Number of catalyst layers ( $R_{catalyst}$ )    
 Number of empty catalyst layers ( $R_{empty}$ )    
 Ammonia Slip (Slip) provided by vendor    
 Volume of the catalyst layers (VOL<sub>catalyst</sub>) (Enter "UNK" if value is not known)    
 Flue gas flow rate (Q<sub>fluegas</sub>) (Enter "UNK" if value is not known)    
 Gas temperature at the SCR inlet (T)    
 Base case fuel gas volumetric flow rate factor (Q<sub>fuel</sub>)    

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft <sup>3</sup>
29.4% aqueous NH <sub>3</sub>	56 lbs/ft <sup>3</sup>

  
 Select the reagent used

Enter the cost data for the proposed SCR:

Desired dollar-year    
 CEPCI for 2021  Enter the CEPCI value for 2021  2016 CEPCI    
CEPCI = Chemical Engineering Plant Cost Index   
 Annual Interest Rate (i)    
 Reagent (Cost<sub>reagent</sub>)    
 Electricity (Cost<sub>elec</sub>)    
\*\$0.0361/kWh is a default value for electricity cost. User should enter actual value, if known.   
 Catalyst cost (CC<sub>catalyst</sub>)    
\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)   
\*\$27.00 is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.   
 Operator Labor Rate    
\* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.   
 Operator Hours/Day    
\* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.   
 Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =    
 Administrative Charges Factor (ACF) =

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$0.560/gallon 29% ammonia solution *ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 <a href="https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf">https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf</a>	
Electricity Cost (\$/kWh)	0.0361	U.S. Energy Information Administration, Electric Power Annual 2016, Table 8.4, Published December 2017. Available at: <a href="https://www.eia.gov/electricity/annual/pdf/epa.pdf">https://www.eia.gov/electricity/annual/pdf/epa.pdf</a> .	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	141,468	2016 fuel oil data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at <a href="http://www.eia.gov/electricity/data/eia923/">http://www.eia.gov/electricity/data/eia923/</a> .	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA), Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Office of Air and Radiation, May 2018. Available at: <a href="https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6">https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6</a> .	



# Maalaea M10 SCR

## SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate ( $Q_B$ ) =	$Bmw \times NPHR =$	138	MMBtu/hour
Maximum Annual MW Output (Bmw) =	$Bmw \times 8760 =$	109,500	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		36,600	MWhs
Heat Rate Factor (HRF) =	$NPHR/10 =$	1.10	
Total System Capacity Factor ( $CF_{total}$ ) =	$(Boutput/Bmw) \times (t_{scr}/t_{plant}) =$	0.334	fraction
Total operating time for the SCR ( $t_{op}$ ) =	$CF_{total} \times 8760 =$	2928	hours
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	89.9	percent
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	356.68	lb/hour
Total NO <sub>x</sub> removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	522.17	tons/year
NO <sub>x</sub> removal factor (NRF) =	$EF/80 =$	1.12	
Volumetric flue gas flow rate ( $q_{flue\ gas}$ ) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700) n_{scr} =$	63,681	acfm
Space velocity ( $V_{space}$ ) =	$q_{flue\ gas}/Vol_{catalyst} =$	57.94	/hour
Residence Time	$1/V_{space}$	0.02	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO <sub>2</sub> Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$	< 3	
Elevation Factor (ELEV) =	$14.7\ psia/P =$		
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	14.7	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

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Not applicable; factor applies only to coal-fired boilers

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflight systems.grc.nasa.gov/education/rocket/atmos.html>.

### Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(interest\ rate) \times (1 / ((1 + interest\ rate)^Y - 1))$ , where $Y = H_{catalyst} / (t_{SCR} \times 24\ hours)$ rounded to the nearest integer	0.1799	Fraction
Catalyst volume ( $Vol_{catalyst}$ ) =	$2.81 \times Q_B \times EF_{adj} \times Slip_{adj} \times NO_{x_{adj}} \times S_{adj} \times (T_{adj}/N_{scr})$	1,099.12	Cubic feet
Cross sectional area of the catalyst ( $A_{catalyst}$ ) =	$q_{flue\ gas} / (16ft/sec \times 60\ sec/min)$	66	ft <sup>2</sup>
Height of each catalyst layer ( $H_{layer}$ ) =	$(Vol_{catalyst} / (R_{layer} \times A_{catalyst})) + 1$ (rounded to next highest integer)	7	feet

### SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor ( $A_{SCR}$ ) =	$1.15 \times A_{catalyst}$	76	ft <sup>2</sup>
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	8.7	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	63	feet

### Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft <sup>3</sup>

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ( $m_{reagent}$ ) =	$(NO_{x_{in}} \times Q_B \times EF \times SRF \times MW_R) / MW_{NO_x} =$	139	lb/hour
Reagent Usage Rate ( $m_{sol}$ ) =	$m_{reagent} / Csol =$	478	lb/hour
	$(m_{sol} \times 7.4805) / Reagent\ Density =$	64	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24) / Reagent\ Density =$	21,500	gallons (storage needed to store a 14 day reagent supply rounded to)

### Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i \times (1 + i)^n / ((1 + i)^n - 1) =$ Where $n$ = Equipment Life and $i$ = Interest Rate	0.0824

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (CoalF \times HRF)^{0.43} =$ where $A$ = Bmw for utility boilers	72.93	kW

# Maalaea M10 SCR

## Cost Estimate

### Total Capital Investment (TCI)

#### TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEV \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEV \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEV \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEV \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEV \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEV \times RF$$

Total Capital Investment (TCI) =	\$4,083,532	in 2021 dollars
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### Annual Costs

#### Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$147,783 in 2021 dollars
Indirect Annual Costs (IDAC) =	\$338,326 in 2021 dollars
Total annual costs (TAC) = DAC + IDAC	\$486,110 in 2021 dollars

#### Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	$0.005 \times TCI =$	\$20,418 in 2021 dollars
Annual Reagent Cost =	$m_{SO_2} \times Cost_{reag} \times t_{op} =$	\$104,696 in 2021 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$7,709 in 2021 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	\$14,962 in 2021 dollars
Direct Annual Cost =		\$147,783 in 2021 dollars

#### Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$1,843 in 2021 dollars
Capital Recovery Costs (CR)=	$CRF \times TCI =$	\$336,483 in 2021 dollars
Indirect Annual Cost (IDAC) =	$AC + CR =$	\$338,326 in 2021 dollars

### Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$486,110 per year in 2021 dollars
NOx Removed =	522 tons/year
Cost Effectiveness =	\$931 per ton of NOx removed in 2021 dollars

# Maalaea M11 SCR

## Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency  
Air Economics Group  
Health and Environmental Impacts Division  
Office of Air Quality Planning and Standards  
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO<sub>x</sub> emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO<sub>x</sub> within a specific temperature range to produce N<sub>2</sub> and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#ccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NO<sub>x</sub> reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

### Instructions

**Step 1:** Please select on the *Data Inputs* tab and click on the *Reset Form* button. This will clear many of the input cells and reset others to default values.

**Step 2:** Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

**Step 3:** Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

**Step 4:** Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ( $Vol_{catalyst}$ ) or flue gas flow rate ( $Q_{flue\ gas}$ ), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

**Step 5:** Once all of the data fields are complete, select the *SCR Design Parameters* tab to see the calculated design parameters and the *Cost Estimate* tab to view the calculated cost data for the installation and operation of the SCR.

## Maalaea M11 SCR

	NOx (lb/MMBtu)	NOx (tons/year)	Annual heat input MMBtu/year	Fuel heating value (Btu/gal)	gal/year	gal/year (calculated)	Operating hours (hrs/yr)	Estimated annual MWhs	estimated days/year
M10	2.884	580.3	402,410	137169	2,933,686	2,933,680	5,336	66,698	222
M11	2.877	506.2	351,916	137169	2,565,572	2,565,565	4,678	58,471	195
M12	2.027	405.9	395,391	137169	2,882,514	2,882,510	5,291	66,143	220
M13	2.171	419.5	381,950	137169	2,784,528	2,784,521	4,944	61,803	206

# Maalaea M11 SCR

## Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?    
 What type of fuel does the unit burn?    
 Is the SCR for a new boiler or retrofit of an existing boiler?    
 Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?    
 What is the higher heating value (HHV) of the fuel?    
 What is the estimated annual MWh output?    
 Enter the net plant heat input rate (NPHR)    
 If the NPHR is not known, use the default NPHR value:   

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

  
 Plant Elevation

Not applicable to units burning fuel oil or natural gas   
 Type of coal burned:    
 Enter the sulfur content (%S) =    
 Not applicable to units burning fuel oil or natural gas   
 Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.   

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.38	11,243
Sub-Bituminous	0	0.41	8,823
Lignite	0	0.82	6,688

  
 Please click the calculate button to calculate weighted average values based on the data in the table above.   
 For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method.   
 Method 1   
 Method 2   
 Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates ( $t_{scr}$ )    
 Number of days the boiler operates ( $t_{boiler}$ )    
 Inlet NO<sub>x</sub> Emissions (NO<sub>x,i</sub>) to SCR    
 Outlet NO<sub>x</sub> Emissions (NO<sub>x,o</sub>) from SCR    
 Stoichiometric Ratio Factor (SRF)    
\*The SRF value of 1.05 is a default value. User should enter actual value, if known.   
 Estimated operating life of the catalyst ( $H_{catalyst}$ )    
 Estimated SCR equipment life    
\* For utility boilers, the typical equipment life of an SCR is at least 30 years.   
 Concentration of reagent as stored ( $C_{stored}$ )    
 Density of reagent as stored ( $\rho_{stored}$ )    
 Number of days reagent is stored ( $t_{stored}$ )    
\*The reagent concentration of 29% and density of 56 lb/cf are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.   
 Number of SCR reactor chambers ( $n_{scr}$ )    
 Number of catalyst layers ( $R_{catalyst}$ )    
 Number of empty catalyst layers ( $R_{empty}$ )    
 Ammonia Slip (Slip) provided by vendor    
 Volume of the catalyst layers (VOL<sub>catalyst</sub>) (Enter "UNKN" if value is not known)    
 Flue gas flow rate (Q<sub>fluegas</sub>) (Enter "UNKN" if value is not known)    
 Gas temperature at the SCR inlet (T)    
 Base case fuel gas volumetric flow rate factor (Q<sub>fuel</sub>)    

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft <sup>3</sup>
29.4% aqueous NH <sub>3</sub>	56 lbs/ft <sup>3</sup>

  
 Select the reagent used

Enter the cost data for the proposed SCR:

Desired dollar-year    
 CEPCI for 2021  Enter the CEPCI value for 2021  2016 CEPCI    
CEPCI = Chemical Engineering Plant Cost Index   
 Annual Interest Rate (i)    
 Reagent (Cost<sub>reagent</sub>)    
 Electricity (Cost<sub>elec</sub>)    
\*\$0.0361/kWh is a default value for electricity cost. User should enter actual value, if known.   
 Catalyst cost (CC<sub>catalyst</sub>)    
\*\$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.   
 Operator Labor Rate    
\* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.   
 Operator Hours/Day    
\* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.   
 Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =    
 Administrative Charges Factor (ACF) =

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$0.560/gallon 29% ammonia solution *ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf)	
Electricity Cost (\$/kWh)	0.0361	U.S. Energy Information Administration, Electric Power Annual 2016, Table 8.4, Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	141,468	2016 fuel oil data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA), Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Office of Air and Radiation, May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

# Maalaea M11 SCR

## SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q <sub>b</sub> ) =	Bmw x NPHR =	138	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	109,500	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		32,000	MWhs
Heat Rate Factor (HRF) =	NPHR/10 =	1.10	
Total System Capacity Factor (CF <sub>total</sub> ) =	(Boutput/Bmw)*(tscr/tplant) =	0.292	fraction
Total operating time for the SCR (t <sub>op</sub> ) =	CF <sub>total</sub> x 8760 =	2560	hours
NOx Removal Efficiency (EF) =	(NOx <sub>in</sub> - NOx <sub>out</sub> )/NOx <sub>in</sub> =	89.9	percent
NOx removed per hour =	NOx <sub>in</sub> x EF x Q <sub>b</sub> =	355.71	lb/hour
Total NO <sub>x</sub> removed per year =	(NOx <sub>in</sub> x EF x Q <sub>b</sub> x t <sub>op</sub> )/2000 =	455.31	tons/year
NO <sub>x</sub> removal factor (NRF) =	EF/80 =	1.12	
Volumetric flue gas flow rate (q <sub>flue gas</sub> ) =	Q <sub>fuel</sub> x QB x (460 + T)/(460 + 700)n <sub>scr</sub> =	63,681	acfm
Space velocity (V <sub>space</sub> ) =	q <sub>flue gas</sub> /Vol <sub>catalyst</sub> =	58.02	/hour
Residence Time	1/V <sub>space</sub>	0.02	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO <sub>2</sub> Emission rate =	(%S/100)x(64/32)*1x10 <sup>6</sup> /HHV =	< 3	
Elevation Factor (ELEV) =	14.7 psia/P =		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6] <sup>5.256</sup> x (1/144)* =	14.7	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

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Not applicable; factor applies only to coal-fired boilers

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflight systems.grc.nasa.gov/education/rocket/atmos.html>.

### Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)/(1+interest rate) <sup>Y</sup> - 1, where Y = H <sub>catalyst</sub> /(t <sub>SCR</sub> x 24 hours) rounded to the nearest integer	0.1799	Fraction
Catalyst volume (Vol <sub>catalyst</sub> ) =	2.81 x Q <sub>b</sub> x EF <sub>adj</sub> x Slip <sub>adj</sub> x NOx <sub>adj</sub> x S <sub>adj</sub> x (T <sub>adj</sub> /N <sub>scr</sub> )	1,097.50	Cubic feet
Cross sectional area of the catalyst (A <sub>catalyst</sub> ) =	q <sub>flue gas</sub> / (16ft/sec x 60 sec/min)	66	ft <sup>2</sup>
Height of each catalyst layer (H <sub>layer</sub> ) =	(Vol <sub>catalyst</sub> /(R <sub>layer</sub> x A <sub>catalyst</sub> )) + 1 (rounded to next highest integer)	7	feet

### SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A <sub>SCR</sub> ) =	1.15 x A <sub>catalyst</sub>	76	ft <sup>2</sup>
Reactor length and width dimensions for a square reactor =	(A <sub>SCR</sub> ) <sup>0.5</sup>	8.7	feet
Reactor height =	(R <sub>layer</sub> + R <sub>empty</sub> ) x (7ft + H <sub>layer</sub> ) + 9ft	63	feet

### Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft <sup>3</sup>

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m <sub>reagent</sub> ) =	(NOx <sub>in</sub> x Q <sub>b</sub> x EF x SRF x MW <sub>R</sub> )/MW <sub>NOx</sub> =	138	lb/hour
Reagent Usage Rate (m <sub>sol</sub> ) =	m <sub>reagent</sub> /Csol =	477	lb/hour
	(m <sub>sol</sub> x 7.4805)/Reagent Density	64	gal/hour
Estimated tank volume for reagent storage =	(m <sub>sol</sub> x 7.4805 x t <sub>storage</sub> x 24)/Reagent Density =	21,400	gallons (storage needed to store a 14 day reagent supply rounded)

### Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+i) <sup>n</sup> / ((1+i) <sup>n</sup> - 1) = Where n = Equipment Life and i = Interest Rate	0.0824

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF) <sup>0.43</sup> = where A = Bmw for utility boilers	72.93	kW

# Maalaea M11 SCR

## Cost Estimate

### Total Capital Investment (TCI)

#### TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEV F \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEV F \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEV F \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEV F \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEV F \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEV F \times RF$$

Total Capital Investment (TCI) =	\$4,083,532	in 2021 dollars
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### Annual Costs

#### Total Annual Cost (TAC)

$$TAC = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$133,387 in 2021 dollars
Indirect Annual Costs (IDAC) =	\$338,132 in 2021 dollars
<b>Total annual costs (TAC) = DAC + IDAC</b>	<b>\$471,519 in 2021 dollars</b>

#### Direct Annual Costs (DAC)

$$DAC = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Catalyst Cost})$$

Annual Maintenance Cost =	$0.005 \times TCI =$	\$20,418 in 2021 dollars
Annual Reagent Cost =	$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$	\$91,290 in 2021 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{elect} \times t_{op} =$	\$6,740 in 2021 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	\$14,940 in 2021 dollars
<b>Direct Annual Cost =</b>		<b>\$133,387 in 2021 dollars</b>

#### Indirect Annual Cost (IDAC)

$$IDAC = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$1,649 in 2021 dollars
Capital Recovery Costs (CR) =	$CRF \times TCI =$	\$336,483 in 2021 dollars
<b>Indirect Annual Cost (IDAC) =</b>	<b>AC + CR =</b>	<b>\$338,132 in 2021 dollars</b>

### Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$471,519 per year in 2021 dollars
NOx Removed =	455 tons/year
<b>Cost Effectiveness =</b>	<b>\$1,036 per ton of NOx removed in 2021 dollars</b>

# Maalaea M12 SCR

## Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency  
Air Economics Group  
Health and Environmental Impacts Division  
Office of Air Quality Planning and Standards  
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO<sub>x</sub> emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO<sub>x</sub> within a specific temperature range to produce N<sub>2</sub> and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#ccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NO<sub>x</sub> reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

### Instructions

**Step 1:** Please select on the *Data Inputs* tab and click on the *Reset Form* button. This will clear many of the input cells and reset others to default values.

**Step 2:** Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

**Step 3:** Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

**Step 4:** Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ( $Vol_{catalyst}$ ) or flue gas flow rate ( $Q_{flue\ gas}$ ), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

**Step 5:** Once all of the data fields are complete, select the *SCR Design Parameters* tab to see the calculated design parameters and the *Cost Estimate* tab to view the calculated cost data for the installation and operation of the SCR.



## Maalaea M12 SCR

	NOx (lb/MMBtu)	NOx (tons/year)	Annual heat input MMBtu/year	Fuel heating value (Btu/gal)	gal/year	gal/year (calculated)	Operating hours (hrs/yr)	Estimated annual MWhs	estimated days/year
M10	2.884	580.3	402,410	137,169	2,933,686	2,933,680	5,336	66,698	222
M11	2.877	506.2	351,916	137,169	2,565,572	2,565,565	4,678	58,471	195
M12	2.027	405.9	395,391	137,169	2,882,514	2,882,510	5,291	66,143	220
M13	2.171	419.5	381,950	137,169	2,784,528	2,784,521	4,944	61,803	206

# Maalaea M12 SCR

## Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?    
 What type of fuel does the unit burn?    
 Is the SCR for a new boiler or retrofit of an existing boiler?    
 Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?    
 What is the higher heating value (HHV) of the fuel?    
 What is the estimated annual MWh output?    
 Enter the net plant heat input rate (NPHR)    
 If the NPHR is not known, use the default NPHR value:   

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

  
 Plant Elevation

Not applicable to units burning fuel oil or natural gas   
 Type of coal burned:    
 Enter the sulfur content (%S) =    
 Not applicable to units burning fuel oil or natural gas   
 Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.   

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.38	11,243
Sub-Bituminous	0	0.41	8,823
Lignite	0	0.82	6,688

  
 Please click the calculate button to calculate weighted average values based on the data in the table above.   
 For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method.   
 Method 1   
 Method 2   
 Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates ( $t_{scr}$ )    
 Number of days the boiler operates ( $t_{boiler}$ )    
 Inlet NO<sub>x</sub> Emissions (NO<sub>x,i</sub>) to SCR    
 Outlet NO<sub>x</sub> Emissions (NO<sub>x,o</sub>) from SCR    
 Stoichiometric Ratio Factor (SRF)    
\*The SRF value of 1.05 is a default value. User should enter actual value, if known.   
 Estimated operating life of the catalyst ( $H_{catalyst}$ )    
 Estimated SCR equipment life    
\* For utility boilers, the typical equipment life of an SCR is at least 30 years.   
 Concentration of reagent as stored ( $C_{stored}$ )    
 Density of reagent as stored ( $\rho_{stored}$ )    
 Number of days reagent is stored ( $t_{stored}$ )    
\*The reagent concentration of 29% and density of 56 lb/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.   
 Number of SCR reactor chambers ( $n_{scr}$ )    
 Number of catalyst layers ( $R_{catalyst}$ )    
 Number of empty catalyst layers ( $R_{empty}$ )    
 Ammonia Slip (Slip) provided by vendor    
 Volume of the catalyst layers (VOL<sub>catalyst</sub>) (Enter "UNLK" if value is not known)    
 Flue gas flow rate (Q<sub>fluegas</sub>) (Enter "UNLK" if value is not known)    
 Gas temperature at the SCR inlet (T)    
 Base case fuel gas volumetric flow rate factor (Q<sub>fuel</sub>)    

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft <sup>3</sup>
29.4% aqueous NH <sub>3</sub>	56 lbs/ft <sup>3</sup>

  
 Select the reagent used

Enter the cost data for the proposed SCR:

Desired dollar-year    
 CEPCI for 2021  Enter the CEPCI value for 2021  2016 CEPCI    
CEPCI = Chemical Engineering Plant Cost Index   
 Annual Interest Rate (i)    
 Reagent (Cost<sub>reagent</sub>)    
 Electricity (Cost<sub>elec</sub>)    
\*\$0.0361/kWh is a default value for electricity cost. User should enter actual value, if known.   
 Catalyst cost (CC<sub>catalyst</sub>)    
\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)   
 \*\$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.   
 Operator Labor Rate    
\* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.   
 Operator Hours/Day    
\* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.   
 Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =    
 Administrative Charges Factor (ACF) =

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$0.560/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf)	
Electricity Cost (\$/kWh)	0.0361	U.S. Energy Information Administration, Electric Power Annual 2016, Table 8.4, Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	141,468	2016 fuel oil data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA), Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Office of Air and Radiation, May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

# Maalaea M12 SCR

## SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate ( $Q_b$ ) =	$Bmw \times NPHR =$	138	MMBtu/hour
Maximum Annual MW Output (Bmw) =	$Bmw \times 8760 =$	109,500	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		36,300	MWhs
Heat Rate Factor (HRF) =	$NPHR/10 =$	1.10	
Total System Capacity Factor ( $CF_{total}$ ) =	$(Boutput/Bmw) \times (t_{scr}/t_{plant}) =$	0.332	fraction
Total operating time for the SCR ( $t_{top}$ ) =	$CF_{total} \times 8760 =$	2904	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in} =$	90.1	percent
NOx removed per hour =	$NOx_{in} \times EF \times Q_b =$	251.21	lb/hour
Total NO <sub>x</sub> removed per year =	$(NOx_{in} \times EF \times Q_b \times t_{op})/2000 =$	364.76	tons/year
NO <sub>x</sub> removal factor (NRF) =	$EF/80 =$	1.13	
Volumetric flue gas flow rate ( $q_{flue\ gas}$ ) =	$Q_{fuel} \times QB \times (460 + T)/(460 + 700)n_{scr} =$	63,681	acfm
Space velocity ( $V_{space}$ ) =	$q_{flue\ gas}/Vol_{catalyst} =$	68.43	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO <sub>2</sub> Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$	< 3	
Elevation Factor (ELEV) =	$14.7\ psia/P =$		
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7) / 518.6]^{5.256} \times (1/144) =$	14.7	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

405 tpy uncontrolled

Not applicable; factor applies only to coal-fired boilers

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflight systems.grc.nasa.gov/education/rocket/atmos.html>.

### Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(interest\ rate) / (1 + (1 + interest\ rate)^Y - 1)$ , where $Y = H_{catalyst} / (t_{SCR} \times 24\ hours)$ rounded to the nearest integer	0.1799	Fraction
Catalyst volume ( $Vol_{catalyst}$ ) =	$2.81 \times Q_b \times EF_{adj} \times Slip_{adj} \times NOx_{adj} \times S_{adj} \times (T_{adj}/N_{scr})$	930.62	Cubic feet
Cross sectional area of the catalyst ( $A_{catalyst}$ ) =	$q_{flue\ gas} / (16ft/sec \times 60\ sec/min)$	66	ft <sup>2</sup>
Height of each catalyst layer ( $H_{layer}$ ) =	$(Vol_{catalyst} / (R_{layer} \times A_{catalyst})) + 1$ (rounded to next highest integer)	6	feet

### SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor ( $A_{SCR}$ ) =	$1.15 \times A_{catalyst}$	76	ft <sup>2</sup>
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	8.7	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + H_{layer}) + 9ft$	60	feet

### Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft <sup>3</sup>

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ( $m_{reagent}$ ) =	$(NOx_{in} \times Q_b \times EF \times SRF \times MW_R) / MW_{NOx} =$	98	lb/hour
Reagent Usage Rate ( $m_{sol}$ ) =	$m_{reagent} / Csol =$	337	lb/hour
	$(m_{sol} \times 7.4805) / Reagent\ Density$	45	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24) / Reagent\ Density =$	15,200	gallons (storage needed to store a 14 day reagent supply rounded)

### Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n / ((1+i)^n - 1) =$ Where n = Equipment Life and i = Interest Rate	0.0824

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (CoalF \times HRF)^{0.43} =$ where A = Bmw for utility boilers	72.93	kW

# Maalaea M12 SCR

## Cost Estimate

### Total Capital Investment (TCI)

#### TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:	$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEV \times RF$
For Oil and Natural Gas-Fired Utility Boilers >500 MW:	$TCI = 62,680 \times B_{MW} \times ELEV \times RF$
For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :	$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEV \times RF$
For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :	$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEV \times RF$
For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:	$TCI = 5,700 \times Q_B \times ELEV \times RF$
For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:	$TCI = 7,640 \times Q_B \times ELEV \times RF$

Total Capital Investment (TCI) =	\$4,083,532	in 2021 dollars
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### Annual Costs

#### Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$113,866 in 2021 dollars
Indirect Annual Costs (IDAC) =	\$338,312 in 2021 dollars
<b>Total annual costs (TAC) = DAC + IDAC</b>	<b>\$452,178 in 2021 dollars</b>

#### Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	\$20,418 in 2021 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op} =$	\$73,134 in 2021 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$7,645 in 2021 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	\$12,668 in 2021 dollars
<b>Direct Annual Cost =</b>		<b>\$113,866 in 2021 dollars</b>

#### Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	\$1,829 in 2021 dollars
Capital Recovery Costs (CR) =	CRF x TCI =	\$336,483 in 2021 dollars
<b>Indirect Annual Cost (IDAC) =</b>	<b>AC + CR =</b>	<b>\$338,312 in 2021 dollars</b>

### Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$452,178 per year in 2021 dollars
NOx Removed =	<b>365 tons/year</b>
<b>Cost Effectiveness =</b>	<b>\$1,240 per ton of NOx removed in 2021 dollars</b>

# Maalaea M13 SCR

## Air Pollution Control Cost Estimation Spreadsheet For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency  
Air Economics Group  
Health and Environmental Impacts Division  
Office of Air Quality Planning and Standards  
(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO<sub>x</sub> emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO<sub>x</sub> within a specific temperature range to produce N<sub>2</sub> and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: <http://www3.epa.gov/ttn/catc/products.html#ccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

- (1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
- (3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
- (4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NO<sub>x</sub> reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at <http://www.epa.gov/airmarkets/power-sector-modeling>. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

### Instructions

**Step 1:** Please select on the *Data Inputs* tab and click on the *Reset Form* button. This will clear many of the input cells and reset others to default values.

**Step 2:** Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

**Step 3:** Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

**Step 4:** Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ( $Vol_{catalyst}$ ) or flue gas flow rate ( $Q_{flue\ gas}$ ), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

**Step 5:** Once all of the data fields are complete, select the *SCR Design Parameters* tab to see the calculated design parameters and the *Cost Estimate* tab to view the calculated cost data for the installation and operation of the SCR.

## Maalaea M13 SCR

	NOx (lb/MMBtu)	NOx (tons/year)	Annual heat input MMBtu/year	Fuel heating value (Btu/gal)	gal/year	gal/year (calculated)	Operating hours (hrs/yr)	Estimated annual MWhs	estimated days/year
M10	2.884	580.3	402,410	137,169	2,933,686	2,933,680	5,336	66,698	222
M11	2.877	506.2	351,916	137,169	2,565,572	2,565,565	4,678	58,471	195
M12	2.027	405.9	395,391	137,169	2,882,514	2,882,510	5,291	66,143	220
M13	2.171	419.5	381,950	137,169	2,784,528	2,784,521	4,944	61,803	206

# Maalaea M13 SCR

## Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?    
 What type of fuel does the unit burn?    
 Is the SCR for a new boiler or retrofit of an existing boiler?    
 Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?    
 What is the higher heating value (HHV) of the fuel?    
 What is the estimated annual MWh output?    
 Enter the net plant heat input rate (NPHR)    
 If the NPHR is not known, use the default NPHR value:   

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

  
 Plant Elevation

Not applicable to units burning fuel oil or natural gas   
 Type of coal burned:    
 Enter the sulfur content (%S) =    
 Not applicable to units burning fuel oil or natural gas   
 Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.   

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.38	11,243
Sub-Bituminous	0	0.41	8,823
Lignite	0	0.82	6,688

  
 Please click the calculate button to calculate weighted average values based on the data in the table above.   
 For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method.   
 Method 1   
 Method 2   
 Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates ( $t_{scr}$ )    
 Number of days the boiler operates ( $t_{boiler}$ )    
 Inlet NO<sub>x</sub> Emissions (NO<sub>x,i</sub>) to SCR    
 Outlet NO<sub>x</sub> Emissions (NO<sub>x,o</sub>) from SCR    
 Stoichiometric Ratio Factor (SRF)    
\*The SRF value of 1.05 is a default value. User should enter actual value, if known.   
 Estimated operating life of the catalyst ( $H_{catalyst}$ )    
 Estimated SCR equipment life    
\* For utility boilers, the typical equipment life of an SCR is at least 30 years.   
 Concentration of reagent as stored ( $C_{stored}$ )    
 Density of reagent as stored ( $\rho_{stored}$ )    
 Number of days reagent is stored ( $t_{stored}$ )    
\*The reagent concentration of 29% and density of 56 lb/cf are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.   
 Number of SCR reactor chambers ( $n_{scr}$ )    
 Number of catalyst layers ( $R_{catalyst}$ )    
 Number of empty catalyst layers ( $R_{empty}$ )    
 Ammonia Slip (Slip) provided by vendor    
 Volume of the catalyst layers (VOL<sub>catalyst</sub>) (Enter "UNKN" if value is not known)    
 Flue gas flow rate (Q<sub>fluegas</sub>) (Enter "UNKN" if value is not known)    
 Gas temperature at the SCR inlet (T)    
 Base case fuel gas volumetric flow rate factor (Q<sub>fuel</sub>)    

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft <sup>3</sup>
29.4% aqueous NH <sub>3</sub>	56 lbs/ft <sup>3</sup>

  
 Select the reagent used

Enter the cost data for the proposed SCR:

Desired dollar-year    
 CEPCI for 2021  Enter the CEPCI value for 2021  2016 CEPCI    
CEPCI = Chemical Engineering Plant Cost Index   
 Annual Interest Rate (i)    
 Reagent (Cost<sub>reagent</sub>)    
 Electricity (Cost<sub>elec</sub>)    
\*\$0.0361/kWh is a default value for electricity cost. User should enter actual value, if known.   
 Catalyst cost (CC<sub>reagent</sub>)    
\*\$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.   
 Operator Labor Rate    
\* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.   
 Operator Hours/Day    
\* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.   
 Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =    
 Administrative Charges Factor (ACF) =

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$0.560/gallon 29% ammonia solution *ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf)	
Electricity Cost (\$/kWh)	0.0361	U.S. Energy Information Administration, Electric Power Annual 2016, Table 8.4, Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	141,468	2016 fuel oil data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA), Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Office of Air and Radiation, May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

# Maalaea M13 SCR

## SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate ( $Q_b$ ) =	$Bmw \times NPHR =$	138	MMBtu/hour
Maximum Annual MW Output (Bmw) =	$Bmw \times 8760 =$	109,500	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		35,000	MWhs
Heat Rate Factor (HRF) =	$NPHR/10 =$	1.10	
Total System Capacity Factor ( $CF_{total}$ ) =	$(Boutput/Bmw) \times (t_{scr}/t_{plant}) =$	0.320	fraction
Total operating time for the SCR ( $t_{top}$ ) =	$CF_{total} \times 8760 =$	2800	hours
NOx Removal Efficiency (EF) =	$(NO_{x,in} - NO_{x,out})/NO_{x,in} =$	90.3	percent
NOx removed per hour =	$NO_{x,in} \times EF \times Q_b =$	269.64	lb/hour
Total NO <sub>x</sub> removed per year =	$(NO_{x,in} \times EF \times Q_b \times t_{op})/2000 =$	377.49	tons/year
NO <sub>x</sub> removal factor (NRF) =	$EF/80 =$	1.13	
Volumetric flue gas flow rate ( $q_{flue\ gas}$ ) =	$Q_{fuel} \times QB \times (460 + T)/(460 + 700)n_{scr} =$	63,681	acfm
Space velocity ( $V_{space}$ ) =	$q_{flue\ gas}/Vol_{catalyst} =$	66.28	/hour
Residence Time	$1/V_{space}$	0.02	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO <sub>2</sub> Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$	< 3	
Elevation Factor (ELEV) =	$14.7\ psia/P =$		
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144) \times =$	14.7	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.00	

418 tpy uncontrolled

Not applicable; factor applies only to coal-fired boilers

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

\* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflight systems.grc.nasa.gov/education/rocket/atmos.html>.

### Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate}) / (1 + (\text{interest rate})^Y - 1)$ , where $Y = H_{catalyst} / (t_{SCR} \times 24 \text{ hours})$ rounded to the nearest integer	0.1799	Fraction
Catalyst volume ( $Vol_{catalyst}$ ) =	$2.81 \times Q_b \times EF_{adj} \times Slip_{adj} \times NO_{x,adj} \times S_{adj} \times (T_{adj}/N_{scr})$	960.82	Cubic feet
Cross sectional area of the catalyst ( $A_{catalyst}$ ) =	$q_{flue\ gas} / (16\text{ft}/\text{sec} \times 60\ \text{sec}/\text{min})$	66	ft <sup>2</sup>
Height of each catalyst layer ( $H_{layer}$ ) =	$(Vol_{catalyst} / (R_{layer} \times A_{catalyst})) + 1$ (rounded to next highest integer)	6	feet

### SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor ( $A_{SCR}$ ) =	$1.15 \times A_{catalyst}$	76	ft <sup>2</sup>
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	8.7	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7\text{ft} + H_{layer}) + 9\text{ft}$	60	feet

### Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/ft <sup>3</sup>

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ( $m_{reagent}$ ) =	$(NO_{x,in} \times Q_b \times EF \times SRF \times MW_R) / MW_{NOx} =$	105	lb/hour
Reagent Usage Rate ( $m_{sol}$ ) =	$m_{reagent} / Cs_{sol} =$	361	lb/hour
	$(m_{sol} \times 7.4805) / \text{Reagent Density}$	48	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24) / \text{Reagent Density} =$	16,300	gallons (storage needed to store a 14 day reagent supply rounded)

### Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n / ((1+i)^n - 1) =$ Where n = Equipment Life and i = Interest Rate	0.0824

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where A = Bmw for utility boilers	72.93	kW



# Maalaea M13 SCR

## Cost Estimate

### Total Capital Investment (TCI)

#### TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEV F \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEV F \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEV F \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEV F \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEV F \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEV F \times RF$$

Total Capital Investment (TCI) =	\$4,083,532	in 2021 dollars
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### Annual Costs

#### Total Annual Cost (TAC)

$$TAC = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$116,556 in 2021 dollars
Indirect Annual Costs (IDAC) =	\$338,211 in 2021 dollars
<b>Total annual costs (TAC) = DAC + IDAC</b>	<b>\$454,767 in 2021 dollars</b>

#### Direct Annual Costs (DAC)

$$DAC = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Catalyst Cost})$$

Annual Maintenance Cost =	$0.005 \times TCI =$	\$20,418 in 2021 dollars
Annual Reagent Cost =	$m_{sol} \times \text{Cost}_{reag} \times t_{op} =$	\$75,687 in 2021 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{elect} \times t_{op} =$	\$7,372 in 2021 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	\$13,079 in 2021 dollars
<b>Direct Annual Cost =</b>		<b>\$116,556 in 2021 dollars</b>

#### Indirect Annual Cost (IDAC)

$$IDAC = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$1,728 in 2021 dollars
Capital Recovery Costs (CR) =	$CRF \times TCI =$	\$336,483 in 2021 dollars
<b>Indirect Annual Cost (IDAC) =</b>	<b>AC + CR =</b>	<b>\$338,211 in 2021 dollars</b>

### Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$454,767 per year in 2021 dollars
NOx Removed =	<b>377</b> tons/year
<b>Cost Effectiveness =</b>	<b>\$1,205</b> per ton of NOx removed in 2021 dollars

# DOH-CAB Responses to Comments

**SUMMARY OF COMMENTS RECEIVED  
ON HAWAII'S DRAFT REGIONAL HAZE STATE IMPLEMENTATION PLAN (RH-SIP)  
FOR THE SECOND IMPLEMENTATION PERIOD (2018-2028) &  
DRAFT AIR PERMITS TO INCORPORATE REGIONAL HAZE CONTROL MEASURES  
(Docket No. 19-CA-PA-08, Draft RH-SIP)  
(Docket No. 19-CA-PA-09, Draft Permit Amendments)**

**I. OVERVIEW**

Pursuant to 40 Code of Federal Regulations (CFR) §51.102, Hawaii Revised Statutes Chapter 342B-13, and Hawaii Administrative Rules (HAR), Chapter 11-60.1, 30-day public comment periods were administered to consider the subject draft RH-SIP and significant modifications to covered source permits (CSPs) for three electric plants subject to regional haze emission reductions. The public comment period was held from June 24, 2022, to July 24, 2022, in order to receive comments on the draft RH-SIP. As to the draft permits, the public comment period was from July 1, 2022, to July 30, 2022. Permits were amended to incorporate regional haze control measures for the following facilities:

Hawaiian Electric Companies

- 1) Hawaii Electric Light Company, Inc. (Hawaii Electric Light), CSP No. 0234-01-C
- 2) Hawaii Electric Light Company, Inc. (Hawaii Electric Light), CSP No. 0235-01-C
- 3) Maui Electric Company, Ltd. (Maui Electric), CSP No. 0232-01-C

The Department of Health Clean Air Branch (DOH-CAB) received comments on the draft RH-SIP from three (3) commentors. Comments and DOH-CAB's responses are addressed below in SECTION II, WRITTEN COMMENTS AND RESPONSES (6-24-2022 to 7-24-2022 Comment Period for Draft RH-SIP). Comments were received from the following commenters:

Comments on Draft RH-SIP	
Commenter	Date Received
United States Department of Interior	July 18, 2022, Letter
Hawaiian Electric	July 22, 2022, Letter
National Parks Conservation Association & The Coalition to Protect America's National Parks	July 24, 2022, Letter with Twelve (12) Exhibits.

The DOH-CAB received comments on the draft permit amendments from one (1) commentor. Comments and DOH-CAB's response to the comments are addressed in SECTION III, WRITTEN COMMENTS AND RESPONSES (7-1-2022 to 7-30-2022 Comment Period for Draft Permit Amendments). Comments were received from the following commenter:

Comments on Draft Permit Amendments	
Commenter	Date Received
Hawaiian Electric	July 29, 2022, Letter

The public notice announcements indicated that if requested a virtual public hearing would be held on Tuesday, August 2, 2022, at 9:00 am Hawaii Time. No request for a hearing was made as a result of the public notice announcements and no hearing was held.

On August 5, 2022, DOH-CAB received a comment from EPA on the draft permit amendment for Puna Generating Station (CSP No. 0235-01-C). The Comment and DOH-CAB's response are addressed in SECTION IV, WRITTEN COMMENT AND RESPONSE (6-24-2022 to 8-8-2022 EPA Review Period, EPA Comment Received on 8-5-2022).

## II. WRITTEN COMMENTS AND RESPONSES (6-24-2022 to 7-24-2022 Comment Period for Draft RH-SIP)

### A. United States Department of Interior:

The National Park Service (NPS) supports the emissions reduction measures DOH-CAB has identified in the SIP. These include the commitment to federally enforceable retirements of boilers at two facilities, and a requirement to switch to a cleaner fuel at a third. The NPS understands that decisions on potential controls for two facilities, the Maalaea Generating Station on Maui and the Mauna Loa Macadamia Nut Corporation Plant on Hawaii, will be addressed in an upcoming SIP revision.

The NPS looks forward to reviewing supplemental SIP materials when they become available and will consider providing additional feedback on these two facilities at that time.

#### Response to Comment A:

We appreciate the NPS providing us the opportunity for early engagement and federal land manager (FLM) consultation during the development of our RH-SIP.

DOH-CAB is committed to reducing haze-causing pollution and addressing regional haze in our national parks. We look forward to continuing to work together and receiving your feedback on our supplemental SIP materials as they are completed.

### B. Hawaiian Electric:

#### Comment 1:

#### Elimination of the Oahu sources from consideration is appropriate

Elimination of the Oahu sources from consideration is appropriate. Hawaiian Electric agrees with the DOH's determination that sources on Oahu are sufficiently distant from the two national parks, taking into account in particular prevailing winds that will virtually never cause their emissions to impair visibility in Hawaii's distant Class I areas. Based on these factors among others, Hawaiian Electric believes that the DOH is correct in concluding that controls on Oahu sources are not reasonable for RHR purposes. This conclusion is also consistent with the DOH and EPA's determination during the first decadal review.

#### Response to Comment B.1:

The weighted emission potential/area of influence (WEP/AOI) analysis showed that sources nearby the Class I areas had the greatest potential to impair visibility in Hawaii's national parks. The WEP/AOI analysis for Kalaeloa Partners L.P., Kahe, and Waiau power plants on the island of Oahu, initially screened with Q/d, did not suggest that these sources have a high potential to impair visibility.

A supplemental analysis found that winds with the necessary direction, magnitude, and duration to blow emissions from the Kalaeloa Partners L.P., Kahe, and Waiau power plants on Oahu toward, and reach Hawaii's Class I areas are extremely rare. Therefore, Kalaeloa Partners L.P., Kahe, and Waiau power plants on Oahu were excluded from requiring controls in this second regional haze planning period.

Comment 2:

Additional Nitrogen Oxide (NO<sub>x</sub>) controls are costly and have questionable benefit

Hawaiian Electric agrees with DOH's statements in the draft SIP that NO<sub>x</sub> is not a significant contributor to haze: a) Nitrate haze formation is primarily a cold weather phenomenon and is very low in Hawaii given its warm year-round conditions; b) This is also supported by the very low nitrate haze impacts shown by Hawaii's IMPROVE data.

However, in contrast to the above-noted statements, the DOH has imposed NO<sub>x</sub> controls and has also indicated in the draft SIP that it is continuing to review certain sources at Maalaea for possible additional NO<sub>x</sub> controls in response to the NPS review of potential costs based on an analysis using non-applicable equations in EPA's Control Cost Manual. Because, as the DOH itself admits in the draft SIP, NO<sub>x</sub> is not a significant contributor to haze and Hawaiian Electric previously demonstrated that NO<sub>x</sub> controls are not necessary or effective for visibility improvement in Hawaii, Hawaiian Electric does not agree that additional NO<sub>x</sub> controls are necessary particularly at Maalaea on Maui which is typically downwind of the Class I areas relative to the prevailing winds.

The DOH in the draft SIP has indicated that the data submitted for Maalaea are incomplete and that a vendor quote would be useful. Despite DOH's comments, a sufficient vendor site-specific analysis was provided on June 1, 2022, that should be sufficient for Maalaea and no further controls should be required.

In addition to the fact that it is unclear whether any measurable visibility benefit would be gained by additional NO<sub>x</sub> controls, the DOH has underestimated the costs of controls for Hawaiian Electric throughout the draft SIP which in turn makes it appear that many of those controls, including the possible additional NO<sub>x</sub> controls for Maalaea, are reasonable because they fall at or below the \$5,800 per ton threshold for implementation.

Response to Comment B.2:

DOH-CAB does not state specifically in the draft RH-SIP that NO<sub>x</sub> is an insignificant contributor to haze. The DOH-CAB stated that the potential to form haze from NO<sub>x</sub> is considered low and the IMPROVE data for both national parks indicate an impact from nitrates which is much lower than that at many monitors in other Class I areas throughout the country.

Although it was indicated that nitrate impacts were considered low in Hawaii given its warm year-round conditions, data from the NPS shows that temperatures in Haleakala National Park can vary widely from 80 degrees Fahrenheit (F) to 30 degrees F and at the Mauna Loa summit of Hawaii Volcanoes National Park, winter temperatures and snow are a possibility during any season.<sup>1,2</sup>

EPA guidance also notes that because regional haze results from a multitude of sources over a broad geographic area, progress may require addressing many relatively small contributions to impairment. Thus, a measure may be necessary for reasonable progress even if that measure in isolation does not result in perceptible visibility impairment.

<sup>1</sup> [Weather - Haleakalā National Park \(U.S. National Park Service\) \(nps.gov\)](https://www.nps.gov/haleakala/learn/management/management-planning.htm)

<sup>2</sup> [Weather and Climate - Hawai'i Volcanoes National Park \(U.S. National Park Service\) \(nps.gov\)](https://www.nps.gov/hawaii/learn/management/management-planning.htm)

The WEP/AOI analysis to screen sources for the four-factor analysis determined that the Kahului and Maalaea Generating Stations were facilities with the highest potential to contribute to visibility impairment from ammonium nitrates at Haleakala National Park. The analysis found that the Kanoeleuha-Hill and Puna Generating stations were among the three highest ranked facilities for their potential to impair visibility from ammonium nitrates at Hawaii Volcanoes National Park.

The results of the four-factor analyses found that a fuel switch and NO<sub>x</sub> controls are required for boilers at the Kahului and Kanoelehua-Hill Generating Stations and that NO<sub>x</sub> controls are required for diesel engine generators at the Maalaea Generating Station. Hawaiian Electric agreed to an enforceable shut down of the boilers instead of implementing regional haze control measures selected in the four-factor analyses for the Kahului and Kanoelehua-Hill Generating Stations. Potential NO<sub>x</sub> controls for the Maalaea Generating Station will be addressed in a SIP revision.

Comment 3:

DOH estimation of costs of controls are understated

The DOH has underestimated the costs of control measures in several respects, including with respect to the interest rate applied to the cost of capital and construction multipliers.

Hawaiian Electric's June 16, 2021, letter presented justifications for the relevant interest rate and a Hawai'i construction cost multiplier used in the four-factor analysis; yet DOH did not fully adopt these adjustments, which results in an underestimation of the true cost of controls. The use of the lower costs is exacerbated by the fact that in several instances the DOH has approved controls even though the estimated costs exceeded the \$5,800 dollar threshold because DOH asserted that the costs were sufficiently close to the threshold.

Hawaiian Electric disagreed with the DOH's initial use of the prime interest rate of 3.25% in its economic analysis as the cost of capital in annualizing capital costs. As explained in Hawaiian Electric's letter dated June 16, 2021, Hawaiian Electric's true cost of capital is greater than 7% and is documented in proceedings with the State of Hawaii Public Utilities Commission (PUC). Use of an artificially low interest rate in DOH's calculations makes controls such as selective catalytic reduction (SCR) that require high capital expenses seem more economically reasonable than they truly are. In an apparent response to Hawaiian Electric's comments, the DOH adjusted their interest rate assumption to 6.56% for Hawai'i Island sources and 5.31% for Maui sources. However, these values are still lower than Hawaiian Electric's true cost of debt which in 2021 was greater than 7% and would likely be even higher today due to inflation. Since Hawaiian Electric's firm-specific interest rate is fully documented before a state regulatory agency such as the PUC, it is much more appropriate for use when annualizing the capital costs of potential expenditures than the rate generated by DOH. Hawaiian Electric noted that the 7% rate was suggested by KPLP in their four factor report as well, see Appendix D.

Response to Comment B.3:

It is important to consider that the control cost threshold of \$5,800/ton is a guideline for evaluating cost effective controls and is not considered a definitive line. Control measures that are above the control cost threshold may still be considered reasonable.

For cost multiplier concerns, air pollution control cost estimation spreadsheets in EPA's Control Cost Manual (CCM) do not account for Maui and Hawaii Island construction cost multipliers. However, spreadsheets do have inputs for retrofit factors. As stated in DOH-CAB's November 9, 2021, letter to Hawaiian Electric, retrofit factors pertain to the difficulty of installing a piece of hardware, regardless of location. While it is appropriate to take into consideration the higher

costs of transporting equipment and supplies, as well as higher labor rates, in unique areas like Hawaii and Alaska, those higher costs must be itemized, justified, and documented.

Concerning interest rates, we again refer you to DOH-CAB's response letter dated November 9, 2021, which explains the foundation of how we arrived at your firm-specific nominal interest rate. Your "Rate Making ROE" published on Hawaiian Electric's website at: <https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics/financial> is based on the PUC methodology and used for determining whether there will be any sharing of actual earnings. The "Book ROE" (also published at the same website) is more appropriately used because it is a measure of a company's actual profit or "return" on shareholders' investments. The "Book ROE" represents the opportunity cost or the return on investment that is lost by investors when the equity or investment funds are withdrawn to fund capital investments. The primary difference between both methods is that the "Ratemaking ROE" includes items such as incentive compensation and certain other costs not paid for by the customers that are incurred by the Company as part of running its business. These added costs inflate the return on investment and are not representative of the actual return on investment.

DOH-CAB notes that for KPLP, an interest rate of 3.25% was used in our final assessment. We refer you to Page 77 of Appendix D, which summarized the changes that were made in our evaluation.

Understandably, interest rates will change over time, however, the principles used in determining interest rates should remain the same.

Comment 4:

#### Timing of Controls Implementation

There are some older generating units that Hawaiian Electric anticipates shutting down in the future due to the projected increase of renewable generation that is scheduled to come online. In these instances, rather than install new expensive controls on these sources, based on discussions with Hawaiian Electric the DOH in the draft SIP requires Hawaiian Electric to shutdown these sources by December 31, 2027 (Kanoelehua-Hill Boilers Hill 5 & 6 and Kahului boilers K1-K4). Although at the time this shutdown date in 2027 appeared reasonable, circumstances outside of Hawaiian Electric's control have changed since that time. More recently, many supply chain issues are delaying anticipated operation dates for renewable projects that could make compliance with the shutdown schedule while still preserving the reliability of the grid more difficult. It is Hawaiian Electric's understanding based on EPA guidance that the State of Hawaii in the draft SIP could still take credit for these shutdowns as part of the reasonable progress demonstration for this decadal period even if the shutdowns were achieved by December 31, 2028 (one year later than currently proposed). This is confirmed in an email from EPA's Office of Air Quality Planning and Standards (OAQPS) to Hawaiian Electric's consultant, Robert Paine of AECOM. Accordingly, to help minimize grid reliability concerns, Hawaiian Electric requests that the deadline for shutdown for Kanoelehua-Hill boilers Hill 5 & 6 and Kahului boilers K1-K4 be revised to December 31, 2028.

Response to Comment B.4:

As discussed at the meeting between Hawaiian Electric and DOH-CAB on October 7, 2021, Hawaiian Electric agreed to an enforceable permit condition to permanently shut down boilers at the Kahului and Kanoelehua-Hill Generating Stations by December 31, 2027. The compliance time for the shut downs was based on the compliance time of up to five years to implement controls selected for the boilers in the four-factor analyses. Controls selected included a fuel switch from fuel oil No. 6 to ultralow sulfur diesel (ULSD) plus installation of selective catalytic

reduction (SCR) and NO<sub>x</sub> combustion controls after the fuel switch. Hawaiian Electric was provided the option to either shut down the boilers by December 31, 2027, or implement controls selected from the four-factor analyses. Hawaiian Electric choose to shut down the boilers instead of implementing control measures selected in the four-factor analyses.

At this time DOH-CAB cannot consider the request to extend the compliance date for retiring the boilers because it will involve additional review, another public comment period, and prevent the state from meeting the August 15, 2022, deadline for submitting Hawaii's RH-SIP to EPA. This deadline was announced by EPA on April 7, 2022, with EPA's intent to issue Findings of Failure to Submit to states that do not submit their RH-SIPs for the second planning period by August 15, 2022. Therefore, due to the tight schedule for submitting the RH-SIP by EPA's deadline, the DOH-CAB is unable to accommodate your request for an extension.

The request for extending the compliance date for shutting down the boilers was received late in the process of preparing Hawaii's RH-SIP for EPA's approval. Please note that Hawaiian Electric's consultant received confirmation from OAQPS on June 1, 2021, that a unit may be excluded from a four-factor analysis based on a closure date as late as the end of 2028. Yet Hawaiian Electric waited until July 22, 2022, towards the end of the public comment period for the RH-SIP to request the extension of the compliance date for shutting down the boilers.

DOH-CAB, however; can consider an extension of the compliance date for retiring boilers at the Kahului and Kanoelehua-Hill Generating Stations when addressing regional haze controls for the Maalaea Generating and Mauna Loa Macadamia Nut Corporation Plant in a SIP revision. Consideration of an extension to the compliance date for retiring boilers will depend on timely submission of information relevant to why it is no longer feasible for one or more specific units to close by December 31, 2027.

Comment 5:

#### Maalaea Facility

The NPS's review of the four-factor analysis for Maalaea Generating Station identified in the draft SIP questioned the references used by Hawaiian Electric to derive cost effectiveness estimates and referred instead to the EPA Cost Control Manual, which is not an appropriate source for controls in Hawaii, nor where Hawaiian Electric presented a site-specific versus a generic estimate.

The 2012 internal engineering report Hawaiian Electric used to estimate capital costs of SCR and installation were prepared by Black and Veatch as a study for Hawaiian Electric and was never intended to be used externally; therefore, Hawaiian Electric shared the cost estimate tables with the DOH in a letter dated June 1, 2022, with a request for confidential treatment.

Hawaiian Electric's cost estimates are relevant and were based on vendor quotes obtained for the Maalaea engines with Hawaii-specific and site-specific considerations. It is more appropriate than the analysis performed by the NPS using the 7th edition of the EPA Cost Control Manual, which are based on generic information for boilers (not engines).

The NPS noted that the annual operating costs used in the four-factor analysis cited EPA's technical support document dated 2015 which in turn referenced 2010 and 2006 documents. Based on Hawaiian Electric's current research, despite the date of these documents, they are the most current EPA control costing for diesel engine generators.



In contrast, to reviewing references for diesel generators, the NPS analysis operating cost estimates were based on EPA equations relevant to boilers not diesel engines and are therefore not as relevant.

Finally, in a letter dated June 15, 2022, after the Black and Veatch information was provided to the DOH, the cost data which were based on 2019 costs were updated to 2021 costs to provide an updated estimate.

Response to Comment B.5:

Potential NO<sub>x</sub> controls for the Maalaea Generating Station will be addressed in a SIP revision. Please see DOH-CAB's response to Comment B.2.

Comment 6:

On numerous occasions during this process, Hawaiian Electric has pointed the DOH to the Company's Renewable Portfolio and the state Renewable Portfolio Standards mandate to reach 100 percent renewables by 2045 as well as other state statutes including the state Greenhouse Gas regulations, all of which serve to support Hawaiian Electric's assertion that these requirements are sufficient to meet the RHR reasonable progress even absent the controls that are proposed. Hawaiian Electric also proposed several methods for making these requirements federally enforceable. There were several documents including the DOH 5-Year Regional Haze Progress Report for Federal Implementation Plan dated October 2027 and a survey that the DOH responded to that suggested this same proposition.

Response to Comment B.6:

DOH-CAB emphasizes the need for committed deadlines as federally enforceable control measures when considering the RPS. Please note that the RPS was considered for extending the proposed regional haze compliance dates for the Kahului, Kanoiehua-Hill, and Puna Generating Stations. However, the RPS cannot be used as a control measure since it is not federally enforceable. According to Hawaiian Electric's Power Supply Improvement Plan (PSIP) for meeting the mandate of 100 percent RPS by 2045, Boilers K1 – K4 are scheduled to be removed from service at the Kahului Generating Station in 2024. However, Hawaiian Electric is now requesting an enforceable shut down date agreed upon for these boilers be extended from the beginning of 2028 to the end of 2028. Please note also that Kanoiehua-Hill Generating Station Boilers Hill 5 and Hill 6, planned to be removed from service in 2020 in accordance with Hawaiian Electric's PSIP, are still operating. Hawaiian Electric is now requesting that an enforceable shut down date agreed upon for these boilers be extended from the beginning of 2028 to the end of 2028 as well.

Greenhouse gas (GHG) emission caps incorporated into the permits for electric plants on the Islands of Oahu, Molokai, Maui, and Hawaii are addressed in the RH-SIP for information only as part of Hawaii's long-term strategy. The GHG emission caps, that are state only requirements, serve a co-benefit of limiting pollutant emissions that can cause visibility impairment. The GHG emission caps will not be used as a control measure for reasonable progress in this second regional haze planning period.

Comment 7:

The August 2021 EPA study, which is still valid according to EPA's OAQPS, suggests that Hawaii is much closer to natural background than indicated in the proposed SIP documents raising issues with respect to necessity for the control measures identified by the DOH. (Source: <https://www.epa.gov/system/files/documents/2021-08/epa-454-r-21-007.pdf>).

#### Response to Comment B.7:

As indicated in an email from DOH-CAB to Hawaiian Electric on March 21, 2022, the glidepath graphs in EPA's 2021 study are outdated. Modeling projections from EPA's study were updated on the Western Regional Air Partnership (WRAP) Technical Support System (TSS) in the Modeling Express Tools under Hawaii Volcanic – Adjusted EPA Modeling Results, Hawaii – URP Glidepath with Visibility Projections. Projections on the WRAP TSS are based on Interagency Monitoring of Protective Visual Environments (IMPROVE) data that was adjusted using an alternative approach according to EPA's white paper for regional haze.<sup>3</sup> The adjustments combine data from two IMPROVE sites representing Haleakala National Park using ratios of extinction for each chemical component during the overlap period and provide volcanic adjustments for Haleakala National Park and Hawaii Volcanoes National Park to account for impacts from episodic volcanic events (sulfates) on extinction during the most anthropogenically impaired days. The IMPROVE data for the most anthropogenically impaired days was also adjusted for wildfires (organic mass by carbon and light absorbing carbon) and dust storms (mainly coarse mass and fine soil).

Note that volcanic impacts would not be completely screened out after adjusting the IMPROVE data for episodic events due to the continuous nature of the Kilauea eruption. Therefore, modeling projections from scaling 2028 modeling results with the observed 2014 to 2018 IMPROVE data on the most impaired days would still be influenced by sulfates from volcanic activity. For example, even if all U.S. anthropogenic sources are zeroed out, modeling projections show a level of visibility at Hawaii Volcanoes National Park that is above the glidepath. However, the Hawaii Volcanoes National Park IMPROVE monitor in 2019, during a period with significant decrease in SO<sub>2</sub> venting after the Kilauea eruption ceased, shows an observed deciview value that is below the glidepath.

#### Comment 8:

The DOH's current estimates of the volcanic sulfate emissions are understated. For example, the EGU + industrial SO<sub>2</sub> emissions from Maui and Hawaii counties are roughly the same according to the 2017 EPA National Emissions Inventory. However, the DOH's estimate of the anthropogenic-caused sulfate haze for Hawaii Volcanoes National Park is about four times as high as that at the Haleakala IMPROVE monitor. Since the emissions from each island are comparable, the DOH may be underestimating the volcanic impact and overstating the anthropogenic improvement needed to reach "natural" conditions.

#### Response to Comment B.8.

The IMPROVE monitors measure both natural and anthropogenic haze species. As stated in the response to Comment B.7, volcanic impacts would not be completely screened out after adjusting the IMPROVE data for episodic events due to the continuous nature of the Kilauea eruption. Therefore, sulfate caused haze measured by the IMPROVE monitor at Hawaii Volcanoes National Park is much higher than that measured by the IMPROVE monitor at Haleakala National Park due to its close proximity to the Kilauea Volcano.

#### Comment 9:

The DOH's assumption that the volcanic emissions do not contribute at all to nitrate haze may be incorrect. The article in Journal of Volcanology and Geothermal Research dated February 2022 explains that volcanos can create considerable thermal NO<sub>x</sub> from hot lava contact with air as well as volcano-induced lightning.<sup>4</sup>

<sup>3</sup> [https://www.epa.gov/system/files/documents/2021-08/white\\_paper\\_for\\_regional\\_haze\\_hi\\_volcano\\_adjust\\_final.pdf](https://www.epa.gov/system/files/documents/2021-08/white_paper_for_regional_haze_hi_volcano_adjust_final.pdf)

<sup>4</sup> Source: <https://www.sciencedirect.com/science/article/pii/S037702732100278X>

Response to Comment B.9:

It was indicated in Hawaiian Electric's four-factor analyses that volcanic activity is the largest source of NO<sub>x</sub> in the state with a NO<sub>x</sub> emission rate of roughly 125,000 tons per year, likely caused by thermal contact of air with lava. As stated in DOH-CAB's July 8, 2020, and July 10, 2020, letters to Hawaiian Electric in response to these four-factor analyses, use of the ratio of world-wide volcano NO<sub>x</sub> to world-wide volcano SO<sub>2</sub> is likely not appropriate to use for estimating NO<sub>x</sub> emissions from the Kilauea Volcano. Also, IMPROVE data shows that annual light extinction from ammonium nitrates for the most impaired days at Haleakala National Park over the current visibility period (2014-2018 when the volcano was erupting) are higher than those at Hawaii Volcanoes National Park where the volcano with a lava lake is located.

Comment 10:

The visibility data highlighted in several figures in the proposed SIP show data for the years 2014 – 2018. There was significant volcanic activity during this period which gives the impression that visibility improvement has not been made and the Hawaii Class I areas are far from natural visibility conditions. It should be noted that more recent visibility data through 2020 show visibility impairment is much lower.<sup>5</sup>

Response to Comment B.10:

Please see DOH-CAB's response to Comment B.7

Comment 11

Hawaiian Electric encourages DOH to eliminate NO<sub>x</sub> from evaluation as a haze precursor because NO<sub>x</sub> contribution to visibility impairment is minimal. EPA guidance allows states to eliminate potential haze precursor emissions that have a minimal visibility impact.

Response to Comment B.11:

Please see DOH-CAB's response to Comment B.2.

Comment 12

However, if NO<sub>x</sub> must be evaluated, Hawaiian Electric encourages the DOH to incorporate recognition of the lower potential of NO<sub>x</sub> to form nitrate haze (evidenced by the lower nitrate haze in the monitoring data) in decisions on what controls are reasonable. This could be done using a more meaningful visibility impairment metric, or at least a lower \$/ton threshold for NO<sub>x</sub> versus SO<sub>2</sub>). In contrast, for example, in this decadal period review, both of DOH's screening approaches (Q/d and WEP/AOI) weighted NO<sub>x</sub> and SO<sub>2</sub> emissions equally. Likewise, the DOH used the same cost-effectiveness threshold to select/eliminate controls. Although Statewide anthropogenic emissions of NO<sub>x</sub> (ton/year) are higher than SO<sub>2</sub> (ton/year), the DOH's estimates that SO<sub>2</sub> visibility impairment, after "screening out" volcanic impacts, is approximately 15 times higher than nitrate impacts at Haleakala National Park and approximately 90 times higher at Hawaii Volcanoes National Park. There is no basis to weigh NO<sub>x</sub> controls the same as SO<sub>2</sub> and adding further NO<sub>x</sub> controls for haze mitigation is simply not supported by the science or monitoring data.

<sup>5</sup> Source : [http://views.cira.colostate.edu/fed/Sites/?appkey=SBA\\_AqrvVisibility](http://views.cira.colostate.edu/fed/Sites/?appkey=SBA_AqrvVisibility)

Response to Comment B.12:

Please see DOH-CAB's response to Comment B.2.

Comment 13

The DOH's RHR decadal review would be more meaningful if the DOH had used an "adjusted" Glidepath. An example is shown in the EPA study which suggests that Hawaii is much closer to natural background than indicated in the proposed SIP documents. Accordingly, Hawaiian Electric strongly encourages the DOH in this and future decadal reviews to adopt an adjusted glidepath which filters out international contributions and natural sources. International contributions were not included although the draft SIP recognizes that the rules allow them to do so (draft SIP Executive Summary). Unless the DOH understands and accounts for these contributions, the DOH will not be able to confidently understand how much Hawaii anthropogenic sources contribute to impairment or where the Class I areas are relative to a path to "natural background." See Hawaiian Electric letter of April 12, 2022.

Response to Comment B.13:

As indicated in the response to Comment B.7, volcanic impacts would not be completely screened out after adjusting the IMPROVE data for episodic events due to the continuous nature of the Kilauea eruption. Therefore, modeling projections from scaling 2028 modeling results with the observed 2014 to 2018 IMPROVE data on the most impaired days would still be influenced by sulfates from volcanic activity. Since the visibility metric of deciview and glidepath framework to determine reasonable progress is not fully developed to account for continuous volcanic activity, additional resources to adjust the glidepath for international emissions was not justified. A more appropriate visibility metric to determine reasonable progress in Hawaii's Class I areas may be based solely on federally enforceable emission reductions.

C. National Parks Conservation Association & The Coalition to Protect America's National Parks:

Comment 1:

We urge DOH-CAB to revise its Proposed SIP as follows:

- (1) Make the necessary corrections to the Four-Factor Analyses at the unit at the Maalaea Power Plant, which will result in emission limits;
- (2) As expeditiously as possible, either obtain from the sources or conduct the incomplete and needed Four-Factor Analyses, including SIP provisions.
- (3) Ensure that emission limitations (and shut down requirements) and monitoring, recordkeeping and reporting requirements are included in the SIP as regulatory provisions and submitted to EPA for approval, which first go through public notice and comment, and
- (4) Fully consider environmental justice impacts of emissions.

Response to Comment C.1:

As stated in the draft RH-SIP, four-factor analyses for the Maalaea Generating Station and Mauna Loa Macadamia Nut Corporation Plant will be submitted in supplemental documents as an RH-SIP revision. Regional haze control measures found to be feasible in the four-factor analyses will be incorporated into permit amendments with the applicable monitoring, recordkeeping, and reporting requirements. DOH-CAB will provide the public the opportunity to comment and request a public hearing on the draft SIP revision.

Please see DOH-CAB's response to Comments C.10 to C.15 for environmental justice concerns.

Comment 2:

Throughout its Proposed SIP DOH-CAB asserts that because Hawaii's Class I areas are currently below the adjusted uniform rate of progress needed to achieve the 2064 visibility end goal and are projected to remain below the rate of progress through 2028, DOH-CAB's sources need not install as stringent controls during this planning period.

Response to Comment C.2:

DOH-CAB does not state anywhere in the draft RH-SIP that Hawaii sources need not install as stringent controls during this planning period because Hawaii's Class I areas are currently below the adjusted uniform rate of progress (URP).

The URP is used to determine the amount of visibility improvement in deciviews per year needed for the most impaired days during each implementation period to attain natural visibility conditions by 2064. However, in selecting enforceable control measures, the DOH-CAB relied on the four-factor analyses for determining cost effective commitments for specific units by 2028. Reasonable progress goals were established based on emission reductions from the control measures selected. The WEP/AOI analysis was an effective method used in this implementation period to screen sources for four-factor analysis.

Comment 3:

### DOH-CAB Must Correct Its Errors at the Maalaea Power Plant

DOH-CAB must correct the errors in the Four-Factor Analyses for the four 12.5 MW diesel engine generators (M10, M11, M12, and M13) Maalaea Power Plant, following those identified by the NPS. Once that is done, the figures will be cost-effective and DOH-CAB's SIP must require that the source meet emissions limits that reflect installation and operation of SCR controls at units M10, M11, M12, and M13.

The Proposed SIP included requirements for FITR on Units M1, M2 and M3. The Conservation Organizations suggest that DOH-CAB evaluate replacement of the engines with Tier 4 engines. NPCA commissioned a comprehensive report on reasonable progress Four-Factor Analysis for the oil and gas industry. That report included cost estimates for replacement of older engines with the lowest emitting Tier 4 engines and demonstrates how it can be very cost effective depending on how frequently the engines were operated. We included that report as an exhibit to these comments. DOH-CAB must evaluate replacement of the M1, M2 and M3 engines with Tier 4 engines and use the information in NPCA-commissioned March 2020 report included with these comments.

Response to Comment C.3:

The FLMs concluded that there may be additional cost-effective opportunities to control nitrogen oxide (NO<sub>x</sub>) emissions from four (4) larger diesel engines (M10–M13) at the Maalaea Generating Station on Maui. After further review of the four-factor analysis for the Maalaea Generating Station to address comments from the FLMs, the DOH-CAB determined that the four-factor analysis for Maalaea Generating Station is incomplete. A contributing factor that impeded progress towards completing the analysis was the handling of information that was deemed confidential. Due to time constraints, the DOH-CAB will complete this four-factor analysis in an upcoming revision to Hawaii's RH-SIP.

The DOH-CAB may consider that a four-factor analysis be conducted to determine the cost per ton of pollutant removed for replacing M1, M2, and M3 at the Maalaea Generating Station with Tier 4 engines.

#### Comment 4

As the NPS consultation comments noted, because DOH-CAB's proposed cost-effectiveness threshold was \$5,800/ton, all the above costs were not considered cost-effective. Notably, DOH-CAB's control cost threshold justification was thin in that it relied solely on the Chemical Engineering Plant Cost Index (CEPCI) to escalate costs between 2009 and 2019, which is a period of ten years. Using CEPCI for this purpose was inappropriate because ten years is far outside the time window suitable for escalation, which is usually regarded as five years. Escalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate. Moreover, DOH-CAB's Proposed SIP acknowledged that its: [C]ontrol cost threshold is a *guideline* for evaluating cost effective controls and is not considered a definitive line. Control measures that are above the control cost threshold may still be considered reasonable.

#### Response to Comment C.4:

The \$5,800 cost per ton of pollutant removed threshold was specifically discussed during consultation meetings between the DOH-CAB, EPA, and NPS, and was collectively decided as reasonable. The CEPCI is an index that tracks costs of equipment, construction labor, buildings, and supervision in chemical process industries. According to EPA's Control Cost Manual, the CEPCI is an index that has been used extensively by EPA for cost escalation purposes. The control cost manual states that the CEPCI is typically acceptable and most accurate when used over a 5-year-or-less time period. However, in consultation meetings between the DOH-CAB, EPA, and NPS it was concluded that the CEPCI is an acceptable guideline to determine reasonable progress for regional haze, and that \$5,800 per ton of pollutant removed is a reasonable cost threshold. The cost for this threshold was escalated from the \$5,000 per ton cost threshold generally accepted as reasonable in the first regional haze planning period. Although this agreed upon cost threshold was a factor for determining the reasonableness of selecting controls, it was not to be a bright line, as supported by EPA's guidance. Controls are selected at the state's discretion, and some controls over the \$5,800/ton of pollutant removed threshold were considered. The selected \$5,800 cost threshold resulted in additional control measures for contributing sources and will result in the vital protection of visibility in Hawaii's national parks.

#### Comment 5:

The Proposed SIP and Appendix P Lack Clarity in What DOH-CAB Intends to Include in Its SIP Submittal for the Source Retirement Provisions, Emission Limitations and Monitoring, recordkeeping and Reporting Provisions.

#### Response to Comment C.5:

Hawaii's RH-SIP, Chapter 7, Table 7.5-4 summarizes DOH-CAB intent of the proposed retirements, provisions, and regional haze rule limits. Appendix P includes the draft permits that contains the federally enforceable control measures with the monitoring, record keeping and reporting requirements. The permit amendments for the Kahului, Kanoiehua-Hill, and Puna Generating Stations will be issued and included in the RH-SIP for EPA approval. A thirty-day (30-day) public comment period and forty-five-day (45-day) review period by EPA is required before the permits can be issued. The public comment periods for the permits and RH-SIP were initiated in parallel.

#### Comment 6:

DOH-CAB's Proposed SIP Does not Reference the Specific Provisions in the Permits that it Intends to Request that EPA Approve as Federally Enforceable.

#### Response to Comment C.6:

Please see DOH-CAB's response to Comment C.5.

#### Comment 7

Draft Permit Amendment for CSP No. 0232-01-C. The Proposed SIP contains the draft permit amendment for the Maui Electric Company, Ltd. (Maui Electric), Kahului Generating Station, covering Four (4) Boilers. Although the Proposed SIP indicated that DOH-CAB issued a final permit for the retirement of Boilers K-1, K-2, K-3, and K-4 at the Kahului Generating Station by December 31, 2027, the Proposed SIP did not include the final permit in the SIP. The permit amendment included for the Kahului Generating Station in Appendix P was clearly marked as "draft" (as were all the permits in the Appendix). The Proposed SIP did not explain this discrepancy. Neither the Proposed SIP nor Appendix P explain whether the draft permit is a SIP permit or a Title V permit. Additionally, the draft permit had an expiration date, and it is unclear how that impacts the Act's SIP requirement, which requires that SIP measures must be permanent. Furthermore, the Proposed SIP included the draft Attachment to the permit not the entire permit. By only including the draft Attachment to the permit and not the entire permit, the ability of the public to comment due on the provisions of the proposed additions was restricted. For example, the Attachment includes cross-references to sections of the permit they were not provided access to (e.g., Section F cross-references Standard Condition No. 28). Standard Condition No. 28 is not in the Attachment. Additionally, the SIP must not contain conflicting methods for determining compliance and because the entire permit was not provided, the Conservation Organizations could not assess whether there were/are conflicting methods of compliance. Furthermore, the Proposed SIP is unclear if it intends to include the entire Permit Amendment/Attachment in the SIP as regulatory text, or just portions. The Proposed SIP must so specify. We urge DOH-CAB to renote the SIP, provide clarification and full access to the missing information.

#### Response to Comment C.7:

A thirty (30) day public comment period and a forty-five (45) day EPA review period must be provided before the permit amendments can be issued. The final Title V permits will be incorporated into Appendix X of the final RH-SIP that is sent to EPA for approval.

Facilities are allowed to operate under an application shield if a complete renewal application is received prior to the permit expiration date. As indicated in the permit amendments, the permit expiration dates will be revised upon issuance of the permit renewal.

EPA, Region 9 instructed DOH-CAB to only include regional haze rule requirements in the permit amendments. If all other permit conditions not directly related to the regional haze permit amendments were included with the regional haze provisions, the RH-SIP would need to be revised if any other portion of the permit is amended. The regional haze provisions were included in Attachment II – RH: Special Conditions – Regional Haze Requirements. Attachment II – RH: Special Conditions – Regional Haze Requirements will be combined with the main permit when it is renewed.

Permit amendments for the RH-SIP are for incorporating regional haze provisions only. A copy of existing permit provisions can be obtained by filling out a Request to Access Government Records Form-PDF Fillable and sending it to DOH-CAB for processing.<sup>6</sup>

#### Comment 8

Draft Permit Amendment for CSP No. 0234-01-C. The Proposed SIP contains the draft permit amendment for the Hawaii Electric Light Company, Inc. (Hawaii Electric Light) Kanoelehua-Hill Generating Station covering Two (2) Boilers, One (1) Combustion Turbine, and Four (4) Diesel Engines. The Conservation Organizations' concerns with the draft permit amendments for the Kanoelehua-Hill Generating Station are the same as those identified for the Kahului Generating Station.

Response to Comment C.8:

Please see DOH-CAB's response to Comment C.7.

#### Comment 9

Hawaii's Proposed SIP Failed to include all Sources: The Proposed SIP Lacks a Four-Factor Analysis and Emission Limits for the Mauna Loa Macadamia Nut Corporation Plant.

Response to Comment C.9:

The Mauna Loa Macadamia Nut Corporation Plant was not identified during the initial screening using Q/d ratios. The WEP/AOI analysis later identified Mauna Loa Macadamia Nut Corporation Plant as having relatively high potential to affect visibility at Hawaii Volcanoes National Park. DOH-CAB initially submitted a request for a four-factor analysis in its letter dated May 6, 2021, and have since submitted an email dated November 4, 2021, and two additional letters dated January 7, 2022, and July 19, 2022, with comments on Mauna Loa Macadamia Nut Corporation Plant's four-factor analysis. Due to time constraints, the DOH-CAB will complete its review of this four-factor analysis in an upcoming revision to Hawaii's RH-SIP. The four-factor analysis for the Mauna Loa Macadamia Nut Corporation Plant, that is incomplete at this time, is provided in Appendix P.

#### Comment 10

DOH-CAB Must Do More to Analyze Environmental Justice Impacts of its Regional Haze SIP, and Must Ensure Its SIP Will Reduce Emissions and Minimize Harms to Disproportionately Impacted Communities.

#### Comment 11

Proposed SIP did not to meet the environmental justice and civil rights requirements.

#### Comment 12

DOH-CAB can facilitate EPA's consideration of environmental justice to comply with Federal Executive Orders.

<sup>6</sup> <https://health.hawaii.gov/cab/files/2022/05/Request-to-Access-a-Government-Record-Form-PDF-Fillable.pdf>



### Comment 13

DOH-CAB ignored EPA's Regional Haze Guidance and Clarification Memo, which directs states to take environmental justice concerns and impacts into consideration.

### Comment 14

EPA must consider environmental justice when it reviews and takes action on Hawaii's SIP.

### Comment 15

DOH-CAB must consider environmental justice under Title VI of the Civil Rights Act.

### Response to Comments C.10 to C.15

The requirements that Hawaii is subject to under EPA's Regional Haze Rule are applicable to regional haze in our two national parks (Hawaii Volcanoes National Park and Haleakala National Park). Hawaii's long-term strategy and reasonable progress goals provide for an improvement in visibility for the most impaired days and ensure no degradation in visibility for the clearest days since the baseline period, with respect to anthropogenic emissions.

EPA's July 2021 guidance encourages states to consider whether there may be equity and environmental justice impacts when developing regional haze strategies and gives states the discretion to consider environmental justice in determining the measures that are necessary to make reasonable progress in visibility for Hawaii's Class I areas. Even though the regional haze rule does not require analysis of environmental justice, Hawaii's RH-SIP has identified and selected additional emission controls and emission unit shut down requirements for sources that will result in better air quality for areas surrounding the sources as well as in Hawaii's Class I areas. The sources which were selected for control measures are existing sources, and any emission reduction strategies resulting from Hawaii's RH-SIP will provide direct benefits for all communities in Hawaii, by protecting visibility in our national parks.

### **III. COMMENTS AND RESPONSES (7-1-2022 to 7-30-2022 Comment Period for Draft Permit Amendments)**

Hawaiian Electric:

Comment:

The Operational and Emissions Limitation sections of the draft amendments for the Kahului Generating Station (Attachment II – RH, Special Condition C.1) and the Kanoelehua-Hill Generating Station (Attachment II – RH, Special Condition C.1.b) require the permanent shutdown of Kahului boilers K1 through K4 and Kanoelehua-Hill boilers Hill 5 and Hill 6 by December 31, 2027. Based on the justification below, Hawaiian Electric requests to revise the compliance deadline for the Kahului and Kanoelehua-Hill boilers to December 31, 2028 which is, based on prior EPA correspondence, allowed by the EPA.

The remaining independent power producer renewable energy projects are facing significant delays resulting in significantly delayed in service dates due to various reasons, including but not limited to the following:

- 1) Equipment was confiscated because of the U.S. Customs and Boarder Protection's Withhold Release Order that impacted imports of certain silica-based products;
- 2) Supplier delays due to government lockdowns in China relating to COVID-19;

- 3) Supply chain issues related to COVID-19; and
- 4) Current market conditions requiring cost increases and amendments to the Power Purchase Agreements.

Response to Comment:

Please see DOH-CAB's response to Comment B.4.

#### **IV. WRITTEN COMMENTS AND RESPONSES (6-24-2022 to 8-8-2022 EPA Review Period, EPA Comment Received on 8-5-2022)**

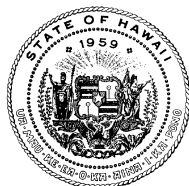
Comment

EPA requested that DOH-CAB change the cover page of the permit amendment for the Puna Generating Station to state that, except for Special Condition Nos. C5 and D.4 of Attachment IIC that will be updated in a separate permit amendment to remove existing regional haze provisions associated with the SO<sub>2</sub> emissions cap, all other permit conditions of CSP No. 0235-01-C as issued on October 12, 2018, and amended on October 22, 2020, shall not be affected and shall remain valid.

Response to Comment

DOH-CAB revised the cover page of CSP No. 0235-01-C for the Puna Generating Station as requested.

# Final Permit Amendments and Technical Support Documents (TSDs)



**CERTIFIED MAIL**  
**RETURN RECEIPT REQUESTED**  
(7018 0040 0000 8040 8686)

**STATE OF HAWAII**  
**DEPARTMENT OF HEALTH**  
P.O. Box 3378  
HONOLULU, HAWAII 96801-3378

In reply, please refer to:  
File:

22-338E CAB  
File No. 0232

August 10, 2022

Mr. John Mauri  
Director, Generation – Maui County  
Maui Electric Company, Ltd.  
P.O. Box 398  
Kahului, Hawaii 96733

Dear Mr. Mauri:

**SUBJECT: Amendment of Covered Source Permit (CSP) No. 0232-01-C  
Maui Electric Company, Ltd. (Maui Electric)  
Kahului Generating Station  
Four (4) Boilers  
Located At: 200 Hobron Avenue, Kahului, Maui  
UTM: 763,673 m East and 2,313,143 m North, Zone 4 (NAD-83)  
Date of Expiration: December 22, 2014 (Expiration Date to be Revised Upon Permit Renewal)**

In accordance with Hawaii Administrative Rules (HAR), Chapter 11-60.1, the Department of Health, Clean Air Branch (herein after referred to as Department), hereby amends CSP No. 0232-01-C issued to Maui Electric for Kahului Generating Station on December 23, 2009, and amended on October 22, 2020.

In accordance with HAR §11-60.1-10(a)(2) and (a)(3) and pursuant to Clean Air Act (CAA) §169A(g)(1), this permit amendment incorporates an enforceable commitment to retire Boilers K-1, K-2, K-3, and K-4 at the Kahului Generating Station by December 31, 2027. To make reasonable progress from long-term strategies in Hawaii's Regional Haze State Implementation Plan (RH-SIP), the regional haze program offers flexibility in considering an enforceable commitment to source retirement by 2028 as an option to requiring regional haze control measures selected from a four-factor analysis. This amendment is based on your revised regional haze four-factor analysis dated September 25, 2020; additional information received from your letters dated March 30, 2021, June 16, 2021, and August 2, 2021; discussions between the Department and Hawaiian Electric on October 7, 2021, and February 25, 2022; and Section II.B.3.e of the Environmental Protection Agency's (EPA's) Guidance on Regional Haze State Implementation Plans for the Second Implementation Period dated August 20, 2019.

CSP No. 0232-01-C issued on December 23, 2009, and amended on October 22, 2020, is amended as follows:

Added Attachment:


Attachment II - RH: Special Conditions - Regional Haze Requirements

All other permit conditions of CSP No. 0232-01-C issued on December 23, 2009, and amended on October 22, 2020, shall not be affected and shall remain valid.

Mr. John Mauri  
August 10, 2022  
Page 2

If there are any questions regarding these matters, please contact Mr. Dale Hamamoto of the Clean Air Branch at (808) 586-4200.

Sincerely,



JOANNA L. SETO, P.E., CHIEF  
Environmental Management Division

DH:tkg

Enclosures

**ATTACHMENT II - RH: SPECIAL CONDITIONS  
REGIONAL HAZE REQUIREMENTS  
COVERED SOURCE PERMIT NO. 0232-01-C**

**Amended Date: August 10, 2022**

**Expiration Date: December 22, 2014**  
(Expiration Date to be Revised Upon Permit Renewal)

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility:

**Section A. Equipment Description**

1. Attachment II – RH of this permit encompasses the following boilers:

<b>Unit</b>	<b>Description</b>
K-1	5.0 MW (nominal), 94 MMBtu/hr, Combustion Engineering Boiler, Serial No. 13413, with electric igniters
K-2	5.0 MW (nominal), 94 MMBtu/hr, Combustion Engineering Boiler, Serial No. 15345, with total combined 2.5 ft <sup>3</sup> /hr capacity gas fired igniters
K-3	11.5 MW (nominal), 172 MMBtu/hr, Combustion Engineering Boiler, Serial No. 17343, with total combined 3.3 ft <sup>3</sup> /hr capacity gas fired igniters
K-4	12.5 MW (nominal), 181 MMBtu/hr, Babcock and Wilcox Boiler, Serial No. PF13030 with total combined 10 ft <sup>3</sup> /hr capacity gas fired igniters
Note: Megawatt (MW), Hour (hr), Cubic Feet (ft <sup>3</sup> ), and Million British Thermal Unit (MMBtu)	

(Auth.: HAR §11-60.1-3)

2. In accordance with HAR §11-60.1-10(a)(2) and (a)(3), this permit amendment incorporates federally enforceable regional haze control measures specified in Hawaii’s Regional Haze State Implementation Plan (RH-SIP) for Boilers K-1, K-2, K-3, and K-4 pursuant to CAA §169A(g)(1) and 40 Code of Federal Regulations (CFR) §51.308(f)(2)(iv).

(Auth.: HAR §11-60.1-5, §11-60.1-10, 40 CFR §51.308(f), CAA §169A)<sup>1,2</sup>

**Section B. Applicable Federal Regulations**

1. Regional haze provisions for the boilers are required pursuant to the following federal regulations:
- a. 40 CFR Part 51, Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Subpart P, Protection of Visibility;
  - b. 40 CFR Part 52, Approval and Promulgation of Implementation Plans, Subpart A, General Provisions; and
  - c. 40 CFR Part 52, Approval and Promulgation of Implementation Plans, Subpart M, Hawaii, §52.633, Visibility Protection.

(Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-90, §11-60.1-161, 40 CFR §51.300, §52.02, §52.633)<sup>1</sup>

2. The permittee shall comply with all applicable requirements of these standards, including all emission limits, notification, testing, monitoring, and reporting requirements. The major requirements of these standards are detailed in the special conditions of this attachment.

(Auth.: HAR §11-60.1-90, 40 CFR §52.633)<sup>1</sup>

### **Section C. Operational and Emission Limitations**

1. Regional Haze Rule Limit

Boilers K-1, K-2, K-3, and K-4 shall be permanently shut down **by December 31, 2027**.

(Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-90, 40 CFR §51.308, §52.633;  
CAA §169A)<sup>1,2</sup>

2. Shut Down Notification

The Department shall be notified when all boilers are permanently shut down in accordance with Attachment II - RH, Special Condition No. E.3.

(Auth: HAR §11-60.1-10, §11-60.1-90; 40 CFR §51.308, §52.633, CAA §169A)<sup>1,2</sup>

### **Section D. Monitoring and Recordkeeping Requirements**

1. Records

All records, including support information, shall be maintained for **at least five (5) years** following the date of the monitoring sample, measurement, test, report, or application. Support information includes calibration, maintenance, inspection, and repair records and copies of all reports required by this permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the U.S. EPA, Department, or its representative(s) upon request.

(Auth.: HAR §11-60.1-5, §11-60.1-81, §11-60.1-11, §11-60.1-90)

### **Section E. Notification and Reporting Requirements**

1. Standard Condition Reporting

Notification and reporting pertaining to the following events shall be done in accordance with Attachment I, Standard Condition Nos. 17 and 24, respectively.

- a. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
- b. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90; SIP §11-60-10, §11-60.1-16)<sup>3</sup>

## 2. Deviations

The permittee shall report (in writing) **within five (5) working days** any deviations from the permit requirements, including those attributed to upset conditions, the probable cause of such deviations and any corrective actions or preventive measures taken. Corrective actions may include a requirement for stack testing, more frequent monitoring, or the implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-16, §11-60.1-90)

## 3. Regional Haze Shut Down Notification

**Within thirty (30) days** of permanently shutting down the boilers as required by Attachment II - RH, Special Condition No. C.1, the permittee shall submit written notification to the Department on the permittee's compliance with the condition, including the date of compliance.

(Auth: HAR §11-60.1-10, §11-60.1-90; 40 CFR §51.308, §52.633; CAA §169A)<sup>1,2</sup>

## 4. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA Region 9, the Compliance Certification Form pursuant to HAR, Subsection 11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:
  - i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification including the requirements of Section 114(a)(3) of the CAA or any applicable monitoring and analysis provisions of Section 504(b) of the CAA;



- vi. Brief description of any deviation including identifying as possible exceptions to compliance any periods during which compliance is required and which the excursion or exceedances as defined in 40 CFR Part 64 occurred; and
- vii. Any additional information as required by the Department including information to determine compliance.

- b. The compliance certification shall be submitted **within sixty (60) days after** the end of each calendar year and shall be signed and dated by a responsible official or authorized representative.
- c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-86, §11-60.1-90)

#### **Section F. Agency Notification**

Any document (including reports) required to be submitted by this permit shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citation to the CFR identified under a particular condition, indicates that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citation to the CAA identified under a particular condition, indicates that the permit condition complies with the specified provision(s) of the CAA.

<sup>3</sup>The citation to the State Implementation Plan (SIP) identified under a particular condition, indicates that the permit condition complies with the specified provision(s) of the SIP.

**TECHNICAL SUPPORT DOCUMENT  
PERMIT AMENDMENT  
REGIONAL HAZE STATE IMPLEMENTATION PLAN  
Covered Source Permit (CSP) No. 0232-01-C**

**Applicant:** Maui Electric Company, Ltd. (Maui Electric)  
**Facility:** Kahului Generating Station  
**Located At:** 200 Hobron Avenue, Kahului, Maui  
UTM: 763,673 m East and 2,313,143 m North, Zone 4 (NAD-83)

**Mailing Address:** P.O. Box 398  
Kahului, Hawaii 96733

**Responsible Official:** John Mauri  
Director, Generation – Maui County  
Maui Electric  
(808) 872-3245

**Contact:** Karin Kimura  
Director, Environmental Division  
Hawaiian Electric Company, Inc. (Hawaiian Electric)  
(808) 543-4500  
[karin.kimura@hawaiianelectric.com](mailto:karin.kimura@hawaiianelectric.com)

The Standard Industrial Classification Code (SICC) for this facility is 4911 – Electric Services

## Project

This permit amendment incorporates regional haze control measures specified for the boilers in Hawaii's Regional Haze State Implementation Plan (RH-SIP) in accordance with Hawaii Administrative Rules (HAR) §11-60.1-10(a)(2) and (a)(3) and Clean Air Act (CAA) §169A(g)(1). The regional haze program for the second planning period offers **flexibility** in that not all sources of emissions are required to be evaluated and a selection of a source for analysis does not necessarily mean that additional emission control measures will ultimately be required for the selected source.<sup>1</sup> In addition, the regional haze program offers **options** to consider either the *four statutory factors or five other additional factors* when selecting sources for control measure analysis. One of the five additional factors to exclude a source from a four-factor analysis is source retirement and replacement schedules.<sup>1</sup>

After notifying Hawaiian Electric of controls selected for Kahului Generating Station Boilers K-1 through K-4, Hawaiian Electric ultimately decided to commit to an enforceable shut down of the boilers rather than implementing controls selected from the four-factor analysis. The four-factor analysis initially performed for the Kahului Generating Station to select regional haze control measures is provided in Enclosure 1. Hawaiian Electric's decision to shut down the boilers was relayed at a meeting between the Hawaii Department of Health, Clean Air Branch (CAB) and Hawaiian Electric on October 7, 2021. As such, the permit amendment for Kahului Generating Station incorporates the following limit:

Maui Electric shall permanently shut down Boilers K-1 through K-4 by **December 31, 2027**.

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<sup>1</sup>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, Environmental Protection Agency (EPA), August 20, 2019.

The CAA §110(a)(2) requires that state implementation plan (SIP) submittals include enforceable control measures and emission limitations to meet applicable CAA requirements, and that the submittals show that the State has authority to carry out the SIP. Thus, the relevant control measures and emission limitations must be finalized in order for the Environmental Protection Agency (EPA) to approve the SIP. 40 Code of Federal Regulations (CFR) Part 51, Appendix V, Section 2.1 also details the administrative criteria for determining the completeness of SIP submissions. Section 2.1(b) requires that the state submittal include the permit as issued in final form, with evidence that includes the date of adoption or final issuance as well as the effective date. Therefore, EPA recommends the CAB finalize the permitting process for incorporating the regional haze controls prior to sending the RH-SIP with these permit conditions to the EPA for approval into the SIP.<sup>2</sup> As such, the CAB plans to implement the proposed permit amendment for the Kahului Generating Station in accordance with HAR §11-60.1-10(a)(2) and (a)(3).

## Background

In the first regional haze planning period (2001-2018), the emphasis was on Best Available Retrofit Technology (BART) to address reasonable progress that included a 0.5 deciview threshold. In this second planning period (2018-2028), there is no BART or deciview threshold. The focus in the second planning period is on determining reasonable progress through analysis of the four factors identified in CAA §169(g)(1).

The EPA regional haze guidance dated August 20, 2019, (guidance) explains that because regional haze results from a multitude of sources over a broad geographic area, progress may require addressing many relatively small contributions to impairment. Thus, a measure may be necessary for reasonable progress even if that measure in isolation does not result in perceptible visibility impairment.

## Permitted Equipment Subject to Regional Haze Rule Limit

<u>Unit</u>	<u>Description</u>
K-1	5.0 MW (nominal), 94 MMBtu/hr, Combustion Engineering Boiler, Serial No. 13413, with electric igniters;
K-2	5.0 MW (nominal), 94 MMBtu/hr, Combustion Engineering Boiler, Serial No. 15345, with Total Combined 2.5 ft <sup>3</sup> /hr capacity gas fired igniters;
K-3	11.5 MW (nominal), 172 MMBtu/hr, Combustion Engineering Boiler, Serial No. 17343, with Total Combined 3.3 ft <sup>3</sup> /hr capacity gas fired igniters; and
K-4	12.5 MW (Nominal), 181 MMBtu/hr, Babcock and Wilcox Boiler, Serial No. PF13030, with total combined 10 ft <sup>3</sup> /hr capacity gas fired igniters.

## Air Pollution Controls

There are no existing controls for units operating at the Kahului Generating Station.

Air pollution controls will not be required because the permit will specify a federally enforceable limit to permanently retire Boilers K-1, K-2, K-3, and K-4 by December 31, 2027.

<sup>2</sup>EPA's email response dated July 23, 2021, titled, "Final Form of Permits for RH SIP".

## Applicable Requirements

### State Requirements:

#### Hawaii Administrative Rules

Title 11, Chapter 60.1	Air Pollution Control
Subchapter 1	General Requirements
HAR 11-60.1-1	Definitions
Subchapter 2	General Prohibitions
HAR 11-60.1-31	Applicability
HAR 11-60.1-32	Visible Emissions
HAR 11-60.1-38	Sulfur Oxides from Fuel Combustion
HAR 11-60.1-39	Storage of Volatile Organic Compounds (VOC)
Subchapter 5	Covered Sources
Subchapter 6	Fees for Covered Sources, Noncovered Sources, and Agricultural Burning
HAR 11-60.1-111	Definitions
HAR 11-60.1-112	General Fee Provisions for Covered Sources
HAR 11-60.1-113	Application Fees for Covered Sources
HAR 11-60.1-114	Annual Fees for Covered Sources
HAR 11-60.1-115	Basis of Annual Fees for Covered Sources
Subchapter 9	Hazardous Air Pollution Sources
HAR 11-60.1-174	Maximum Achievable Control Technology (MACT) Emission Standards
Subchapter 10	Field Citations
Subchapter 11	Greenhouse Gas Emissions

### DOH-In-House Annual Emission Reporting

The CAB requests annual emissions reporting from facilities that have facility wide emissions of a single air-pollutant exceeding DOH (in-house) triggering levels or is a covered source. **Prior to December 31, 2027**, annual emissions (In-house) reporting **is applicable** because the triggering levels are exceeded as shown in the “Project Emissions” section of this review.

### Federal Requirements:

#### Regional Haze Program Requirements

40 CFR Part 51, Subpart P, Protection of Visibility **is applicable** for regulating this facility. Cost effective control measures for reasonable progress goals towards achieving natural visibility by 2064 were identified from a four-factor analysis of the Kahului Generating Station pursuant to 40 CFR §51.308 (f)(2) and EPA’s guidance. Please refer to Enclosure 1 for details. Hawaiian Electric chose to shut down the boilers by 2028 rather than implement control measures selected in the four-factor analysis.

40 CFR Part 52, Approval and Promulgation of Implementation Plans, Subpart M, Hawaii, §52.633, Visibility Protection, is applicable for regulating the boilers that will require an enforceable shut down limit pursuant to 40 CFR Part 51, Subpart P.

## National Emission Standards for Hazardous Air Pollutants (NESHAP)

40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard, **Subpart JJJJJJ**, NESHAP requirements for Area Sources for Industrial, Commercial, and Institutional Boilers Area Sources **is applicable** to Boilers K-1, K-2, K-3, and K-4. As indicated on Page 3-1 of Maui Electric's Energy Assessment of February 2014, Boilers K-1 through K-4 are equipped with oxygen trim systems that continuously measure the amount of free oxygen in the boiler combustion air, and then adjusts the amount of air into the combustion chamber for optimum performance. Since the units use oxygen trim systems, the boilers are subject to five (5) year tune-ups instead of biennial tune-ups. Boilers K-1, K-2, K-3, and K-4 are existing oil-fired sources as determined in §63.11194(b) because these sources were constructed prior to June 4, 2010, and therefore, are not subject to the emission limits in Subpart JJJJJJ, Table 1.

## Air Emission Reporting Requirements (AERR)

40 CFR Part 51, Subpart A, **AERR is applicable**. Refer to the section titled "Project Emissions" of this review. AERR is based on the emissions of criteria air pollutants from point sources (as defined in 40 CFR Part 51, Subpart A), which equals or exceeds the Type A and B triggering levels.

## Major Source

This facility **is a major source** because potential emissions of criteria pollutant(s) exceed(s) major source threshold(s).

## Non-Applicable Requirements

### *Federal Requirements:*

### New Source Performance Standard (NSPS)

40 CFR Part 60 – NSPS, **Subpart D**, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971, **is not applicable** because the boilers were constructed prior to August 17, 1971.

40 CFR Part 60 – NSPS, **Subpart Da**, Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978, **is not applicable** because the boilers are less than 250 MMBtu/hr in capacity and were constructed prior to September 18, 1978.

40 CFR Part 60 – NSPS, **Subpart Db**, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units **is not applicable** to boilers at the facility over 100 MMBtu/hr heat rate input capacity since this equipment was constructed prior to June 19, 1984.

40 CFR Part 60 – NSPS, **Subpart Dc**, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units **is not applicable** because the boilers were constructed prior to June 9, 1989.

40 CFR Part 60, **Subpart Kb**, Standards of Performance for Volatile Organic Liquid Storage Vessels **is not applicable** to the storage tanks listed as insignificant activities because the maximum true vapor pressure of the liquid VOC stored inside the tank is less than 3.5 kilopascals (kPa) and 15.0 kPa respectively based on storage tank capacities. Refer to Enclosure 2 for the evaluation.

### NESHAP

The facility is not a major source for HAPs and **is not subject** to NESHAPS requirements under 40 CFR Part 61.

The facility is not subject to 40 CFR Part 63 – NESHAP for source categories (Maximum Achievable Control Technology (MACT) Standards) as follows:

Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

The boilers **are not subject to** this standard because the facility is not a major source of HAP emissions.

Subpart UUUUU – National Emissions Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units

The boilers **are not subject to** this standard because they are not a fossil fuel-fired combustion unit of more than 25 megawatts electric (Mwe) that serves a generator that produces electricity for sale in accordance with 40 CFR §63.10042.

### Compliance Assurance Monitoring (CAM), 40 CFR Part 64

The purpose of CAM is to provide a reasonable assurance that compliance is being achieved with large emissions units that rely on air pollution control device equipment to meet an emissions limit or standard. Pursuant to 40 CFR Part 64, for CAM to be applicable, the emissions unit must:

- (1) Be located at a major source;
- (2) Be subject to an emissions limit or standard;
- (3) Use a control device to achieve compliance;
- (4) Have potential pre-control emissions that are greater than the major source level; and
- (5) Not otherwise be exempt from CAM.

This source **is not subject to CAM** pursuant to 40 CFR §64.2(b) because there are no emission limits specified for equipment operating at this facility.

### Best Available Control Technology (BACT)

A BACT analysis **is not required** since this is not a new source, nor are there any modifications that increase emissions.

A BACT analysis is required for new or modified sources that have the potential to emit or increase emissions above significant amounts as defined in HAR §11-60.1-1.

## Prevention of Significant Deterioration (PSD)

PSD review **does not apply**. Note, the boiler units were grandfathered from PSD review because they were constructed prior to January 6, 1975.

PSD review applies to new major stationary sources and major modifications to these types of sources. The facility is not a new major stationary source, nor does this amendment make any major modifications to a major stationary source as defined in 40 CFR Part 52.21. A major modification is defined as a project at an existing major source that will result in a significant and a significant net emissions increase above specified thresholds for pollutants subject to regulation.

## Alternate Operating Scenarios

This modification does not affect the alternate operating scenarios in the permit.

## Insignificant Activities

Insignificant activities identified in the previous permit application review are as follows:

- a. A 400 kW Waukesha black start diesel engine generator (DEG) is considered an insignificant activity pursuant to HAR §11-60.1-82(f)(5). As indicated by the applicant, the diesel engine does not supply power to the grid and only operates during emergencies to start the boilers when there is a power outage. Also, this DEG operates on average about fifty-six (56) hours per year.
- b. Three (3) 27,976-barrel fuel oil No. 6 storage tanks are considered insignificant activities pursuant to HAR §11-60.1-82(f)(7) due to the low vapor pressure of the fuel oil No. 6.
- c. A 35,300-gallon used lube oil storage tank (Tank No. 5) is an insignificant activity pursuant to HAR §11-60.1-82(f)(1).
- d. A 9,492-gallon fuel oil No. 2 storage tank (Tank No. 6) is an insignificant activity pursuant to HAR §11-60.1-82(f)(1).
- e. A 460-gallon diesel tank for the black start DEG is an insignificant activity pursuant to HAR §11-60.1-82(f)(1).
- f. A 500-gallon propane tank for boiler igniter fuel is an insignificant activity pursuant to HAR §11-60.1-82(f)(1).
- g. 250-gallon tote tank(s) for specification used oil qualify as an insignificant activity pursuant to HAR §11-60.1-82(f)(1).
- h. Fuel burning equipment less than one (1) MMBtu/hr, other than smoke house generators and gasoline fired industrial equipment are exempt in accordance with HAR §11-60.1-82(f)(2).
- i. Paint spray booths that emit less than two (2) tons per year on any regulated air pollutant are exempt pursuant to HAR §11-60.1-82(f)(6).
- j. Other activities that emit less than 500 lb/yr of HAP, except lead; 300 pound per year of lead; 3,500 tons per year of carbon dioxide equivalent (CO<sub>2</sub>e); two (2) tons per year of each regulated pollutant not already identified above pursuant; and which are determined on a case by case basis to be insignificant activities are exempt pursuant to HAR §11-60.1-82(f)(7).

## Project Emissions

### 1. Emissions

Emissions of nitrogen oxides (NO<sub>x</sub>), carbon monoxide (CO), VOCs, particulate matter (PM), PM<sub>10</sub>, PM<sub>2.5</sub>, sulfur dioxide (SO<sub>2</sub>), sulfuric acid (H<sub>2</sub>SO<sub>4</sub>), ammonia (NH<sub>3</sub>), and HAPs were previously evaluated based on burning fuel oil No. 6 and specification used oil fired in Boilers K-1 through K-4 in Review of Application for Significant Permit Modification No. 0232-06. Except for NH<sub>3</sub>, PM<sub>10</sub>, and PM<sub>2.5</sub>, the emission rates were taken from the permittee's renewal application received on December 19, 2014. Annual emissions were based on the maximum capacity of the equipment and 8,760 hours per year of operation. The NH<sub>3</sub> emission factors are based on Tables 5-2 and 5-5, for fuel oil combustion and SCR ammonia slip (if SCR was implemented), from EPA's final report dated August 1994 titled, "Development and Selection of Ammonia Emission Factors." The H<sub>2</sub>SO<sub>4</sub> emission rate was based on information from source testing that indicated H<sub>2</sub>SO<sub>4</sub> is proportional to 13.83% of the SO<sub>2</sub> emission rate. It was assumed that forty-five percent (45%) of the total PM was PM<sub>2.5</sub> and seventy-nine percent (79%) of the total PM was PM<sub>10</sub> based on AP-42, Appendix B.2, Table B.2-2 (Page B.2-12) for boilers firing a mixture of fuel oil No. 6 including petroleum. A total combined 300,000 gallon per year fuel limit was assumed to calculate HAP emissions for firing the boilers on specification used oil. A summary of the emissions with the reporting thresholds are listed in the following table for existing emissions. Please refer to Enclosure 3 for details of the calculations and emission estimates for other operating scenarios that would have applied if control measures (fuel switch, SCR, and combustion controls) from the four-factor analysis were implemented.

**Existing Emissions Relative to Reporting Thresholds (TPY)**

Pollutants	Emissions Existing Fuel Oil No. 6	AERR <sup>a,b</sup>				Major Source		DOH (In-House) Reporting	
		Every-year (Type A sources)		Triennial (Type B sources)					
		Thresholds	Applies	Thresholds	Applies	Thresholds	Applies	Thresholds	Applies
SO <sub>2</sub>	5,219.1	2,500	Yes	100	Yes	100	Yes	25	Yes
H <sub>2</sub> SO <sub>4</sub>	684.7	--	NA	--	NA	--	NA	--	NA
NO <sub>x</sub>	1,472.0	2,500	No	100	Yes	100	Yes	25	Yes
CO	157.0	2,500	No	1,000	No	100	Yes	250	No
VOC	10.9	250	No	100	No	100	No	25	No
PM	1,527.2	--	NA	--	NA	100	Yes	25	Yes
PM <sub>10</sub>	1,206.5	250	Yes	100	Yes	--	NA	25	Yes
PM <sub>2.5</sub>	687.3	250	Yes	100	Yes	--	NA	--	NA
Lead (P <sub>b</sub> )	3.79E-02	--	NA	0.5	No	--	NA	--	NA
NH <sub>3</sub>	13.5	250	No	100	No	--	NA	--	NA
HAP <sub>single</sub>	3.08	--	NA	--	NA	10	No	--	NA
HAPs <sub>total</sub>	3.31	--	NA	--	NA	25	No	5	No
GHG (CO <sub>2</sub> e)	386,882	--	NA	--	NA	--	NA	--	NA

<sup>a</sup>Type A sources are a subset of the Type B sources and are the larger emitting sources by pollutant. The threshold for NO<sub>x</sub> is ≥2,500 TPY, the proposed fuel switch and cap do not trigger Type A reporting.

<sup>b</sup>Except for Lead (P<sub>b</sub>), which is based on actual, each pollutant is evaluated based on worst case emissions.



## 2. Carbon Dioxide Equivalent (CO<sub>2</sub>e) Emissions

CO<sub>2</sub>e emissions are calculated in accordance with 40 CFR Part 98, §98.33 and summarized in the following table. Mass based emission are from Enclosure 4 and are based on emission factors from 40 CFR §98 Appendix, Table C-1 and C-2. Each boiler is assumed to operate for 8,760 hours/yr. The emergency diesel engine generator that meets the definition in 40 CFR §98.6, and fugitive emissions from tanks and fueling operations are not defined as stationary fuel combustion sources and therefore, excluded from greenhouse gas (GHG) reporting pursuant to 40 CFR Part 98, Subpart A, §98.2(a)(3) and 40 CFR §98.30. The global warming potentials (GWP) from 40 CFR §98 Appendix, Table A-1 are used to calculate the CO<sub>2</sub>e emissions.

**CO<sub>2</sub>e Emissions<sup>a</sup>**

GHG	GWP	GHG Mass-Based Emissions (TPY)	CO <sub>2</sub> e Based Emissions (TPY) <sup>c</sup>	CO <sub>2</sub> e Based Emissions (MT) <sup>b, c</sup>
Carbon Dioxide (CO <sub>2</sub> )	1	385,559.1	385,559.1	349,773.3
Methane (CH <sub>4</sub> )	25	15.6	391.0	354.7
Nitrous Oxide (N <sub>2</sub> O)	298	3.1	932.1	845.6
<b>Total Emissions<sup>c</sup></b>			<b>386,882</b>	<b>350,974</b>

<sup>a</sup>Mass based emissions are provided in Enclosure 4.

<sup>b</sup>1 U.S. Ton = 0.907184741 metric-tons (MT)

<sup>c</sup>Totals may not sum due to independent rounding.

### Ambient Air Quality Assessment

There are no emission increases for the federally enforceable emission limit to shut down the boilers by 2028. Therefore, an ambient air quality impact assessment (AAQIA) is not required for this permit amendment.

### Significant Permit Conditions

- Regional Haze Rule Limit:** Boilers K-1 through K-4 shall be permanently shut down by **December 31, 2027**.

Reason: Regional haze condition is added to comply with the requirements of 40 CFR Part 51, Subpart P and 40 CFR Part 52, Subpart M.

### Conclusion and Recommendation

This permit amendment incorporates regional haze control measures specified for the boilers in Hawaii's RH-SIP in accordance with HAR §11-60.1-10(a)(2) and (a)(3), CAA §169A(g)(1), and 40 CFR §51.308(f)(2)(iv). Pursuant to Hawaii's RH-SIP for the second planning period (2018-2028), CSP No. 0232-01-C for the Kahului Generating Station is being amended to incorporate the following regional haze limit:

- Boilers K-1 through K-4 shall be permanently shut down **by December 31, 2027**.

Maui Electric's four-factor analysis for Kahului Generating Station was reviewed with other available data provided by the Western Regional Air Partnership (WRAP) with consultation from both the EPA, Region 9 and the National Park Service (NPS). Based on our review, it is determined that the enforceable permit limit to shut down the boilers would provide a federally enforceable action to assure reasonable progress towards the achievement of natural visibility by 2064.

Recommend issuance of the significant amendment to the CSP subject to a sixty-day (60-day) formal review of the State's regional haze implementation plan by the NPS, thirty-day (30-day) public review and comment period in accordance with HAR §11-60.1 and 40 CFR §51.102, forty-five-day (45-day) EPA review period, and incorporation of the significant permit condition. It should be noted that this permit amendment will be part of the Hawaii's RH SIP in the second planning period.

Dale Hamamoto  
June 9, 2022

## Enclosure 1: Kahului Generating Station Control Measure Analysis

The four-factor analysis initially performed for the Kahului Generating Station is not required because Hawaiian Electric chose to permanently shut down the boilers rather than implement the control measures selected. For information, in considering the *four statutory factors* with a floor cost threshold of \$5,800 per ton of pollutant removed, the following control measures were selected in the four-factor analysis to make reasonable progress for the second planning period:

1. By **four (4) years from permit issuance**, switch from burning fuel oil No. 6, diesel, and specification used oil in Boilers K-1 through K-4 to ultra-low sulfur diesel (ULSD) with 0.0015% maximum sulfur content for reducing sulfur dioxide (SO<sub>2</sub>), nitrogen oxide (NO<sub>x</sub>), and particulate matter less than ten microns (PM<sub>10</sub>); and
2. By **December 31, 2027**, retrofit the boilers with selective catalytic reduction (SCR) and combustion controls (which includes low NO<sub>x</sub> burners (LNBS), flue gas recirculation (FGR), and over fire air (OFA)), or the required combination of these controls to further reduce and meet the NO<sub>x</sub> emission limits.

In considering the five (5) additional factors, a state may use one or more of these factors to exclude sources from the requirement of a control measure analysis. Emission reductions due to ongoing air pollution control programs is a primary consideration for reasonable progress since Hawaii's Renewable Portfolio Standards (RPS) have been enacted and reasonable progress is being made. Source retirement and replacement schedule is also a consideration since the RPS requires producers of electricity for sale to replace fossil-fueled sources with renewable sources phased in over time to ultimately achieve a goal of 100% renewable by 2045. In considering source retirement and replacement, the regional haze program requires an enforceable commitment to retire or replace these sources by 2028 for the second planning period to make reasonable progress. Pursuant to Hawaii's RH-SIP for the second planning period (2018-2028), the permit amendment incorporates the following Regional Haze Rule limit:

Boilers K-1 through K-4 shall be permanently shut down by December 31, 2027.

Because there is an enforceable shut down limit for the boilers by 2028, control measures initially selected in the four-factor analysis are not required. Refer to the sub-section titled; "Time Necessary for Compliance" for the discussion that led to the decision for using one of the five (5) additional factors for excluding these sources from the control measure analysis.

### *Four-Factor Analysis:*

Control measures that were under consideration for implementation by 2028 were determined based on the four-factor analysis performed by Hawaiian Electric for which Maui Electric is a subsidiary for the Kahului Generating Station. The four-factor analysis considers the following:

1. Cost of compliance;
2. The remaining useful life of the affected anthropogenic source of visibility impairment;
3. Time necessary for compliance; and
4. The energy and non-air quality environmental impacts of compliance.

## Enclosure 1: Kahului Generating Station Control Measure Analysis

Implementation of controls selected from the four-factor analysis would allow Hawaiian Electric to continue operating the Kahului boilers beyond 2027. The four-factor analysis for boilers at Kahului Generating Station is provided below for information.

### Calculating the Cost of Compliance:

A driving factor in selecting reasonable control measures is the cost of compliance, which is the cost effectiveness or the cost per tons of pollutant removed. Annualized amortization of capital cost or equivalent uniform annual cost (EUAC) is described in Environmental Protection Agency's (EPA's) Air Pollution Control Cost Manual and is one of the methodologies used to determine the cost of controls.

Costs were based on the following factors and assumptions:

1. Nominal interest rate.
2. Thirty (30) year remaining useful life for SCR retrofits to boilers.
3. Twenty-five (25) year remaining useful life for atomization equipment and berm liners.
4. Twenty (20) year remaining useful life for combustion controls (OFA, LNB, and/or FGR).
5. SCR retrofit factor of 1.
6. Maui Construction Cost Multiplier of 1.0.

### *Nominal Interest Rate*

Nominal interest rate described in EPA's Air Pollution Control Cost Manual, 7<sup>th</sup> edition\_2017 (CCM), Section 1, Chapter 2 (Pages 14 to 16), is the rate firms actually face. Chapter 2, Section 2.5.2 of the CCM recognizes that the determination of the firm-specific nominal interest rates depend on how they plan to finance their purchases, i.e., whether the firm intends to borrow to finance their investment or finance their purchases through cash holding or other means of equity. The CCM further states, if firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates given the potential difficulties in eliciting accurate firm-specific nominal interest rates since it may be regarded as confidential business information or difficult to verify.

Hawaiian Electric expressed their intent on using a weighted average cost of capital (WACC) method in their letter dated June 16, 2021, which comprises principally of a long-term debt interest rate of 4.54% and common equity interest rate of 9.5% as sources to finance their capital expenditures. Hawaiian Electric currently has a Moody long-term issuer rating of Baa1 and the prevailing Baa corporate bond yield shown in the Federal Reserve Economic Data at: <https://fred.stlouisfed.org/series/BAA> is less than 4%. Therefore, the 4.54% rate for the long-term debt used by Hawaiian Electric was replaced with the current Baa corporate bond yield as posted on the Federal Reserve website. For common equity, an interest rate of 9.5% is used by Hawaiian Electric which appears to be the ratemaking return of common equity (ROE) as explained on Hawaiian Electric's website at: <https://www.hawaiianelectric.com/about-us/key-performance-metrics/financial>. The "Ratemaking ROE" is the ROE that is authorized by the PUC and is not the actual ROE that investors receive. The purpose for the Ratemaking ROE is to determine whether there will be any sharing of actual earnings that exceed the threshold authorized by the PUC. The "Book ROE" is more appropriately used because it is a measure of a company's actual profit or "return" on shareholders' investments and best represents the opportunity cost or the amount of potential gain investors miss out on when common equity or

Enclosure 1: **Kahului Generating Station Control Measure Analysis**

investment funds are withdrawn for use to fund capital investments. The following table shows in red fonts, CAB's modifications to the WACC method used by Hawaiian Electric to derive the nominal interest rate for the Maui Island sources after consulting with the EPA.<sup>3</sup>

Maui Island Sources

	A	B	C	D
Source of Capital	Amount in Thousands	Percent of Total	Earnings	Weighted Earnings B X C
Short-Term Debt	6,718	1.37%	3.00%	0.041%
Long-Term Debt <sup>a</sup>	189,712	38.68%	3.24%	1.253%
Hybrid Securities	9,590	1.96%	7.16%	0.140%
Preferred Stock	4,804	0.98%	8.15%	0.080%
Common Equity <sup>b</sup>	279,655	57.02%	6.65%	3.792%
Total	490,479	100.00%		
Weighted Average Cost of Capital =				5.31%

<sup>a</sup> Moody's Seasoned Monthly Baa Corporate Bond Yield, (Percent) from:

<https://fred.stlouisfed.org/series/BAA>

<sup>b</sup> Hawaiian Electric book return of common equity (ROE) from:

<https://www.hawaiianelectric.com/about-us/key-performance-metrics/financial>

### Useful Life

In the situation of an enforceable requirement for the source to cease operation before the end of the useful life of the controls under consideration, EPA guidance allows the use of the enforceable shut down date as the end of the remaining useful life. If no enforceable shut down date exists for units requiring controls, the remaining useful life is the full useful life of the control under consideration.

Remaining useful life of thirty (30) years is used for SCR retrofits to boilers based on EPA's CCM, Section 2.4.2, Chapter 2 of the for SCR.

Twenty-five (25) years is assumed for atomization equipment and berm liners based on the referenced PUC filing in Hawaiian Electric's letter dated June 16, 2021, since there is no documented useful life for installation of fuel atomization systems and tank containment liners in the CCM. As indicated in the PUC filing (Docket Number 2020-0187) on November 10, 2020, for the Waiiau fuel tank containment project berm lining, the life expectancy of the liner, accounting for a majority of the capital costs, is upwards of twenty-five (25) years.

Twenty (20) years is assumed for OFA, LNB, and/or FGR.

<sup>3</sup>EPA email response dated July 12, 2021, titled, "Regional Haze Control Cost Interest Rate".

**Capital Cost to Fuel Switch**

Additional capital cost is required to support the boiler fuel switch as identified in Hawaiian Electric’s letter dated June 16, 2021, which includes completing the engineering research and design, boiler modifications to add fuel atomization, and installation of secondary containment liners. Required modifications to the boiler fuel-atomization system and fuel pumps are essential to allow for thorough combustion of the ULSD at the burner nozzle due to the difference in viscosity. Due the low viscosity of ULSD, the installation of secondary containment liners are required for larger fuel tanks that will switch from storing residual fuel oil No. 6 to ULSD to comply with EPA’s Spill Prevention, Controls, and Countermeasures (SPCC) Rule. This liner protects surface waters, drinking water, and ground water in the event of inadvertent release of ULSD to the environment.

In addition, fuel atomization is a process that breaks down liquid fuel into a mist-like spray to prepare for vaporization. The capital cost estimate to add mechanical fuel atomization of ULSD is based on the Black and Veatch (B&V) engineering studies for a similar project at the Waiau Power Generating Station, which provides an estimated average cost of about \$1.1 million (based on June 2013 dollars) per boiler for an average boiler size of 62.375 MW. The costs for each boiler at the Kahului Generating Station, which are all smaller than boilers at the Waiau Power Generating Station, are scaled down from the \$1.1 million per boiler reference cost using the "six-tenths factor" rule of thumb. This cost scaling method is based on the empirically observed relationship between the cost and the size of equipment. As size increases, cost increases by an exponent of six-tenths, e.g.  $cost1/cost2 = (size1/size2)^{0.6}$ .

The following table shows the additional capital expenditure estimates for adding the fuel atomization methodology to the boilers at Kahului Generating Station.

**Cost Estimate to add Fuel Atomization  
(Based on 2013 dollars)**

Unit	Size 1 MW	(Size 1/Size 2 <sup>a</sup> ) <sup>0.6</sup>	Capital Cost 1 Estimate <sub>2013</sub> <sup>b, c</sup>
Kahului K-1	5	2.20E-01	\$241,974
Kahului K-2	5	2.20E-01	\$241,974
Kahului K-3	11.5	3.63E-01	\$398,846
Kahului K-4	12.5	3.81E-01	\$419,307

- <sup>a</sup> Waiau Average Boiler Size 2 = 62.375 MW each.
- <sup>b</sup> Waiau reference boiler atomization Cost 2 = \$1,100,000 Capital Cost Estimate each from the B&V engineering studies are summarized as follows:
- <sup>c</sup> As size increases, cost increases by an exponent of six-tenths, e.g.  $cost1/cost2 = (size1/size2)^{0.6}$ .

Therefore,  $cost 1 = (size1/size2)^{0.6} \times cost 2$

**B&V Cost Summary by Unit**

	Mechanical Atomization	Steam Atomization
Waiau 3	\$926,874	\$1,013,300
Waiau 4	\$1,278,158	\$1,298,430
Waiau 5	\$1,063,623	\$914,646
Waiau 6	\$1,069,044	\$919,029
Waiau 7	\$1,126,858	\$1,525,645
Waiau 8	\$1,117,481	\$1,514,077
Ave Unit Cost	\$1,097,006	\$1,197,521

Enclosure 1: **Kahului Generating Station Control Measure Analysis**

The cost estimates are converted to 2019 dollars by applying the ratio of the Chemical Engineering Plant Cost Index (CEPCI) for 2019 of 607.5 divided by the CEPCI for 2013 of 567.3 or 107% as illustrated in the following table (refer to the Chemical Engineering Plant Cost Index Table on the last page of Enclosure 5):

**Cost Estimate to add Fuel Atomization  
(Adjustment to 2019 dollars)**

Unit	Size 1 MW	Capital Cost 1 Estimate <sub>2013</sub>	CEPCI <sub>2019</sub> /CEPCI <sub>2013</sub>	Capital Cost 1 Estimate <sub>2019</sub>
Kahului K-1	5	\$241,974	107%	\$259,121
Kahului K-2	5	\$241,974	107%	\$259,121
Kahului K-3	11.5	\$398,846	107%	\$427,109
Kahului K-4	12.5	\$419,307	107%	\$449,020

The capital cost estimate to install berm lining for the fuel switch to ULSD is based on the Hawaiian Electric cost estimates presented in their PUC filing (Docket Number 2020-0187) on November 10, 2020, for the Waiau fuel tank containment project berm lining. The capital costs for the Waiau project is \$5.23 Million to line an area of 78,400 square feet. Costs for the Kahului Generating Station are based on a scaling of the Waiau's Project costs to the smaller size of the combined berm areas.

**Cost Estimate for Secondary Containment Liner**

Island	Units	Berm Area to Line (Size 1)	(Size 1/Size 2) <sup>a,0.6</sup>	Capital Cost 1 Estimate <sup>b, c</sup>
Maui	Kahului K1 - K4	43,000	6.97E-01	\$3,645,710

<sup>a</sup> Waiau Reference Berm Area (Size 2) = 78,400 Square Feet

<sup>b</sup> Waiau Reference Liner Project Cost 2 = \$ 5,230,000 Capital Cost

<sup>c</sup> As size increases, cost increases by an exponent of six-tenths, e.g. cost1/cost2 = (size1/size2)<sup>0.6</sup>.

Therefore, cost 1 = (size1/size2)<sup>0.6</sup> x cost 2

Breakdown of the liner capital cost estimate of \$3,645,710 were by boiler capacity (MW) of each unit relative to the combined boiler capacity of 34 MW.

**Breakdown of Cost Estimate for Secondary Containment Liner by Units**

Units	Boiler Capacity (MW)	Capital Cost Estimate
Kahului K-1	5	\$536,324
Kahului K-2	5	\$536,324
Kahului K-3	11.5	\$1,233,544
Kahului K-4	12.5	\$1,340,809

Enclosure 1: **Kahului Generating Station Control Measure Analysis**

Capital Cost of SCR and Combustion Controls for NOx

The following table summarizes the Total Capital Investment or Capital Cost (in 2019 dollars) from Tables 7-1 and 7-2 in Enclosure 7 to refit the boilers with Combustion Controls and SCR for reducing emissions of NOx:

Units	K-1	K-2	K-3	K-4
Capital Cost of Combustion Controls (2019)	\$793,563	\$802,159	\$1,297,190	\$1,316,750
Capital Cost of SCR (2019)	\$2,623,236	\$2,656,291	\$4,345,933	\$4,387,432

Construction Cost Multiplier

Maui Electric used a Maui Island construction cost multiplier of 1.2 in the cost analysis for installing SCR. While it is appropriate to take into consideration the higher costs of transporting equipment and supplies, as well as higher labor rates, in unique areas like Hawaii and Alaska, those higher costs were not itemized, justified, and documented by Maui Electric. Therefore, a construction cost multiplier of 1.0 is assumed in estimating the cost of SCR for the Kahului Generating Station.

Capital Recovery Factors (CRF)

The CRFs listed in the following table are developed from the nominal interest rate and useful life of equipment:

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

	Control Measure→	Combustion Control (OFA, LNB, and/or FGR)	Atomization & Liner	SCR for Boilers
i	Nominal Interest Rate	5.31%	5.31%	5.31%
n	Useful Life (yrs)	20	25	30
CRF	Capital Recovery Factor	<b>0.0824</b>	<b>0.0732</b>	<b>0.0674</b>

Annual Cost and Cost Effectiveness:

The CRF amortizes capital cost to an equivalent annualized capital cost or the equivalent uniform annual cash flow (EUAC) approach, more commonly referred to as “amortization”. The combined annualized capital cost combined with annual operations and maintenance cost divided by the annual reduction in pollutants provides the cost effectiveness for each control measure as illustrated in the following tables:



Enclosure 1: **Kahului Generating Station Control Measure Analysis**

**Fuel Switch**

	<b>Units</b>	<b>K-1</b>	<b>K-2</b>	<b>K-3</b>	<b>K-4</b>
a	Capital Cost of Atomization	\$259,121	\$259,121	\$427,109	\$449,020
b	Capital Cost of Liners	\$536,324	\$536,324	\$1,233,544	\$1,340,809
c	Combined Capital Cost (2019) <sup>a</sup>	\$795,444	\$795,444	\$1,660,653	\$1,789,829
d	CRF	0.0732	0.0732	0.0732	0.0732
e	Annualized Capital Cost <sup>b</sup>	\$58,200	\$58,200	\$121,500	\$131,000
f	Annual Fuel Cost Differential <sup>c</sup>	\$1,704,479	\$1,473,028	\$5,225,092	\$4,511,548
g	Annual Cost of Fuel Switch <sup>d</sup>	\$1,762,679	\$1,531,228	\$5,346,592	\$4,642,548
h	Total SO <sub>2</sub> , NO <sub>x</sub> , and PM <sub>10</sub> Reduced (tpy) <sup>c</sup>	345.4	300.0	1062.1	875.0
i	Cost Effectiveness (\$/ton) <sup>e</sup>	<b>\$5,103</b>	<b>\$5,104</b>	<b>\$5,034</b>	<b>\$5,306</b>

a  $c = a + b$

b  $e = c * d$ , (truncated to the hundredth in Hawaiian Electric's spreadsheet).

c Refer to Table 6-1 of Enclosure 6. [Source: Data from Table 6.1 updated Aug 2021, of AECOM\_Ltr\_Att\_4\_Kahului\_RH\_FourFactor\_Analysis\_Tables.].

d  $g = e + f$

e  $i = g / h$

**Combustion Control**

	<b>Units</b>	<b>K-1</b>	<b>K-2</b>	<b>K-3</b>	<b>K-4</b>
a	Capital Cost (2019) <sup>a</sup>	\$793,563	\$802,159	\$1,297,190	\$1,316,750
b	CRF	0.0824	0.0824	0.0824	0.0824
c	Annualized Capital Cost (EUAC) <sup>b</sup>	\$65,362	\$66,070	\$106,843	\$108,454
d	Fixed O&M <sup>a</sup>	\$11,903	\$12,032	\$19,458	\$19,751
e	Variable O&M <sup>a</sup>	\$3,430	\$2,964	\$10,514	\$9,078
f	Annual Cost of Combustion Control <sup>c</sup>	<b>\$80,695</b>	<b>\$81,066</b>	<b>\$136,815</b>	<b>\$137,284</b>

a Refer to Table 7-1 of Enclosure 7. O&M represents operating and maintenance. [Source: Data from Kahului Appendix Table A-1 updated Aug 2021 of AECOM\_Ltr\_Att\_4\_Kahului\_RH\_FourFactor\_Analysis\_Tables.]

b  $c = a * b$

c  $f = c + d + e$

Enclosure 1: **Kahului Generating Station Control Measure Analysis**

**Fuel Switch + Combustion Control**

	<b>Units</b>	<b>K-1</b>	<b>K-2</b>	<b>K-3</b>	<b>K-4</b>
a	Annual Cost of Fuel Switch <sup>a</sup>	\$1,762,679	\$1,531,228	\$5,346,592	\$4,642,548
b	Annual Cost of Combustion Control <sup>b</sup>	\$80,695	\$81,066	\$136,815	\$137,284
c	Annual Cost of Fuel Switch + Combustion Control <sup>c</sup>	\$1,843,374	\$1,612,294	\$5,483,407	\$4,779,832
d	Baseline NOx Emissions in 2017 <sup>d</sup> (tpy)	65.8	62.3	292.6	182.7
e	NOx Removed after Fuel Switch <sup>e</sup> (tpy)	40.1	38.0	131.7	82.2
f	NOx Emissions after Fuel Switch <sup>f</sup> (tpy)	25.7	24.3	160.9	100.5
g	Additional NOx Removed from Combustion Control <sup>g</sup> (tpy)	12.9	12.1	80.5	50.2
h	NOx Emissions after Fuel Switch + Combustion Control <sup>h</sup> (tpy)	12.8	12.2	80.5	50.3
i	Reduction of SO <sub>2</sub> , NOx, and PM <sub>10</sub> from Fuel Switch <sup>e</sup> (tpy)	345.4	300.0	1062.1	875.0
j	Total Reductions of SO <sub>2</sub> , NOx, and PM <sub>10</sub> <sup>i</sup> (tpy)	358.2	312.2	1,142.6	925.2
k	Cost Effectiveness <sup>j</sup> (\$/ton)	<b>\$5,149</b>	<b>\$5,168</b>	<b>\$4,797</b>	<b>\$5,167</b>

- a From row g in the Fuel Switch Table.
- b From row f in the Combustion Control Table.
- c  $c = a + b$
- d Refer to Table 6-2 of Enclosure 6. [Source: Data from Table 4-4 updated Aug 2021, of AECOM\_Ltr\_Att\_4\_Kahului\_RH\_FourFactor\_Analysis\_Tables.]
- e Refer to Table 6-1 of Enclosure 6. [Source: Data from Table 6.1 updated Aug 2021, of AECOM\_Ltr\_Att\_4\_Kahului\_RH\_FourFactor\_Analysis\_Tables.]
- f  $f = d - e$
- g  $g = f * 50\%$ , Additional reductions in NOx emissions assuming 50% control efficiency from combustion controls after fuel switch.
- h  $h = f - g$
- i  $j = h + i$
- j  $k = c / j$

**SCR**

	<b>Units</b>	<b>K-1</b>	<b>K-2</b>	<b>K-3</b>	<b>K-4</b>
a	Capital Cost (2019) <sup>a</sup>	\$2,623,236	\$2,656,291	\$4,345,933	\$4,387,432
b	CRF	0.0674	0.0674	0.0674	0.0674
c	Annualized Capital Cost (EUAC) <sup>b</sup>	\$176,722	\$178,949	\$292,777	\$295,573
d	Fixed O&M <sup>a</sup>	\$17,313	\$17,532	\$28,683	\$28,957
e	Variable O&M <sup>a</sup>	\$30,918	\$27,532	\$98,385	\$76,068
f	Annual Cost of SCR <sup>c</sup>	\$224,954	\$224,013	\$419,846	\$400,598

- a Refer to Table 7-2 of Enclosure 7. [Source: Data from Kahului Appendix Table A-2 Updated Aug 2021 of AECOM\_Ltr\_Att\_4\_Kahului\_RH\_FourFactor\_Analysis\_Tables.]
- b  $c = a * b$
- c  $f = c + d + e$

Enclosure 1: **Kahului Generating Station Control Measure Analysis**

**Fuel Switch + SCR**

	<b>Units</b>	<b>K-1</b>	<b>K-2</b>	<b>K-3</b>	<b>K-4</b>
a	Annual Cost of Fuel Switch <sup>a</sup>	\$1,762,679	\$1,531,238	\$5,346,592	\$4,642,548
b	Annual Cost of SCR <sup>b</sup>	\$224,954	\$224,013	\$419,846	\$400,598
c	Annual Cost of Fuel Switch + SCR Control <sup>c</sup>	\$1,987,633	\$1,755,241	\$5,766,437	\$5,043,147
d	NOx Emissions after Fuel Switch (tpy) <sup>d</sup>	25.7	24.3	160.9	100.5
e	Additional NOx Removed with SCR (tpy) <sup>e</sup>	23.1	21.9	144.8	90.5
f	SO <sub>2</sub> , NOx, and PM <sub>10</sub> Removed from Fuel Switch <sup>f</sup> (tpy)	345.4	300.0	1,062.1	875.0
g	SO <sub>2</sub> , NOx, and PM <sub>10</sub> Removed from SCR + Fuel Switch <sup>g</sup> (tpy)	368.5	321.9	1,206.9	965.4
h	Cost Effectiveness <sup>h</sup>	<b>\$5,387</b>	<b>\$5,451</b>	<b>\$4,777</b>	<b>\$5,221</b>

a From row g in the Fuel Switch Table.

b From row f in the SCR Table.

c  $c = a + b$

d From row f in the Fuel Switch + Combustion Control Table.

e  $g = f * 90\%$ , Additional reductions in NOx emissions assuming 90% control efficiency with SCR after fuel switch.

f Refer to Table 6-1 of Enclosure 6. [Source: Data from Table 6.1, of AECOM\_Ltr\_Att\_4\_Kahului\_RH\_FourFactor\_Analysis\_Tables.].

g  $g = e + f$

h  $h = c / g$

**Additional NOx Removed with SCR and Combustion Control after Fuel Switch**

	<b>Units</b>	<b>K-1</b>	<b>K-2</b>	<b>K-3</b>	<b>K-4</b>
a	2017 Annual Heat Input <sup>a</sup> (MMBtu/yr)	313,473	270,907	960,954	829,725
b	NOx Emission Limit <sup>b</sup> (lb/MMBtu)	0.05	0.05	0.05	0.05
c	Emissions from SCR after Fuel Switch + Combustion Control <sup>c</sup> (tpy)	7.8	6.8	24.0	20.7
d	NOx Emissions after Fuel Switch <sup>d</sup> (tpy)	25.7	24.3	160.9	100.5
e	Additional NOx Removed with SCR + Combustion Control after Fuel Switch <sup>e</sup> (tpy)	<b>17.9</b>	<b>17.5</b>	<b>136.9</b>	<b>79.8</b>

a 2017 annual boiler heat input as shown on Table 4-4 of AECOM\_Ltr\_Attc\_4\_Kahului\_RH\_FourFactor\_Analysis\_Tables.

b Section 2.3.5 in the SCR Cost Manual Chapter 7, Edition 2016, Revision 2017 (Manual) states that the annual average outlet NOx should not be less than 0.04 lb/MMBtu, or at a level that results in a removal efficiency greater than 90%, unless a guarantee has been obtained from a vendor. However, section 2.3.5 of Chapter 7 of the Manual also states that 0.05 lb/MMBtu outlet NOx based on a 30-day (boiler operating) average should be obtainable by a power plant boiler with an SCR system.<sup>4</sup>

c  $c = a * b * (1 \text{ ton} / 2,000 \text{ lbs})$

d From row f in the Fuel Switch + Combustion Control Table.

e  $e = d - c$

<sup>4</sup>EPA email response dated July 29, 2021, titled, "NOx Limit".

Enclosure 1: **Kahului Generating Station Control Measure Analysis**

**Cost Effectiveness of SCR + Combustion Control + Fuel Switch**

	<b>Units</b>	<b>K-1</b>	<b>K-2</b>	<b>K-3</b>	<b>K-4</b>
a	Annual Cost of Fuel Switch + Combustion Control <sup>a</sup>	\$1,843,374	\$1,612,294	\$5,483,407	\$4,779,832
b	Annual Cost of SCR <sup>b</sup>	\$224,954	\$224,013	\$419,846	\$400,598
c	Annual Cost of Fuel Switch + Combustion Control + SCR <sup>c</sup>	\$2,068,328	\$1,836,307	\$5,903,253	\$5,180,430
d	Baseline NOx Emissions in 2017 (tpy) <sup>b</sup>	65.8	62.3	292.6	182.7
e	NOx Emissions after Fuel Switch <sup>e</sup> (tpy)	25.7	24.3	160.9	100.5
f	NOx Removed after Fuel Switch <sup>f</sup> (tpy)	40.1	38.0	131.7	82.2
g	Additional NOx Removed with SCR + Combustion Control after Fuel Switch <sup>g</sup> (tpy)	17.8	17.5	136.9	79.7
h	Total NOx Removed after Fuel Switch + Combustion Control + SCR <sup>h</sup> (tpy)	58.1	55.6	268.7	162.1
i	SO <sub>2</sub> Removed after Fuel Switch <sup>i</sup> (tpy)	292.9	253.1	897.8	775.2
j	PM <sub>10</sub> Removed after Fuel Switch <sup>i</sup> (tpy)	12.4	8.9	32.6	17.6
k	Total Pollutants Removed after Fuel Switch + Combustion Control + SCR <sup>j</sup> (tpy)	363	318	1,199	955
l	Cost Effectiveness of Fuel Switch + Combustion Control + SCR <sup>i</sup> (\$/ton)	<b>\$5,698</b>	<b>\$5,775</b>	<b>\$4,923</b>	<b>\$5,424</b>

a From row c in the Fuel Switch + Combustion Control Table.

b From row f in the SCR Table.

c c = a + b

d Refer to Table 6-2 of Enclosure 6. [Source: 2017 NOx emissions as shown on Table 4-4 of AECOM\_Ltr\_Attch\_4\_Kahului\_RH\_FourFactor\_Analysis\_Tables].

e From row f in the Fuel Switch + Combustion Control Table.

f Section 2.3.4 in Chapter 2 of the SCR Cost Manual Chapter 7, Edition 2016, Revision 2017 states that the inlet NOx (NOxin) is the emission level in the flue gas exit stream from a boiler, which also accounts for combustion controls at the inlet of the SCR system.

g From row e in the Additional NOx Removed with SCR and Combustion Control after Fuel Switch Table assuming 0.05 lb/MMBtu NOx emissions from SCR after fuel switch and combustion controls.

h h = f + g

i Refer to Table 6-1 of Enclosure 6. [Source: 2017 data as shown on Table 6-1 of AECOM\_Ltr\_Attch\_4\_Kahului\_RH\_FourFactor\_Analysis\_Tables.]

j k = h + i + j

k l = c / k

## Enclosure 1: Kahului Generating Station Control Measure Analysis

Hawaiian Electric's Power Supply Improvement Plan (PSIP) to retire Kahului Generating Station was not initially used as an enforceable control measure because Hawaiian Electric was unable to provide a firm commitment date as to when the renewable projects will be available as an alternate source of energy to replace energy generated with fossil fuels. 40 CFR Part 51, §51.308(f)(2) states that the long-term strategy must include the enforceable emission limitations, compliance schedules and other measures necessary to make reasonable progress. Section II.B.5.e) of EPA's Guidance on Regional Haze State Implementation Plans for the Second Implementation Period further states, "The time necessary for compliance generally is considered to be a source-by-source question, with each source required to comply by a date that is reasonable for that source." As such, a lack of a firm schedule for retiring plant equipment precludes the use of this plan as a federally enforceable control measure. However, in our meeting on October 7, 2021, Hawaiian Electric agreed to commit to an enforceable source retirement date by the end of the second planning period. Refer to the section titled, "Time Necessary for Compliance" in this review for details of our discussion.

### Establish a Reasonable Cost Threshold:

In the first planning period, \$5,000/ton of pollutant removed in 2009 dollars (one year into the first regional haze planning period) was the established cost threshold for cost effective control measures. This cost threshold was inflated to \$5,800/ton to represent 2019 dollars (one year into the second regional haze planning period) by multiplying the \$5,000/ton threshold in 2009 by the ratio of the 2019-to-2009 Chemical Engineering Plant Cost Index (CEPCI). The CEPCI, used extensively by the EPA for this type of analysis, is the basis for this application. Refer to Enclosure 5 for the CEPCI data.

### Time Necessary for Compliance:

Hawaiian Electric indicated in their letter dated June 16, 2021, that if a specific compliance date is necessary for switching fuel, it proposes December 31, 2027. Explanations from Hawaiian Electric to justify its proposed compliance schedule included:

- Switching from fuel oil No. 6 to ULSD and installing combustion controls and SCR for boilers at the Kahului Generating Station requires significant capital investments.<sup>5</sup> Because of the planned implementation of the renewable portfolio standard (RPS) goals, these investments will only have short-lived benefits and potentially impose significant costs to the Hawaiian Electric customers.<sup>6</sup>
- A more flexible schedule will allow Hawaiian Electric's current efforts to the RPS goal to be realized, including the retirement and lower utilization of some of these facilities.<sup>5,6</sup>
- Additional costs for the fuel switch are secondary containment liners for the larger fuel oil tanks that will switch to store ULSD.<sup>5,6</sup>
- Additional costs involving fuel atomization modifications for the boilers due to the lower viscosity of ULSD are also required.<sup>5,6</sup>
- There have been unexpected delays for some of the renewable projects. There are factors that are not completely within Hawaiian Electric's control including when the Hawaii Public Utilities Commission (PUC) will approve the projects or other delays with installing the facilities.<sup>5</sup>
- Additional time is needed to obtain PUC approval of the projects.<sup>5</sup>

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<sup>5</sup>Hawaiian Electric's June 16, 2021, letter

<sup>6</sup>Hawaiian Electric's March 30, 2021, letter.

## Enclosure 1: Kahului Generating Station Control Measure Analysis

In CAB discussions with EPA, Region 9, it was agreed that a three-year (3-year) duration following issuance of the permit for implementing fuel switching and five-year (5-year) duration following issuance of the permit for implementing SCR and combustion controls were reasonable based on information from regional haze four-factor analyses. Compliance deadlines should be specific, objectively determined, and justified as reasonable considering available historical data regarding time necessary for the installation of similar control measures.<sup>1</sup> A specific compliance date was specified to accomplish fuel switches for boilers at the Kahului Generating Station which is consistent with EPA guidance and the four-factor analyses.

According to Hawaiian Electric's PSIP, boilers operating at the Kahului Generating Station will be retired in 2024. However, as indicated in an email from Ms. Marisa Melzer of Hawaiian Electric on September 17, 2021, the actual schedule for retiring these units has not been firmly established.

In discussions with EPA and the National Park Service (NPS) there was disagreement with allowing an extension of time for switching fuels to implement the RPS goals for retiring equipment. Again, the compliance deadline needs to be based on historical data of the time necessary for installation of similar control measures. Hawaiian Electric indicated that installation of equipment and secondary containment improvements will take up to two (2) years. Because the project costs are estimated to exceed the PUC threshold of \$2.5 million, the project will also require PUC approval which typically takes up to twelve (12) months but could take longer if the process is contested or if the application is not well supported.<sup>7</sup>

Based on source-specific factors, CAB considered an extension of the time to accomplish a fuel switch to ULSD at the Kahului Generating Station reasonable to allow additional time of up to two (2) years for PUC approval and an additional two (2) years to install tank containment liners and fuel atomization systems after the PUC approval process. Therefore, CAB proposed to extend the compliance date for fuel switching from three (3) years to four (4) years after issuance of the permit amendment to incorporate this regional haze control measure for the Kahului boilers.

The cost of installing fuel atomization systems and secondary tank containment liners to switch fuel to ULSD for the Kahului boilers ranged from \$5,103/ton to \$5,306/ton and the cost of SCR plus combustion controls after the fuel switch ranged from \$4,923/ton to \$5,775/ton which are below the \$5,800/ton threshold. Refer to tables titled "Fuel Switch" and "Cost Effectiveness of SCR + Combustion Control + Fuel Switch" on Pages 16 and 19, respectively, of this technical support document. However, during a meeting on October 7, 2021, Hawaiian Electric agreed to an enforceable shut down of the Kahului boilers by December 31, 2027. EPA guidance allows an option of not selecting sources for control measure analysis that have an enforceable commitment to be retired or replaced by 2028<sup>1</sup>. Therefore, regional haze control measures are not required for the Kahului Generating Station boilers.

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<sup>7</sup>PUC email dated October 13, 2021.

## Enclosure 1: Kahului Generating Station Control Measure Analysis

In our meeting with Hawaiian Electric on October 7, 2021, we discussed planned renewable energy projects that are either already approved or have been submitted for PUC approval with a proposed combined production capacity and infrastructure that will enable Kahului Generating Station to permanently retire by the end of the second planning period. Additional projects need to come onto the system before Hawaiian Electric is able to shut down approximately 40 MW of power generation from the Kahului Generating Station. A project with 60 MW capacity approved by the PUC may be done by end of 2023. A number of other projects, currently in contested case hearings, are likely to be online in 2023. Another project that needs to get approved is a switch yard in Kahului to preclude a bottleneck. Once these projects are complete, Hawaiian Electric plans to convert the generators for Kahului K-3 and K-4 to synchronous condensers, followed by retiring Kahului K-1 and K-2 by the end of 2024, possibly further into the future. Once Kahului boilers are retired, these boilers will no longer need to generate steam to operate the synchronous condensers. Therefore, fuel combustion will cease and an air permit will no longer be needed. Based on KIUC's 2019 Annual Report<sup>8</sup>, synchronous condensers require little or no fuel to provide inertia, fault current, voltage support, and frequency stabilization to the grid, which is vital given the intermittent nature of most sources of renewable energy. Hawaiian Electric prefers to push out the fuel switch date to 2027 over committing to an enforceable source retirement date, however, is willing to commit to either fuel switch or to retire these boilers if they are able to extend their commitment date to the end of 2027. In review of these factors, the CAB considers the option to retire the Kahului Generating Facility by December 31, 2027, to be a realistically achievable and more cost-effective approach to make reasonable progress.

### Energy and Non-Air Quality Environmental Impacts of Compliance:

Fuel switching from residual oil to ULSD may have an indirect energy impact during fuel refining, however, Section II.B.4.e) of EPA's Guidance<sup>1</sup> recommends that states focus their analysis on direct energy consumption at the source rather than indirect energy inputs needed to produce raw materials. Therefore, the energy impact of refining ULSD is accounted for by including the annual fuel cost difference between fuel oil No. 6 and ULSD in with the cost of compliance. Firing ULSD will have a direct energy impact due to reduced boiler efficiency if an atomization system is not installed. Also, the lower viscosity of ULSD can have non-air quality environmental impacts in the event of inadvertent or accidental spills. Therefore, the annualized capital cost of installing both an atomization system and secondary containments to comply with SPCC requirements are also included as an annualized cost of compliance.

Combustion controls do not have non-air quality environment impacts; however, improper feed rate of OFA can result in heat loss and decreased boiler efficiency.

### Control Measures:

Since the permit amendment will specify a federally enforceable limit to permanently retire the Kahului Generating Station boilers by December 31, 2027, the following control measures will not be required:

1. A fuel switch from fuel oil No. 6 and specification used oil to ULSD containing 0.0015% maximum sulfur content **within four (4) years from permit issuance** to reduce SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub>; and

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<sup>8</sup>[https://website.kiuc.coop/sites/kiuc/files/documents/annualreport/AnnualReport19\\_web.pdf](https://website.kiuc.coop/sites/kiuc/files/documents/annualreport/AnnualReport19_web.pdf)

## Enclosure 1: Kahului Generating Station Control Measure Analysis

2. SCR and combustion controls after the fuel switch by **December 31, 2027**, to further control NO<sub>x</sub>.

An LNB retrofit can achieve approximately 35 to 55 percent reductions in NO<sub>x</sub>, and 40 to 60 percent reductions when used with OFA, both from uncontrolled levels. The LNB limits NO<sub>x</sub> formation by: (1) reducing oxygen in the primary combustion zone; (2) reducing flame temperature; and (3) reducing residence time at peak temperature.

FGR can lower emissions of NO<sub>x</sub> by as much as 40 to 50 percent in some boilers. This is accomplished by recirculating a portion of the flue gas from the economizer or air heater outlet back to the furnace that reduces oxygen and flame temperature in the combustion zone. Carbon monoxide (CO) levels remain constant or are reduced because flue gas introduced into the early stages of combustion with the air fuel mixing is intensified.

OFA is a technique in which a percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. OFA limits NO<sub>x</sub> by: (1) suppressing thermal NO<sub>x</sub> by partially delaying and extending the combustion process resulting in less intense combustion and cooler flame temperatures; (2) reducing flame temperature that limits thermal NO<sub>x</sub> formation; and/or (3) reducing residence time at peak temperature that limits thermal NO<sub>x</sub> formation. The re-mixing of flue gases causes secondary combustion, releasing heat that transfers through the boiler heating surfaces and into the water within the vessel. Theoretically, stoichiometric combustion optimizes the process, where every available fuel molecule released is matched by an oxygen molecule resulting in a flue gas with no CO and oxygen. However, the feed rate is critical since a lack of OFA can increase emissions of CO and other combustibles, and result in heat loss and decreased boiler efficiency. An over-abundance of OFA will also result in heat loss absorbed by the excess air, which can also decrease boiler efficiency.

SCR is a post combustion control measure where ammonia (NH<sub>3</sub>) is injected into the boiler's flue gas stream in presence of a catalyst to reduce the emissions of NO<sub>x</sub>.

### Ambient Air Quality Assessment:

For incorporating regional haze control measures for the boilers if an enforceable shut down limit had not been specified in the permit, an AAQIA would still not have been performed based on the following:

1. Except for the emissions of NH<sub>3</sub> from the SCR system, which is not a criteria pollutant or HAP, there are no increase in the emissions of all criteria pollutants and HAPs; and
2. An emission limit of ten (10) parts per million by volume dry (ppmvd) would have been specified for NH<sub>3</sub> slip. According to EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-032), ammonia slip at this level does not result in plume formation or human health hazard.



Enclosure 1: **Kahului Generating Station Control Measure Analysis**

Significant Permit Conditions:

The following significant permit conditions would have been required if there was no enforceable permit limit to shut down the boilers by 2028:

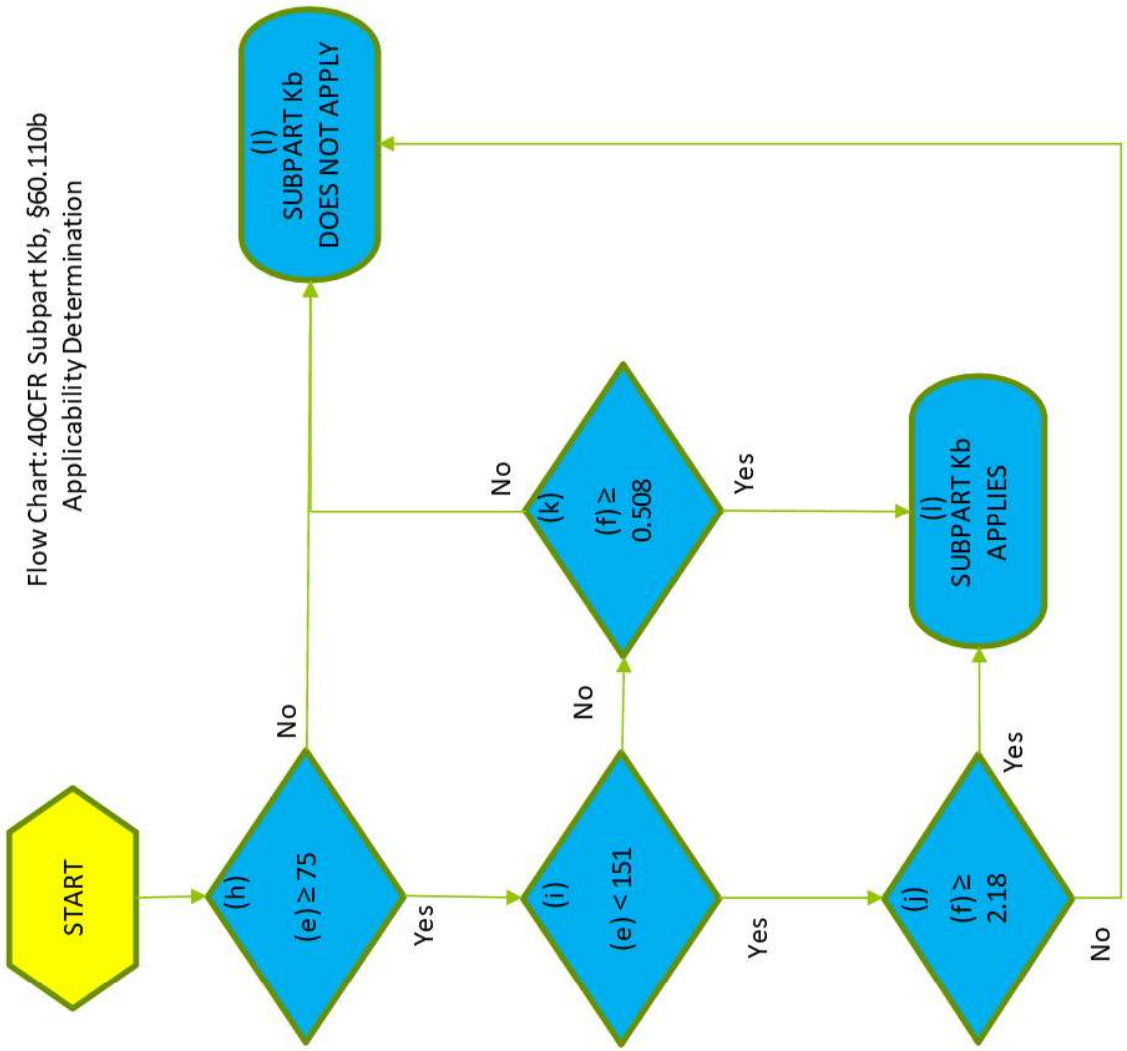
1. **Four (4) years from permit issuance**, Kahului Generating Station, Boilers K-1, K-2, K-3, and K-4 shall only be fired on ULSD with a maximum sulfur content not to exceed 0.0015% by weight.
2. **By December 31, 2027**, Kahului Generating Station, Boilers K-1, K-2, K-3, and K-4 shall be subject to an emission limit of 0.05 lb/MMBtu in any thirty-day (30-day) rolling average per boiler for NO<sub>x</sub>. In addition, these boilers shall be subject to a three-hour (3-hour) average NH<sub>3</sub> exhaust concentration limit of ten (10) ppmvd at the SCR outlet.
3. Incorporate installation, calibration, operation, maintenance, and testing requirements of the continuous emissions monitoring system (CEMS) for NO<sub>x</sub> and NH<sub>3</sub> slip monitoring system. This includes the record keeping and reporting requirements.

Reason: Four-factor analysis for second planning period (2018-2028) and Section 2.3.5 in Chapter 2 of EPA's SCR Control Cost Manual Chapter 7, edition 2016, revision 2017.<sup>4</sup>



Enclosure 2: Storage Tanks

Flow Chart: 40CFR Subpart Kb, §60.110b  
Applicability Determination



Enclosure 3: **Project Emissions of Criteria Pollutants and HAPs**

1. Summary of Criteria Pollutants, NH<sub>3</sub>, and H<sub>2</sub>SO<sub>4</sub> Emissions:

Table 3-1-1

Pollutants	Boiler Units Fired on Existing Fuel Oil No. 6 (TPY)				Sub-Totals
	K-1	K-2	K-3	K-4	
SO <sub>2</sub>	906.8	906.8	1,659.3	1,746.1	5,219.1
H <sub>2</sub> SO <sub>4</sub>	119.0	119.0	217.7	229.1	684.7
NO <sub>x</sub>	237.5	237.5	465.2	531.8	1,472.0
CO	27.3	27.3	49.9	52.5	157.0
VOC <sup>a</sup>	1.5	1.5	3.8	4.0	10.9
PM	158.4	280.1	604.7	483.9	1,527.2
PM <sub>10</sub>	125.2	221.3	477.8	382.3	1,206.5
PM <sub>2.5</sub>	71.3	126.1	272.2	217.8	687.3
Lead (P <sub>b</sub> )	4.14E-03	4.14E-03	7.58E-03	7.98E-03	2.38E-02
NH <sub>3</sub> Fuel Combustion	2.4	2.4	4.3	4.5	13.5

Table 3-1-2

Pollutants	Boiler Units with Fuel Switched to ULSD (TPY)				Sub-Totals
	K-1	K-2	K-3	K-4	
SO <sub>2</sub>	0.6	0.6	1.1	1.2	3.6
H <sub>2</sub> SO <sub>4</sub>	0.1	0.1	0.2	0.2	0.5
NO <sub>x</sub>	58.8	58.8	129.1	135.9	382.7
CO	14.7	14.7	26.9	28.3	84.6
VOC <sup>a</sup>	0.7	1.6	1.4	1.4	5.1
PM	3.8	3.8	7.0	7.4	22.0
PM <sub>10</sub>	2.9	2.9	5.4	5.7	16.9
PM <sub>2.5</sub>	0.7	0.7	1.3	1.4	4.2
Lead (P <sub>b</sub> )	2.13E-02	3.71E-03	6.78E-03	7.14E-03	3.89E-02
NH <sub>3</sub> Fuel Combustion	2.4	2.4	4.3	4.5	13.5

Enclosure 3: **Project Emissions of Criteria Pollutants and HAPs**

**Table 3-1-3**

Pollutants	Boiler Units with Proposed SCR + Combustion Controls (TPY)				Sub-Totals
	K-1	K-2	K-3	K-4	
SO <sub>2</sub>	0.6	0.6	1.1	1.2	3.6
H <sub>2</sub> SO <sub>4</sub>	0.1	0.1	0.2	0.2	0.5
NO <sub>x</sub>	20.6	20.6	37.7	39.6	118.5
CO	14.7	14.7	26.9	28.3	84.6
VOC <sup>a</sup>	0.7	1.6	1.4	1.4	5.1
PM	3.8	3.8	7.0	7.4	22.0
PM <sub>10</sub>	2.9	2.9	5.4	5.7	16.9
PM <sub>2.5</sub>	0.7	0.7	1.3	1.4	4.2
Lead (Pb)	2.13E-02	3.71E-03	6.78E-03	7.14E-03	3.89E-02
NH <sub>3</sub> Fuel Combustion	2.4	2.4	4.3	4.5	13.5
NH <sub>3</sub> SCR	4.1	4.1	7.5	7.9	23.7
NH <sub>3</sub> Combined	6.5	6.5	11.8	12.5	37.2

**2. Details of Criteria Pollutants and H<sub>2</sub>SO<sub>4</sub> Emissions:**

**Table 3-2-1. a. 5 MW (94 MMBtu/hr) Boiler Emissions (Unit K-1)**

Pollutant	Existing <sup>a</sup>		Proposed Fuel Switch <sup>b</sup>		
	Emission Rates using Fuel Oil No. 6		Emission Factor (lb/10 <sup>3</sup> gal)	Emission Rates with ULSD	
	(lb/hr)	(tpy)		(lb/hr) <sup>c</sup>	(tpy) <sup>d</sup>
SO <sub>2</sub> <sup>f</sup>	207.04	907	--	1.43E-01	0.6
H <sub>2</sub> SO <sub>4</sub> <sup>g</sup>	27.16	119	--	1.88E-02	0.1
NO <sub>x</sub>	54.22	237	20.0	13.4	58.8
CO	6.23	27	5.0	3.4	14.7
VOCs <sup>h</sup>	0.35	1.5	0.252	0.2	0.7
PM	36.17	158	1.3	0.9	3.8
PM <sub>10</sub> <sup>i</sup>	28.57	125	1.0	0.7	2.9
PM <sub>2.5</sub> <sup>i</sup>	16.28	71	0.25	0.2	0.7
Lead (Pb) <sup>j</sup>	9.46E-04	4.14E-03	--	4.87E-03	2.13E-02
NH <sub>3</sub> <sup>k</sup>	0.5	2.4	0.80	0.5	2.4

Enclosure 3: **Project Emissions of Criteria Pollutants and HAPs**

**Table 3-2-1. b. 5 MW (94 MMBtu/hr) Boiler Emissions (Unit K-1)**

Pollutant	Proposed SCR + Combustion Controls <sup>e</sup>					
	Emission Factor	Emission Rate with ULSD+LNB/FGR		NOx Emission Limit	Emission Rates	
	(lb/10 <sup>3</sup> gal)	(lb/hr) <sup>c</sup>	(tpy) <sup>d</sup>	(lb/MMBtu)	(lb/hr)	(tpy) <sup>d</sup>
SO <sub>2</sub> <sup>f</sup>	--	--	--	--	1.43E-01	0.6
H <sub>2</sub> SO <sub>4</sub> <sup>g</sup>	--	--	--	--	1.88E-02	0.1
NO <sub>x</sub>	10.0	6.7	29.4	0.05	4.7	20.6
CO	--	--	--	--	3.4	14.7
VOCs <sup>h</sup>	--	--	--	--	0.2	0.7
PM	--	--	--	--	0.9	3.8
PM <sub>10</sub> <sup>i</sup>	--	--	--	--	0.7	2.9
PM <sub>2.5</sub> <sup>i</sup>	--	--	--	--	0.2	0.7
Lead (Pb) <sup>j</sup>	--	--	--	--	4.87E-03	2.13E-02
NH <sub>3</sub> <sup>k</sup>	0.80	--	--	--	0.9	4.1

**Table 3-2-2.a 5 MW (94 MMBtu/hr) Boiler Emissions (Unit K-2)**

Pollutant	Existing <sup>a</sup>			Proposed Fuel Switch <sup>b</sup>		
	Emission Rates using Fuel Oil No. 6			Emission Factor	Emission Rates with ULSD	
	(lb/hr)	(g/s)	(tpy)	(lb/10 <sup>3</sup> gal)	(lb/hr) <sup>c</sup>	(tpy) <sup>d</sup>
SO <sub>2</sub> <sup>f</sup>	207.04	26.141	907	--	1.43E-01	0.6
H <sub>2</sub> SO <sub>4</sub> <sup>g</sup>	27.16	3.430	119	--	1.88E-02	0.1
NO <sub>x</sub>	54.22	6.846	237	20.0	13.4	58.8
CO	6.23	0.787	27	5.0	3.4	14.7
VOCs <sup>h</sup>	0.35	0.044	1.5	0.252	0.4	1.6
PM	63.96	8.076	280	1.3	0.9	3.8
PM <sub>10</sub> <sup>i</sup>	50.53	6.380	221	1.0	0.7	2.9
PM <sub>2.5</sub> <sup>i</sup>	28.78	3.634	126	0.25	0.2	0.7
Lead (Pb) <sup>j</sup>	9.46E-04	1.19E-04	4.14E-03	--	8.46E-04	3.71E-03
NH <sub>3</sub> <sup>k</sup>	0.5	0.4	2.4	0.80	0.5	2.4

**Table 3-2-2.b 5 MW (94 MMBtu/hr) Boiler Emissions (Unit K-2)**

Pollutant	Proposed SCR + Combustion Controls <sup>e</sup>					
	Emission Factor	Emission Rates with ULSD+LNB/FGR		NOx Emission Limit	Emission Rates	
	(lb/10 <sup>3</sup> gal)	(lb/hr) <sup>c</sup>	(tpy) <sup>d</sup>	(lb/MMBtu)	(lb/hr)	(tpy) <sup>d</sup>
SO <sub>2</sub> <sup>f</sup>	--	--	--	--	1.43E-01	0.6
H <sub>2</sub> SO <sub>4</sub> <sup>g</sup>	--	--	--	--	1.88E-02	0.1
NO <sub>x</sub>	10.0	6.7	29.4	0.05	4.7	20.6
CO	--	--	--	--	3.4	14.7
VOCs <sup>h</sup>	--	--	--	--	0.4	1.6
PM	--	--	--	--	0.9	3.8
PM <sub>10</sub> <sup>i</sup>	--	--	--	--	0.7	2.9
PM <sub>2.5</sub> <sup>i</sup>	--	--	--	--	0.2	0.7
Lead (Pb) <sup>j</sup>	--	--	--	--	8.46E-04	3.71E-03
NH <sub>3</sub> <sup>k</sup>	1.40	--	--	--	0.9	4.1

Enclosure 3: **Project Emissions of Criteria Pollutants and HAPs**

**Table 3-2-3.a 11.5 MW (172 MMBtu/hr) Boiler Emissions (Unit K-3)**

Pollutant	Existing <sup>a</sup>			Proposed Fuel Switch <sup>b</sup>		
	Emission Rates using Fuel Oil No. 6			Emission Factor <sup>b</sup>	Emission Rates with ULSD <sup>b</sup>	
	(lb/hr)	(g/s)	(tpy)		(lb/10 <sup>3</sup> gal)	(lb/hr) <sup>c</sup>
SO <sub>2</sub> <sup>f</sup>	378.83	47.832	1659	--	2.62E-01	1.1
H <sub>2</sub> SO <sub>4</sub> <sup>g</sup>	49.70	6.276	218	--	3.43E-02	0.2
NO <sub>x</sub>	106.21	13.410	465	24.0	29.5	129.1
CO	11.39	1.438	50	5.0	6.1	26.9
VOCs <sup>h</sup>	0.87	0.110	3.8	0.252	0.310	1.4
PM	138.06	17.432	605	1.3	1.6	7.0
PM <sub>10</sub> <sup>i</sup>	109.08	13.773	478	1.0	1.2	5.4
PM <sub>2.5</sub> <sup>i</sup>	62.14	7.846	272	0.25	0.3	1.3
Lead (Pb) <sup>j</sup>	1.73E-03	2.18E-04	7.58E-03	--	1.55E-03	6.78E-03
NH <sub>3</sub> <sup>k</sup>	1.0	1.2	4.3	0.80	1.0	4.3

**Table 3-2-3.b 11.5 MW (172 MMBtu/hr) Boiler Emissions (Unit K-3)**

Pollutant	Proposed SCR + Combustion Controls <sup>e</sup>					
	Emission Factor	Emission Rates with ULSD+LNB/FGR		NO <sub>x</sub> Emission Limit	Emission Rates	
		(lb/10 <sup>3</sup> gal)	(lb/hr) <sup>c</sup>		(tpy) <sup>d</sup>	(lb/hr)
SO <sub>2</sub> <sup>f</sup>	--	--	--	--	2.62E-01	1.1
H <sub>2</sub> SO <sub>4</sub> <sup>g</sup>	--	--	--	--	3.43E-02	0.2
NO <sub>x</sub>	10.0	12.3	53.8	0.05	8.6	37.7
CO	--	--	--	--	6.1	26.9
VOCs <sup>h</sup>	--	--	--	--	0.3	1.4
PM	--	--	--	--	1.6	7.0
PM <sub>10</sub> <sup>i</sup>	--	--	--	--	1.2	5.4
PM <sub>2.5</sub> <sup>i</sup>	--	--	--	--	0.3	1.3
Lead (Pb) <sup>j</sup>	--	--	--	--	1.55E-03	6.78E-03
NH <sub>3</sub> <sup>k</sup>	1.40	--	--	--	1.7	7.5

**Table 3-2-4.a 12.5 MW (181 MMBtu/hr) Boiler Emissions (Unit K-4)**

Pollutant	Existing <sup>a</sup>			Proposed Fuel Switch <sup>b</sup>		
	Emission Rates using Fuel Oil No. 6			Emission Factor <sup>b</sup>	Emission Rates with ULSD <sup>b</sup>	
	(lb/hr)	(g/s)	(tpy)		(lb/10 <sup>3</sup> gal)	(lb/hr) <sup>c</sup>
SO <sub>2</sub> <sup>f</sup>	398.66	50.336	1746	--	2.75E-01	1.2
H <sub>2</sub> SO <sub>4</sub> <sup>g</sup>	52.30	6.604	229	--	3.61E-02	0.2
NO <sub>x</sub>	121.420	15.331	532	24.0	31.0	135.9
CO	11.990	1.514	53	5.0	6.5	28.3
VOCs <sup>h</sup>	0.920	0.116	4.0	0.252	0.310	1.4
PM	110.480	13.949	484	1.3	1.7	7.4
PM <sub>10</sub> <sup>i</sup>	87.280	11.020	382	1.0	1.3	5.7
PM <sub>2.5</sub> <sup>i</sup>	49.720	6.278	218	0.25	0.3	1.4
Lead (Pb) <sup>j</sup>	1.82E-03	2.30E-04	7.98E-03	--	1.63E-03	7.14E-03
NH <sub>3</sub> <sup>k</sup>	1.0	1.3	4.5	0.80	1.0	4.5

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**Table 3-2-4.b 12.5 MW (181 MMBtu/hr) Boiler Emissions (Unit K-4)**

Pollutant	Proposed SCR + Combustion Controls <sup>e</sup>					
	Emission Factor	Emission Rates with ULSD+LNB/FGR		NOx Emission Limit	Emission Rates	
	(lb/10 <sup>3</sup> gal)	(lb/hr) <sup>c</sup>	(tpy) <sup>d</sup>	(lbs/MMBtu)	(lb/hr)	(tpy) <sup>d</sup>
SO <sub>2</sub> <sup>f</sup>	--	--	--	--	2.75E-01	1.2
H <sub>2</sub> SO <sub>4</sub> <sup>g</sup>	--	--	--	--	3.61E-02	0.2
NO <sub>x</sub>	10.0	12.9	56.6	0.05	9.1	39.6
CO	--	--	--	--	6.5	28.3
VOCs <sup>h</sup>	--	--	--	--	0.3	1.4
PM	--	--	--	--	1.7	7.4
PM <sub>10</sub> <sup>i</sup>	--	--	--	--	1.3	5.7
PM <sub>2.5</sub> <sup>i</sup>	--	--	--	--	0.3	1.4
Lead (Pb) <sup>j</sup>	--	--	--	--	1.63E-03	7.14E-03
NH <sub>3</sub> <sup>k</sup>	1.40	--	--	--	1.8	7.9

Footnotes to Tables 3-2-2.a through 3-2-4.b:

- a Existing emission rates were based on the Review of Application for Significant Permit Modification No. 0232-06. Except for PM<sub>10</sub> and PM<sub>2.5</sub>, the rates were taken from the permittee's renewal application received on December 19, 2014. The applicant applied a factor of safety that is more conservative than the AP-42 emission factor based on source test data.
- b Proposed fuel switch to ULSD three (3) years from permit issuance. Unless otherwise specified, emission factors from AP-42 Section 1.3 (5/10) for distillate oil are assumed.
- c Divided emission factors by 140 MMBtu/10<sup>3</sup> gal to convert to lb/MMBtu for distillate oil then multiply by the maximum boiler capacity (MMBtu/hr) to determine the emission rate in lb/hr.
- d Emission rate (tpy) = Emission rate (lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lb).
- e Proposed boiler retrofit(s) with SCR with LNB/OFA/FGR to further lower the emissions of NOx by December 31, 2027. Emission factor from AP-42 Section 1.3 (5/10) for distillate oil with LNB/FGR retrofits (to reduce emissions of NOx) for industrial boilers >100 MMBtu/hr is assumed. Emissions of NOx for Boilers K-1, K-2, K-3, and K-4 are reduced to 0.05 lb/MMBtu when retrofitted with SCR + combustion controls based on guidance from EPA's CCM.
- f SO<sub>2</sub> emission rate calculations for ULSD are determined as follows:

Unit	AP-42 Emission Factor <sup>1</sup>	AP-42 Emission Factor <sup>2</sup>	Heat Input	Emission Rate
	(lb/10 <sup>3</sup> gal)	(lb/MMBtu)	(MMBtu/hr)	(lb/hr)
K-1	0.213	1.52E-03	94.0	1.43E-01
K-2	0.213	1.52E-03	94.0	1.43E-01
K-3	0.213	1.52E-03	172.0	2.62E-01
K-4	0.213	1.52E-03	181.0	2.75E-01

<sup>1</sup> AP-42 Section 1.3 (5/10) using a sulfur content of 0.0015%.

<sup>2</sup> Divide by 140MMBtu/10<sup>3</sup> gal to convert emission factors to an energy basis (lb/MMBtu).

- g H<sub>2</sub>SO<sub>4</sub> emission lb/hr = 13.12% of SO<sub>2</sub> emission rate. The ratio is derived from the 08/19/94 SCEC report for Maalaea unit M16 source test.
- h TOC/VOC emission factor are from Table 1.3-3 of AP-42 Section 1.3 (5/10) for industrial boilers fired with distillate oil distillate oil.
- i For industrial boilers fired with fuel oil No. 6, it was assumed that forty-five percent (45%) of the total PM was PM<sub>2.5</sub> and seventy-nine percent (79%) of the total PM was PM<sub>10</sub> based on Application for Significant Permit Modification No. 0232-06. For industrial boilers fired with distillate oil, PM<sub>10</sub> and PM<sub>2.5</sub> emission factors are from Table 1.3-6 of AP-42 Section 1.3 (5/10).
- j Refer to the respective inorganic HAP emission rate.
- k NH<sub>3</sub> emission factors are based on Tables 5-2 and 5-5, for fuel oil combustion and SCR ammonia slip, from EPA's final report dated August 1994 titled, "Development and Selection of Ammonia Emission Factors" at: <https://www3.epa.gov/ttn/chief/old/efdocs/ammonia.pdf>



**3. Summary of HAPs Emissions:**

**Table 3-3-1. Emissions of Organic HAPs**

HAP	Emissions (TPY)					
	Existing	Proposal to Fire Boilers on ULSD				
	Boilers fired on Fuel Oil No.6 & Spec used Oil	K-1	K-2	K-3	K-4	Subtotal
Acenaphthene <sup>a</sup>		6.21E-05	6.21E-05	1.14E-04	1.19E-04	<b>3.57E-04</b>
Acenaphthylene <sup>a</sup>		7.44E-07	7.44E-07	1.36E-06	1.43E-06	<b>4.28E-06</b>
Acetaldehyde	<b>1.32E-01</b>	0.00E+00	0.00E+00	0.00E+00	0.00E+00	<b>0.00E+00</b>
Anthracene <sup>a</sup>		3.59E-06	3.59E-06	6.56E-06	6.91E-06	<b>2.06E-05</b>
Benzene <sup>b</sup>	<b>7.00E-03</b>	6.29E-04	6.29E-04	1.15E-03	1.21E-03	<b>3.62E-03</b>
Ethylbenzene		1.87E-04	1.87E-04	3.42E-04	3.60E-04	<b>1.08E-03</b>
Formaldehyde	<b>0.01</b>	9.70E-02	9.70E-02	1.78E-01	1.87E-01	<b>5.59E-01</b>
HCL	<b>4.95E-03</b>	0.00E+00	0.00E+00	0.00E+00	0.00E+00	<b>0.00E+00</b>
Naphthalene		3.32E-03	3.32E-03	6.08E-03	6.40E-03	<b>1.91E-02</b>
1,1,1-Trichloroethane		6.94E-04	6.94E-04	1.27E-03	1.34E-03	<b>3.99E-03</b>
Toluene	<b>1.50E-02</b>	1.82E-02	1.82E-02	3.34E-02	3.51E-02	<b>1.05E-01</b>
o-Xylene		3.21E-04	3.21E-04	5.87E-04	6.17E-04	<b>1.84E-03</b>
Benz(a)anthracene <sup>a</sup>		1.18E-05	1.18E-05	2.16E-05	2.27E-05	<b>6.79E-05</b>
Benzo(b,k)fluoranthene <sup>a</sup>		4.35E-06	4.35E-06	7.96E-06	8.38E-06	<b>2.50E-05</b>
Benzo(g,h,i)perylene <sup>a</sup>		6.65E-06	6.65E-06	1.22E-05	1.28E-05	<b>3.83E-05</b>
Chrysene <sup>a</sup>		7.00E-06	7.00E-06	1.28E-05	1.35E-05	<b>4.03E-05</b>
Dibenzo(a,h) anthracene <sup>a</sup>		4.91E-06	4.91E-06	8.99E-06	9.46E-06	<b>2.83E-05</b>
Fluoranthene <sup>a</sup>		1.42E-05	1.42E-05	2.60E-05	2.74E-05	<b>8.19E-05</b>
Fluorene <sup>a</sup>		1.31E-05	1.31E-05	2.41E-05	2.53E-05	<b>7.57E-05</b>
Indo(1,2,3-cd)pyrene <sup>a</sup>		6.29E-06	6.29E-06	1.15E-05	1.21E-05	<b>3.62E-05</b>
Phenanthrene <sup>e</sup>		3.09E-05	3.09E-05	5.65E-05	5.95E-05	<b>1.78E-04</b>
Pyrene <sup>a</sup>		1.25E-05	1.25E-05	2.29E-05	2.41E-05	<b>7.19E-05</b>
Polycyclic Organic Matter	<b>7.00E-03</b>					

Enclosure 3: Project Emissions of Criteria Pollutants and HAPs

**Table 3-3-2. Emissions of Inorganic Compounds of HAPs**

HAP	Emissions (TPY)					
	Existing	Proposing to Fire Boilers on ULSD				
	Boilers fired on Fuel Oil No.6 & Spec used Oil	K-1	K-2	K-3	K-4	Subtotal
Antimony Compounds	1.10E-02					0.00E+00
Arsenic Compounds	8.00E-03	1.65E-03	1.65E-03	3.01E-03	3.17E-03	9.48E-03
Barium						0.00E+00
Beryllium Compounds	3.01E-04	1.24E-03	1.24E-03	2.26E-03	2.38E-03	7.11E-03
Cadmium Compounds	7.00E-03	1.24E-03	1.24E-03	2.26E-03	2.38E-03	7.11E-03
Chromium Compounds	4.00E-03	1.24E-03	1.24E-03	2.26E-03	2.38E-03	7.11E-03
Chromium VI <sup>b</sup>	5.08E-06					0.00E+00
Cobalt Compounds	5.10E-02					0.00E+00
Copper		NA	NA	NA	NA	0.00E+00
Lead Compounds	8.00E-03	3.71E-03	3.71E-03	6.78E-03	7.14E-03	2.13E-02
Manganese Compounds	4.90E-02	2.47E-03	2.47E-03	4.52E-03	4.76E-03	1.42E-02
Mercury Compounds	1.20E-02	1.24E-03	1.24E-03	2.26E-03	2.38E-03	7.11E-03
Molybdenum						0.00E+00
Nickel Compounds	3.081	1.24E-03	1.24E-03	2.26E-03	2.38E-03	7.11E-03
Phosphorus	0.006					0.00E+00
Selenium Compounds	0.004	6.18E-03	6.18E-03	1.13E-02	1.19E-02	3.55E-02
Vanadium						0.00E+00
Zinc		NA	NA	NA	NA	0.00E+00

**Table 3-3-4. HAP Emissions Summary**

HAP	Emissions (TPY)	
	Existing	Proposing
	Boilers fired on Fuel Oil No.6 & Spec used Oil	Boilers Fired on ULSD
HAP <sub>Single Highest</sub> <sup>c</sup>	--	5.59E-01
HAP <sub>Total</sub>	3.308	0.81

**Footnotes:**

- a Polycyclic organic matter.
- b Identified by EPA's integrated risk information system (IRIS) as a known human carcinogen by inhalation.
- c Single highest speciated organic HAP is formaldehyde.

**4. Details of HAPs Emissions of Organic Compounds:**

**Table 3-4-1. 5 MW (94 MMBtu/hr) Boiler Emissions of HAPs (Units K-1 and K-2)**

Organic Compound	Listed in Section 9 of HAR 11-60.1 <sup>c</sup>	Emission Factor (EF) <sup>a</sup>	Emissions Rate (ER) <sup>b</sup>	Annual Emissions
		(lb/10 <sup>3</sup> gal)	(lbs/hr)	(tpy)
		(a)	(b)=94*(a)/140	(c)=(b)*8760/2000
Acenaphthene <sup>e</sup>	N+	2.11E-05	1.42E-05	6.21E-05
Acenaphthylene <sup>e</sup>	N+	2.53E-07	1.70E-07	7.44E-07
Acetaldehyde	1	--	--	--
Anthracene <sup>e</sup>	N+	1.22E-06	8.19E-07	3.59E-06
Benzene	15	2.14E-04	1.44E-04	6.29E-04
Ethylbenzene	76	6.36E-05	4.27E-05	1.87E-04
Formaldehyde <sup>f</sup>	86	3.30E-02	2.22E-02	9.70E-02
HCL	96	--	--	--
Naphthalene	118	1.13E-03	7.59E-04	3.32E-03
1,1,1-Trichloroethane	106	2.36E-04	1.58E-04	6.94E-04
Toluene	151	6.20E-03	4.16E-03	1.82E-02
o-Xylene	169	1.09E-04	7.32E-05	3.21E-04
Benz(a)anthracene <sup>e</sup>	N+	4.01E-06	2.69E-06	1.18E-05
Benzo(b,k)fluoranthene <sup>e</sup>	N+	1.48E-06	9.94E-07	4.35E-06
Benzo(g,h,i)perylene <sup>e</sup>	N+	2.26E-06	1.52E-06	6.65E-06
Chrysene <sup>e</sup>	N+	2.38E-06	1.60E-06	7.00E-06
Dibenzo(a,h)anthracene <sup>e</sup>	N+	1.67E-06	1.12E-06	4.91E-06
Fluoranthene <sup>e</sup>	N+	4.84E-06	3.25E-06	1.42E-05
Fluorene <sup>e</sup>	N+	4.47E-06	3.00E-06	1.31E-05
Indo(1,2,3-cd)pyrene <sup>e</sup>	N+	2.14E-06	1.44E-06	6.29E-06
Phenanthrene <sup>e</sup>	N+	1.05E-05	7.05E-06	3.09E-05
Pyrene <sup>e</sup>	N+	4.25E-06	2.85E-06	1.25E-05
OCDD	N	3.10E-09	2.08E-09	NA

Enclosure 3: **Project Emissions of Criteria Pollutants and HAPs**

**Table 3-4-2. 11.5 MW (172 MMBtu/hr) Boiler Emissions of HAPs (Unit K-3)**

Organic Compound	Listed in Section 9 of HAR 11-60.1 <sup>c</sup>	Emission Factor (EF) <sup>a</sup>	Emissions Rate (ER) <sup>b</sup>	Annual Emissions
		(lb/10 <sup>3</sup> gal)	(lbs/hr)	(tpy)
		(a)	(b)=172*(a)/140	(c)=(b)*8760/2000
Acenaphthene <sup>e</sup>	N+	2.11E-05	2.59E-05	1.14E-04
Acenaphthylene <sup>e</sup>	N+	2.53E-07	3.11E-07	1.36E-06
Acetaldehyde	1	--	--	--
Anthracene <sup>e</sup>	N+	1.22E-06	1.50E-06	6.56E-06
Benzene	15	2.14E-04	2.63E-04	1.15E-03
Ethylbenzene	76	6.36E-05	7.81E-05	3.42E-04
Formaldehyde <sup>f</sup>	86	3.30E-02	4.05E-02	1.78E-01
HCL	96	--	--	--
Naphthalene	118	1.13E-03	1.39E-03	6.08E-03
1,1,1-Trichloroethane	106	2.36E-04	2.90E-04	1.27E-03
Toluene	151	6.20E-03	7.62E-03	3.34E-02
o-Xylene	169	1.09E-04	1.34E-04	5.87E-04
Benz(a)anthracene <sup>e</sup>	N+	4.01E-06	4.93E-06	2.16E-05
Benzo(b,k)fluoranthene <sup>e</sup>	N+	1.48E-06	1.82E-06	7.96E-06
Benzo(g,h,i)perylene <sup>e</sup>	N+	2.26E-06	2.78E-06	1.22E-05
Chrysene <sup>e</sup>	N+	2.38E-06	2.92E-06	1.28E-05
Dibenzo(a,h)anthracene <sup>e</sup>	N+	1.67E-06	2.05E-06	8.99E-06
Fluoranthene <sup>e</sup>	N+	4.84E-06	5.95E-06	2.60E-05
Fluorene <sup>e</sup>	N+	4.47E-06	5.49E-06	2.41E-05
Indo(1,2,3-cd)pyrene <sup>e</sup>	N+	2.14E-06	2.63E-06	1.15E-05
Phenanthrene <sup>e</sup>	N+	1.05E-05	1.29E-05	5.65E-05
Pyrene <sup>e</sup>	N+	4.25E-06	5.22E-06	2.29E-05
OCDD	N	3.10E-09	3.81E-09	NA

Enclosure 3: **Project Emissions of Criteria Pollutants and HAPs**

**Table 3-4-3. 12.5 MW (181 MMBtu/hr) Boiler Emissions of HAPs (Units K-4)**

Organic Compound	Listed in Section 9 of HAR 11-60.1 <sup>c</sup>	Emission Factor (EF) <sup>a</sup>	Emissions Rate (ER) <sup>b</sup>	Annual Emissions
		(lb/10 <sup>3</sup> gal)	(lbs/hr)	(tpy)
		(a)	(b)=181*(a)/140	(c)=(b)*8760/2000
Acenaphthene <sup>e</sup>	N+	2.11E-05	2.73E-05	1.19E-04
Acenaphthylene <sup>e</sup>	N+	2.53E-07	3.27E-07	1.43E-06
Acetaldehyde	1	--	--	--
Anthracene <sup>e</sup>	N+	1.22E-06	1.58E-06	6.91E-06
Benzene	15	2.14E-04	2.77E-04	1.21E-03
Ethylbenzene	76	6.36E-05	8.22E-05	3.60E-04
Formaldehyde <sup>f</sup>	86	3.30E-02	4.27E-02	1.87E-01
HCL	96	--	--	--
Naphthalene	118	1.13E-03	1.46E-03	6.40E-03
1,1,1-Trichloroethane	106	2.36E-04	3.05E-04	1.34E-03
Toluene	151	6.20E-03	8.02E-03	3.51E-02
o-Xylene	169	1.09E-04	1.41E-04	6.17E-04
Benz(a)anthracene <sup>e</sup>	N+	4.01E-06	5.18E-06	2.27E-05
Benzo(b,k)fluoranthene <sup>e</sup>	N+	1.48E-06	1.91E-06	8.38E-06
Benzo(g,h,i)perylene <sup>e</sup>	N+	2.26E-06	2.92E-06	1.28E-05
Chrysene <sup>e</sup>	N+	2.38E-06	3.08E-06	1.35E-05
Dibenzo(a,h)anthracene <sup>e</sup>	N+	1.67E-06	2.16E-06	9.46E-06
Fluoranthene <sup>e</sup>	N+	4.84E-06	6.26E-06	2.74E-05
Fluorene <sup>e</sup>	N+	4.47E-06	5.78E-06	2.53E-05
Indo(1,2,3-cd)pyrene <sup>e</sup>	N+	2.14E-06	2.77E-06	1.21E-05
Phenanthrene <sup>e</sup>	N+	1.05E-05	1.36E-05	5.95E-05
Pyrene <sup>e</sup>	N+	4.25E-06	5.49E-06	2.41E-05
OCDD	N	3.10E-09	4.01E-09	NA

**Footnotes to Tables 4-4-1, 4-4-2, and 4-4-3:**

- a Emission factors for speciated organic compounds from fuel oil combustion in Table 1.3-9 of AP-42, Section 1.3 (05/10) were assumed since there are no factors available for organic compounds specific to distillate fuel.
- b Divide emission factors by 140 MMBtu/10<sup>3</sup> gal to convert to lb/MMBtu for distillate oil then multiply by the boiler capacity (MMBtu/hr) to determine the emission rate in lb/hr.
- c "N" indicates the organic compound is not listed in Section 9 of HAR §11-60.1 nor EPA's list of HAPs and is not included with the total emissions unless it is accompanied with a "+", which denotes that the HAP were included based on footnotes d or e.
- d HAP as defined by Section 112(b) of the Clean Air Act as specified in footnote<sup>b</sup> of Table 1.4-3, AP-42, Section 1.4.
- e HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Act as specified in footnote<sup>c</sup> of Table 1.4-3, AP-42, Section 1.4.

5. Details of HAPs Emissions of Inorganic Compounds:

Table 3-5-1. 5 MW (94 MMBtu/hr) Boiler Emissions (Units K-1 and K-2)

Inorganic Compounds	Listed in Section 9 of HAR 11-60.1 <sup>c</sup>	Fuel Oil No. 6			Distillate Oil		
		Emission Factor <sup>a</sup>	Emissions Rate (ER)	Annual Emissions	Emission Factor (EF) <sup>b</sup>	Emissions Rate (ER) <sup>c</sup>	Annual Emissions
		(lb/10 <sup>3</sup> gal)	(lbs/hr)	(tpy)	(lb/10 <sup>6</sup> MMBtu)	(lbs/hr)	(tpy)
		(1)	(2) = 94*(1)/140	(3) =(2)*8760/2000	(a)	(b) = 94*(a)	(c) =(b)*8760/2000
Antimony <sup>a</sup>	N <sub>epa</sub>	5.25E-03	3.53E-03	1.54E-02	--	--	--
Arsenic	173	1.32E-03	8.86E-04	3.88E-03	4	3.76E-04	1.65E-03
Barium	N	2.57E-03	1.73E-03	7.56E-03	--	--	--
Beryllium	174	2.78E-05	1.87E-05	8.18E-05	3	2.82E-04	1.24E-03
Cadmium	175	3.98E-04	2.67E-04	1.17E-03	3	2.82E-04	1.24E-03
Chromium	176	8.45E-04	5.67E-04	2.49E-03	3	2.82E-04	1.24E-03
Chromium VI	176	2.48E-07	1.67E-07	7.29E-07	--	--	--
Cobalt <sup>a</sup>	177	6.02E-03	4.04E-03	1.77E-02	--	--	--
Copper	N	1.76E-03	1.18E-03	5.18E-03	6	5.64E-04	NA
Lead (Pb)	181	1.51E-03	1.01E-03	4.44E-03	9	8.46E-04	3.71E-03
Manganese	182	3.00E-03	2.01E-03	8.82E-03	6	5.64E-04	2.47E-03
Mercury	183	1.13E-04	7.59E-05	3.32E-04	3	2.82E-04	1.24E-03
Molybdenum	N	7.87E-04	5.28E-04	2.31E-03	--	--	--
Nickel	185	8.45E-02	5.67E-02	2.49E-01	3	2.82E-04	1.24E-03
Phosphorus <sup>a</sup>	133	9.46E-03	6.35E-03	2.78E-02	--	--	--
Selenium	188	6.83E-04	4.59E-04	2.01E-03	15	1.41E-03	6.18E-03
Vanadium	N	3.18E-02	2.14E-02	9.35E-02	--	--	--
Zinc	N	2.91E-02	1.95E-02	8.56E-02	4	3.76E-04	NA

Enclosure 3: **Project Emissions of Criteria Pollutants and HAPs**

**Table 3-5-2. 11.5 MW (172 MMBtu/hr) Boiler Emissions (Unit K-3)**

Inorganic Compounds	Listed in Section 9 of HAR 11-60.1 <sup>c</sup>	Fuel Oil No. 6			Distillate Oil		
		Emission Factor <sup>a</sup>	Emissions Rate (ER)	Annual Emissions	Emission Factor (EF) <sup>b</sup>	Emission Factor <sup>a</sup>	Emissions Rate (ER)
		(lb/10 <sup>3</sup> gal)	(lbs/hr)	(tpy)	(lb/10 <sup>6</sup> MMBtu)	(lbs/hr)	(tpy)
		(1)	(2)= 172*(1)/140	(3)= (2)*8760/2000	(a)	(b)=172*(a)	(c)= (b)*8760/2000
Antimony <sup>a</sup>	N <sub>epa</sub>	5.25E-03	6.45E-03	2.83E-02	--	--	--
Arsenic	173	1.32E-03	1.62E-03	7.10E-03	4	6.88E-04	3.01E-03
Barium	N	2.57E-03	3.16E-03	1.38E-02	--	--	--
Beryllium	174	2.78E-05	3.42E-05	1.50E-04	3	5.16E-04	2.26E-03
Cadmium	175	3.98E-04	4.89E-04	2.14E-03	3	5.16E-04	2.26E-03
Chromium	176	8.45E-04	1.04E-03	4.55E-03	3	5.16E-04	2.26E-03
Chromium VI	176	2.48E-07	3.05E-07	1.33E-06	--	--	--
Cobalt <sup>a</sup>	177	6.02E-03	7.40E-03	3.24E-02	--	--	--
Copper	N	1.76E-03	2.16E-03	9.47E-03	6	1.03E-03	NA
Lead (Pb)	181	1.51E-03	1.86E-03	8.13E-03	9	1.55E-03	6.78E-03
Manganese	182	3.00E-03	3.69E-03	1.61E-02	6	1.03E-03	4.52E-03
Mercury	183	1.13E-04	1.39E-04	6.08E-04	3	5.16E-04	2.26E-03
Molybdenum	N	7.87E-04	9.67E-04	4.23E-03	--	--	--
Nickel	185	8.45E-02	1.04E-01	4.55E-01	3	5.16E-04	2.26E-03
Phosphorus <sup>a</sup>	133	9.46E-03	1.16E-02	5.09E-02	--	--	--
Selenium	188	6.83E-04	8.39E-04	3.68E-03	15	2.58E-03	1.13E-02
Vanadium	N	3.18E-02	3.91E-02	1.71E-01	--	--	--
Zinc	N	2.91E-02	3.58E-02	1.57E-01	4	6.88E-04	NA

Enclosure 3: **Project Emissions of Criteria Pollutants and HAPs**

**Table 3-5-3. 12.5 MW (181 MMBtu/hr) Boiler Emissions (Units K-4)**

Inorganic Compounds	Listed in Section 9 of HAR 11-60.1 <sup>c</sup>	Fuel Oil No. 6			Distillate Oil		
		Emission Factor <sup>a</sup>	Emissions Rate (ER)	Annual Emissions	Emission Factor (EF) <sup>b</sup>	Emission Factor <sup>a</sup>	Emissions Rate (ER)
		(lbs/gal)	(lbs/hr)	(tpy)	(lb/10 <sup>6</sup> MMBtu)	(lbs/hr)	(tpy)
		(1)	(2)= 181*(1)/140	(3)= (2)*8760/2000	(a)	(b)=181*(a)	(c)= (b)*8760/2000
Antimony <sup>a</sup>	N <sub>epa</sub>	5.25E-03	6.79E-03	2.97E-02	--	--	--
Arsenic	173	1.32E-03	1.71E-03	7.47E-03	4	7.24E-04	3.17E-03
Barium	N	2.57E-03	3.32E-03	1.46E-02	--	--	--
Beryllium	174	2.78E-05	3.59E-05	1.57E-04	3	5.43E-04	2.38E-03
Cadmium	175	3.98E-04	5.15E-04	2.25E-03	3	5.43E-04	2.38E-03
Chromium	176	8.45E-04	1.09E-03	4.78E-03	3	5.43E-04	2.38E-03
Chromium VI	176	2.48E-07	3.21E-07	1.40E-06	--	--	--
Cobalt <sup>a</sup>	177	6.02E-03	7.78E-03	3.41E-02	--	--	--
Copper	N	1.76E-03	2.28E-03	9.97E-03	6	1.09E-03	NA
Lead (Pb)	181	1.51E-03	1.95E-03	8.55E-03	9	1.63E-03	7.14E-03
Manganese	182	3.00E-03	3.88E-03	1.70E-02	6	1.09E-03	4.76E-03
Mercury	183	1.13E-04	1.46E-04	6.40E-04	3	5.43E-04	2.38E-03
Molybdenum	N	7.87E-04	1.02E-03	4.46E-03	--	--	--
Nickel	185	8.45E-02	1.09E-01	4.78E-01	3	5.43E-04	2.38E-03
Phosphorus <sup>a</sup>	133	9.46E-03	1.22E-02	5.36E-02	--	--	--
Selenium	188	6.83E-04	8.83E-04	3.87E-03	15	2.72E-03	1.19E-02
Vanadium	N	3.18E-02	4.11E-02	1.80E-01	--	--	--
Zinc	N	2.91E-02	3.76E-02	1.65E-01	4	7.24E-04	NA

Footnotes to Tables 3-5-1, 3-5-2, and 3-5-3:

- a For uncontrolled No. 6 fuel oil fired boilers only, emission factors are from Table 1.3-11 of AP-42, Section 1.3 (05/10).
- b Factors are for distillate oil fired boilers are from Table 1.3-10 of AP-42, Section 1.3 (05/10).
- c Emission rate = emission factor (lb/10<sup>6</sup> gal), multiplied by the boiler capacity (MMBtu/hr) to determine the emission rate in lb/hr.
- d "N" indicates the inorganic compound is not listed in section 9 of HAR §11-60.1. "N<sub>epa</sub>" indicates the compound is listed on EPA's current list of compounds.



Enclosure 4: GHG Emissions

**Table 4-1. Summary of Mass Based Emissions (TPY)**

Pollutant	Boiler Unit K-1	Boiler Unit K-2	Boiler Unit K-3	Boiler Unit K-4	Totals
Carbon Dioxide (CO <sub>2</sub> )	66,991.8	66,991.8	122,580.7	128,994.8	385,559.1
Methane (CH <sub>4</sub> )	2.7	2.7	5.0	5.2	15.6
Nitrous Oxide (N <sub>2</sub> O)	0.5	0.5	1.0	1.0	3.1

**Table 4-2. 5 MW (94 MMBtu/hr) Boiler Mass Based Emissions (Units K-1 & K-2)**

Pollutant	Emission Factor kg/MMBtu	TPY Emission Rate Biogenic	TPY Emission Rate Anthropogenic <sup>a</sup>	Total TPY Emissions
Carbon Dioxide (CO <sub>2</sub> )	73.96	0.0	66,991.8	66,991.8
Methane (CH <sub>4</sub> )	3.00E-03	0.0	2.7	2.7
Nitrous Oxide (N <sub>2</sub> O)	6.00E-04	0.0	0.5	0.5

<sup>a</sup>TPY Emission = (EF kg/MMBtu)(94 MMBtu/hr)(2.2 lb/kg)(ton/2,000 lb)(8,760 hr/yr).

**Table 4-3. 11.5 MW (172 MMBtu/hr) Boiler Mass Based Emissions (Unit K-3)**

Pollutant	Emission Factor kg/MMBtu	TPY Emission Rate Biogenic	TPY Emission Rate Anthropogenic <sup>a</sup>	Total TPY Emissions
Carbon Dioxide (CO <sub>2</sub> )	73.96	0.0	122,580.7	122,580.7
Methane (CH <sub>4</sub> )	3.00E-03	0.0	5.0	5.0
Nitrous Oxide (N <sub>2</sub> O)	6.00E-04	0.0	1.0	1.0

<sup>a</sup>TPY Emission = (EF kg/MMBtu)(172 MMBtu/hr)(2.2 lb/kg)(ton/2,000 lb)(8,760 hr/yr).

**Table 4-4. 12.5 MW (181 MMBtu/hr) Boiler Mass Based Emissions (Unit K-4)**

Pollutant	Emission Factor kg/MMBtu	TPY Emission Rate Biogenic	TPY Emission Rate Anthropogenic <sup>a</sup>	Total TPY Emissions
Carbon Dioxide (CO <sub>2</sub> )	73.96	0.0	128,994.8	128,994.8
Methane (CH <sub>4</sub> )	3.00E-03	0.0	5.2	5.2
Nitrous Oxide (N <sub>2</sub> O)	6.00E-04	0.0	1.0	1.0

<sup>a</sup>TPY Emission = (EF kg/MMBtu)(181 MMBtu/hr)(2.2 lb/kg)(ton/2,000 lb)(8,760 hr/yr).

**Enclosure 5: Chemical Engineering Plant Cost Index Table**

Year	Index	CEPCI % growth from 2000	CEPCI % growth from 2001	CEPCI % growth from 2002	CEPCI % growth from 2003	CEPCI % growth from 2004	CEPCI % growth from 2005	CEPCI % growth from 2006	CEPCI % growth from 2007	CEPCI % growth from 2008	CEPCI % growth from 2009	CEPCI % growth from 2010	CEPCI % growth from 2011	CEPCI % growth from 2012	CEPCI % growth from 2013	CEPCI % growth from 2014
2000	394.1															
2001	394.3	100%														
2002	395.6	100%	100%													
2003	402.0	102%	102%	102%												
2004	444.2	113%	113%	112%	110%											
2005	468.2	119%	119%	118%	116%	105%										
2006	499.6	127%	127%	126%	124%	112%	107%									
2007	525.4	133%	133%	133%	131%	118%	112%	105%								
2008	575.4	146%	146%	145%	143%	130%	123%	115%	110%							
2009	521.9	132%	132%	132%	130%	117%	111%	104%	99%	91%						
2010	550.8	140%	140%	139%	137%	124%	118%	110%	105%	96%	106%					
2011	593.2	151%	150%	150%	148%	134%	127%	119%	113%	103%	114%	108%				
2012	582.2	148%	148%	147%	145%	131%	124%	117%	111%	101%	112%	106%	98%			
2013	567.3	144%	144%	143%	141%	128%	121%	114%	108%	99%	109%	103%	96%	97%		
2014	576.1	146%	146%	146%	143%	130%	123%	115%	110%	100%	110%	105%	97%	99%	102%	
2015	556.8	141%	141%	141%	139%	125%	119%	111%	106%	97%	107%	101%	94%	96%	98%	97%
2016	541.7	137%	137%	137%	135%	122%	116%	108%	103%	94%	104%	98%	91%	93%	95%	94%
2017	574.0	146%	146%	145%	143%	129%	123%	115%	109%	100%	110%	104%	97%	99%	101%	100%
2018	603.1	153%	153%	152%	150%	136%	129%	121%	115%	105%	116%	109%	102%	104%	106%	105%
2019	607.5	154%	154%	154%	151%	137%	130%	122%	116%	106%	116%	110%	102%	104%	107%	105%

Enclosure 6: **Cost Data**

Table 6-1

Cost Effectiveness of Fuel Switch to ULSD

Source: Table 6.1 updated Aug 2021, of AECOM Ltr Att 4 Kahului RH FourFactor Analysis Tables.

Unit	Control Option	SO <sub>2</sub> Reduced <sup>A</sup> (ton/yr)	NO <sub>x</sub> Reduced <sup>A</sup> (ton/yr)	PM <sub>10</sub> Reduced <sup>A</sup> (ton/yr)	Total SO <sub>2</sub> , NO <sub>x</sub> , and PM <sub>10</sub> (ton/yr)	Total Annual Cost <sup>B</sup> (\$/yr)	Cost Effectiveness (all pollutants) (\$/ton)
K1	ULSD	292.9	40.1	12.4	345.4	\$1,762,679	\$5,103
K2	ULSD	253.1	38.0	8.9	300.0	\$1,531,228	\$5,104
K3	ULSD	897.8	131.7	32.6	1,062.1	\$5,346,592	\$5,034
K4	ULSD	775.2	82.2	17.6	875.0	\$4,642,548	\$5,306

<sup>A</sup> The SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub> reduced are from Tables ~~3-4 and 3-5~~ 3-5, Table 4-4, and Table 5-2~~3~~, respectively of spreadsheet titled, "Kahului RH 4-Factor Report Tables 2020-0918\_changed tracking".

<sup>B</sup> Annual costs for switching to ~~a residual of ULSD blend or~~ ULSD are described under the "Summary Calculations" below. ~~from Tables 3-4 and 3-5.~~ The annual costs of fuel switching are based on 2019 dollars.

Summary Calculations

Summary

Control Option	Cost Effectiveness (\$/ton)	
	Minimum	Maximum
ULSD	\$5,000	\$5,000
Total Cost	Annual	20-yr
ULSD	13,300,000	266,000,000

Enclosure 6: **Cost Data**

Table 6-1 (Continued)  
Cost Effectiveness of Fuel Switch to ULSD

Source: Table 6.1, of AECOM\_Ltr\_Att\_4\_Kahului\_RH\_FourFactor\_Analysis\_Tables.

**Capital costs for atomization and tank containment liners**

	Annual Fuel costs	Capital Recovery	Total Annual Cost	
			Annual Cost	Annual Cost
K1	\$1,704,479	\$58,200	\$1,762,679	
K2	\$1,473,028	\$58,200	\$1,531,228	
K3	\$5,225,092	\$121,500	\$5,346,592	
K4	\$4,511,548	\$131,000	\$4,642,548	

For Annual Fuel Cost refer to Table 3-5 of spreadsheet titled, "Kahului RH 4-Factor Report Tables 2020-0918\_changed tracking"

Capital Costs for ULSD Atomization and Tank Containment Liners

	Total Annualized
K1	\$795,444
K2	\$795,444
K3	\$1,660,653
K4	\$1,789,829

See tab labeled "Total Fuel Cap Cost" in spreadsheet titled "Worksheets for HE Ltr 2021 06-19" (latest rev).

Life	25 yrs
Interest rate	5.31% Firm-specific cost of capital.
CRF	0.0732 Capital recovery factor

$$\text{Capital Recovery Factor (CRF)} = [i \times (1+i)^a] / [(1+i)^a - 1]$$

Where:

**i** = Nominal Interest Rate  
a = Equipment life

Enclosure 6: **Cost Data**

Table 6-2

NO<sub>x</sub> Cost Effectiveness Summary updated Aug 2021

[Source: Data from Table 4-4 updated Aug 2021 of AECOM\_Ltr\_Attch\_4\_Kahului\_RH\_FourFactor\_Analysis\_Tables.]

Unit	Control Option	2017 NO <sub>x</sub> Emissions <sup>A</sup> (tpy)	Controlled Emission Level <sup>B,C</sup> (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled NO <sub>x</sub> Emissions (tpy)	NO <sub>x</sub> Reduced (ton/yr)	Total Annual Cost <sup>D,E</sup> (\$/yr)	Cost Effectiveness (\$/ton)	NO <sub>x</sub> Reduced (%)
K1	ULSD <sup>D</sup>	65.8	0.16	313,473	25.7	40.1	\$1,762,679	\$43,915	
	Combustion Controls	65.8	0.30	313,473	47.0	18.8	\$80,695	\$4,297	29%
	SCR	65.8	0.10	313,473	15.7	50.1	\$224,954	\$4,488	76%
	SCR+Combustion Controls	65.8	0.05	313,473	7.8	58.0	\$305,649	\$5,273	88%
K2	ULSD <sup>D</sup>	62.3	0.18	270,907	24.3	38.0	\$1,531,228	\$40,292	61%
	Combustion Controls	62.3	0.30	270,907	40.6	21.7	\$81,066	\$3,742	35%
	SCR	62.3	0.10	270,907	13.5	48.8	\$224,013	\$4,595	78%
	SCR+Combustion Controls	62.3	0.05	270,907	6.8	55.5	\$305,079	\$5,494	89%
K3	ULSD <sup>D</sup>	292.6	0.33	960,954	160.9	131.7	\$5,346,592	\$40,606	45%
	Combustion Controls	292.6	0.30	960,954	144.1	148.5	\$136,815	\$922	51%
	SCR	292.6	0.10	960,954	48.0	244.6	\$419,846	\$1,717	84%
	SCR+Combustion Controls	292.6	0.05	960,954	24.0	268.6	\$556,661	\$2,073	92%
K4	ULSD <sup>D</sup>	182.7	0.24	829,725	100.5	82.2	\$4,642,548	\$56,468	45%
	Combustion Controls	182.7	0.30	829,725	124.5	58.2	\$137,284	\$2,357	32%
	SCR	182.7	0.10	829,725	41.5	141.2	\$400,598	\$2,837	77%
	SCR+Combustion Controls	182.7	0.05	829,725	20.7	162.0	\$537,882	\$3,321	89%

<sup>A</sup> Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

<sup>B</sup> The controlled emission level for ULSD is based on the No. 2 fuel oil emission factor from AP-42, Table 1.3-1, dated May 2010.

<sup>C</sup> Controlled emission levels based on "Alternative Control Techniques (ACT) Document - NO<sub>x</sub> Emissions from Utility Boiler" EPA, 1994.

<sup>D</sup> Annual costs for switching to ~~a residual oil/ULSD blend or~~ ULSD are from Enclosure 2 Tables 2-13-4 ~~and 3-5~~. The annual costs of fuel switching are based on 2019 dollars. The control options of switching to ~~a residual oil/ULSD blend or~~ ULSD are listed since it's ~~more~~ **the most** cost-effective SO<sub>2</sub> solution than switching to a **residual oil/ULSD blend**, residual oil/0.4% maximum sulfur diesel blend, or 0.4% maximum sulfur diesel.

<sup>E</sup> See Enclosure 3 for **combustion control and SCR** total annual cost calculations.

## Enclosure 7: NOx Control Cost Estimates

**Table 7-1  
Kahului Combustion Controls Capital and O&M Cost Estimate**

[Source: Kahului Appendix Table A-1 updated Aug 2021 of AECOM Ltr Att 4 Kahului RH FourFactor Analysis Tables]

Parameters/Costs	Equation	K1	K2	K3	K4
Boiler design capacity, mmBtu/hr (C)		94	94	172	181
2017 Annual Heat Input, MMBtu/yr (H)		313,473	270,907	960,954	829,725
Unit Size, kW (kW)		5,900	6,000	12,700	13,000
Unit Size, MW (MW)		5.9	6.0	12.7	13.0
Capital recovery factor <b>(CRF)</b> a. Equipment CRF, 20-yr life, 5.31% <b>Nominal Interest Rate</b>	= $[i \times (1+i)^a] / [(1+i)^a - 1]$ where, <b>i = Nominal Interest Rate</b> a = equipment life	<b>0.0824</b>	<b>0.0824</b>	<b>0.0824</b>	<b>0.0824</b>
Cost Index (CI) <sup>A</sup> a. 2019 b. 2004	607.5 444.2				
Total Capital Investment <b>or Capital Cost</b> <sup>B,C</sup> TCI (\$)	= \$24/kW x kW x (300/MW) <sup>0.359</sup> x (CI <sub>2019</sub> /CI <sub>2004</sub> )	<b>\$793,563</b>	<b>\$802,159</b>	<b>\$1,297,190</b>	<b>\$1,316,750</b>
Direct Annual Operating Costs \$/yr Variable O&M Costs <sup>D</sup>	= (\$0.08 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x 10 <sup>6</sup> Btu/mmBtu x (CI <sub>2019</sub> /CI <sub>2004</sub> )	\$3,430	\$2,964	\$10,514	\$9,078
Indirect Annual Costs, \$/yr 1. Fixed O&M Costs <sup>E</sup> 2. Capital recovery <b>(Annualized Capital Cost)</b>	= \$0.36/kW x Nameplate capacity (MW) x (1000 kW/MW) x (300/MW) <sup>0.359</sup> x (CI <sub>2019</sub> /CI <sub>2004</sub> ) = Equipment CRF x TCI	\$11,903 <b>\$65,362</b>	\$12,032 <b>\$66,070</b>	\$19,458 <b>\$106,843</b>	\$19,751 <b>\$108,454</b>
<b>Total Annual Cost \$/yr</b>	= Direct Annual Costs + Indirect Annual Costs	<b>\$80,695</b>	<b>\$81,066</b>	<b>\$136,815</b>	<b>\$137,284</b>

**Source:** All costs were estimated using Section 4.3 and Appendix D of the WRAP guidance document, *Analysis of Combustion Controls for Reducing NOx Emissions from Coal-fired EGUs in the WRAP Region*, dated September 6, 2005. The cost method developed for coal-fired EGUs was utilized for the residual oil-fired boilers being addressed by this report, since the number of EGUs of similar size and fuel type to the boilers being addressed by this report is small and cost estimates are not as established. Further, pulverized coal can burn similar to oil, and thus combustion control system options for both fuel types are similar.

<sup>A</sup> Cost Index: Chemical Engineering Plant Cost Index (CEPCI). Chemical Engineering Journal.

<sup>B</sup> TCI for LNB and LNB w/over fire air for wall boilers ranges from \$6/kW to \$24/kW, the high end of the range was used due to Hawaii's remote location. The cost of FGR and OFA are expected to be covered by this range and have an expected similar level of NO<sub>x</sub> control.

<sup>C</sup> Scaling factor = (300/Nameplate capacity)<sup>0.359</sup>

<sup>D</sup> The variable O&M costs for LNB and LNB w/over fire air for wall boilers ranges from 0.05 mills/kW-hr to 0.08 mills/kW-hr, the high end of the range was used due to Hawaii's remote location. The cost of FGR and OFA are expected to be covered by this range and have an expected similar level of NO<sub>x</sub> control.

<sup>E</sup> The fixed O&M costs for LNB and LNB w/over fire air for wall boilers ranges from \$0.09/kW to \$0.36/kW, the high end of the range was used due to Hawaii's remote location.

**Enclosure 7: NOx Control Cost Estimates**

**Table 7-2  
Kahului SCR Capital and O&M Cost Estimate**

*[Source: Kahului Appendix Table A-2 Updated Aug 2021 of AECOM Ltr Att 4 Kahului RH FourFactor Analysis Tables]*

		K1	K2	K3	K4
MW		5.9	6.0	12.7	13.0
Baseline NOx Emission Rate (lb/MMBtu)		0.42	0.46	0.61	0.44
2017 Annual Heat Input, MMBtu/yr		313,473	270,907	960,954	829,725
Max Heat Input (MMBtu/hr)		94	94	172	181
Capital Recovery Factor (CRF)		<b>0.0674</b>	<b>0.0674</b>	<b>0.0674</b>	<b>0.0674</b>
Cost Index <sup>A</sup>					
	2019	607.5			
	1999	390.6			
B =	(lb/MMBtu)	0.42	0.46	0.61	0.44
C =	(%)	90	90	90	90
A =	(kW)	5,900	6,000	12,700	13,000
Z (Eq. 1) =		0.90	0.90	0.92	0.90
Capital Cost (Eq. 2)	(\$/kW)	\$286	\$285	\$220	\$217
Capital Cost (2019)	(\$)	<b>\$2,623,236</b>	<b>\$2,656,291</b>	<b>\$4,345,933</b>	<b>\$4,387,432</b>
Maui Construction Cost Multiplier <sup>B</sup>		<b>1.000</b>	<b>1.000</b>	<b>1.000</b>	<b>1.000</b>
Maui Capital Cost (2019)		<b>\$2,623,236</b>	<b>\$2,656,291</b>	<b>\$4,345,933</b>	<b>\$4,387,432</b>
Annualized Capital Cost	(\$/yr)	<b>\$176,722</b>	<b>\$178,949</b>	<b>\$292,777</b>	<b>\$295,573</b>
G =		0.38	0.33	0.64	0.52
H =	(MMBtu/hr)	94	94	172	181
D =	(\$/kW)	\$445	\$443	\$342	\$337
Fixed O&M <sup>C</sup> (Eq. 3)	(\$/yr)	\$17,313	\$17,532	\$28,683	\$28,957
Variable O&M Cost (Eq. 4)	(\$/yr)	\$30,918	\$27,532	\$98,385	\$76,068
Total Annual Cost	(\$/yr)	<b>\$224,954</b>	<b>\$224,013</b>	<b>\$419,846</b>	<b>\$400,598</b>

$$Z = \left[ \left( \frac{B}{1.5} \right)^{0.05} \left( \frac{C}{100} \right)^{0.4} \right]$$

Equation 1

$$D = 75 \left\{ 300,000 \frac{Z}{A} \right\}^{0.35}$$

Equation 2

Where:

- D = Capital cost (\$/kW)
- B = NO<sub>x</sub> (lb/10<sup>6</sup> Btu) at the inlet of the SCR reactor
- C = NO<sub>x</sub> removal efficiency (%)
- A = Plant capacity (kW)

$$E = D \times A \times C$$

Equation 3

Where:

- E = Fixed O&M cost (\$/yr)
- D = Capital cost (\$/kW) from Equation 1
- A = Plant capacity (kW)
- C = A constant, 0.0066 yr<sup>-1</sup>

**Enclosure 7: NOx Control Cost Estimates**

**Table 7-2 (Continued)  
Kahului SCR Capital and O&M Cost Estimate**

*[Source: Kahului Appendix Table A-2 Updated Aug 2021 of AECOM\_Ltr\_Att\_4\_Kahului\_RH\_FourFactor\_Analysis\_Tables]*

$$F = G \{ 225 \times [ 0.37 B \times H \times (C/100) \times (8760/2000) ] \times 1.005 \times 1.05 + 0.025 \times D \times A \times Z + 1.45 \times A \} \quad \text{Equation 4}$$

Where:

- F = Variable O&M Cost (\$/yr)
- G = Annual capacity factor (expressed as a fraction)
- B = Inlet NO<sub>x</sub> (lb/MMBtu); range of 0.15 - 2.5 lb/MMBtu
- H = Heat input (MMBtu/hr)
- C = NO<sub>x</sub> removal efficiency; range of 80-95%
- D = Capital cost (\$/kW)
- A = Plant capacity (kW)

Capital Recovery Factor (CRF) =  $[ i \times (1+i)^n ] / [ (1+i)^n - 1 ]$

**CRF = 0.0674**

Where:

<b>i = Nominal Interest Rate (%) =</b>	<b>5.31%</b>
<b>n = Useful Life (yrs) =</b>	<b>30</b>

**Source:** *Cost of Selective Catalytic Reduction (SCR) Application for NO<sub>x</sub> Control on Coal-Fired Boilers*, EPA/600/R-01/087, October 2001. A cost method developed for coal-fired EGUs was utilized for the residual oil-fired boilers being addressed by this report, since the number of EGUs of similar size and fuel type to the boilers being addressed by this report is small and cost estimates are not as established. Further, pulverized coal can burn similar to oil, and thus combustion control system options for both fuel types are similar.

<sup>A</sup> Cost Index: Chemical Engineering Plant Cost Index (CEPCI). Chemical Engineering Journal.

<sup>B</sup> The Maui construction cost multiplier is based on cost of construction geographical multipliers from the *RMeans Mechanical Cost Data 2016* to account for factors unique to Maui's location plus an additional factor to account for additional Hawaiian Electric loadings and overhead.

<sup>C</sup> Fixed Costs include elements such as labor, station power, capital additions/improvements



Enclosure 7: **NOx Control Cost Estimates**

Table 7-2 (Continued)

$$F = G\{225 \times [0.37B \times H \times (C/100) \times (8760/2000)] \times 1.005 \times 1.05 + 0.025 \times D \times A \times Z + 1.45 \times A\}$$

Equation 4

Where:

- F = Variable O&M Cost (\$/yr)
- G = Annual capacity factor (expressed as a fraction)
- B = Inlet NO<sub>x</sub> (lb/MMBtu); range of 0.15 - 2.5 lb/MMBtu
- H = Heat input (MMBtu/hr)
- C = NO<sub>x</sub> removal efficiency; range of 80-95%
- D = Capital cost (\$/kW)
- A = Plant capacity (kW)

$$\text{Capital Recovery Factor (CRF)} = [I \times (1+i)^a] / [(1+i)^a - 1]$$

CRF = 0.0674

Where:

- I = Interest Rate (5.31% interest)
- a = Equipment life (30 yrs)

**Source:** *Cost of Selective Catalytic Reduction (SCR) Application for NOx Control on Coal-Fired Boilers*, EPA/600/R-01/087, October 2001. A cost method developed for coal-fired EGUs was utilized for the residual oil-fired boilers being addressed by this report, since the number of EGUs of similar size and fuel type to the boilers being addressed by this report is small and cost estimates are not as established. Further, pulverized coal can burn similar to oil, and thus combustion control system options for both fuel types are similar.

<sup>A</sup> Cost Index: Chemical Engineering Plant Cost Index (CEPCI). Chemical Engineering Journal.

<sup>B</sup> The Maui construction cost multiplier of 1.0 is assumed.

<sup>C</sup> Fixed Costs include elements such as labor, station power, capital additions/improvements.

**Enclosure 7: NOx Control Cost Estimates**

Table 7-2 (Continued)

Kahului Combustion Controls Capital and O&M Cost Estimate updated Aug 2021

[Source: Kahului Appendix Table A-1 Updated Aug 2021 of AECOM Ltr Att 4 Kahului RH FourFactor Analysis Tables]

Parameters/Costs	Equation	K1	K2	K3	K4
Boiler design capacity, mmBtu/hr (C)		94	94	172	181
2017 Annual Heat Input, MMBtu/yr (H)		313,473	270,907	960,954	829,725
Unit Size, kW (kW)		5,900	6,000	12,700	13,000
Unit Size, MW (MW)		5.9	6.0	12.7	13.0
Capital recovery factor a. Equipment CRF, 20-yr life, 5.31% interest	$= [i \times (1+i)^n] / [(1+i)^n - 1]$ where i = interest rate, n = equipment life	0.0824	0.0824	0.0824	0.0824
Cost Index (CI) <sup>A</sup> a. 2019 b. 2004	607.5 444.2				
Total Capital Investment <sup>B,C</sup> TCI (\$)	$= \$24/\text{kW} \times \text{kW} \times (300/\text{MW})^{0.359} \times (CI_{2019}/CI_{2004})$	\$793,563	\$802,159	\$1,297,190	\$1,316,750
Direct Annual Operating Costs \$/yr Variable O&M Costs <sup>D</sup>	$= (\$0.08 \text{ mills}/\text{kW-hr}/1000) \times (1 \text{ kW-hr}/10,000 \text{ Btu}) \times H \times 10^6 \text{ Btu}/\text{mmBtu} \times (CI_{2019}/CI_{2004})$	\$3,430	\$2,964	\$10,514	\$9,078
Indirect Annual Costs, \$/yr 1. Fixed O&M Costs <sup>E</sup>	$= \$0.36/\text{kW} \times \text{Nameplate capacity (MW)} \times (1000 \text{ kW}/\text{MW}) \times (300/\text{MW})^{0.359} \times (CI_{2019}/CI_{2004})$	\$11,903	\$12,032	\$19,458	\$19,751
2. Capital recovery	= Equipment CRF x TCI	\$65,362	\$66,070	\$106,843	\$108,454
<b>Total Annual Cost \$/yr</b>	= Direct Annual Costs + Indirect Annual Costs	<b>\$80,695</b>	<b>\$81,066</b>	<b>\$136,815</b>	<b>\$137,284</b>

Notes to Table 7-2

**Source:** All costs were estimated using Section 4.3 and Appendix D of the WRAP guidance document, *Analysis of Combustion Controls for Reducing NOx Emissions from Coal-fired EGUs in the WRAP Region*, dated September 6, 2005. The cost method developed for coal-fired EGUs was utilized for the residual oil-fired boilers being addressed by this report, since the number of EGUs of similar size and fuel type to the boilers being addressed by this report is small and cost estimates are not as established. Further, pulverized coal can burn similar to oil, and thus combustion control system options for both fuel types are similar.

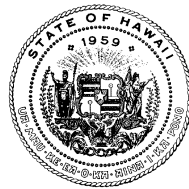
<sup>A</sup>Cost Index: Chemical Engineering Plant Cost Index (CEPCI). Chemical Engineering Journal.

<sup>B</sup>TCI for LNB and LNB w/over fire air for wall boilers ranges from \$6/kW to \$24/kW, the high end of the range was used due to Hawaii's remote location. The cost of FGR and OFA are expected to be covered by this range and have an expected similar level of NO<sub>x</sub> control.

<sup>C</sup>Scaling factor = (300/Nameplate capacity)<sup>0.359</sup>

<sup>D</sup>The variable O&M costs for LNB and LNB w/over fire air for wall boilers ranges from 0.05 mills/kW-hr to 0.08 mills/kW-hr, the high end of the range was used due to Hawaii's remote location. The cost of FGR and OFA are expected to be covered by this range and have an expected similar level of NO<sub>x</sub> control.

<sup>E</sup>The fixed O&M costs for LNB and LNB w/over fire air for wall boilers ranges from \$0.09/kW to \$0.36/kW, the high end of the range was used due to Hawaii's remote location.



**CERTIFIED MAIL**  
**RETURN RECEIPT REQUESTED**  
(7018 0040 0000 8040 8679)

**STATE OF HAWAII**  
**DEPARTMENT OF HEALTH**  
P.O. Box 3378  
HONOLULU, HAWAII 96801-3378

In reply, please refer to:  
File:

**22-339E CAB**  
**File No. 0234**

August 10, 2022

Mr. Everett Lacro  
Director, Generation – Hawaii Island  
Hawaii Electric Light Company, Inc.  
P.O. Box 1027  
Hilo, Hawaii 96721-1027

Dear Mr. Lacro:

**SUBJECT: Amendment of Covered Source Permit (CSP) No. 0234-01-C  
Hawaii Electric Light Company, Inc. (Hawaii Electric Light)  
Kanoelehua-Hill Generating Station  
Two (2) Boilers, One (1) Combustion Turbine, and Four (4) Diesel Engines  
Located At: 54 Halekauila Street, Hilo, Hawaii  
Date of Expiration: January 17, 2010 (Expiration Date to be Revised Upon Permit Renewal)**

In accordance with Hawaii Administrative Rules (HAR), Chapter 11-60.1, the Department of Health, Clean Air Branch (herein after referred to as Department), hereby amends CSP No. 0234-01-C issued to Hawaii Electric Light for the Kanoelehua-Hill Generating Station on January 18, 2005, and amended on June 6, 2018, and October 22, 2020.

In accordance with HAR §11-60.1-10(a)(2) and (a)(3) and pursuant to Clean Air Act (CAA) §169A(g)(1), this permit amendment incorporates an enforceable commitment to retire Boilers Hill 5 and Hill 6 at the Kanoelehua-Hill Generating Station by December 31, 2027. To make reasonable progress for long-term strategies in Hawaii's Regional Haze State Implementation Plan (RH-SIP), the regional haze program allows for an enforceable commitment to source retirement by 2028 as an option to requiring regional haze control measures selected from a four-factor analysis. This amendment is based on your revised regional haze four-factor analysis dated September 25, 2020; additional information received from your letters dated March 30, 2021, June 16, 2021, and August 2, 2021; discussions between the Department and Hawaiian Electric on October 7, 2021, and February 25, 2022; and Section II.B.3.e of the Environmental Protection Agency's (EPA's) Guidance on Regional Haze State Implementation Plans for the Second Implementation Period dated August 20, 2019

The permit amendment also carries over existing regional haze permit provisions to cap sulfur dioxide (SO<sub>2</sub>) emissions and incorporates these provisions into a new permit attachment (Attachment II – RH) that includes all regional haze conditions. The cap limits the sum of total SO<sub>2</sub> emissions from Boilers Hill 5 and Hill 6 and the Puna Generating Station Boiler to 3,550 tons per year.

Mr. Everett Lacro  
August 10, 2022  
Page 2

CSP No. 0234-01-C issued on January 18, 2005, and amended on June 6, 2018, and October 22, 2020, is amended as follows:

Added Attachment:

Attachment II – RH: Special Conditions – Regional Haze Requirements

Except for Attachment IIC that will be updated in a separate permit amendment to remove existing regional haze provisions associated with the SO<sub>2</sub> emissions cap, all other permit conditions of CSP No. 0234-01-C issued on January 18, 2005, and amended on June 6, 2018, and October 22, 2020, shall not be affected and shall remain valid.

If there are any questions, please contact Mr. Kai Erickson of the Clean Air Branch at (808) 586-4200.

Sincerely,



JOANNA L. SETO, P.E., CHIEF  
Environmental Management Division

MM/CKE:tkg

Enclosure

**ATTACHMENT II - RH: SPECIAL CONDITIONS  
REGIONAL HAZE REQUIREMENTS  
COVERED SOURCE PERMIT NO. 0234-01-C**

**Amended Date: August 10, 2022**

**Expiration Date: January 17, 2010**  
(Expiration Date to be Revised Upon Permit Renewal)

In addition to the standard conditions of the CSP, the following special conditions shall apply to the permitted facility:

**Section A. Equipment Description**

1. This attachment encompasses the following equipment and associated appurtenances:

Unit	Description
Hill 5	14.1 MW Combustion Engineering Boiler, Model No. VU 60
Hill 6	23 MW Combustion Engineering Boiler, Model No. VU 60.
Note: Megawatt (MW)	

(Auth.: HAR §11.60.1-3)

2. In accordance with HAR §11-60.1-10(a)(2) and (a)(3), this permit amendment incorporates federally enforceable regional haze control measures specified in Hawaii's Regional Haze State Implementation Plan (RH-SIP) for Boilers Hill 5 and Hill 6 pursuant to §169A(g)(1) of the CAA and 40 Code of Federal Regulations (CFR) §51.308(f)(2)(iv).

(Auth.: HAR §11-60.1-5, §11-60.1-10, 40 CFR §51.308(f), CAA §169A)<sup>1,2</sup>

**Section B. Applicable Federal Regulations**

1. Regional haze provisions for the boilers are required pursuant to the following federal regulations:
- a. 40 CFR Part 51, Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Subpart P, Protection of Visibility;
  - b. 40 CFR Part 52, Approval and Promulgation of Implementation Plans, Subpart A, General Provisions; and
  - c. 40 CFR Part 52, Approval and Promulgation of Implementation Plans, Subpart M, Hawaii, §52.633, Visibility Protection.

(Auth.: HAR §11.60.1-3; §11-60.1-10, §11-60.1-90, §11-60.1-161; 40 CFR §51.300, §52.02, §52.633)<sup>1</sup>

2. The permittee shall comply with all of the applicable requirements of these standards, including all emission limits, notification, testing, monitoring, recordkeeping, and reporting requirements. The major requirements of these standards are detailed in the Special Conditions of this attachment.

(Auth.: HAR §11.60.1-3; §11-60.1-10, §11-60.1-90, §11-60.1-161; 40 CFR §51.300, §52.02, §52.633)<sup>1</sup>

### **Section C. Operational and Emission Limitations**

#### 1. Regional Haze Rule Limits

- a. Permit provisions for the regional haze SO<sub>2</sub> emissions cap are as follows:
  - i. The total combined SO<sub>2</sub> emissions from Kanoelehua-Hill Generating Station, Boilers Hill 5 and Hill 6, and Puna Generating Station, Boiler, shall not exceed 3,550 tons in any rolling twelve-month (12-month) period.
  - ii. Compliance with the SO<sub>2</sub> emissions cap specified in Attachment II - RH, Special Condition No. C.1.a.i, is required at all times **on and after December 31, 2018**.
- b. **By December 31, 2027**, Boilers Hill 5 and Hill 6 shall be permanently shut down.

(Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-90; 40 CFR §51.308, §52.633; CAA §169A)<sup>1,2</sup>

#### 2. Shut Down Notification

The Department shall be notified when all boilers are permanently shut down in accordance with Attachment II - RH, Special Condition No. E.3.

(Auth.: HAR §11-60.1-10, §11-60.1-90; 40 CFR §51.308, §52.633; CAA §169A)<sup>1,2</sup>

### **Section D. Monitoring and Recordkeeping Requirements**

#### 1. Records

All records, including support information, shall be maintained for **at least five (5) years** following the date of the monitoring sample, measurement, test, report, or application. Support information includes calibration, maintenance, inspection, and repair records and copies of all reports required by this permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to the U.S. EPA, Department, or its representative(s) upon request.

(Auth.: HAR §11-60.1-5, §11-60.1-81, §11-60.1-11, §11-60.1-90)

## 2. Regional Haze – SO<sub>2</sub> Emissions Cap

- a. All fuel fired by boilers at the Kanoelehua-Hill and Puna Generating Stations shall be sampled and tested in accordance with the most current American Society for Testing and Materials (ASTM) methods. A representative sample of each batch of fuel received shall be analyzed for its sulfur content and heat value following ASTM D4057. The samples shall be analyzed for total sulfur content of the fuel using ASTM D129, or alternatively D1266, D1552, D2622, D4294, D5453, or D7039. The analysis may be performed by the permittee, the supplier, or third-party lab.
- b. The permittee shall calculate and record on a monthly basis the SO<sub>2</sub> emissions for each boiler unit (Puna Generating Station, Boiler, and the Kanoelehua-Hill Generating Station, Boilers Hill 5 and Hill 6) for the preceding month based on the fuel sulfur content, fuel heating value, and total gallons of fuel burned.
- c. The permittee shall calculate and record the total combined SO<sub>2</sub> emissions for all boiler units (Puna Generating Station, Boiler, and Kanoelehua-Hill Generating Station, Boilers Hill 5 and Hill 6) on a monthly and rolling twelve-month (12-month) basis.
- d. The permittee shall maintain, monthly, the following supporting documents:
  - i. The total gallons of each type of fuel fired in the boilers for the month; and
  - ii. The information used to calculate SO<sub>2</sub> emissions for the month such as the sulfur content of the fuel, fuel density, fuel heating value, and basis for the fuel sulfur content used (fuel analysis showing date sample collected, type of fuel, sulfur content, and fuel heating value).

(Auth.: HAR §11-60.1-3, §11-60.1-90; CFR §52.633)<sup>1</sup>

### **Section E. Notification and Reporting Requirements**

#### 1. Standard Condition Reporting

Notification and reporting pertaining to the following events shall be done in accordance with Attachment I, Standard Condition Nos. 17 and 24, respectively.

- a. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
- b. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90; SIP §11-60-10, §11-60.1-16)<sup>3</sup>

## 2. Deviations

The permittee shall report (in writing) **within five (5) working days** any deviations from the permit requirements, including those attributed to upset conditions, the probable cause of such deviations and any corrective actions or preventive measures taken. Corrective actions may include a requirement for stack testing, more frequent monitoring, or the implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-16, §11-60.1-90)

## 3. Regional Haze Shut Down Notification

**Within thirty (30) days** of permanently shutting down the boilers as required by Attachment II - RH, Special Condition No. C.1.b, the permittee shall submit written notification to the Department on the permittee's compliance with the condition, including the date of compliance.

(Auth.: HAR §11-60.1-10; §11-60.1-90; 40 CFR §51.308, §52.633; CAA §169A)<sup>1</sup>

## 4. Compliance Certification

- a. During the permit term, the permittee shall submit at least **annually** to the Department and U.S. EPA, Region 9, the attached **Compliance Certification Form** pursuant to HAR §11-60.1-86. The permittee shall indicate whether compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:
  - i. The identification of each term or condition of the permit that is the basis of the certification;
  - ii. The compliance status;
  - iii. Whether compliance was continuous or intermittent;
  - iv. The methods used for determining the compliance status of the source currently and over the reporting period;
  - v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification, including the requirements of Section 114 (a)(3) of the CAA or any applicable monitoring and analysis provisions of Section 504 (b) of the CAA;
  - vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and which the excursions or exceedances as defined in 40 CFR Part 64 occurred; and
  - vii. Any additional information as required by the Department, including information to determine compliance.



- b. The compliance certification shall be submitted **within sixty (60) days** after the end of each calendar year, and shall be signed and dated by a responsible official.
- c. Upon the written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

#### 5. Monitoring Reports

The permittee shall submit **semi-annually** the following written report to the Department and U.S. EPA, Region 9. The report shall be submitted within **sixty (60) days** following the end of each semi-annual calendar period (January 1 to June 30 and July 1 to December 31) and be signed and dated by a responsible official. The following enclosed form, or equivalent form, shall be used for reporting:

#### **Monitoring Report Form: Sulfur Dioxide (SO<sub>2</sub>) Emissions – Boilers**

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90; 40 CFR §51.308 §52.633; CAA §169A)<sup>1,2</sup>

#### 6. EPA Notification

The permittee shall notify U.S. EPA, Region 9 in writing, of any exceedance of the emission cap specified in Attachment II - RH, Special Condition C.1.a, within **thirty (30) days** of such exceedance.

(Auth.: HAR §11-60.1-90; 40 CFR §52.633)<sup>1</sup>

### **Section F. Agency Notification**

Any document (including reports) required to be submitted by this permit shall be done in accordance with Attachment I, Standard Condition No. 29.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

<sup>1</sup>The citation to the CFR identified under a particular condition, indicates that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citation to the CAA identified under a particular condition, indicates that the permit condition complies with the specified provision(s) of the CAA.

<sup>3</sup>The citation to the State Implementation Plan (SIP) identified under a particular condition, indicates that the permit condition complies with the specified provision(s) of the SIP.

**TECHNICAL SUPPORT DOCUMENT  
PERMIT AMENDMENT  
REGIONAL HAZE STATE IMPLEMENTATION PLAN  
Covered Source Permit (CSP) No. 0234-01-C**

**Applicant:** Hawaii Electric Light Company, Inc. (Hawaii Electric Light)  
**Facility:** Kanoelehua-Hill Generating Station  
**Located At:** Hilo, Hawaii  
UTM Coordinates: 284,300 m E and 2,179,800 m N,  
Zone 5, Old Hawaiian

**Mailing Address:** Hawaii Electric Light  
P.O. Box 1027  
Hilo, Hawaii 96721-1027

**Responsible Official:** Everett Lacro  
Director, Generation – Hawaii Island  
Hawaii Electric Light Company, Inc.  
(808) 969-0437

**Point of Contract:** Karin Kimura  
Director, Environmental Department  
Hawaiian Electric Company, Inc. (Hawaiian Electric)  
(808) 543-4522; karin.kimura@hawaiianelectric.com

The Standard Industrial Classification Code (SICC) for this facility is 4911 - Electric Services.

## Project

This permit amendment incorporates regional haze control measures specified in Hawaii's Regional Haze State Implementation Plan (RH-SIP) in accordance Hawaii Administrative Rules (HAR) §11-60.1-10(a)(2) and (a)(3), Clean Air Act (CAA) §169A(g)(1), and 40 Code of Federal Regulations (CFR) §51.308(f)(2)(iv). The regional haze program for the second planning period offers **flexibility** in that not all sources of emissions are required to be evaluated and a selection of a source for analysis does not necessarily mean that additional emission control measures will ultimately be required for the selected source.<sup>1</sup> In addition, the regional haze program offers **options** to consider either the four (4) statutory factors or five (5) other additional factors when selecting sources for control measure analysis. One (1) of the five (5) additional factors to exclude a source from a four-factor analysis is source retirement and replacement schedules.<sup>1</sup>

After notifying Hawaiian Electric of controls selected for Kanoelehua-Hill Generating Station Boilers Hill 5 and Hill 6, Hawaiian Electric ultimately decided to commit to an enforceable shut down of the boilers rather than implementing controls selected from the four-factor analysis. The four-factor analysis initially performed for the Kanoelehua-Hill Generating Station to select regional haze control measures is provided in Enclosure 1. Hawaiian Electric's decision to shut down the boilers was relayed at a meeting between the Hawaii Department of Health Clean Air Branch (CAB) and Hawaiian Electric on October 7, 2021. As such, the permit amendment for Kanoelehua-Hill Generating Station incorporates the following limit:

Boilers Hill 5 and Hill 6 shall be permanently shut down **by December 31, 2027**.

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<sup>1</sup>Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, EPA, August 20, 2019.

The CAA §110(a)(2) requires that state implementation plan (SIP) submittals include enforceable control measures and emission limitations to meet applicable CAA requirements, and that the submittals show that the State has authority to carry out the SIP. Thus, the relevant control measures and emission limitations must be finalized in order for the Environmental Protection Agency (EPA) to approve the SIP. 40 CFR Part 51, Appendix V, Section 2.1 also details the administrative criteria for determining the completeness of SIP submissions. Section 2.1(b) requires that the state submittal include the permit as issued in final form, with evidence that includes the date of adoption or final issuance as well as the effective date. Therefore, the EPA recommends that the Department of Health, Clean Air Branch (CAB), finalize the permitting process for incorporating the regional haze controls prior to sending the RH-SIP with these permit conditions to EPA for approval into the SIP.<sup>2</sup> As such, CAB plans to implement the proposed permit amendment for the Kanoelehua-Hill Generating Station in accordance with HAR §11-60.1-10(a)(2) and §11-60.1-10(a)(3).

## Background

For the first planning period, a 3,550 ton per year sulfur dioxide (SO<sub>2</sub>) emissions limit is specified in existing permits for boilers at the Puna and Kanoelehua-Hill Generating Stations. For the second planning period which affects these plants, this limit will be carried over into each facility's permit amendment for improving visibility in Hawaii's two (2) Class I Areas for this second planning period. Hawaii's two (2) Class I Areas are Haleakala National Park on Maui and Hawaii Volcanoes National Park on the Big Island (Hawaii).

In the first regional haze planning period (2001-2018), the emphasis was on Best Available Retrofit Technology (BART) to address reasonable progress that included a 0.5 deciview threshold. In this second planning period (2018-2028), there is no BART or deciview threshold. The focus in the second planning period is on determining reasonable progress through analysis of the four (4) factors identified in CAA §169A(g)(1). However, as previously mentioned, commitment to an enforceable shut down can exclude a source from the four-factor analysis.

The EPA regional haze guidance dated August 20, 2019, (guidance)<sup>1</sup> explains that because regional haze results from a multitude of sources over a broad geographic area, progress may require addressing many relatively small contributions to impairment. Thus, a measure may be necessary for reasonable progress even if that measure in isolation does not result in perceptible visibility impairment.

## Permitted Equipment Subject to Regional Haze Rule Limits

<u>Unit</u>	<u>Description</u>
Hill 5	14.1 MW Combustion Engineering Boiler, Model No. VU 60; and
Hill 6	23 MW Combustion Engineering Boiler, Model No. VU 60.

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<sup>2</sup> EPA's email response dated July 23, 2021, titled, "Final Form of Permits for RH SIP".

## Air Pollution Controls

Diesel engine generators (DEGs) D-11, D-15, D-16, and D-17 at the plant are equipped with a diesel oxidation catalyst to control carbon monoxide (CO) emissions. The diesel oxidation catalyst is a requirement to comply with 40 CFR Part 63 National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE), Subpart ZZZZ. The diesel oxidation catalyst will reduce CO emissions by at least 70% or limit CO emissions to twenty-three (23) parts per million dry volume (ppmvd) at 15% O<sub>2</sub>. Federal RICE regulations require the use of ultra-low sulfur diesel (ULSD) in accordance with 40 CFR §80.510(c). Requirements from the RICE NESHAP are being incorporated into the permit renewal for this facility.

Air pollution controls were initially selected for Boilers Hill 5 and Hill 6 in the four-factor analysis. These regional haze control measures will not be required because the permit will specify a federally enforceable limit to shut down the boilers by December 31, 2027. Please refer to Enclosure 1.

## Applicable Requirements

### *State Requirements:*

#### Hawaii Administrative Rules

Title 11, Chapter 60.1	Air Pollution Control
Subchapter 1	General Requirements
Subchapter 2	General Prohibitions
HAR 11-60.1-31	Applicability
HAR 11-60.1-32	Opacity Requirements
HAR 11-60.1-38	Sulfur Oxides from Fuel Combustion
HAR 11-60.1-39	Storage of Volatile Organic Compounds
Subchapter 5	Covered Sources
Subchapter 6	Fees for Covered Sources, Noncovered Sources, and Agricultural Burning
HAR 11-60.1-111	Definitions
HAR 11-60.1-112	General Fee Provisions for Covered Sources
HAR 11-60.1-113	Application Fees for Covered Sources
HAR 11-60.1-114	Annual Fees for Covered Sources
HAR 11-60.1-115	Basics of Annual Fees for Covered Sources
Subchapter 8	Standards of Performance for Stationary Sources
Subchapter 9	Hazardous Air Pollutants Sources
HAR 11-60.1-174	Maximum Achievable Control Technology (MACT) Emission Sources
Subchapter 10	Field Citations
Subchapter 11	Greenhouse Gas Emissions

## Federal Requirements

### Regional Haze Program Requirements

40 CFR Part 51, Subpart P, Protection of Visibility **is applicable** based on the analysis performed pursuant to CFR §51.308(f)(2) and EPA's guidance. Cost effective control measures for reasonable progress goals towards achieving natural visibility by 2064 were identified from the four-factor analysis of the Kanoelehua-Hill Generating Station. Please refer to Enclosure 1. Hawaiian Electric chose to shut down the boilers by 2028 rather than implement control measures selected in the four-factor analysis.

40 CFR Part 52, Approval and Promulgation of Implementation Plans, Subpart M, Hawaii, §52.633, Visibility Protection, is applicable. The Kanoelehua-Hill Generating Station boilers require an enforceable shut down limit pursuant to 40 CFR Part 51, Subpart P.

### National Emission Standards for Hazardous Air Pollutants (NESHAP)

40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard, **Subpart JJJJJJ**, NESHAP requirements for Area Sources for Industrial, Commercial, and Institutional Boilers Area Sources **is applicable** to Boilers Hill 5 and Hill 6. As indicated in Hawaiian Electric's Energy Assessment of February 2014, Boilers Hill 5 and Hill 6 are equipped with oxygen trim systems that continuously measure the amount of free oxygen in the boiler combustion air, and then adjusts the amount of air into the combustion chamber for optimum performance. Since the units use oxygen trim systems, the boilers are subject to five (5) year tune-ups instead of biennial tune-ups. Boilers Hill 5 and Hill 6 are existing oil-fired sources as determined in §63.11194(b) because these sources were constructed prior to June 4, 2010, and therefore, are not subject to the emission limits in Subpart JJJJJJ, Table 1.

40 CFR Part 63, **Subpart ZZZZ**, NESHAPS for Stationary RICE or DEG **is applicable** to DEGs D-11, D-15, D-16, and D-17. On September 25, 2012, the CAB approved the installation of Miratech V-CAT Diesel Catalyst on Units D-11, D-15, D-16, and D-17 for meeting the CO reduction requirements in this NESHAP.

### Air Emission Reporting Requirements (AERR)

40 CFR Part 51, Subpart A, **AERR is applicable**. Refer to section titled "Project Emissions" of this review. AERR is based on the emissions of criteria air pollutants from point sources (as defined in 40 CFR Part 51, Subpart A), which exceed the AERR thresholds as shown in the following table:

Pollutant <sup>a</sup>	Potential Emissions (TPY)	AERR Triggering Levels <sup>b</sup> (TPY)		Pollutant	In-house Total Facility Triggering Levels <sup>a</sup> (TPY)
		1 Year Cycle (Type A)	3 Year Cycle (Type B)		
NO <sub>x</sub>	3,556 (before boiler shut down) 2,434 (after boiler shut down)	≥2,500	100	NO <sub>x</sub>	≥25
SO <sub>2</sub>	3,872 (before boiler shut down) 322 (after boiler shut down)	≥2,500	100	SO <sub>2</sub>	≥25
CO	433 (before boiler shut down) 304 (after boiler shut down)	≥2,500	1,000	CO	≥250

Pollutant <sup>a</sup>	Potential Emissions (TPY)	AERR Triggering Levels <sup>b</sup> (TPY)		Pollutant	In-house Total Facility Triggering Levels <sup>a</sup> (TPY)
		1 Year Cycle (Type A)	3 Year Cycle (Type B)		
PM <sub>10</sub> /PM <sub>2.5</sub>	800 (before boiler shut down) 108 (after boiler shut down)	≥250/250	100	PM <sub>10</sub> /PM <sub>2.5</sub>	≥25/25
VOC	139 (before boiler shut down) 119 (after boiler shut down)	≥250	100	VOC	≥25
Pb	0.016	---	≥0.5 (actual)	Pb	≥5
HAPs	5.09 (before boiler shut down) 2.71 (after boiler shut down)	---	---	HAPs	≥5

<sup>a</sup>NO<sub>x</sub> - nitrogen oxide, PM<sub>10</sub> - particulate matter (PM) less than 10 microns in diameter, PM<sub>2.5</sub> PM less than 2.5 microns in diameter, VOC - volatile organic compound, Pb - lead, and HAPs - hazardous air pollutants.

<sup>b</sup>Based on potential emissions, except for lead. Based on 2020 actual emissions.

### DOH-In-House Annual Emission Reporting

The CAB requests annual emissions reporting from facilities that have facility wide emissions exceeding DOH (in-house) reporting levels and for all covered sources. Annual emissions (In-house) reporting **is applicable** because this is a covered source.

### Major Source

This facility **is a major source** because potential emissions of criteria pollutant(s) exceed(s) major source threshold(s).

### Non-Applicable Requirements

#### Federal Requirements

#### New Source Performance Standard (NSPS)

40 CFR, Part 60 – NSPS, **Subpart D**, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971, **is not applicable** because the boilers were constructed prior to August 17, 1971.

40 CFR, Part 60 – NSPS, **Subpart Da**, Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978, **is not applicable** because the boilers are less than 250 MMBtu/hr in capacity and were constructed prior to September 18, 1978.

40 CFR, Part 60 – NSPS, **Subpart Db**, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units **is not applicable** to the boilers at this facility that are over 100 MMBtu/hr heat rate input capacity because these units were constructed prior to June 19, 1984.

40 CFR, Part 60 – NSPS, **Subpart Dc**, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units **is not applicable** because the boilers were constructed prior to June 9, 1989.

40 CFR Part 60, **Subpart Kb**, Standards of Performance for Volatile Organic Liquid Storage Vessels **is not applicable** to the storage tanks because the maximum true vapor pressure of the liquid VOC stored inside the tank is less than 3.5 kilopascals (kPa) and 15.0 kPa, respectively.

The facility **is not subject** to 40 CFR Part 60, **Subpart KKKK** because CT-1 commenced construction, modification, or reconstruction before February 18, 2005. CT-1 was installed in December 1962.

### NESHAP

The facility is not a major source for HAPs and **is not subject** to NESHAPS requirements under 40 CFR Part 61.

### Compliance Assurance Monitoring (CAM), 40 CFR Part 64

The purpose of CAM is to provide a reasonable assurance that compliance is being achieved with large emissions units that rely on air pollution control device equipment to meet an emissions limit or standard. Pursuant to 40 CFR Part 64, for CAM to be applicable, the emissions unit must:

- (1) Be located at a major source;
- (2) Be subject to an emissions limit or standard;
- (3) Use a control device to achieve compliance;
- (4) Have potential pre-control emissions that are greater than the major source level; and
- (5) Not otherwise be exempt from CAM.

This source **is not subject to CAM** pursuant to 40 CFR §64.2(b) because the emission limitations and standards to which the facility is subject were promulgated after November 15, 1990.

### Best Available Control Technology (BACT)

A BACT analysis **is not required** since this is not a new source, nor are there any modifications that increase emissions.

A BACT analysis is required for new or modified sources that have the potential to emit or increase emissions above significant amounts as defined in HAR §11-60.1-1.

### Prevention of Significant Deterioration (PSD)

PSD review **does not apply**. Note, the boiler units were grandfathered from PSD review because they were constructed prior to January 6, 1975.

PSD review applies to new major stationary sources and major modifications to these types of sources. The facility is not a new major stationary source, nor does this amendment make any major modifications to a major stationary source as defined in 40 CFR Part 52.21. A major modification is defined as a project at an existing major source that will result in a significant and a significant net emissions increase above specified thresholds for pollutants subject to regulation.

**Alternate Operating Scenarios:**

This modification does not affect the alternate operating scenarios in the permit.

**Insignificant Activities/Exemptions:**

No change from Renewal Application No. 0234-02.

**Project Emissions:**

Existing emissions of NO<sub>x</sub>, CO, VOCs, PM, PM<sub>10</sub>, PM<sub>2.5</sub>, SO<sub>2</sub>, and HAPs were previously evaluated based on equipment in Review of Application for Significant Permit Modification No. 0234-05. Annual emissions were based on the maximum capacity of the equipment and 8,760 hours per year of operation. A total combined 36,500 gallon per year fuel limit was assumed to calculate HAP emissions for firing the boilers on specification used oil. Emissions are shown in the tables below:

NO <sub>x</sub> Emissions					
Unit	AP-42 EF (lb/MMBtu)	Assumed EF (lb/MMBtu)	Heat Input (MMBtu/hr)	Emission Rate (lb/hr)	Emission Rate (TPY)
Hill 5	0.313	0.7008	197	138.06	605
Hill 6	0.00714	0.05	249	12.45	517
CT-1	0.88	0.8800	177.2	155.94	683
D-11	3.2	3.7198	20.2	75.14	329
D-15	3.2	3.7198	29.1	108.25	474
D-16	3.2	3.7198	29.1	108.25	474
D-17	3.2	3.7198	29.1	108.25	474
Total→					3,556 (before boiler shut down) 2,434 (after boiler shut down)

CO Emissions					
Unit	AP-42 EF (lb/MMBtu)	Assumed EF (lb/MMBtu)	Heat Input (MMBtu/hr)	Emission Rate (lb/hr)	Emission Rate (TPY)
Hill 5	0.033	0.0662	197	13	57
Hill 6	0.033	0.0662	249	16	72
CT-1	0.0033	0.0960	177.2	17	75
D-11	0.26	0.4859	20.2	10	43
D-15	0.26	0.4860	29.1	14	62
D-16	0.26	0.4860	29.1	14	62
D-17	0.26	0.4860	29.1	14	62
Total→					433 (before boiler shut down) 304 (after boiler shut down)



VOC Emissions						
Unit	AP-42 EF (lb/MMBtu)	Assumed EF (lb/MMBtu)	Heat Input (MMBtu/hr)	Emission Rate (lb/hr)	Emission Rate (TPY)	
Hill 5	0.00249	0.01005	197	1.98	9	
Hill 6	0.00249	0.01005	249	2.50	11	
CT-1	0.00041	0.03397	177.2	6.02	26	
D-11	0.082	0.20000	20.2	4.04	18	
D-15	0.082	0.20000	29.1	5.82	25	
D-16	0.082	0.20000	29.1	5.82	25	
D-17	0.082	0.20000	29.1	5.82	25	
Total →					139 (before boiler shut down) 119 (after boiler shut down)	

PM/PM <sub>10</sub> /PM <sub>2.5</sub> Emissions						
Unit	AP-42 EF (lb/MMBtu)	Assumed EF (lb/MMBtu)	Heat Input (MMBtu/hr)	Emission Rate (lb/hr)	Emission Rate (TPY)	
Hill 5	0.144	0.292	197	57.45	252	
Hill 6	0.144	0.403	249	100.40	440	
CT-1	0.012	0.0732	177.2	12.97	57	
D-11	0.0763	0.1678	20.2	3.39	15	
D-15	0.0763	0.0914	29.1	2.66	12	
D-16	0.0763	0.0914	29.1	2.66	12	
D-17	0.0763	0.0914	29.1	2.66	12	
Total →					800 (before boiler shut down) 108 (after boiler shut down)	

SO <sub>2</sub> Emissions						
Unit	AP-42 EF (lb/MMBtu)	Mass Balance EF (lb/MMBtu)	Heat Input (MMBtu/hr)	Emission Rate (lb/hr)	Emission Rate (TPY)	
					No SO <sub>2</sub> Cap	SO <sub>2</sub> Cap
Hill 5	N/A	2.2005	197	433.50	1,899	3,550
Hill 6	N/A	2.2005	249	547.92	2,400	
CT-1	N/A	0.4130	177.2	73.18	321	
D-11	N/A	0.0015	20.2	0.03	0.13	
D-15	N/A	0.0015	29.1	0.04	0.18	
D-16	N/A	0.0015	29.1	0.04	0.18	
D-17	N/A	0.0015	29.1	0.04	0.18	
Total →					3,872 (before boiler shut down) 322 (after boiler 6 shut down)	

HAP Emissions									
HAP	Emissions (TPY)								
	CT-1	Hill 5	Hill 6	D-11	D15	D-16	D-17	Spec Oil	Total
Acetaldehyde	1.96E-02			2.23E-03	3.21E-03	3.21E-03	3.21E-03		<b>3.14E-02</b>
Acrolein	6.12E-03			6.97E-04	1.00E-03	1.00E-03	1.00E-03		<b>9.83E-03</b>
1,3 Butadiene	1.24E-02			1.42E-03	2.04E-03	2.04E-03	2.04E-03		
Benzene	4.27E-02	1.23E-03	1.56E-03	6.87E-02	9.89E-02	9.89E-02	9.89E-02		<b>4.11E-01</b>
Ethylbenzene		3.66E-04	4.62E-04						<b>8.28E-04</b>
Formaldehyde	2.17E-01	3.51E-01	4.44E-01	6.98E-03	1.01E-02	1.01E-02	1.01E-02		<b>1.05</b>
HCL								1.32E-02	<b>1.32E-02</b>
Naphthalene	2.72E-02	6.50E-03	8.22E-03	1.15E-02	1.66E-02	1.66E-02	1.66E-02		<b>1.03E-01</b>
Phosphorus		5.44E-02	6.88E-02						<b>1.23E-01</b>
Toluene	2.18E-01	3.57E-02	4.51E-02	2.49E-02	3.58E-02	3.58E-02	3.58E-02		<b>4.31E-01</b>
Xylene	1.50E-01	6.27E-04	7.93E-04	1.71E-02	2.46E-02	2.46E-02	2.46E-02		<b>2.42E-01</b>
Antimony Compounds		3.02E-02	3.82E-02						<b>6.84E-02</b>
Arsenic Compounds	8.54E-03	7.59E-03	9.60E-03	9.73E-04	1.40E-03	1.40E-03	1.40E-03	4.40E-02	<b>7.49E-02</b>
Beryllium Compounds	2.41E-04	1.60E-04	2.02E-04	2.74E-05	3.95E-05	3.95E-05	3.95E-05		<b>7.49E-04</b>
Cadmium Compounds	3.73E-03	2.29E-03	2.89E-03	4.25E-04	6.12E-04	6.12E-04	6.12E-04	3.72E-03	<b>1.49E-02</b>
Chromium Compounds	8.54E-03	4.86E-03	6.14E-03	9.73E-04	1.40E-03	1.40E-03	1.40E-03	8.00E-03	<b>3.27E-02</b>
Cobalt Compounds		3.46E-02	4.38E-02					8.40E-05	<b>7.85E-02</b>
Lead Compounds	1.09E-02	8.69E-03	1.10E-02	1.24E-03	1.78E-03	1.78E-03	1.78E-03		<b>3.71E-02</b>
Manganese Compounds	6.13E-01	1.73E-02	2.18E-02	6.99E-02	1.01E-01	1.01E-01	1.01E-01	2.72E-02	<b>1.05</b>
Mercury Compounds	9.31E-04	6.65E-04	8.22E-04	1.06E-04	1.53E-04	1.53E-04	1.53E-04		<b>2.97E-03</b>
Nickel Compounds	3.57E-03	4.86E-01	6.14E-01	4.07E-04	5.86E-04	5.86E-04	5.86E-04	4.40E-03	<b>1.11</b>
Polycyclic Organic Matter	3.10E-02	7.48E-03	9.45E-03	1.88E-02	2.70E-02	2.70E-02	2.70E-02		<b>1.48E-01</b>
Selenium Compounds	1.94E-02	3.93E-03	4.97E-03	2.21E-03	3.19E-03	3.19E-03	3.19E-03		<b>4.01E-02</b>
Total (before boiler shut down)	<b>1.39</b>	<b>1.05</b>	<b>1.33</b>	<b>0.228</b>	<b>0.329</b>	<b>0.329</b>	<b>0.329</b>	<b>0.101</b>	<b>5.09</b>
Total (after boiler shut down)	<b>1.39</b>	<b>0</b>	<b>0</b>	<b>0.228</b>	<b>0.329</b>	<b>0.329</b>	<b>0.329</b>	<b>0.101</b>	<b>2.71</b>

Greenhouse Gas Emissions			
GHG	GWP	GHG Mass-Based Emissions (TPY)	CO <sub>2</sub> e Based Emissions (TPY)
Carbon Dioxide (CO <sub>2</sub> )	1	526,752 (before boiler shut down) 203,323 (after boiler shut down)	526,752 (before boiler shut down) 203,323 (after boiler shut down)
Methane (CH <sub>4</sub> )	25	21.167 (before boiler shut down) 8.247 (after boiler shut down)	529 (before boiler 6 shut down) 206 (after boiler shut down)
Nitrous Oxide (N <sub>2</sub> O)	298	4.228 (before boiler shut down) 1.651 (After boiler shut down)	1,260 (before boiler 6 shut down) 491 (after boiler shut down)
Total Emissions→			528,542 (before boiler shut down) 204,020 (after boiler shut down)

Note: Emissions are provided in Enclosure 2.

### Ambient Air Quality Impact Assessment (AAQIA):

There are no emission increases for the federally enforceable emission limit to shut down the boilers by 2028. Therefore, an AAQIA is not required for this permit amendment.

## Significant Permit Conditions:

### 1. Regional Haze Rule Limits

#### a. Boiler Shut Down

Boilers Hill 5 & Hill 6 shall be permanently shut down by **December 31, 2027**.

#### b. Regional Haze – SO<sub>2</sub> Emissions Cap

- i. Kanoelehua-Hill Generating Station, Boilers Hill 5 and Hill 6, combined with Puna Generating Station, Boiler, shall not emit or cause to be emitted SO<sub>2</sub> in excess of 3,550 tons per year, calculated as the sum of total SO<sub>2</sub> emissions for all three (3) units over a rolling twelve-month (12-month) period.
- ii. Compliance with the SO<sub>2</sub> emissions cap is required at all times **on and after December 31, 2018**.

Reason: Regional haze conditions are added to comply with the requirements of 40 CFR Part 51, Subpart P and 40 CFR Part 52, Subpart M. The SO<sub>2</sub> emissions cap remains unchanged from the permit amendment issued on June 6, 2018.

## Conclusion and Recommendation:

This permit amendment incorporates the regional haze control measures specified for the boilers in Hawaii's RH-SIP in accordance with HAR §11-60.1-10(a)(2) and (a)(3), CAA §169A(g)(1), and 40 CFR §51.308(f)(2)(iv). Pursuant to the RH-SIP for the second planning period, CSP No. 0234-01-C for the Kanoelehua-Hill Generating Station is being amended to carry over the existing regional haze SO<sub>2</sub> emissions cap and incorporate the following regional haze limit:

Boilers Hill 5 and Hill 6 shall be permanently shut down **by December 31, 2027**

Hawaiian Electric's four-factor analysis for Kanoelehua-Hill Generating Station was reviewed with other available data provided by the Western Regional Air Partnership (WRAP) with consultation from both the EPA, Region 9 and the National Park Service (NPS). Based on our review, it is determined that the enforceable permit limit to shut down the boilers would provide federally enforceable actions to assure reasonable progress towards the achievement of natural visibility by 2064.

Recommend issuance of the amendment to the CSP subject to a sixty-day (60-day) formal review of the State's regional haze implementation plan by the NPS, thirty-day (30-day) public review and comment period in accordance with HAR §11-60.1 and 40 CFR §51.102, forty-five day (45-day) EPA review period, and incorporation of the significant permit conditions. It should be noted that this permit amendment will be part of the Hawaii's RH-SIP for the second planning period.

Kai Erickson  
May 6, 2022

## Enclosure 1: Kanoelehua-Hill Generating Station Control Measure Analysis

The four-factor analysis initially performed for the Kanoelehua-Hill Generating Station is not required because Hawaiian Electric chose to permanently shut down Boilers Hill 5 and Hill 6 rather than implement the control measure selected. For information, in considering the *four (4) statutory factors* with a floor cost threshold of \$5,800 per ton of pollutant removed, the following control measures were selected in the four-factor analysis to make reasonable progress for the second regional haze planning period:

1. By **four years from permit issuance**, switch from burning fuel oil No. 6, diesel, and specification used oil in Boilers Hill 5 and Hill 6 to ultra-low sulfur diesel (ULSD) with 0.0015% maximum sulfur content for reducing sulfur dioxide (SO<sub>2</sub>), nitrogen oxide (NO<sub>x</sub>), and particulate matter less than ten microns (PM<sub>10</sub>); and
2. By **December 31, 2027**, retrofit the boilers with selective catalytic reduction (SCR) and combustion controls (which includes low NO<sub>x</sub> burners (LNBS), flue gas recirculation (FGR), and over fire air (OFA)), or the required combination of these controls to further reduce and meet the NO<sub>x</sub> emission limits.

### *Four-Factor Analysis:*

Control measures under consideration for implementation by 2028 were determined based on the four-factor analysis performed by Hawaiian Electric for the Kanoelehua-Hill Generating Station. The four-factor analysis considers the following:

1. Cost of compliance;
2. The remaining useful life of the affected anthropogenic source of visibility impairment;
3. Time necessary for compliance; and
4. The energy and non-air quality environmental impacts of compliance.

Implementation of controls selected from the four-factor analysis would allow Hawaiian Electric to continue operating the Kanoelehua-Hill boilers beyond 2027. The four-factor analysis for boilers at Kanoelehua-Hill Generating Station is provided below for information.

### *Calculating the Cost of Compliance:*

A driving factor in selecting reasonable control measures is the cost of compliance, which is the cost effectiveness or the dollar cost per tons of pollutant removed. Annualized amortization of capital cost or equivalent uniform annual cost (EUAC) is described in EPA's Air Pollution Control Cost Manual and is one of the methodologies used to determine the cost of controls. Costs were based on the following factors and assumptions:

1. Nominal interest rate.
2. Thirty (30) year remaining useful life for SCR retrofits to boilers.
3. Twenty-five (25) year remaining useful life for atomization equipment and berm liners.
4. Twenty (20) year remaining useful life for all other controls (including SCR retrofits to diesel engine generators).
5. SCR retrofit factor of 1.0.
6. Hawaii Construction Cost Multiplier of 1.0.

## Enclosure 1: Kanoelehua-Hill Generating Station Control Measure Analysis

### Nominal Interest Rate

Nominal interest rate described in Section 1, Chapter 2 (Pages 14 to 16) of the EPA's Air Pollution Control Cost Manual, 7<sup>th</sup> edition\_2017 (CCM), is the rate firms actually face. Chapter 2, Section 2.5.2 of the CCM recognizes that the determination of the firm-specific nominal interest rates depends on how they plan to finance their purchases, i.e., whether the firm intends to borrow to finance their investment or finance their purchases through cash holding or other means of equity. The CCM further states, if firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates given the potential difficulties in eliciting accurate firm-specific nominal interest rates since it may be regarded as confidential business information or difficult to verify.

Hawaiian Electric expressed their intent on using a weighted average cost of capital (WACC) method in their letter dated June 16, 2021, which comprises principally of a long-term debt interest rate of 4.79% and common equity interest rate of 9.5% as sources to finance their capital expenditures. Hawaiian Electric currently has a Moody long-term issuer rating of Baa1 and the prevailing Baa corporate bond yield shown in the Federal Reserve Economic Data at: <https://fred.stlouisfed.org/series/BAA> is less than 4%. Therefore, the 4.79% rate for the long-term debt used by Hawaiian Electric was replaced with the current Baa corporate bond yield as posted on the Federal Reserve website. For common equity, an interest rate of 9.5% is used by Hawaiian Electric which appears to be the ratemaking return of common equity (ROE) as explained on Hawaiian Electric's website at: <https://www.hawaiianelectric.com/about-us/key-performance-metrics/financial>. The "Ratemaking ROE" is the ROE that is authorized by the PUC and is not the actual ROE that investors receive. The purpose for the Ratemaking ROE is to determine whether there will be any sharing of actual earnings that exceed the threshold authorized by the PUC. The "Book ROE" is more appropriately used because it is a measure of a company's actual profit or "return" on shareholders' investments and best represents the opportunity cost or the amount of potential gain investors miss out on when common equity or investment funds are withdrawn for use to fund capital investments. The following table shows in red fonts, CAB's modifications to the WACC method used by Hawaiian Electric to derive the nominal interest rate for the Hawaii Island sources after consulting with EPA.<sup>3</sup>

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<sup>3</sup>EPA email response dated July 12, 2021, titled, "Regional Haze Control Cost Interest Rate".

Enclosure 1: **Kanoelehua-Hill Generating Station Control Measure Analysis**

Hawaii Island Sources

	A	B	C	D
Source of Capital	Amount in Thousands	Percent of Total	Earnings	Weighted Earnings B X C
Short-Term Debt	Not Reported	0.61%	3.75%	0.02%
Long-Term Debt <sup>a</sup>		40.59%	3.24%	1.32%
Hybrid Securities		0.80%	7.83%	0.06%
Preferred Stock		1.17%	8.12%	0.10%
Common Equity <sup>b</sup>		56.83%	8.92%	5.07%
Total		100.00%		
Weighted Average Cost of Capital =				6.56%

<sup>a</sup> Moody's Seasoned Monthly Baa Corporate Bond Yield, (Percent) from:

<https://fred.stlouisfed.org/series/BAA>

<sup>b</sup> Hawaiian Electric book return of common equity (ROE) from:

<https://www.hawaiianelectric.com/about-us/key-performance-metrics/financial>

Useful Life

In the situation of an enforceable requirement for the source to cease operation before the end of the useful life of the controls under consideration, the EPA guidance allows the use of the enforceable shut down date as the end of the remaining useful life. If no enforceable shut down date exists for units requiring controls, the remaining useful life is the full useful life of the control under consideration.

Remaining useful life of thirty (30) years is used for SCR retrofits to boilers based on Section 2.4.2, Chapter 2 of EPA's CCM for SCR.

Twenty-five (25) years is assumed for atomization equipment and berm liners based on the referenced PUC filing in Hawaiian Electric's letter dated June 16, 2021, since there is no documented useful life for installation of fuel atomization systems and tank containment liners in the CCM. As indicated in the PUC Docket Number 2020-0187 filed on November 10, 2020, for the Waiiau Fuel Tank Containment Project Berm Lining, the life expectancy of the liner, accounting for a majority of the capital costs, is upwards of twenty-five (25) years.

Twenty (20) years is assumed for all other control equipment.

Capital Cost to Fuel Switch

Additional capital cost is required to support the boiler fuel switch as identified in Hawaiian Electric's letter dated June 16, 2021, which includes completing the engineering research and design, boiler modifications to add fuel atomization, and installation of secondary containment liners. Required modifications to the boiler fuel-atomization system and fuel pumps are essential to allow for thorough combustion of the ULSD at the burner nozzle due to the difference in viscosity. Due the low viscosity of ULSD, the installation of secondary containment

Enclosure 1: **Kanoelehua-Hill Generating Station Control Measure Analysis**

liners is required for larger fuel tanks that will switch from storing residual fuel oil No. 6 to ULSD to comply with the EPA's Spill Prevention, Controls, and Countermeasures (SPCC) Rule. This liner protects surface waters, drinking water, and ground water in the event of inadvertent release of ULSD to the environment.

In addition, fuel atomization is a process that breaks down liquid fuel into a mist-like spray to prepare for vaporization. The capital cost estimate to add mechanical fuel atomization of ULSD is based on the Black and Veatch (B&V) engineering studies for a similar project at the Waiiau Generating Station, which provides an estimated average cost of about \$1.1 million (based on June 2013 dollars) per boiler for an average boiler size of 62.375 MW. The costs for each boiler at the Kanoelehua-Hill Generating Station, which are all smaller than the boilers at the Waiiau Power Generating Station, are scaled down from the \$1.1 million per boiler reference cost using the "six-tenths factor" rule of thumb. This cost scaling method is based on the empirically observed relationship between the cost and the size of equipment. As size increases, cost increases by an exponent of six-tenths, e.g.,  $cost1/cost2 = (size1/size2)^{0.6}$ .

The table below shows the additional capital expenditure estimates for adding fuel atomization to boilers at the Kanoelehua-Hill Generating Station.

**Cost Estimate to add Fuel Atomization  
(Based on 2013 dollars)**

Unit	Size 1 MW	(Size 1/Size 2) <sup>0.6</sup>	Capital Cost 1 Estimate <sub>2013</sub> <sup>b, c</sup>
Hill 5	14	4.08E-01	\$448,811
Hill 6	23	5.50E-01	\$604,537

<sup>a</sup> Waiiau Average Boiler Size 2 = 62.375 MW each.

<sup>b</sup> Waiiau reference boiler atomization Cost 2 = \$1,100,000 Capital Cost Estimate each from B&V engineering studies summarize below.

<sup>c</sup> As size increases, cost increases by an exponent of six-tenths, e.g.,  $cost1/cost2 = (size1/size2)^{0.6}$ .

Therefore,  $cost 1 = (size1/size2)^{0.6} \times cost 2$

**B&V Cost Summary by Unit**

	Mechanical Atomization	Steam Atomization
Waiiau 3	\$926,874	\$1,013,300
Waiiau 4	\$1,278,158	\$1,298,430
Waiiau 5	\$1,063,623	\$914,646
Waiiau 6	\$1,069,044	\$919,029
Waiiau 7	\$1,126,858	\$1,525,645
Waiiau 8	\$1,117,481	\$1,514,077
Ave Unit Cost	\$1,097,006	\$1,197,521

The cost estimates are converted to 2019 dollars by applying the ratio of the Chemical Engineering Plant Cost Index (CEPCI) for 2019 of 607.5 divided by the CEPCI for 2013 of 567.3 or 107% as illustrated in the following table (refer to Enclosure 3 for the CEPCI data):

Enclosure 1: **Kanoelehua-Hill Generating Station Control Measure Analysis**

**Cost Estimate to add Fuel Atomization  
(Adjustment to 2019 dollars)**

Unit	Size 1 MW	Capital Cost 1 Estimate <sub>2013</sub>	CEPCI <sub>2019</sub> /CEPCI <sub>2013</sub>	Capital Cost 1 Estimate <sub>2019</sub>
Hill 5	14	\$448,811	107%	\$480,614
Hill 6	23	\$604,537	107%	\$647,376

The capital cost estimate to install berm lining for fuel switch to ULSD is based on the Hawaiian Electric cost estimates presented in their PUC Docket Number 2020-0187 filed on November 10, 2020, for the Waiiau Generating Station Fuel Tank Containment Project Berm Lining. The capital cost for the Waiiau Project is \$5.23 million to line an area of 78,400 square feet. Costs for the Kanoelehua-Hill Generating Station are based on a scaling of the Waiiau's Project costs to the smaller size of the combined berm areas.

**Cost Estimate for Secondary Containment Liner**

Island	Units	Berm Area to Line (Size 1)	(Size 1/Size 2) <sup>a,0.6</sup>	Capital Cost 1 Estimate <sup>b, c</sup>
Hawaii	Hill 5, Hill 6	63,000	8.77E-01	\$4,584,641

<sup>a</sup> Waiiau Reference Berm Area (Size 2) = 78,400 Square Feet

<sup>b</sup> Waiiau Reference Liner Project Cost 2 = \$ 5,230,000 Capital Cost

<sup>c</sup> As size increases, cost increases by an exponent of six-tenths, e.g.  $cost1/cost2 = (size1/size2)^{0.6}$ .  
Therefore,  $cost 1 = (size1/size2)^{0.6} \times cost 2$

Breakdown of the liner capital cost estimate of \$4,584,641 was by boiler capacity (MW) of each unit relative to the combined boiler capacity of 34 MW.

**Breakdown of Cost Estimate for Secondary Containment Liner by Units**

Units	Boiler Capacity (MW)	Capital Cost Estimate
Hill 5	14	\$1,735,622
Hill 6	23	\$2,851,378

**Capital Cost of SCR and Combustion Controls for NOx**

The following table summarizes the total capital investment or capital cost (in 2019 dollars) to refit the boilers with combustion controls and SCR for reducing NOx emissions:

Units	Hill 5	Hill 6
Capital Cost of Combustion Controls (2019)	\$1,387,123	\$1,423,621
Capital Cost of SCR (2019)	\$5,575,916	\$7,643,145



Enclosure 1: **Kanoelehua-Hill Generating Station Control Measure Analysis**

**Construction Cost Multiplier**

Hawaiian Electric used a Hawaii Island construction cost multiplier of 1.2 in the cost analysis for installing SCR. While it is appropriate to take into consideration the higher costs of transporting equipment and supplies, as well as higher labor rates in unique areas like Hawaii and Alaska, those higher costs were not itemized, justified, and documented by Hawaiian Electric. Therefore, a construction cost multiplier of 1.0 is assumed in estimating the cost of SCR for the Kanoelehua-Hill Generating Station.

**Capital Recovery Factor (CRF)**

The CRF listed in the following table was developed from the nominal interest rate and useful life of equipment:

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

	Control Measure→	All Other	Atomization & Liner	SCR
i	Nominal Interest Rate	6.56%	6.56%	6.56%
n	Useful Life (yrs)	20	25	30
CRF	Capital Recovery Factor	<b>0.0912<sup>a</sup></b>	<b>0.0824<sup>a</sup></b>	<b>0.0771<sup>a</sup></b>

<sup>a</sup> Due to rounding of the CRF, calculations from AECOM\_Ltr\_Att\_6\_KanoelehuaHill\_RH\_FourFactor\_Analysis\_Tables may vary slightly from the following tables.

**Annual Cost and Cost Effectiveness**

The CRF amortizes capital cost to an equivalent annualized capital cost or the equivalent uniform annual cash flow (EUAC) approach, more commonly referred to as “amortization”. The combined annualized capital cost combined with annual operations and maintenance cost divided by the annual reduction in pollutions provides the cost effectiveness for each control measure as illustrated in the following tables:

Enclosure 1: **Kanoelehua-Hill Generating Station Control Measure Analysis**

**Fuel Switch**

	<b>Units</b>	<b>Hill 5</b>	<b>Hill 6</b>
a	Capital Cost of Atomization	\$480,614	\$647,376
b	Capital Cost of Liners	\$1,735,622	\$2,851,378
c	Combined Capital Cost (2019) <sup>a</sup>	\$2,216,236	\$3,498,754
d	CRF	0.0824	0.0824
e	Annualized Capital Cost <sup>b</sup>	\$182,600	\$288,300
f	Annual Fuel Cost Differential <sup>c</sup>	\$4,120,758	\$6,762,141
g	Annual Cost of Fuel Switch <sup>d</sup>	\$4,303,358	\$7,050,441
h	Total SO <sub>2</sub> , NO <sub>x</sub> , and PM <sub>10</sub> Reduced (tpy) <sup>c</sup>	954.1	1,443.8
i	Cost Effectiveness (\$/ton) <sup>e</sup>	<b>\$4,510</b>	<b>\$4,883</b>

<sup>a</sup>  $c = a + b$

<sup>b</sup>  $e = c * d$ , (rounded to the nearest 100)

<sup>c</sup> Source: Data from Table 6.1 updated May 2021, of AECOM\_Ltr\_Att\_6\_K-Hill\_RH\_FourFactor\_Analysis\_Tables.

<sup>d</sup>  $g = e + f$

<sup>e</sup>  $i = g / h$

**Combustion Control**

	<b>Units</b>	<b>Hill 5</b>	<b>Hill 6</b>
a	Capital Cost (2019) <sup>a</sup>	\$1,387,123	\$1,423,621
b	CRF	0.0912	0.0912
c	Annualized Capital Cost (EUAC) <sup>b</sup>	\$126,505	\$129,834
d	Fixed O&M <sup>a</sup>	\$20,807	\$21,354
e	Variable O&M <sup>a</sup>	\$9,611	\$5,914
f	Annual Cost of Combustion Control <sup>c</sup>	<b>\$156,923</b>	<b>\$157,102</b>

<sup>a</sup> O&M represents operating and maintenance. [Source: Data from Kanoelehua-Hill Appendix Table A-1 updated Aug 2021 of AECOM\_Ltr\_Att\_6\_KanoelehuaHill\_RH\_FourFactor\_Analysis\_Tables.]

<sup>b</sup>  $c = a * b$

<sup>c</sup>  $f = c + d + e$

Enclosure 1: **Kanoelehua-Hill Generating Station Control Measure Analysis**

**Fuel Switch + Combustion Control**

	<b>Units</b>	<b>Hill 5</b>	<b>Hill 6</b>
a	Annual Cost of Fuel Switch <sup>a</sup>	\$4,303,358	\$7,050,441
b	Annual Cost of Combustion Control <sup>b</sup>	\$156,923	\$157,102
c	Annual Cost of Fuel Switch + Combustion Control <sup>c</sup>	\$4,460,281	\$7,207,543
d	Baseline NOx Emissions in 2017 <sup>d</sup> (tpy)	251.5	353.6
e	NOx Removed after Fuel Switch <sup>e</sup> (tpy)	113.2	70.7
f	NOx Emissions after Fuel Switch <sup>f</sup> (tpy)	138.3	282.9
g	Additional NOx Removed from CC <sup>g</sup> (tpy)	69.2	141.5
h	NOx Emissions after Fuel Switch + Combustion Control <sup>h</sup> (tpy)	69.1	141.4
i	Reduction of SO <sub>2</sub> , NOx, and PM <sub>10</sub> from FS <sup>e</sup> (tpy)	954	1,444
j	Total Reductions of SO <sub>2</sub> , NOx, and PM <sub>10</sub> <sup>i</sup> (tpy)	1,023	1,585
k	Cost Effectiveness <sup>j</sup> (\$/ton)	<b>\$4,360</b>	<b>\$4,547</b>

a From row g in the Fuel Switch Table.

b From row f in the Combustion Control Table.

c  $c = a + b$

d Source: Data from Table 4-4 of AECOM\_Ltr\_Att\_6\_KanoelehuaHill\_RH\_FourFactor\_Analysis\_Tables.

e Source: Data from Table 6-1 of AECOM\_Ltr\_Att\_6\_KanoelehuaHill\_RH\_FourFactor\_Analysis\_Tables.

f  $f = d - e$

g  $g = f * 50\%$ ; Additional reductions in NOx emissions assuming 50% control efficiency from combustion controls after fuel switch.

h  $h = f - g$

i  $j = h + i$

j  $k = c / j$

**SCR**

	<b>Units</b>	<b>Hill 5</b>	<b>Hill 6</b>
a	Capital Cost (2019) <sup>a</sup>	\$4,646,597	\$6,369,287
b	CRF	0.0771	0.0771
c	Annualized Capital Cost (EUAC) <sup>b</sup>	\$358,252	\$491,072
d	Fixed O&M <sup>a</sup>	\$30,668	\$42,037
e	Variable O&M <sup>a</sup>	\$84,318	\$145,403
f	Annual Cost of SCR <sup>c</sup>	\$473,238	\$678,512

a Source: Data from K-Hill\_Appendix Table A-2, Updated Aug 2021 of AECOM\_Ltr\_Att\_6\_KanoelehuaHill\_RH\_FourFactor\_Analysis\_Tables.

b  $c = a * b$

c  $f = c + d + e$

Enclosure 1: Kanoelehua-Hill Generating Station Control Measure Analysis

**Fuel Switch + SCR**

	<b>Units</b>	<b>Hill 5</b>	<b>Hill 6</b>
<b>a</b>	Annual Cost of Fuel Switch <sup>a</sup>	\$4,303,358	\$7,050,441
<b>b</b>	Annual Cost of SCR <sup>b</sup>	\$473,238	\$678,512
<b>c</b>	Annual Cost of Fuel Switch + SCR <sup>c</sup>	\$4,776,569	\$7,728,953
<b>d</b>	NOx Emissions after Fuel Switch (tpy) <sup>d</sup>	138.3	282.9
<b>e</b>	Additional NOx Removed with SCR (tpy) <sup>e</sup>	124.5	254.6
<b>f</b>	SO <sub>2</sub> , NOx, and PM <sub>10</sub> Removed from Fuel Switch <sup>f</sup> (tpy)	954	1,444
<b>g</b>	SO <sub>2</sub> , NOx, and PM <sub>10</sub> Removed from SCR + Fuel Switch <sup>g</sup> (tpy)	1,079	1,698
<b>h</b>	Cost Effectiveness <sup>h</sup>	<b>\$4,427</b>	<b>\$4,551</b>

**a** From row g in the Fuel Switch Table.

**b** From row f in the SCR Table.

**c**  $c = a + b$

**d** From row f in the Fuel Switch + Combustion Control Table.

**e**  $e = d * 90\%$ ; Additional reductions in NOx emissions assuming 90% control efficiency with SCR after fuel switch.

**f** Source: Total reductions of SO<sub>2</sub>, NOx, and PM<sub>10</sub> as shown on Table 6-1 of AECOM\_Ltr\_Attc\_6\_K-Hill\_RH\_FourFactor\_Analysis\_Tables.

**g**  $g = e + f$

**h**  $h = c / g$

**Additional NOx Removed with SCR and Combustion Control after Fuel Switch**

	<b>Units</b>	<b>Hill 5</b>	<b>Hill 6</b>
<b>a</b>	2017 Annual Heat Input <sup>a</sup> (MMBtu/yr)	878,441	1,441,517
<b>b</b>	NOx Emission Limit <sup>b</sup> (lb/MMBtu)	0.05	0.05
<b>c</b>	NOx Emissions from SCR after Fuel Switch + Combustion Control <sup>c</sup> (tpy)	22.0	36.0
<b>d</b>	NOx Emissions after Fuel Switch <sup>d</sup> (tpy)	138.3	282.9
<b>e</b>	Additional NOx Removed with SCR + Combustion Control after Fuel Switch <sup>e</sup> (tpy)	<b>116.3</b>	<b>246.9</b>

**a** 2017 annual boiler heat input as shown on Table 4-4 of AECOM\_Ltr\_Att\_6\_KanoelehuaHill\_RH\_FourFactor\_Analysis\_Tables.

**b** Section 2.3.5 in the SCR Cost Manual Chapter 7, edition 2016, revision 2017 (Manual) states that the annual average outlet NOx should not be less than 0.04 lb/MMBtu, or at a level that results in a removal efficiency greater than 90%, unless a guarantee has been obtained from a vendor. However, section 2.3.5 of Chapter 7 of the Manual also states that 0.05 lb/MMBtu outlet NOx based on a 30-day (boiler operating) average should be obtainable by a power plant boiler with an SCR system.<sup>4</sup>

**c**  $c = a * b * (1 \text{ ton} / 2,000 \text{ lbs})$

**d** From row f in the Fuel Switch + Combustion Control Table.

**e**  $e = d - c$

<sup>4</sup>EPA email response dated July 29, 2021, titled, "NOx Limit".

Enclosure 1: **Kanoelehua-Hill Generating Station Control Measure Analysis**

**Cost Effectiveness of SCR + Combustion Control + Fuel Switch**

	<b>Units</b>	<b>Hill 5</b>	<b>Hill 6</b>
<b>a</b>	Annual Cost of Fuel Switch + Combustion Control <sup>a</sup>	\$4,460,281	\$7,207,543
<b>b</b>	Annual Cost of SCR <sup>b</sup>	\$473,238	\$678,512
<b>c</b>	Annual Cost of Fuel Switch + Combustion Control + SCR <sup>c</sup>	\$4,933,519	\$7,885,055
<b>d</b>	Baseline NOx Emissions in 2017 (tpy) <sup>b</sup>	251.5	353.6
<b>e</b>	NOx Emissions after Fuel Switch <sup>e</sup> (tpy)	138.3	282.9
<b>f</b>	NOx Removed after Fuel Switch <sup>f</sup> (tpy)	113.2	70.7
<b>g</b>	Additional NOx Removed with SCR + Combustion Control after Fuel Switch <sup>g</sup> (tpy)	95.2	228.4
<b>h</b>	Total NOx Removed after Fuel Switch + Combustion Control + SCR <sup>h</sup> (tpy)	208.4	299.1
<b>i</b>	SO <sub>2</sub> Removed after Fuel Switch <sup>i</sup> (tpy)	819.9	1,345.5
<b>j</b>	PM <sub>10</sub> Removed after Fuel Switch <sup>i</sup> (tpy)	21	27.5
<b>k</b>	Total Pollutants Removed after Fuel Switch + Combustion Control + SCR <sup>j</sup> (tpy)	1,070	1,691
<b>l</b>	Cost Effectiveness of Fuel Switch + Combustion Control + SCR <sup>i</sup> (\$/ton)	<b>\$4,611</b>	<b>\$4,663</b>

**a** From row c in the Fuel Switch + Combustion Control Table.

**b** From row f in the SCR Table.

**c**  $c = a + b$

**d** Source: 2017 NOx emissions as shown on Table 4-4 of AECOM\_Ltr\_Attch\_6\_KanoelehuaHill\_RH\_FourFactor\_Analysis\_Tables.

**e** From row f in the Fuel Switch + Combustion Control Table.

**f** Section 2.3.4 in Chapter 2 of the SCR Cost Manual Chapter 7, edition 2016, revision 2017 states that the inlet NOx (NOxin) is the emission level in the flue gas exit stream from a boiler, which also accounts for combustion controls at the inlet of the SCR system.

**g** From row e in the Additional NOx Removed with SCR and Combustion Control after Fuel Switch Table assuming 0.05 lb/MMBtu NOx emissions from SCR after fuel switch and combustion controls.

**h**  $h = f + g$

**i** Source: 2017 data as shown on Table 6-1 of AECOM\_Ltr\_Attch\_4\_Kanoelehua-Hill\_RH\_FourFactor\_Analysis\_Tables.

**j**  $k = h + i + j$

**k**  $i = c / k$

## Enclosure 1: Kanoelehua-Hill Generating Station Control Measure Analysis

Hawaiian Electric's Power Supply Improvement Plan (PSIP) to retire boilers at the Kanoelehua-Hill Generating Station was not initially used as an enforceable control measure because Hawaiian Electric was unable to provide a firm commitment date as to when the renewable projects will be available to replace fossil fuel sources. 40 CFR Part 51, §51.308(f)(2) states that the long-term strategy must include the enforceable emission limitations, compliance schedules, and other measures necessary to make reasonable progress. Section II.B.5.e of the EPA's Guidance on Regional Haze State Implementation Plans for the Second Implementation Period further states, "The time necessary for compliance generally is considered to be a source-by-source question, with each source required to comply by a date that is reasonable for that source."<sup>1</sup> As such, a lack of a firm schedule for retiring plant equipment precludes the use of this plan as a federally enforceable control measure. However, in our meeting on October 7, 2021, Hawaiian Electric agreed to commit to an enforceable source retirement date by the end of the second planning period. Refer to the section titles, "Time Necessary for Compliance" in this review for details of our discussion.

### *Establish a Reasonable Cost Threshold:*

In the first planning period, \$5,000/ton of pollutant removed in 2009 dollars (one year into the first regional haze planning period) was the established cost threshold for cost effective control measures. This cost threshold was inflated to \$5,800/ton to represent 2019 dollars (one year into the second regional haze planning period) by multiplying the \$5,000/ton threshold in 2009 by the ratio of the 2019-to-2009 CEPCI. The CEPCI, used extensively by the EPA for this type of analysis, is the basis for this application.

### *Time Necessary for Compliance:*

Hawaiian Electric indicated in their letter dated June 16, 2021, that if a specific compliance date is necessary for switching fuel, it proposes December 31, 2027.<sup>5</sup> Explanations from Hawaiian Electric to justify its proposed compliance schedule included:

- Switching from fuel oil No. 6 to ULSD and installing combustion controls and SCR for boilers at the Kanoelehua-Hill Generating Station requires significant capital investments.<sup>5</sup> Because of the planned implementation of the renewable portfolio standard (RPS) goals, these investments will only have short-lived benefits and potentially impose significant costs to the Hawaiian Electric customers.<sup>6</sup>
- A more flexible schedule will allow Hawaiian Electric's current efforts to the RPS goal to be realized, including the retirement and lower utilization of some of these facilities.<sup>5</sup>
- Additional costs for the fuel switch are secondary containment liners for the larger fuel oil tanks that will switch to store ULSD.<sup>5,6</sup>
- Additional costs involving fuel atomization modifications for the boilers due to the lower viscosity of ULSD are also required.<sup>5,6</sup>
- There have been unexpected delays for some of the renewable projects. There are factors that are not completely within Hawaiian Electric's control including when the Hawaii Public Utilities Commission (PUC) will approve the projects or other delays with installing the facilities.<sup>5</sup>

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<sup>5</sup>Hawaiian Electric's June 16, 2021, letter.

<sup>6</sup>Hawaiian Electric's March 30, 2021, letter.

## Enclosure 1: Kanoelehua-Hill Generating Station Control Measure Analysis

- Additional time is needed to obtain PUC approval of the projects and complete the engineering studies, design engineering, and construction required to install containment liners and modify equipment to implement the fuel switch.<sup>5</sup>

In CAB discussions with the EPA, Region 9, it was agreed that a three-year (3-year) duration following issuance of the permit for implementing fuel switching and five-year (5-year) duration following issuance of the permit for implementing SCR and combustion controls were reasonable based on information from regional haze four-factor analyses. Compliance deadlines should be specific, objectively determined, and justified as reasonable considering available historical data regarding time necessary for the installation of similar control measures<sup>1</sup>. A specific compliance date was specified to accomplish fuel switches for boilers at the Kanoelehua-Hill Generating Station which is consistent with EPA guidance and the four-factor analyses.

According to Hawaiian Electric's PSIP, boilers operating at the Kanoelehua-Hill Generating Station will be retired in 2024. However, as indicated in an email from Ms. Marisa Melzer of Hawaiian Electric on September 17, 2021, the actual schedule for retiring these units has not been firmly established.

In discussions with the EPA and the National Park Service (NPS) there was disagreement with allowing an extension of time for switching fuels to implement the RPS goals for retiring equipment. Again, the compliance deadline needs to be based on historical data of the time necessary for installation of similar control measures. Hawaiian Electric indicated that installation of equipment and secondary containment improvements will take up to two (2) years. Because the project costs are estimated to exceed the PUC threshold of \$2.5 million dollars, the project will also require PUC approval which can take up to two (2) years due to the extensive application review process.

The cost of installing fuel atomization systems and secondary tank containment liners to switch fuel to ULSD for the Kanoelehua-Hill boilers ranged from \$4,510/ton to \$4,883/ton and the cost of SCR plus combustion controls after the fuel switch ranged from \$4,611/ton to \$4,663/ton which are below the \$5,800/ton threshold. Refer to tables titled "Fuel Switch" and "Cost Effectiveness of SCR + Combustion Control + Fuel Switch" on Pages 17, and 20, respectively, of this technical support document. However, during a meeting on October 7, 2021, Hawaiian Electric agreed to an enforceable shut down of the Kanoelehua-Hill Generating Station boilers by December 31, 2027. The EPA guidance allows an option of not selecting sources for control measure analysis that have an enforceable commitment to be retired or replaced by 2028.<sup>1</sup> Therefore, regional haze add-on controls are not required for the Kanoelehua-Hill Generating Station boilers.

In our meeting with Hawaiian Electric on October 7, 2021, we discussed planned renewable energy projects that are either already approved by PUC or have been submitted for PUC approval with a proposed combined production capacity and infrastructure that will enable Kanoelehua-Hill Generating Station to permanently retire Boilers Hill 5 and Hill 6 by the end of the second planning period. Additional renewable energy sources need to come onto the system before Hawaiian Electric is able to shut down power generation from the Kanoelehua-Hill Generating Station. Hawaiian Electric prefers to push out the fuel switch date

## Enclosure 1: Kanoelehua-Hill Generating Station Control Measure Analysis

to 2027 committing to an enforceable source retirement date, however, is willing to commit to either fuel switch or to retire these boilers if they are able to extend their commitment date to the end of 2027. In review of these factors, the CAB considers the option to retire the Kanoelehua-Hill Generating Station Boilers by December 31, 2027, to be a realistically achievable and more cost-effective approach to make reasonable progress. As a contributing factor, both the NPS and the EPA do not consider extending the duration for implementing a fuel switch past three years as reasonable without justifiable supporting documentation.

### *Energy and Non-Air Quality Environmental Impacts of Compliance:*

Fuel switching from residual oil to ULSD may have an indirect energy impact during fuel refining, however, Section II.B.4. e) of EPA's Guidance<sup>1</sup> recommends that states focus their analysis on direct energy consumption at the source rather than indirect energy inputs needed to produce raw materials. Therefore, the energy impact of refining ULSD is accounted for by including the annual fuel cost difference between fuel oil No. 6 and ULSD in with the cost of compliance. Firing ULSD will have a direct energy impact due to reduced boiler efficiency if an atomization system is not installed. Also, the lower viscosity of ULSD can have non-air quality environmental impacts in the event of inadvertent or accidental spills. Therefore, the annualized capital cost of installing both an atomization system and secondary containments to comply with SPCC requirements are also included as an annualized cost of compliance.

Combustion controls do not have non-air quality environment impacts. However, improper feed rate of OFA can result in heat loss and decreased boiler efficiency.

### *Control Measures:*

Since the permit amendment will specify a federally enforceable limit to permanently retire the Kanoelehua-Hill Generating Station boilers by December 31, 2027, the following control measures will not be required:

1. A fuel switch from fuel oil No. 6 and specification used oil to ULSD containing 0.0015% maximum sulfur content to reduce SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub>; and
2. SCR and combustion controls after the fuel switch to further control NO<sub>x</sub>.

An LNB retrofit can achieve approximately 35% to 55% reductions in NO<sub>x</sub>, and 40% to 60% reductions when used with OFA, both from uncontrolled levels. The LNB limits NO<sub>x</sub> formation by: (1) reducing oxygen in the primary combustion zone; (2) reducing flame temperature; and (3) reducing residence time at peak temperature.

FGR can lower emissions of NO<sub>x</sub> by as much as 40% to 50% in some boilers. This is accomplished by recirculating a portion of the flue gas from the economizer or air heater outlet back to the furnace that reduces oxygen and flame temperature in the combustion zone. Carbon monoxide (CO) levels remain constant or are reduced because flue gas introduced into the early stages of combustion with the air fuel mixing is intensified.



## Enclosure 1: Kanoelehua-Hill Generating Station Control Measure Analysis

OFA is a technique in which a percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. OFA limits NO<sub>x</sub> by: (1) suppressing thermal NO<sub>x</sub> by partially delaying and extending the combustion process resulting in less intense combustion and cooler flame temperatures; (2) reducing flame temperature that limits thermal NO<sub>x</sub> formation; and/or (3) reducing residence time at peak temperature that also limits thermal NO<sub>x</sub> formation. The re-mixing of flue gases causes secondary combustion, releasing heat that transfers through the boiler heating surfaces and into the water within the vessel. Theoretically, stoichiometric combustion optimizes the process, where every available fuel molecule released is matched by an oxygen molecule resulting in a flue gas with no CO and oxygen. However, the feed rate is critical since a lack of OFA can increase emissions of CO and other combustibles, and result in heat loss and decreased boiler efficiency. An over-abundance of OFA will also result in heat loss absorbed by the excess air, which can also decrease boiler efficiency.

SCR is a post combustion control measure where ammonia (NH<sub>3</sub>) is injected into the boiler's flue gas stream in presence of a catalyst to reduce the emissions of NO<sub>x</sub>.

### *Air Quality Modeling Assessment:*

For incorporating the regional haze control measures selected in the four-factor analysis, an AAQIA would not be performed based on the following:

1. Except for the emissions of NH<sub>3</sub> from the SCR system, there are no increase in the emissions of all criteria pollutants and HAPs; and
2. An emission limit of ten (10) parts-per-million by volume dry (ppmvd) would have been specified for NH<sub>3</sub> slip. According to the EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-032), ammonia slip at this level does not result in plume formation or human health hazard.

### *Emissions:*

Criteria pollutant emissions (namely SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub>) after fuel switching from fuel oil No. 6 to ULSD are provided for information. These control measures would have been required if there was no enforceable shut down limit specified for the boilers. Emissions are based on the following assumptions:

- a. Emission factors are based on Table 1.3-6 of AP-42 Section 1.3 (5/10) for distillate fuel fired in industrial boilers;
- b. Emission factor for NO<sub>x</sub> for industrial boilers >100 MMBtu/hr fired on distillate oil with LNB/FGR retrofits in AP-42 Section 1.3 (5/10) is assumed when combustion controls are retrofitted on Boilers Hill 5 and Hill 6;
- c. Emissions of NO<sub>x</sub> for Boilers Hill 5 and Hill 6 are reduced to 0.05 lb/MMBtu when retrofitted with SCR + combustion controls based on guidance from the EPA's CCM;
- d. A maximum sulfur content of 0.0015% used in determining emissions of SO<sub>2</sub>; and
- e. The maximum boiler capacity operating at 8,760 hours per boiler a year is assumed.

Enclosure 1: **Kanoelehua-Hill Generating Station Control Measure Analysis**

NO <sub>x</sub> Emissions					
Unit <sup>a,b,c</sup>	AP-42 EF (lb/MMBtu)	Assumed EF (lb/MMBtu)	Heat Input (MMBtu/hr)	Emission Rate (lb/hr)	Emission Rate (TPY)
Hill 5 – ULSD, SCR, LNB/FGR/OFA	0.00714	0.05	197	9.85	605 (existing permit) 43 (after fuel switch & NO <sub>x</sub> control devices)
Hill 6 – ULSD, SCR, LNB/FGR/OFA	0.00714	0.05	249	12.45	517 (existing permit) 55 (after fuel switch & NO <sub>x</sub> control devices)
CT-1	0.88	0.8800	177.2	155.94	683
D-11	3.2	3.7198	20.2	75.14	329
D-15	3.2	3.7198	29.1	108.25	474
D-16	3.2	3.7198	29.1	108.25	474
D-17	3.2	3.7198	29.1	108.25	474
Total→					3,556 (existing permit) 2,532 (after fuel switch & NO <sub>x</sub> control devices)

<sup>a</sup>FGR - Flue Gas Recirculation, LNB - Low NO<sub>x</sub> Burner, OFA – Overfire Air, SCR - Selective Catalytic Reduction, ULSD – Ultra Low Sulfur Diesel.

<sup>b</sup>(10 lb/1,000 gal for LNB/FGR)(1-.90 for SCR)(197 MMBTU/hr)(8,760 hr/yr)(1,000 gal/140 MMBtu)(ton/2,000 lb) = 6.16 tons NO<sub>x</sub>/yr. No data for LNB/FGR in combination with OFA.

<sup>c</sup>(10 lb/1,000 gal for LNB/FGR)(1-.90 for SCR)(249 MMBTU/hr)(8,760 hr/yr)(1,000 gal/140 MMBtu)(ton/2,000 lb) =7.79 tons NO<sub>x</sub>/yr. No data for LNB/FGR in combination with OFA.

CO Emissions					
Unit	AP-42 EF (lb/MMBtu)	Assumed EF (lb/MMBtu)	Heat Input (MMBtu/hr)	Emission Rate (lb/hr)	Emission Rate (TPY)
Hill 5	0.033 (before fuel switch) 0.036 (after fuel switch)	0.0662	197	13	57
Hill 6	0.033 (before fuel switch) 0.036 (after fuel switch)	0.0662	249	16	72
CT-1	0.0033	0.0960	177.2	17	75
D-11	0.26	0.4859	20.2	10	43
D-15	0.26	0.4860	29.1	14	62
D-16	0.26	0.4860	29.1	14	62
D-17	0.26	0.4860	29.1	14	62
Total→					304 (no change)

Enclosure 1: **Kanoiehua-Hill Generating Station Control Measure Analysis**

VOC Emissions					
Unit	AP-42 EF (lb/MMBtu)	Assumed EF (lb/MMBtu)	Heat Input (MMBtu/hr)	Emission Rate (lb/hr)	Emission Rate (TPY)
Hill 5	0.00249 (before fuel switch) 0.00507 (after fuel switch)	0.01005	197	1.98	9
Hill 6	0.00249 (before fuel switch) 0.00507 (after fuel switch)	0.01005	249	2.50	11
CT-1	0.00041	0.03397	177.2	6.02	26
D-11	0.082	0.20000	20.2	4.04	18
D-15	0.082	0.20000	29.1	5.82	25
D-16	0.082	0.20000	29.1	5.82	25
D-17	0.082	0.20000	29.1	5.82	25
Total →					139 (no change)

PM/PM <sub>10</sub> /PM <sub>2.5</sub> Emissions					
Unit	AP-42 EF (lb/MMBtu)	Assumed EF (lb/MMBtu)	Heat Input (MMBtu/hr)	Emission Rate (lb/hr)	Emission Rate (TPY)
Hill 5	0.144 (before fuel switch) 0.014 (after fuel switch)	0.014	197	57.45 2.76	252 (before fuel switch) 12 (after fuel switch)
Hill 6	0.144 (before fuel switch) 0.014 (after fuel switch)	0.014	249	100.40 3.49	440 (before fuel switch) 15 (after fuel switch)
CT-1	0.012	0.0732	177.2	12.97	57
D-11	0.0763	0.1678	20.2	3.39	15
D-15	0.0763	0.0914	29.1	2.66	12
D-16	0.0763	0.0914	29.1	2.66	12
D-17	0.0763	0.0914	29.1	2.66	12
Total →					800 (existing permit) 135 (after fuel switch)

Enclosure 1: **Kanoelehua-Hill Generating Station Control Measure Analysis**

Unit	Mass Balance EF (lb/MMBtu)	Heat Input (MMBtu/hr)	Emission Rate (lb/hr)	Emission Rate (TPY)	
				No SO <sub>2</sub> Cap	SO <sub>2</sub> Cap
Hill 5 <sup>b</sup>	2.2005 (before fuel switch)	197	433.50	1,899 (before fuel switch)	3,550
	0.0015 (after fuel switch)		0.30	1.31 (after fuel switch)	
Hill 6 <sup>b</sup>	2.2005 (before fuel switch)	249	547.92	2,400 (before fuel switch)	
	0.0015 (after fuel switch)		0.37	1.62 (after fuel switch)	
CT-1 <sup>a</sup>	0.4130	177.2	73.18	321	
D-11 <sup>b</sup>	0.0015	20.2	0.03	0.13	
D-15 <sup>b</sup>	0.0015	29.1	0.04	0.18	
D-16 <sup>b</sup>	0.0015	29.1	0.04	0.18	
D-17 <sup>b</sup>	0.0015	29.1	0.04	0.18	
Total →				3,872 (existing permit) 325 (after fuel switch)	

<sup>a</sup>Heat content of ultra-low sulfur diesel was assumed to be 19,858 Btu/lb with maximum allowable sulfur content of 0.0015%. SO<sub>2</sub> emission lb/MMBtu = (lb/19,858 Btu)(10<sup>6</sup> Btu/MMBtu)(0.000015)(64.06 SO<sub>2</sub>/32.06 S) = 0.0015 lb/MMBtu.

<sup>b</sup>Heat content of fuel oil No. 2 was assumed to be 19,372 Btu/lb with maximum allowable sulfur content of 0.4%. SO<sub>2</sub> emission lb/MMBtu = (lb/19,372 Btu)(10<sup>6</sup> Btu/MMBtu)(0.004)(64.06 SO<sub>2</sub>/32.06 S) = 0.4126 lb/MMBtu.

<sup>c</sup>Heat content of 2% sulfur fuel oil was assumed to be 18,161 Btu/lb with maximum allowable sulfur content of 2%. SO<sub>2</sub> emission lb/MMBtu = (lb/18,161 Btu)(10<sup>6</sup> Btu/MMBtu)(0.02)(64.06 SO<sub>2</sub>/32.06 S) = 2.2005 lb/MMBtu.

**Significant Permit Conditions:**

The following significant permit conditions would have been required if there was no enforceable permit limit to shut down the boilers by 2028:

- a. Four (4) years from permit issuance, Kanoelehua-Hill Generating Station, Boilers Hill 5 and Hill 6 shall only be fired on ULSD with a maximum sulfur content not to exceed 0.0015% by weight.
- b. December 31, 2027, Kanoelehua-Hill Generating Station, Boilers Hill 5 and Hill 6 shall be subject to an emission limit of 0.05 lb/MMBtu in any thirty-day (30-day) rolling average per boiler for NO<sub>x</sub>. In addition, these boilers shall be subject to a three-hour (3-hour) average NH<sub>3</sub> exhaust concentration limit of ten (10) ppmvd at the SCR outlet.
- c. Incorporate installation, calibration, operation, maintenance, and testing requirements of the continuous emissions monitoring system (CEMS) for NO<sub>x</sub> and performance testing for NH<sub>3</sub> slip. This includes the recordkeeping and reporting requirements.

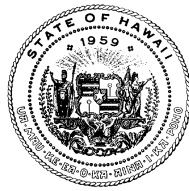
Reason: Four-factor analysis for the second planning period (2018-2028) and Section 2.3.5 in Chapter 2 of EPA's SCR Control Cost Manual Chapter 7, edition 2016, revision 2017.<sup>4</sup>

Enclosure 2: **GHG Emissions Spreadsheet**

Kanoelehua Hill Generating Station GHG Emissions						
Unit	Heat Input (MMBtu/hr)	Fuel	GHG	GHG Mass-Based Emissions (TPY)	GWP	GHG CO <sub>2</sub> e Based Emissions (TPY)
Hill 5	197	Fuel oil No. 6	CO <sub>2</sub>	142,860	1	142,860
			CH <sub>4</sub>	5.707	25	143
			N <sub>2</sub> O	1.141	298	340
Hill 6	249	Fuel oil No. 6	CO <sub>2</sub>	180,569	1	180,569
			CH <sub>4</sub>	7.213	25	180
			N <sub>2</sub> O	1.443	298	430
CT-1	177.2	Fuel oil No. 2	CO <sub>2</sub>	126,551	1	126,551
			CH <sub>4</sub>	5.133	25	128
			N <sub>2</sub> O	1.027	298	306
D-11	20.2	ULSD	CO <sub>2</sub>	14,426	1	14,426
			CH <sub>4</sub>	0.585	25	15
			N <sub>2</sub> O	0.117	298	35
-15	29.1	ULSD	CO <sub>2</sub>	20,782	1	20,782
			CH <sub>4</sub>	0.843	25	21
			N <sub>2</sub> O	0.169	298	50
D-16	29.1	ULSD	CO <sub>2</sub>	20,782	1	20,782
			CH <sub>4</sub>	0.843	25	21
			N <sub>2</sub> O	0.169	298	50
D-17	29.1	ULSD	CO <sub>2</sub>	20,782	1	20,782
			CH <sub>4</sub>	0.843	25	21
			N <sub>2</sub> O	0.169	298	50
Total ----->						528,542

Note: Emission Factors are from 40 CFR Part 98, Mandatory Reporting of Greenhouse Gases.





**CERTIFIED MAIL**  
**RETURN RECEIPT REQUESTED**  
(7018 0040 0000 8040 8709)

**STATE OF HAWAII**  
**DEPARTMENT OF HEALTH**  
P.O. Box 3378  
HONOLULU, HAWAII 96801-3378

In reply, please refer to:  
File:

22-342E CAB  
File No. 0235

August 10, 2022

Mr. Everett Lacro  
Director, Generation – Hawaii Island  
Hawaii Electric Light Company, Inc.  
P.O. Box 1027  
Hilo, Hawaii 96721-1027

Dear Mr. Lacro:

**SUBJECT: Amendment of Covered Source Permit (CSP) No. 0235-01-C  
Hawaii Electric Light Company, Inc. (Hawaii Electric Light)  
Puna Generating Station  
One (1) 20 MW Combustion Turbine with a 600 KW Black Start  
Diesel Engine Generator, and One (1) 15.5 MW Boiler with a  
Multi-Cyclone Dust Collector  
Located At: Keaau, Hawaii  
UTM Coordinates: 286.65 km East, 2,172.34 km North,  
Zone 5, Old Hawaiian  
Date of Expiration: October 11, 2023**

In accordance with Hawaii Administrative Rules (HAR), Chapter 11-60.1, the Department of Health, Clean Air Branch (herein after referred to as Department), hereby amends CSP No. 0235-01-C issued to Hawaii Electric Light for the Puna Generating Station on October 12, 2018, and amended on October 22, 2020. In accordance with HAR §11-60.1-10(a)(2) and (a)(3) and Clean Air Act (CAA) §169A(g)(1), this permit amendment incorporates regional haze control measures specified for the Puna Boiler in Hawaii's Regional Haze State Implementation Plan (RH-SIP). This amendment is based on your revised regional haze four-factor analysis dated September 25, 2020; additional information received from your letters dated March 30, 2021, June 16, 2021, and August 2, 2021; and discussions between the Department and Hawaiian Electric on October 7, 2021, and February 25, 2022.

Pursuant to Hawaii's RH-SIP for the second planning period (2018-2028), the amendment incorporates a fuel switch for the Puna Boiler to only ultra-low sulfur diesel (ULSD) with 0.0015% maximum sulfur content **by four (4) years from permit issuance** for reducing sulfur dioxide (SO<sub>2</sub>), nitrogen oxide (NO<sub>x</sub>), and particulate matter less than ten microns (PM<sub>10</sub>).

The permit amendment also carries over existing regional haze permit provisions to cap SO<sub>2</sub> emissions and incorporates these provisions into a new permit attachment (Attachment II - RH) that includes all regional haze conditions. The cap limits the sum of total SO<sub>2</sub> emissions from the Puna Generating Station Boiler and Boilers Hill 5 and Hill 6 at the Kanoelehua-Hill Generating Station to 3,550 tons per year.

Mr. Everett Lacro  
August 10, 2022  
Page 2

CSP No. 0235-01-C issued on October 12, 2018, and amended on October 22, 2020, is amended as follows:

Added Attachment:

Attachment II - RH: Special Conditions – Regional Haze Requirements

Except for Special Condition Nos. C.5 and D.4 of Attachment IIC that will be updated in a separate permit amendment to remove existing regional haze provisions associated with the SO<sub>2</sub> emissions cap, all other permit conditions of CSP No. 0235-01-C as issued on October 12, 2018, and amended on October 22, 2020, shall not be affected and shall remain valid.

If there are any questions regarding these matters, please contact Mr. Kai Erickson of the Clean Air Branch at (808) 586-4200.

Sincerely,

  
JOANNA L. SETO, P.E., CHIEF  
Environmental Management Division

MM/CKE:tkg

Enclosures



**ATTACHMENT II - RH: SPECIAL CONDITIONS  
REGIONAL HAZE REAUREMENTS  
COVERED SOURCE PERMIT NO. 0235-01-C**

**Issuance Date: August 10, 2022**

**Expiration Date: October 11, 2023**

In addition to the Standard Conditions of the CSP, the following Special Conditions shall apply to the permitted facility:

**Section A. Equipment Description**

1. Attachment II - RH encompasses the following equipment and associated appurtenances:

<b>Unit</b>	<b>Description</b>
Boiler	15.5 MW Combustion Engineering Boiler, Model No. VU-40, 249 MMBtu/hr.
DC	Barron Base III multi-cyclone dust collector, duct from boiler exhaust, Model No. 120-14, manufactured in November 1980.
Note: Megawatt (MW), Hour (hr), Million British Thermal Unit (MMBtu)	

(Auth.: HAR §11-60.1-3)

2. In accordance with HAR §11-60.1-10(a)(2) and (a)(3), CAA §169A(g)(1), and 40 Code of Federal Regulations (CFR) §51.308(f)(2)(i), this permit amendment incorporates federally enforceable regional haze control measures specified in Hawaii's RH-SIP for the boiler at Puna Generating Station.

(Auth.: HAR §11-60.1-5, §11-60.1-10; 40 CFR §51.308(f); CAA §169A)<sup>1,2</sup>

**Section B. Applicable Federal Regulations**

1. Regional haze provisions for the boilers are required pursuant to the following federal regulations:
  - a. 40 CFR Part 51, Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Subpart P, Protection of Visibility;
  - b. 40 CFR Part 52, Approval and Promulgation of Implementation Plans, Subpart A, General Provisions; and
  - c. 40 CFR Part 52, Approval and Promulgation of Implementation Plans, Subpart M, Hawaii, §52.633, Visibility Protection.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161, §11-60.1-174; 40 CFR §51.308, §52.633)<sup>1</sup>

2. The permittee shall comply with all applicable provisions of these standards, including all emission limits, notification, testing, monitoring, recordkeeping, and reporting requirements. The major requirements of these standards are detailed in the Special Conditions of this attachment.

(Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-90, §11-60.1-161; 40 CFR §51.300, §52.02, §52.633)<sup>1</sup>

**Section C. Operational and Emission Limitations**

1. Regional Haze Rule Limits

- a. Permit provisions for the regional haze SO<sub>2</sub> emissions cap are as follows:
  - i. The total combined SO<sub>2</sub> emissions from the Puna Generating Station, Boiler, and Kanoelehua - Hill Generating Station, Boilers Hill 5 and Hill 6, shall not exceed 3,550 tons in any rolling twelve-month (12-month) period.
  - ii. Compliance with the SO<sub>2</sub> emissions cap specified in Attachment II - RH, Special Condition No. C.1.a.i is required at all times **on and after December 31, 2018**.
- b. **By four (4) years from permit issuance**, the Puna Boiler shall be fired only on ULSD with a maximum sulfur content not to exceed 0.0015% by weight.

(Auth.: HAR §11-60.1-3, §11-60.1-10, §11-60.1-90; 40 CFR §51.308, §52.633; CAA §169A)<sup>1,2</sup>

**Section D. Monitoring and Recordkeeping Requirements**

1. Records

All records, including support information, shall be maintained for **at least five (5) years** from the date of the monitoring sample, measurement, test, report, or application. Support information includes all maintenance, inspection, and repair records, and copies of all reports required by this permit. These records shall be true, accurate, and maintained in a permanent form suitable for inspection and made available to U.S. Environmental Protection Agency (EPA), the Department, or its representative(s) upon request.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90; 40 CFR 52.633)<sup>1</sup>

2. Regional Haze – SO<sub>2</sub> Emissions Cap

- a. All fuel fired by boilers at the Puna and Kanoelehua-Hill Generating Stations shall be sampled and tested in accordance with the most current American Society for Testing and Materials (ASTM) methods. A representative sample of each batch of fuel received shall be analyzed for its sulfur content and heat value following ASTM D4057. The samples shall be analyzed for total sulfur content of the fuel using ASTM D129, or alternatively D1266, D1552, D2622, D4294, D5453, or D7039. The analysis may be performed by the permittee, the supplier, or third-party lab.

- b. The permittee shall calculate and record on a monthly basis the SO<sub>2</sub> emissions for each boiler unit (Puna Generating Station, Boiler, and the Kanoelehua Hill Generating Station, Boilers Hill 5 and Hill 6) for the preceding month based on the fuel sulfur content, fuel heating value, and total gallons of fuel burned.
- c. The permittee shall calculate and record the total combined SO<sub>2</sub> emissions for all boiler units (Puna Generating Station, Boiler, and Kanoelehua Hill Generating Station, Boilers Hill 5 and Hill 6) on a monthly and rolling twelve-month (12-month) basis.
- d. The permittee shall maintain, monthly, the following documents:
  - i. The total gallons of each type of fuel fired in the boiler for the month; and
  - ii. The information used to calculate SO<sub>2</sub> emissions for the month such as the sulfur content of the fuel, density of the fuel, fuel heating value, and the basis for the sulfur content used (fuel analysis showing date sample collected, type of fuel, sulfur content, and fuel heating value).

(Auth.: HAR §11-60.1-3, §11-60.1-90; 40 CFR 52.633)<sup>1</sup>

## **Section E. Notification and Reporting Requirements**

### 1. Standard Condition Reporting

Notification and reporting pertaining to the following events shall be done in accordance with Attachment I, Standard Condition Nos. 16, 17, and 24, respectively:

- a. Intent to shut down air pollution control equipment for necessary scheduled maintenance while the plant is still in operation;
- b. Emissions of air pollutants in violation of HAR, Chapter 11-60.1 or this permit (excluding technology-based emission exceedances due to emergencies); and
- c. Permanent discontinuance of construction, modification, relocation, or operation of the facility covered by this permit.

(Auth.: HAR §11-60.1-8, §11-60.1-15, §11-60.1-16, §11-60.1-90; SIP §11-60-10, §11-60-16)<sup>3</sup>

### 2. Deviations

The permittee shall report to the Department in writing **within five (5) working days** any deviations from permit requirements, including those attributable to upset conditions, the probable cause of such deviations and any corrective actions or preventive measures taken. Corrective actions may include a requirement for additional source testing, more frequent monitoring, or could trigger implementation of a corrective action plan.

(Auth.: HAR §11-60.1-3, §11-60.1-15, §11-60.1-16, §11-60.1-90)

3. Regional Haze Control Measure Notification

**Within thirty (30) days** of the Puna Boiler permanently switching to burn only ULSD as required by Attachment II - RH, Special Condition No.C.1.b, the permittee shall submit written notification to the Department on the permittee's compliance with the condition, including the date of compliance.

(Auth.: HAR §11-60.1-10; §11-60.1-90; 40 CFR §51.308, §52.633; CAA §169A)<sup>1,2</sup>

4. Compliance Certification

a. During the permit term, the permittee shall submit at least annually to the Department and U.S. EPA, Region 9, the attached Compliance Certification Form pursuant to HAR, Subsection 11-60.1-86. The permittee shall indicate whether or not compliance is being met with each term or condition of this permit. The compliance certification shall include, at a minimum, the following information:

- i. The identification of each term or condition of the permit that is the basis of the certification;
- ii. The compliance status;
- iii. Whether compliance was continuous or intermittent;
- iv. The methods used for determining the compliance status of the source currently and over the reporting period;
- v. Any additional information indicating the source's compliance status with any applicable enhanced monitoring and compliance certification, including the requirements of Section 114(a)(3) of the CAA or any applicable monitoring and analysis provisions of Section 504(b) of the CAA;
- vi. Brief description of any deviations including identifying as possible exceptions to compliance any periods during which compliance is required and in which the excursion or exceedances as defined in 40 CFR Part 64 occurred; and
- vii. Any additional information as required by the Department, including information to determine compliance.

b. The compliance certification shall be submitted within **sixty (60) days** after the end of each calendar year and shall be signed and dated by a responsible official.

c. Upon written request of the permittee, the deadline for submitting the compliance certification may be extended, if the Department determines that reasonable justification exists for the extension.

(Auth.: HAR §11-60.1-4, §11-60.1-86, §11-60.1-90)

5. Monitoring Report

The permittee shall submit **semi-annually** the following written report to the Department and U.S. EPA, Region 9. The report shall be submitted within **sixty (60) days** following the end of each semi-annual calendar period (January 1 to June 30 and July 1 to December 31) and be signed and dated by a responsible official. The following enclosed form, or equivalent form, shall be used for reporting:

**Monitoring Report Form: Sulfur Dioxide (SO<sub>2</sub>) Emissions – Boilers**

(Auth.: HAR §11-60.1-3, §11-60.1-5, §11-60.1-11, §11-60.1-90; 40 CFR §51.308 §52.633; CAA §169A)<sup>1,2</sup>

6. EPA Notification

The permittee shall notify U.S. EPA, Region 9 in writing, of any exceedance of the emission cap specified in Attachment II – RH, Special Condition C.1.a, within **thirty (30) days** of such exceedance.

(Auth.: HAR §11-60.1-90; 40 CFR §52.633)<sup>1</sup>

**Section F. Agency Notification**

Any document (including reports) required to be submitted by this CSP shall be done in accordance with Attachment I, Standard Condition No. 28.

(Auth.: HAR §11-60.1-4, §11-60.1-90)

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<sup>1</sup>The citations to the CFR identified under a particular condition, indicate that the permit condition complies with the specified provision(s) of the CFR. Due to the integration of the preconstruction and operating permit requirements, permit conditions may incorporate more stringent requirements than those set forth in the CFR.

<sup>2</sup>The citation to the CAA identified under a particular condition, indicates that the permit condition complies with the specified provision(s) of the CAA.

<sup>3</sup>The citation to the State Implementation Plan (SIP) identified under a particular condition, indicates that the permit condition complies with the specified provision(s) of the SIP.

**TECHNICAL SUPPORT DOCUMENT  
 PERMIT AMENDMENT  
 REGIONAL HAZE STATE IMPLEMENTATION PLAN  
 Covered Source Permit (CSP) No. 0235-01-C**

**Applicant:** Hawaii Electric Light Company, Inc. (Hawaii Electric Light)  
**Facility:** Puna Generating Station  
**Location:** Puna Mill Road, Keaau, Hawaii  
 UTM: 286.65 km East, 2,172.34 km North (Zone 5, Old Hawaiian)  
**SIC Code:** 4911 (Electrical Services)  
**Mailing Address:** P.O. Box 1027  
 Hilo, Hawaii 96721-1027

<b>Contact</b>	<b>Name</b>	<b>Title</b>	<b>Phone &amp; Mailing Address</b>
<b>Responsible Official:</b>	Everett Lacro	Director, Generation – Hawaii Island	(808) 969-0437 P.O. Box 1027, Hilo, Hawaii 96721
<b>Other Contact:</b>	Karin Kimura	Director, Environmental Division	(808) 543-4500 P.O. Box 2750, Honolulu, Hawaii 96840

**Project**

This permit amendment incorporates a regional haze control measure specified for the Puna Boiler in Hawaii’s Regional Haze State Implementation Plan (RH-SIP) in accordance with Hawaii Administrative Rules (HAR) §11-60.1-10(a)(2) and (a)(3) and Clean Air Act (CAA) §169A(g)(1). Pursuant to Hawaii’s RH-SIP for the second planning period (2018-2028), the amendment incorporates the following:

- **By four (4) years from permit issuance**, switch from burning fuel oil No. 6, diesel, and specification used oil in the Puna Boiler to ultra-low sulfur diesel (ULSD) with 0.0015% maximum sulfur content to reduce sulfur dioxide (SO<sub>2</sub>), nitrogen oxide (NO<sub>x</sub>), and particulate matter less than ten microns (PM<sub>10</sub>).

The CAA §110(a)(2) requires that State Implementation Plan (SIP) submittals include enforceable control measures and emission limitations to meet applicable CAA requirements, and that the submittals show that the State has authority to carry out the SIP. Thus, the relevant control measures and emission limitations must be finalized in order for the Environmental Protection Agency (EPA) to approve the SIP. 40 Code of Federal Regulations (CFR) Part 51, Appendix V, Section 2.1 also details the administrative criteria for determining the completeness of SIP submissions. Section 2.1(b) requires that the state submittal include the permit as issued, in final form, with evidence that includes the date of adoption or final issuance as well as the effective date.

Therefore, the EPA recommends the Department of Health, Clean Air Branch (CAB) finalize the permitting process for incorporating the regional haze controls prior to sending the RH-SIP with these permit conditions to the EPA for approval into the SIP.<sup>1</sup> As such, the CAB plans to implement the proposed permit amendment for the Puna Generating Station in accordance with HAR §11-60.1-10(a)(2) and §11-60.1-10(a)(3).

## Background

In the first regional haze planning period (2001-2018), the emphasis was on Best Available Retrofit Technology (BART) which included a 0.5 deciview threshold to address reasonable progress. In this second planning period (2018-2028), there is no BART or deciview threshold. The focus in the second planning period is on determining reasonable progress through analysis of the four (4) factors identified in CAA §169A(g)(1).

The EPA regional haze guidance dated August 20, 2019, (guidance)<sup>2</sup> explains that because regional haze results from a multitude of sources over a broad geographic area, progress may require addressing many relatively small contributions to impairment. Thus, a measure may be necessary for reasonable progress even if that measure in isolation does not result in perceptible visibility impairment.<sup>2</sup>

## Four-Factor Analysis:

Control measures for the Puna Generating Station under consideration for the second planning period were determined based on the four-factor analysis performed by Hawaiian Electric for which Hawaii Electric Light is a subsidiary. The four-factor analysis considers the following:

1. Cost of compliance;
2. The remaining useful life of the affected anthropogenic source of visibility impairment;
3. Time necessary for compliance; and
4. The energy and non-air quality environmental impacts of compliance.

### *Calculating the Cost of Compliance:*

A driving factor in selecting reasonable control measures is the cost of compliance, which is the cost effectiveness or the cost per ton of pollutant removed. Annualized amortization of capital cost or equivalent uniform annual cost (EUAC) is described in EPA's Air Pollution Control Cost Manual and is one of the methodologies used to determine the cost of controls. Costs were based on the following factors and assumptions:

1. Nominal interest rate.
2. Twenty-five (25) year remaining useful life for atomization equipment and berm liners.
3. Hawaii Construction Cost Multiplier of 1.0.

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<sup>1</sup>EPA's email response dated July 23, 2021, titled "Final Form of Permits for RH SIP".

<sup>2</sup>EPA Guidance on Regional Haze State Implementation Plan for Second Implementation Period, EPA, August 20, 2019

## Nominal Interest Rate

Nominal interest rate described in EPA’s Air Pollution Control Cost Manual (CCM), 7<sup>th</sup> edition\_2017, Section 1, Chapter 2 (Pages 14 to 16) is the rate firms actually face. CCM Chapter 2, Section 2.5.2 recognizes that the determination of the firm-specific nominal interest rate depends on how they plan to finance their purchases, i.e., whether the firm intends to borrow to finance their investment or finance their purchases through cash holding or other means of equity. The CCM further states, if firm-specific nominal interest rates are not available, then the bank prime rate can be an appropriate estimate for interest rates given the potential difficulties in eliciting accurate firm-specific nominal interest rates since it may be regarded as confidential business information or difficult to verify.

Hawaiian Electric expressed their intent on using a weighted average cost of capital (WACC) method in their letter dated June 16, 2021, which comprises principally of a long-term debt interest rate of 4.79% and common equity interest rate of 9.5% as sources to finance their capital expenditures. The prevailing Baa corporate bond yield shown in the Federal Reserve Economic Data at: <https://fred.stlouisfed.org/series/BAA> replaced the 4.79% rate for the long-term debt since Hawaiian Electric currently has a Moody long-term issuer rating of Baa1. Also, the 9.5% common equity interest rate was more appropriately substituted with an 8.92% “Book Return on Equity” from Hawaiian Electric’s website at: <https://www.hawaiianelectric.com/about-us/key-performance-metrics/financial> since this rate is a measure of a company’s actual profit or “return” on shareholders investments. The following table shows in red fonts, CAB’s modifications to the WACC method used by Hawaiian Electric to derive the nominal interest rate for the Hawaii Island sources after consulting with EPA.<sup>3</sup>

Hawaii Island Sources

	A	B	C	D
Source of Capital	Amount in Thousands	Percent of Total	Earnings	Weighted Earnings B X C
Short-Term Debt	Not Reported	0.61%	3.75%	0.02%
Long-Term Debt <sup>a</sup>		40.59%	3.24%	1.32%
Hybrid Securities		0.80%	7.83%	0.06%
Preferred Stock		1.17%	8.12%	0.10%
Common Equity <sup>b</sup>		56.83%	8.92%	5.07%
Total		100.00%		
Weighted Average Cost of Capital =				6.56%

<sup>a</sup> Moody’s Seasoned Monthly Baa Corporate Bond Yield, (Percent) from:

<https://fred.stlouisfed.org/series/BAA>

<sup>b</sup> Hawaiian Electric book return of common equity (ROE) from:

<https://www.hawaiianelectric.com/about-us/key-performance-metrics/financial>

<sup>3</sup>EPA email response dated July 12, 2021, titled, “Regional Haze Control Cost Interest Rate”.



## Useful Life

In the situation of an enforceable requirement for the source to cease operation before the end of the useful life of the controls under consideration, EPA guidance allows the use of the enforceable shut down date as the end of the remaining useful life. If no enforceable shut down date exists for units requiring controls, the remaining useful life is the full useful life of the control under consideration.

Twenty-five (25) years is assumed for atomization equipment and berm liners based on the referenced PUC filing in Hawaiian Electric's letter dated June 16, 2021, since there is no documented useful life for installation of fuel atomization systems and tank containment liners in the CCM. As indicated in the PUC filing (Docket Number 2020-0187) filed on November 10, 2020, for the Waiiau Fuel Tank Containment Project Berm Lining, the life expectancy of the liner, accounting for a majority of the capital costs, is upwards of twenty-five (25) years.

## Capital Cost to Fuel Switch

Additional capital cost is required to support the boiler fuel switch as identified in Hawaiian Electric's letter dated June 16, 2021, which includes completing the engineering research and design, boiler modifications to add fuel atomization, and installation of secondary containment liners. Required modifications to the boiler fuel-atomization system and fuel pumps are essential to allow for thorough combustion of the ULSD at the burner nozzle due to the difference in viscosity. Due to the low viscosity of ULSD, the installation of secondary containment liners is required for larger fuel tanks that will switch from storing residual fuel oil No. 6 to ULSD to comply with EPA's Spill Prevention, Controls, and Countermeasures (SPCC) Rule. This liner protects surface waters, drinking water, and ground water in the event of inadvertent release of ULSD to the environment.

In addition, fuel atomization is a process that breaks down liquid fuel into a mist-like spray to prepare for vaporization. The capital cost estimate to add mechanical fuel atomization of ULSD is based on the Black and Veatch (B&V) engineering studies for a similar project at the Waiiau Power Generating Station, which provides an estimated average cost of about \$1.1 million (based on June 2013 dollars) per boiler for an average boiler size of 62.375 MW. The cost for the boiler at the Puna Generating Station, which is smaller than the boilers at the Waiiau Power Generating Station, are scaled down from the \$1.1 million per boiler reference cost using the "six-tenths factor" rule of thumb. This cost scaling method is based on the empirically observed relationship between the cost and the size of equipment. As size increases, cost increases by an exponent of six-tenths, e.g.,  $cost1/cost2 = (size1/size2)^{0.6}$ .

The following table shows the additional capital expenditure estimate for adding fuel atomization to the boiler at Puna Generating Station:

**Cost Estimate to add Fuel Atomization  
(Based on 2013 dollars)**

Unit	Size 1 MW	(Size 1/Size 2) <sup>0.6</sup>	Capital Cost 1 Estimate <sub>2013</sub> <sup>b, c</sup>
Puna Boiler	15.5	4.34-E01	\$477,074

<sup>a</sup> Waiau Average Boiler Size 2 = 62.375 MW each.

<sup>b</sup> Waiau reference boiler atomization Cost 2 = \$1,100,000 Capital Cost Estimate each from the B&V engineering studies summarized as follows:

**B&V Cost Summary by Unit**

	Mechanical Atomization	Steam Atomization
Waiau 3	\$926,874	\$1,013,300
Waiau 4	\$1,278,158	\$1,298,430
Waiau 5	\$1,063,623	\$914,646
Waiau 6	\$1,069,044	\$919,029
Waiau 7	\$1,126,858	\$1,525,645
Waiau 8	\$1,117,481	\$1,514,077
Ave Unit Cost	\$1,097,006	\$1,197,521

<sup>c</sup> As size increases, cost increases by an exponent of six-tenths, e.g.,  $\text{cost1/cost2} = (\text{size1/size2})^{0.6}$ .  
Therefore,  $\text{cost 1} = (\text{size1/size2})^{0.6} \times \text{cost 2}$

The cost estimates are converted to 2019 dollars by applying the ratio of the Chemical Engineering Plant Cost Index (CEPCI) for 2019 of 607.5 divided by the CEPCI for 2013 of 567.3 or 107% as illustrated in the CEPCI data table on Page 6 of this technical support document.

**Cost Estimate to add Fuel Atomization  
(Adjustment to 2019 dollars)**

Unit	Size 1 MW	Capital Cost 1 Estimate <sub>2013</sub>	CEPCI <sub>2019</sub> /CEPCI <sub>2013</sub>	Capital Cost 1 Estimate <sub>2019</sub>
Puna Boiler	15.5	\$477,074	107%	\$510,880

The capital cost estimate to install berm lining for the fuel switch to ULSD is based on the Hawaiian Electric cost estimates presented in their PUC filing (Docket Number 2020-0187) filed on November 10, 2020, for the Waiau Generating Station Fuel Tank Containment Project Berm Lining. The capital costs for the Waiau project were \$5.23 million to line an area of 78,400 square feet. Costs for the Puna Generating Station were based on a scaling of the Waiau's project costs to the smaller size of the combined berm areas.

**Cost Estimate for Secondary Containment Liner**

Island	Units	Berm Area to Line (Size 1)	(Size 1/Size 2) <sup>0.6</sup>	Capital Cost 1 Estimate <sup>b, c</sup>
Hawaii	Puna Boiler	17,539	4.07E-01	\$2,128,648

<sup>a</sup> Waiau Reference Berm Area (Size 2) = 78,400 Square Feet

<sup>b</sup> Waiau Reference Liner Project Cost 2 = \$ 5,230,000 Capital Cost

<sup>c</sup> As size increases, cost increases by an exponent of six-tenths, e.g.,  $\text{cost1/cost2} = (\text{size1/size2})^{0.6}$ .  
Therefore,  $\text{cost 1} = (\text{size1/size2})^{0.6} \times \text{cost 2}$

**CEPCI**

		<b>Chemical Engineering Plant Cost Index (CEPCI)</b>																	
Year	Index	CEPCI % growth from 2000	CEPCI % growth from 2001	CEPCI % growth from 2002	CEPCI % growth from 2003	CEPCI % growth from 2004	CEPCI % growth from 2005	CEPCI % growth from 2006	CEPCI % growth from 2007	CEPCI % growth from 2008	CEPCI % growth from 2009	CEPCI % growth from 2010	CEPCI % growth from 2011	CEPCI % growth from 2012	CEPCI % growth from 2013	CEPCI % growth from 2014			
2000	394.1																		
2001	394.3	100%																	
2002	395.6	100%	100%																
2003	402.0	102%	102%	102%															
2004	444.2	113%	113%	112%	110%														
2005	468.2	119%	119%	118%	116%	105%													
2006	499.6	127%	127%	126%	124%	112%	107%												
2007	525.4	133%	133%	133%	131%	118%	112%	105%											
2008	575.4	146%	146%	145%	143%	130%	123%	115%	110%										
2009	521.9	132%	132%	132%	130%	117%	111%	104%	99%	91%									
2010	550.8	140%	140%	139%	137%	124%	118%	110%	105%	96%	106%								
2011	593.2	151%	150%	150%	148%	134%	127%	119%	113%	103%	114%	108%							
2012	582.2	148%	148%	147%	145%	131%	124%	117%	111%	101%	112%	106%	98%						
2013	567.3	144%	144%	143%	141%	128%	121%	114%	108%	99%	109%	103%	96%	97%					
2014	576.1	146%	146%	146%	143%	130%	123%	115%	110%	100%	110%	105%	97%	99%	102%				
2015	566.8	141%	141%	141%	139%	125%	119%	111%	106%	97%	107%	101%	94%	96%	98%	97%			
2016	541.7	137%	137%	137%	135%	122%	116%	108%	103%	94%	104%	98%	91%	93%	95%	94%			
2017	574.0	146%	146%	145%	143%	129%	123%	115%	109%	100%	110%	104%	97%	99%	101%	100%			
2018	603.1	153%	153%	152%	150%	136%	129%	121%	115%	105%	116%	109%	102%	104%	106%	105%			
2019	607.5	154%	154%	154%	151%	137%	130%	122%	116%	106%	116%	110%	102%	104%	107%	105%			

### Capital Recovery Factors (CRF)

The CRF listed in the following table was developed from the nominal interest rate and useful life of equipment:

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

	Control Measure→	Atomization & Liner
<b>i</b>	Nominal Interest Rate	6.56%
<b>n</b>	Useful Life (yrs)	25
<b>CRF</b>	Capital Recovery Factor	<b>0.0824<sup>a</sup></b>

<sup>a</sup> Due to rounding of the CRF, calculations from AECOM\_Ltr\_Att\_6\_Puna\_RH\_FourFactor\_Analysis\_Tables may vary slightly from CRF in the table.

### Annual Cost and Cost Effectiveness

The CRF amortizes capital cost to an equivalent annualized capital cost or the equivalent uniform annual cash flow approach, more commonly referred to as “amortization”. The combined annualized capital cost combined with annual operations and maintenance cost divided by the annual reduction in pollution provides the cost effectiveness for each control measure as illustrated in the following table:

#### Fuel Switch

	Units	Puna Boiler
<b>a</b>	Capital Cost of Atomization	\$510,880
<b>b</b>	Capital Cost of Liners	\$2,128,648
<b>c</b>	Combined Capital Cost (2019) <sup>a</sup>	\$2,639,528
<b>d</b>	CRF	0.0824
<b>e</b>	Annualized Capital Cost <sup>b</sup>	\$217,500
<b>f</b>	Annual Fuel Cost Differential <sup>c</sup>	\$923,985
<b>g</b>	Annual Cost of Fuel Switch <sup>d</sup>	\$1,141,485
<b>h</b>	Total SO <sub>2</sub> , NO <sub>x</sub> , and PM <sub>10</sub> Reduced (tpy) <sup>c</sup>	197
<b>i</b>	Cost Effectiveness (\$/ton) <sup>e</sup>	<b>\$5,804</b>

<sup>a</sup> **c = a + b**

<sup>b</sup> **e = c \* d, (rounded to the nearest 100)**

<sup>c</sup> [Source: Data from Table 6.1 updated Aug 2021, of ECOM\_Ltr\_Att\_4\_Puna\_RH\_FourFactor\_Analysis\_Tables].

<sup>d</sup> **g = e + f**

<sup>e</sup> **i = g / h**

*Establish a Reasonable Cost Threshold:*

In the first planning period, \$5,000/ton of pollutant removed in 2009 dollars (one year into the first regional haze planning period) was the established cost threshold for cost effective control measures. This cost threshold was inflated to \$5,800/ton to represent 2019 dollars (one year into the second regional haze planning period) by multiplying the \$5,000/ton threshold in 2009 by the ratio of the 2019-to-2009 CEPCI. The CEPCI, used extensively by the EPA for this type of analysis, is the basis for this application. Please see CEPI data table on Page 6.

*Time Necessary for Compliance:*

Hawaiian Electric indicated in their letter dated June 16, 2021, that a reasonable compliance date would be four (4) years from permit issuance.<sup>4</sup> Explanations from Hawaiian Electric to justify its proposed compliance schedule included:

- Switching from fuel oil No. 6 to ULSD for the boiler at the Puna Generating Station requires significant capital investments. Because of the planned implementation of the renewable portfolio standard (RPS) goals, these investments will only have short-lived benefits and potentially impose significant costs to the Hawaiian Electric customers.<sup>5</sup>
- A more flexible schedule will allow Hawaiian Electric's current efforts toward the RPS goal to be realized, including the retirement and lower utilization of some facilities.<sup>5</sup>
- Additional costs for the fuel switch are secondary containment liners for the larger fuel oil tanks that will switch to store ULSD.<sup>4,5</sup>
- Additional costs involving fuel atomization modifications for the boilers due to the lower viscosity of ULSD are also required.<sup>4,5</sup>
- There have been unexpected delays for some of the renewable projects. There are factors that are not completely within Hawaiian Electric's control including when the Hawaii Public Utilities Commission (PUC) will approve the projects or other delays with installing the facilities.<sup>4</sup>
- Additional time is needed to obtain PUC approval of the projects and complete the engineering studies, design engineering, and construction required to install containment liners and modify equipment to implement the fuel switch.<sup>4</sup>

In CAB discussions with the EPA, Region 9, it was agreed that a three-year (3-year) duration following issuance of the permit for implementing the fuel switch was reasonable based on information from regional haze four-factor analyses. Compliance deadlines should be specific, objectively determined, and justified as reasonable considering available historical data regarding time necessary for the installation of similar control measures.<sup>2</sup> A specific compliance date was specified to accomplish the fuel switch for the boiler at the Puna Generating Station which is consistent with EPA guidance and the four-factor analyses.

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<sup>4</sup>Hawaiian Electric's June 16, 2021, letter.

<sup>5</sup>Hawaiian Electric's March 30, 2021, letter.

According to Hawaiian Electric's Power Supply Improvement Plan (PSIP), the boiler operating at the Puna Generating Station was to be retired in 2020. However, as indicated in an email from Ms. Marisa Melzer of Hawaiian Electric on September 17, 2021, the actual schedule for retiring this unit has not been firmly established.

In discussions with EPA and the National Park Service (NPS) there was disagreement with allowing an extension of time for switching fuels to implement the RPS goals for retiring equipment. Again, the compliance deadline needs to be based on historical data of the time necessary for installation of similar control measures. Hawaiian Electric indicated that installation of equipment and secondary containment improvements will take up to two (2) years. Because the project costs are estimated to exceed the PUC threshold of \$2.5 million, the project will also require PUC approval which can take up to two (2) years due to the extensive review process. The cost of installing the fuel atomization system and secondary tank containment liners to switch fuel for the Puna Boiler was found to be \$5,804/ton which is slightly above the \$5,800/ton threshold. Refer to table titled "Fuel Switch" on Page 7 of this technical support document. Since this cost is extremely close to the threshold, CAB cannot ignore considering the boiler fuel switch as a cost-effective measure. Therefore, CAB has decided to propose a fuel switch for the Puna Generating Station Boiler as a regional haze control measure.

Based on source-specific factors, CAB considers an extension of the time to accomplish a fuel switch to ULSD at the Puna Generating Station reasonable to allow additional time of up to two (2) years for PUC approval and an additional two (2) years to install tank containment liners and fuel atomization systems after the PUC approval process. Therefore, CAB proposes to extend the compliance date for fuel switching to four (4) years after issuance of the permit amendment to incorporate this regional haze control measure for the Puna Boiler.

*Energy and Non-Air Quality Environmental Impacts of Compliance:*

Fuel switching from fuel oil No. 6 to ULSD may have an indirect energy impact during fuel refining, however, EPA's Guidance<sup>2</sup> Section II.B.4.e) recommends that states focus their analysis on direct energy consumption at the source rather than indirect energy inputs needed to produce raw materials. Therefore, the energy impact of refining ULSD is accounted for by including the annual fuel cost difference between fuel oil No. 6 and ULSD in with the cost of compliance. Firing ULSD will have a direct energy impact due to reduced boiler efficiency if an atomization system is not installed. Also, the lower viscosity of ULSD can have non-air quality environmental impacts in the event of inadvertent or accidental spills. Therefore, the annualized capital cost of installing both an atomization system and secondary containments to comply with SPCC requirements are also included as an annualized cost of compliance.

*Control Measures:*

Since the permit amendment does not specify a federally enforceable limit to permanently retire the Puna Generating Station Boiler, the following control measure must be implemented **by four (4) years from permit issuance:**

A fuel switch from fuel oil No. 6, diesel, and specification used oil to ULSD containing 0.0015% maximum sulfur content to reduce SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub>.

*Hawaii's Federal Implementation Plan for Regional Haze:*

Hawaii's Federal Implementation Plan (FIP) for regional haze specifies a 3,550 ton per year SO<sub>2</sub> emissions limit for the Puna and Kanoelehua-Hill Generating Stations. This limit will be carried over from the existing permit and incorporated into each affected facility's permit amendment for this second planning period to ensure reasonable progress for improving visibility in mandatory Class I Areas. Hawaii's two (2) mandatory Class I Areas are Haleakala National Park on Maui and Hawaii Volcanoes National Park on the Big Island (Hawaii). Boilers subject to the limit are Boilers Hill 5 and Hill 6 from the Kanoelehua-Hill plant and Boiler from the Puna plant.

**Permitted Equipment Subject to Regional Haze Rule Limit**

<u>Unit</u>	<u>Equipment Description</u>
Boiler	15.5 MW Combustion Engineering Boiler, 249 MMBtu/hr, Model No. VU-40, manufactured in November 1980, fired on diesel No. 2, fuel oil No. 6, and specification used oil, with max 2% sulfur content by weight. ULSD with maximum sulfur content of 0.0015% by weight shall be the only fuel fired at all times starting <b>by four (4) years from permit issuance and continuing thereafter.</b>
DC	Barron Base III Multi-Cyclone Dust Collector, duct from boiler exhaust, Model No. 120-14, manufactured in November 1980.

**Air Pollution Controls**

There is a multi-cyclone dust collector servicing the Puna Generating Station Boiler. The pollution control measure required pursuant to the Regional Haze Rule is as follows:

Regional Haze Control Based on Four-Factor Analysis <sup>a,b</sup>		
Power Plant	Control Selected If no Enforceable Shut Down	Compliance Date
Puna	Fuel Switch to ULSD for Puna Boiler	Four years from permit issuance

<sup>a</sup>Refer to the sub-section titled "Control Measures" under the "Background" section of this technical support document.  
<sup>b</sup>Other permitted equipment for the facility includes a 20 MW combustion turbine generator (CT-3) with a water injection system and a 600 kw black start diesel engine generator (PBSG1).

## Applicable Requirements

### *State Requirements:*

#### **Hawaii Administrative Rules (HAR)**

- Chapter 11-59, Ambient Air Quality Standards
- Chapter 11-60.1 Air Pollution Control
  - Subchapter 1, General Requirements
  - Subchapter 2, General Prohibitions
    - HAR 11-60.1-31, Applicability
    - HAR 11-60.1-32, Visible Emissions
    - HAR 11-60.1-33 Fugitive Dust
    - HAR 11-60.1-38, Sulfur Oxides from Fuel Combustion
  - Subchapter 5, Covered Sources
  - Subchapter 6, Fees for Covered Sources, Noncovered Sources, and Agricultural Burning
    - HAR 11-60.1-111 Definitions
    - HAR 11-60.1-112 General Fee Provisions for Covered Sources
    - HAR 11-60.1-113 Application Fees for Covered Sources
    - HAR 11-60.1-114 Annual Fees for Covered Sources
    - HAR 11-60.1-115 Basis of Annual Fees for Covered Sources
  - Subchapter 8, Standards of Performance for Stationary Sources
    - HAR 11-60.1-161 New Source Performance Standards
  - Subchapter 9, Hazardous Air Pollutant Sources
    - HAR 11-60.0-174 Maximum Achievable Control Technology (MACT) Emission Sources
  - Subchapter 10, Field Citations
  - Subchapter 11, Greenhouse Gas Emissions

### *Federal Requirements:*

#### Regional Haze Program Requirements

40 CFR Part 51, Subpart P, Protection of Visibility **is applicable** to this facility. Cost effective control measures for reasonable progress goals towards achieving natural visibility by 2064 were identified from the four-factor analysis of the Puna Generating Station pursuant to CFR §51.308 (f)(2) and EPA's guidance.

40 CFR Part 52, Approval and Promulgation of Implementation Plans, Subpart M, Hawaii, §52.633, Visibility Protection, is applicable to the Puna Generating Station Boiler and will require a fuel switch pursuant to 40 CFR Part 51, Subpart P.



**New Source Performance Standard (NSPS)**

40 CFR Part 60, Subpart GG is applicable to stationary gas turbines with a heat input at peak load equal to or greater than ten (10) MMBtu/hr and at facilities with such gas turbines that commence construction, reconstruction, or modification after October 3, 1977. This facility is subject to this standard because CT-3 has the heat input capacity of 275 MMBtu/hr and it was installed on January 30, 1992.

**National Emission Standards for Hazardous Air Pollutants (NESHAP)**

40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard, **Subpart JJJJJJ**, NESHAP requirements for Area Sources for Industrial, Commercial, and Institutional Boilers Area Sources **is applicable** to the Puna Boiler because it is an existing unit located at an area source of HAP emissions and does not meet the exemption criteria defined in 40 CFR §63.11195.

40 CFR Part 63, **Subpart ZZZZ**, NESHAPS for Stationary Reciprocating Internal Combustion Engines (RICE) or DEG **is applicable** because PBSD1 was constructed before June 12, 2006, and hence is an existing stationary RICE located at an area source of HAP emissions. The permittee must comply with the applicable emission limitations and operating limitations no later than May 3, 2013. However, as an emergency engine, this unit can be exempted from the requirements of this subpart except that it must operate in accordance with 40 CFR §63.6640(f)(2) of Subpart ZZZZ. Black Start Diesel Engine Generator PBSD1 was permitted to meet all applicable requirements in 40 CFR Part 63, Subpart ZZZZ for non-emergency engines.

**Air Emission Reporting Requirements (AERR)**

40 CFR Part 51, Subpart A, **AERR is applicable**. AERR is based on emissions of criteria pollutants (as defined in 40 CFR, Subpart A), which exceed the AERR thresholds as shown in the following table:

Pollutant <sup>a</sup>	Potential Emissions Before Fuel Switch (TPY)	Potential Emissions After Fuel Switch (TPY)	AERR Triggering Levels <sup>b</sup> (TPY)		DOH Reporting Levels (TPY)
			1 Year Cycle (Type A)	3 Year Cycle (Type B)	
CO	2,156	2,156	≥2,500	≥1,000	≥250
NO <sub>x</sub>	1,025	375	≥2,500	≥100	≥25
SO <sub>2</sub>	2,882	524	≥2,500	≥100	≥25
PM <sub>10</sub> /PM <sub>2.5</sub>	399	102	≥250/250	≥100	≥25
VOC	1,314	1,314	≥250	100	≥25
Pb (see note b)	0.036	0.036	----	≥0.5 (actual)	≥5
HAPs	3.45	3.45	----	----	≥5

<sup>a</sup>PM<sub>10</sub> - particulate matter less than 10 microns in diameter, PM<sub>2.5</sub> particulate matter less than 2.5 microns in diameter, VOC - volatile organic compound, Pb - lead, and HAPs - hazardous air pollutants.

<sup>b</sup>Based on potential emissions, except for lead. Lead is based on actual emissions from 2020.

## DOH-In-House Annual Emission Reporting

The CAB requests annual emissions reporting from those facilities that have facility-wide emissions exceeding in-house reporting levels and for all covered sources. Annual emissions reporting is required because this facility is a covered source.

### Major Source

This facility is a major source because potential emissions of criteria pollutant(s) exceed(s) major source threshold(s) even after the fuel switch to ULSD.

### Non-Applicable Requirements

#### Federal Requirements

#### New Source Performance Standard (NSPS)

40 CFR, Part 60 – NSPS, Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971, is not applicable because the boiler was constructed prior to August 17, 1971.

40 CFR, Part 60 – NSPS, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978, is not applicable because the boiler is less than 250 MMBtu/hr in capacity and was constructed prior to September 18, 1978.

40 CFR, Part 60 – NSPS, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units for boilers over 100 MMBtu/hr heat rate input capacity is not applicable because the boiler was constructed prior to June 19, 1984.

40 CFR, Part 60 – NSPS, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units is not applicable because the boiler was constructed prior to June 9, 1989.

The facility is not subject to 40 CFR Part 60 Subpart IIII, because PBSG1 commenced construction before July 11, 2005.

The facility is not subject to 40 CFR Part 60 Subpart KKKK because CT-3 commenced construction, modification, or reconstruction before February 18, 2005.

40 CFR Part 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels is not applicable to the storage tanks listed as insignificant activities because the maximum true vapor pressure of the liquid VOC stored inside the tank is less than 3.5 kilopascals (kPa) and 15.0 kPa respectively based on storage tank capacities.

## NESHAP

The facility is not a major source for HAPs and **is not subject** to NESHAP requirements under 40 CFR, Part 61.

The facility **is not subject** to 40 CFR Part 63 – NESHAP for source categories (Maximum Achievable Control Technology (MACT) standards) as follows:

Subpart YYYY – National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

CT-3 and the boiler **are not subject to** these standards because the facility is not a major source of HAP emissions.

Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electricity Utility Steam Generation Units

The boiler **is not subject to** this standard because it is not a fossil fuel-fired combustion unit of more than 25 megawatts electric (Mwe) that serves a generator that produces electricity for sale in accordance with 40 CFR §63.10042.

### Compliance Assurance Monitoring (CAM), 40 CFR Part 64

The purpose of CAM is to provide a reasonable assurance that compliance is being achieved with large emissions units that rely on air pollution control device equipment to meet an emissions limit or standard. Pursuant to 40 CFR Part 64, for CAM to be applicable, the emissions unit must:

- (1) Be located at a major source;
- (2) Be subject to an emissions limit or standard;
- (3) Use a control device to achieve compliance;
- (4) Have potential pre-control emissions that are greater than the major source level; and
- (5) Not otherwise be exempt from CAM.

This source **is not subject to CAM** pursuant to 40 CFR §64.2(b). Although CT-3 relies on a water injection system to achieve compliance with federal NO<sub>x</sub> standards (PSD/BACT and Subpart GG), a continuous emission monitoring system (CEMS) is used to determine compliance with the NO<sub>x</sub> emissions limit. Also, the water injection system servicing CT-3 for controlling NO<sub>x</sub>, is not considered a control device for purposes of the CAM regulation. Water injection is considered a passive control measure that acts to prevent NO<sub>x</sub> from forming. Therefore, CAM does not apply to CT-3. For the boiler, a multi-cyclone dust collector is used to control particulate; however, there is no particulate emissions limit that applies to this equipment. There are also no emission limits that apply to the black start diesel engine generator. As such, CAM does not apply to this facility.

### Best Available Control Technology (BACT)

A BACT analysis **is not required** since this is not a new source, nor are there any modifications that increase emissions.

### Alternate Operating Scenarios

This modification does not affect the alternate operating scenarios in the permit.

### Prevention of Significant Deterioration (PSD)

PSD review applies to new major stationary sources and major modifications to these types of sources. A PSD review was done in November 1991 for this facility. The facility is not subject to a new PSD review because it is an existing major stationary source as defined in HAR, Title 11, Chapter 60.1, Subchapter 7 and 40 CFR Part 52, §52.21 for any single air pollutant and the modification to switch fuel for the boiler to ULSD will not cause a significant increase in emissions.

### Insignificant Activities/Exemptions

Insignificant activities identified by the applicant that meet the exemption criteria specified in HAR §11-60.1-82(f) and (g) are listed as follows:

<u>Basis for Exemption</u>	<u>Description</u>
§11-60.1-82(f)(1)	1. A 10,521-gallon fixed roof day tank for CT-3; 2. A 10,920-gallon fixed roof day tank for the boiler; and 3. A 3,990-gallon fixed roof igniter tank for storing #2 fuel oil.
§11-60.1-82(f)(2)	There may occasionally be fuel burning equipment with a heat input capacity less than 1 MMBtu/hr used at the station.
§11-60.1-82(f)(5)	There may occasionally be standby generators and other emergency equipment.
§11-60.1-82(f)(6)	Spray paint booths.
§11-60.1-82(f)(7)	1. A 209,286-gallon fuel oil #6 storage tank; 2. A 461,160-gallon fuel oil #6 storage tank; 3. Two 169,344-gallon #2 diesel fuel storage tanks; 4. Fugitive equipment leaks from valves, flanges, pump seals and any VOC water separators; 5. Solvents used for maintenance purposes; and 6. Acid or vertan may be used for periodic boiler cleaning.
§11-60.1-82(g)(1)	Welding booths.
§11-60.1-82(g)(2)	Handheld equipment for maintenance and testing purposes, with reasonable precautions taken to prevent PM from becoming airborne.
§11-60.1-82(g)(3)	Laboratory equipment for chemical and physical analysis.
§11-60.1-82(g)(6)	Diesel powered fire pump.

<u>Basis for Exemption</u>	<u>Description</u>
§11-60.1-82(g)(8)	Gasoline fired portable industrial equipment less than 25 hp.
§11-60.1-82(g)(9)	Plant maintenance and upkeep activities, such as painting, sandblasting, woodworking, painting, etc.
§11-60.1-82(g)(12)	Stacks and vents to prevent escape of seer gases through plumbing traps.
§11-60.1-82(g)(13)	Consumer use of office equipment and products.

### Project Emissions

Emissions from the Puna Boiler, CT-3, and PBSG1 were calculated. Emission rates for criteria pollutants, i.e., SO<sub>2</sub>, NO<sub>x</sub>, CO, VOC, and PM/PM<sub>10</sub> are based on an evaluation of AP-42 emission factors, stack test data, and permit limits. To be conservative, the applicant assumed that PM<sub>10</sub> and PM<sub>2.5</sub> emissions were equal to PM emissions. Because of the uncertainties associated with AP-42 emission factors, compliance factors (based on stack test data) greater than the AP-42 emission factors were used to determine certain emission rates. Some of the HAP emission rates were determined by using EPRI PISCES Air Toxic Database, while some were determined using 1994 test data for Hawaiian Electric's Waiiau Station.

### Emissions from the Puna Boiler

Emissions for criteria pollutants from the boiler were estimated with compliance factors (source test data) other than emission factors in AP-42, 1.3 (05/10) for fuel oil No. 6 based on the boiler heat input of 249 MMBtu/hr. The emission rate for SO<sub>2</sub> before the fuel switch to ULSD was calculated using mass balance based on 2.0% sulfur content, fuel oil No. 6 heat content of 18,161 Btu/lb and all sulfur converted to SO<sub>2</sub>. Emission rate for SO<sub>2</sub> after the fuel switch to ULSD was calculated using a mass balance based on 0.0015% sulfur content, ULSD heat content of 19,858 Btu/lb, and all sulfur converted to SO<sub>2</sub>. Emissions from the boiler are provided in Enclosure 1 for firing fuel oil No. 6 and summarized below. At all times, **by four (4) years from permit issuance**, ULSD will be the only allowable fuel.

Pollutant	AP-42 EF (lb/MMBtu)	Applied EF (lb/MMBtu)	Emission Rate (lb/hr)	Potential Emissions (TPY)
CO	F.O. No 6 - 0.033 ULSD - 0.036	0.066	16.43	71.96 (existing permit)
NO <sub>x</sub>	F.O. No 6 - 0.313 ULSD - 0.171	F.O. No. 6 - 0.767 ULSD - 0.171	F.O. No 6 – 190.98 ULSD – 42.58	836.5 (existing permit) 186.5 (after fuel switch)
SO <sub>2</sub>	F.O No 6 - 2.093 ULSD - 0.0015	F.O No. 6 – 2.200 <sup>a</sup> ULSD – 0.0015 <sup>b</sup>	F.O. No 6 – 547.80 ULSD – 0.374	2,399.4 (existing permit) 1.64 (after fuel switch)
VOC	0.005	0.010	2.49	10.9
PM	F.O. No 6 - 0.144 ULSD - 0.014	F.O. No. 6 - 0.287 ULSD - 0.014	F.O. No. 6 - 71.46 ULSD - 3.49	313.0 (existing permit) 15.3 (after fuel switch)
PM <sub>10</sub>				
PM <sub>2.5</sub>				
HAPs	0.001	0.0017	0.44	1.9
CO <sub>2e</sub>				181,181.0

<sup>a</sup>Heat content of fuel oil No. 6 was assumed to be 18,161 Btu/lb with maximum allowable sulfur content of 2.0%. SO<sub>2</sub> emission lb/MMBtu = (lb/18,161 Btu)(10<sup>6</sup> Btu/MMBtu)(0.02)(64.06 SO<sub>2</sub>/32.06 S) = 2.20 lb/MMBtu.

<sup>b</sup>Heat content of ULSD was assumed to be 19,858 Btu/lb with maximum allowable sulfur content of 0.0015%. SO<sub>2</sub> emission lb/MMBtu = (lb/19,858 Btu)(10<sup>6</sup> Btu/MMBtu)(0.000015)(64.06 SO<sub>2</sub>/32.06 S) = 0.0015 lb/MMBtu.

## Emissions from CT-3

Emission limits for criteria pollutants from CT-3 were established in PSD Permit HI 90-04 and has been kept in current CSP No. 0235-01-C issued on November 15, 2002. In the renewal of the current permit, the applicant proposed to operate CT-3 25% (6.165 MW) of peak load (24.66 MW) for no more than sixty-six (66) hours for any rolling twelve-month (12-month) period. This change of operation will not increase air pollutant emissions above the permitted emission limits in the current permit. Emission limit (3-hour average) for CT-3 and the emission factors derived from the limit for CO, NO<sub>x</sub>, SO<sub>2</sub>, VOC, and PM/PM<sub>10</sub> are shown in the table below. The detailed calculations can be found in Enclosure 2.

Pollutant	Load	Applied EF (lb/MMBtu)	Emission Rate (lb/hr)	Potential Emissions (TPY)
CO	100%	0.097	26.8	117.4
	75%-<100%	0.205	56.4	247.0
	50%-<75%	0.658	181.0	792.8
	<50%	1.729	475.6	2,083.1
NO <sub>x</sub>	≤100%	0.154	42.3	185.3
SO <sub>2</sub>	≤100%	0.4	110.0	481.8
VOC	100%	0.003	0.8	3.5
	75%-<100%	0.009	2.6	11.4
	50%-<75%	0.102	28.1	123.1
	<50%	1.082	297.6	1,303.5
PM	≤100%	0.072	19.7	86.3
PM <sub>10</sub>	≤100%			
PM <sub>2.5</sub>	≤100%			
HAPs	≤100%	1.25E-3	3.45E-1	1.5
CO <sub>2e</sub>	≤100%			197,072.3

The proposed change of operation below 25% of peak load for maximum sixty-six (66) hours for any rolling annual year will not increase the emissions equal to or above the significant level defined in §11-60.1-81. The project emissions for this proposed operation are listed in the table below. The detailed calculations and discussion are provided in Enclosure 2.

Pollutant	Emission Rate (lb/hr)	Potential Emissions (TPY)	Significant Threshold (TPY)
CO	475.6	15.7	25
NO <sub>x</sub>	42.3	1.4	10
SO <sub>2</sub>	110.0	3.6	10
PM	19.7	0.7	6.25
PM <sub>10</sub>	19.7	0.7	3.75
PM <sub>2.5</sub>	PM <sub>2.5</sub>	19.7	2.5
	SO <sub>2</sub>	110.0	10
	NO <sub>x</sub>	42.3	10
O <sub>3</sub>	NO <sub>x</sub>	42.3	10
	VOC	297.6	10
Lead	3.85E-3	1.27E-4	0.15
Fluorides	2.77E-3	9.14E-5	2
Sulfuric Acid Mist	14.4	0.5	2
CO <sub>2e</sub>		1,485	10,000

### Emissions from PBSG1

Emissions from PBSG1 were estimated with emission factors from AP-42, 3.4 (10/96). Potential annual emissions in TPY are based on annual operation limit of three hundred (300) hours. The project emissions are shown in Enclosure 3 and summarized below:

Pollutant	AP-42 EF (lb/MMBtu)	Emission Rate (lb/hr)	Potential Emissions (TPY)
CO	0.8500	5.39	0.81
NO <sub>x</sub>	3.2000	20.29	3.04
SO <sub>2</sub>	0.4040	2.56	0.38
VOC	0.0819	0.52	0.08
PM	0.0697	0.44	0.07
PM <sub>10</sub>	0.0697	0.44	0.07
PM <sub>2.5</sub>	0.0697	0.44	0.07
HAPs	0.0016	9.98E-3	1.50E-3
CO <sub>2e</sub>			143.3

## Total Emissions

The total potential emissions from this facility are summarized below:

### 1. Hazardous Air Pollutant Emissions

HAP	Emissions (TPY)			
	Boiler	CT-3	PBSG1	Total
Acetaldehyde	2.38 E-03		2.40E-05	2.40E-03
Acrolein			7.49E-06	7.49E-06
1,3 Butadiene		1.93E-02		1.93E-02
Benzene	3.34E-03	6.62E-02	7.38E-04	7.03E-02
Ethylbenzene	4.62E-04			4.62E-04
Formaldehyde	2.40E-01	3.37E-01	7.50E-05	5.77E-01
Phosphorus	6.88E-02			6.88E-02
1,1,1-Trichloroethane	1.72E-03			1.72E-03
Toluene	4.51E-02		2.67E-04	4.53E-02
Xylene	7.93E-04		1.84E-04	9.76E-04
POM	9.45E-03	4.82E-02	2.02E-04	5.78E-02
Antimony Compounds	3.82E-02			3.82E-02
Arsenic Compounds	9.60E-03	1.32E-02		2.28E-02
Beryllium Compounds	2.02E-04	3.37E-04		5.76E-04
Cadmium Compounds	2.89E-03	5.78E-03		8.68E-03
Chromium Compounds	7.95E-03	1.32E-02		2.12E-02
Cobalt Compounds	4.38E-02			4.38E-02
Lead Compounds	1.10E-02	1.69E-02		2.78E-02
Manganese Compounds	2.55E-02	9.52E-01		9.77E-01
Mercury Compounds	5.43E-03	1.45E-03		6.88E-03
Nickel Compounds	1.42E+00	5.54E-03		1.42E+00
Selenium Compounds	4.97E-03	3.01E-02		3.51E-02
Total	1.94	1.51	1.50	3.45

### 2. Criteria Pollutant Emissions

Pollutant	Emissions (TPY)			
	Boiler	CT-3	PBSG1	Total
CO	72.0	2,083.1	0.8	2,156 (existing permit)
NO <sub>x</sub>	836.5 (existing permit) 186.5 (after fuel switch)	185.3	3.0	1,025 (existing permit) 375 (after fuel switch)
SO <sub>2</sub>	2,399.4 (existing permit) 1.64 (after fuel switch)	481.8	0.4	2,882 (existing permit) 484 (after fuel switch)
VOC	10.9	1,303.5	0.1	1,314 (existing permit)
PM	313.0 (before fuel switch) 15.3 (after fuel switch)	86.3	0.1	399 (existing permit) 102 (after fuel switch)
PM <sub>10</sub>				
PM <sub>2.5</sub>				



### 3. Greenhouse Gas

GHG	GWP	GHG Mass-Based Emissions (TPY)	CO <sub>2</sub> e Based Emissions (TPY) <sup>a</sup>
Carbon Dioxide (CO <sub>2</sub> )	1	377,112	377,112
Methane (CH <sub>4</sub> )	25	15.2	380
Nitrous Oxide (N <sub>2</sub> O)	298	3.03	903
Total Emissions:			378,397

<sup>a</sup>Totals may not sum due to independent rounding.

### Air Quality Assessment

No ambient air quality analysis (AAQA) is required since the proposed change is not a significant modification and there is no increase in the calculated emissions. The AAQA performed for existing permit issued on November 15, 2002, is still valid.

### Significant Permit Conditions

#### 1. Regional Haze Rule Limits

##### a. Boiler Fuel Switch

**By four (4) years from permit issuance**, the Puna Generating Station Boiler shall only be fired on ULSD with a maximum sulfur content not to exceed 0.0015% by weight.

##### b. Regional Haze – SO<sub>2</sub>- Emissions Cap

- i. Kanoelehua-Hill Generating Station, Boilers Hill 5 and Hill 6, combined with Puna Generating Station, Boiler, shall not emit or cause to be emitted SO<sub>2</sub> in excess of 3,550 tons per year, calculated as the sum of total SO<sub>2</sub> emissions for all three (3) units over a rolling twelve-month (12-month) period.
- ii. Compliance with the SO<sub>2</sub> emissions cap specified in Attachment IIC, Special Condition No. C.2.a. is required at all times **on and after December 31, 2018**.

Reason: Regional haze conditions are added to comply with the requirements of 40 CFR Part 51, Subpart P and 40 CFR Part 52, Subpart M. The SO<sub>2</sub> emissions cap remains unchanged from the permit amendment issued on June 6, 2018.

### Conclusion and Recommendation

This permit amendment incorporates the regional haze control measures specified for the Puna Boiler in Hawaii's RH-SIP in accordance with HAR §11-60.1-10(a)(2) and (a)(3) and CAA §169A(g)(1). Pursuant to Hawaii's RH-SIP for the second planning period (2018-2028), CSP No. 0235-01-C for the Puna Generating Station is being amended to incorporate the following regional haze limit:

- By four (4) years from permit issuance, switch from burning fuel oil No. 6, specification used oil, and diesel No. 2 in the Puna Boiler to ULSD with 0.0015% maximum sulfur content to inherently lower SO<sub>2</sub>, NO<sub>x</sub>, and PM<sub>10</sub> emissions.

Recommend issuance of the significant amendment to the CSP subject to a sixty (60) day formal review of the State's regional haze implementation plan by the NPS, thirty (30) day public review and comment period in accordance with HAR §11-60.1 and 40 CFR §51.102, forty-five (45) day EPA review period, and incorporation of the significant permit conditions. It should be noted that this permit amendment will be part of the Hawaii's RH-SIP in the second planning period.

Kai Erickson  
May 12, 2022

Enclosure 1: Boiler Emissions					
AP-42 Section 1.3 (05/10) - Fuel Oil Combustion					
AP-42 EF (lb/MMBtu) = AP-42 EF (lb/10 <sup>3</sup> gal) / Heat Value (150 MMBtu/10 <sup>3</sup> gal)					
Emission (lb/hr or kg/hr) = Heat Input (249 MMBtu/hr) x Applied EF (lb/MMBtu or kg/hr)					
Emission (TPY) = Emission (lb/hr) x Hour Limit (8760 hr/yr) / 2000 (lb/ton)					
Emission (TPY) = Emission (kg/hr) x Hour Limit / 1000 (kg/ton)					
	Value	Unit	Notes		
Hour Limit	8760	hr/yr			
Fuel Consumption	1740	gal/hr	Manufacturer's data		
No. 6 Oil Sulfur Content	2	%			
No. 6 Oil Heating Value	150	MMBtu/10 <sup>3</sup> gal			
Heat Input Rate	249	MMBtu/hr	Applicant's info		
Used oil Consumption	23,500	gal/yr	Applicant's info (90 gal/hr)		
Pollutant	AP-42 EF (lb/10 <sup>3</sup> gal)	AP-42 EF (lb/MMBtu)	Applied EF (lb/MMBtu)	Emissions (lb/hr)	Emissions (TPY)
CO	5.00	0.033	0.066	16.43	72.0
NO <sub>x</sub>	47.00	0.313	0.767	190.98	836.5
SO <sub>2</sub>	314.00	2.093	2.200	547.80	2,399.4
VOC	0.76	0.005	0.010	2.49	10.9
PM <sup>2</sup>	21.60	0.144	0.287	71.46	313.0
PM-10 <sup>2</sup>	21.60	0.144	0.287	71.46	313.0
PM-2.5 <sup>2</sup>	21.60	0.144	0.287	71.46	313.0
Hazardous Air Pollutant (HAP)	AP-42 EF (lb/10 <sup>3</sup> gal)	AP-42 EF (lb/MMBtu)	Applied EF (lb/MMBtu)	Emissions (lb/hr)	Emissions (TPY)
Acetaldehyde <sup>4</sup>			2.18E-06	5.43E-04	2.38E-03
Acrolein					
1,3-Butadiene					
Benzene <sup>5</sup>	2.14E-04	1.43E-06	3.06E-06	7.62E-04	3.34E-03
Ethylbenzene	6.36E-05	4.24E-07	4.24E-07	1.06E-04	4.62E-04
Formaldehyde	3.30E-02	2.20E-04	2.20E-04	5.48E-02	2.40E-01
Phosphorus	9.46E-03	6.31E-05	6.31E-05	1.57E-02	6.88E-02
1,1,1-Trichloroethane	2.36E-04	1.57E-06	1.57E-06	3.92E-04	1.72E-03
Toluene	6.20E-03	4.13E-05	4.13E-05	1.03E-02	4.51E-02
Xylene	1.09E-04	7.27E-07	7.27E-07	1.81E-04	7.93E-04
POM	1.30E-03	8.67E-06	8.67E-06	2.16E-03	9.45E-03
Antimony Compounds	5.25E-03	3.50E-05	3.50E-05	8.72E-03	3.82E-02
Arsenic Compounds	1.32E-03	8.80E-06	8.80E-06	2.19E-03	9.60E-03
Beryllium Compounds	2.78E-05	1.85E-07	1.85E-07	4.61E-05	2.02E-04
Cadmium Compounds	3.98E-04	2.65E-06	2.65E-06	6.61E-04	2.89E-03
Chromium Compounds	1.09E-03	7.29E-06	7.29E-06	1.81E-03	7.95E-03
Cobalt Compounds	6.02E-03	4.01E-05	4.01E-05	9.99E-03	4.38E-02
Lead Compounds	1.51E-03	1.01E-05	1.01E-05	2.51E-03	1.10E-02
Manganese Compounds <sup>5</sup>	3.00E-03	2.00E-05	2.34E-05	5.83E-03	2.55E-02
Mercury Compounds <sup>5</sup>	1.13E-04	7.53E-07	4.98E-06	1.24E-03	5.43E-03
Nickel Compounds <sup>5</sup>	8.45E-02	5.63E-04	1.30E-03	3.24E-01	1.42E+00
Selenium Compounds	6.83E-04	4.55E-06	4.55E-06	1.13E-03	4.97E-03
Total HAPs	1.54E-01	1.03E-03	1.78E-03	4.43E-01	1.94E+00
Green House Gas (GHG)	GWP	Applied EF <sup>6</sup> (kg/MMBtu)	Mass-Based Emissions (kg/hr)	Mass-Based Emissions (TPY)	CO <sub>2</sub> e Based Emissions (TPY)
CO <sub>2</sub>	1	75.10	18,699.90	180,570.80	180,570.8
CH <sub>4</sub>	25	3.00E-03	0.75	7.21	180.3
N <sub>2</sub> O	298	6.00E-04	0.15	1.44	429.9
Total				180,579.46	181,181.04
notes:					
1. EF are applied with a compliance factor greater than 1 provided by the applicant.					
2. Assume PM=PM-10=PM-2.5 to be conservative.					
3. EF selected from the biggest among AP-42, EPRI PISCES Air Toxic Database, and test data.					
4. EF based on 1994 Waiuu 7 Test data					
5. EF from EPRI PISCES Air Toxic Database					
6. EF from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98, Tables C-1 and C-2).					

Enclosure 2: CT-3 Emissions					
AP-42 Section 3.1 (04/00) - Stationary Gas Turbines					
Emission (lb/hr or kg/hr) = Heat Input (249 MMBtu/hr) x Applied EF (lb/MMBtu or kg/hr)					
Emission (TPY) = Emission (lb/hr) x Hour Limit / 2000 (lb/ton)					
Emission (TPY) = Emission (kg/hr) x Hour Limit / 1000 (kg/ton)					
	Value	Unit	Notes		
Hour Limit	8760	hr/yr			
Fuel Consumption		gal/hr	Manufacturer's data		
No. 2 Oil Sulfur Content	0.4	%			
No. 2 Oil Heating Value	140	MMBtu/10 <sup>3</sup> gal			
Heat Input Rate	275	MMBtu/hr	Applicant's info		
Hour Limit (<25% peak load Operation)	66	hr/yr	Proposed by applicant		
1. CT-3 Emission for operation at various load					
Pollutant	Load	AP-42 EF (lb/MMBtu)	Applied EF (lb/MMBtu)	Emissions <sup>2</sup> (lb/hr)	Emissions <sup>3</sup> (TPY)
NO <sub>x</sub>	≤100%	0.24	0.154	42.3	185.3
SO <sub>2</sub>	≤100%	0.404	0.400	110.0	481.8
PM <sup>4</sup>	≤100%	1.20E-02	0.072	19.7	86.3
PM-10 <sup>4</sup>	≤100%	4.30E-03	0.072	19.7	86.3
PM-2.5 <sup>4</sup>	≤100%		0.072	19.7	86.3
CO	100%	0.076	0.097	26.8	117.4
	75%-100%		0.205	56.4	247.0
	50%-75%		0.658	181.0	792.8
	<50%		1.729	475.6	2083.1
VOC	100%	4.10E-04	0.003	0.8	3.5
	75%-100%		0.009	2.6	11.4
	50%-75%		0.102	28.1	123.1
	<50%		1.082	297.6	1303.5
Hazardous Air Pollutant (HAP)	AP-42 EF (lb/MMBtu)	Applied EF (lb/MMBtu)	Emissions (lb/hr)	Emissions <sup>3</sup> (TPY)	
Acetaldehyde					
Acrolein					
1,3-Butadiene	1.60E-05	1.60E-05	4.40E-03	1.93E-02	
Benzene	5.50E-05	5.50E-05	1.51E-02	6.62E-02	
Ethylbenzene					
Formaldehyde	2.80E-04	2.80E-04	7.70E-02	3.37E-01	
Phosphorus					
1,1,1-Trichloroethane					
Toluene					
Xylene					
POM	4.00E-05	4.00E-05	1.10E-02	4.82E-02	
Antimony Compounds					
Arsenic Compounds	1.10E-05	1.10E-05	3.03E-03	1.32E-02	
Beryllium Compounds	3.10E-07	3.10E-07	8.53E-05	3.73E-04	
Cadmium Compounds	4.80E-06	4.80E-06	1.32E-03	5.78E-03	
Chromium Compounds	1.10E-05	1.10E-05	3.03E-03	1.32E-02	
Cobalt Compounds					
Lead Compounds	1.40E-05	1.40E-05	3.85E-03	1.69E-02	
Manganese Compounds	7.90E-04	7.90E-04	2.17E-01	9.52E-01	
Mercury Compounds	1.20E-06	1.20E-06	3.30E-04	1.45E-03	
Nickel Compounds	4.60E-06	4.60E-06	1.27E-03	5.54E-03	
Selenium Compounds	2.50E-05	2.50E-05	6.88E-03	3.01E-02	
Total HAPs	1.25E-03	1.25E-03	3.45E-01	1.51E+00	
Green House Gas (GHG)	GWP	Applied EF <sup>5</sup> (kg/MMBtu)	Mass-Based Emissions (kg/hr)	Mass-Based Emissions <sup>3</sup> (TPY)	CO <sub>2</sub> e Based Emissions <sup>3</sup> (TPY)
CO <sub>2</sub>	1	73.96	20,339.00	196,398.35	196,398.4
CH <sub>4</sub>	25	3.00E-03	0.83	7.97	199.2
N <sub>2</sub> O	298	6.00E-04	0.17	1.59	474.8
Total				196,407.91	197,072.3
notes:					
1. EF are calculated based on emission limit.					
2. Emission limit set in PSD permit HI 90-04.					
3. Emissions based on 8,760 hr/yr.					
4. Assume PM=PM-10=PM-2.5 to be conservative.					
5. EF from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98, Tables C-1 and C-2).					

2. Projected emissions at operation below 25% of peak load for 66 hrs					
Pollutant		AP-42 EF (lb/MMBtu)	Applied EF (lb/MMBtu)	Emissions (lb/hr)	Emissions <sup>6</sup> (TPY)
NO <sub>x</sub> <sup>1</sup>		0.24	0.302	42.3 <sup>2</sup>	1.4
CO <sup>1</sup>		0.076	3.397	475.6 <sup>2</sup>	15.7
SO <sub>2</sub> <sup>1</sup>		0.404	7.871	110 <sup>2</sup>	36.4
PM <sup>1,3</sup>		1.20E-02	0.141	19.7 <sup>2</sup>	0.7
PM-10 <sup>1,3</sup>		1.20E-02	0.141	19.7 <sup>2</sup>	0.7
PM-2.5	PM-2.5 <sup>3</sup>	1.20E-02	0.141	19.7 <sup>2</sup>	0.7
	NO <sub>x</sub> <sup>1</sup>	0.24	0.302	42.3 <sup>2</sup>	1.4
	SO <sub>2</sub> <sup>1</sup>	0.40	7.87	110 <sup>2</sup>	36.4
O <sub>3</sub>	NO <sub>x</sub> <sup>1</sup>	0.24	0.30	42.3 <sup>2</sup>	1.4
	VOC <sup>1</sup>	4.10E-04	2.126	297.6 <sup>2</sup>	9.8
Lead		1.40E-05	1.40E-05	3.85E-03	1.27E-04
Fluorides <sup>4</sup>			1.01E-05	2.77E-03	9.14E-05
Sulphuric Acid Mist (H <sub>2</sub> SO <sub>4</sub> ) <sup>5</sup>			5.24E-02	14.4	0.5
CO <sub>2</sub> e					1,484.8
Green House Gas (GHG)	GWP	Applied EF <sup>7</sup> (kg/MMBtu)	Mass- Based Emissions (kg/hr)	Mass- Based Emissions <sup>6</sup> (TPY)	CO <sub>2</sub> e Based Emissions <sup>6</sup> (TPY)
CO <sub>2</sub>	1	73.96	20,339.00	1,479.71	1,479.7
CH <sub>4</sub>	25	3.00E-03	0.83	6.00E-02	1.50E+00
N <sub>2</sub> O	298	6.00E-04	0.17	1.20E-02	3.58E+00
Total				<b>1,479.79</b>	<b>1,484.8</b>

notes:

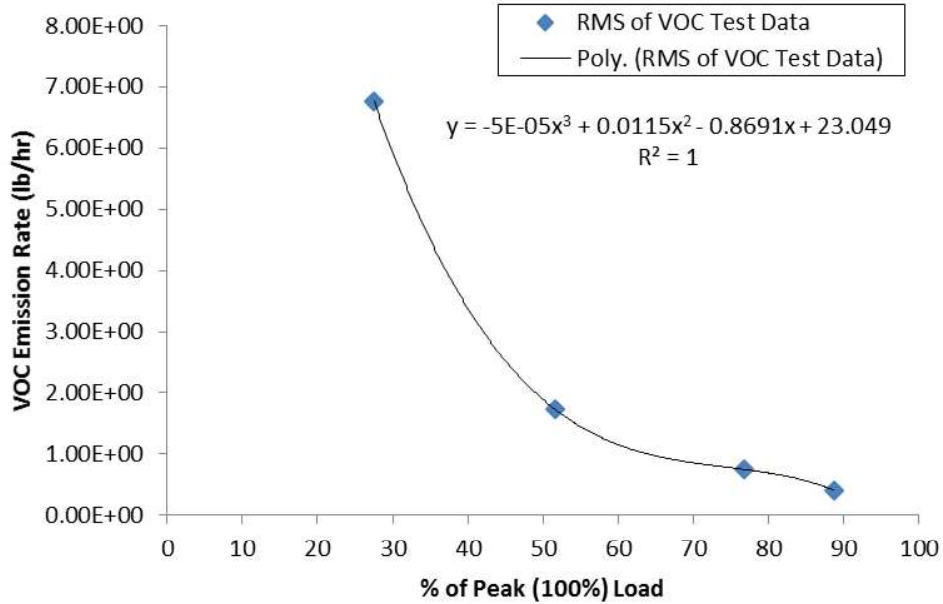
- EF are calculated based on emission limit.
- Emission limit set in PSD permit HI 90-04.
- Assume PM=PM-10=PM-2.5 to be conservative.
- Emission rate for Fluorides based on fuel test results of 0.2ppm dated 04/11/85.
- Emission rate for H<sub>2</sub>SO<sub>4</sub> based on MECO M16 source test result dated 08/19/94.
- Emissions based on 66 hr/yr.
- EF from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98, Tables C-1 and C-2).

The tables above summarize the project emissions based on a maximum operation of sixty-six (66) hours per rolling twelve-month (12-month) period at loads less than 25% of peak load with water injection and show that the project qualifies as a minor modification because the project emissions are below levels specified in HAR §11-60.1-81. The emissions are estimated by the following methods:

1. Calculated based on emission rate limits set in current CSP No. 0235-01-C issued on November 15, 2002:
  - a. The emission limit of VOC at 25% of peak load is taken as the maximum emission rate.

In the following figure, the root mean square (RMS) of tested VOC emission rate in each year of 2005, 2008, 2009, 2012, and 2015 is plotted against the RMS of percentage of peak load in corresponding year. The plot shows the relationship between the VOC emission rate and the load is as:

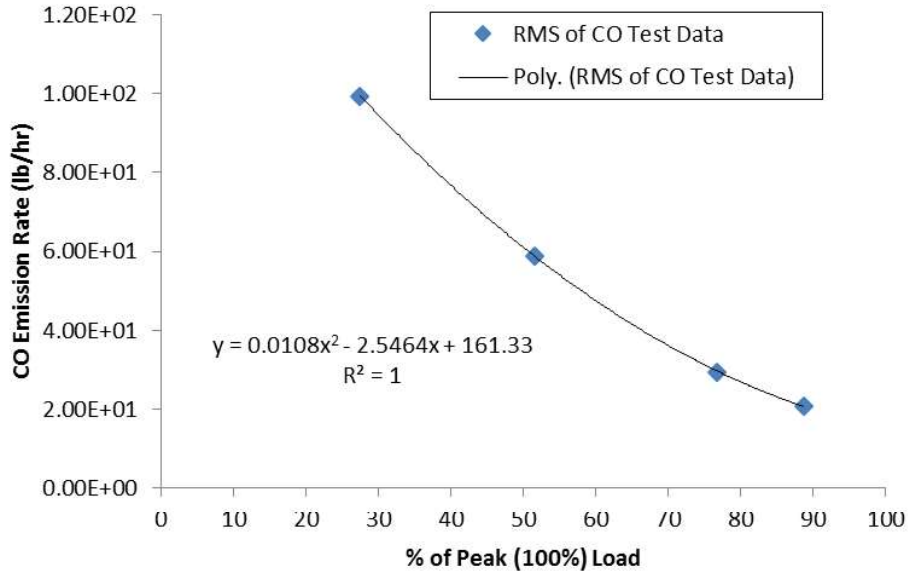
$$y = -5E-05x^3 + 0.0115x^2 - 0.8691x + 23.049$$



Taking the first order derivative  $dy/dx = -1.5E-04x^2 + 0.023x - 0.8691 = 0 \Rightarrow x_1=69, x_2=84$

For  $x < 69$ ,  $(dy/dx) > 0$ . Therefore, as load decreases, VOC emission rate increases. Theoretically, at  $x=0$ ,  $y = 23.05$  lb/hr would be the maximum emission rate of VOC. Therefore, taking the limited emission rate of 297.6 lb/hr at 25% of peak load is very conservative. The calculated annual VOC emission based on this agrees with the reasoning used by the applicant.

b. The emission limit of CO at 25% of peak load is taken as the maximum emission rate.

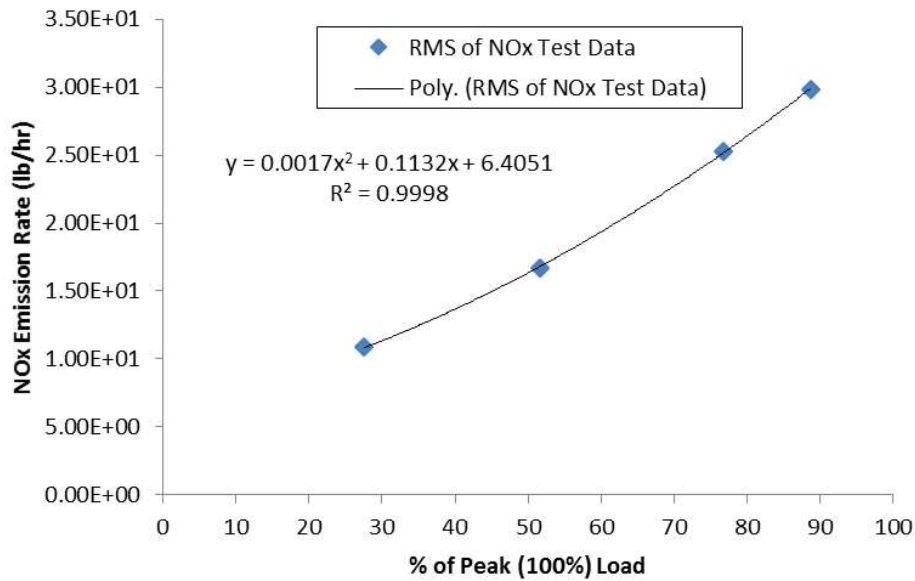


In the figure above, the RMS of tested CO emission rate in each year of 2005, 2008, 2009, 2012, and 2015 is plotted against the RMS of percentage of peak load in corresponding year. The plot shows the relationship between the CO emission rate and the load as:

$$y = 0.0108x^2 - 2.5464x + 161.33 \Rightarrow y = 0.0108(x - 118)^2 + 11 > 0$$

For  $x < 118$ ,  $y$  increases as  $x$  decreases. This means CO emission rate increases as load decreases. Theoretically, 161.33 lb/hr would be the maximum emission rate for CO at load of 0. Therefore, taking the limited emission rate of 457.6 lb/hr at 25% of peak load is very conservative. The calculated annual CO emission based on this agrees with the reasoning used by the applicant.

- c. The emission limit of NO<sub>x</sub> is taken as the maximum emission rate.



In the figure above, RMS of tested NO<sub>x</sub> emission rate in each year of 2005, 2008, 2009, 2012, and 2015 is plotted against the RMS of percentage of peak load in corresponding year. The plot shows the relationship between the NO<sub>x</sub> emission rate and the load as:

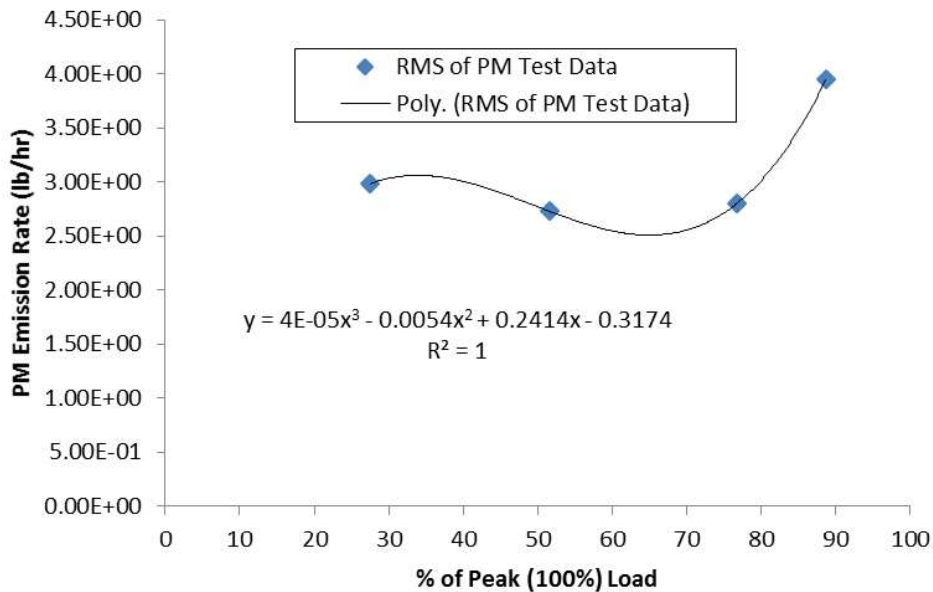
$$y = 0.0017x^2 + 0.1132x + 6.4051$$

For  $x > 0$ ,  $y$  decreases as  $x$  decreases. This means that NO<sub>x</sub> emission rate decreases as load decreases and the maximum emission rate of 34.7 lb/hr should occur at the peak load. Therefore, taking the emission limit of 42.3 lb/hr is conservative. The calculated annual NO<sub>x</sub> emission based on this agrees with the reasoning used by the applicant.

- d. The emission limit of PM/PM<sub>10</sub>/PM<sub>2.5</sub> is taken as the maximum emission rate. In the following figure, the RMS of tested PM emission rate in each year of 2005, 2008, 2009, 2012, and 2015 is plotted against the RMS of percentage of peak load in corresponding year. The plot shows the relationship between the PM emission rate and the load is as:

$$y = 4E-05x^3 - 0.0054x^2 + 0.2414x - 0.3174$$





$$dy/dx = 1.2E-04x^2 - 0.0108x + 0.2414 = 0 \Rightarrow x_1 = 35 \text{ and } x_2 = 65$$

For  $x < 35$  and  $x > 65$ ,  $(dy/dx) > 0$ , and hence  $y$  decreases as  $x$  decreases. For  $35 < x < 65$ ,  $y$  decreases as  $x$  increases. Theoretically, the maximum PM emission rate of 9.8 lb/hr should occur at the peak load. Therefore, taking the emission limit of 17.6 lb/hr is very conservative. The calculated annual PM emission based on this agrees with the reasoning used by the applicant.

- e. The emission limit of  $SO_2$  is taken as the maximum emission rate.

The  $SO_2$  emission factor is directly proportional to fuel sulfur content and is a constant as the sulfur content is not changing. As the load (heat input) decreases, the emission rate decreases. Therefore, taking the emission limit of 110 lb/hr set for operation above 25% of peak load will be conservative.

2. Calculated based on source test data:

The fluorides and sulfuric acid ( $H_2SO_4$ ) emission factors are dependent on fuel type. Thus, these emission factors remain constant as load varies. Therefore, fluorides, and  $H_2SO_4$  emissions decrease with decreasing load. Worst-case emissions will occur when the CT is operating at peak load. Calculating the emissions based on source test data when CT-3 was fired on same type of fuel and operated above 25% of peak load will be conservative.

3. Calculated based on AP-42 EF:

The lead emission factors are dependent on fuel type. Thus, its emission factor remains constant as load varies. Therefore, lead emissions decrease with decreasing load. Worst-case emissions will occur when the CT is operating at peak load. Calculating the emissions based on AP-42 will be safe.

For comparison, the justifications that the applicant used for estimating the emissions are listed in the following. These methods reach the same results concluded in the tables shown at the beginning of this enclosure.

Based on the emission limits for CT3 as specified in the CSP and source performance test data, load reduction has the following impacts on the CT emission factors:

- The SO<sub>2</sub> emission factor is directly proportional to fuel sulfur content. Thus, the SO<sub>2</sub> emission factor remains constant.
- The lead, fluorides, and H<sub>2</sub>SO<sub>4</sub> emission factors are dependent on fuel type. Thus, these emission factors remain constant.
- The NO<sub>x</sub> emission factor decreases with decreasing load; refer to Figure 1.
- The CO, VOC, PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emission factors increase with decreasing load.

Since SO<sub>2</sub>, NO<sub>x</sub>, lead, fluorides, and H<sub>2</sub>SO<sub>4</sub> emissions decrease with decreasing load, emission rates below 25% of peak load (6.165 MW) are not needed. Worst-case emissions will occur when the CT is operating at peak load. Thus, project SO<sub>2</sub>, NO<sub>x</sub>, lead, fluorides, and H<sub>2</sub>SO<sub>4</sub> emissions are based on the CT operating at peak load.

Based on comparison of the permitted emission rates for CO, VOC, and PM/PM<sub>10</sub> and source test data, the permitted emission rates for these pollutants at 25% of peak load are conservative; refer to Figures 2 through 6. Thus, project CO, VOC, and PM/PM<sub>10</sub> are based on the CT operating at 25% of peak load and PM<sub>2.5</sub> emissions are based on PM/PM<sub>10</sub> emissions.

Table 1 summarizes the project emissions based on a maximum operation of sixty-six (66) hours per rolling twelve-month (12-month) period at loads less than 25% of peak load with water injection and shows that the project qualifies as a minor modification because the project emissions are below levels specified in HAR §11-60.1-81.

**Table 1 – Project Emissions Calculations**

Pollutant	CT3		Significant Level <sup>2</sup> (tpy)	Significant Modification Required (Yes/No)	
	Operation Below 25% of Peak Load with Water Injection Project Emissions <sup>1</sup>				
	(lb/hr per CT)	(tpy total)			
CO	475.6	15.69	25	No	
NO <sub>x</sub>	42.3	1.40	10	No	
SO <sub>2</sub>	39.0	1.29	10	No	
PM	19.7	0.65	6.25	No	
PM <sub>10</sub> <sup>4</sup>	19.7	0.65	3.75	No	
PM <sub>2.5</sub> <sup>3, 4</sup>	PM <sub>2.5</sub>	19.7	0.65	2.5	No
	SO <sub>2</sub>	110	3.63	10	
	NO <sub>x</sub>	42.3	1.40	10	
O <sub>3</sub> <sup>5</sup>	NO <sub>x</sub>	42.3	1.40	10	No
	VOC	297.60	9.82	10	
Lead	3.85E-03	1.27E-04	0.15	No	
Fluorides	2.77E-03	9.14E-05	2	No	
Sulfuric Acid Mist (H <sub>2</sub> SO <sub>4</sub> )	14.4	0.475	2	No	
CO <sub>2e</sub>		1,485	10,000	No	

Notes:

1. Project tpy values based on 66 hrs/yr.
2. Minor modification significant levels from HAR §11-60.1-81.
3. PM<sub>2.5</sub> emissions and PM<sub>10</sub> emissions shall include gaseous emissions from a source or activity which condense to form particulate matter at ambient temperatures (40 CFR §52.21(b)(50)(i)(a) and HAR §11-60.1-1).
4. In addition to the 10 tpy significant level for direct PM<sub>2.5</sub> emissions, the project is significant for PM<sub>2.5</sub> if SO<sub>2</sub> or NO<sub>x</sub> emissions exceed 40 tpy (40 CFR §52.21(b)(23)(i) and HAR §11-60.1-1).
5. The project is significant for O<sub>3</sub> if NO<sub>x</sub> or VOC emissions exceed 40 tpy (40 CFR §52.21(b)(23)(i) and HAR §11-60.1-1).

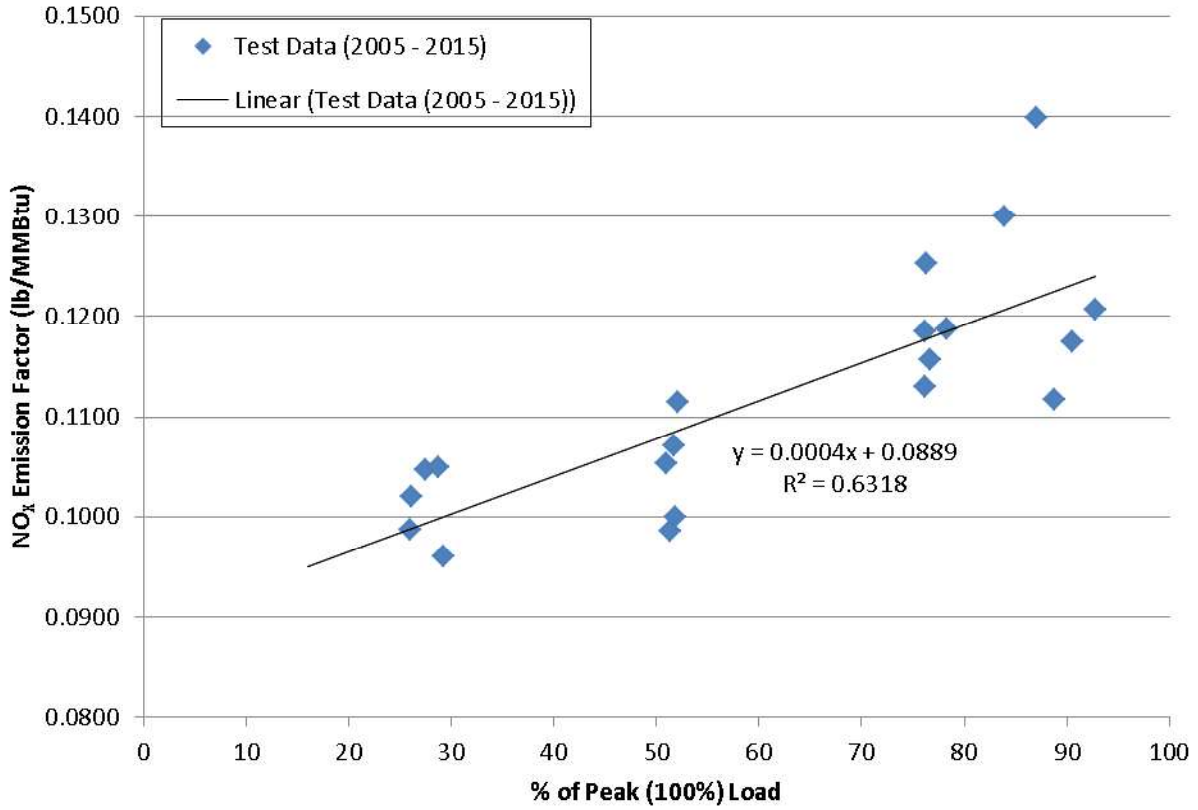
**Table 2 – GHG Emissions Calculations**

Units	Heat Input (MMBtu/yr)	GHG Pollutant <sup>1</sup>	Emission Factor <sup>2</sup> (kg/MMBtu)	Global Warming Potential <sup>3</sup>	GHG Emissions CO <sub>2e</sub> (tpy)
CT3	18,150	CO <sub>2</sub>	73.96	1	1,479.7
		N <sub>2</sub> O	6.0E-04	298	3.58E+00
		CH <sub>4</sub>	3.0E-03	25	1.50E+00
<b>Total CO<sub>2e</sub> =</b>					<b>1,484.8</b>

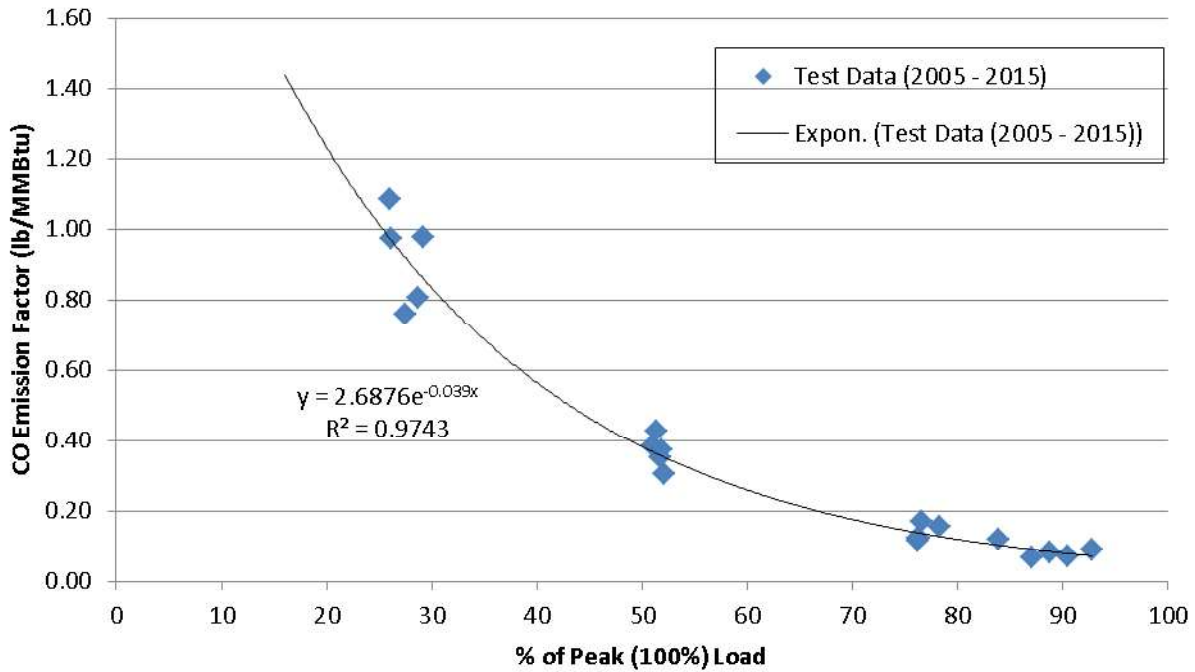
Notes:

1. Greenhouse Gas (GHG) pollutants from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98.32).
2. Emission factors from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98, Tables C-1 and C-2).
3. Global Warming Potentials from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98, Table A-1).
4. Project tpy values based on 66 hrs/yr.

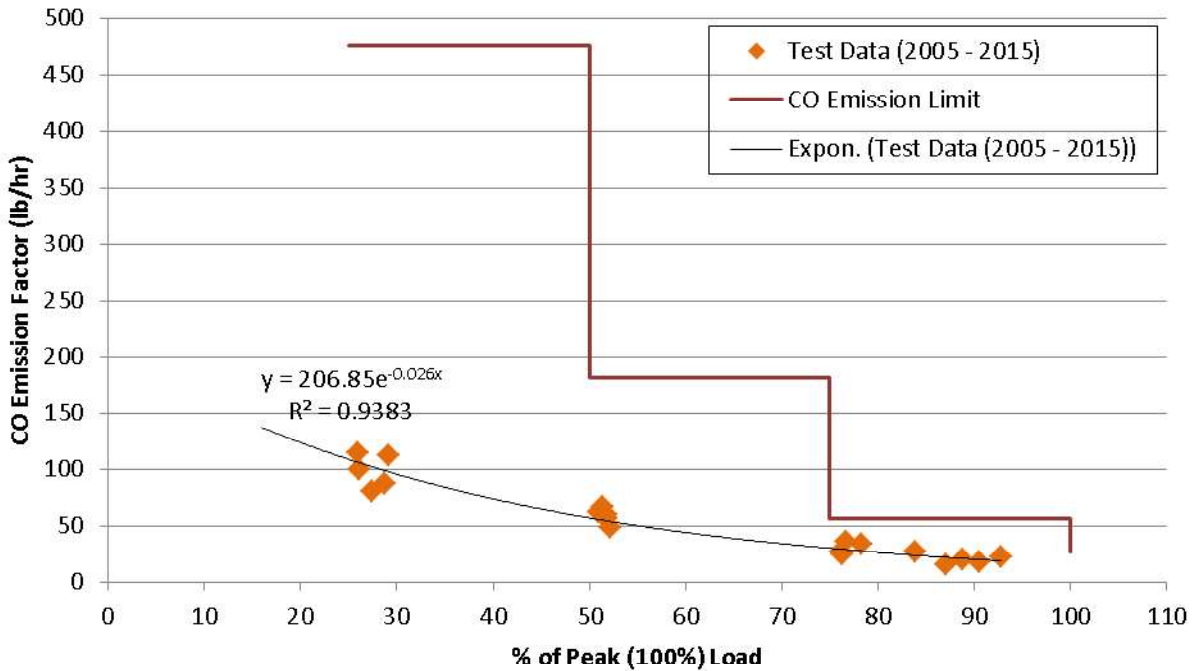
**Figure 1 – Relationship Between NO<sub>x</sub> Emission Factor and Load**



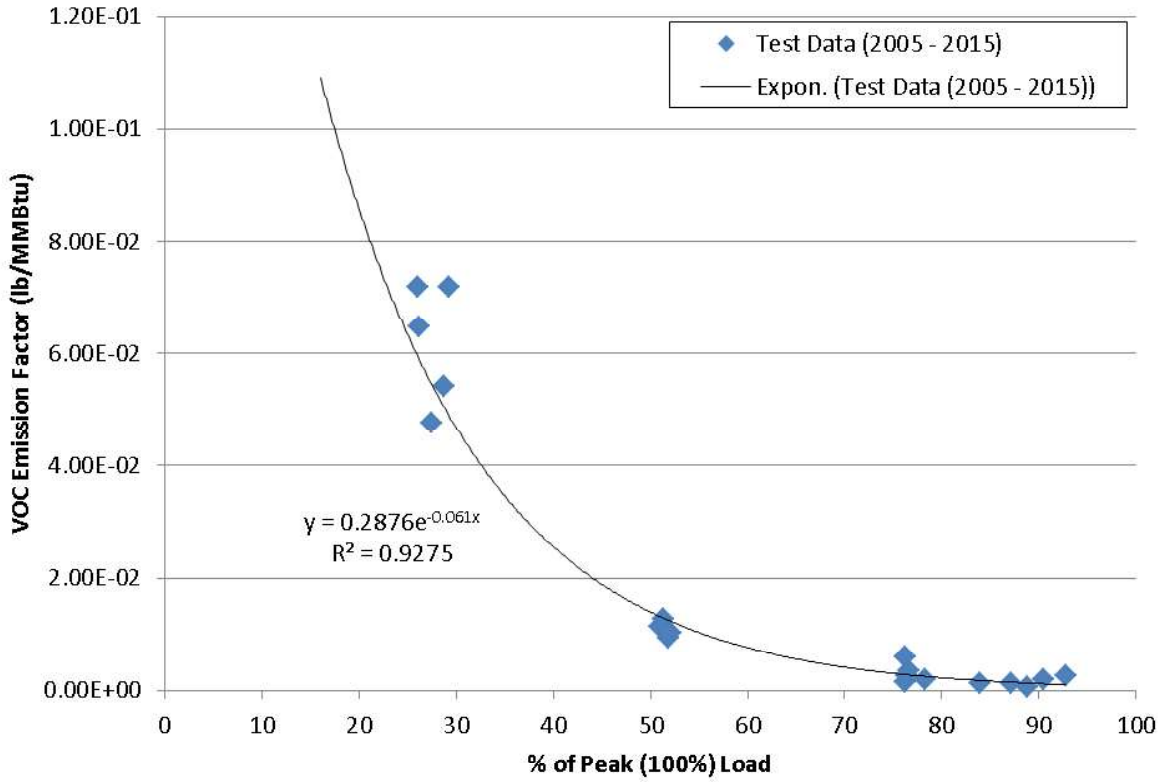
**Figure 2 – Relationship Between CO Emission Factor and Load**



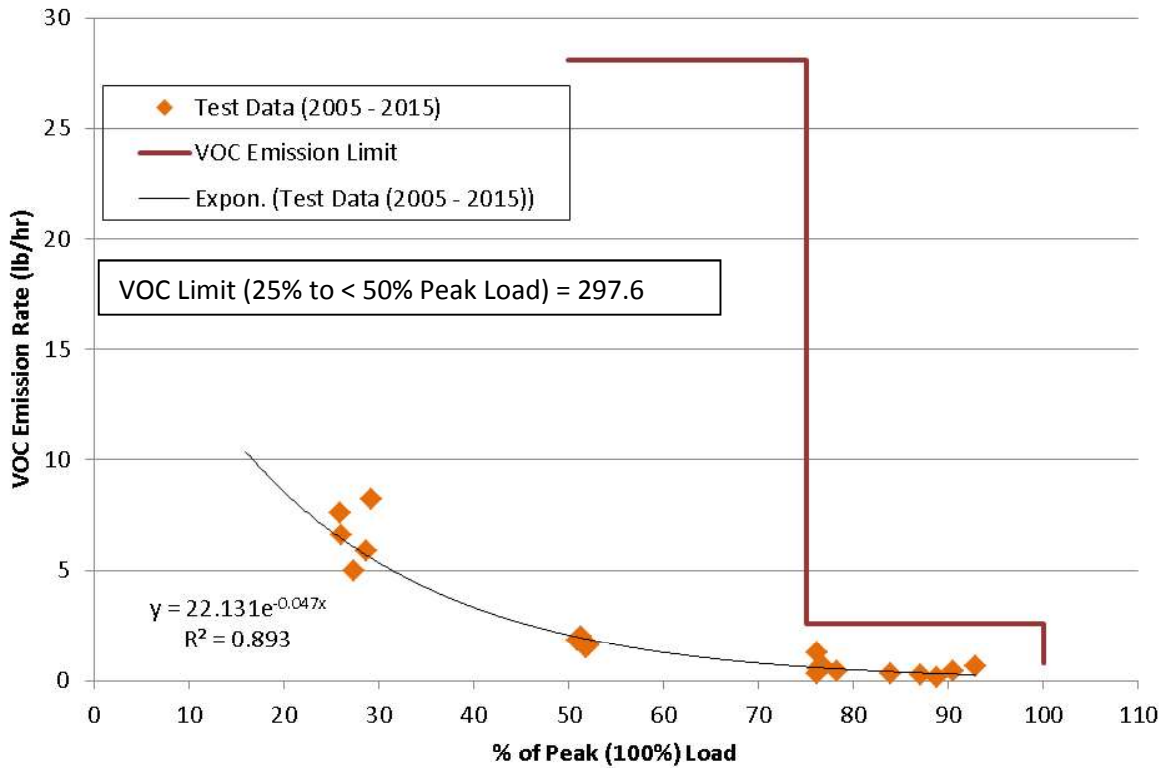
**Figure 3 – Comparison of CO Source Test Data and CO Emission Limits**



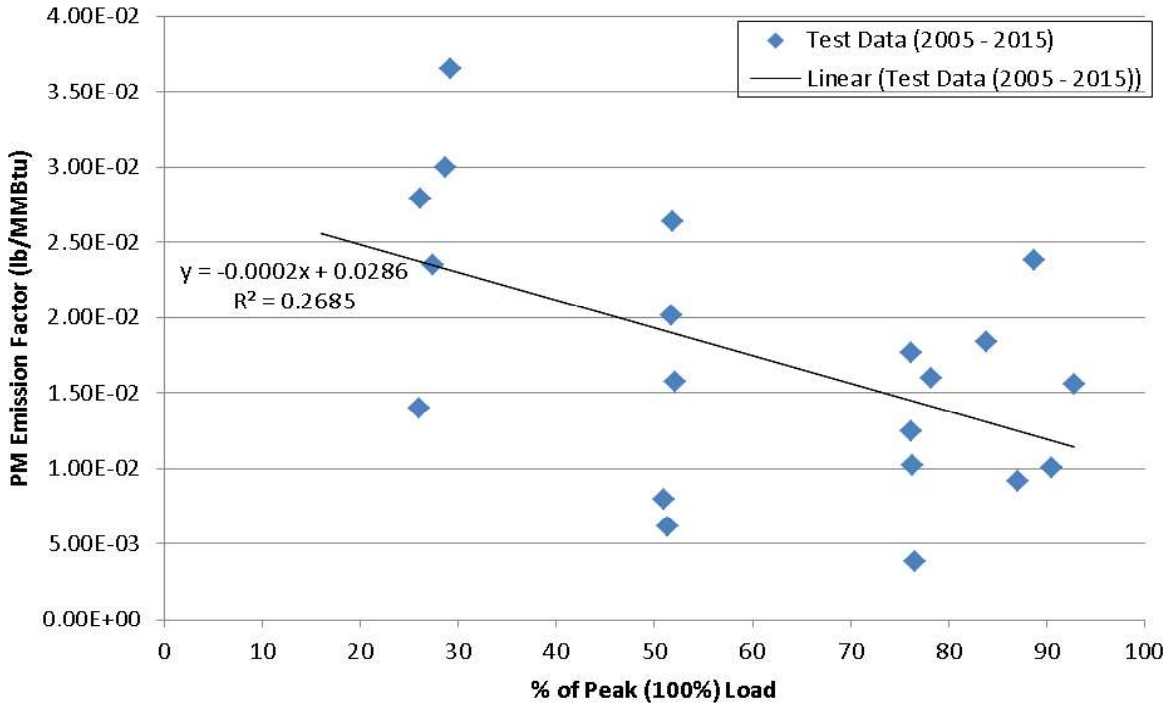
**Figure 4 – Relationship Between VOC Emission Factor and Load**



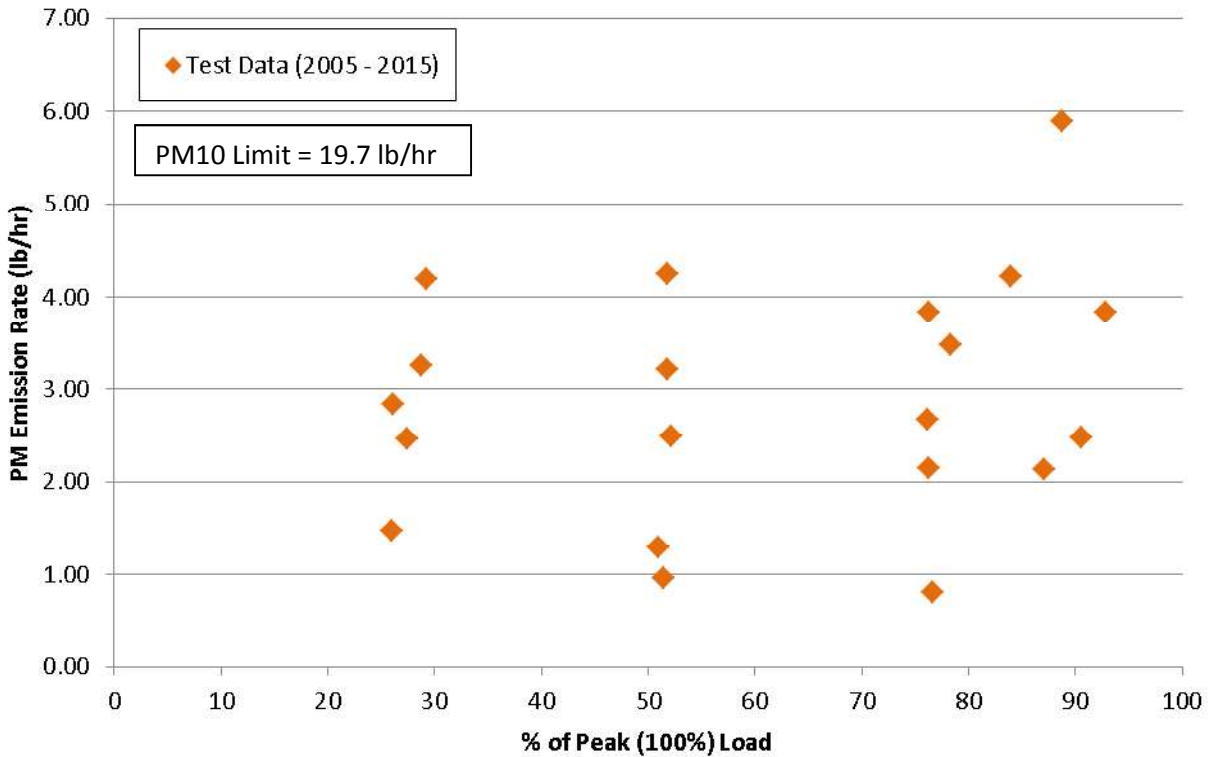
**Figure 5 – Comparison of VOC Source Test Data and VOC Emission Limits**



**Figure 6 – Relationship Between PM Emission Factor and Load**



**Figure 6 – Relationship Between PM Emission Factor and Load**



**Enclosure 3: PBSG1 Emissions**

AP-42 Section 3.3 (10/96) - Large Stationary Diesel and All Stationary Dual-Fuel Engines  
 Emission (lb/hr) = Heat Input Value (6.34 MMBtu/hr) x Applied EF (lb/MMBtu)  
 Emission (TPY) = Emission (lb/hr) x Hour Limit (300 hr/yr) / 2000 (lb/ton)  
 Emission (TPY) = Emission (kg/hr) x Hour Limit (300 hr/yr) / 1000 (kg/ton)

	Value	Unit	Notes
Hour Limit	300	hr/yr	
Fuel Consumption		gal/hr	Manufacturer's data
No. 2 Oil Sulfur Content	0.4	%	
No. 2 Oil Heating Value	139	MMBtu/10 <sup>3</sup> gal	
Heat Input Rate	6.34	MMBtu/hr	Applicant's info

Pollutant	AP-42 EF (lb/MMBtu)	Applied EF (lb/MMBtu)	Emissions (lb/hr)	Emissions (TPY)
CO	0.85	0.85	5.39	<b>0.81</b>
NO <sub>x</sub>	3.20	3.20	20.29	<b>3.04</b>
SO <sub>2</sub>	0.404	0.404	2.56	<b>0.38</b>
VOC	0.0819	0.0819	0.52	<b>0.08</b>
PM <sup>1</sup>	0.0697	0.0697	0.44	<b>0.07</b>
PM-10 <sup>1</sup>	0.0697	0.0697	0.44	<b>0.07</b>
PM-2.5 <sup>1</sup>	0.0697	0.0697	0.44	<b>0.07</b>

Hazardous Air Pollutant (HAP)	AP-42 EF (lb/MMBtu)	Applied EF (lb/MMBtu)	Emissions (lb/hr)	Emissions (TPY)
Acetaldehyde	2.52E-05	2.52E-05	1.60E-04	<b>2.40E-05</b>
Acrolein	7.88E-06	7.88E-06	5.00E-05	<b>7.49E-06</b>
1,3-Butadiene				
Benzene	7.76E-04	7.76E-04	4.92E-03	<b>7.38E-04</b>
Ethylbenzene				
Formaldehyde	7.89E-05	7.89E-05	5.00E-04	<b>7.50E-05</b>
Phosphorus				
1,1,1-Trichloroethane				
Toluene	2.81E-04	2.81E-04	1.78E-03	<b>2.67E-04</b>
Xylene	1.93E-04	1.93E-04	1.22E-03	<b>1.84E-04</b>
POM	2.12E-04	2.12E-04	1.34E-03	<b>2.02E-04</b>
Antimony Compounds				
Arsenic Compounds				
Beryllium Compounds				
Cadmium Compounds				
Chromium Compounds				
Cobalt Compounds				
Lead Compounds				
Manganese Compounds				
Mercury Compounds				
Nickel Compounds				
Selenium Compounds				
Total HAPs	1.57E-03	1.57E-03	9.98E-03	<b>1.50E-03</b>

Green House Gas (GHG)	GWP	Applied EF <sup>2</sup> (kg/MMBtu)	Mass-Based Emissions (kg/hr)	Mass-Based Emissions (TPY)	CO <sub>2</sub> e Based Emissions (TPY)
CO <sub>2</sub>	1	75.10	476.13	142.84	142.8
CH <sub>4</sub>	25	3.00E-03	0.02	0.006	0.1
N <sub>2</sub> O	298	6.00E-04	3.8E-03	1.14E-03	0.3
Total				<b>142.85</b>	<b>143.3</b>

notes:

1. Assume PM=PM-10=PM-2.5 to be conservative.
2. EF from the Mandatory Greenhouse Gas Reporting rule (40 CFR §98, Tables C-1 and C-2).