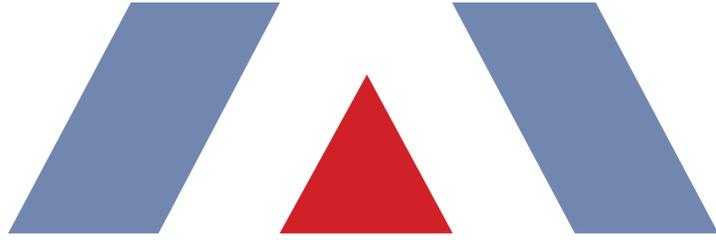


**Appendix H: Regional Haze Four-Factor Analysis
Hawaiian Electric Light Company, Inc.
Puna Generating Station**

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Initial Four – Factor Analysis

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REGIONAL HAZE FOUR-FACTOR ANALYSIS

Puna Generating Station



**Hawaiian
Electric**

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TABLE OF CONTENTS

1. EXECUTIVE SUMMARY	1-1
2. BACKGROUND AND ADDITIONAL FACTORS	2-1
2.1. Regional Haze Rule Background	2-1
2.2. Additional Factors.....	2-3
3. SULFUR DIOXIDE FOUR-FACTOR ANALYSIS	3-1
3.1. Sulfur Dioxide Control Options.....	3-1
3.2. Four-Factor Analysis	3-2
3.3. Sulfur Dioxide Conclusion	3-5
4. NITROGEN OXIDES FOUR-FACTOR ANALYSIS	4-1
4.1. Nitrogen oxides Control Options.....	4-1
4.2. Four-Factor Analysis	4-4
4.3. Nitrogen Oxides Conclusion.....	4-7
5. PARTICULATE MATTER FOUR-FACTOR ANALYSIS	5-1
5.1. Particulate Matter Control Options.....	5-1
5.2. Four-Factor Analysis	5-2
5.3. Particulate Matter Conclusion	5-5
APPENDIX A: DETAILED COSTING	A-I
APPENDIX B: HAWAIIAN ELECTRIC REGIONAL HAZE VISIBILITY CONSIDERATIONS	B-I
APPENDIX C: HAWAI'I'S RENEWABLE PORTFOLIO STANDARDS CONTRIBUTION TO REGIONAL HAZE PROGRESS	C-I

LIST OF TABLES

Table 3-1. Baseline SO ₂ Emissions	3-1
Table 3-2. SO ₂ Cost Effectiveness of Switching to a Residual/Distillate Blended Fuel	3-4
Table 3-3. SO ₂ Cost Effectiveness of Switching to Distillate Fuel	3-4
Table 4-1. Baseline NO _x Emissions	4-1
Table 4-2. Control Effectiveness of Technically Feasible NO _x Control Technologies	4-3
Table 4-3. NO _x Cost Effectiveness of LNB with OFA and SCR	4-6
Table 5-1. Baseline PM ₁₀ Emissions	5-1
Table 5-2. PM ₁₀ Cost Effectiveness of Wet ESP, Wet Scrubber and Switching to Distillate Fuel	5-4

1. EXECUTIVE SUMMARY

The State of Hawai‘i has two Class I areas (National Parks) that trigger compliance with the Regional Haze Rule (RHR); Hawai‘i’s Mandatory Federal Class I Areas are Haleakalā National Park on Maui Island and Hawai‘i Volcanoes National Park on the Hawai‘i Island. This report documents the results of the Regional Haze Rule (RHR) second planning period four-factor analysis conducted by Trinity Consultants (Trinity) on behalf of Hawaiian Electric¹ for the Puna boiler and combustion turbine (CT-3) at the Puna Generating Station (Puna). The Puna boiler is a 15.5 megawatt (MW) tangentially-fired boiler that currently burns residual oil, and CT-3 is 20 MW simple cycle combustion turbine that currently burns diesel. Also, Appendix B and Appendix C contain analyses performed by AECOM Technical Services, Inc. (AECOM) of a fifth factor that includes a review of visibility impacts.

This report addresses the options that could be considered that have the potential to lower emissions and the potential to show reasonable progress towards the RHR goals. The results of the four-factor analysis herein are consistent with the conclusions reached for the first planning period Best Available Retrofit Technology (BART) five-factor analysis for the Hawai‘i Electric Light Kanoiehua-Hill Generating Station. Other long-term emission reduction strategies, such as those included as part of Hawai‘i’s Renewable Portfolio Standards (RPS), are viable alternatives to emission reductions via command and control. Hawaiian Electric and AECOM met with the Department of Health (DOH) on February 12, 2020 to present special circumstances that apply in Hawai‘i that should be given consideration in the development of the Hawai‘i Regional Haze SIP. Significant among those circumstances is Hawai‘i’s Statutory RPS which have put the state on a timetable to accomplish the same goals as the RHR twenty years before the actual Regional Haze 2064 target date. These same issues were addressed by the EPA in the Federal Implementation Plan (FIP) and the State of Hawai‘i Department of Health in their Progress Report² that was approved by the EPA effective on September 11, 2019. These special considerations are discussed further in Appendix B and Appendix C to this report.

Based on the four-factor analysis, Hawaiian Electric does not propose any emission reduction measures in addition to its RPS program to meet the RHR requirements.

¹ 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.

² 5-Year Regional Haze Progress Report For Federal Implementation Plan, Hawai‘i State Department of Health, October 2017, EPA-R09-OAR-2018-0744-0004.

2. BACKGROUND AND ADDITIONAL FACTORS

2.1. REGIONAL HAZE RULE BACKGROUND

In the 1977 amendments to the federal Clean Air Act (CAA), the U.S. Congress set a nation-wide goal to restore national parks and wilderness areas to natural visibility conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the EPA published the final RHR (40 CFR Part 51, Subpart P). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres)³, and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A). This is known as a four-factor analysis.

(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B). The uniform rate of progress or improvement is sometimes referred to as the glidepath and is part of the state's Long Term Strategy (LTS).

During the first implementation period the EPA issued a FIP (77 FR 61478, October 9, 2012; see also *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii Air Division* U.S. EPA Region 9, May 14, 2012) which determined for the first planning period that NO_x was not contributing to regional haze significantly as to require control measures, and that the Oahu sources were not significantly contributing to regional haze. Additionally, as part of the EPA's decision with respect to BART controls, the EPA took into account that controls would result in "unduly increasing electricity rates in Hawai'i." (see 77 FR 31707, May 29, 2012).

The control measures that were imposed established an emissions cap of 3,550 tons of SO₂ per year from the fuel oil-fired boilers at Hawai'i Electric Light's Hill, Shipman and Puna generating stations, beginning in January 1, 2018, at an estimated cost of 7.9 million dollars per year. According to the FIP, this represents a reduction of 1,400 tons per year from the total projected 2018 annual emissions of SO₂ from these facilities. This control measure, in conjunction with SO₂ and NO_x emissions control requirements that are already in place, was found to ensure that reasonable progress is made during

³ The Class I areas in the state of Hawai'i include the Hawai'i Volcanoes National Park on the Hawai'i Island, and Haleakalā National Park on Maui.

this first planning period toward the national goal of no anthropogenic visibility impairment by 2064 at Hawai'i's two Class I areas.

The second implementation planning period (2019-2028) for the national regional haze efforts is currently underway. The EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (SIP Guidance)⁴ provides guidance for the development of the implementation plans. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural (or "biogenic") and manmade (or "anthropogenic") sources of emissions. EPA's *Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program* (Visibility Guidance)⁵ provides guidance to the states on methods for selecting the twenty (20) percent most impaired days to track visibility and determining natural visibility conditions. The approach described in this guidance document does not attempt to account for haze formed from natural volcanic emissions; however, the 2017 RHR 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. Because natural visibility can only be estimated or inferred, visibility impairment also is estimated or inferred rather than directly measured.

EPA's Visibility Guidance states that although they did not attempt to account for haze formed by natural volcanic emissions:

We encourage states with Class I areas affected by volcanic emissions to work with their EPA Regional office to determine an appropriate approach for determining which days are the 20 percent most anthropogenically impaired days.

In the *5-Year Regional Haze Progress Report For Federal Implementation Plan*⁶ the DOH acknowledges the impact of SO₂ from the Kilauea volcano with the following statement:

A majority of the visibility degradation is due to the ongoing release of SO₂ from Kilauea volcano with emissions that vary by hundreds of thousands of tons from one year to another. Visibility improvement from significant reductions in Maui and Hawaii Island point source SO₂ is obscured by sulfate from natural volcanic SO₂ that overwhelms sulfate from anthropogenic SO₂ sources.

Step 1 of the EPA's SIP Guidance is to identify the twenty (20) percent most anthropogenically impaired days and the twenty (20) percent clearest days and determine baseline, current, and natural visibility conditions for each Class I area within the state (40 CFR 51.308(f)(1)). Hawaiian Electric has concerns that this key step may not be accounted for during the second implementation planning and the development of Hawai'i's RHR State Implementation Plan (SIP). The identification of the twenty (20) percent most impaired days sets the foundation for identifying any needed emission reductions.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this, the Western Regional Air Partnership (WRAP), with Ramboll US Corporation, reviewed the 2014 National Emissions Inventory (NEI) and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I

⁴ Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019, EPA-457/B-19-003.

⁵ Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, EPA-454/R-18-010, December 2018.

⁶ 5-Year Regional Haze Progress Report For Federal Implementation Plan, Hawai'i State Department of Health, October 2017, EPA-R09-OAR-2018-0744-0004.

area. The WRAP Guidance itself states that EPA has concerns over only relying on the Q/d method for screening sources. The EPA points out that the Q/d metric is only a rough indicator of actual visibility impact because it does not consider transport direction/pathway and dispersion and photochemical processes. To address EPA's concern, the WRAP subcommittee recommends a second step, application of the weighted emissions potential analysis (WEP).⁷ On September 11, 2019, the DOH informed Hawai'i Electric Light that its Puna Generating Station was identified, based on the Q/d analysis, as one of the sources potentially contributing to regional haze at Volcanoes National Park. This report responds to the DOH September 2019 request to Hawaiian Electric to submit a four-factor analysis for Puna.

The SIP Guidance requires that the selection of controls necessary to make reasonable progress must consider the five required factors listed in section 51.308(f)(2)(iv), and other factors that are reasonable to consider. Hawaiian Electric and AECOM prepared summary, included in Section 2.2, which describes special circumstances that apply in Hawai'i that should be considered during the development of the Hawai'i Regional Haze SIP.

2.2. ADDITIONAL FACTORS

Hawaiian Electric and AECOM met with the DOH on February 12, 2020 to present special circumstances applicable in Hawai'i that should be considered during the development of the Hawai'i Regional Haze SIP. Significant among those circumstances is Hawai'i's Statutory RPS which have put the state on a timetable to accomplish the same goals as the RHR twenty years before the Regional Haze 2064 target date. These same issues were addressed by the EPA in the FIP and the DOH in its Progress Report that was approved by the EPA, effective on September 11, 2019. These special considerations are discussed further in Appendix B and Appendix C to this report and summarized in the following sections.

2.2.1. Lack of Contribution to Visibility Impairment Due to Warm Weather Conditions

The potential for the formation of haze due to NO_x emissions is very low in Hawai'i because of the warm weather conditions year-round. Nitrate Haze composition analyses for the Haleakalā and Hawai'i Volcanoes National Parks from the IMPROVE web site are included in Appendix B to this report. The data for both national parks show that the contribution of nitrates to haze is very low. It is low as a percentage of the total haze composition, but it is also low as an absolute value for extinction (visibility impairment). The minimal impact of nitrate haze is clearly illustrated in the Hawai'i National Park monitoring data and is much lower than found at many monitors in other Class I areas around the country. This is in large part due to the unique chemistry of nitrate haze which is discussed further in Appendix B to this report.

Due to the low haze impact of NO_x, the DOH should not consider NO_x controls for the Second Decadal Review for Puna. A similar conclusion was reached during the First Decadal Review, for which the EPA did not consider NO_x controls to be material.

2.2.2. Contribution to Visibility Impairment from Volcanic Activity

Volcanic activity on the Hawai'i Island represents a unique challenge to understanding haze in Hawai'i Class I areas. The Kilauea volcano on Hawai'i Island has been active for several years, and the levels of SO₂ emissions are being monitored by the United States Geological Survey. In addition to volcanoes being large sources of SO₂, they also emit significant amounts of NO_x. It should also be noted that

⁷ WRAP Reasonable Progress Source Identification and Analysis Protocol For Second 10-year Regional Haze State Implementation Plans, dated February 27, 2019
<https://www.wrapair2.org/pdf/final%20WRAP%20Reasonable%20Progress%20Source%20Identification%20and%20Analysis%20Protocol-Feb27-2019.pdf>.

volcanic activity on Hawai'i Island is the largest source of NO_x in the state. Nitrate haze is a very small component in Hawai'i's Class I areas, which is expected given the nitrate chemistry as explained in Appendix B to this report. Direct particulate matter (PM) emissions constitute a very small portion of haze and significant portions are due to volcanic emissions as explained in Appendix B to this report. Visibility improvements made from significant reductions of point source SO₂ in Maui and Hawai'i Island is obscured by sulfate from natural volcanic SO₂ that overwhelms sulfate from anthropogenic SO₂ sources. Anthropogenic sources (from power plants) are projected to be phased out well before the end point of the Regional Haze Rule (i.e., 2064) by Hawai'i's State Law: Renewable Portfolio Standards (RPS). Thus, the DOH should limit the haze precursors control evaluations solely to SO₂ for the Second Decadal Review for Puna.

2.2.3. Renewable Portfolio Standards

Based on AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, SO₂, NO_x, and PM₁₀ emissions from Puna do not significantly contribute to regional haze. The low impact that Puna may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (Hawai'i Revised Statute (HRS) §269-92) and consistent with the Hawai'i Clean Energy Initiative (HCEI). Both past and projected future decreases in fossil-fueled electric generating unit (EGU) usage are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the RHR. The RPS will substantially reduce emissions of haze precursors (especially SO₂) by 2045. Therefore, further requirements for controls would not affect the showing of further progress under the RHR and, thus, are not needed at this time. This is further discussed in Appendix C to this report. Although RPS is listed as a control measure (which is consistent with the Hawaii Progress Report for Phase 1), it was not necessary to review the RPS in the context of the four-factor analysis as these measures are already planned for implementation and although there are additional costs, they are inherent in the RPS program.

3. SULFUR DIOXIDE FOUR-FACTOR ANALYSIS

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that SO₂ emissions from Puna do not significantly contribute to regional haze. However, the four-factor analysis is provided in response to DOH's request. The first step in the analysis is to establish a baseline for emissions. Per DOH's letter dated September 11, 2019, calendar year 2017 actual emissions are used to define the baseline emissions for the four-factor analysis. Table 3-1 lists the baseline SO₂ emissions for Puna.

Table 3-1. Baseline SO₂ Emissions

Unit	Fuel Sulfur ^A	SO ₂ Emissions	
		(lb/MMBtu) ^B	(TPY) ^C
Boiler	1.69%	1.87	184.0
CT-3	0.054%	5.51E-02	2.9
		Total	186.9

^A Calendar year 2017 annual average residual oil sulfur content.

^B The SO₂ emission factors are based on 100% conversion of fuel sulfur to SO₂ and the calendar year 2017 annual average fuel density (8.33 lb/gal for residual oil; 6.96 lb/gal for diesel) and higher heating value (150,985 Btu/gal for residual oil; 136,533 Btu/gal for diesel).

^C Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

3.1. SULFUR DIOXIDE CONTROL OPTIONS

The characterization of emission controls available and applicable to the source is a necessary step before the four-factors can be analyzed. SO₂ emissions are generated during fuel oil combustion from the oxidation of sulfur contained in the fuel. Available SO₂ control technologies for the boilers are:

- Flue Gas Desulfurization (FGD) systems
 - Dry Sorbent Injection (DSI)
 - Spray Dryer Absorber (SDA)
 - Wet Scrubber
 - Circulating Dry Scrubber (CDS)
- Fuel Switching
- Renewable Portfolio Standards (RPS)

The feasibility of these controls is discussed in the following sections.

CT-3 operates on a very limited basis, and post-combustion SO₂ controls are not feasible for combustion turbines. Therefore, fuel switching to ULSD is the only feasible option to reduce SO₂ emissions.

3.1.1. Post-Combustion Controls

FGD applications have not been used historically for SO₂ control on oil-fired boilers the size of those operated at the Puna Generating Station. As there are no known FGD applications for similar oil-fired boilers, the performance of FGDs on oil-fired boilers is unknown. The EPA took this into account when evaluating the Best Available Retrofit Technology (BART) presumptive SO₂ emission rate for oil-fired units and determined that the presumptive emission rate should be based on the sulfur content of the

fuel oil, rather than on FGD⁸. Since there are no applications of FGD on oil-fired boilers in the U.S., FGDs are considered technically infeasible for the control of SO₂ from the Puna boiler.

3.1.2. Fuel Switching

The Puna boiler currently burns residual high sulfur fuel oil with a maximum sulfur content of 2.0 percent by weight. The average sulfur content of the residual high sulfur fuel oil purchased in 2017 was approximately 1.69 percent by weight. Switching to a lower sulfur fuel would reduce SO₂ emissions in proportion to the reduction in fuel sulfur content.⁹

On Oahu, 0.5 percent by weight low sulfur fuel oil is produced, and is used at Hawaiian Electric's Kahe and Waiiau Generating Stations on Oahu. However, it is not a technically feasible option for the Puna boiler. This low sulfur fuel oil has a higher viscosity and pour point than the residual high sulfur fuel oil used by the Puna boiler and the current fuel supply chain from Oahu to the Puna boiler cannot support this quality of fuel that is semi-solid at ambient temperatures. For the low sulfur fuel oil to be burned by the Puna boiler, the piping and tanks that are used to transport and store the oil would need to be heated, at a cost of 500 thousand (\$500,000) to 1 million dollars (\$1,000,000), which is not economically feasible because of the very limited remaining time that oil will be burned by the Puna boiler. There are however, technically feasible options which include blending the current residual high sulfur fuel oil with a lower sulfur distillate fuel or switching completely to a lower sulfur distillate fuel. The SO₂ four-factor analysis will evaluate both options.

CT-3 is currently permitted to burn diesel with a maximum sulfur content of 0.4 percent by weight. The average sulfur content of the diesel purchased in 2017 was approximately 0.054 percent by weight. Due to the limited operations of CT-3, 2017 emissions were less than three (3) tons of SO₂, and any reduction in fuel sulfur content is expected to have a negligible impact on regional haze. Therefore, the four-factor analysis was not conducted for CT-3.

3.1.3. Renewable Portfolio Standards

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that SO₂ emissions from Puna do not significantly contribute to regional haze. The low impact that Puna may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (HRS §269-92) and consistent with the HCEI. Both past and projected future decreases in fossil-fueled EGU usage are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the RHR. The RPS will substantially reduce emissions of haze precursors (especially SO₂) by 2045. Therefore, further requirements for controls would not affect the showing of further progress under the RHR and, thus, are not needed at this time. This is further discussed in Appendix C to this report. Although RPS is listed as a control measure (which is consistent with the Hawaii Progress Report for Phase 1) it was not necessary to review the RPS in the context of the four-factor analysis as these measures are already planned for implementation and although there are additional costs, they are inherent in the RPS program.

3.2. FOUR-FACTOR ANALYSIS

As discussed above, fuel switching to a residual/distillate blended fuel or a lower sulfur diesel is the only technically feasible option to reduce SO₂ emissions for the Puna boiler. For the second planning period,

⁸ *Summary of Comments and Responses on the 2004 and 2001 Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations* EPA Docket Number OAR-2002-0076.

⁹ Natural gas has less sulfur than the existing residual fuel oil. However, natural gas is not a technically feasible option because there is no natural gas supply in Hawai'i.

the focus is on determining reasonable progress through analyses of the four factors identified in Section 169A(g)(1) of the CAA:

1. The cost of compliance;
2. The time necessary to achieve compliance;
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements.

The four factors for switching the Puna boiler to a lower sulfur residual/distillate blended fuel, or a lower sulfur diesel are discussed in the following sections.

3.2.1. Cost of Compliance

The cost effectiveness of the fuel switching was determined by calculating the annual incremental cost of switching to a lower sulfur fuel divided by the reduction in SO₂ emissions. Switching fuel would require changes to the injectors and the fuel system; however, these expenses were not included in the analysis.

Puna currently purchases residual high sulfur fuel oil from Par Hawaii Refining, LLC; current fuel costs were obtained from 2019 actual fuel purchases. The fuels are refined on Oahu, and changes in quantities of residual high sulfur fuel oil and distillate fuels would require new contracts with fuel suppliers. This adds a level of uncertainty to the cost of compliance.

Table 3-2 presents a summary of the cost effectiveness of switching from residual high sulfur fuel oil to residual high sulfur fuel oil/distillate blended fuel with a maximum sulfur content of 1.0 percent by weight. The cost effectiveness is determined by dividing the annual cost increase in fuel by the annual reduction in SO₂ emissions. The cost effectiveness of switching to a residual high sulfur fuel oil/distillate blended fuel with a maximum sulfur content of 1.0 percent by weight is \$7,422 per ton SO₂ and would increase fuel cost 600 thousand dollars (\$600,000) annually and 9 million dollars (\$9,000,000) over fifteen (15) years.

Table 3-3 presents a summary of the cost effectiveness of switching from residual high sulfur fuel oil to distillate fuel with a maximum sulfur content of 0.4 percent by weight. The cost effectiveness is determined by dividing the annual cost increase in fuel by the annual reduction in SO₂ emissions. The cost effectiveness of switching to a distillate fuel with a maximum sulfur content of 0.4 percent by weight is \$6,921 per ton SO₂ and would increase fuel cost 1 million dollars (\$1,000,000) annually and 15 million dollars (\$15,000,000) over fifteen (15) years.

3.2.2. Time Necessary to Achieve Compliance

If the DOH determines that switching from residual high sulfur fuel oil to a residual high sulfur fuel oil/distillate blended fuel or a lower sulfur diesel is needed to achieve reasonable progress, it is anticipated that this change could be implemented within two to three years.

Table 3-2. SO₂ Cost Effectiveness of Switching to a Residual/Distillate Blended Fuel

Unit	Current Residual Oil ^A					Residual/Distillate Blend (1.0% maximum Sulfur) ^B						
	2017 Average Sulfur Content (%)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	2017 Annual Heat Input (MMBtu/yr)	2017 SO ₂ Emissions (tpy)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Controlled SO ₂ Emissions (tpy)	SO ₂ Reduced (tpy)	Fuel Cost Differential ^C		SO ₂ Cost Effectiveness (\$/ton)
										(\$/Gal)	(\$/year)	
Boiler	1.69%	150,985	1,304,562	196,969	184.0	141,953	1,387,568	103.61	80.39	0.43	596,654	7,422

^A Based on 2017 average fuel properties and fuel usage.

^B Based on a blend of 37.5% residual oil and 62.5% diesel fuel and the weighted average of the 2017 fuel HHV and density and contract fuel sulfur limits (2.0% for residual oil and 0.4% for diesel).

^C Based on actual 2019 fuel purchases by Hawai'i Electric Light.

Table 3-3. SO₂ Cost Effectiveness of Switching to Distillate Fuel

Unit	Current Residual Oil ^A					Diesel (0.4% maximum Sulfur) ^B						
	2017 Average Sulfur Content (%)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	2017 Annual Heat Input (MMBtu/yr)	2017 SO ₂ Emissions (tpy)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Controlled SO ₂ Emissions (tpy)	SO ₂ Reduced (tpy)	Fuel Cost Differential ^C		SO ₂ Cost Effectiveness (\$/ton)
										(\$/Gal)	(\$/year)	
Boiler	1.69%	150,985	1,304,562	196,969	184.0	136,533	1,442,648	40.18	143.82	0.69	995,427	6,921

^A Based on 2017 average fuel properties and fuel usage.

^B Based on 2017 average HHV and density and contract fuel sulfur limit (0.4%).

^C Based on actual 2019 fuel purchases by Hawai'i Electric Light.

3.2.3. Energy and Non-Air Quality Environmental Impacts

There are no energy and non-air quality environmental impacts of compliance for fuel switching. The cost increase associated with fuel switching to a lower sulfur fuel will increase the cost of the electricity produced by Puna. This increase will impact the price of electricity for Hawaiian Electric customers because it will not only increase the cost of electricity produced by Puna, but it will also increase the cost of electricity that Hawaiian Electric purchases from independent power producers (IPPs). The contracts with the IPPs are tied to Hawaiian Electric's "avoided cost" of producing electricity. Thus, as Hawaiian Electric's fuel costs increase for Puna, the price that the IPPs receive for the electricity they provide increases. As a result, the costs of all electricity sources on Hawai'i Island increase as Hawaiian Electric's fuel costs increase.

3.2.4. Remaining Useful Life

The cost of compliance does not contain any capital cost. Therefore, the remaining useful life of the Puna boiler is not needed to annualize the capital cost. However, Hawaiian Electric intends to retire the Puna boiler after securing replacement with renewable sources as RPS plans are carried out to achieve the goal of 100% which is necessary to meet Hawai'i's statutory requirement to discontinue the use of fossil fuels for electric generation by 2045. This retirement may significantly shorten the estimated time the control equipment is used, as calculated in the analysis, and would serve to further increase the removal cost per ton for SO₂.

3.3. SULFUR DIOXIDE CONCLUSION

The cost effectiveness of switching to a residual high sulfur fuel oil/distillate blended fuel with a maximum sulfur content of 1.0 percent by weight is \$7,400 per ton SO₂ and would increase fuel cost 600 thousand dollars (\$600,000) annually and 9 million dollars (\$900,000) over fifteen (15) years. The cost effectiveness of switching to a distillate fuel with a maximum sulfur content of 0.4 percent by weight is \$6,900 per ton SO₂ and would increase fuel cost 1 million dollars (\$1,000,000) annually and 15 million dollars (\$15,000,000) over fifteen (15) years. These costs are greater than the BART and reasonable progress thresholds established in the first planning period of \$5,600 per ton and \$5,500 per ton, respectively.¹¹

While there are no fuel changes or add-on controls proposed, it should be mentioned that other long-term emission reduction strategies, such as those included as part of the Hawai'i RPS, may be viable alternatives that would create greater benefits.

¹¹ *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawai'i*, U.S. EPA Region 9, May 14, 2012.

4. NITROGEN OXIDES FOUR-FACTOR ANALYSIS

AECOM’s analysis, *Appendix C: Hawai‘i’s Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that NO_x emissions from Puna do not significantly contribute to regional haze. However, the four-factor analysis is provided in response to DOH’s request. The first step in the analysis is to establish a baseline for emissions. Per DOH’s letter dated September 11, 2019, calendar year 2017 actual emissions are used to define the baseline emissions for the four-factor analysis. Table 4-1 lists the baseline NO_x emissions for Puna.

Table 4-1. Baseline NO_x Emissions

Unit	NO _x Emissions		
	Primary Fuel Emissions Factor (lb/MMBtu) ^A	Adjusted Emission Factor (lb/MMBtu) ^B	(TPY) ^C
Boiler	0.213	0.230	22.7
CT-3	0.131	--	6.8
Total			29.5

^A Calendar year 2017 emission factors from the 2018 Emissions Fee Report.

^B The adjusted emission factor include emissions from the ignition fuels and used oil.

^C Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

CT-3 operates on a very limited basis. Total 2017 NO_x emissions from CT-3 was less than seven (7) tons, and any reductions in NO_x emissions are expected to have a negligible impact on regional haze reasonable progress. Therefore, the four-factor analysis was not conducted for CT-3.

4.1. NITROGEN OXIDES CONTROL OPTIONS

The characterization of emission controls available and applicable to the source is a necessary step before the four-factors can be analyzed. NO_x emissions are produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e., fuel versus combustion air) has led to the use of the terms “thermal NO_x” and “fuel NO_x.” Thermal NO_x emissions are produced when elemental nitrogen in the combustion air is oxidized by high combustion temperatures. Fuel NO_x emissions are created by the oxidation of nitrogen contained in the fuel. NO_x emissions from residual oil can be up to fifty percent fuel NO_x.¹²

The formation of NO_x compounds in utility boilers is sensitive to the method of firing and combustion controls utilized. Nitrogen oxide (NO) is typically the predominant form of NO_x emissions from fossil fuel combustion, with the remaining NO_x being the form of nitrogen dioxide (NO₂). The NO₂/NO_x in-stack ratio for boilers is typically less than ten percent.

Available NO_x control technologies for the boilers are categorized as combustion or post-combustion controls. Combustion controls reduce the peak flame temperature and excess air in the furnace, which minimizes NO_x formation. Post-combustion controls convert NO_x in the flue gas to molecular nitrogen and water. Available NO_x control technologies for the boilers are:

- Combustion Controls

¹² AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.3.

- Flue Gas Recirculation (FGR)
- Overfire Air (OFA)
- Low NO_x Burners (LNB)
- Post-Combustion Controls
 - Selective Catalytic Reduction (SCR)
 - Selective Non-Catalytic Reduction (SNCR)
- Renewable Portfolio Standards (RPS)

The feasibility of these controls is discussed in the following sections.

4.1.1. Combustion Controls

4.1.1.1. Flue Gas Recirculation (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical FGR system, flue gas is collected from the combustion chamber or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the “combustion air” (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures, which in turn reduces thermal NO_x formation. When operated without additional controls, the NO_x control range for tangentially-fired boilers is approximately 0.15-0.20 lb/MMBtu.¹³ This control is a technically feasible option for the Puna boiler.

4.1.1.2. Overfire Air (OFA)

OFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_x by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_x is most likely to be formed. OFA as a single NO_x control technique results in estimated NO_x emissions for tangentially-fired boilers of approximately 0.20-0.30 lb/MMBtu.¹⁴ This control is a technically feasible option for the Puna boiler.

4.1.1.3. Low NO_x Burners (LNB)

LNB technology utilizes advanced burner design to reduce NO_x formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. In the primary zone, NO_x formation is limited by either one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_x formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_x formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_x formation.

The estimated NO_x control range for LNBs for tangentially-fired boilers is approximately 0.15-0.20 lb/MMBtu.¹⁵ When combined with OFA, the estimated NO_x control range for tangentially-fired boilers is approximately 0.15-0.20 lb/MMBtu.¹⁶ LNB systems are technically feasible for the Puna boiler.

¹³ “Alternative Control Techniques (ACT) Document – NO_x Emissions from Utility Boiler” EPA, 1994.

¹⁴ Ibid.

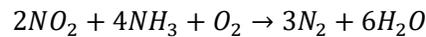
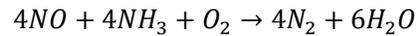
¹⁵ Ibid.

¹⁶ Ibid.

4.1.2. Post-Combustion Controls

4.1.2.1. Selective Catalytic Reduction (SCR)

SCR refers to the process in which NO_x is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because the ammonia preferentially reacts with NO_x rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions are:



The SCR process requires a reactor, catalyst, ammonia storage, and an ammonia injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_x concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. The estimated NO_x control range for SCR is approximately 0.03-0.10 lb/MMBtu for tangentially-fired boilers.¹⁷ This control is a technically feasible option for the Puna boiler.

4.1.2.2. Selective Non-Catalytic Reduction (SNCR)

In SNCR systems, a reagent (ammonia or urea) is injected into the flue gas in the furnace within an appropriate temperature window. The NO_x and reagent react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia- and urea-based SNCR processes require three or four times as much reagent as SCR systems to achieve similar NO_x reductions. The estimated NO_x control range for SNCR for tangentially-fired boilers is approximately 0.20-0.25 lb/MMBtu.¹⁸ This control is a technically feasible option for the Puna boiler.

4.1.3. Rank of Technically Feasible NO_x Control Options by Effectiveness

The next step is to rank the technically feasible options according to effectiveness. Table 4-2 provides a ranking of the control levels for the controls listed in the previous section.

Table 4-2. Control Effectiveness of Technically Feasible NO_x Control Technologies

Control Technology	Estimated Controlled Level
	(lb/MMBtu)
SCR	0.03 - 0.10
LNB & OFA	0.15 - 0.20
FGR	0.15 - 0.20
LNB	0.15 - 0.20
SNCR	0.20 - 0.25
OFA	0.20 - 0.30

The control levels in Table 4-2 are presented as a range. This is due to the specific level of control that is achievable for the Puna boiler based on the application of the controls listed in Table 4-2 is unknown. It is believed that combustion controls such as LNB and possibly LNB in combination with OFA or FGR can achieve a NO_x emissions level of approximately 0.15 lb/MMBtu for the Puna boiler. As noted in Table

¹⁷ Ibid.

¹⁸ Ibid.

4-1, the Puna boiler is currently emitting 0.23 lb/MMBtu. Further, it is believed that SCR can achieve a NO_x emissions level of approximately 0.10 lb/MMBtu.

4.1.4. Renewable Portfolio Standards

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that NO_x emissions from Puna do not significantly contribute to regional haze. The low impact that Puna may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (HRS §269-92) and consistent with the HCEI. Both past and projected future decreases in fossil-fueled EGU usage are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the RHR. The RPS will substantially reduce emissions of haze precursors (especially SO₂) by 2045. Therefore, further requirements for controls would not affect the showing of further progress under the RHR and, thus, are not needed at this time. This is further discussed in Appendix C to this report. Although RPS is listed as a control measure (which is consistent with the Hawaii Progress Report for Phase 1) it was not necessary to review the RPS in the context of the four-factor analysis as these measures are already planned for implementation and although there are additional costs, they are inherent in the RPS program.

4.2. FOUR-FACTOR ANALYSIS

As discussed above, LNB and SCR are the best feasible option to reduce NO_x emissions. For the second planning period, the focus is on determining reasonable progress through analyses of the four factors identified in Section 169A(g)(1) of the CAA:

1. The cost of compliance;
2. The time necessary to achieve compliance;
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements.

The four factors for adding LNB and SCR are discussed in the following sections.

4.2.1. Cost of Compliance

For purposes of this four-factor analysis, the capital costs, operating costs, and cost effectiveness of LNB with OFA and SCR have been estimated. The cost effectiveness of LNB with OFA is based on a controlled NO_x emissions level of 0.15 lb/MMBtu. At this time, it is unknown if LNBs alone can achieve this level of emissions or if LNB combined with OFA or FGR would be required to meet this level. Therefore, the costing is based on LNB with OFA, it is assumed that a NO_x emissions level of 0.15 lb/MMBtu can be achieved with LNB with OFA. As the level of NO_x emissions is comparable to SNCR combustion controls, the only add-on control that would be expected to result in lower achievable NO_x emissions rates than combustion controls is SCR.

The cost effectiveness of SCR is based on a controlled NO_x emissions level of 0.10 lb/MMBtu. The SCR costing is based on generic EPA control costing¹⁹ which does not consider Hawai'i's remote location which results in additional shipping and higher construction cost. To account for these higher costs, a Hawai'i Island construction cost multiplier²⁰ of 1.840 was applied to the capital SCR cost.

¹⁹ Assessment of Non-EGU NO_x 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.

²⁰ The Maui construction cost multiplier is based on cost of construction geographical multipliers from the *RSMMeans 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.

Table 4-3 presents a summary of the cost effectiveness of adding LNB and SCR. The cost effectiveness is determined by dividing the annual cost by the annual reduction in NO_x emissions. The cost effectiveness of LNB with OFA equals \$17,377 per ton of NO_x and the total cost equals 100 thousand dollars (\$100,000) annually and 1.5 million dollars (\$1,500,000) over fifteen (15) years. The cost effectiveness of SCR equals \$79,415 per ton of NO_x and the total cost equals 1 million dollars (\$1,000,000) annually and 15 million dollars (\$15,000,000) over fifteen (15) years.

The cost of compliance assumes that the capital costs will be amortized over fifteen (15) years. However, Hawaiian Electric intends to retire the Puna boiler after securing replacement with renewable sources as RPS plans are carried out to achieve the goal of 100% renewables which is necessary to meet Hawai'i's statutory requirement to use no fossil fuel for electric generation by 2045. This means that the amortization period may be less than fifteen (15) years, and the cost of controls will be higher.

4.2.2. Time Necessary to Achieve Compliance

If the DOH determines that controls are needed to achieve reasonable progress goals, it is anticipated that this change could be implemented in three to five years.

4.2.3. Energy and Non-Air Quality Environmental Impacts

SCR systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist.

SCR can potentially cause significant environmental impacts related to the storage of ammonia, and the storage of aqueous ammonia above 10,000 pounds is regulated by the risk management program (RMP) because the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. SCR will likely also cause the release of unreacted ammonia to the atmosphere. This is referred to as ammonia slip. Ammonia slip from SCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_x, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution, which also leads to an excess of unreacted ammonia. Ammonia released from SCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate and ammonium nitrate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

4.2.4. Remaining Useful Life

The remaining useful life of the Puna boiler does not impact the annualized capital costs of potential controls because the useful life of the Puna boiler is assumed to be as long as the capital cost recovery period, which is fifteen (15) years, for this four-factor analysis. However, Hawaiian Electric intends to retire the Puna boiler after securing replacement with renewable sources as RPS plans are carried out to achieve the goal of 100% renewables which is necessary to meet Hawai'i's statutory requirement to discontinue the use of fossil fuels for electricity generation by 2045. This retirement may significantly shorten the estimated time the control equipment is used as calculated in the analysis and would serve to further increase the removal cost per ton for NO_x.

Table 4-3. NO_x Cost Effectiveness of LNB with OFA and SCR

Unit	Control Option	2017 NO_x Emissions (tpy)	Controlled Emission Level^A (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled NO_x Emissions (tpy)	NO_x Reduced (ton/yr)	Total Annual Cost^B (\$/yr)	Cost Effectiveness (\$/ton)
Boiler	LNB+OFA	22.7	0.15	196,969	14.8	7.9	137,754	17,377
	SCR	22.7	0.10	196,969	9.8	12.9	1,020,609	79,415

^A Controlled emission levels based on “Alternative Control Techniques (ACT) Document – NO_x Emissions from Utility Boiler” EPA, 1994.

^B See Appendix A for total annual cost calculations.

4.3. NITROGEN OXIDES CONCLUSION

The cost effectiveness of LNB with OFA is \$17,400 per ton of NO_x and the total cost equals 100 thousand dollars (\$100,000) annually and 1.5 million dollars (\$1,500,000) over fifteen (15) years. This cost is similar to the BART analyses conducted for the first planning period. For the first planning period, EPA concluded the emission reductions provided by LNB are unlikely to provide a measurable visibility benefit at Hawai'i Volcanoes National Park or Haleakalā National Park.²³

The cost effectiveness of SCR is \$79,400 per ton of NO_x and the total cost equals 1 million dollars (\$1,000,000) annually and 15 million dollars (\$15,000,000) over fifteen (15) years for the Puna boiler. This cost is similar to the BART analyses conducted for the first planning period. For the first planning period, EPA concluded that SCR was not cost effective.²⁴

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Additionally, reductions in NO_x emissions are expected to have a negligible impact on regional haze. Therefore, Hawaiian Electric does not propose any NO_x emissions reductions in addition to its RPS program to meet the RHR requirements.

²³ *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawai'i*, U.S. EPA Region 9, May 14, 2012.

²⁴ *Ibid.*

5. PARTICULATE MATTER FOUR-FACTOR ANALYSIS

AECOM’s analysis, *Appendix C: Hawai‘i’s Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that PM₁₀ emissions from Puna do not significantly contribute to regional haze. However, the four-factor analysis is provided in response to DOH’s request. The first step in the analysis is to establish a baseline for emissions. Per DOH’s letter dated September 11, 2019, calendar year 2017 actual emissions are used to define the baseline emissions for the four-factor analysis. Table 5-1 lists the baseline PM₁₀ emissions for Puna.

Table 5-1. Baseline PM₁₀ Emissions

Unit	PM ₁₀ Emissions		(TPY) ^C
	Primary Fuel Emissions Factor (lb/MMBtu) ^A	Adjusted Emission Factor (lb/MMBtu) ^B	
Boiler	0.0983	0.100	9.8
CT-3	0.0201	--	1.05
Total			10.8

^A Calendar year 2017 emission factors from the 2018 Emissions Fee Report.

^B The adjusted emission factor include emissions from the ignition fuels and used oil.

^C Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

5.1. PARTICULATE MATTER CONTROL OPTIONS

PM₁₀ emissions depend predominantly on the grade of fuel fired. Combustion of lighter distillate oils results in lower PM₁₀ emissions than heavier residual oils. Distillate oils have lower ash and sulfur content than residual oil, therefore, producing less PM₁₀ emissions.

Available PM₁₀ control technologies for the Puna boiler are:

- Post-Combustion Controls
 - Dry or Wet Electrostatic Precipitator (ESP)
 - Fabric Filters
 - Wet Scrubber
 - Cyclone
- Fuel Switching
- Renewable Portfolio Standards (RPS)

The feasibility of these controls is discussed in the following sections.

CT-3 operates on a very limited basis, and post-combustion PM₁₀ controls are not feasible for combustion turbines. Fuel switching from diesel to ULSD is not expected to significantly reduce PM₁₀ emissions. Due to the limited operations of CT-3, 2017 PM₁₀ emissions were less than two (2) tons. Any reduction in PM₁₀ emissions from CT-3 is expected to have a negligible impact on regional haze. Therefore, the four-factor analysis was not conducted for CT-3.

5.1.1. Post-Combustion Controls

PM₁₀ emissions from residual oil-fired boilers tend to be sticky and small. Because of these properties and a general lack of existence in practice, dry ESP, cyclones, and fabric filters are not good technological matches for the Puna boiler.

A wet ESP operates very similarly to a dry ESP but is a better technological match for oil-fired boilers because it is not sensitive to small and sticky particulates. The wet ESP utilizes water to collect and remove the particles and produces a waste-water product. Flue gas leaving the wet ESP will be saturated and may result in a visual steam plume. The estimated PM₁₀ control efficiency is up to ninety percent for a wet ESP.²⁵ Wet ESP is a technically feasible option for control of PM₁₀ for the Puna boiler.

In wet scrubbers PM₁₀ is removed from flue gas when the gas stream is brought into contact with a scrubbing liquid using several approaches: spraying the gas stream with the liquid, forcing the gas stream through a pool of liquid, or by some other contact method. The PM₁₀ in the gas stream is captured in the scrubbing liquid. The PM₁₀-laden scrubbing liquid is separated from the gas stream, and the resultant scrubbing liquid is treated prior to discharge or reuse in the plant. Problems associated with scrubbers include corrosion issues, high power requirements, and water-disposal challenges. However, the use of wet scrubbers for the Puna boiler is considered a technically feasible option. The estimated PM₁₀ removal efficiency for a wet scrubber is fifty-sixty percent.²⁶

5.1.2. Fuel Switching

Residual oil has inherent ash that contributes to the emissions of filterable PM₁₀. Distillate fuels have less ash and ultimately lower filterable PM₁₀ emissions. Filterable PM₁₀ emissions could be reduced by switching to distillate fuel. Section 1 discussed the option of fuel switching with respect to reducing SO₂ emissions. As discussed in Section 1, Hawai'i Electric Light has limited fuel options. Switching to a distillate fuel will result in the PM₁₀ emissions reductions and is technically feasible.

5.1.3. Renewable Portfolio Standards

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that PM₁₀ emissions from Puna do not significantly contribute to regional haze. The low impact that Puna may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (HRS §269-92) and consistent with the HCEI. Both past and projected future decreases in fossil-fueled EGU usage are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the RHR. The RPS will substantially reduce emissions of haze precursors (especially SO₂) by 2045. Therefore, further requirements for controls would not affect the showing of further progress under the RHR and, thus, are not needed at this time. This is further discussed in Appendix C to this report. Although RPS is listed as a control measure (which is consistent with the Hawaii Progress Report for Phase 1) it was not necessary to review the RPS in the context of the four-factor analysis as these measures are already planned for implementation and although there are additional costs, they are inherent in the RPS program.

5.2. FOUR-FACTOR ANALYSIS

As discussed above, wet ESP, wet scrubber, and switching to distillate fuel are the best feasible options to reduce PM₁₀ emissions. For the second planning period, the focus is on determining reasonable progress through analyses of the four factors identified in Section 169A(g)(1) of the CAA:

1. The cost of compliance;

²⁵ AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1.

²⁶ Ibid.

2. The time necessary to achieve compliance;
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements.

The four factors for adding wet ESP, wet scrubber, and switching to distillate fuel are discussed in the following sections.

5.2.1. Cost of Compliance

For purposes of this four-factor analysis, the capital costs, operating costs, and cost effectiveness of wet ESP, wet scrubber, and switching to distillate fuel have been estimated. The cost effectiveness calculation is based on the following reduction in PM₁₀ emissions:

- Wet Scrubber – fifty percent,
- Switching to distillate fuel – sixty-seven percent to eighty-two percent, and
- Wet ESP – ninety percent.

Table 5-2 presents a summary of the cost effectiveness of wet scrubbers, switching to distillate fuel, and wet ESP. The cost effectiveness are:

- Wet Scrubber - \$39,200 per ton and the total cost equals 200 thousand dollars (\$200,000) annually and 3 million dollars (\$3,000,000) over fifteen (15) years,
- Switching to distillate fuel – \$121,700 per ton and the total cost equals 1 million dollars (\$1,000,000) annually and 15 million dollars (\$15,000,000) over fifteen (15) years, and
- Wet ESP - \$611,200 per ton and the total cost equals 5.4 million dollars (\$5,400,000) annually and 81 million dollars (\$81,000,000) over fifteen (15) years.

5.2.2. Time Necessary to Achieve Compliance

If the DOH determines that a wet scrubber or wet ESP is needed to achieve reasonable progress goals, it is anticipated that this change could be implemented in three to five years. If the DOH determines that switching a distillate fuel is needed to achieve reasonable progress, it is anticipated that this change could be implemented within two to three years.

5.2.3. Energy and Non-Air Quality Environmental Impacts

ESPs, by design, apply energy to the particles they are collecting. This energy usage can be significant, especially if the wet ESP is designed to control submicron size particles where more energy is applied to collect more of the particles. Wet scrubbers require a substantial amount of energy to force exhaust gases through the scrubber.

Both wet ESPs and wet scrubbers generate wastewater streams that must either be treated on-site or sent to a wastewater treatment plant. Further, the wastewater treatment process will generate a filter cake that would likely require landfilling.

Table 5-2. PM₁₀ Cost Effectiveness of Wet ESP, Wet Scrubber and Switching to Distillate Fuel

Unit	Control Option	2017 PM₁₀ Emissions (tpy)	Level of Control^A (%)	Controlled PM₁₀ Emissions (tpy)	PM₁₀ Reduced (ton/yr)	Total Annual Cost^B (\$/yr)	Cost Effectiveness (\$/ton)
	Wet Scrubber	9.8	50	4.9	4.9	191,948	39,173
Boiler	Distillate Fuel	9.8	83	1.6	8.2	995,427	121,660
	Wet ESP	9.8	90	1.0	8.8	5,390,449	611,162

^A Wet scrubber and wet ESP controlled emission levels based on AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1. The controlled emissions level for switching to a distillate fuel is based on the ratio of PM₁₀ emissions from distillate combustion from AP-42, Tables 1.3-2 and 1.3-6 and the baseline emission factor.

^B See Appendix A for total annual cost calculations for wet scrubber and wet ESP. The annual cost of switching to a distillate fuel is based on the incremental fuel cost from Table 3-3.

5.2.4. Remaining Useful Life

The remaining useful life of the Puna boiler does not impact the annualized capital costs of potential controls because the useful life of the Puna boiler is assumed to be as long as the capital cost recovery period, which is fifteen (15) years, for this four-factor analysis. However, Hawaiian Electric intends to retire the Puna boiler after securing replacement with renewable sources as RPS plans are carried out to achieve the goal of 100% renewables which is necessary to meet Hawai'i's statutory requirement to discontinue the use of fossil fuels for electric generation by 2045. This retirement may significantly shorten the estimated time the control equipment is used as calculated in the analysis and would serve to further increase the removal cost per ton for PM₁₀.

5.3. PARTICULATE MATTER CONCLUSION

The cost effectiveness of all the PM₁₀ controls evaluated for all the Puna boiler is more than \$39,200 per ton, and for most controls is more than \$121,700 per ton. The total cost of PM₁₀ controls ranges from 200 thousand dollars (\$200,000) annually and 3 million dollars (\$3,000,000) over fifteen (15) years to 5.4 million dollars (\$5,400,000) annually and 81 million dollars (\$81,000,000) over fifteen (15) years. These costs are similar to the BART analyses conducted for the first planning period. For the first planning period, the EPA concluded that PM₁₀ controls were not cost effective.²⁷

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Therefore, Hawaiian Electric does not propose any PM₁₀ emissions reductions in addition to its RPS program to meet the RHR requirements.

²⁷ Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawai'i, U.S. EPA Region 9, May 14, 2012.

APPENDIX A: DETAILED COSTING

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Appendix Table A-1. LNB with OFA Capital and O&M Cost Estimate

Parameters/Costs	Equation	Boiler
Boiler design capacity, mmBtu/hr (C)		249
Boiler Type		Tangential
2017 Annual Heat Input, MMBtu/yr (H)		196,969
Unit Size, kW (kW)		15,500
Unit Size, MW (MW)		15.5
Capital recovery factor a. Equipment CRF, 15-yr life, 7% interest	$= [I \times (1+i)^a] / [(1+i)^a - 1]$, where I = interest rate, a = equipment life	0.11
Cost Index (CI) ^A a. 2018 b. 2004	603.1 444.2	
Total Capital Investment ^{B,C} TCI (\$)	$= \$18/\text{kW} \times \text{kW} \times (300/\text{MW})^{0.359} \times (\text{CI}_{2018}/\text{CI}_{2004}) - \text{Tangential}$	\$1,097,419
Direct Annual Operating Costs \$/yr Variable O&M Costs ^D	$= \$0.03 \text{ mills}/\text{kW-hr}/1000 \times (1 \text{ kW-hr}/10,000 \text{ Btu}) \times H \times 10^6$ $\text{Btu}/\text{mmBtu} \times (\text{CI}_{2018}/\text{CI}_{2004}) - \text{Tangential}$	\$802
Indirect Annual Costs, \$/yr 1. Fixed O&M Costs ^E 2. Capital recovery	$= \$0.27/\text{kW} \times \text{Nameplate capacity (MW)} \times (1000 \text{ kW}/\text{MW}) \times$ $(300/\text{MW})^{0.359} \times (\text{CI}_{2018}/\text{CI}_{2004}) - \text{Tangential}$ $= \text{Equipment CRF} \times \text{TCI}$	\$16,461 \$120,491
Total Annual Cost \$/yr	$= \text{Direct Annual Costs} + \text{Indirect Annual Costs}$	\$137,754

Source: All costs were estimated using Section 4.3 and Appendix D of the WARP 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.

^A Cost Index: Chemical Engineering Plant Cost Index (CEPCI). Chemical Engineering Journal.

^B TCI for LNB and LNB w/over fire air for tangential boilers ranges from \$6/kW to \$24/kW, the high end of the range was used due to Hawaii's remote location.

^C Scaling factor = $(300/\text{Nameplate capacity})^{0.359}$

^D The variable O&M costs for LNB and LNB w/over fire air for tangential 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.

^E The fixed O&M costs for LNB and LNB w/over fire air for tangential boilers ranges from \$0.09/kW to \$0.36/kW, the high end of the range was used due to Hawaii's remote location.

Appendix Table A-2. Boiler SCR Capital and O&M Cost Estimate

			Boiler
MW			15.5
Baseline NOx Emission Rate (lb/MMBtu)			0.23
2017 Annual Heat Input, MMBtu/yr			196,969
Max Heat Input (MMBtu/hr)			249
Capital Recovery Factor (CRF)			0.11
Cost Index ^A			
	2018	603.1	
	1999	390.6	
B =	(lb/MMBtu)		0.23
C =	(%)		90
A =	(kW)		15,500
Z (Eq. 1) =			0.87
Capital Cost (Eq. 2)	(\$/kW)		\$202
Capital Cost (2018)	(\$)		\$4,828,200
Hawai'i Island Construction Cost Multiplier ^B			1.840
Hawai'i Island Capital Cost (2018)			\$8,883,888
Annualized Capital Cost	(\$/yr)		\$975,403
G =			0.09
H =	(MMBtu/hr)		249
D =	(\$/kW)		\$311
Fixed O&M ^C (Eq. 3)	(\$/yr)		\$31,866
Variable O&M Cost (Eq. 4)	(\$/yr)		\$13,340
Total Annual Cost	(\$/yr)		\$1,020,609

$$Z = \left[\frac{B}{1.5} \right]^{0.05} \left(\frac{C}{100} \right)^{0.4} \quad \text{Equation 1}$$

$$D = 75 \left\{ 300,000 \frac{Z}{A} \right\}^{0.35} \quad \text{Equation 2}$$

Where:

D = Capital cost (\$/kW)
 B = NO_x (lb/10⁶ Btu) at the inlet of the SCR reactor
 C = NO_x removal efficiency (%)
 A = Plant capacity (kW)

$$E = D \times A \times C \quad \text{Equation 3}$$

Where:

E = Fixed O&M cost (\$/yr)
 D = Capital cost (\$/kW) from Equation 1
 A = Plant capacity (kW)
 C = A constant, 0.0066 yr⁻¹

$$F = G \left\{ 225 \times \left[0.37B \times H \times \left(\frac{C}{100} \right) \times \left(\frac{8760}{2000} \right) \right] \times 1.005 \times 1.05 + 0.025 \times D \times A \times Z + 1.45 \times A \right\} \quad \text{Equation 4}$$

Where:

F = Variable O&M Cost (\$/yr)
 G = Annual capacity factor (expressed as a fraction)
 B = Inlet NO_x (lb/MMBtu); range of 0.15 - 2.5 lb/MMBtu
 H = Heat input (MMBtu/hr)
 C = NO_x removal efficiency; range of 80-95%
 D = Capital cost (\$/kW)
 A = Plant capacity (kW)

$$\text{Capital Recovery Factor (CRF)} = \frac{I \times (1+i)^a}{[(1+i)^a - 1]} \quad \text{CRF} = 0.11$$

Where:

I = Interest Rate (7% interest)
 a = Equipment life (15 yrs)

Source: *Cost of Selective Catalytic Reduction (SCR) Application for NO_x 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.

^A Cost Index: Chemical Engineering Plant Cost Index (CEPCI). Chemical Engineering Journal.

^B The Hawai'i Island construction cost multiplier is based on cost of construction geographical multipliers from the *RSMeans 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.

^C Fixed Costs include elements such as labor, station power, capital additions/improvements

Appendix Table A-3. Scrubber Capital and O&M Cost Estimate

Parameters/Costs	Equation/Reference	Boiler
Exhaust Temperature (K)	T_{stack}	422.0
Exhaust Temperature (F)	Converted from degrees K	299.9
Exhaust Moisture Content (%)	MS - Typical Values	12.00%
Exhaust Flow Rate (m ³ /s) ¹	CSP Application	79.5
Exhaust Flow Rate (ACFM) ¹	Converted from (m ³ /s)	168,429
Exhaust Flow Rate (SCFM)	$ACFM * ((68+460)/(T_{stack}+460))$	117,025
m _{wv} (lb/min)	SCFM * MC * 18/385	657
m _a (lb/min)	SCFM * (1-MC) * 29/385	4,815
humidity ratio	m_{wv}/m_a	0.14
humid volume (ft ³ /min)	h (Estimated from psychrometric chart)	23.00
Q _{SAT}	$h * m_a$	110,738.88
Purchased Equipment Cost (Tables 2.5 and 2.6 for a Stainless Steel Low Energy scrubber, 2002 Dollars)	$1.15 * (150 * Q_{SAT}^{0.56})$	\$115,238
Direct Costs - Table 2.8		
Purchased equipment costs		
Packaged Unit (A1)	As estimated, AA	\$115,238
Auxiliary Costs (A2)	$A2 = 0.1 * A1$	\$11,524
Equipment Costs (A)	$A = A1 + A2$	\$126,762
Instrumentation	0.10 A	\$12,676
Sales taxes	0.03 A	\$3,803
Freight	0.05 A	\$6,338
Purchased Equipment cost, PEC	B = 1.18 A	\$149,579
Direct Installation Costs		
Foundation & supports	0.06 B	\$8,975
Handling & erection	0.40 B	\$59,832
Electrical	0.01 B	\$1,496
Piping	0.05 B	\$7,479
Insulation for ductwork	0.03 B	\$4,487
Painting	0.01 B	\$1,496
Direct Installation Costs, DIC	0.56 B	\$83,764
Total Direct Costs, TDC	PEC + DIC	\$233,344
Indirect Costs (installation) Table 2.8		
Engineering	0.10 B	\$14,958
Construction & field expenses	0.10 B	\$14,958
Contractor fees	0.10 B	\$14,958
Start-up	0.01 B	\$1,496
Performance test	0.01 B	\$1,496
Model study	--	
Contingencies	0.03B	\$4,487
Total Indirect Costs, IC	0.35 B	\$52,353
Cost Index ⁵		
a. 2018	603.1	
b. 2002	395.6	
Capital recovery factor (CRF)	$CRF = [1 \times (1+i)^a] / [(1+i)^a - 1]$, where I = interest rate, a = equipment life	0.11
	a. Equipment CRF, 15-yr life, 7% interest	
Total Capital Investment (2018 Dollars)	(TDC + IC) * (Retrofit factor of 1.4) * (CI₂₀₁₈/CI₁₉₉₉) (Retrofit factor based on average provided for ESP on Page 3-41). No specific factor provided for scrubber, so factor for ESP was relied on.	\$609,770
Annual Costs		
Direct Annual Costs - Section 3.4.1		
Operating Labor		
Operator	3hr/shift*2shifts/day*360 days/yr * \$20/hr	\$43,200
Supervisor	15% of operator	\$6,480
Maintenance		
	Assumed similar labor requirements as to that required for ESP per Section 6, Page 3-47 of OAQPS Cost manual (\$20.00/hr, 7.5 h/wk, 44 wk/yr)	\$6,600
Labor	100% of maintenance labor	\$6,600
Material		\$6,600
Utilities		
	Utilities currently not estimated due to variability	
Total Direct Annual Cost		\$62,880
Annual Indirect Costs, IC		
Administrative charges	2% of Total Capital Investment	\$12,195
Property tax	1% of Total Capital Investment	\$6,098
Insurance	1% of Total Capital Investment	\$6,098
Overhead	60% of total labor and material costs	\$37,728
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	\$66,950
Total Indirect Annual Costs		\$129,068
Total Annual Cost		\$191,948

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 2 - Wet Scrubbers for Particulate Matter, dated July 2002 (EPA/452/B-02-001).

¹ Exhaust parameters from Cover Source Permit Application.

² From Chemical Engineering Plant Cost Index (CEPCI)

DRAFT

Appendix Table A-4. Wet ESP Capital and O&M Cost Estimate

Parameters/Costs	Equation	Boiler
Average High Exhaust Flow Rate (m ³ /s) ¹		79.5
Average High Exhaust Flow Rate (ACFM) ¹		168,429
Annual Operating Time (hrs, θ) ²		8,760
ESP efficiency (from white paper)		90%
ESP Plate Area (ft ²) ⁴	$ESCA = -\ln(p)/w_e \times 5.080 \times Q$	6,274
Purchased Equipment Cost (Table 3.14 for 90% Control Efficiency and 15,000 ACFM bins)	\$25.5/acfm	\$4,294,946
Basic Equipment Costs -Table 3.12	0.45 × Equipment Cost	\$1,932,726
Direct Costs - Table 3.16		
Purchased equipment costs		
ESP + auxiliary equipment (A)	As estimated, A	\$6,227,672
Instrumentation	0.10 A	\$622,767
Sales taxes	0.03 A	\$186,830
Freight	0.05 A	\$311,384
Purchased Equipment cost, PEC	B = 1.18 A	\$7,348,653
Direct Installation Costs		
Foundation & supports	0.04 B	\$293,946
Handling & erection	0.50 B	\$3,674,326
Electrical	0.08 B	\$587,892
Piping	0.01 B	\$73,487
Insulation for ductwork	0.02B	\$146,973
Painting	0.02B	\$146,973
Direct Installation Costs, DIC	0.67 B	\$4,923,597
Total Direct Costs, TDC	PEC + DIC	\$12,272,250
Indirect Costs (installation) Table 3.16		
Engineering	0.20B	\$1,469,731
Construction & field expenses	0.20B	\$1,469,731
Contractor fees	0.10B	\$734,865
Start-up	0.01B	\$73,487
Performance test	0.01B	\$73,487
Model study	0.02B	\$146,973
Contingencies	0.03B	\$220,460
Total Indirect Costs, IC	0.57B	\$4,188,732
Cost Index ⁵		
a. 2018	603.1	
b. 1999	390.6	
Capital recovery factor (CRF)	$CRF = [I \times (1+i)^a] / [(1+i)^a - 1]$, where I = interest rate, a = equipment life a. Equipment CRF, 15-yr life, 7% interest	0.11
Total Capital Investment (2018 Dollars)	(TDC + IC) * (Retrofit factor of 1.4)*(CI₂₀₁₈/CI₁₉₉₉) (Retrofit factor based on average provided for ESP on Page 3-41).	\$35,582,860
Annual Costs		
Direct Annual Costs - Section 3.4.1		
Operating Labor		
Operator	2hr/shift*2shifts/day*365 days/yr * \$20/hr	\$29,200
Supervisor	15% of operator	\$4,380
Maintenance		
Labor	For ESP plate area < 50,000 ft ² = \$4125	\$4,125
Utilities		
	Utilities currently not estimated due to variability	
Total Direct Annual Cost		\$37,705
Annual Indirect Costs, IC		
Administrative charges	2% of Total Capital Investment	\$711,657
Property tax	1% of Total Capital Investment	\$355,829
Insurance	1% of Total Capital Investment	\$355,829
Overhead	60% of total labor and material costs	\$22,623
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	\$3,906,807
Total Indirect Annual Costs		\$5,352,744
TOTAL ANNUAL COST		\$5,390,449

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 3 - Electrostatic Precipitators, dated September 1999 (EPA/452/B-02-001).

¹ Exhaust parameters from Cover Source Permit Application.

² Electricity cost form U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.

³ Water cost from Maui County (<https://www.mauicounty.gov/216/Water-Charges>) lowest general rate.

⁴ For ESP Plate Area (Section 3.2.1):

$p = 1 - (\text{Control Efficiency } \%)$

$5.080 \text{ ft}^2/\text{kacfm} = 1 \text{ (s/m)}$

$w_e =$ effective migration velocity (m/s), assume $w_e = 31.4 \text{ cm/s}$ for Bituminous coal fly ash for a design efficiency of 95% from Table 3.3 (no

listings for 90% efficiency or fuel oil)

$Q =$ system flow rate (kacfm)

⁵ From Chemical Engineering Plant Cost Index (CEPCI)

APPENDIX B: HAWAIIAN ELECTRIC REGIONAL HAZE VISIBILITY CONSIDERATIONS

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Appendix B: Hawaiian Electric Regional Haze Visibility Considerations

Fifth Factor Considerations for SO₂, NO_x, and PM Controls

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March 31, 2020

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Hawaiian Electric¹ Regional Haze Visibility Considerations

Fifth Factor Considerations for SO₂, NO_x and PM Controls

1. Executive Summary

The EPA has issued multiple guidance documents to assist states and facilities address the requirements of the Regional Haze Rule (“RHR”). This guidance allows states to consider, as part of their review of the Four Factor evaluation of possible emission controls for the Second Decadal Review, a “5th factor” which involves consideration of visibility impacts of candidate control options. This appendix introduces several Hawai‘i-specific issues that impact the visibility impact of potential sulfur dioxide (“SO₂”), nitrogen oxides (“NO_x”) and particulate matter (“PM”) control options for Hawaiian Electric sources relative to the two Class I areas in Hawai‘i: the Haleakalā National Park on the island of Maui and the Hawai‘i Volcanoes National Park on Hawai‘i Island. The issues discussed in this report are summarized below:

- 1) Due to unique atmospheric chemistry, NO_x emissions tend to remain in the gaseous (and invisible) phase in warm weather, and only form NO₃ (“nitrate”) particulate aerosol in cold weather. This is verified by monitoring data in the Interagency Monitoring of Protected Visual Environments (“IMPROVE”) network in the two national parks mentioned above.
- 2) The persistent East North East (“ENE”) trade winds experienced by the state of Hawai‘i places emission sources on several islands (or portions of islands such as Maui) downwind of the national parks, limiting the likelihood that any emissions from these sources would even reach the parks. Modeling conducted with the California Puff Model (“CALPUFF”) for the First Decadal Review confirms the minimal potential for haze impact of the subject Hawaiian Electric sources on the islands of Oahu and Maui due to the predominance of the trade winds. The EPA’s Federal Implementation Plan (“FIP”) issued in 2012 agreed with this assessment.
- 3) EPA previously determined that in Hawai‘i haze due to direct PM was a very small component of haze and that further controls would not be effective in improving visibility. The observed haze speciation is reviewed in this report to confirm this determination.
- 4) The State of Hawai‘i Department of Health Clean Air Branch (“DOH”) should request the EPA (consistent with their first decadal review approach) to set aside NO_x and PM from the list of

¹ “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.

DRAFT

haze precursors for Hawai'i due to the unique NO_x haze chemistry and climate, leaving SO₂ as the primary precursor pollutant for haze. Hawaiian Electric requests that the DOH make this proposal to the EPA.

- 5) In the recent past, volcanic activity on Hawai'i Island has produced as much as 2 million tons of SO₂ emissions per year^{2,3} (emissions vary yearly), as well as roughly 125,000 tons of NO_x emissions per year⁴. These volcanic SO₂ emissions are about three orders of magnitude (approximately 1,000 times) greater than anthropogenic SO₂ emissions. Although the IMPROVE monitors indicate that sulfate haze is the most important haze species, it is evident from monthly haze trends and the likelihood of winds from the volcanic activity reaching the IMPROVE monitors that the overwhelming sulfate haze influence comes from natural sources (i.e., volcanic activity).

The locations of the affected Hawaiian Electric sources and the two national parks are shown in Figure B-1. The remainder of this appendix presents details of the above issues and recommendations for how this information should be considered in selection of facilities for Four-Factor analyses and for evaluating potential pollutant control options.

² Information on the volcanic SO₂ emissions in 2014 was provided by the EPA in their SO₂ National Ambient Air Quality Technical Support Document at EPA's 2016 SO₂ NAAQS TSD, at <https://www.epa.gov/sites/production/files/2016-03/documents/hi-epa-tsd-r2.pdf>.

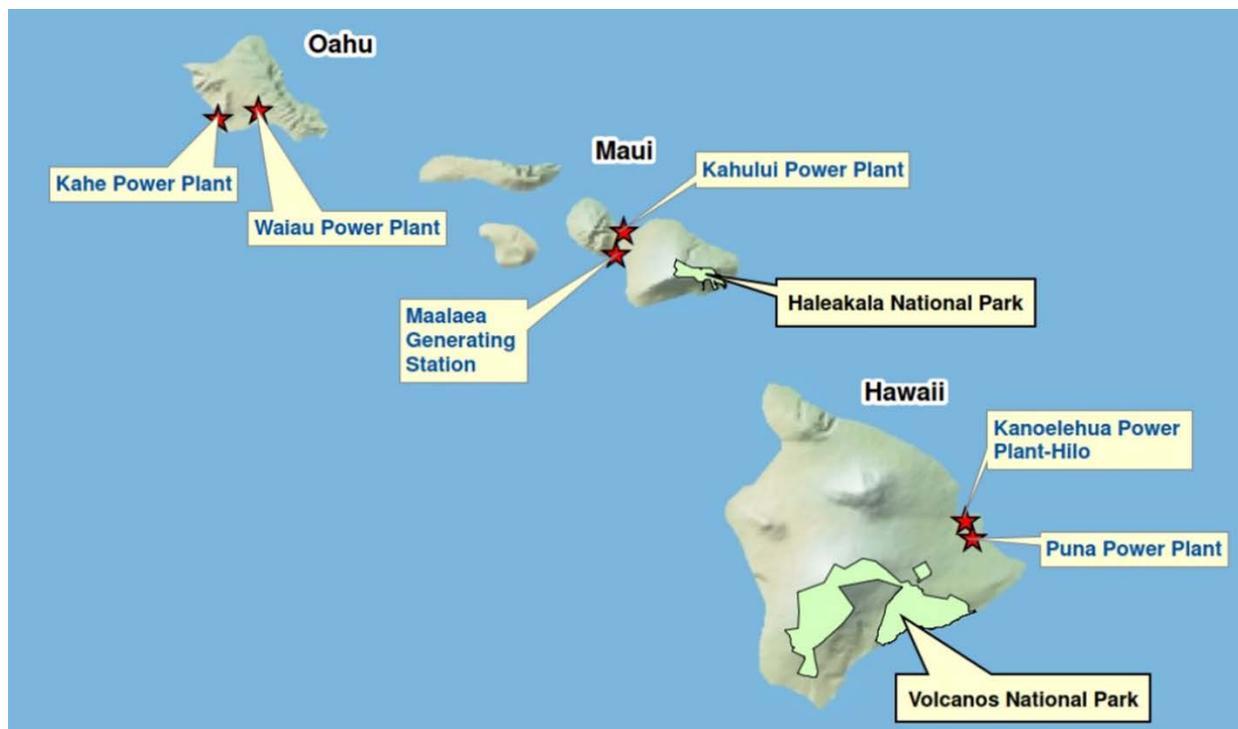
³ Information on 2014–2017 volcanic SO₂ emissions is available in this journal article: Elias T, Kern C, Horton KA, Sutton AJ and Garbeil H. (2018) Measuring SO₂ Emission Rates at Kīlauea Volcano, Hawaii, Using an Array of Upward-Looking UV Spectrometers, 2014–2017. *Front. Earth Sci.* 6:214. doi: 10.3389/feart.2018.00214. <https://www.frontiersin.org/articles/10.3389/feart.2018.00214/full>.

⁴ The 125,000 tons per year of NO_x assumes NO_x emissions rate equals 6% of SO₂ emissions rate. The 6% is derived from worldwide volcanic NO_x emissions estimate of 1.0 Teragram ("Tg" – trillion grams)/year ("yr") nitric oxide ("NO") (or 1.5 Tg/yr NO₂) from <https://www.chemistryworld.com/features/a-volcanic-breath-of-life/3004482.article> and worldwide volcanic SO₂ estimate of 23 Tg/yr from <https://www.nature.com/articles/srep44095>.

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Figure B-1:

Location of Hawaiian Electric Sources Asked to Conduct Four-Factor Analyses and PSD Class I Areas



2. EPA Guidance Regarding Considerations of Visibility Impacts

The EPA issued “Guidance on Regional Haze State Implementation Plans for the Second Implementation Period”⁵ in August 2019. This guidance allows states to consider, as part of its consideration of emission controls to include for the Second Decadal Review a “5th factor” which involves consideration of visibility impacts of candidate control options. A companion document⁶ issued in September 2019 that involves the EPA’s visibility modeling results for 2028 is entitled, “Availability of Modeling Data and Associated Technical Support Document for the EPA’s Updated 2028 Visibility Air Quality Modeling”.

On Page 11 of the August 2019 guidance, the EPA states:

“When selecting sources for analysis of control measures, a state may focus on the PM species that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors.” . . .

⁵ Available at https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

⁶ Available at https://www3.epa.gov/ttn/scram/reports/2028_Regional_Haze_Modeling-Transmittal_Memo.pdf.

DRAFT

“Also, it may be reasonable for a state to not consider measures for control of the remaining pollutants from sources that have been selected on the basis of their emissions of the dominant pollutants”

Further, on Page 36 and 37, the EPA states:

“Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal.” . . .

“. . . EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress.”

Consequently, the extremely low likelihood for impact to Class I visibility impairment from control of certain facility pollutants and the plant locations relative to the Class I areas is appropriate for consideration when evaluating the need for further control of these emissions for Regional Haze Reasonable Progress.

3. Nitrate Haze Composition Analysis

Nitrate haze composition analyses for the Haleakalā and Hawai‘i Volcanoes National Parks are available at the IMPROVE web site at <http://vista.cira.colostate.edu/Improve/pm-and-haze-composition/>. Figure B-2 provides various charts for the haze species composition at the Haleakalā Crater IMPROVE site, and Figure B-3 provides a time series of stacked bars by species for a recent year at that site. Figures B-4 and B-5 provide similar information for the Hawai‘i Volcanoes IMPROVE site. Note that these figures show information for the worst 20 percent (“%”) impaired days, which is the focus of the RHR for reducing haze. The goal for each decadal review is to track the progress of haze reduction for the worst 20% impaired days; reviewing the composition of haze on these days is a key element in understanding what precursor pollutants to control to achieve the goal.

The data for both National Parks shows that the contribution of nitrates to haze is very low as a percentage of the total, but it is also low as an absolute value for extinction (visibility impairment). The total nitrate haze impairment is approximately 1 inverse megameter (“ Mm^{-1} ”), equivalent to approximately 0.25 deciview (“dv”), or less. This is the impairment at these monitors due to ALL sources, natural and anthropogenic, and as noted below, the volcanic emissions are much greater than the entire state’s anthropogenic NO_x emissions for recent years with SO₂ volcanic emissions of roughly 2 million tons per year (“TPY”).

The minimal impact of nitrate haze is clearly illustrated in the Hawai‘i National Park monitoring data and is much smaller than found at many monitors in other Class I areas around the country. This is in large part due to the unique chemistry of nitrate haze, as discussed below.

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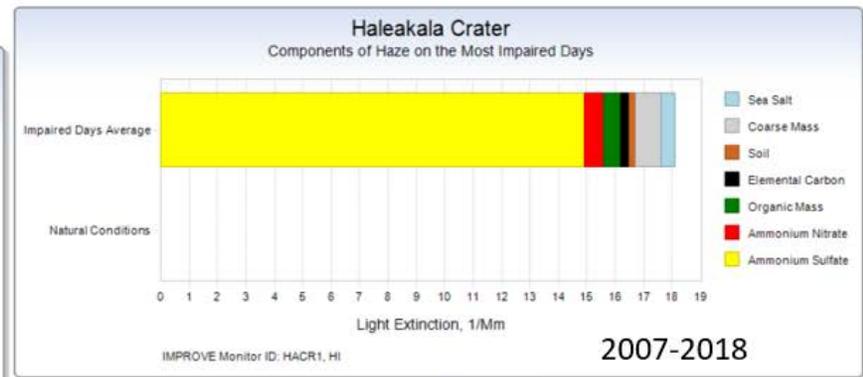
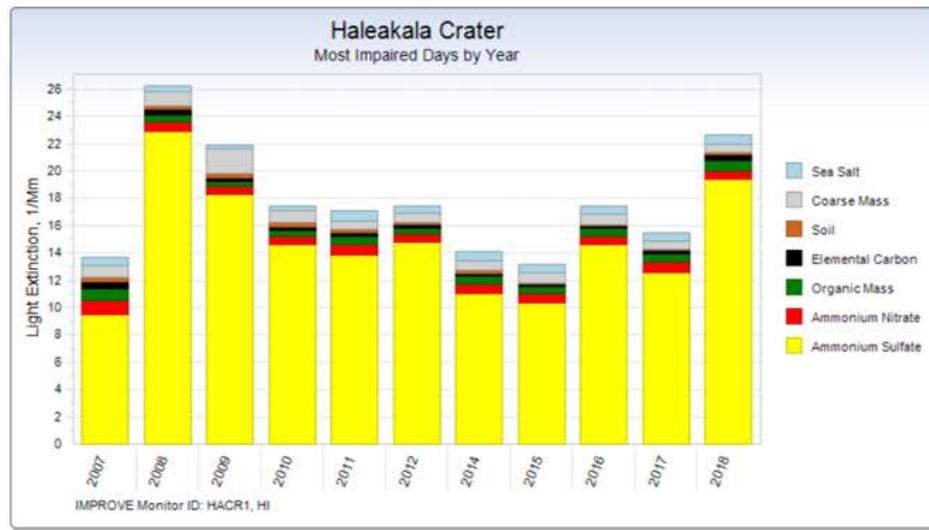
The chemistry of nitrate haze formation is highly dependent upon ambient temperature, and to a lesser extent upon humidity. As discussed in the CALPUFF model formulation⁷ and in CALPUFF courses (see Figure B-8), total nitrate in the atmosphere ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous nitric acid (“ HNO_3 ”) (invisible, and not haze-producing) and nitrate (“ NO_3 ”) haze particles according to the equilibrium relationship between the two species, which is affected by temperature and humidity.

⁷ Documentation for the CALPUFF modeling system is available from links provided at <https://www.epa.gov/scram/air-quality-dispersion-modeling-alternative-models#calpuff>.

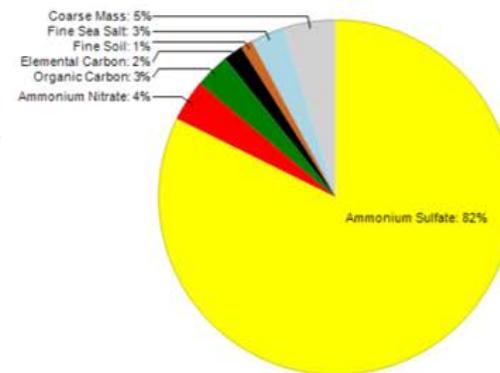
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Figure B-2: Charts Showing the Worst 20% Haze Days Multiple-Year Species Composition for the Haleakalā Crater IMPROVE Site

Light Extinction Summary - Most Impaired Days



Most Impaired Days 2007-2018
Haleakala Crater

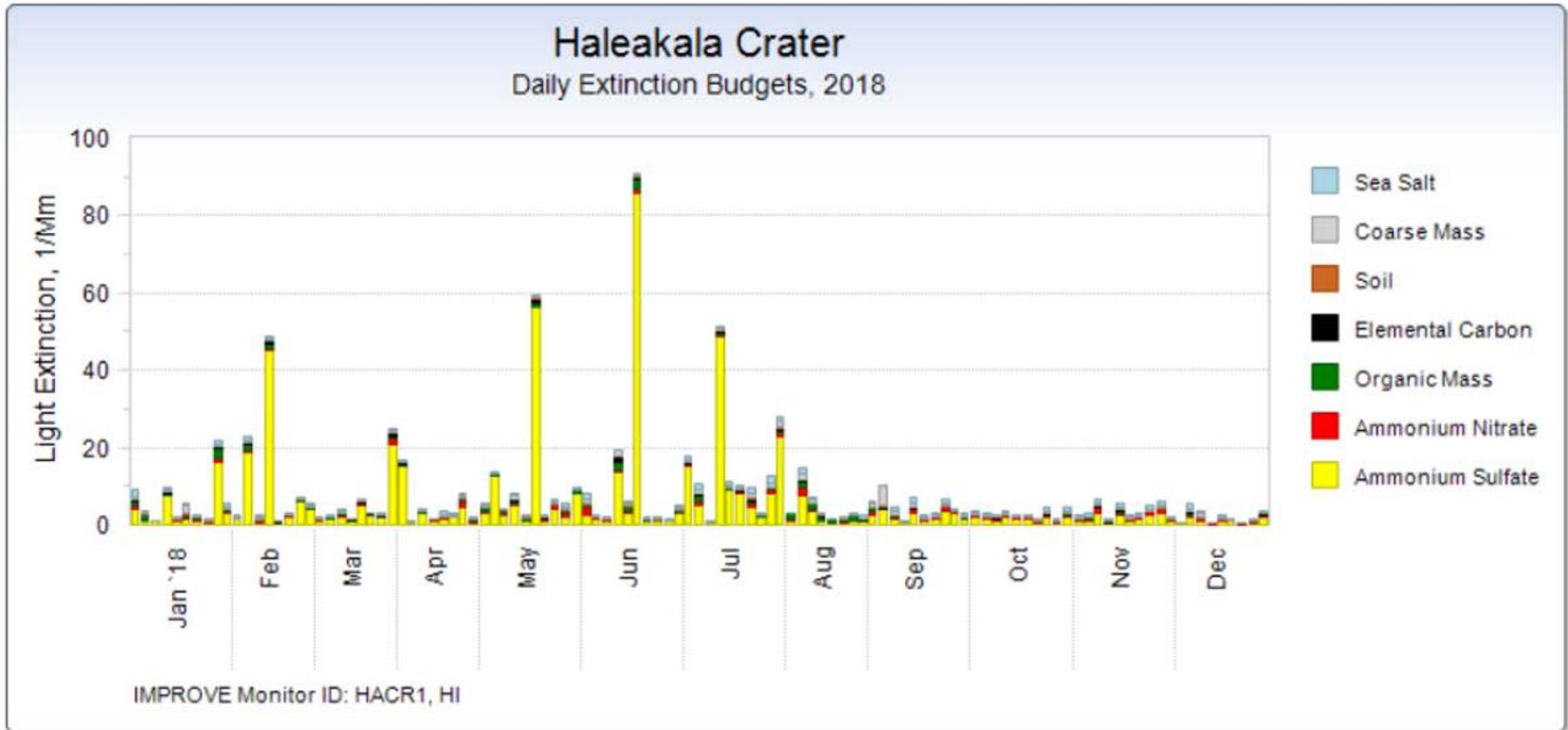


Haleakala Crater IMPROVE monitor

Data source for Figures B-2 through B-5: http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF_VisSum.

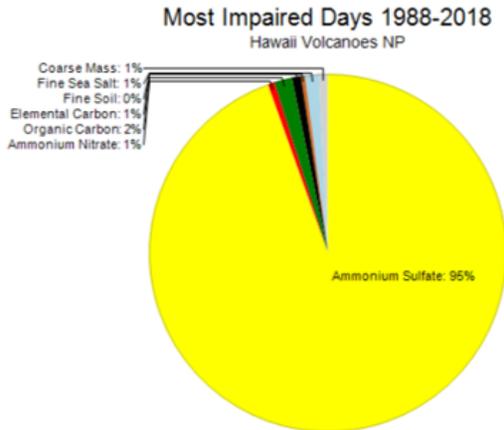
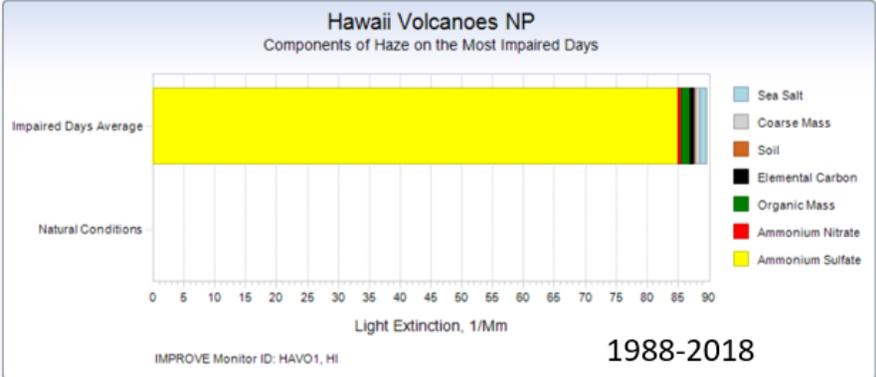
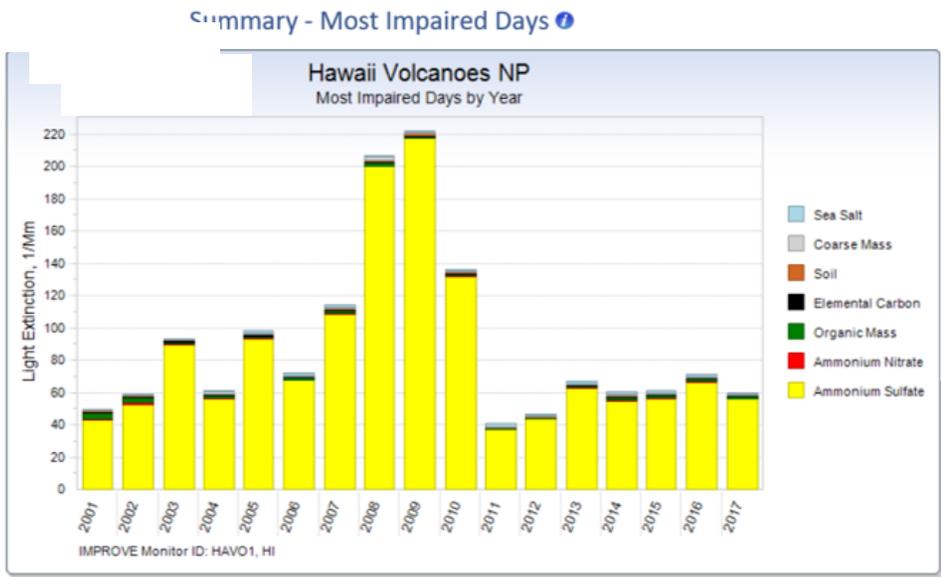
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Figure B-3: Time Series of 2018 Daily Haze Extinction Composition Plots for the Haleakalā Crater IMPROVE Site



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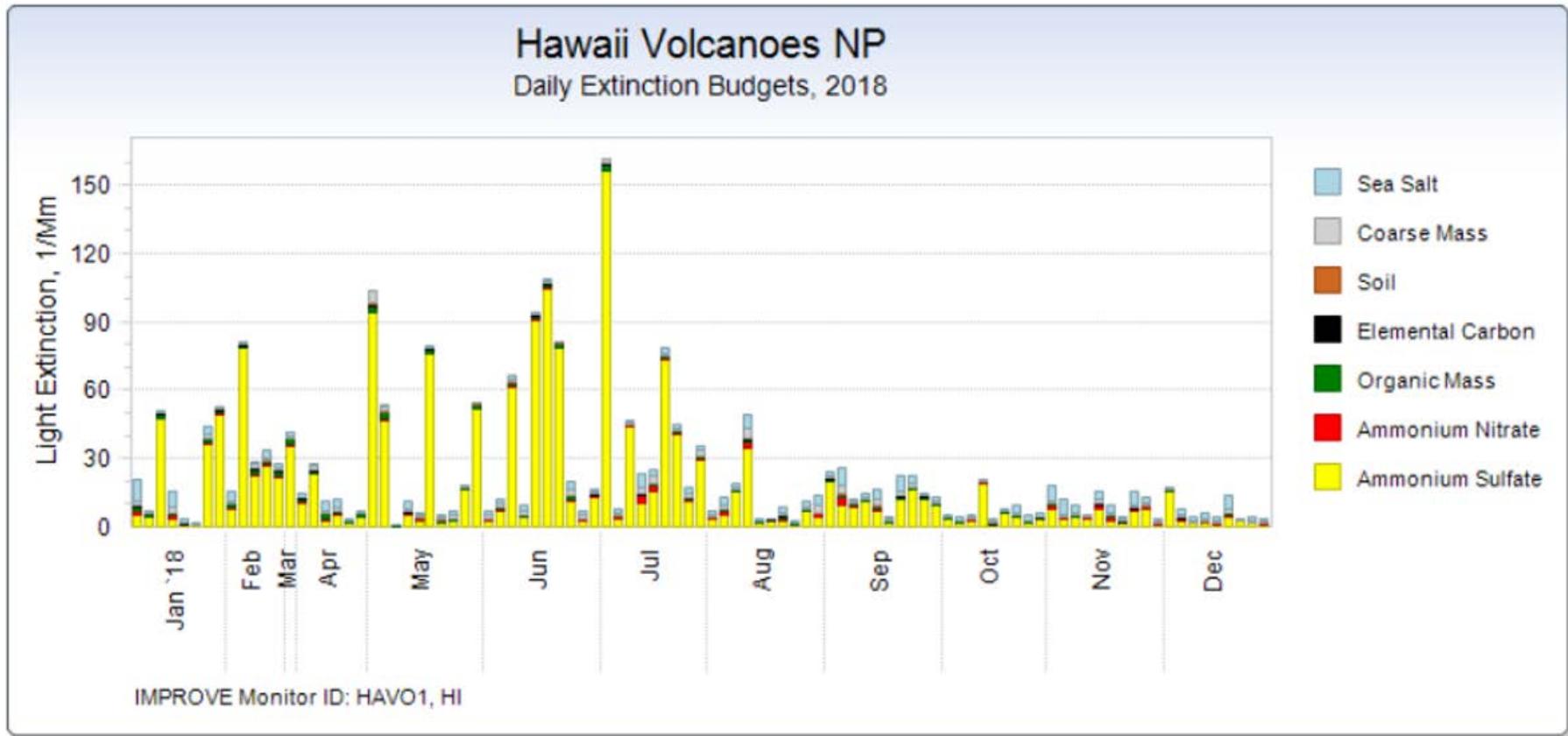
Figure B-4: Charts Showing the Worst 20% Haze Days Multiple-Year Species Composition for the Hawai'i Volcanoes IMPROVE Site



Hawai'i Volcanoes NP IMPROVE monitor

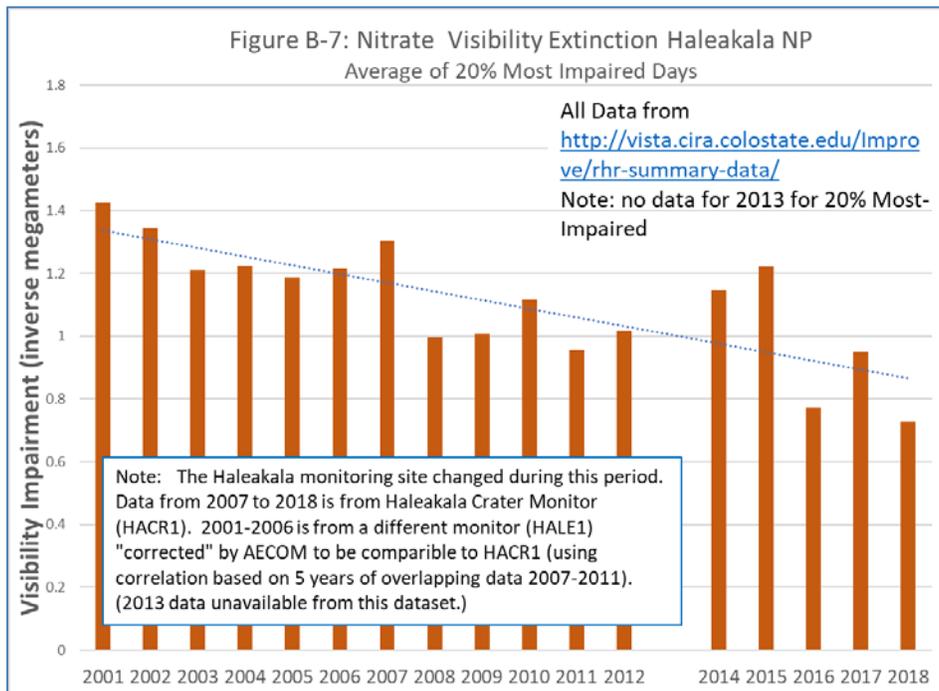
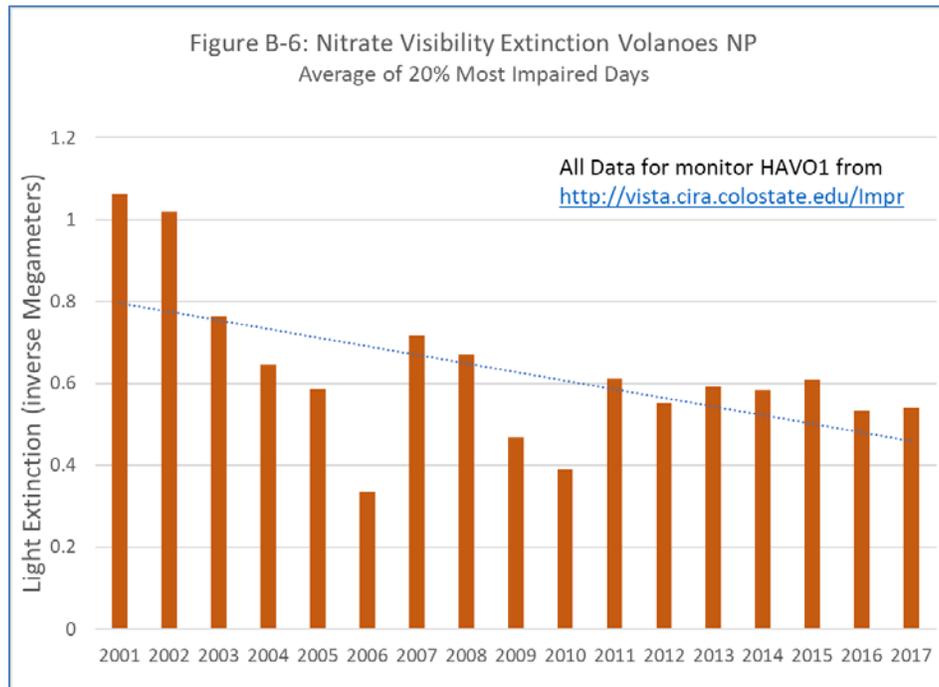
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Figure B-5: Time Series of 2018 Daily Haze Extinction Composition Plots for the Hawai'i Volcanoes IMPROVE Site



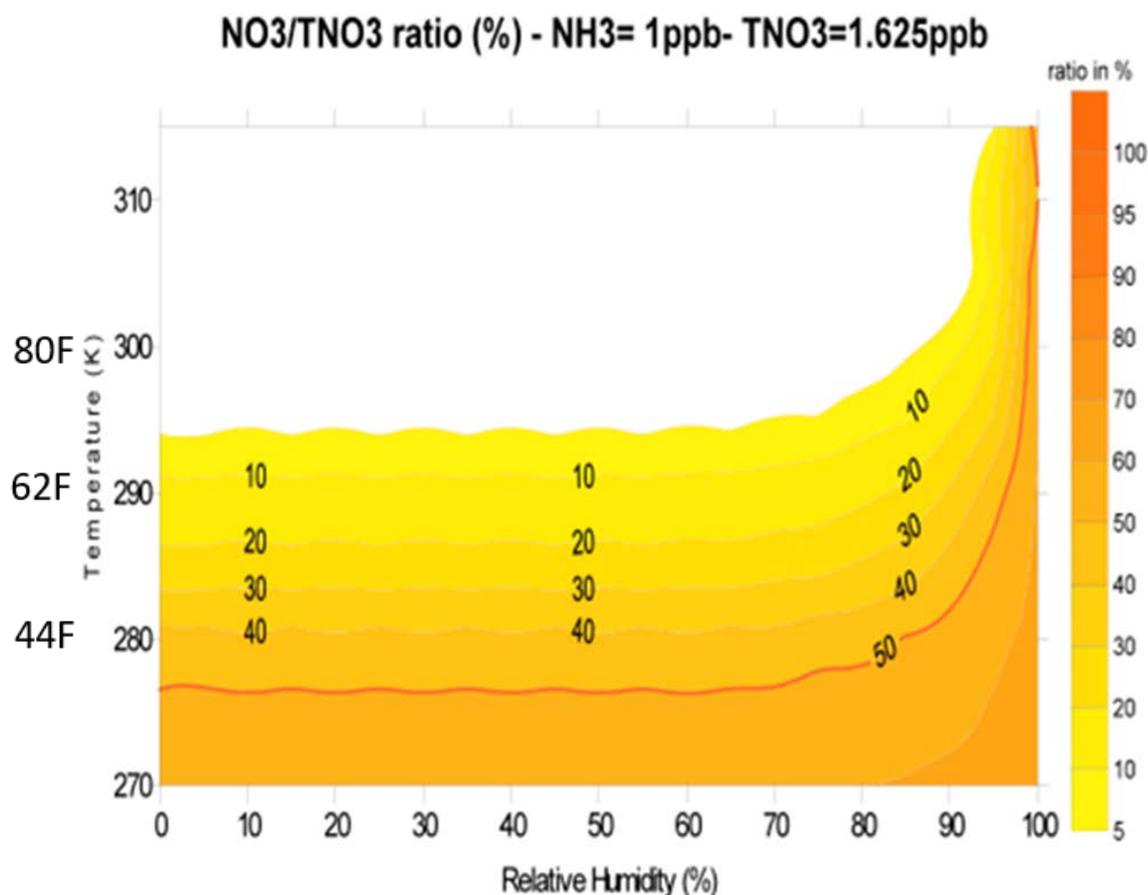
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The nitrate contribution to visibility impairment in the above bar charts is shown as a narrow “red” segment. The small size relative to other constituents clearly shows that nitrate is only a small contributor. Additionally, the Figures B-6 and B-7 below which presents only the ammonium nitrate visibility impairment also shows that nitrates, already small contribution, is trending downward.



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Figure B-8: CALPUFF Example Plot of Aerosol Percentage of Total NO_x Equilibrium



The potential for the formation of haze due to NO_x emissions is very low in Hawai'i because of the warm weather conditions year-round. This strong dependency of the equilibrium relationship between invisible gaseous HNO₃ and visible NO₃ haze particles as a function of ambient temperature is illustrated in Figure B-8. In Figure B-8, it is evident that for most conditions, the percentage of total nitrate in the form of particulate (NO₃) is less than 20% for temperatures above approximately 286 degrees Kelvin (approximately 55 degrees Fahrenheit). Temperatures at most locations in Hawai'i rarely get that low and are not that low at any of the Hawaiian Electric plant locations.

This dependency of nitrate haze formation as a function of temperature (and season) for more seasonally-varying locations in the United States is shown in the September 2019 EPA modeling report² in Figure B-9 (from Appendix A of that report). This figure shows that the thermodynamics of the nitrate haze equilibrium result in much greater particulate formation in winter versus other seasons for more temperate climates, while NO_x emissions are expected to be relatively constant over the entire year. This implies that NO_x emission reductions would only be effective for haze reduction during cold winter months, while consideration of NO_x emission reductions in other months is relatively ineffective.

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It should also be noted that volcanic activity on Hawai'i Island is the largest source of NO_x in the state. Volcanoes are commonly thought of as large sources of SO₂, but they also emit significant amounts of NO_x. Laboratory analysis⁸ of NO_x emissions content in volcanic exhaust indicates a substantial component, likely caused by thermal contact of air with lava. The annual worldwide volcano NO_x emissions (as NO₂) is estimated³ at approximately 1.5 teragrams ("Tg" – trillion grams), while annual worldwide volcano SO₂ emissions are estimated⁹ at approximately 23 Tg. This suggests that the level of NO_x emissions is approximately equal to 6% of the total SO₂ emissions from volcanos. Hawai'i volcanic activity is estimated to have annual SO₂ emissions of approximately 2 million TPY of SO₂. This suggests that the volcanic emissions of NO_x in Hawai'i are about 125,000 TPY. This level of natural NO_x emissions is approximately 3 times greater than all anthropogenic NO_x emissions in the entire state of Hawai'i (vehicle exhaust, industrial emissions, and other combustion sources) based upon the EPA's state emissions trends data¹⁰ for 2017. Also, these estimated volcanic NO_x emissions are approximately 10 times greater than the cumulative total 2017 NO_x emissions emitted by all six Hawaiian Electric plants being reviewed for the Second Decadal Review.

In summary, nitrate haze is a very small component in Hawai'i's Class I areas, which is expected given nitrate chemistry and is verified by the IMPROVE monitoring data. Additionally, the biggest NO_x source is the Kilauea volcano (approximately 125,000 TPY versus statewide³ approximately 21,000 TPY from transportation and approximately 21,000 TPY from fuel combustion, of which only a small fraction are from Hawaiian Electric facilities). The multiple-year average of the nitrate haze impact for worst 20% days at the two areas is approximately Mm⁻¹, or less than 0.5 delta-dv. This total nitrate haze impact is less than the de minimis contribution threshold used to eliminate a single source from consideration for controls during the First Decadal Review period.

Due to the low haze impact of NO_x (even if every source in the state and the volcano was eliminated), the state of Hawai'i should limit the haze precursors control evaluations to SO₂ for the Second Decadal Review. A similar conclusion was reached during the First Decadal Review, for which the EPA did not consider NO_x controls to be material. The State of Hawai'i Department of Health should work with the EPA to provide this technical justification to remove NO_x as a haze precursor for the state of Hawai'i.

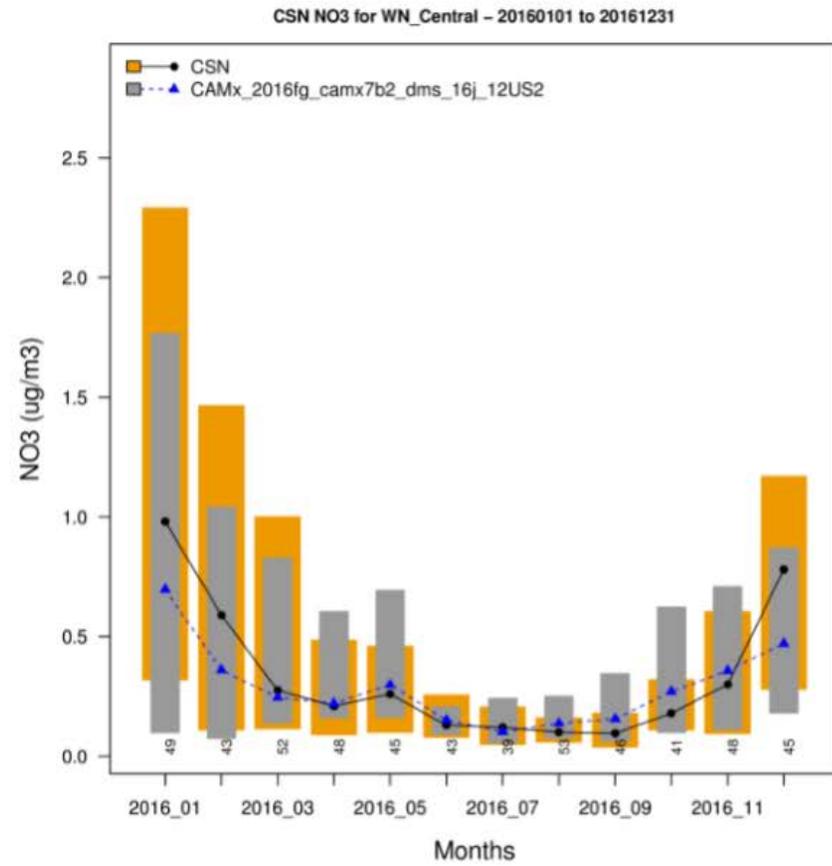
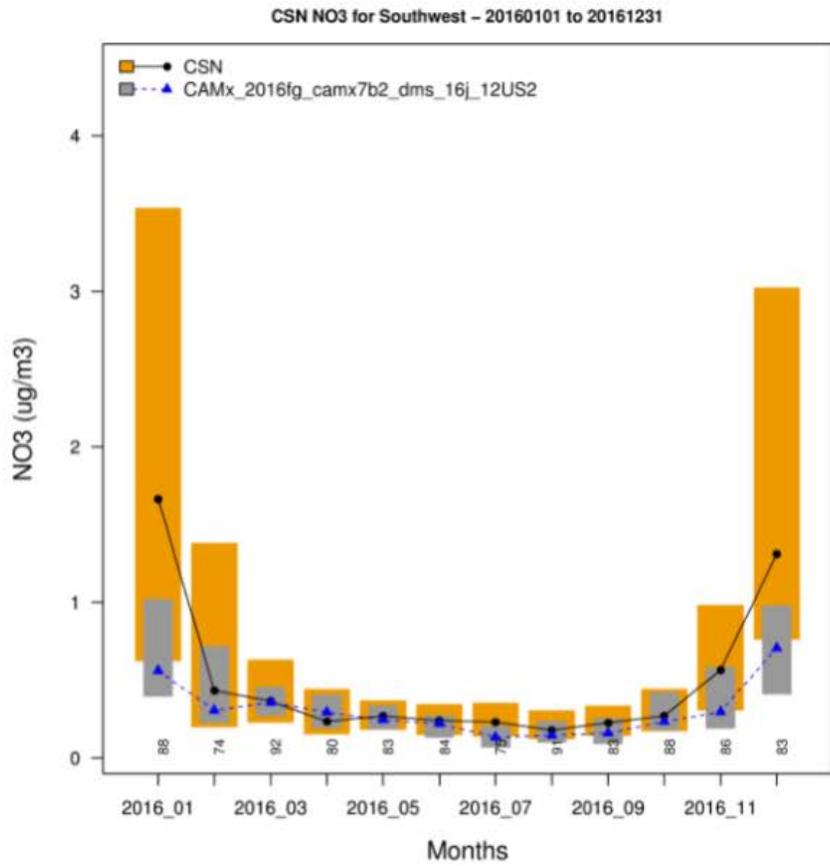
⁸ Mather, T., 2004. A Volcanic Breath of Life? Chemistry World, 30 November 2004 Featured Article. <https://www.chemistryworld.com/features/a-volcanic-breath-of-life/3004482.article>.

⁹ Carn, S., V. Fioletov, C. McLinden, C. Li, and N. Krotkov, 2017. A decade of global volcanic SO₂ measured from space. *Sci. Rep.* 7, 44095; doi: 10.1038/srep44095. <https://www.nature.com/articles/srep44095.pdf>.

¹⁰ <https://www.epa.gov/air-emissions-inventories/air-pollutant-emissions-trends-data>.

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Figure B-9: Monthly Variation of Nitrate Particulate Concentrations for Selected IMPROVE Sites from EPA 2019 Modeling Report



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4. PM Species Haze Composition Analysis

In their Federal Implementation Plan Technical Support Document¹¹, EPA noted that “due to the overwhelming contribution of sulfate to visibility impairment at the nearby Hawaii Volcanoes Class I area, it is unlikely that reductions in these pollutants [NO_x and PM]...would have a measurable impact on visibility at that area.”

It is clear from a review of the haze speciation shown in Figures B-2 through B-5 that the contribution to haze of direct particulate species such as elemental carbon, soil, and coarse mass is relatively low. Furthermore, emissions of coarse PM mass (ash) from the volcanic activity can be very high (clearly evident from photos of volcanic activity) to the extent that it may result in aviation alerts. These emissions can be much greater than emissions from power plants and can constitute a significant portion of the direct PM-caused haze shown in Figures B-2 through B-5. The remaining human-caused haze due to direct PM emissions is therefore a very small component of the total haze, and this determination is consistent with EPA’s 2012 assessment.

5. Predominant Trade Winds in Hawai’i

The EPA’s FIP for Hawai’i for the First Decadal Review (77 FR 61478, October 9, 2012) acknowledged the direction of the predominant trade winds in Hawai’i and thus did not require controls on upwind sources (i.e., sources on Oahu and Maui). Figure B-10 shows the locations of the Hawaiian Electric sources and the national parks, along with wind rose plots for airports on Maui and Oahu. The wind rose plots show that the wind is almost always from the northeast and rarely blows from the Hawaiian Electric facilities on Oahu or Maui toward either of Hawai’i’s Class I areas.

The EPA CALPUFF modeling conducted for the First Decadal Review confirms the expected low impacts from sources on Maui, even though the sources were relatively close to Haleakalā National Park. This result is due to the fact, as stated above, that winds rarely blow the emissions from sources downwind from the parks back to the parks, and the CALPUFF modeling confirmed the low impact from occasional periods when the wind may blow toward the parks from the sources modeled. The Western Regional Air Partnership (“WRAP”) Q/d analysis that included several sources on the islands of Oahu and Maui in the four-factor analysis did not consider the wind patterns. A review of past modeling and the EPA’s 2012 FIP should lead to a dismissal of those sources from inclusion in four-factor analyses for the second decadal review period.

The geometry and wind roses shown Figure B-10 and previous CALPUFF modeling both indicate that Hawaiian Electric generating stations on Oahu and Maui would have minimal impact to Class I area haze. Because of this, and the minimal impact of NO_x due to nitrate chemistry, consideration of potential

¹¹ EPA, May 14, 2012. Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii. EPA docket EPA-R09-OAR-2012-0345-0002 via www.regulations.gov.

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additional pollution controls at Hawaiian Electric facilities for Regional Haze progress should be limited to SO₂ for sources on Hawai'i Island.

6. Natural Sources of SO₂ From Volcanic Activity

Volcanic activity on the Hawai'i Island represents a unique and challenging complication to understating haze in Hawai'i Class I areas. The Kilauea volcano on Hawai'i Island has been active for several years, and the levels of SO₂ emissions are being monitored by the United States Geological Survey. As shown in Figure B-11¹² (related to the SO₂ National Ambient Air Quality Standards implementation and monitoring), there were over 2 million tons of SO₂ emissions from volcanic activity on Hawai'i Island in the year 2014, compared to roughly 2,000 tons of power plant SO₂ emissions for that year. As noted in a *Frontiers in Earth Science* 2018 article¹³, the volcanic SO₂ emissions have been relatively steady at levels close to 2 million TPY for the period of 2014 to 2017.

The extremely high levels of natural SO₂ emissions present a significant challenge for defining "impaired" haze days because the same pollutant (i.e., SO₂) is emitted by volcanic activity and the power plants and other combustion sources. Therefore, the RHR glidepath for the two Class I areas in Hawai'i is difficult to establish if naturally-caused haze is to be excluded from the analysis.

There appears to be very little anthropogenic haze impairment remaining at Haleakalā National Park because there are very few sources on Maui upwind of the park and there are no land masses upwind of Maui for thousands of kilometers. For Hawai'i Island, the natural sources of SO₂ are part of (or adjacent to) the park, so they are likely to be a large and continuous source of naturally-caused haze.

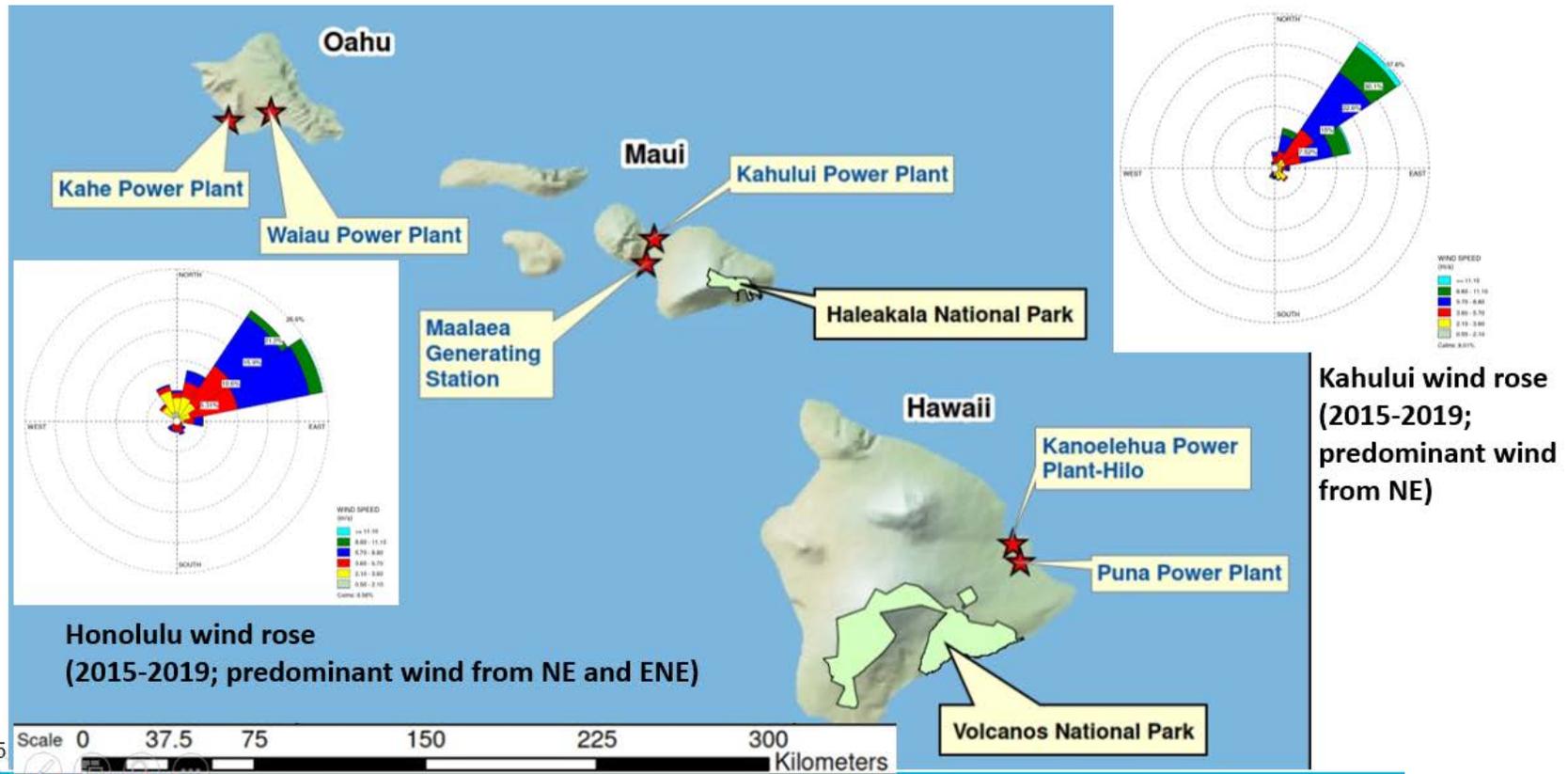
Even the anthropogenic sources (from power plants) are projected to be phased out well before the end point of the RHR (i.e., 2064) by Hawai'i's State Renewable Portfolio Standards Law ("RPS") implementing requirements to convert 100% of the state's electrical generation to renewable energy sources. This RPS law (Hawai'i Revised Statute §269-92) will substantially reduce emissions of haze precursors by 2045. Further details of the past and future benefits of the RPS requirements are detailed in separate Appendix C.

¹² <https://www.epa.gov/sites/production/files/2016-03/documents/hi-epa-tds-r2.pdf>.

¹³ Elias, T., C. Kern, K. Horton, A. Sutton, and H. Garbeil, 2018. Measuring SO₂ Emission Rates at Kilauea Volcano, Hawai'i, Using an Array of Upward-Looking UV Spectrometers, 2014–2017. *Front. Earth Sci.* 6:214. doi: 10.3389/feart.2018.00214. <https://www.frontiersin.org/articles/10.3389/feart.2018.00214/full>.

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Figure B-10: Geography of Hawaiian Electric Sources Asked to Conduct Four-Factor Analyses and PSD Class I Areas, with Wind Roses

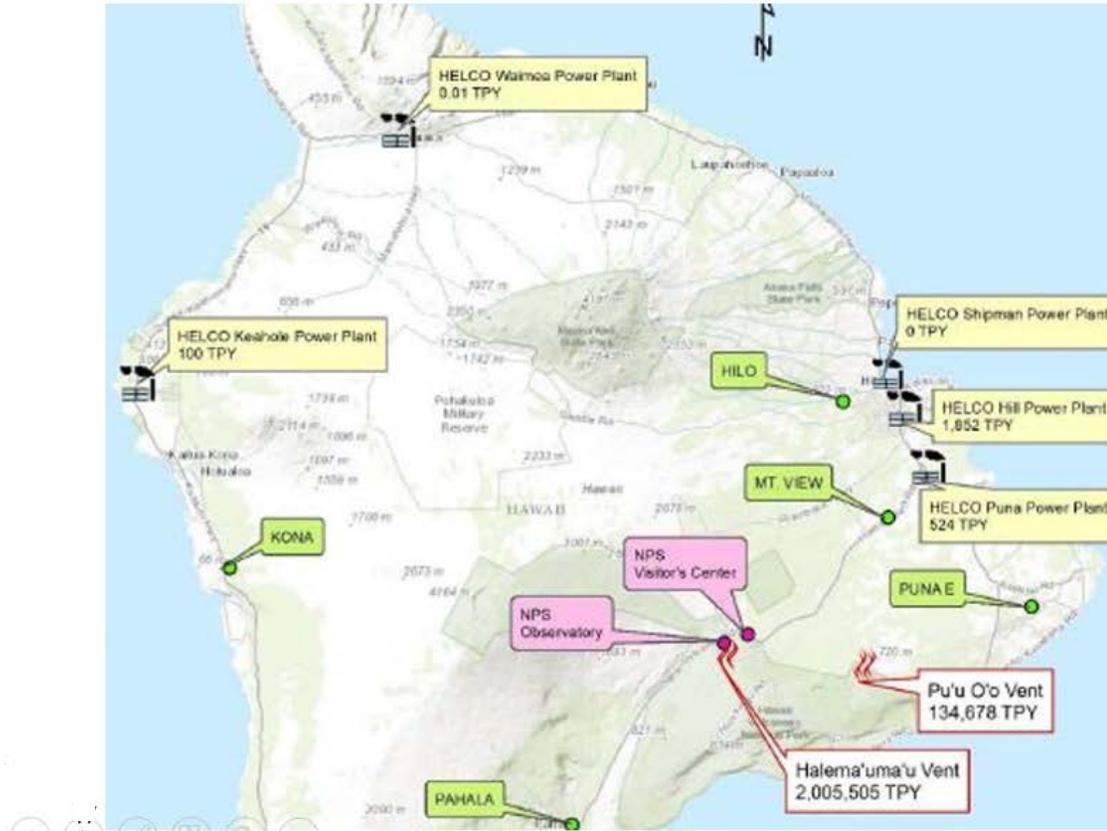


Kahului wind rose
(2015-2019;
predominant wind
from NE)

Honolulu wind rose
(2015-2019; predominant wind from NE and ENE)

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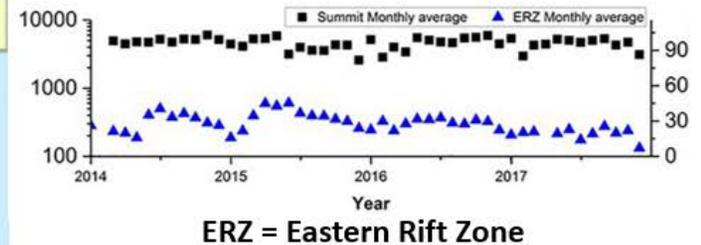
Figure B-11: Geography of Hawaiian Electric Sources Asked to Conduct Four-Factor Analyses and PSD Class I Areas, with Wind Roses



2017 SO₂ Emissions (from NEI)

site name	TPY SO ₂
HELCO - Keahole Power Plant	81.94
HELCO - Waimea Power Plant	0.00
HELCO - Kanoelehua Power Plant/ HILL	2167.18
HELCO - Puna Power Plant	186.84

2014-2017 Volcano SO₂ Emissions average about 1.86 Million TPY



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7. Conclusions

The state of Hawai'i is isolated from all other states and has very unique regional haze issues due, in part, to its tropical climate, the prevalent trade winds, very large natural emissions of haze precursors, and statewide commitment to renewable energy.

- Emission sources on Oahu and Maui are downwind of Hawai'i's Class I areas and do not contribute to haze issues, such that additional emission controls would not contribute to further reasonable progress at either of Hawai'i's Class I area National Parks. This is consistent with the EPA's First Decadal Review findings.
- Additionally, NO_x emissions do not significantly contribute to haze in Hawai'i due to the nitrate chemistry and Hawai'i's warm climate, and additional NO_x controls would likewise not contribute to further reasonable progress. Therefore, NO_x should not be regulated as a contributing precursor to haze in Hawai'i; especially from Oahu and Maui sources that are downwind of the parks. If they are reviewed as precursors, consideration should be given to their insignificant contribution when evaluating possible controls.
- Direct PM emissions constitute a very small portion of the haze associated with the worst 20% haze days in the Hawai'i Class I areas. Furthermore, significant portions of the observed haze in the categories of elemental carbon, soil, and coarse mass are due to volcanic emissions. Therefore, further PM controls on power plant sources would not have a significant benefit for visibility at these Class I areas.
- For the above reasons, the only pollutant that should be considered for possible haze controls in the state of Hawai'i is SO₂ which is consistent with the findings of the First Decadal Review. Furthermore, the only Hawaiian Electric sources to be considered for a four factor analysis for SO₂ should be those that are predominantly upwind of a Class I area which include only the Puna and Kanoelehua-Hill Generating Stations on Hawai'i Island.
- Hawai'i's Class I area haze impacts are principally due to natural sources. Volcanic emissions of precursor SO₂ during the 2014-2017 period of analysis were three orders of magnitude greater than the anthropogenic emissions on Hawai'i Island. Volcanic NO_x emissions were about three times greater than all the state's NO_x emissions. Since these natural emissions are the principal cause of haze at the two Class I areas in the state and are difficult to distinguish from the relatively small amount of anthropogenically-caused haze, photochemical grid modeling is not practical or even needed. The definition of "impaired days" for Hawai'i Volcanoes National Park as referenced in some of the figures in this report is uncertain due to the overwhelming influence of natural emissions of SO₂.
- For Haleakalā National Park, with the lack of upwind anthropogenic sources, it could be reasonably concluded that natural conditions are already attained, and no further Reasonable Progress modeling (or controls) is needed. For Hawai'i Volcanoes National Park, the only United

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States anthropogenic potential sources are those upwind of the park on Hawai'i Island; all other sources in the state are not contributing to haze at the Class I areas.

- Implementation of Hawai'i's RPS (discussed in detail in Appendix C) will provide a dramatic reduction of virtually all power plant haze-causing emissions in the state of Hawai'i well before the year 2064. This Hawai'i state law established enforceable requirements that a certain percentage of electricity must be generated from renewable energy sources by the end of identified benchmark years leading to 100% renewable energy by 2045. The interim targets are 30 percent by 2020, 40 percent by 2030, and 70 percent by 2040 which provide an RPS "glide path" for EGUs that mirrors the RHR visibility improvement glide path for the next few decades. No separate new regional haze measures for EGUs are needed to assure reasonable progress for this decadal period.

Plans for renewable energy sources, the likely reduction in utilization of fossil-fueled electric generation in this interim period, the unique climate and wind patterns, and the difficulty of addressing the high volcanic emissions should be considered in the current planning for the Second Decadal Review process for the state of Hawai'i.

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APPENDIX C: HAWAI‘I’S RENEWABLE PORTFOLIO STANDARDS
CONTRIBUTION TO REGIONAL HAZE PROGRESS

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Appendix C: Hawai'i's Renewable Portfolio Standards ("RPS") Contribution to Regional Haze Progress

AECOM Project Number: 60626547

Prepared for:



**Hawaiian
Electric**

PO Box 2750
Honolulu, HI 96840

Prepared by:

AECOM

AECOM Technical Services, Inc.
500 West Jefferson, Suite 1600
Louisville, KY 40202

March 30, 020

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Hawai'i's Renewable Portfolio Standards ("RPS") Contribution to Regional Haze Progress

1. Executive Summary

Hawai'i's ongoing conversion of fossil-fueled electric generation to renewable energy sources as mandated by the Hawai'i Revised Statute ("HRS") §269-92 Renewable Portfolio Standards ("RPS") is significantly decreasing emissions from Hawai'i's electric generating stations. Past actual and expected future decreases in usage of fossil-fueled electric generating units ("EGUs") are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the Regional Haze Rule ("RHR"). Emissions from the majority of Hawai'i's electric generating plants are not a significant contributor to haze at Class I areas (for reasons explained in Appendix B). Further, their very low impact is being mitigated under the RPS state law. This rate of progress from the RPS law can be relied upon for further emissions reductions from EGUs in the coming years and thus separate further requirements for EGU controls under the RHR are not needed at this time. The following sections of this appendix provide a background on the RPS requirements and progress to date, and high confidence of continued progress consistent with the goals of the RHR.

2. Renewable Portfolio Standards

In 2002 the Hawai'i RPS legislation set voluntary goals for converting the islands' electrical generation from fossil fuels to renewable energy. In 2005, the RPS was set into law as binding requirements for Hawai'i electric utility companies. The law requires that electric utilities in Hawai'i achieve 100% of their electric generation from renewable energy sources by 2045 and meet a series of interim limits for the percentages of their electricity sales that must be provided by renewables (e.g., 30% renewable by 2020, and 40% by 2030, etc.). Renewable energy sources such as solar, hydro and wind energy have no direct emissions. Others such as biomass combustion have significantly lower emissions (especially sulfur dioxide ("SO₂")) than fossil fuels. Consequently, the RPS law results in steady progress in emissions reductions from electric utilities creating, in effect, an "RPS glidepath" providing dramatic reduction of electric generating unit emissions by mid-century.

The RPS program, although not directly related to the Regional Haze Rule, is providing emissions reductions and improvements to air quality consistent with the goals of the RHR.

Table C-1 shows the interim and final RPS for EGUs along with the Regional Haze adjusted glidepath emissions reductions goals¹.

¹ Regional Haze Adjusted Glidepath assumes consistent reductions in haze precursor emissions impacts from all U.S. anthropogenic sources from the baseline average of 2000-2004 to zero impacts in 2064, i.e. natural background.

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Table C-1 Comparison of RPS and Regional Haze Glidepaths

Year	RPS Renewable Requirement % of Electricity Sales	Regional Haze Glidepath % Visibility Improvement
2010	10%	8%
2015	15%	17%
2020	30%	25%
2030	40%	42%
2040	70%	58%
2045	100%	67%
2065		100%

This table illustrates that the emissions reductions from EGUs under the RPS are similar to the visibility goals of the Regional Haze Program in the intermediate years and become much more stringent in later years. The RPS seeks to achieve 100% renewable electrical supply by 2045, which is twenty years earlier than the RHR target of 2065 to achieve natural background visibility in Class I areas.

3. Historical RPS Achievement

Hawaiian Electric², and other electric utility providers in Hawai‘i, have made excellent progress in developing and supporting renewable energy sources. Figure C-1 below shows the percentage of all electrical sales statewide provided by renewable sources since the RPS inception (green columns).³ It also shows as a line illustrating the RPS interim standards (with proportional progress assumed between RPS milestone years). This figure illustrates that Hawai‘i EGUs have made significant progress to date and have been ahead of the RPS interim targets.

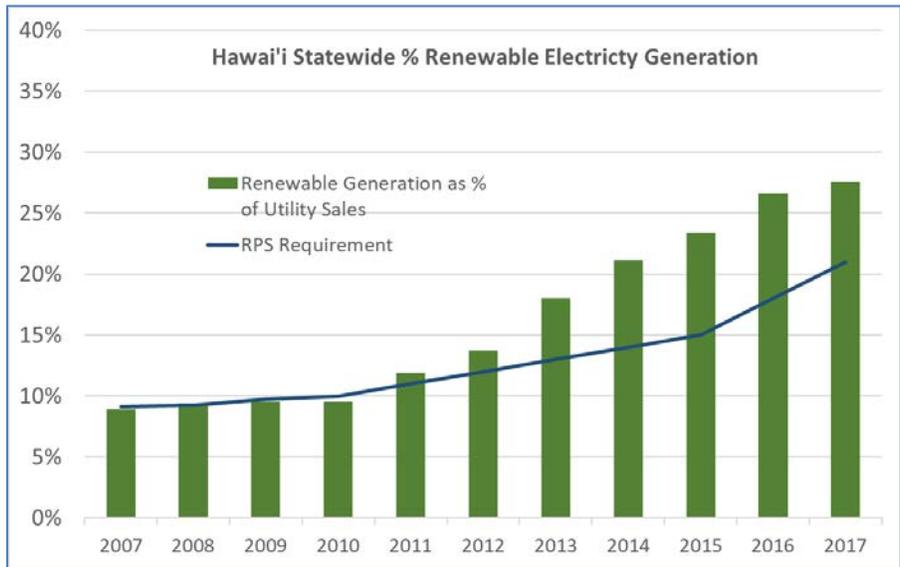
Hawaiian Electric represents majority of Hawai‘i’s electric generation. Figure C-2 shows the renewable energy source percentages for this same period specifically for Hawaiian Electric. The data follows the same trend as the statewide figures and this figure also shows a breakdown of the type of renewable energy technology used.

² “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.

³ Hawai‘i Public Utility Commission (PUC), “Report to the 2019 Legislature on Hawai‘i’s Renewable Portfolio Standards”, Dec. 2018 https://puc.hawaii.gov/wp-content/uploads/2018/12/RPS-2018-Legislative-Report_FINAL.pdf.

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Figure C-1 Statewide Renewable Portfolio Progress



Source: https://puc.hawaii.gov/wp-content/uploads/2018/12/RPS-2018-Legislative-Report_FINAL.pdf

Figure C-2 Hawaiian Electric Companies RPS Achievement by Generation Technology⁴



⁴ PUC Dec. 2018 Report, Figure 2, page 7.

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4. Future RPS Achievability

To date, Hawai'i's electric utilities have generally met or exceeded the RPS requirements. Continued progress consistent with RPS is expected to continue. Projects and plans are already in place to continue this rapid RPS shift to renewable energy sources for the period of interest of the next decadal period of the RHR. In its December 2018 report to the state legislature, the Hawai'i Public Utility Commission ("PUC") indicated that "future renewable projects under construction or planned for the HECO Companies and KIUC should ensure that the state remains on track for meeting the 2020 and 2030 RPS targets."⁵

Figure C-3 below shows Hawaiian Electric's projection of percent renewables through 2030 presented in the December 2018 PUC report. This projected progress remains well ahead of the RPS requirements which also is ahead of the requirements of the Regional Haze glidepath goals.

Figure C-3 Hawaiian Electric Companies RPS Expectation by 2030 Technology⁶

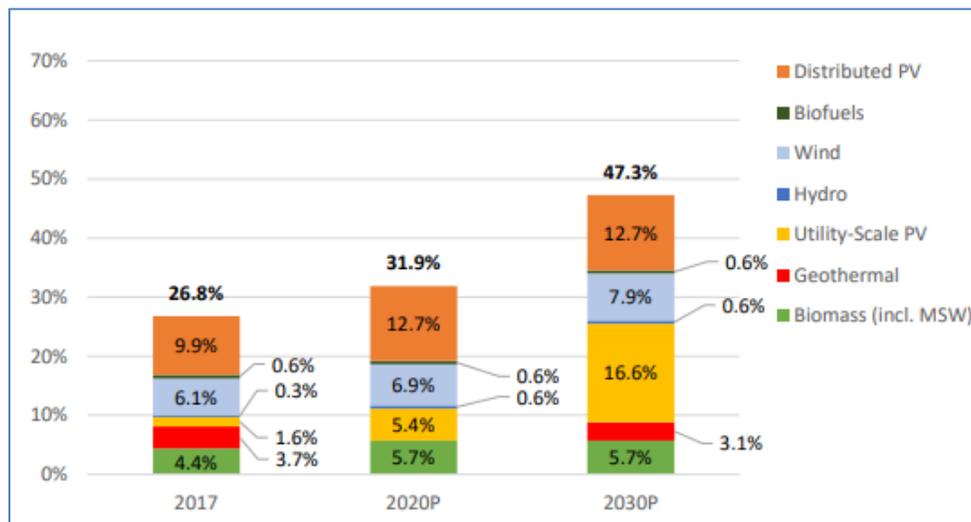


Table C-2 below shows the past actual and future forecast for Hawaiian Electric from the previous two figures (from PUC's 2018 report) together with the requirements of RPS and the goals of the RHR. Hawaiian Electric's renewable energy progress and forecast is ahead of both programs. Additionally, Hawaiian Electric has an internal target to achieve 100% renewables by 2040, five years ahead of the RPS requirement and 25 years ahead of the RHR goals.

⁵ PUC Dec. 2018 Report, page 2.

⁶ PUC Dec. 2018 Report, Figure 2, page 16.

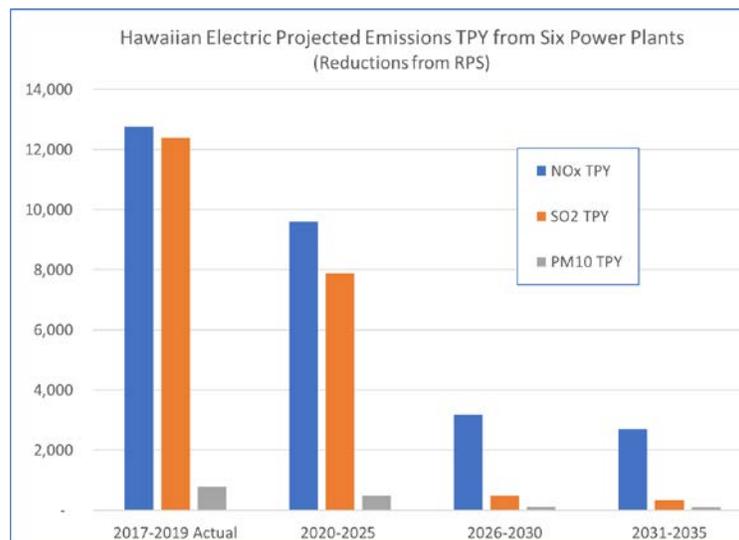
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Table C-2 Comparison of RPS and Regional Haze Glidepaths

Year	RPS Renewable Requirement % of Electricity Sales	Regional Haze Glidepath % Visibility Improvement	Hawaiian Electric % Renewables
2010	10%	8%	9.5% (actual)
2015	15%	17%	23.2% (actual)
2020	30%	25%	31.9% (projection)
2030	40%	42%	47.3% (projection)
2040	70%	58%	100% (goal)
2045	100%	67%	100% (goal)

Hawaiian Electric’s latest projections show an even more rapid shift to renewable energy sources than forecasted in 2018. This will continue to decrease Hawaiian Electric facility emissions. For example, Figure C-4 illustrates Hawaiian Electric’s latest forecast emissions trends for total nitrogen oxides (“NOx”), sulfur dioxide (“SO₂”) and Particulate Matter (“PM₁₀”) emissions (in tons per year “TPY”) from the six power plants (Waiau and Kahe Generating Stations on Oahu, Kahului and Maalaea on Maui, and Kanoiehua-Hill and Puna on Hawai’i) requested to conduct Four-Factor Analyses by the Hawai’i Department of Health (“DOH”). These dramatic emissions decreases illustrate the expected progress from RPS alone – without any additional RHR measures. The forecast emissions shown in Figure C-4 was derived from recent fuel consumption projections based on the resource plans and planning assumptions submitted to the PUC as part of Hawaiian Electric’s 2016 Power Supply Improvement Plan (“PSIP”) which was accepted by the PUC and recent renewable project applications.

Figure C-4 Hawaiian Electric NOx Forecast Emissions



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The emissions reduction is quite rapid and most of the projected reduction by Hawaiian Electric are expected to be in place prior to 2028, the next Regional Haze planning milestone.

Although this projection is based on reasonable assumptions, plans are subject to change as there is some uncertainty regarding future projections and forecast assumptions. For this reason and due to energy security issues, Hawaiian Electric cannot commit to specific dates for particular emissions reductions or final retirements of any specific generating station. Nevertheless, Hawaiian Electric is on an aggressive path to end fossil-fueled generation and replace it with renewable energy sources – especially during this next decadal period. This progress should be sufficient for Hawaiian Electric’s contribution to the state’s efforts regarding reasonable progress of the RHR for the current Regional Haze decadal review.

5. Reliance on RPS for this Regional Haze Decadal Review

The RPS requirements are part of Hawai’i state law. An electric utility failing to meet the RPS requirements is subject to enforcement action and penalties by the PUC unless the PUC determines the electric utility is unable to meet the RPS due to factors beyond its reasonable control. However, given the progress to date of the Hawai’i electric utilities acquiring renewable generation and expectations for planned renewable projects in the near future, it is reasonable to expect that RPS will result in continued steady progress, at least through 2030.

The DOH can rely on the RPS for regional haze progress without having to impose separate RHR requirements in facility permits. This is supported by EPA guidance which states that “Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and verifiable basis for quantifying any change in future emissions due to operational changes may be another.”⁷

Even if progress were slower than currently expected, it would not prevent the RPS from being relied upon as the major EGU contribution to meeting Hawai’i’s regional haze goals. The time perspective of the Regional Haze Program is long. Making wise decisions that help achieve the long-term goals is important. Hawai’i electric utilities are currently focusing resources on advancing renewable energy projects that will permanently displace fossil-fueled unit generation and fossil-fueled combustion emissions. These ongoing RPS efforts help achieve the long-term goals of the RHR and provide permanent emissions reductions and other societal benefits. In contrast, new investments in conventional emissions controls on aging fossil-fueled units provide only modest short-term benefits impose additional costs on rate payers and will have no lasting value when those units are deactivated or retired.

⁷ Guidance on Regional Haze State Implementation Plans for the Second Implementation Period – August 2019 at page 17. https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

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Comments on Four – Factor Analysis

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STATE OF HAWAII
DEPARTMENT OF HEALTH
P.O. Box 3378
HONOLULU, HAWAII 96801-3378

In reply, please refer to:
File:

20-322E CAB
File No. 0235

July 8, 2020

Ms. Karen Kimura
Director, Environmental Division
Hawaiian Electric
P.O. Box 2750
Honolulu, Hawaii 96840-0001

Dear Ms. Kimura:

**Subject: Four-Factor Analysis for Regional Haze
Covered Source Permit No. 0235-01-C
Hawaii Electric Light Company, Inc. (HELCO)
Puna Generating Station
Located At: Puna Mill Road, Keaau, Hawaii
UTM: 86,646 Meters East and 2,172,337 Meters North, Zone 5**

The Department of Health, Clean Air Branch (CAB) acknowledges receipt of the subject four-factor analysis on March 31, 2020 and has determined the analysis to be incomplete. Please refer to the attached comments for completing the four-factor analysis. Pursuant to 40 Code of Federal Regulations (CFR) §51.308 (d)(1) of the Regional Haze Rule (RHR), the four-factor analysis will be used to establish control measures and reasonable progress goals for Hawaii's Regional Haze State Implementation Plan (RH-SIP).

The CAB requests that you address the comments and resubmit the subject four-factor analysis with the appropriate revisions by **August 10, 2020**.

If there are any questions regarding this matter, please contact Mr. Dale Hamamoto of my staff at (808) 586-4200.

Sincerely,

A handwritten signature in blue ink, appearing to read "Marianne Rossio".

MARIANNE ROSSIO, P.E.
Manager, Clean Air Branch

DH:rkb

Attachments

- c: Debra Miller, National Park Service, Air Resources Division,
12795 W. Alameda Parkway, Lakewood, CO 80228
- Don Shepherd, National Park Service, Air Resources Division,
12795 W. Alameda Parkway, Lakewood, CO 80228
- Melanie Peters, National Park Service, NPS-Air,
P.O. Box 25287, Denver, CO 80225-0287

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Attachment I

After our review and feedback from the National Park Service (NPS) and Environmental Protection Agency (EPA), Region 9, we have the following comments on the subject four-factor analysis provided for the boiler (Unit Boiler) and combustion turbine (Unit CT-3):

- a. The cost per ton of sulfur dioxide (SO₂) removed was provided for switching boiler fuel from high sulfur residual fuel oil No. 6 (maximum sulfur content of 2%) to a residual/distillate fuel blend with 1% sulfur content and from high sulfur residual fuel oil No. 6 to distillate fuel oil with 0.4% sulfur content. However, there was no cost analysis provided for a fuel switch from high sulfur residual fuel oil No. 6 to ultralow sulfur diesel (ULSD). Please provide the following for switching boiler fuel from high sulfur residual fuel oil No. 6 to ULSD:
 - i) The cost per ton of SO₂, nitrogen oxide (NO_x), and particulate matter less than ten (10) microns in diameter (PM₁₀) reduced; and
 - ii) The cost per total combined tons of SO₂, NO_x, and PM₁₀ reduced.
- b. Sections 3.2.2 and 5.2.2 of the analysis state that fuel switching could be implemented within two (2) to three (3) years. Other facilities have reported that a fuel switch could be accomplished within as short as one (1) year. The amount of time specified for switching fuels at the Puna Generating Station seems excessive. Please explain the reason for the long compliance time and whether there are ways to reduce the time for implementing this control measure.
- c. Section 3.2.3 states that fuel switching to a lower sulfur fuel will increase the cost of electricity. Although the topic was discussed in the technical support document for the Regional Haze Federal Implementation Plan, it is not something we can generally take into consideration for the regional haze four-factor analysis in this second planning period.
- d. Section 3.2.4 states that Hawaiian Electric intends to retire the boiler at Puna Generating Station after securing renewable sources as replacement(s) since the Renewable Portfolio Standards (RPS), adopted by the State of Hawaii and as codified in Hawaii Revised Statute (HRS) §269-92, will be carried out. Hawaiian Electric's Power Supply Improvement Plan also states that Hawaiian Electric intends to retire the boiler at Puna Generating Station in 2020; however, while these standards are subject to enforcement action by the Hawaii Public Utilities Commission, provisions mandated by the RPS are state only requirements which are not federally enforceable under the federal Clean Air Act. 40 CFR §51.308(f)(2) allows the retirement of the boiler as an emission reduction measure; however, Hawaiian Electric must commit to a shutdown date for this boiler as an enforceable compliance measure necessary for making reasonable progress. Section 3.3 further expresses intent of the Puna Generating Station to forego fuel switching and other control measures examined in this analysis in favor of relying on the RPS without regards to the RHR, which mandates federally enforceable permit emission limits and/or RH-SIP approved rule provisions in establishing the long-term strategy for regional haze. Section 5 of Appendix C in the analysis states that the RPS can be relied on for regional haze progress without having to impose separate RHR requirements in the facility permits. As stated above, the RPS is not federally enforceable. The federally enforceable shutdown could be used as a control measure to show reasonable progress if Hawaiian Electric agrees to make a commitment to the shutdown through a federally enforceable permit limit.

Attachment I

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- f. Please add the combination of FGR plus low NO_x burner (LNB) and overfire air (OFA) to Table 4.2 and evaluate the cost effectiveness of this combined NO_x control measure for the boiler.
- g. Selective non-catalytic reduction (SNCR) is listed as a technically feasible control option; however, the cost effectiveness of SNCR was not evaluated. Please evaluate the cost effectiveness of SNCR for reducing NO_x emissions from the boiler.
- h. Please add the combination of SNCR plus LNB and OFA to Table 4.2 and evaluate the cost effectiveness of this combined NO_x control measure for the boiler.
- i. Please add the combination of SCR plus LNB and OFA to Table 4.2 and evaluate the cost effectiveness of this combined NO_x control measure for the boiler.
- j. A controlled emission level for NO_x of 0.1 pound per million British thermal unit (lb/MMBtu) was assumed for SCR in Table 4-3.

It is generally assumed that new SCR can achieve 0.05 lb/MMBtu (or lower) on an annual basis. The current (2019) CCM states that a 0.05 lb/MMBtu outlet NO_x rate based on a 30-day (boiler operating) average should be obtainable by a power plant boiler with an SCR system.

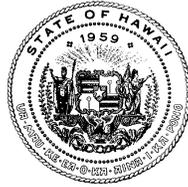
- k. Sections 4.2.4 and 5.2.4 state that the remaining useful life of the boiler does not impact the annualized cost of potential controls because the useful life of the boiler is assumed to be at least as long as the capital cost recovery period, which is fifteen (15) years. Potential control measures under consideration include LNB with OFA and SCR to reduce NO_x emissions and wet scrubber, fuel switching to distillate, and wet electrostatic precipitator for reducing PM₁₀ emissions. These sections of the analysis also state that HECO intends to retire the boiler (please refer to comment d). If Hawaiian Electric agrees to include in the analysis, a retirement date that it expects to shutdown this boiler as an enforceable compliance measure, the amortize costs of the potential control measures may be based on the shutdown date. In the situation where an enforceable shutdown date does not exist, the remaining useful life of a control under consideration should be the full period of the useful life of that control as recommended by EPA's Control Cost Manual (CCM). In Appendix A, for detailed costing, a useful life of fifteen (15) years is used, however, the current (2019) CCM specifies a remaining useful life for SCR at power plants of thirty (30) years and twenty (20) years for other sources.
- l. In Appendix A, for detailed costing, an interest rate of seven percent (7%) is used for determining the capital recovery factor; however, the CCM spreadsheets recommend using the current bank prime rate (currently at 3.25%) to estimate the costs of additional emission controls, rather than seven percent (7%) used in the analysis. Please see the following site for the current bank prime rate: <https://www.federalreserve.gov/releases/h15/>). The prime interest rate has not been seven percent (7%) or higher in the past twelve (12) years. A three percent (3%) interest rate may also be considered.

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- m. In Table A-2 of Appendix A, a “Hawaii Island Construction Cost Multiplier” of 1.840 for SCR is used based on the cost of construction geographical multipliers from the “RSMeans Mechanical Cost Data 2016” to account for factors unique to the Hawaii Island location plus an additional factor to account for additional Hawaiian Electric loadings and overhead. Retrofit factors pertain to the difficulty of installing a piece of hardware, regardless of location. While we recognize that 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 or Alaska, those higher costs must be itemized, justified, and documented.
- n. Appendix B of the four-factor analysis indicated that, in the recent past, Hawaii’s volcanic SO₂ emissions are about 1,000 times greater than anthropogenic SO₂ emissions and volcanic activity in Hawaii produced as much as two (2) million tons of SO₂ per year. Please note that SO₂ emissions have significantly decreased after the Kilauea eruption ended in September 2018. The United States Geological Survey (USGS) stated, that in 2019, the summit is the only source releasing enough SO₂ emissions to be quantified using ultra-violet spectroscopy. Preliminary USGS results for 2019 indicate an average summit daily SO₂ emission rate of about 43 tons and an annual total SO₂ emission rate of about 17,119 tons which is far lower than the two (2) million tons of SO₂ reported to be emitted by the volcano in Appendix B. Note that the total combined SO₂ emissions from point sources screened for four-factor analyses were about 18,058 tons per year in 2017 which is 939 tons higher than preliminary USGS estimates of volcanic SO₂ for 2019. Since Kilauea eruptive activity ended in September 2018, those point sources now play a more significant part in SO₂ visibility impacts.
- o. Appendix B of the four-factor analysis also noted that volcanic activity on Hawaii Island is the largest source of NO_x in the state based on a NO_x emission estimate for the Kilauea Volcano of roughly 125,000 tons per year. Data, indicating worldwide volcano NO_x and SO₂ emissions of 1.5 and 23 teragrams, respectively, was used for the estimate. It was stated that the NO_x was likely caused by thermal contact of air with lava. Based on the NO_x/SO₂ ratio using the worldwide numbers, it was then assumed that NO_x emissions from Kilauea Volcano are about 6% of the volcano’s total SO₂ emissions. It was also assumed that Hawaii volcanic activity emits approximately two (2) million tons per year of SO₂. Please note that the global ratio of NO_x/SO₂ is likely not appropriate to use for estimating NO_x emissions from the Kilauea Volcano. Interagency Monitoring of Protected Visual Environments 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 is located. Also, while volcanic SO₂ emissions were reported to be as high as two (2) million tons per year when the Kilauea Volcano was erupting, SO₂ emissions have significantly decreased after the Kilauea eruption ended in September 2018. There currently is no lava in the Kilauea summit crater. Instead, a lake of water has formed in the Kilauea crater after the volcano stopped erupting towards the end of 2018. Please refer to: <https://earthobservatory.nasa.gov/images/146687/a-new-lakewater-not-lavaon-kilauea>
- p. In the four-factor analysis, Hawaiian Electric states that no reduction measures in addition to Hawaii’s Renewable Portfolio Standards are proposed to meet the RHR requirements. While provisions mandated by the RPS are subject to enforcement action by the Hawaii Public Utilities Commission, these are state only enforceable requirements which are not federally enforceable under the federal Clean Air Act. The RHR requires federally enforceable emission limits and/or RH-SIP approved rule provisions in establishing the long-term strategy for regional haze. As an option, Hawaiian Electric may propose caps for the emissions of visibility impairing pollutants

Attachment I

(SO₂, NO_x, and PM₁₀) based on anticipated emission reductions from the RPS as a reasonable progress measure that could be incorporated into permits. These emission caps would need to occur in the second planning period (2018-2028) in order to be credited as a control measure for reasonable progress. Additional measures for showing reasonable progress include federally enforceable plant shutdowns as described in comment d above. In essence, Hawaiian Electric could propose: 1) federally enforceable conditions for retiring units during the second implementation planning period (2018-2028) and include those units and retirement dates in the four-factor analysis along with a four-factor analysis of the remaining equipment; 2) propose federally enforceable emission control measures such as fuel switching or add-on controls with the associated pollutant reductions, or 3) propose federally enforceable permit limits such as emission caps, for operational flexibility, or hour restrictions with the associated compliance dates or any combination of 1, 2, or 3 above



STATE OF HAWAII
DEPARTMENT OF HEALTH
P.O. Box 3378
HONOLULU, HAWAII 96801-3378

July 8, 2020

FILE COPY

BRUCE S. ANDERSON, Ph.D.
DIRECTOR OF HEALTH

DH

Initials _____
Mailed Out _____

In reply, please refer to:
File:

20-322E CAB
File No. 0235

Ms. Karen Kimura
Director, Environmental Division
Hawaiian Electric
P.O. Box 2750
Honolulu, Hawaii 96840-0001

Dear Ms. Kimura:

**Subject: Four-Factor Analysis for Regional Haze
Covered Source Permit No. 0235-01-C
Hawaii Electric Light Company, Inc. (HELCO)
Puna Generating Station
Located At: Puna Mill Road, Keaau, Hawaii
UTM: 86,646 Meters East and 2,172,337 Meters North, Zone 5**

The Department of Health, Clean Air Branch (CAB) acknowledges receipt of the subject four-factor analysis on March 31, 2020 and has determined the analysis to be incomplete. Please refer to the attached comments for completing the four-factor analysis. Pursuant to 40 Code of Federal Regulations (CFR) §51.308 (d)(1) of the Regional Haze Rule (RHR), the four-factor analysis will be used to establish control measures and reasonable progress goals for Hawaii's Regional Haze State Implementation Plan (RH-SIP).

The CAB requests that you address the comments and resubmit the subject four-factor analysis with the appropriate revisions by **August 10, 2020**.

If there are any questions regarding this matter, please contact Mr. Dale Hamamoto of my staff at (808) 586-4200.

Sincerely,

A handwritten signature in blue ink that reads "Marianne Rossio".

MARIANNE ROSSIO, P.E.
Manager, Clean Air Branch

DH:rkb

Attachments

c: Debra Miller, National Park Service, Air Resources Division,
12795 W. Alameda Parkway, Lakewood, CO 80228
Don Shepherd, National Park Service, Air Resources Division,
12795 W. Alameda Parkway, Lakewood, CO 80228
Melanie Peters, National Park Service, NPS-Air,
P.O. Box 25287, Denver, CO 80225-0287

DRAFT

Attachment I

After our review and feedback from the National Park Service (NPS) and Environmental Protection Agency (EPA), Region 9, we have the following comments on the subject four-factor analysis provided for the boiler (Unit Boiler) and combustion turbine (Unit CT-3):

- a. The cost per ton of sulfur dioxide (SO₂) removed was provided for switching boiler fuel from high sulfur residual fuel oil No. 6 (maximum sulfur content of 2%) to a residual/distillate fuel blend with 1% sulfur content and from high sulfur residual fuel oil No. 6 to distillate fuel oil with 0.4% sulfur content. However, there was no cost analysis provided for a fuel switch from high sulfur residual fuel oil No. 6 to ultralow sulfur diesel (ULSD). Please provide the following for switching boiler fuel from high sulfur residual fuel oil No. 6 to ULSD:
 - i) The cost per ton of SO₂, nitrogen oxide (NO_x), and particulate matter less than ten (10) microns in diameter (PM₁₀) reduced; and
 - ii) The cost per total combined tons of SO₂, NO_x, and PM₁₀ reduced.
- b. Sections 3.2.2 and 5.2.2 of the analysis state that fuel switching could be implemented within two (2) to three (3) years. Other facilities have reported that a fuel switch could be accomplished within as short as one (1) year. The amount of time specified for switching fuels at the Puna Generating Station seems excessive. Please explain the reason for the long compliance time and whether there are ways to reduce the time for implementing this control measure.
- c. Section 3.2.3 states that fuel switching to a lower sulfur fuel will increase the cost of electricity. Although the topic was discussed in the technical support document for the Regional Haze Federal Implementation Plan, it is not something we can generally take into consideration for the regional haze four-factor analysis in this second planning period.
- d. Section 3.2.4 states that Hawaiian Electric intends to retire the boiler at Puna Generating Station after securing renewable sources as replacement(s) since the Renewable Portfolio Standards (RPS), adopted by the State of Hawaii and as codified in Hawaii Revised Statute (HRS) §269-92, will be carried out. Hawaiian Electric's Power Supply Improvement Plan also states that Hawaiian Electric intends to retire the boiler at Puna Generating Station in 2020; however, while these standards are subject to enforcement action by the Hawaii Public Utilities Commission, provisions mandated by the RPS are state only requirements which are not federally enforceable under the federal Clean Air Act. 40 CFR §51.308(f)(2) allows the retirement of the boiler as an emission reduction measure; however, Hawaiian Electric must commit to a shutdown date for this boiler as an enforceable compliance measure necessary for making reasonable progress. Section 3.3 further expresses intent of the Puna Generating Station to forego fuel switching and other control measures examined in this analysis in favor of relying on the RPS without regards to the RHR, which mandates federally enforceable permit emission limits and/or RH-SIP approved rule provisions in establishing the long-term strategy for regional haze. Section 5 of Appendix C in the analysis states that the RPS can be relied on for regional haze progress without having to impose separate RHR requirements in the facility permits. As stated above, the RPS is not federally enforceable. The federally enforceable shutdown could be used as a control measure to show reasonable progress if Hawaiian Electric agrees to make a commitment to the shutdown through a federally enforceable permit limit.

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- j. A controlled emission level for NO_x of 0.1 pound per million British thermal unit (lb/MMBtu) was assumed for SCR in Table 4-3.

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Attachment I

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Responses to Comments and Revised Four – Factor Analysis

DRAFT

Attachment 2

Responses to the DOH's July 8, 2020 Comments

Regional Haze Four-Factor Analysis, Dated March 31, 2020

Puna Generating Station

Hawai'i Electric Light Company, Inc.

- a. The cost per ton of sulfur dioxide (SO₂) removed was provided for switching boiler fuel from high sulfur residual fuel oil No. 6 (maximum sulfur content of 2%) to a residual/distillate fuel blend with 1% sulfur content and from high sulfur residual fuel oil No. 6 to distillate fuel oil with 0.4% sulfur content. However, there was no cost analysis provided for a fuel switch from high sulfur residual fuel oil No. 6 to ultralow sulfur diesel (ULSD). Please provide the following for switching boiler fuel from high sulfur residual fuel oil No. 6 to ULSD:
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 - ii) The cost per total combined tons of SO₂, NO_x, and PM₁₀ reduced.

Response – The requested costs will be provided in the updated four-factor analysis report.

- b. Sections 3.2.2 and 5.2.2 of the analysis state that fuel switching could be implemented within two (2) to three (3) years. Other facilities have reported that a fuel switch could be accomplished within as short as one (1) year. The amount of time specified for switching fuels at the Puna Generating Station seems excessive. Please explain the reason for the long compliance time and whether there are ways to reduce the time for implementing this control measure.

Response - Two to three years is a realistic estimate of the timeframe for fuel switching because of several factors: 1) Hawaiian Electric generally requests that the State of Hawai'i Public Utilities Commission (Commission) approve fuel contracts and issue its Decision and Order within one year following the filing of the application to the Commission; 2) Hawaiian Electric needs to go through a formal process to request bids from fuel suppliers; 3) Negotiations with the fuel supplier can take up to four months; 4) The schedule for any required infrastructure modifications are dependent on the extent of the required changes; 5) If fuel switching is required at other Hawaiian Electric facilities, the type of fuel to be switched and used, the effect on the fuel supply, and ability for the local refinery to accommodate the change may significantly be impacted; and 6) Imported fuel may be required if there is a lack of local supply.

- c. Section 3.2.3 states that fuel switching to a lower sulfur fuel will increase the cost of electricity. Although the topic was discussed in the technical support document for the Regional Haze Federal Implementation Plan, it is not something we can generally take into consideration for the regional haze four-factor analysis in this second planning period.

Response – Fuel costs are directly reflected in customer electricity rates on all islands Hawaiian Electric provides electricity; this is an important cost to the community that must be considered. Hawaiian Electric encourages the DOH to use the flexibility in the EPA's SIP guidance ¹ in the selection of control measures necessary to make reasonable progress and to consider additional factors when developing the long-term strategy to improve visibility at Class I areas. Also, note that given the fragile condition of the state's fuel supply because of Hawaiian Electric's position

¹ Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019, EPA-457/B-19-003.

as a major customer in the market, a fuel supply change could have sweeping effects on the island's market that may not be apparent from the cost estimates associated with Hawaiian Electric such as the ability of the local refinery to accommodate the change and potential need for imported fuel. Hawaiian Electric suggests that the DOH needs to take these factors into account in its decision-making process.

- d. Section 3.2.4 states that Hawaiian Electric intends to retire the boiler at Puna Generating Station after securing renewable sources as replacement(s) since the Renewable Portfolio Standards (RPS), adopted by the State of Hawaii and as codified in Hawaii Revised Statute (HRS) §269-92, will be carried out. Hawaiian Electric's Power Supply Improvement Plan also states that Hawaiian Electric intends to retire the boiler at Puna Generating Station in 2020; however, while these standards are subject to enforcement action by the Hawaii Public Utilities Commission, provisions mandated by the RPS are state only requirements which are not federally enforceable under the federal Clean Air Act. 40 CFR §51.308(f)(2) allows the retirement of the boiler as an emission reduction measure; however, Hawaiian Electric must commit to a shutdown date for this boiler as an enforceable compliance measure necessary for making reasonable progress. Section 3.3 further expresses intent of the Puna Generating Station to forego fuel switching and other control measures examined in this analysis in favor of relying on the RPS without regards to the RHR, which mandates federally enforceable permit emission limits and/or RH-SIP approved rule provisions in establishing the long-term strategy for regional haze. Section 5 of Appendix C in the analysis states that the RPS can be relied on for regional haze progress without having to impose separate RHR requirements in the facility permits. As stated above, the RPS is not federally enforceable. The federally enforceable shutdown could be used as a control measure to show reasonable progress if Hawaiian Electric agrees to make a commitment to the shutdown through a federally enforceable permit limit.

Response - As Hawaiian Electric set forth in the four-factor analysis report (see in particular Appendix C) continues to assert that several of its programs can in fact be used to show that their emissions are being reduced in a manner that shows reasonable progress.

EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (SIP Guidance) allows for the use of renewable energy programs as an alternative to permit limits. Also, the SIP Guidance encourages the use of projected 2028 emissions in selecting emission controls required to show reasonable progress and allows for energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes. Hawaiian Electric's progress towards meeting the RPS is documented in annual reports to the Public Utility Commission (PUC) see also Appendix C to the four-factor analysis reports. In addition, the status of future renewable projects is listed on the *Renewable Project Status Board* on the Hawaiian Electric website.² The addition of renewable energy is an operational change that reduces fossil fuel consumption, which results in reductions in emissions of visibility impairing pollutants.

The EPA's Regional Haze SIP Guidance supports the use of the State's RPS as an alternative to permit limits as it states:

"Step 3: Selection of sources for analysis

...

Selection of emissions information when estimating visibility impacts (or surrogates) for source selection purposes

² Renewable Project Status Board (<https://www.hawaiianelectric.com/clean-energy-hawaii/our-clean-energy-portfolio/renewable-project-status-board>)

All of the techniques described above require estimates of source emissions. Generally, we recommend that states use estimates of 2028 emissions (resolved by day and hour, as appropriate) to estimate visibility impacts (or related surrogates) when selecting sources, rather than values of recent year emissions. By doing so, sources that are projected on a reasonable basis to cease or greatly reduce their operations or to install much more effective emissions controls by 2028 may be removed from further consideration early in the SIP development process, which can reduce analytical costs. Generally, the estimate of a source's 2028 emissions is based at least in part on information on the source's operation and emissions in a representative historical period. However, there may be circumstances under which it is reasonable to project that 2028 operations will differ significantly from historical emissions. Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes may be another. A state considering using assumptions about future operating parameters that are significantly different than historical operating parameters should consult with its EPA Regional office.

If a state uses a value for emissions in an earlier year, we recommend the state consider whether emissions have appreciably changed (or will change) between the earlier year, the current period, and the projected future year (2028). It is especially important to consider whether source emissions have increased or are likely to increase in the future compared to earlier emissions values.

Use of actual emissions versus allowable emissions

Generally, we recommend that a reasonably projected actual level of source operation in 2028 be used to estimate 2028 actual emissions for purposes of selecting sources for control measure analysis. Source operation during a historical period can inform this projection, but temporary factors that suppressed or bolstered the level of operation in the historical period should be considered, along with factors that indicate a likely increase or decrease in operation.

...

Step 4: Characterization of factors for emission control measures

...

Examples of types of emission control measures states may consider States have the flexibility to reasonably determine which control measures to evaluate, and the following is a list of example types of control measures that states may consider:

...

Energy efficiency and renewable energy measures that could be applied elsewhere in a state to reduce emissions from EGUs.

...

EPA understands that some states may be interested in exploring such measures for their second implementation period SIPs, which is generally appropriate. We suggest such states discuss the measures and programs and their incorporation into the SIP with their EPA Regional office..."³

³ Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, page 17, August 2019, EPA-457/B-19-003. <https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period>

Based on the above EPA guidance, the selection of controls for the long-term strategy (LTS) can include alternatives to permit limits and rely on projected emissions based on the planned transition to 100% renewable energy. For example, various RPS goals across the 48 contiguous states were used as inputs in the EPA's Integrated Planning Model (IPM)^{4,5} to project EGU emissions. The CAM_x modeling used these projected emissions to support the LTS for 2028 (SIP Guidance Steps 5 and 6).

Hawaiian Electric is willing to work with the DOH and EPA Region IX on an alternative to permit limits that relies on the State's RPS goals. The State of Hawai'i apparently contemplated that both the RPS and GHG emissions cap could be used to show reasonable progress in the 2018 Western States Planning Readiness Survey For Regional Haze State Implementation Plans For The Second Implementation Period Survey Results And Discussion (Readiness Survey)⁶. The Readiness Survey that was conducted by the Western Regional Air Partnership (WRAP) states:

Hawaiian Electric plans to use Hawai'i's existing Renewable Portfolio Standard (RPS) as a measure to make reasonable progress. The RPS ultimately requires the Hawaiian Electric Company to establish 100% renewable energy sales by 2045 to reduce fossil fuel consumption for mitigating GHGs. Mitigating GHGs will also reduce pollutants that impair visibility as a co-benefit. Hawaiian Electric Companies' Power Supply Improvement Plan (PSIP) provides future plans for the utility and independent power producers to achieve 100% RPS by 2045. The PSIP may be used to establish permit conditions to limit the emissions of pollutants that impair visibility for meeting reasonable progress goals. In accordance with our Hawai'i Administrative Rules (HAR), point sources are subject to a GHG emission cap to ensure emissions from stationary sources (both minor and major) return to 1990 GHG levels by 2020. The GHG emissions cap must be at least 16% below the baseline level unless the affected facility demonstrates that a 16% reduction is unattainable.

Although based on the analysis herein, we do not believe that permit conditions are required to use the RPS to show progress, nor is it practical to do so given the difficulty in predicting the specifics of the RPS progress. However, Hawaiian Electric intends to provide a further analysis that may include additional strategies to include these two programs in its updated four-factor analysis report.

- e. Flue gas recirculation (FGR) is listed as a technically feasible control option; however, the cost effectiveness of FGR was not evaluated. Please evaluate the cost effectiveness of FGR for reducing boiler NO_x emissions.

Response – The combustion controls in the four-factor analysis includes various air pollution reduction technologies and combinations of these technologies. FGR can be combined with LNB,

⁴ Technical Support Document for EPA's Updated 2028 Regional Haze Modeling, pages 11-12, September 2019. https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf

⁵ Power Sector Modeling Platform v6 November 2018. <https://www.epa.gov/airmarkets/power-sector-modeling-platform-v6-november-2018>

⁶ 2018 (final 1/2019) 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)

if needed. The LNB with overfire air (OFA) costing provided in Appendix Table A-1 of the four-factor analysis was based on costing provided for LNB and LNB with overfire air. The cost of FGR and OFA are expected to be covered by this range and have a similar expected level of NO_x control. Therefore, the costing provided in Appendix Table A-1 of the four-factor analysis is applicable to range of various combustion controls and combinations of these controls.

For clarification, the provided costing for “LNB w/overfire” air will be renamed to “Combustion Controls” in the updated four-factor analysis report and the discussion in the four-factor analysis will also be updated accordingly.

- f. Please add the combination of FGR plus low NO_x burner (LNB) and overfire air (OFA) to Table 4.2 and evaluate the cost effectiveness of this combined NO_x control measure for the boiler.

Response – See response to item e.

- g. Selective non-catalytic reduction (SNCR) is listed as a technically feasible control option; however, the cost effectiveness of SNCR was not evaluated. Please evaluate the cost effectiveness of SNCR for reducing NO_x emissions from the boiler.

Response – As stated in Section 4.1.2.2 of the four-factor analysis report, the estimated NO_x control range for SNCR for the Puna Boiler is 0.20-0.25 lb/MMBtu. This estimated control range is in the same range as combustion controls.⁷ SNCR is only effective in a relatively high and narrow temperature range and therefore is not suitable for all applications. Several factors determine whether SNCR is an appropriate control for a source, including temperature, residence time, the feasibility of installing reagent injection ports, and the NO_x concentration.⁸ These site-specific operating and design characteristics of the emission unit must be evaluated on a case-by-case basis to determine whether SNCR is feasible. For these reasons, the effectiveness of SNCR will be based on the upper range of the estimated controlled emissions level.

EPA's SNCR costing spreadsheet was used to calculate the SNCR cost effectiveness for the Kahe Generating Station's units K1 and K5 (wall-fired boiler), K6 (wall-fired boiler with LNB), and K3 (tangentially-fired boiler). The SNCR cost effectiveness calculations for K1, K3, K5, and K6 are provided as representative costing for wall-fired and tangentially-fired boilers. Hawaiian Electric proposes to use this SNCR costing as a representative analysis for boilers at the Kahe, Waiau, Kahului, Kanoelehua-Hill, and Puna Generating Stations instead of providing SNCR costing for each boiler. Due to the uncertainty in the level of control offered by SNCR, the upper control range was used (0.40 lb/MMBtu for wall-fired boilers (K1 and K5) and 0.25 lb/MMBtu for tangentially-fired boilers) in the cost effectiveness calculations. For K6 a control level of 25% (0.15 lb/MMBtu) was used in the cost effectiveness calculation.

The expanded cost effectiveness results for Kahe units K1, K3, K5, and K6 are provided in Attachment 3 included with this Response to Comments attachment. The cost effectiveness of SNCR is greater than combustion controls and offers less control. SNCR has a lower cost effectiveness than SCR and SCR plus combustion controls. However, SNCR results in a lower level of control than SCR alone and SCR plus combustion controls. Based on the provided SNCR results, SNCR does not offer a significantly better control option than combustion controls, SCR, or SCR plus combustion controls.

⁷ *Alternative Control Techniques (ACT) Document – NO_x Emissions from Utility Boiler*, EPA, 1994.

⁸ *Cost Control Manual, Selective Noncatalytic Reduction*, EPA, 2019.

The SNCR upper control range for the Puna Boiler (tangentially-fired boiler) is 0.25 lb/MMBtu based on the evaluation performed for Kahe unit K3 which is also a tangentially-fired boiler.

The SNCR costing spreadsheet and the cost effectiveness results are provided in Attachment 4 included with this Response to Comments attachment.

- h. Please add the combination of SNCR plus LNB and OFA to Table 4.2 and evaluate the cost effectiveness of this combined NO_x control measure for the boiler.

Response – Due to the uncertainty in the level of control offered by SNCR, the combination of combustion controls and SNCR has the same level of expected control range as SNCR alone, approximately 0.20-0.40 lb/MMBtu for wall-fired boilers and approximately 0.15-0.25 lb/MMBtu for tangentially-fired boilers. The SNCR plus combustion controls cost effectiveness calculations for Kahe K1, K5, and K3 are provided as representative costing for wall-fired and tangentially-fired boilers, respectively. The cost effectiveness calculation is based on controlled emission levels of 0.2 lb/MMBtu for Kahe K1 (wall-fired boiler) and 0.15 lb/MMBtu for Kahe K3 (tangentially-fired boiler).

The expanded cost effectiveness results for Kahe K1, K3, K5, and K6 are provided in Attachment 3 included with this Response to Comments attachment and will be also be included in the updated four-factor analysis report. SNCR plus combustion controls has a lower cost effectiveness than SCR and SCR plus combustion controls. However, SNCR plus combustion controls results in a lower level of control than SCR and SCR plus combustion controls. Based on the provided SNCR plus combustion controls results, SNCR plus combustion controls does not offer a significantly better control option than SCR or SCR plus combustion controls. Hawaiian Electric proposes to use this SNCR plus combustion controls costing as a representative analysis for boilers at the Kahe, Waiau, Kahului, Kanoiehua-Hill, and Puna Generating Stations instead of provided SNCR costing for each boiler.

The SNCR upper control range for the Puna Boiler (tangentially-fired boiler) is 0.25 lb/MMBtu based on the evaluation performed for Kahe unit K3 which is also a tangentially-fired boiler.

The SNCR costing spreadsheet and the cost effectiveness results are provided in Attachment 4 included with this Response to Comments attachment.

- i. Please add the combination of SCR plus LNB and OFA to Table 4.2 and evaluate the cost effectiveness of this combined NO_x control measure for the boiler.

Response – The combination of SCR plus combustion controls is expected to reduce NO_x emissions to 0.05 lb/MMBtu and will be added to Table 4-2 and the cost effectiveness of SCR plus combustion controls will be added to Table 4-3 in the updated four-factor analysis report.

- j. A controlled emission level for NO_x of 0.1 pound per million British thermal unit (lb/MMBtu) was assumed for SCR in Table 4-3.

It is generally assumed that new SCR can achieve 0.05 lb/MMBtu (or lower) on an annual basis. The current (2019) CCM states that a 0.05 lb/MMBtu outlet NO_x rate based on a 30-day (boiler operating) average should be obtainable by a power plant boiler with an SCR system.

Response – The 0.05 lb/MMBtu referenced in the CCM generally applies to boilers equipped with combustion controls. As stated in the above response, the combination of SCR plus combustion controls is expected to reduce NO_x emissions to 0.05 lb/MMBtu. For this reason, the

level of SCR control was set to 0.1lb/MMBtu. The requested updates will be provided in the updated four-factor analysis report.

- k. Sections 4.2.4 and 5.2.4 state that the remaining useful life of the boiler does not impact the annualized cost of potential controls because the useful life of the boiler is assumed to be at least as long as the capital cost recovery period, which is fifteen (15) years. Potential control measures under consideration include LNB with OFA and SCR to reduce NO_x emissions and wet scrubber, fuel switching to distillate, and wet electrostatic precipitator for reducing PM₁₀ emissions. These sections of the analysis also state that HECO intends to retire the boiler (please refer to comment d). If Hawaiian Electric agrees to include in the analysis, a retirement date that it expects to shutdown this boiler as an enforceable compliance measure, the amortize costs of the potential control measures may be based on the shutdown date. In the situation where an enforceable shutdown date does not exist, the remaining useful life of a control under consideration should be the full period of the useful life of that control as recommended by EPA's Control Cost Manual (CCM). In Appendix A, for detailed costing, a useful life of fifteen (15) years is used, however, the current (2019) CCM specifies a remaining useful life for SCR at power plants of thirty (30) years and twenty (20) years for other sources.

Response - The capital recovery period will be increased to the CCM recommended value of 30-years for boiler controls (combustion controls, SCR, SO₂ post-combustion controls, and PM post-combustion controls). The capital cost recovery period updates will be included in the updated four-factor analysis report. Hawaiian Electric is still evaluating the retirement of its sources as part of the Regional Haze program, but due to the complexity of retirement factors Hawaiian Electric may provide additional information in the updated four-factor analysis report.

- l. In Appendix A, for detailed costing, an interest rate of seven percent (7%) is used for determining the capital recovery factor; however, the CCM spreadsheets recommend using the current bank prime rate (currently at 3.25%) to estimate the costs of additional emission controls, rather than seven percent (7%) used in the analysis. Please see the following site for the current bank prime rate: <https://www.federalreserve.gov/releases/h15/>. The prime interest rate has not been seven percent (7%) or higher in the past twelve (12) years. A three percent (3%) interest rate may also be considered.

Response – Hawaiian Electric will continue to use an interest rate of 7% because it is more appropriate than the prime interest rate for the four-factor analyses. The cost analyses follow the Office of Management and Budget (OMB) and EPA Air Pollution Cost Control Manual (CCM) guidance by using an interest rate of 7% for evaluating the cost of capital recovery. The EPA cost manual states that:

*"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."*⁹

For these analyses, which evaluates equipment costs that may take place more than five (5) years into the future, it is important to ensure that the selected interest rate represents a longer-term view of corporate borrowing rates. The CCM cites the bank prime rate as one indicator of the cost of borrowing as an option for use when the specific nominal interest rate is not

⁹ Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, p. 15. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

available. Over the past 20 years, the annual average prime rate has varied from 3.25% to 9.23%, with an overall average of 4.86% over the 20-year period.¹⁰ However, the EPA CCM cautions the use of bank prime rates and states:

*"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."*¹¹

For this reason, the prime rate should be considered the low end of the range for estimating capital cost recovery. Actual borrowing costs experienced by firms are typically higher.

For economic evaluations of the impact of federal regulations, the OMB uses an interest rate of 7%. OMB Circular A-4 states:

*"As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector."*¹²

The above statement is confirmed in the EPA CCM with the following statement:

*"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. The 3% discount rate represents the social discount rate when consumption is displaced by regulation and the 7% rate represents the social discount rate when capital investment is displaced."*¹³

- m. In Table A-2 of Appendix A, a "Hawaii Island Construction Cost Multiplier" of 1.840 for SCR is used based on the cost of construction geographical multipliers from the "RSMeans Mechanical Cost Data 2016" to account for factors unique to the Hawai'i Island location plus an additional factor to account for additional Hawaiian Electric loadings and overhead. Retrofit factors pertain to the difficulty of installing a piece of hardware, regardless of location. While we recognize that 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 or Alaska, those higher costs must be itemized, justified, and documented.

¹⁰ Board of Governors of the Federal Reserve System Data Download Program, "H.15 Selected Interest Rates," accessed April 16, 2020.
<https://www.federalreserve.gov/datadownload/Download.aspx?rel=H15&series=8193c94824192497563a23e3787878ec&filetype=sheetml&label=include&layout=seriescolumn&from=01/01/2000&to=12/31/2020>

¹¹ Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, p. 16. U.S. EPA Air Economics Group, November 2017.
https://www.epa.gov/sites/production/files/2017-12/documents/epacmcostestimationmethodchapter_7thedition_2017.pdf

¹² OMB Circular A-4, <https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf> - "

¹³ Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, pp. 16-17. U.S. EPA Air Economics Group, November 2017.
https://www.epa.gov/sites/production/files/2017-12/documents/epacmcostestimationmethodchapter_7thedition_2017.pdf

Response – The use of a retrofit factor in lieu of itemized costing is a common method contained in the EPA CCM. The EPA CCM lists the following specific factors that impact retrofit costs:

- The amount of available space between and around the economizer and air heater;
- Congestion downstream of the air heater (i.e., buildings, ID fan, or stack);
- The age/vintage and manufacturer of the boiler;
- The design margin of the existing ID fan (i.e., the need to upgrade or replace fan impellers, replace ID fans, or add booster fans);
- The capacity, condition, and design margins of the electrical distribution system;
- The design margins of the existing structural steel support systems;
- The positive and negative design pressure of the furnace; and
- The number, nature, and type of existing items that must be relocated to accommodate the add-on controls and associated systems.

Although all of the factors listed above will impact the retrofit costs for the Puna Boiler, to determine the specific degree of impact for each individual factor would require a more detailed engineering study to evaluate, provide, and itemize the cost impact of the above factors. It is estimated that such an engineering study could take five (5) months to complete at a cost of approximately \$148,750. In addition, Hawai'i's higher construction cost impacts the cost to address the required equipment upgrades and space constraints which require relocation of existing equipment. Based on these factors, rather than engage in additional time consuming and costly studies, the more conservative upper range of the retrofit factor was selected.

- n. Appendix B of the four-factor analysis indicated that, in the recent past, Hawaii's volcanic SO₂ emissions are about 1,000 times greater than anthropogenic SO₂ emissions and volcanic activity in Hawaii produced as much as two (2) million tons of SO₂ per year. Please note that SO₂ emissions have significantly decreased after the Kilauea eruption ended in September 2018. The United States Geological Survey (USGS) stated, that in 2019, the summit is the only source releasing enough SO₂ emissions to be quantified using ultra-violet spectroscopy. Preliminary USGS results for 2019 indicate an average summit daily SO₂ emission rate of about 43 tons and an annual total SO₂ emission rate of about 17,119 tons which is far lower than the two (2) million tons of SO₂ reported to be emitted by the volcano in Appendix B. Note that the total combined SO₂ emissions from point sources screened for four-factor analyses were about 18,058 tons per year in 2017 which is 939 tons higher than preliminary USGS estimates of volcanic SO₂ for 2019. Since Kilauea eruptive activity ended in September 2018, those point sources now play a more significant part in SO₂ visibility impacts.

Response – Hawaiian Electric agrees that the volcanic SO₂ emissions have significantly decreased since September 2018. The four-factor analysis report Appendix B will be updated to acknowledge this change in the volcanic emissions. However, Hawaiian Electric does not believe that this changes the overall conclusion of the analysis which indicated that the Hawaiian Electric power plants are not significant contributors to visibility impairment at Hawai'i's Class I areas. Although the percent impact of point sources will increase with less volcanic emissions, the absolute value of the point source impacts remains unchanged.

The four-factor analysis report acknowledged that Hawai'i Electric Light's Puna and Kanoelehua-Hill Generating Stations on Hawai'i Island are predominantly upwind of a Volcano's National Park. However, their combined annual SO₂ emissions of about 2,350 tons/year (2017) are still significantly lower than the 17,119 tons/year SO₂ emitted within the park itself

(preliminary USGS 2019 estimate per DOH letter ¹⁴). As such, the SO₂ emissions from volcanic emissions remain the predominate impact to visibility impairment, even with the reduced eruptive activity. Further because of the minimal impact, if any, any suggested controls are not cost effective.

As discussed in Section 2.1 of the four-factor analysis report, Step 1 of the EPA SIP guidance is to identify the 20 percent most anthropogenically impaired days, which requires factoring out volcanic impacts. Hawaiian Electric understands that volcanic activity has decreased since the September 2018. The reduction in volcanic activity should be visible in the 2019 IMPROVE monitoring data. The DOH should review the 2019 IMPROVE monitoring data to assist with defining the level of anthropogenic impaired.

Additionally, Hawaiian Electric, as a key affected company, should be allowed to participate as a major stakeholder in discussing and reviewing the EPA's photochemical modeling and the Western Regional Air Partnership's Hybrid-Single Particle Lagrangian Integrated Trajectory (HYSPLIT) modeling mentioned during the conference call with Hawaiian Electric and the DOH on July 30, 2020.

- o. Appendix B of the four-factor analysis also noted that volcanic activity on Hawaii Island is the largest source of NO_x in the state based on a NO_x emission estimate for the Kilauea Volcano of roughly 125,000 tons per year. Data, indicating worldwide volcano NO_x and SO₂ emissions of 1.5 and 23 teragrams, respectively, was used for the estimate. It was stated that the NO_x was likely caused by thermal contact of air with lava. Based on the NO_x/SO₂ ratio using the worldwide numbers, it was then assumed that NO_x emissions from Kilauea Volcano are about 6% of the volcano's total SO₂ emissions. It was also assumed that Hawaii volcanic activity emits approximately two (2) million tons per year of SO₂. Please note that the global ratio of NO_x/SO₂ is likely not appropriate to use for estimating NO_x emissions from the Kilauea Volcano. Interagency Monitoring of Protected Visual Environments 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 is located. Also, while volcanic SO₂ emissions were reported to be as high as two (2) million tons per year when the Kilauea Volcano was erupting, SO₂ emissions have significantly decreased after the Kilauea eruption ended in September 2018. There currently is no lava in the Kilauea summit crater. Instead, a lake of water has formed in the Kilauea crater after the volcano stopped erupting towards the end of 2018. Please refer to: <https://earthobservatory.nasa.gov/images/146687/a-new-lakewater-not-lavaon-kilauea>.

Response – Hawaiian Electric recognizes that estimates of NO_x emissions from the volcano are uncertain as are the significance of its impact to nitrate haze. Appendix B of the four-factor analysis will be updated to recognize this and acknowledge that monitoring data does not suggest a large impact from the volcanos. However, more importantly, as discussed in the four-factor analysis report, monitoring data for both National Parks shows that the total contribution of nitrates from all sources to haze is very low as both a percentage of the total impairment, and is also low as an absolute value for extinction (visibility impairment). The total nitrate haze impairment is approximately 1 inverse megameter (“Mm⁻¹”), an extremely small value which is the total due to ALL sources, natural and anthropogenic. The small impact of NO_x emissions to haze formation is due to the unique chemistry of nitrate haze and Hawai'i's generally warm weather year-round as explained in the four-factor analysis report.

¹⁴ State of Hawaii Department of Health. Letter to Hawaiian Electric regarding Four-Factor Analysis for Regional Haze. July 8, 2020.

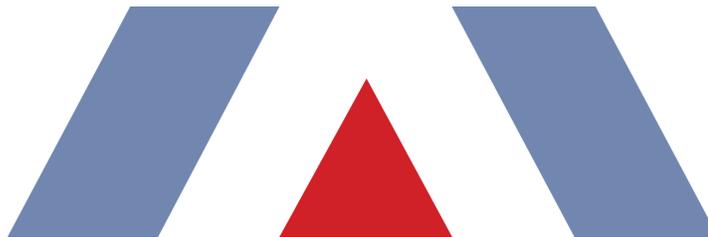
Regarding the noted significant decrease in volcanic SO₂ emissions, see the previous response to item n.

- p. In the four-factor analysis, Hawaiian Electric states that no reduction measures in addition to Hawaii's Renewable Portfolio Standards are proposed to meet the RHR requirements. While provisions mandated by the RPS are subject to enforcement action by the Hawaii Public Utilities Commission, these are state only enforceable requirements which are not federally enforceable under the federal Clean Air Act. The RHR requires federally enforceable emission limits and/or RH-SIP approved rule provisions in establishing the long-term strategy for regional haze. As an option, Hawaiian Electric may propose caps for the emissions of visibility impairing pollutants (SO₂, NO_x, and PM₁₀) based on anticipated emission reductions from the RPS as a reasonable progress measure that could be incorporated into permits. These emission caps would need to occur in the second planning period (2018-2028) to be credited as a control measure for reasonable progress. Additional measures for showing reasonable progress include federally enforceable plant shutdowns as described in comment d above. In essence, Hawaiian Electric could propose: 1) federally enforceable conditions for retiring units during the second implementation planning period (2018-2028) and include those units and retirement dates in the four-factor analysis along with a four-factor analysis of the remaining equipment; 2) propose federally enforceable emission control measures such as fuel switching or add-on controls with the associated pollutant reductions, or 3) propose federally enforceable permit limits such as emission caps, for operational flexibility, or hour restrictions with the associated compliance dates or any combination of 1, 2, or 3 above.

Response – See response to item d.

Revised Four – Factor Analysis

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REGIONAL HAZE FOUR-FACTOR ANALYSIS

Puna Generating Station



**Hawaiian
Electric**

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TABLE OF CONTENTS

1. EXECUTIVE SUMMARY	1-1
2. BACKGROUND AND ADDITIONAL FACTORS	2-1
2.1. Regional Haze Rule Background	2-1
2.2. Additional Factors.....	2-3
3. SULFUR DIOXIDE FOUR-FACTOR ANALYSIS	3-1
3.1. Sulfur Dioxide Control Options.....	3-1
3.2. Four-Factor Analysis	3-3
3.3. Sulfur Dioxide Conclusion	3-7
4. NITROGEN OXIDES FOUR-FACTOR ANALYSIS	4-1
4.1. Nitrogen oxides Control Options.....	4-1
4.2. Four-Factor Analysis	4-5
4.3. Nitrogen Oxides Conclusion.....	4-8
5. PARTICULATE MATTER FOUR-FACTOR ANALYSIS	5-1
5.1. Particulate Matter Control Options.....	5-1
5.2. Four-Factor Analysis	5-3
5.3. Particulate Matter Conclusion	5-5
6. TOTAL COST EFFECTIVENESS OF FUEL SWITCHING	6-1
APPENDIX A: DETAILED COSTING	A-1
APPENDIX B: HAWAIIAN ELECTRIC REGIONAL HAZE VISIBILITY CONSIDERATIONS	B-1
APPENDIX C: HAWAI'I'S RENEWABLE PORTFOLIO STANDARDS CONTRIBUTION TO REGIONAL HAZE PROGRESS	C-1
APPENDIX D: FUEL COST	D-1

DRAFT

LIST OF TABLES

Table 3-1. 2017 Fuel Property Data and Usage Baseline SO ₂ Emissions	3-1
Table 3-2. SO ₂ Cost Effectiveness of Switching to a Residual Oil/Diesel Blended Fuel	3-4
Table 3-3. SO ₂ Cost Effectiveness of Switching to Diesel Fuel	3-4
Table 3-4. SO ₂ Cost Effectiveness of Switching to a Residual Oil/ULSD Blended Fuel	3-5
Table 3-5. SO ₂ Cost Effectiveness of Switching to ULSD	3-5
Table 4-1. Baseline NO _x Emissions	4-1
Table 4-2. NO _x Reduction from Fuel Switching	4-2
Table 4-3. Control Effectiveness of Technically Feasible NO _x Control Technologies	4-4
Table 4-4. NO _x Cost Effectiveness Summary	4-7
Table 5-1. Baseline PM ₁₀ Emissions	5-1
Table 5-2. PM ₁₀ Reduction from Fuel Switching	5-2
Table 5-3. PM ₁₀ Cost Effectiveness Summary	5-4
Table 6-1. Total Cost Effectiveness of Fuel Switching	6-1

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1. EXECUTIVE SUMMARY

The State of Hawai'i has two Class I areas (National Parks) that trigger compliance with the Regional Haze Rule (RHR); Hawai'i's Mandatory Federal Class I Areas are Haleakalā National Park on Maui Island and Hawai'i Volcanoes National Park on the Hawai'i Island. This report documents the results of the Regional Haze Rule (RHR) second planning period four-factor analysis conducted by Trinity Consultants (Trinity) on behalf of Hawaiian Electric¹ for the Puna boiler and combustion turbine (CT-3) at the Puna Generating Station (Puna). The Puna boiler is a 15.5 megawatt (MW) tangentially-fired boiler that currently burns residual oil with a maximum sulfur content of 2.0 percent by weight (residual oil, residual high sulfur fuel oil), and CT-3 is 20 MW simple cycle combustion turbine that currently burns diesel. Also, Appendix B and Appendix C contain analyses performed by AECOM Technical Services, Inc. (AECOM) of a fifth factor that includes a review of visibility impacts.

This report addresses the options that could be considered that have the potential to lower emissions and the potential to show reasonable progress towards the RHR goals. The results of the four-factor analysis herein are consistent with the conclusions reached for the first planning period Best Available Retrofit Technology (BART) five-factor analysis for the Hawai'i Electric Light Kanoelehua-Hill Generating Station. Other long-term emission reduction strategies, such as those included as part of Hawai'i's Renewable Portfolio Standards (RPS), the Hawaiian Electric Partnership Greenhouse Gas Emissions Reduction Plan (GHG ERP) required by Act 234 and the associated State of Hawai'i Department of Health (DOH) GHG Emissions Regulations (Hawaii Administrative Rules Title 11, Chapter 60.1, Subchapter 11) which require State enforceable GHG emissions limits, and Hawai'i's Energy Efficiency Portfolio Standard (EEPS), are viable alternatives to emission reductions from add-on controls and changes in the method of operations.

Hawaiian Electric and AECOM met with the DOH on February 12, 2020 to present special circumstances that apply in Hawai'i that should be given consideration in the development of the Hawai'i Regional Haze State Implementation Plan (SIP). Significant among those circumstances is Hawai'i's Statutory RPS which have put the state on a timetable to accomplish the same goals as the RHR twenty years before the actual Regional Haze 2064 target date. These same issues were addressed by the U.S. Environmental Protection Agency (EPA) in the Federal Implementation Plan (FIP) and the State of Hawai'i Department of Health in their Progress Report² that was approved by the EPA effective on September 11, 2019. These special considerations are discussed further in Appendix B and Appendix C to this report.

Based on the four-factor analysis, Hawaiian Electric does not propose any emission reduction measures in addition to the Hawai'i RPS, EEPS, and the GHG ERP to meet the RHR requirements.

¹ 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.

² 5-Year Regional Haze Progress Report For Federal Implementation Plan, Hawai'i State Department of Health, October 2017, EPA-R09-OAR-2018-0744-0004

DRAFT

2. BACKGROUND AND ADDITIONAL FACTORS

2.1. REGIONAL HAZE RULE BACKGROUND

In the 1977 amendments to the federal Clean Air Act (CAA), the U.S. Congress set a nation-wide goal to restore national parks and wilderness areas to natural visibility conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the EPA published the final RHR (40 CFR Part 51, Subpart P). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Federal Class I areas. The CAA defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres)³, and international parks that were in existence on August 7, 1977.

The RHR requires states to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their jurisdiction. In establishing a reasonable progress goal for a Class I area, each state must:

(A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A). This is known as a four-factor analysis.

(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B). The uniform rate of progress or improvement is sometimes referred to as the glidepath and is part of the state's Long Term Strategy (LTS).

During the first implementation period the EPA issued a FIP (77 FR 61478, October 9, 2012; see also *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii Air Division* U.S. EPA Region 9, May 14, 2012) which determined for the first planning period that NO_x was not contributing to regional haze significantly as to require control measures, and that the Oahu sources were not significantly contributing to regional haze. Additionally, as part of the EPA's decision with respect to BART controls, the EPA took into account that controls would result in "unduly increasing electricity rates in Hawai'i." (see 77 FR 31707, May 29, 2012).

The control measures that were imposed established an emissions cap of 3,550 tons of SO₂ per year from the fuel oil-fired boilers at Hawai'i Electric Light's Hill, Shipman and Puna generating stations, beginning in January 1, 2018, at an estimated cost of 7.9 million dollars per year. According to the FIP, this represents a reduction of 1,400 tons per year from the total projected 2018 annual emissions of SO₂ from these facilities. This control measure, in conjunction with SO₂ and NO_x emissions control requirements that are already in place, was found to ensure that reasonable progress is made during this first planning period toward the national goal of no anthropogenic visibility impairment by 2064 at Hawai'i's two Class I areas.

³ The Class I areas in the state of Hawai'i include the Hawai'i Volcanoes National Park on the Big Island, and Haleakalā National Park on Maui.

DRAFT

The second implementation planning period (2019-2028) for the national regional haze efforts is currently underway. The EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (SIP Guidance)⁴ provides guidance for the development of the implementation plans. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural (or "biogenic") and manmade (or "anthropogenic") sources of emissions. EPA's *Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program* (Visibility Guidance)⁵ provides guidance to the states on methods for selecting the twenty (20) percent most impaired days to track visibility and determining natural visibility conditions. The approach described in this guidance document does not attempt to account for haze formed from natural volcanic emissions; however, the 2017 RHR 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. Because natural visibility can only be estimated or inferred, visibility impairment also is estimated or inferred rather than directly measured.

EPA's Visibility Guidance states that although they did not attempt to account for haze formed by natural volcanic emissions:

We encourage states with Class I areas affected by volcanic emissions to work with their EPA Regional office to determine an appropriate approach for determining which days are the 20 percent most anthropogenically impaired days.

In the *5-Year Regional Haze Progress Report For Federal Implementation Plan*⁶ the DOH acknowledges the impact of SO₂ from the Kilauea volcano with the following statement:

A majority of the visibility degradation is due to the ongoing release of SO₂ from Kilauea volcano with emissions that vary by hundreds of thousands of tons from one year to another. Visibility improvement from significant reductions in Maui and Hawaii Island point source SO₂ is obscured by sulfate from natural volcanic SO₂ that overwhelms sulfate from anthropogenic SO₂ sources.

Step 1 of the EPA's SIP Guidance is to identify the twenty (20) percent most anthropogenically impaired days and the twenty (20) percent clearest days and determine baseline, current, and natural visibility conditions for each Class I area within the state (40 CFR 51.308(f)(1)). Hawaiian Electric has concerns that this key step may not be accounted for during the second implementation planning and the development of Hawai'i's RHR SIP. The identification of the twenty (20) percent most impaired days sets the foundation for identifying any needed emissions reductions.

Pursuant to 40 CFR 51.308(d)(3)(iv), the states are responsible for identifying the sources that contribute to the most impaired days in the Class I areas. To accomplish this, the Western Regional Air Partnership (WRAP), with Ramboll US Corporation, reviewed the 2014 National Emissions Inventory (NEI) and assessed each facility's impact on visibility in Class I areas with a "Q/d" analysis, where "Q" is the magnitude of emissions that impact ambient visibility and "d" is the distance of a facility to a Class I area. The WRAP Guidance itself states that EPA has concerns over only relying on the Q/d method for screening sources. The EPA points out that the Q/d metric is only a rough indicator of actual visibility impact because it does not consider transport direction/pathway and dispersion and photochemical

⁴ Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019, EPA-457/B-19-003

⁵ Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, EPA-454/R-18-010, December 2018

⁶ 5-Year Regional Haze Progress Report For Federal Implementation Plan, Hawai'i State Department of Health, October 2017, EPA-R09-OAR-2018-0744-0004

DRAFT

processes. To address EPA's concern the WRAP subcommittee recommends a second step, application of the weighted emissions potential analysis (WEP).⁷ On September 11, 2019, the DOH informed Hawai'i Electric Light that its Puna Generating Station was identified, based on the Q/d analysis, as one of the sources potentially contributing to regional haze at Volcanoes National Park. This report responds to the DOH September 2019 request to Hawaiian Electric to submit a four-factor analysis for Puna.

The SIP Guidance requires that the selection of controls necessary to make reasonable progress must consider the five required factors listed in section 51.308(f)(2)(iv), and other factors that are reasonable to consider. Hawaiian Electric and AECOM prepared summary, included in Section 2.2, which describes special circumstances that apply in Hawai'i that should be considered during the development of the Hawai'i Regional Haze SIP.

2.2. ADDITIONAL FACTORS

Hawaiian Electric and AECOM met with the DOH on February 12, 2020 to present special circumstances applicable in Hawai'i that should be considered during the development of the Hawai'i Regional Haze SIP. Significant among those circumstances is Hawai'i's Statutory RPS which have put the state on a timetable to accomplish the same goals as the RHR twenty years before the Regional Haze 2064 target date. These same issues were addressed by the EPA in the FIP and the DOH in its Progress Report that was approved by the EPA, effective on September 11, 2019. These special considerations are discussed further in Appendix B and Appendix C to this report and summarized in the following sections.

Additionally, Puna is subject to the DOH's GHG ERP and the associated State enforceable Covered Source Permit limit and thereby, also reduces emissions relevant to the RHR.

2.2.1. Lack of Contribution to Visibility Impairment Due to Warm Weather Conditions

The potential for the formation of haze due to NO_x emissions is very low in Hawai'i because of the warm weather conditions year-round. Nitrate Haze composition analyses for the Haleakalā and Hawai'i Volcanoes National Parks from the IMPROVE web site are included in Appendix B to this report. The data for both national parks show that the contribution of nitrates to haze is very low. It is low as a percentage of the total haze composition, but it is also low as an absolute value for extinction (visibility impairment). The minimal impact of nitrate haze is clearly illustrated in the Hawai'i National Park monitoring data and is much lower than found at many monitors in other Class I areas around the country. This is in large part due to the unique chemistry of nitrate haze which is discussed further in Appendix B to this report.

Due to the low haze impact of NO_x, the DOH should not consider NO_x controls for the Second Decadal Review for Puna. A similar conclusion was reached during the First Decadal Review, for which the EPA did not consider NO_x controls to be material.

2.2.2. Contribution to Visibility Impairment from Volcanic Activity

Volcanic activity on the Hawai'i Island represents a unique challenge to understanding haze in Hawai'i Class I areas. The Kilauea volcano on Hawai'i Island has been active for several years, and the levels of SO₂ emissions are being monitored by the United States Geological Survey. In addition to volcanoes being large sources of SO₂, they also emit significant amounts of NO_x. It should also be noted that

⁷ WRAP Reasonable Progress Source Identification and Analysis Protocol For Second 10-year Regional Haze State Implementation Plans, dated February 27, 2019
(<https://www.wrapair2.org/pdf/final%20WRAP%20Reasonable%20Progress%20Source%20Identification%20and%20Analysis%20Protocol-Feb27-2019.pdf>)

DRAFT

volcanic activity on Hawai'i Island is the largest source of NO_x in the state. Volcanic activity on Hawai'i Island is by far the largest source of both SO₂ and NO_x in the state and dominates visibility impairment to Class I areas as to completely obscure any small impact from anthropogenic sources. Significant portions of direct Particulate Matter (PM) emissions are due to volcanic activity. Any minimal impact of NO_x, and PM emissions from power plants are projected to be eliminated well before the end point of the Regional Haze Rule (i.e., 2064) by Hawai'i's State Law: RPS. Thus, the DOH should limit the haze precursors control evaluations solely to SO₂ for the Second Decadal Review for Puna.

2.2.3. Renewable Portfolio Standards

Based on AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, SO₂, NO_x, and PM₁₀ emissions from Puna do not significantly contribute to regional haze. The low impact that Puna may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (Hawai'i Revised Statute (HRS) §269-92) and consistent with the Hawai'i Clean Energy Initiative (HCEI). Both past and projected future decreases in fossil-fueled electric generating unit (EGU) usage are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the RHR. The RPS will substantially reduce emissions of haze precursors (especially SO₂) by 2045. Therefore, further requirements for controls would not affect the showing of further progress under the RHR and, thus, are not needed at this time. This is further discussed in Appendix C to this report. Although RPS is listed as a control measure (which is consistent with the Hawaii Progress Report for Phase 1), it was not necessary to review the RPS in the context of the four-factor analysis as these measures are already planned for implementation and although there are additional costs, they are inherent in the RPS program.

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3. SULFUR DIOXIDE FOUR-FACTOR ANALYSIS

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that SO₂ emissions from Puna do not significantly contribute to regional haze. However, the four-factor analysis is provided in response to DOH's request. The first step in the analysis is to establish a baseline for emissions. Per DOH's letter dated September 11, 2019, calendar year 2017 actual emissions are used to define the baseline emissions for the four-factor analysis. Table 3-1 lists 2017 annual average fuel property data and fuel usage rates that were used in the control costing calculations and the baseline SO₂ emissions for the Puna units.

Table 3-1. 2017 Fuel Property Data and Usage Baseline SO₂ Emissions

Unit	Primary Fuel	2017 Annual Average Fuel Properties ^A			2017 Annual Fuel Usage ^B		SO ₂ Emissions	
		Sulfur Content	HHV (Btu/gal)	Density (lb/gal)	Volume (gal/yr)	Heat Input (MMBtu/yr)	(lb/MMBtu) ^C	(TPY) ^D
Boiler	Residual Oil	1.69%	150,985	8.33	1,304,562	196,969	1.87	184.0
CT-3	Diesel	0.054%	136,533	6.96	763,193	104,201	5.51E-02	2.9
Total								186.9

^A Calendar year 2017 annual average residual oil sulfur content.

^B To account for ignition fuels and used oil usage the equivalent annual residual oil usage for the Boiler was calculated from the 2017 annual average fuel properties and reported SO₂ emissions.

^C The SO₂ emission factors are based on 100% conversion of fuel sulfur to SO₂ and the calendar year 2017 annual average fuel density and higher heating value.

^D Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

3.1. SULFUR DIOXIDE CONTROL OPTIONS

The characterization of emission controls available and applicable to the source is a necessary step before the four-factors can be analyzed. SO₂ emissions are generated during fuel oil combustion from the oxidation of sulfur contained in the fuel. Available SO₂ control technologies for the boilers are:

- Flue Gas Desulfurization (FGD) systems
 - Dry Sorbent Injection (DSI)
 - Spray Dryer Absorber (SDA)
 - Wet Scrubber
 - Circulating Dry Scrubber (CDS)
- Fuel Switching to a residual/distillate blended fuel or a distillate fuel
- Renewable Portfolio Standards (RPS)

The feasibility of these controls is discussed in the following sections.

CT-3 operates on a very limited basis, and post-combustion SO₂ controls are not feasible for combustion turbines. Therefore, fuel switching to ULSD is the only feasible option to reduce SO₂ emissions.

3.1.1. Post-Combustion Controls

FGD applications have not been used historically for SO₂ control on oil-fired boilers the size of Puna boiler (15.5 MW). As there are no known FGD applications for oil-fired boilers, the performance of FGDs on oil-fired boilers is unknown. CDS was identified by an internal engineering study in 2012 as the best FGD option for the Hawaiian Electric Kahe and Waiau boilers. However, the Hawaiian Electric Kahe and Waiau Boilers range in size from 49 MW to 142 MW in comparison to the Puna boiler which is only 15.5 MW. The SO₂ cost-effectiveness calculations for Kahe and Waiau showed that CDS was the least cost-

DRAFT

effective option to reduce SO₂. The EPA took this into account when evaluating the Best Available Retrofit Technology (BART) presumptive SO₂ emission rate for oil-fired units and determined that the presumptive emission rate should be based on the sulfur content of the fuel oil, rather than on FGD⁸. Since there are no applications of FGD on oil-fired boilers in the U.S., FGD, including CDS, is considered an unproven technology for the control of SO₂ from the Puna boiler because of its size and lack of similar applications.

3.1.2. Fuel Switching

The Puna boiler currently burns residual high sulfur fuel oil with a maximum sulfur content of 2.0 percent by weight. The average sulfur content of the residual high sulfur fuel oil purchased in 2017 was approximately 1.69 percent by weight. Switching to a lower sulfur fuel would reduce SO₂ emissions in proportion to the reduction in fuel sulfur content.⁹

On Oahu, 0.5 percent by weight low sulfur fuel oil is produced, and is used at Hawaiian Electric's Kahe and Waiiau Generating Stations on Oahu. However, it is not a technically feasible option for the Puna boiler. This low sulfur fuel oil has a higher viscosity and pour point than the residual high sulfur fuel oil used by the Puna boiler and the current fuel supply chain from Oahu to the Puna boiler cannot support this quality of fuel that is semi-solid at ambient temperatures. For the low sulfur fuel oil to be burned by the Puna boiler, the piping and tanks that are used to transport and store the oil would need to be heated, at a cost of 500 thousand (\$500,000) to 1 million dollars (\$1,000,000), which is not economically feasible because of the very limited remaining time that oil will be burned by the Puna boiler. There are, however, technically feasible options which include blending the current residual high sulfur fuel oil with a lower sulfur distillate fuel (diesel with a maximum sulfur content of 0.4 percent by weight or ultra-low sulfur diesel (ULSD) with a maximum a maximum sulfur content of 0.0015 percent by weight) or switching completely to a lower sulfur distillate fuel. The SO₂ four-factor analysis evaluates these options.

CT-3 is currently permitted to burn diesel with a maximum sulfur content of 0.4 percent by weight. The average sulfur content of the diesel purchased in 2017 was approximately 0.054 percent by weight. Due to the limited operations of CT-3, 2017 emissions were less than three (3) tons of SO₂, and any reduction in fuel sulfur content is expected to have a negligible impact on regional haze. Therefore, the four-factor analysis was not conducted for CT-3.

3.1.3. Renewable Portfolio Standards

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that SO₂ emissions from Puna do not significantly contribute to regional haze. The low impact that Puna may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (HRS §269-92) and consistent with the HCEI. Both past and projected future decreases in fossil-fueled EGU usage are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the RHR. The RPS will substantially reduce emissions of haze precursors (especially SO₂) by 2045. Therefore, further requirements for controls would not affect the showing of further progress under the RHR and, thus, are not needed at this time. This is further discussed in Appendix C to this report. Although RPS is listed as a control measure (which is consistent with the Hawaii Progress Report for Phase 1) it was not necessary

⁸ *Summary of Comments and Responses on the 2004 and 2001 Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations* EPA Docket Number OAR-2002-0076.

⁹ Natural gas has less sulfur than the existing residual fuel oil. However, natural gas is not a technically feasible option because there is no natural gas supply in Hawai'i.

DRAFT

to review the RPS in the context of the four-factor analysis as these measures are already planned for implementation and although there are additional costs, they are inherent in the RPS program.

3.2. FOUR-FACTOR ANALYSIS

As discussed above, fuel switching to a residual/distillate blended fuel or a lower sulfur diesel is the only technically feasible option to reduce SO₂ emissions for the Puna boiler. For the second planning period, the focus is on determining reasonable progress through analyses of the four factors identified in Section 169A(g)(1) of the CAA:

1. The cost of compliance;
2. The time necessary to achieve compliance;
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements.

The four factors for switching the Puna boiler to a lower sulfur residual/distillate blended fuel, or a lower sulfur diesel are discussed in the following sections.

3.2.1. Cost of Compliance

The cost effectiveness of the fuel switching was determined by calculating the annual incremental cost of switching to a lower sulfur fuel divided by the reduction in SO₂ emissions. Switching fuel would require changes to the injectors and the fuel system; however, these expenses were not included in the analysis.

Puna currently purchases residual high sulfur fuel oil from Par Hawaii Refining, LLC (Par Hawaii); current fuel costs are provided in Appendix D. The fuels are refined on Oahu and changes in quantities of residual high sulfur fuel oil and distillate fuels would require new contracts with fuel suppliers. This adds a level of uncertainty to the cost of compliance. Par Hawaii is the only refinery in Hawai'i and is near its production capacity of ULSD. Therefore, increases in ULSD use would require importing ULSD to Hawai'i and for parity, the price of diesel with a maximum sulfur content of 0.4 percent by weight is based on importing diesel to Hawai'i. Appendix D contains the estimated cost of importing ULSD and diesel to Hawai'i.

Table 3-2 presents a summary of the cost effectiveness of switching from residual high sulfur fuel oil to residual high sulfur fuel oil/distillate blended fuel with a maximum sulfur content of 1.0 percent by weight based on blending the current residual high sulfur fuel oil with diesel with a maximum sulfur content of 0.4 percent by weight. The cost effectiveness is determined by dividing the annual cost increase in fuel by the annual reduction in SO₂ emissions. The cost effectiveness of switching to a residual high sulfur fuel oil/diesel blended fuel with a maximum sulfur content of 1.0 percent by weight is \$6,559 per ton SO₂ and would increase fuel cost 500 thousand dollars (\$500,000) annually and 15 million dollars (\$15,000,000) over thirty (30) years.

Table 3-3 presents a summary of the cost effectiveness of switching from residual high sulfur fuel oil to diesel with a maximum sulfur content of 0.4 percent by weight. The cost effectiveness is determined by dividing the annual cost increase in fuel by the annual reduction in SO₂ emissions. The cost effectiveness of switching to diesel fuel with a maximum sulfur content of 0.4 percent by weight is \$6,119 per ton SO₂ and would increase fuel cost 900 thousand dollars (\$900,000) annually and 27 million dollars (\$27,000,000) over thirty (30) years.

DRAFT

Table 3-2. SO₂ Cost Effectiveness of Switching to a Residual Oil/Diesel Blended Fuel

Unit	Current Residual Oil ^A					Residual Oil/Diesel Blend (1.0% maximum Sulfur) ^B						
	2017 Average Sulfur Content (%)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	2017 Annual Heat Input (MMBtu/yr)	2017 SO ₂ Emissions ^D (tpy)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Controlled SO ₂ Emissions (tpy)	SO ₂ Reduced (tpy)	Fuel Cost Differential ^C		SO ₂ Cost Effectiveness (\$/ton)
										(\$/Gal)	(\$/year)	
Boiler	1.69%	150,985	1,304,562	196,969	184.0	141,953	1,387,568	103.61	80.39	0.38	527,276	6,559

^A Based on 2017 average fuel properties and fuel usage.

^B Based on a blend of 37.5% residual oil and 62.5% diesel fuel and the weighted average of the 2017 fuel HHV and density and contract fuel sulfur limits (2.0% for residual oil and 0.4% for diesel).

^C See Appendix D for fuel cost.

^D Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

Table 3-3. SO₂ Cost Effectiveness of Switching to Diesel Fuel

Unit	Current Residual Oil ^A					Diesel (0.4% maximum Sulfur) ^B						
	2017 Average Sulfur Content (%)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	2017 Annual Heat Input (MMBtu/yr)	2017 SO ₂ Emissions ^D (tpy)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Controlled SO ₂ Emissions (tpy)	SO ₂ Reduced (tpy)	Fuel Cost Differential ^C		SO ₂ Cost Effectiveness (\$/ton)
										(\$/Gal)	(\$/year)	
Boiler	1.69%	150,985	1,304,562	196,969	184.0	136,533	1,442,648	40.18	143.82	0.61	880,015	6,119

^A Based on 2017 average fuel properties and fuel usage.

^B Based on 2017 average HHV and density and contract fuel sulfur limit (0.4%).

^C See Appendix D for fuel cost.

^D Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

DRAFT

Table 3-4. SO₂ Cost Effectiveness of Switching to a Residual Oil/ULSD Blended Fuel

Unit	Current Residual Oil ^A					Residual Oil/ULSD Blend (1.0% maximum Sulfur) ^B						
	2017 Average Sulfur Content (%)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	2017 Annual Heat Input (MMBtu/yr)	2017 SO ₂ Emissions ^D (tpy)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Controlled SO ₂ Emissions (tpy)	SO ₂ Reduced (tpy)	Fuel Cost Differential ^C		SO ₂ Cost Effectiveness (\$/ton)
										(\$/Gal)	(\$/year)	
Boiler	1.69%	150,985	1,304,562	196,969	184.0	144,774	1,360,530	104.98	79.02	0.33	448,975	5,682

^A Based on 2017 average fuel properties and fuel usage.

^B Based on a blend of 50.0% residual oil and 50.0% ULSD fuel and the weighted average of the 2017 fuel HHV and density and contract fuel sulfur limits.

^C See Appendix D for fuel cost.

^D Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

Table 3-5. SO₂ Cost Effectiveness of Switching to ULSD

Unit	Current Residual Oil					ULSD (0.0015% maximum Sulfur)						
	2017 Average Sulfur Content (%)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	2017 Annual Heat Input (MMBtu/yr)	2017 SO ₂ Emissions ^D (tpy)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Controlled SO ₂ Emissions (tpy)	SO ₂ Reduced (tpy)	Fuel Cost Differential ^C		SO ₂ Cost Effectiveness (\$/ton)
										(\$/Gal)	(\$/year)	
Boiler	1.69%	150,985	1,304,562	196,969	184.0	138,563	1,421,516	0.15	183.85	0.65	923,985	5,026

^A Based on 2017 average fuel properties and fuel usage.

^B Based on 2017 average HHV and density and contract fuel sulfur limit.

^C See Appendix D for fuel cost.

^D Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

DRAFT

Table 3-4 presents a summary of the cost effectiveness of switching from a residual high sulfur fuel oil to residual high sulfur fuel oil/ULSD blend with a maximum sulfur content of 1.0 percent by weight based on blending the current residual high sulfur fuel oil with ULSD with a maximum sulfur content of 0.0015 percent. The cost effectiveness is determined by dividing the annual cost increase in fuel by the annual reduction in SO₂ emissions. The cost effectiveness of switching to a residual/ULSD blended fuel with a maximum sulfur content of 1.0 percent by weight is \$5,682 per ton of SO₂ and would increase fuel cost 400 thousand dollars (\$400,000) annually and 12 million dollars (\$12,000,000) over thirty (30) years.

Table 3-5 presents a summary of the cost effectiveness of switching from residual high sulfur fuel oil to ULSD with a maximum sulfur content of 0.0015 percent by weight. The cost effectiveness is determined by dividing the annual cost increase in fuel by the annual reduction in SO₂ emissions. The cost effectiveness of switching to ULSD fuel with a maximum sulfur content of 0.0015 percent by weight is \$5,026 per ton of SO₂ and would increase fuel cost 900 thousand dollars (\$900,000) annually and 27 million dollars (\$27,000,000) over thirty (30) years.

3.2.2. Time Necessary to Achieve Compliance

If the DOH determines that switching from residual high sulfur fuel oil to a residual high sulfur fuel oil/distillate blended fuel or a lower sulfur diesel is needed to achieve reasonable progress, it is anticipated that this change would take two to three years to implement because of several factors: 1) Although not entirely under its control, Hawaiian Electric generally requests that the State of Hawai'i Public Utilities Commission (Commission) approve fuel contracts and issue its Decision and Order within one year following the filing of the application to the Commission; 2) Hawaiian Electric needs to go through a formal process to request bids from fuel suppliers; 3) Negotiations with the fuel supplier can take up to four months; 4) The schedule for any required infrastructure modifications are dependent on the extent on the required changes; 5) If fuel switching is required at other Hawaiian Electric facilities, the type of fuel to be used for replacement, the effect on the fuel supply, and ability of the local refinery to accommodate the change may be significantly impacted; and 6) Imported fuel may be required if there is a lack of local supply.

3.2.3. Energy and Non-Air Quality Environmental Impacts

There are no energy and non-air quality environmental impacts of compliance for fuel switching. The cost increase associated with fuel switching to a lower sulfur fuel will increase the cost of the electricity produced by Puna. This increase will impact the price of electricity for Hawaiian Electric customers because it will not only increase the cost of electricity produced by Puna, but it will also increase the cost of electricity that Hawaiian Electric purchases from independent power producers (IPPs). The contracts with the IPPs are tied to Hawaiian Electric's "avoided cost" of producing electricity. Thus, as Hawaiian Electric's fuel costs increase for Puna, the price that the IPPs receive for the electricity they provide increases. As a result, the costs of all electricity sources on Hawai'i Island increase as Hawaiian Electric's fuel costs increase.

The impact on the price of electricity is an important cost to the community that must be considered. Hawaiian Electric encourages the DOH to use the flexibility in the EPA's SIP guidance¹⁰ in the selection of control measures necessary to make reasonable progress and to consider additional factors when developing the long-term strategy to improve visibility at Class I areas. Also, given the fragile condition of the state's fuel supply and Hawaiian Electric's position as a major customer in the state's fuel market, a fuel supply change could have sweeping effects on the island's fuel market that may not be apparent from the cost estimates associated with Hawaiian Electric such as the ability of the local refinery to accommodate the change and potential need for imported fuel.

¹⁰ Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019, EPA-457/B-19-003.

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3.2.4. Remaining Useful Life

Hawaiian Electric's PSIP¹¹, which was accepted by the Public Utilities Commission on July 14, 2017, includes the statement that the Puna boiler will be retired in 2025. Although the plan is not expressly binding with respect to specific dates, this is a necessary step to meet Hawai'i's statutory requirement to discontinue the use of fossil fuels for electric generation by 2045. This retirement will significantly shorten the estimated time the control equipment is used, as calculated in the analysis, and would serve to further increase the removal cost per ton for SO₂.

3.3. SULFUR DIOXIDE CONCLUSION

The cost effectiveness of switching to a residual high sulfur fuel oil/distillate blended fuel with a maximum sulfur content of 1.0 percent by weight ranges from \$5,700 to \$6,600 per ton SO₂ and would increase the fuel cost over 400 thousand dollars (\$400,000) annually and 12 million dollars (\$12,000,000) over thirty (30) years. The cost effectiveness of switching to a diesel fuel with a maximum sulfur content of 0.4 percent by weight is \$6,100 per ton SO₂ and would increase fuel cost 900 thousand dollars (\$900,000) annually and 27 million dollars (\$27,000,000) over thirty (30) years. The cost effectiveness of switching to ULSD fuel with a maximum sulfur content of 0.0015 percent by weight is \$5,000 per ton of SO₂ and would increase fuel cost 900 thousand dollars (\$900,000) annually and 27 million dollars (\$27,000,000) over thirty (30) years. With the exception of switching to ULSD, these costs are greater than the BART and reasonable progress thresholds established in the first planning period of \$5,600 per ton and \$5,500 per ton, respectively.¹²

While there are no fuel changes or add-on controls proposed, it should be mentioned that other long-term emission reduction strategies, such as those included as part of the Hawai'i RPS, EEPS, and the GHG ERP are viable alternatives that would create greater benefits and allow for the demonstration of reasonable progress.

¹¹ *Hawaiian Electric Companies' PSIP Update Report*, PUC Docket 2014-0183, December 23, 2016.

¹² *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawai'i*, U.S. EPA Region 9, May 14, 2012

DRAFT

4. NITROGEN OXIDES FOUR-FACTOR ANALYSIS

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that NO_x emissions from Puna do not significantly contribute to regional haze. However, the four-factor analysis is provided in response to DOH's request. The first step in the analysis is to establish a baseline for emissions. Per DOH's letter dated September 11, 2019, calendar year 2017 actual emissions are used to define the baseline emissions for the four-factor analysis. Table 4-1 lists the baseline NO_x emissions for Puna.

Table 4-1. Baseline NO_x Emissions

Unit	NO _x Emissions		(TPY) ^C
	Primary Fuel Emissions Factor (lb/MMBtu) ^A	Adjusted Emission Factor (lb/MMBtu) ^B	
Boiler	0.213	0.230	22.7
CT-3	0.131	--	6.8
Total			29.5

^A Calendar year 2017 emission factors from the 2018 Emissions Fee Report.

^B The adjusted emission factor include emissions from the ignition fuels and used oil.

^C Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

CT-3 operates on a very limited basis. Total 2017 NO_x emissions from CT-3 was less than seven (7) tons, and any reductions in NO_x emissions are expected to have a negligible impact on regional haze reasonable progress. Therefore, the four-factor analysis is not conducted for CT-3.

4.1. NITROGEN OXIDES CONTROL OPTIONS

The characterization of emission controls available and applicable to the source is a necessary step before the four-factors can be analyzed. NO_x emissions are produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e., fuel versus combustion air) has led to the use of the terms "thermal NO_x" and "fuel NO_x." Thermal NO_x emissions are produced when elemental nitrogen in the combustion air is oxidized by high combustion temperatures. Fuel NO_x emissions are created by the oxidation of nitrogen contained in the fuel. NO_x emissions from residual oil can be up to fifty percent fuel NO_x.¹³

The formation of NO_x compounds in utility boilers is sensitive to the method of firing and combustion controls utilized. Nitrogen oxide (NO) is typically the predominant form of NO_x emissions from fossil fuel combustion, with the remaining NO_x being the form of nitrogen dioxide (NO₂). The NO₂/NO_x in-stack ratio for boilers is typically less than ten percent.

Available NO_x control technologies for the boilers are categorized as combustion or post-combustion controls. Combustion controls reduce the peak flame temperature and excess air in the furnace, which minimizes NO_x formation. Post-combustion controls convert NO_x in the flue gas to molecular nitrogen and water. Available NO_x control technologies for the boilers are:

- Fuel Switching to a residual/distillate blended fuel or a distillate fuel

¹³ AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.3

DRAFT

- Combustion Controls
 - Flue Gas Recirculation (FGR)
 - Overfire Air (OFA)
 - Low NO_x Burners (LNB)
- Post-Combustion Controls
 - Selective Catalytic Reduction (SCR)
 - Selective Non-Catalytic Reduction (SNCR)
- Renewable Portfolio Standards (RPS)

The feasibility of these controls is discussed in the following sections.

4.1.1. Fuel Switching

The Puna boiler currently burn residual oil. Blending the current residual oil with distillate fuel or switching to a distillate fuel will result in only minor reductions in NO_x emissions due to the lower fuel bound nitrogen content. The NO_x four-factor analysis evaluates both options. Table 4-2 provides the estimated control levels for fuel switching.

Table 4-2. NO_x Reduction from Fuel Switching

Fuel Scenario	AP-42 NO _x Emission Factors ^A	Percent NO _x Reduction
	Tangentially-Fired Boilers (lb/MMBtu)	from Fuel Switching ^B Boiler
Residual Oil	0.213	--
Distillate (ULSD)	0.171	20%
50/50 Blend	--	10%

^A The listed emission factors are from AP-42, Table 1.3-1, dated May 2010.

^B The percent reduction is based on the ratio of AP-42 emissions factors for residual fuel oil and No. 2 fuel oil.

4.1.2. Combustion Controls

4.1.2.1. Flue Gas Recirculation (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical FGR system, flue gas is collected from the combustion chamber or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the “combustion air” (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures, which in turn reduces thermal NO_x formation. When operated without additional controls, the NO_x control range for tangentially-fired boilers is approximately 0.15-0.20 lb/MMBtu.¹⁴ This control is a technically feasible option for the Puna boiler.

4.1.2.2. Overfire Air (OFA)

OFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_x by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_x is most likely to be formed. OFA as a single NO_x control technique results in estimated NO_x emissions for

¹⁴ *Alternative Control Techniques (ACT) Document – NO_x Emissions from Utility Boiler* EPA, 1994.

DRAFT

tangentially-fired boilers of approximately 0.20-0.30 lb/MMBtu.¹⁵ This control is a technically feasible option for the Puna boiler.

4.1.2.3. Low NO_x Burners (LNB)

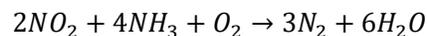
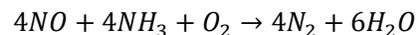
LNB technology utilizes advanced burner design to reduce NO_x formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. In the primary zone, NO_x formation is limited by either one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_x formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_x formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_x formation.

The estimated NO_x control range for LNBs for tangentially-fired boilers is approximately 0.15-0.20 lb/MMBtu.¹⁶ When combined with OFA, the estimated NO_x control range for tangentially-fired boilers is approximately 0.15-0.20 lb/MMBtu.¹⁷ LNB systems are technically feasible for the Puna boiler.

4.1.3. Post-Combustion Controls

4.1.3.1. Selective Catalytic Reduction (SCR)

SCR refers to the process in which NO_x is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because the ammonia preferentially reacts with NO_x rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions are:



The SCR process requires a reactor, catalyst, ammonia storage, and an ammonia injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_x concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. The estimated NO_x control range for SCR is approximately 0.03-0.10 lb/MMBtu for tangentially-fired boilers.¹⁸ When SCR is coupled with combustion controls the estimated NO_x control level is 0.05 lb/MMBtu. This control is a technically feasible option for the Puna boiler.

4.1.3.2. Selective Non-Catalytic Reduction (SNCR)

In SNCR systems, a reagent (ammonia or urea) is injected into the flue gas in the furnace within an appropriate temperature window. The NO_x and reagent react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia- and urea-based SNCR processes require three or four times as much reagent as SCR systems to achieve similar NO_x reductions. The estimated NO_x control range for SNCR for tangentially-fired boilers is approximately 0.15-0.20 lb/MMBtu and 0.13-0.20 lb/MMBtu when combined with combustion controls.¹⁹ The estimated control range for an uncontrolled boiler is in the same range as combustion controls. SNCR is only effective in a relatively high and narrow temperature

¹⁵ Ibid.

¹⁶ Ibid.

¹⁷ Ibid.

¹⁸ Ibid.

¹⁹ Ibid.

range and therefore, is not suitable for all applications. Several factors determine whether SNCR is an appropriate control for a source, including temperature, residence time, the feasibility of installing reagent injection ports, and the NO_x concentration.²⁰ These site-specific operating and design characteristics of the emission unit must be evaluated on a case-by-case basis to determine whether SNCR is feasible. However, the cost effectiveness was evaluated.

4.1.4. Rank of Technically Feasible NO_x Control Options by Effectiveness

The next step is to rank the technically feasible options according to effectiveness. Table 4-3 provides a ranking of the control levels for the controls listed in the previous section.

Table 4-3. Control Effectiveness of Technically Feasible NO_x Control Technologies

Control Technology	Estimated Controlled Level (lb/MMBtu)
SCR+Combustion Controls	0.05
SCR	0.03 - 0.10
LNB & OFA	0.15 - 0.20
FGR	0.15 - 0.20
LNB	0.15 - 0.20
SNCR+Combustion Controls	0.13 - 0.20
SNCR	0.15 - 0.20
OFA	0.20 - 0.30
Fuel Switching	0.18 - 0.21

The control levels in Table 4-3 are presented as a range. This is due to the fact that the specific level of control that is achievable for the Puna boiler based on the application of the controls listed in Table 4-3 is unknown. Engineering studies would be required for the boiler in order to determine the best combustion control option or combinations of control options and the level of control achievable. It is estimated that such an engineering study could take an up to five (5) months to complete at a cost \$148,750 for the Puna boiler. It is anticipated that combustion controls such as LNB and possibly LNB in combination with OFA or FGR can achieve a NO_x emissions level of approximately 0.15 lb/MMBtu for the Puna boiler. As noted in Table 4-1, the Puna boiler is currently emitting 0.23 lb/MMBtu. Further, it is believed that SCR can achieve a NO_x emissions level of approximately 0.10 lb/MMBtu and 0.05 lb/MMBtu when SCR is combined with combustion controls and SNCR can achieve a NO_x emissions level of approximately 0.15 lb/MMBtu and 0.13 lb/MMBtu when SNCR is combined with combustion controls.

4.1.5. Renewable Portfolio Standards

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that NO_x emissions from Puna do not significantly contribute to regional haze. The low impact that Puna may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (HRS §269-92) and consistent with the HCEI. Both past and projected future decreases in fossil-fueled EGU usage are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the RHR. The RPS will substantially reduce emissions of haze precursors (especially SO₂) by 2045. Therefore, further requirements for controls would not affect the showing of further progress under the RHR and, thus, are not needed at this time. This is further discussed in Appendix C to this report. Although RPS is listed as a control measure (which is consistent with the Hawaii Progress Report for Phase 1) it was not necessary

²⁰ *Cost Control Manual, Selective Noncatalytic Reduction*, EPA, 2019.

to review the RPS in the context of the four-factor analysis as these measures are already planned for implementation and although there are additional costs, they are inherent in the RPS program.

4.2. FOUR-FACTOR ANALYSIS

As discussed above, fuel switching, combustion controls, SNCR and SCR are the highest ranking feasible option to reduce NO_x emissions. For the second planning period, the focus is on determining reasonable progress through analyses of the four factors identified in Section 169A(g)(1) of the CAA:

1. The cost of compliance;
2. The time necessary to achieve compliance;
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements.

The four factors for fuel switching, adding combustion controls, SNCR and SCR are discussed in the following sections.

4.2.1. Cost of Compliance

For purposes of this four-factor analysis, the capital costs, operating costs, and cost effectiveness of combustion controls, SNCR and SCR have been estimated. The cost effectiveness of combustion controls is based on a controlled NO_x emissions level of 0.15 lb/MMBtu. At this time, it is unknown if LNBS alone can achieve this level of emissions or if LNB combined with OFA or FGR would be required to meet this level. Therefore, the costing is based on the range of cost for LNB with OFA, the cost of FGR and LNB with FGR are expected to be covered by this range and have a similar level of NO_x control. The costing assumed that a NO_x emissions level of 0.15 lb/MMBtu can be achieved with combustion controls. The cost of fuel switching is discussed in Section 3.1.2.

The cost effectiveness of SNCR is based on a controlled NO_x emissions level of 0.15 lb/MMBtu and 0.13 lb/MMBtu when combustion controls are combined with SNCR. The cost effectiveness of SCR is based on a controlled NO_x emissions level of 0.10 lb/MMBtu and 0.05 lb/MMBtu when combustion controls are combined with SCR. The SCR costing is based on generic EPA control costing²¹ which does not consider Hawai'i's remote location which results in additional shipping and higher construction cost. To account for these higher costs, a Hawai'i Island construction cost multiplier²² of 1.840 was applied to the capital SCR cost.

Table 4-4 presents a summary of the cost effectiveness of fuel switching, adding combustion controls, SNCR, SNCR combined with combustions controls, SCR, and SCR combined with combustion controls. The cost effectiveness is determined by dividing the annual cost by the annual reduction in NO_x emissions. The cost effectiveness of fuel switching exceeds \$197,000 per ton and the total cost exceeds 400 thousand dollars (\$400,000) annually and 12 million dollars (\$12,000,000) over thirty (30) years. The cost effectiveness of combustion controls equals \$13,400 per ton of NO_x and the total cost equals 100 thousand dollars (\$100,000) annually and 3 million dollars (\$3,000,000) over thirty (30) years. The cost effectiveness of SCR equals \$59,700 per ton of NO_x and the total cost equals 800 thousand dollars (\$800,000) annually and 24 million dollars (\$24,000,000) over thirty (30) years. The cost effectiveness of SCR plus combustion control equals \$49,100 per ton of NO_x and the total cost equals 900 thousand dollars (\$900,000) annually and 27 million dollars (\$27,000,000) over thirty (30) years.

²¹ Assessment of Non-EGU NO_x 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

²² The Maui construction cost multiplier is based on cost of construction geographical multipliers from the *RSM Means 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.

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The cost effectiveness of SNCR equals \$29,300 per ton of NO_x and the total cost equals 200 thousand dollars (\$200,000) annually and 6 million dollars (\$6,000,000) over thirty (30) years. The cost effectiveness of SNCR plus combustion control equals \$34,200 per ton of NO_x and the total cost equals 300 thousand dollars (\$300,000) annually and 9 million dollars (\$9,000,000) over thirty (30) years.

These cost ranges assume that the capital costs will be amortized over thirty (30) years with the exception of SNCR, which is amortized over twenty (20). Hawaiian Electric's PSIP²³, which was accepted by the Public Utilities Commission on July 14, 2017, plans that the Puna boiler will be retired in 2025. Although this is not an expressly binding commitment, it is a necessary step to meet Hawai'i's statutory requirement to use no fossil fuel for electricity generation by 2045. This means that the actual amortization period will be less than capital recovery period, and the cost of controls will be higher.

4.2.2. Time Necessary to Achieve Compliance

If the DOH determines that controls are needed to achieve reasonable progress goals, it is anticipated that this change could be implemented in three to five years.

4.2.3. Energy and Non-Air Quality Environmental Impacts

SNCR and SCR systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist.

SNCR and SCR can potentially cause significant environmental impacts related to the storage of ammonia, and the storage of aqueous ammonia above 10,000 pounds is regulated by the risk management program (RMP) because the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. SNCR and SCR will likely also cause the release of unreacted ammonia to the atmosphere. This is referred to as ammonia slip. Ammonia slip from SNCR and SCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_x, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution, which also leads to an excess of unreacted ammonia. Ammonia released from SNCR and SCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate and ammonium nitrate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

4.2.4. Remaining Useful Life

EPA's recommended capital cost recovery periods of thirty (30) years was used for the combustion controls and SCR costing and twenty (20) years was used for SNCR. However, Hawaiian Electric's PSIP²⁴, which was accepted by the Public Utilities Commission on July 14, 2017, includes the statement that the Puna boiler will be retired in 2025. Although the retirement date is not expressly binding with respect to specific dates, it is a necessary step to meet Hawai'i's statutory requirement to discontinue the use of fossil fuels for electricity generation by 2045. This retirement will significantly shorten the estimated time the control equipment is used as calculated in the analysis and would serve to further increase the removal cost per ton for NO_x.

²³ *Hawaiian Electric Companies' PSIP Update Report*, PUC Docket 2014-0183, December 23, 2016.

²⁴ *Ibid.*

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Table 4-4. NO_x Cost Effectiveness Summary

Unit	Control Option	2017 NO_x Emissions^A (tpy)	Controlled Emission Level^{B,C} (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled NO_x Emissions (tpy)	NO_x Reduced (ton/yr)	Total Annual Cost^{D,E} (\$/yr)	Cost Effectiveness (\$/ton)
Boiler	Residual Oil/ULSD Blend ^D	22.7	0.21	196,969	20.4	2.3	448,975	197,786
	ULSD ^D	22.7	0.18	196,969	18.2	4.5	923,985	203,521
	Combustion Controls	22.7	0.15	196,969	14.8	7.9	106,472	13,431
	SNCR	22.7	0.15	196,969	14.8	7.9	232,356	29,311
	SNCR+Combustion Controls	22.7	0.13	196,969	12.8	9.9	338,828	34,235
	SCR	22.7	0.10	196,969	9.8	12.9	766,652	59,655
	SCR+Combustion Controls	22.7	0.05	196,969	4.9	17.8	873,124	49,119

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

^B The controlled emission level for fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 4-2.

^C Controlled emission levels based on “Alternative Control Techniques (ACT) Document – NO_x Emissions from Utility Boiler” EPA, 1994.

^D Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-4 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 a more cost-effective SO₂ solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

^E See Appendix A for the total annual cost calculations for combustion controls, SCR and SNCR.

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4.3. NITROGEN OXIDES CONCLUSION

The cost effectiveness of fuel switching exceeds \$197,000 per ton of NO_x and the total cost exceeds 400 thousand dollars (\$400,000) annually and 12 million dollars (\$12,000,000) over thirty (30) years. Fuel switching is less effective, and the costs are well above the other NO_x controls evaluated.

The cost effectiveness of adding combustion controls to the Puna boiler is \$13,400 per ton of NO_x and the total cost equals 100 thousand dollars (\$100,000) annually and 3 million dollars (\$3,000,000) over thirty (30) years. This cost is similar to the BART analyses conducted for the first planning period. For the first planning period, EPA concluded the emission reductions provided by LNB are unlikely to provide a measurable visibility benefit at Hawai'i Volcanoes National Park or Haleakalā National Park.²⁵

The cost effectiveness of adding SNCR to the Puna boiler equals \$29,300 per ton of NO_x and the total cost equals 200 thousand dollars (\$200,000) annually and 6 million dollars (\$6,000,000) over thirty (30) years. The cost effectiveness of SNCR plus combustion control equals \$34,200 per ton of NO_x and the total cost equals 300 thousand dollars (\$300,000) annually and 9 million dollars (\$9,000,000) over thirty (30) years. The cost effectiveness of SNCR added to uncontrolled boilers is greater than combustion controls and offers less control. SNCR has a lower cost effectiveness than SCR and SCR plus combustion controls. However, SNCR results in a lower level of control than SCR alone and SCR plus combustion controls. Based on these results, SNCR does not offer a significantly better control option than combustion controls, SCR, or SCR plus combustion controls.

The cost effectiveness of adding SCR to the Puna boiler is \$59,700 per ton of NO_x and the total cost equals 800 thousand dollars (\$800,000) annually and 24 million dollars (\$24,000,000) over thirty (30) years for the Puna boiler. The cost effectiveness of SCR plus combustion controls equals \$49,100 per ton of NO_x and the total cost equals 900 thousand dollars (\$900,000) annually and 27 million dollars (\$27,000,000) over thirty (30) years. This cost is similar to the BART analyses conducted for the first planning period. For the first planning period, EPA concluded that SCR was not cost effective.²⁶

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Additionally, reductions in NO_x emissions are expected to have a negligible impact on regional haze. Therefore, Hawaiian Electric does not propose any NO_x emissions reductions in addition to the Hawai'i RPS, EEPS, and the GHG ERP to meet the RHR requirements.

²⁵ *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawai'i*, U.S. EPA Region 9, May 14, 2012

²⁶ *Ibid.*

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5. PARTICULATE MATTER FOUR-FACTOR ANALYSIS

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that PM₁₀ emissions from Puna do not significantly contribute to regional haze. However, the four-factor analysis is provided in response to DOH's request. The first step in the analysis is to establish a baseline for emissions. Per DOH's letter dated September 11, 2019, calendar year 2017 actual emissions are used to define the baseline emissions for the four-factor analysis. Table 5-1 lists the baseline PM₁₀ emissions for Puna.

Table 5-1. Baseline PM₁₀ Emissions

Unit	PM ₁₀ Emissions		(TPY) ^C
	Primary Fuel Emissions Factor (lb/MMBtu) ^A	Adjusted Emission Factor (lb/MMBtu) ^B	
Boiler	0.0983	0.100	9.8
CT-3	0.0201	--	1.05
Total			10.8

^A Calendar year 2017 emission factors from the 2018 Emissions Fee Report.

^B The adjusted emission factor include emissions from the ignition fuels and used oil.

^C Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

5.1. PARTICULATE MATTER CONTROL OPTIONS

PM₁₀ emissions depend predominantly on the grade of fuel fired. Combustion of lighter distillate oils results in lower PM₁₀ emissions than heavier residual oils. Distillate oils have lower ash and sulfur content than residual oil, therefore, producing less PM₁₀ emissions.

Available PM₁₀ control technologies for the Puna boiler are:

- Post-Combustion Controls
 - Dry or Wet Electrostatic Precipitator (ESP)
 - Fabric Filters
 - Wet Scrubber
 - Cyclone
- Fuel Switching to a residual/distillate blended fuel or a distillate fuel
- Renewable Portfolio Standards (RPS)

The feasibility of these controls is discussed in the following sections.

CT-3 operates on a very limited basis, and post-combustion PM₁₀ controls are not feasible for combustion turbines. Fuel switching from diesel to ULSD is not expected to significantly reduce PM₁₀ emissions. Due to the limited operations of CT-3, 2017 PM₁₀ emissions were less than two (2) tons. Any reduction in PM₁₀ emissions from CT-3 is expected to have a negligible impact on regional haze. Therefore, the four-factor analysis was not conducted for CT-3.

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5.1.1. Post-Combustion Controls

PM₁₀ emissions from residual oil-fired boilers tend to be sticky and small. Because of these properties and a general lack of existence in practice, dry ESP, cyclones, and fabric filters are not good technological matches for the Puna boiler.

A wet ESP operates very similarly to a dry ESP but is a better technological match for oil-fired boilers because it is not sensitive to small and sticky particulates. The wet ESP utilizes water to collect and remove the particles and produces a waste-water product. Flue gas leaving the wet ESP will be saturated and may result in a visual steam plume. The estimated PM₁₀ control efficiency is up to ninety percent for a wet ESP.²⁷ Wet ESP is a technically feasible option for control of PM₁₀ for the Puna boiler.

In wet scrubbers PM₁₀ is removed from flue gas when the gas stream is brought into contact with a scrubbing liquid using several approaches: spraying the gas stream with the liquid, forcing the gas stream through a pool of liquid, or by some other contact method. The PM₁₀ in the gas stream is captured in the scrubbing liquid. The PM₁₀-laden scrubbing liquid is separated from the gas stream, and the resultant scrubbing liquid is treated prior to discharge or reuse in the plant. Problems associated with scrubbers include corrosion issues, high power requirements, and water-disposal challenges. However, the use of wet scrubbers for the Puna boiler is considered a technically feasible option. The estimated PM₁₀ removal efficiency for a wet scrubber is fifty-sixty percent.²⁸

5.1.2. Fuel Switching

Residual oil has inherent ash that contributes to the emissions of filterable PM₁₀. Distillate fuels have less ash and ultimately lower filterable PM₁₀ emissions. Filterable PM₁₀ emissions could be reduced by switching to a residual oil/distillate blend or to a distillate fuel. Section 3 discussed the option of fuel switching with respect to reducing SO₂ emissions. As discussed in Section 3, Hawai'i Electric Light has limited fuel options. Switching to a distillate fuel will result in the PM₁₀ emissions reductions and is technically feasible. The PM₁₀ four-factor analysis evaluates both options. Table 5-2 provides the control levels for fuel switching.

Table 5-2. PM₁₀ Reduction from Fuel Switching

Fuel Scenario	AP-42 PM ₁₀ Emission Factors ^A (lb/MMBtu)	Percent PM ₁₀ Reduction from Fuel Switching ^B
Residual Oil	0.1540	--
Distillate (No. 2 Fuel Oil)	0.0236	85%
50/50 Blend	--	43%

^A The listed emission factors are from AP-42, Tables 1.3-1 and 1.3-2, dated May 2010.

^B The percent reduction is based on the ratio of AP-42 emissions factors for residual fuel oil and No. 2 fuel oil.

5.1.3. Renewable Portfolio Standards

AECOM's analysis, *Appendix C: Hawai'i's Renewable Portfolio Standards Contribution to Regional Haze Progress*, concluded that PM₁₀ emissions from Puna do not significantly contribute to regional haze. The low impact that Puna may have on haze is already being reduced through conversion of electric generation to renewable energy sources as mandated by the RPS (HRS §269-92) and consistent with the HCEI. Both past and projected future decreases in fossil-fueled EGU usage are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the RHR. The RPS will substantially reduce emissions of haze precursors (especially SO₂) by 2045. Therefore, further

²⁷ AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1

²⁸ Ibid.

requirements for controls would not affect the showing of further progress under the RHR and, thus, are not needed at this time. This is further discussed in Appendix C to this report. Although RPS is listed as a control measure (which is consistent with the Hawaii Progress Report for Phase 1) it was not necessary to review the RPS in the context of the four-factor analysis as these measures are already planned for implementation and although there are additional costs, they are inherent in the RPS program.

5.2. FOUR-FACTOR ANALYSIS

As discussed above, wet ESP, wet scrubber, and switching to distillate fuel are the best feasible options to reduce PM₁₀ emissions. For the second planning period, the focus is on determining reasonable progress through analyses of the four factors identified in Section 169A(g)(1) of the CAA:

1. The cost of compliance;
2. The time necessary to achieve compliance;
3. The energy and non-air quality environmental impact of compliance; and
4. The remaining useful life of any existing source subject to such requirements.

The four factors for adding wet ESP, wet scrubber, and switching to distillate fuel are discussed in the following sections.

5.2.1. Cost of Compliance

For purposes of this four-factor analysis, the capital costs, operating costs, and cost effectiveness of wet ESP, wet scrubber, and switching to distillate fuel have been estimated. The cost effectiveness calculation is based on the following reduction in PM₁₀ emissions:

- Wet Scrubber – fifty percent,
- Switching to a residual oil/ULSD blend or to ULSD – forty-three percent to eighty-five percent, and
- Wet ESP – ninety percent.

Table 5-3 presents a summary of the cost effectiveness of wet scrubbers, switching to distillate fuel, and wet ESP. The cost effectiveness are:

- Wet Scrubber - \$35,600 per ton and the total cost equals 200 thousand dollars (\$200,000) annually and 6 million dollars (\$6,000,000) over thirty (30) years,
- Switching to a residual oil/ULSD blend or to ULSD – exceeds \$106,000 per ton and the total cost exceeds 400 thousand dollars (\$400,000) annually and 12 million dollars (\$12,000,000) over thirty (30) years, and
- Wet ESP - \$497,000 per ton and the total cost equals 4.4 million dollars (\$4,400,000) annually and 132 million dollars (\$132,000,000) over thirty (30) years.

5.2.2. Time Necessary to Achieve Compliance

If the DOH determines that a wet scrubber or wet ESP is needed to achieve reasonable progress goals, it is anticipated that this change could be implemented in three to five years. If the DOH determines that switching a distillate fuel is needed to achieve reasonable progress, it is anticipated that this change could be implemented within two to three years.

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Table 5-3. PM₁₀ Cost Effectiveness Summary

Unit	Control Option	2017 PM₁₀ Emissions^A (tpy)	Level of Control^B (%)	Controlled PM₁₀ Emissions (tpy)	PM₁₀ Reduced (ton/yr)	Total Annual Cost^{C,D} (\$/yr)	Cost Effectiveness (\$/ton)
Boiler	Wet Scrubber	9.8	50	4.9	4.9	174,674	35,648
	Residual Oil/ULSD Blend ^D	9.8	43	5.6	4.2	448,975	106,544
	ULSD ^D	9.8	85	1.5	8.3	923,985	110,923
	Wet ESP	9.8	90	1.0	8.8	4,382,441	496,875

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

^B Wet scrubber and wet ESP controlled emission levels based on AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1. The controlled emission level for fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 5-2.

^C See Appendix A for total annual cost calculations for wet scrubber and wet ESP.

^D Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-4 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 a more cost-effective SO₂ solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

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5.2.3. Energy and Non-Air Quality Environmental Impacts

ESPs, by design, apply energy to the particles they are collecting. This energy usage can be significant, especially if the wet ESP is designed to control submicron size particles where more energy is applied to collect more of the particles. Wet scrubbers require a substantial amount of energy to force exhaust gases through the scrubber.

Both wet ESPs and wet scrubbers generate wastewater streams that must either be treated on-site or sent to a wastewater treatment plant. Further, the wastewater treatment process will generate a filter cake that would likely require landfilling.

5.2.4. Remaining Useful Life

A capital cost recovery period of thirty (30) years was used for the controls costing. However, Hawaiian Electric's PSIP²⁹, which was accepted by the Public Utilities Commission on July 14, 2017, includes the statement that the Puna boiler will be retired in 2025. Although the plan is not expressly binding with respect to specific dates, it is a necessary step to meet Hawai'i's statutory requirement to discontinue the use of fossil fuels for electricity generation by 2045. This retirement will significantly shorten the estimated time the control equipment is used as calculated in the analysis and would serve to further increase the removal cost per ton for PM₁₀.

5.3. PARTICULATE MATTER CONCLUSION

The cost effectiveness of all the PM₁₀ controls evaluated for all the Puna boiler is more than \$35,600 per ton, and for most controls is more than \$107,000 per ton. The total cost of PM₁₀ controls ranges from 200 thousand dollars (\$200,000) annually and 6 million dollars (\$6,000,000) over thirty (30) years to 4.4 million dollars (\$4,400,000) annually and 132 million dollars (\$132,000,000) over thirty (30) years. These costs are similar to the BART analyses conducted for the first planning period. For the first planning period, the EPA concluded that PM₁₀ controls were not cost effective.³⁰

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Therefore, Hawaiian Electric does not propose any PM₁₀ emissions reductions in addition to the Hawai'i RPS, EEPS, and the GHG ERP to meet the RHR requirements.

²⁹ *Hawaiian Electric Companies' PSIP Update Report*, PUC Docket 2014-0183, December 23, 2016.

³⁰ Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawai'i, U.S. EPA Region 9, May 14, 2012

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6. TOTAL COST EFFECTIVENESS OF FUEL SWITCHING

Table 6-1 lists the cost per total combined tons of SO₂, NO_x, and PM₁₀ reduced for fuel switching the boilers from residual oil to a residual oil/ULSD blend and ULSD. The cost effectiveness is determined by dividing the annual increase in fuel cost by the annual reduction in total SO₂, NO_x, and PM₁₀ emissions. The total cost effectiveness of fuel switching is over \$4,600 per ton of emissions and the total cost exceeds 400 thousand dollars (\$400,000) annually and 12 million dollars (\$12,000,000) over thirty (30) years.

Table 6-1. Total Cost Effectiveness of Fuel Switching

Unit	Control Option	SO ₂	NO _x	PM ₁₀	Total SO ₂ , NO _x	Total	Cost
		Reduced ^A	Reduced ^A	Reduced ^A	and PM ₁₀	Annual	Effectiveness
		(ton/yr)	(ton/yr)	(ton/yr)	Reduced	Cost ^B	(\$/ton)
					(ton/yr)	(\$/yr)	
Boiler	Residual Oil/ULSD Blend	79.0	2.3	4.2	85.5	\$448,975	\$5,251
	ULSD	183.9	4.5	8.3	196.7	\$923,985	\$4,697

^A The SO₂, NO_x, and PM₁₀ reduced are from Tables 3-4 and 3-5, Table 4-4, and Table 5-3, respectively.

^B Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-4 and 3-5. The annual costs of fuel switching are based on 2019 dollars.

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APPENDIX A: DETAILED COSTING

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Appendix Table A-1. Combustion Controls Capital and O&M Cost Estimate

Parameters/Costs	Equation	Boiler
Boiler design capacity, mmBtu/hr (C)		249
Boiler Type		Tangential
2017 Annual Heat Input, MMBtu/yr (H)		196,969
Unit Size, kW (kW)		15,500
Unit Size, MW (MW)		15.5
Capital recovery factor a. Equipment CRF, 30-yr life, 7% interest	$= [I \times (1+i)^a] / [(1+i)^a - 1]$, where I = interest rate, a = equipment life	0.08
Cost Index (CI) ^A a. 2019 b. 2004	607.5 444.2	
Total Capital Investment ^{B,C} TCI (\$)	$= \$18/\text{kW} \times \text{kW} \times (300/\text{MW})^{0.359} \times (\text{CI}_{2019}/\text{CI}_{2004}) - \text{Tangential}$	\$1,105,425
Direct Annual Operating Costs \$/yr Variable O&M Costs ^D	$= \$0.03 \text{ mills}/\text{kW-hr}/1000 \times (1 \text{ kW-hr}/10,000 \text{ Btu}) \times \text{H} \times 10^6$ $\text{Btu}/\text{mmBtu} \times (\text{CI}_{2019}/\text{CI}_{2004}) - \text{Tangential}$	\$808
Indirect Annual Costs, \$/yr 1. Fixed O&M Costs ^E 2. Capital recovery	$= \$0.27/\text{kW} \times \text{Nameplate capacity (MW)} \times (1000 \text{ kW}/\text{MW}) \times$ $(300/\text{MW})^{0.359} \times (\text{CI}_{2019}/\text{CI}_{2004}) - \text{Tangential}$ $= \text{Equipment CRF} \times \text{TCI}$	\$16,581 \$89,082
Total Annual Cost \$/yr	$= \text{Direct Annual Costs} + \text{Indirect Annual Costs}$	\$106,472

Source: All costs were estimated using Section 4.3 and Appendix D of the WRAP guidance document, *Analysis of Combustion Controls for Reducing NO_x 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.

^A Cost Index: Chemical Engineering Plant Cost Index (CEPCI). Chemical Engineering Journal.

^B TCI for LNB and LNB w/over fire air for tangential 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_x control.

^C Scaling factor = (300/Nameplate capacity)^{0.359}

^D The variable O&M costs for LNB and LNB w/over fire air for tangential 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_x control.

^E The fixed O&M costs for LNB and LNB w/over fire air for tangential boilers ranges from \$0.09/kW to \$0.36/kW, the high end of the range was used due to Hawaii's remote location.

Appendix Table A-2. Boiler SCR Capital and O&M Cost Estimate

			Boiler
MW			15.5
Baseline NO _x Emission Rate (lb/MMBtu)			0.23
2017 Annual Heat Input, MMBtu/yr			196,969
Max Heat Input (MMBtu/hr)			249
Capital Recovery Factor (CRF)			0.08
Cost Index ^A			
	2019	607.5	
	1999	390.6	
B =	(lb/MMBtu)		0.23
C =	(%)		90
A =	(kW)		15,500
Z (Eq. 1) =			0.87
Capital Cost (Eq. 2)	(\$/kW)		\$202
Capital Cost (2019)	(\$)		\$4,863,425
Hawai'i Island Construction Cost Multiplier ^B			1.840
Hawai'i Island Capital Cost (2019)			\$8,948,702
Annualized Capital Cost	(\$/yr)		\$721,144
G =			0.09
H =	(MMBtu/hr)		249
D =	(\$/kW)		\$314
Fixed O&M ^C (Eq. 3)	(\$/yr)		\$32,099
Variable O&M Cost (Eq. 4)	(\$/yr)		\$13,410
Total Annual Cost	(\$/yr)		\$766,652

$$Z = \left[\left(\frac{B}{1.5} \right)^{0.05} \left(\frac{C}{100} \right)^{0.4} \right] \quad \text{Equation 1}$$

$$D = 75 \left\{ 300,000 \frac{Z}{A} \right\}^{0.35} \quad \text{Equation 2}$$

Where:

- D = Capital cost (\$/kW)
- B = NO_x (lb/10⁶ Btu) at the inlet of the SCR reactor
- C = NO_x removal efficiency (%)
- A = Plant capacity (kW)

$$E = D \times A \times C \quad \text{Equation 3}$$

Where:

- E = Fixed O&M cost (\$/yr)
- D = Capital cost (\$/kW) from Equation 1
- A = Plant capacity (kW)
- C = A constant, 0.0066 yr⁻¹

$$F = G \left\{ 225 \times \left[0.37 B \times H \times \left(\frac{C}{100} \right) \times \left(\frac{8760}{2000} \right) \right] \times 1.005 \times 1.05 + 0.025 \times D \times A \times Z + 1.45 \times A \right\} \quad \text{Equation 4}$$

Where:

- F = Variable O&M Cost (\$/yr)
- G = Annual capacity factor (expressed as a fraction)
- B = Inlet NO_x (lb/MMBtu); range of 0.15 - 2.5 lb/MMBtu
- H = Heat input (MMBtu/hr)
- C = NO_x removal efficiency; range of 80-95%
- D = Capital cost (\$/kW)
- A = Plant capacity (kW)

$$\text{Capital Recovery Factor (CRF)} = \left[\frac{I \times (1+i)^a}{(1+i)^a - 1} \right] \quad \text{CRF} = 0.08$$

Where:

- I = Interest Rate (7% interest)
- a = Equipment life (30 yrs)

Source: *Cost of Selective Catalytic Reduction (SCR) Application for NO_x 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.

^A Cost Index: Chemical Engineering Plant Cost Index (CEPCI). Chemical Engineering Journal.

^B The Hawai'i Island 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.

^C Fixed Costs include elements such as labor, station power, capital additions/improvements

Appendix Table A-3. Scrubber Capital and O&M Cost Estimate

Parameters/Costs	Equation/Reference	Boiler
Exhaust Temperature (K)	T_{stack}	422.0
Exhaust Temperature (F)	Converted from degrees K	299.9
Exhaust Moisture Content (%)	MS - Typical Values	12.00%
Exhaust Flow Rate (m^3/s) ¹	CSP Application	79.5
Exhaust Flow Rate (ACFM) ¹	Converted from (m^3/s)	168,429
Exhaust Flow Rate (SCFM)	$ACFM * ((68+460)/(T_{stack}+460))$	117,025
m_{wv} (lb/min)	$SCFM * MC * 18/385$	657
m_a (lb/min)	$SCFM * (1-MC) * 29/385$	4,815
humidity ratio	m_{wv}/m_a	0.14
humid volume (ft^3/min)	h (Estimated from psychrometric chart)	23.00
Q_{SAT}	$h * m_a$	110,738.88
Purchased Equipment Cost (Tables 2.5 and 2.6 for a Stainless Steel Low Energy scrubber, 2002 Dollars)	$1.15 * (150 * Q_{SAT}^{0.56})$	\$115,238
Direct Costs - Table 2.8		
Purchased equipment costs		
Packaged Unit (A1)	As estimated, AA	\$115,238
Auxiliary Costs (A2)	$A2 = 0.1 * A1$	\$11,524
Equipment Costs (A)	$A = A1 + A2$	\$126,762
Instrumentation	0.10 A	\$12,676
Sales taxes	0.03 A	\$3,803
Freight	0.05 A	\$6,338
Purchased Equipment cost, PEC	B = 1.18 A	\$149,579
Direct Installation Costs		
Foundation & supports	0.06 B	\$8,975
Handling & erection	0.40 B	\$59,832
Electrical	0.01 B	\$1,496
Piping	0.05 B	\$7,479
Insulation for ductwork	0.03 B	\$4,487
Painting	0.01 B	\$1,496
Direct Installation Costs, DIC	0.56 B	\$83,764
Total Direct Costs, TDC	PEC + DIC	\$233,344
Indirect Costs (installation) Table 2.8		
Engineering	0.10 B	\$14,958
Construction & field expenses	0.10 B	\$14,958
Contractor fees	0.10 B	\$14,958
Start-up	0.01 B	\$1,496
Performance test	0.01 B	\$1,496
Model study	--	
Contingencies	0.03B	\$4,487
Total Indirect Costs, IC	0.35 B	\$52,353
Cost Index ⁵		
a. 2019	607.5	
b. 2002	395.6	
Capital recovery factor (CRF)	$CRF = [I * (1+I)^a] / [(1+I)^a - 1]$, where I = interest rate, a = equipment life	0.08
	a. Equipment CRF, 30-yr life, 7% interest	
Total Capital Investment (2019 Dollars)	(TDC + IC) * (Retrofit factor of 1.4) * (CI₂₀₁₉/CI₁₉₉₉) (Retrofit factor based on average provided for ESP on Page 3-41). No specific factor provided for scrubber, so factor for ESP was relied on.	\$614,219
Annual Costs		
Direct Annual Costs - Section 3.4.1		
Operating Labor		
Operator	3hr/shift*2shifts/day*360 days/yr * \$20/hr	\$43,200
Supervisor	15% of operator	\$6,480
Maintenance		
	Assumed similar labor requirements as to that required for ESP per Section 6, Page 3-47 of OAQPS Cost manual (\$20.00/hr, 7.5 h/wk, 44 wk/yr)	\$6,600
Labor	100% of maintenance labor	\$6,600
Material		\$6,600
Utilities		
	Utilities currently not estimated due to variability	
Total Direct Annual Cost		\$62,880
Annual Indirect Costs, IC		
Administrative charges	2% of Total Capital Investment	\$12,284
Property tax	1% of Total Capital Investment	\$6,142
Insurance	1% of Total Capital Investment	\$6,142
Overhead	60% of total labor and material costs	\$37,728
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	\$49,498
Total Indirect Annual Costs		\$111,794
Total Annual Cost		\$174,674

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 2 - Wet Scrubbers for Particulate Matter, dated July 2002 (EPA/452/B-02-001).

¹ Exhaust parameters from Cover Source Permit Application.

² From Chemical Engineering Plant Cost Index (CEPCI)

Appendix Table A-4. Wet ESP Capital and O&M Cost Estimate

Parameters/Costs	Equation	Boiler
Average High Exhaust Flow Rate (m ³ /s) ¹		79.5
Average High Exhaust Flow Rate (ACFM) ¹		168,429
Annual Operating Time (hrs, θ ¹)		8,760
ESP efficiency (from white paper)		90%
ESP Plate Area (ft ²) ⁴	$ESCA = -\ln(p)/w_e \times 5.080 \times Q$	6,274
Purchased Equipment Cost (Table 3.14 for 90% Control Efficiency and 15,000 ACFM bins)	$\$25.5/\text{acfm}$	\$4,294,946
Basic Equipment Costs -Table 3.12	$0.45 \times \text{Equipment Cost}$	\$1,932,726
Direct Costs - Table 3.16		
Purchased equipment costs		
ESP + auxiliary equipment (A)	As estimated, A	\$6,227,672
Instrumentation	0.10 A	\$622,767
Sales taxes	0.03 A	\$186,830
Freight	0.05 A	\$311,384
Purchased Equipment cost, PEC	B = 1.18 A	\$7,348,653
Direct Installation Costs		
Foundation & supports	0.04 B	\$293,946
Handling & erection	0.50 B	\$3,674,326
Electrical	0.08 B	\$587,892
Piping	0.01 B	\$73,487
Insulation for ductwork	0.02B	\$146,973
Painting	0.02B	\$146,973
Direct Installation Costs, DIC	0.67 B	\$4,923,597
Total Direct Costs, TDC	PEC + DIC	\$12,272,250
Indirect Costs (Installation) Table 3.16		
Engineering	0.20B	\$1,469,731
Construction & field expenses	0.20B	\$1,469,731
Contractor fees	0.10B	\$734,865
Start-up	0.01B	\$73,487
Performance test	0.01B	\$73,487
Model study	0.02B	\$146,973
Contingencies	0.03B	\$220,460
Total Indirect Costs, IC	0.57B	\$4,188,732
Cost Index ⁵		
a. 2019	607.5	
b. 1999	390.6	
Capital recovery factor (CRF)	$CRF = [I \times (1+i)^a] / [(1+i)^a - 1]$, where I = interest rate, a = equipment life a. Equipment CRF, 30-yr life, 7% interest	0.08
Total Capital Investment (2019 Dollars)	(TDC + IC) * (Retrofit factor of 1.4) * (CI₂₀₁₉/CI₁₉₉₉) (Retrofit factor based on average provided for ESP on Page 3-41).	\$35,842,460
Annual Costs		
Direct Annual Costs - Section 3.4.1		
Operating Labor		
Operator	2hr/shift*2shifts/day*365 days/yr * \$20/hr	\$29,200
Supervisor	15% of operator	\$4,380
Maintenance		
Labor	For ESP plate area < 50,000 ft ² = \$4125	\$4,125
Utilities		
	Utilities currently not estimated due to variability	
Total Direct Annual Cost		\$37,705
Annual Indirect Costs, IC		
Administrative charges	2% of Total Capital Investment	\$716,849
Property tax	1% of Total Capital Investment	\$358,425
Insurance	1% of Total Capital Investment	\$358,425
Overhead	60% of total labor and material costs	\$22,623
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	\$2,888,415
Total Indirect Annual Costs		\$4,344,736
TOTAL ANNUAL COST		\$4,382,441

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 3 - Electrostatic Precipitators, dated September 1999 (EPA/452/B-02-001).

¹ Exhaust parameters from Cover Source Permit Application.

² Electricity cost from U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.

³ Water cost from Maui County (<https://www.mauicounty.gov/216/Water-Charges>) lowest general rate.

⁴ For ESP Plate Area (Section 3.2.1):

$p = 1 - (\text{Control Efficiency } \%)$

$5.080 \text{ ft}^2/\text{kacfm} = 1 \text{ (s/m)}$

w_e = effective migration velocity (m/s), assume $w_e = 31.4 \text{ cm/s}$ for Bituminous coal fly ash for a design efficiency of 95% from Table 3.3 (no listings for 90% efficiency or fuel oil)

Q = system flow rate (kacfm)

⁵ From Chemical Engineering Plant Cost Index (CEPCI)

APPENDIX B: HAWAIIAN ELECTRIC REGIONAL HAZE VISIBILITY CONSIDERATIONS

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Appendix B:

Hawaiian Electric Regional Haze Visibility Considerations

Fifth Factor Considerations for SO₂, NO_x, and PM Controls

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Hawaiian Electric¹ Regional Haze Visibility Considerations

Fifth Factor Considerations for SO₂, NO_x and PM Controls

1. Executive Summary

The EPA has issued multiple guidance documents to assist states and facilities address the requirements of the Regional Haze Rule (“RHR”). This guidance allows states to consider, as part of their review of the Four Factor evaluation of possible emission controls for the Second Decadal Review, a “5th factor” which involves consideration of visibility impacts of candidate control options. This appendix introduces several Hawai‘i-specific issues that impact the visibility impact of potential sulfur dioxide (“SO₂”), nitrogen oxides (“NO_x”) and particulate (“PM”) control options for Hawaiian Electric sources relative to the two Class 1 areas in Hawai‘i: the Haleakalā National Park on the island of Maui and the Hawai‘i Volcanoes National Park on Hawai‘i Island. The issues discussed in this report are summarized below:

- 1) Due to unique atmospheric chemistry, NO_x emissions tend to remain in the gaseous (and invisible) phase in warm weather, and only form visible NO₃ (“nitrate”) particulate aerosol in cold weather. This is verified by monitoring data in the Interagency Monitoring of Protected Visual Environments (“IMPROVE”) network in the two national parks mentioned above.
- 2) The persistent East North East (“ENE”) trade winds experienced by the state of Hawai‘i places emission sources on several islands (or portions of islands such as Maui) downwind of the national parks, limiting the likelihood that any emissions from these sources would even reach the parks. Modeling conducted with the California Puff Model (“CALPUFF”) for the First Decadal Review confirms the minimal potential for haze impact of the subject Hawaiian Electric sources on the islands of O‘ahu and Maui due to the predominance of the trade winds. The EPA’s Federal Implementation Plan (“FIP”) issued in 2012 agreed with this assessment.
- 3) EPA previously determined that in Hawai‘i haze due to direct PM was a very small component of haze and that further controls would not be effective in improving visibility. The observed haze speciation is reviewed in this report to confirm this determination.
- 4) The State of Hawai‘i Department of Health Clean Air Branch (“DOH”) should request that the EPA (consistent with their first decadal review approach) set aside NO_x and PM from the list of haze precursors for Hawai‘i due to the unique NO_x haze chemistry and climate, leaving SO₂ as

¹ “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.

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the primary precursor pollutant for haze. Hawaiian Electric requests that the DOH make this proposal to the EPA.

- 5) In the recent past, volcanic activity on Hawai'i Island has produced as much as 2 million tons of SO₂ emissions per year^{2,3} (emissions vary yearly and have decreased significantly since September 2018). Additionally, the volcanic activity, although the volcano eruption ended in September 2018, has contributed significant NO_x emissions in the past⁴. These historic volcanic SO₂ emissions are about three orders of magnitude (approximately 1,000 times) greater than anthropogenic SO₂ emissions. Although the IMPROVE monitors indicate that sulfate haze is the most important haze species, it is evident from monthly haze trends and the likelihood of winds from the volcanic activity reaching the IMPROVE monitors that the overwhelming historic sulfate haze influence comes from natural sources (i.e., volcanic activity).

The locations of the affected Hawaiian Electric sources and the two national parks are shown in Figure B-1. The remainder of this appendix presents details of the above issues and recommendations for how this information should be considered in selection of facilities for Four-Factor analyses and for evaluating potential pollutant control options.

² Information on the volcanic SO₂ emissions in 2014 was provided by the EPA in their SO₂ National Ambient Air Quality Technical Support Document at EPA's 2016 SO₂ NAAQS TSD, at <https://www.epa.gov/sites/production/files/2016-03/documents/hi-epa-tsd-r2.pdf>.

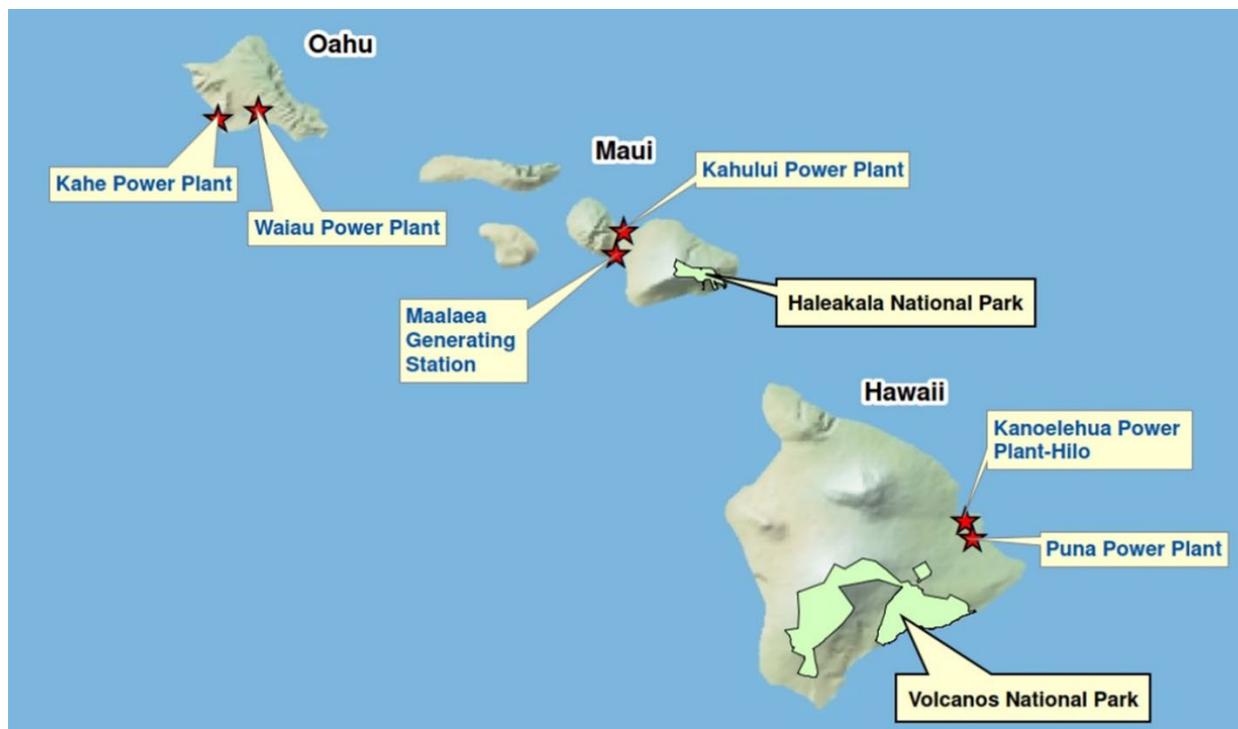
³ Information on 2014-2017 volcanic SO₂ emissions is available in this journal article: Elias T, Kern C, Horton KA, Sutton AJ and Garbeil H. (2018) Measuring SO₂ Emission Rates at Kīlauea Volcano, Hawaii, Using an Array of Upward-Looking UV Spectrometers, 2014–2017. *Front. Earth Sci.* 6:214. doi: 10.3389/feart.2018.00214. <https://www.frontiersin.org/articles/10.3389/feart.2018.00214/full>.

⁴ The NO_x emissions from Hawai'i Island volcanic activity is unknown, but could have historically been as high as 25,000 tons per year if the NO_x emissions rate equals 6% of SO₂ emissions rate. The 6% is derived from worldwide volcanic NO_x emissions estimate of 1.0 Teragram ("Tg" – trillion grams)/year ("yr") nitric oxide ("NO" (or 1.5 Tg/yr NO₂) from <https://www.chemistryworld.com/features/a-volcanic-breath-of-life/3004482.article> and worldwide volcanic SO₂ estimate of 23 Tg/yr from <https://www.nature.com/articles/srep44095>.

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Figure B-1:

Location of Hawaiian Electric Sources Asked to Conduct Four-Factor Analyses and PSD Class I Areas



2. EPA Guidance Regarding Considerations of Visibility Impacts

The EPA issued “Guidance on Regional Haze State Implementation Plans for the Second Implementation Period”⁵ in August 2019. This guidance allows states to consider, as part of its consideration of emission controls to include for the Second Decadal Review a “5th factor” which involves consideration of visibility impacts of candidate control options. A companion document⁶ issued in September 2019 that involves the EPA’s visibility modeling results for 2028 is entitled, “Availability of Modeling Data and Associated Technical Support Document for the EPA’s Updated 2028 Visibility Air Quality Modeling”.

On Page 11 of the August 2019 guidance, the EPA states:

“When selecting sources for analysis of control measures, a state may focus on the PM species that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors.” . . .

⁵ Available at https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

⁶ Available at https://www3.epa.gov/ttn/scram/reports/2028_Regional_Haze_Modeling-Transmittal_Memo.pdf.

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“Also, it may be reasonable for a state to not consider measures for control of the remaining pollutants from sources that have been selected on the basis of their emissions of the dominant pollutants”

Further, on Page 36 and 37, the EPA states:

“Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal.” . . .

“. . . EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress.”

Consequently, the extremely low likelihood for impact to Class I visibility impairment from control of certain facility pollutants and the plant locations relative to the Class I areas is appropriate for consideration when evaluating the need for further control of these emissions for Regional Haze Reasonable Progress.

3. Nitrate Haze Composition Analysis

Nitrate haze composition analyses for the Haleakalā and Hawai‘i Volcanoes National Parks are available at the IMPROVE web site at <http://vista.cira.colostate.edu/Improve/pm-and-haze-composition/>. Figure B-2 provides various charts for the haze species composition at the Haleakalā Crater IMPROVE site, and Figure B-3 provides a time series of stacked bars by species for a recent year at that site. Figures B-4 and B-5 provide similar information for the Hawai‘i Volcanoes IMPROVE site. Note that these figures show information for the worst 20 percent (“%”) impaired days, which is the focus of the RHR for reducing haze. The goal for each decadal review is to track the progress of haze reduction for the worst 20% impaired days; reviewing the composition of haze on these days is a key element in understanding what precursor pollutants to control to achieve the goal.

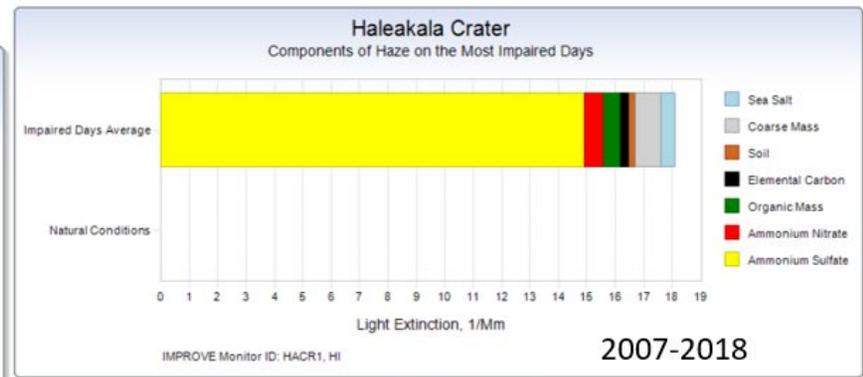
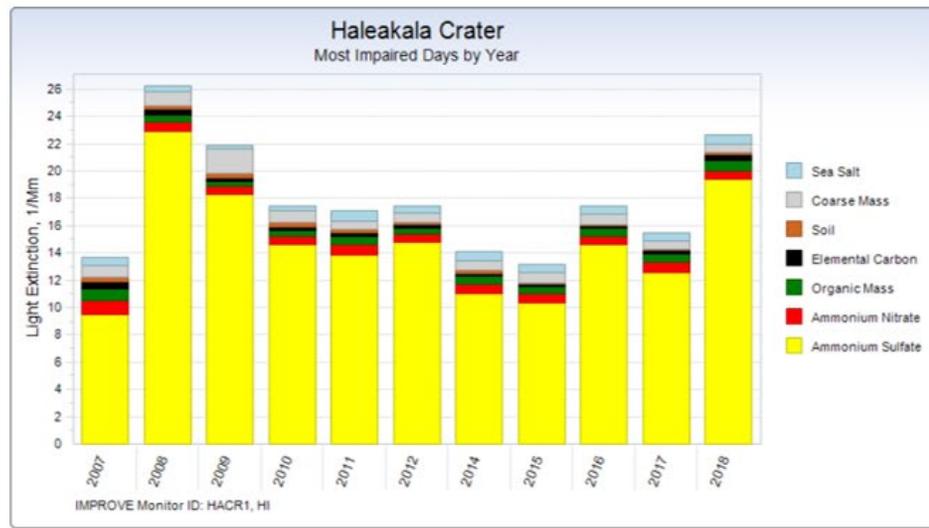
The data for both National Parks shows that the contribution of nitrates to haze is very low as a percentage of the total, but it is also low as an absolute value for extinction (visibility impairment). The total nitrate haze impairment is approximately 1 inverse megameter (“ Mm^{-1} ”), equivalent to approximately 0.25 deciview (“dv”), or less. This is the impairment at these monitors due to ALL sources, natural and anthropogenic.

The minimal impact of nitrate haze is clearly illustrated in the Hawai‘i National Park monitoring data and is much smaller than found at many monitors in other Class 1 areas around the country. This is in large part due to the unique chemistry of nitrate haze, as discussed below.

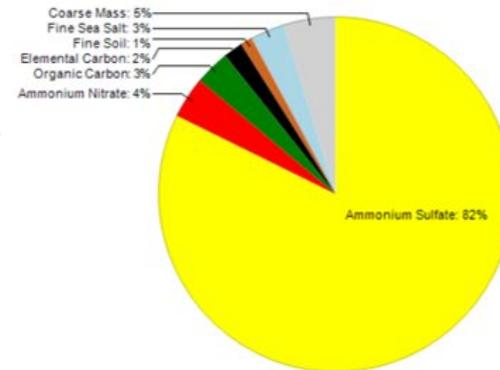
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Figure B-2: Charts Showing the Worst 20% Haze Days Multiple-Year Species Composition for the Haleakalā Crater IMPROVE Site

Light Extinction Summary - Most Impaired Days



Most Impaired Days 2007-2018
Haleakala Crater

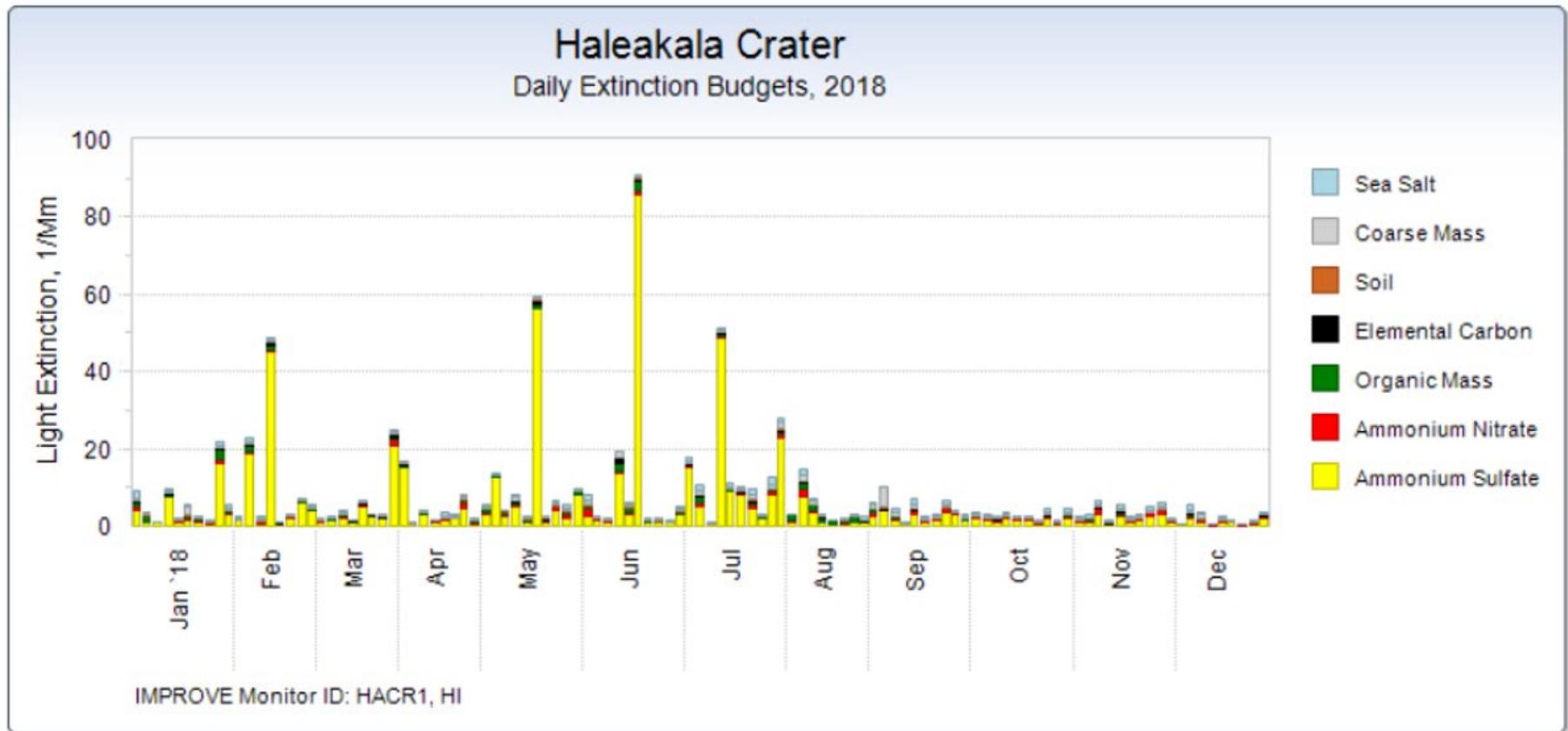


Haleakala Crater IMPROVE monitor

Data source for Figures B-2 through B-5: http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx?appkey=SBCF_VisSum.

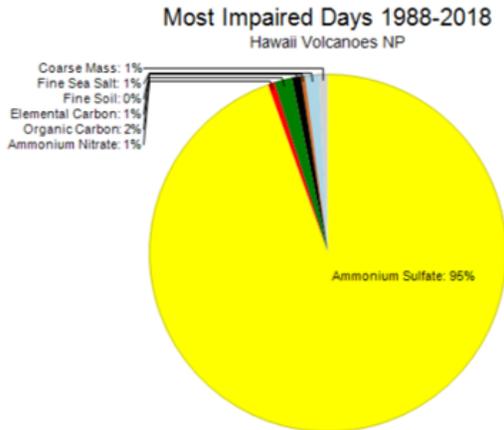
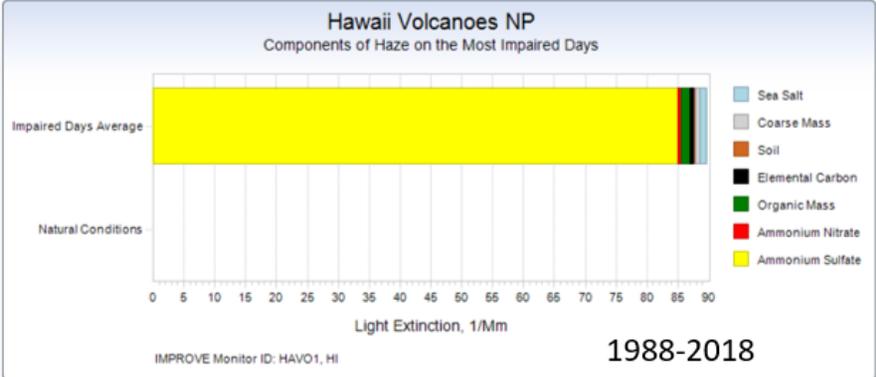
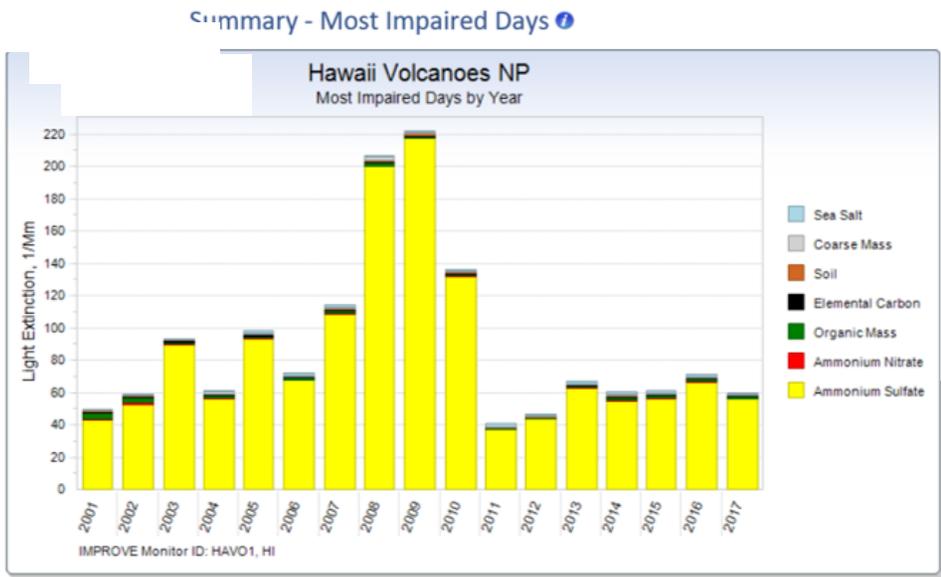
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Figure B-3: Time Series of 2018 Daily Haze Extinction Composition Plots for the Haleakalā Crater IMPROVE Site



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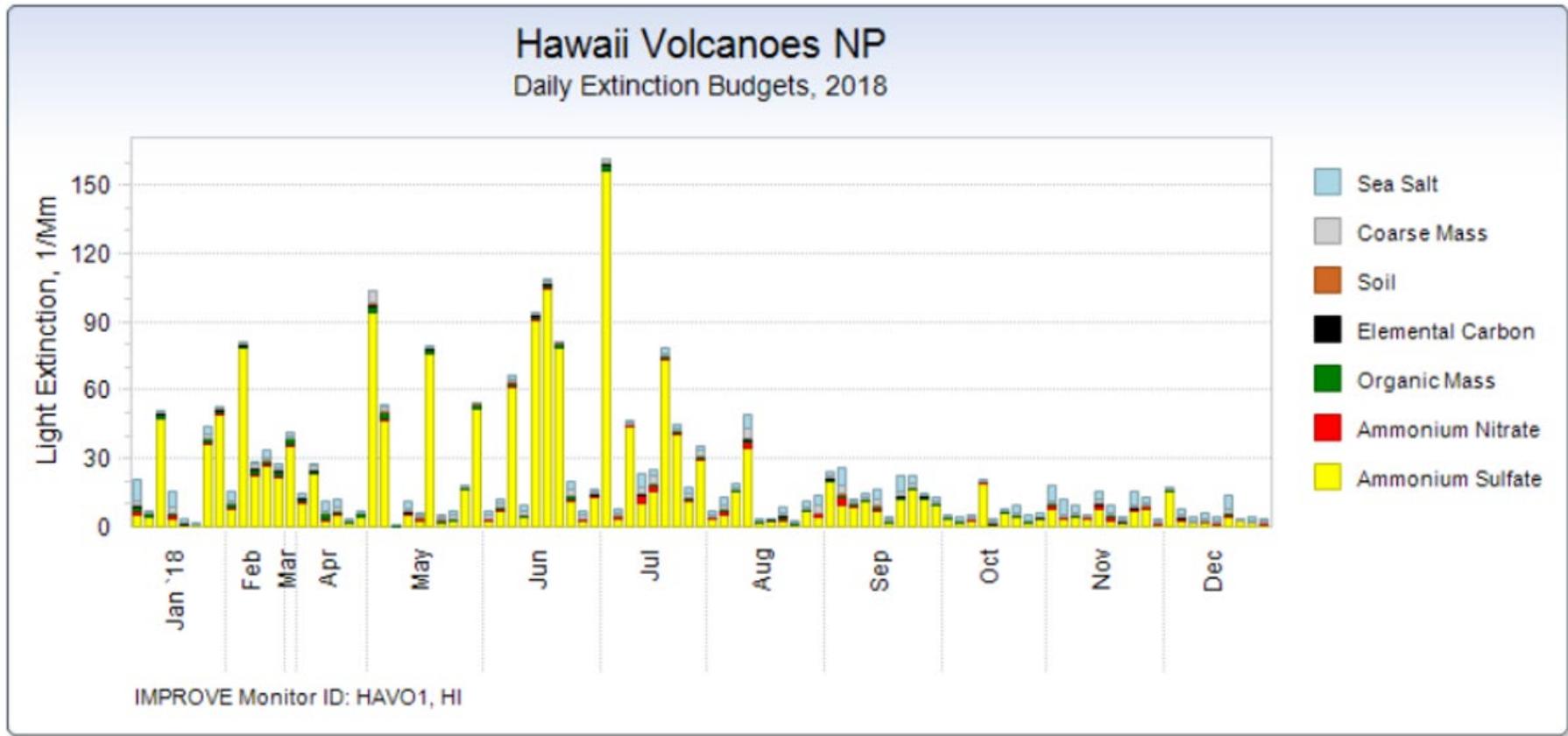
Figure B-4: Charts Showing the Worst 20% Haze Days Multiple-Year Species Composition for the Hawai'i Volcanoes IMPROVE Site



Hawaii Volcanoes NP IMPROVE monitor

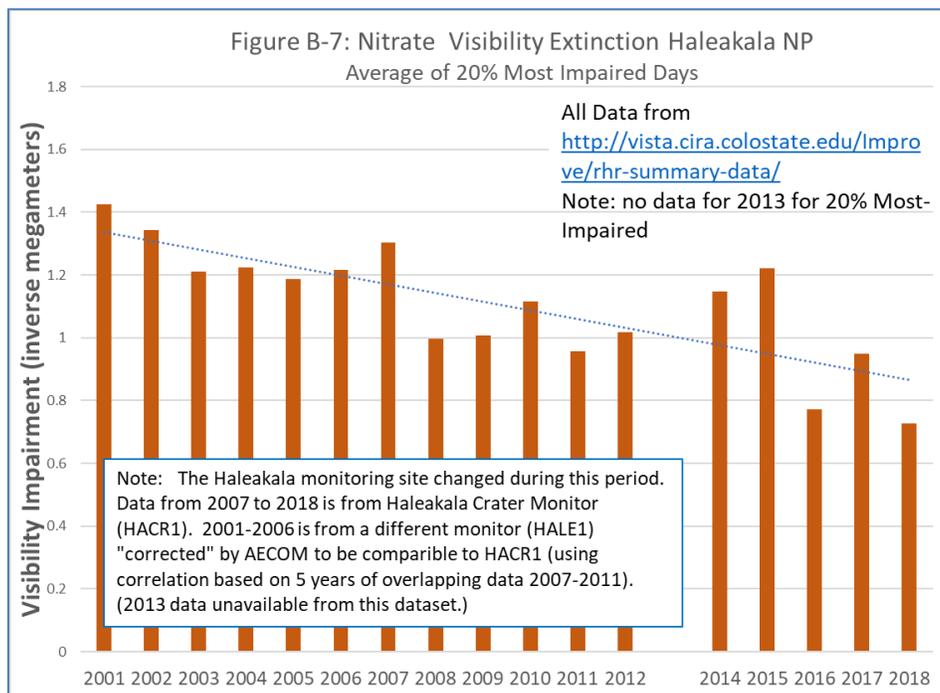
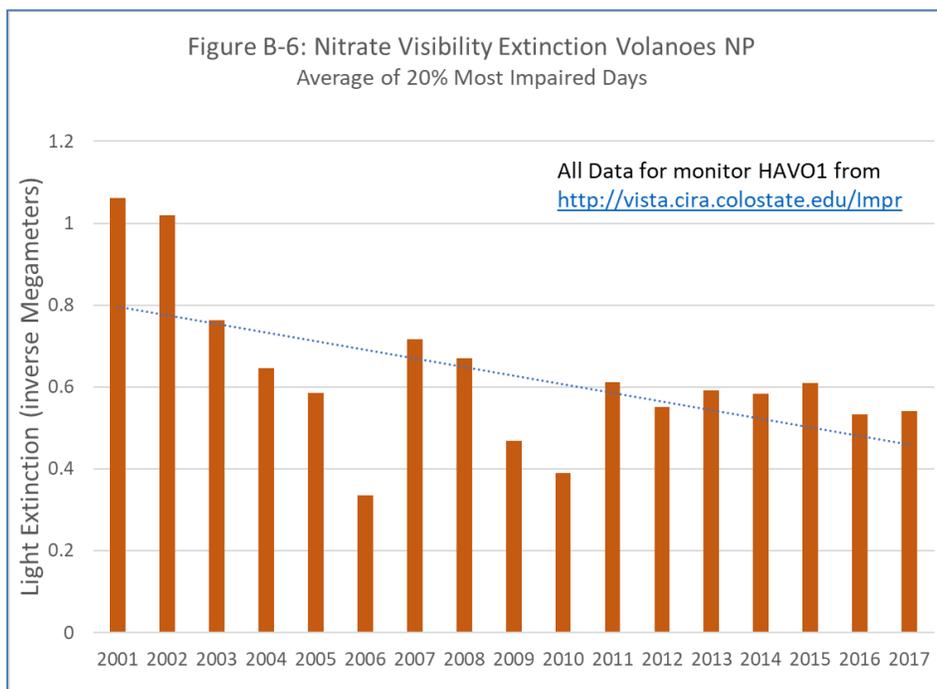
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Figure B-5: Time Series of 2018 Daily Haze Extinction Composition Plots for the Hawai'i Volcanoes IMPROVE Site



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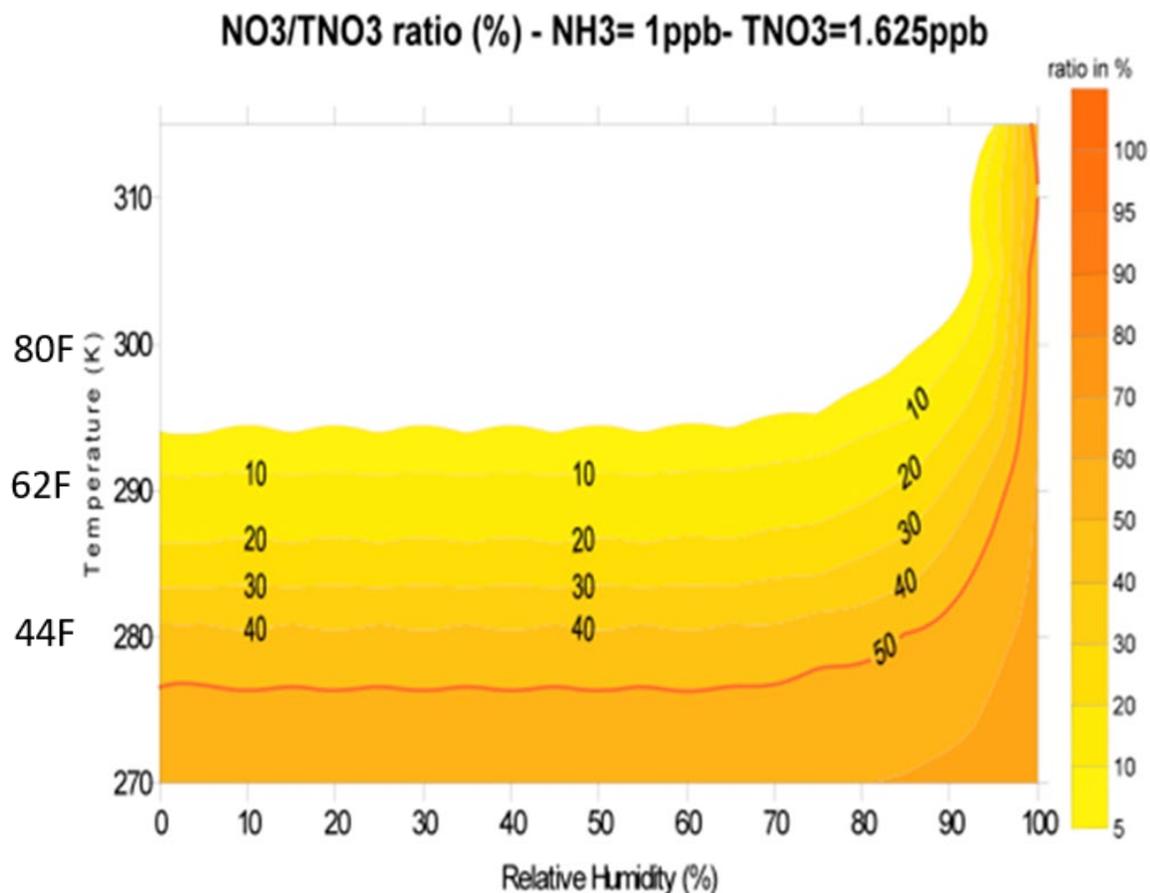
The nitrate contribution to visibility impairment in the above bar charts is shown as a narrow “red” segment. The small size relative to other constituents clearly shows that nitrate is only a small contributor. Additionally, the Figures B-6 and B-7 below which presents only the ammonium nitrate visibility impairment also shows that nitrates, already small contribution, is trending downward.



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The chemistry of nitrate haze formation is highly dependent upon ambient temperature, and to a lesser extent upon humidity. As discussed in the CALPUFF model formulation⁷ and in CALPUFF courses, total nitrate in the atmosphere ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous nitric acid (“ HNO_3 ”) (invisible, and not haze-producing) and nitrate (“ NO_3 ”) haze particles according to the equilibrium relationship between the two species, which is affected by temperature and humidity.

Figure B-8: CALPUFF Example Plot of Aerosol Percentage of Total NOx Equilibrium



The potential for the formation of haze due to NOx emissions is very low in Hawai‘i because of the warm weather conditions year-round. This strong dependency of the equilibrium relationship between invisible gaseous HNO_3 and visible NO_3 haze particles as a function of ambient temperature is illustrated in Figure B-8. In Figure B-8, it is evident that for most conditions, the percentage of total nitrate in the form of particulate (NO_3) is less than 20% for temperatures above approximately 286 degrees Kelvin (approximately 55 degrees Fahrenheit). Temperatures at most locations in Hawai‘i rarely get that low and are not that low at any of the Hawaiian Electric plant locations.

⁷ Documentation for the CALPUFF modeling system is available from links provided at <https://www.epa.gov/scram/air-quality-dispersion-modeling-alternative-models#calpuff>.

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This dependency of nitrate haze formation as a function of temperature (and season) for more seasonally-varying locations in the United States is shown in the September 2019 EPA modeling report² in Figure B-9 (from Appendix A of that report). This figure shows that the thermodynamics of the nitrate haze equilibrium result in much greater particulate formation in winter versus other seasons for more temperate climates, while NO_x emissions are expected to be relatively constant over the entire year. This implies that NO_x emission reductions would only be effective for haze reduction during cold winter months, while consideration of NO_x emission reductions in other months is relatively ineffective.

It should also be noted that volcanic activity on Hawai'i Island may also be a large source of NO_x in the state. Volcanoes are commonly thought of as large sources of SO₂, but they also can emit significant amounts of NO_x. Laboratory analysis⁸ of NO_x emissions content in volcanic exhaust indicates a substantial component, likely caused by thermal contact of air with lava. The annual worldwide volcano NO_x emissions (as NO₂) is estimated³ at approximately 1.5 teragrams ("Tg" – trillion grams).

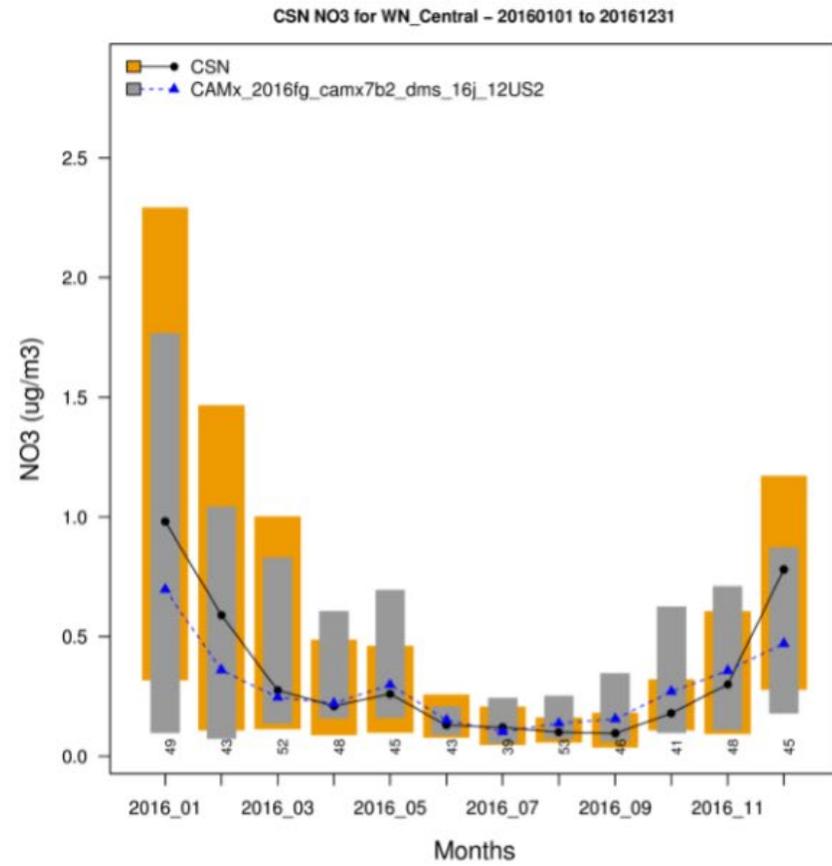
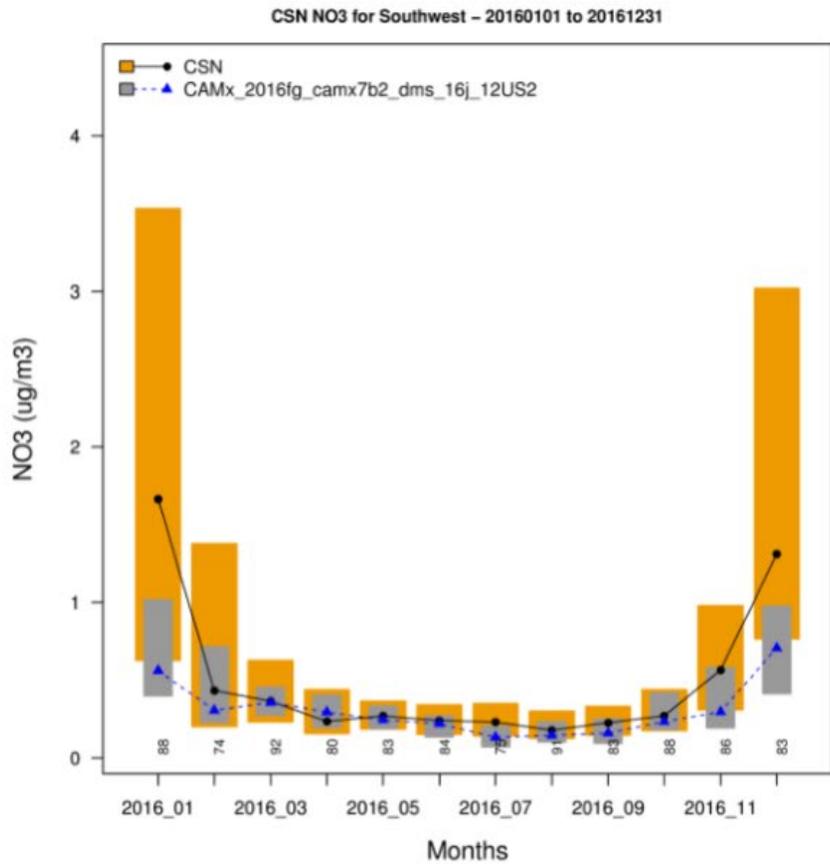
In summary, nitrate haze is a very small component in Hawai'i's Class I areas, which is expected given nitrate chemistry and is verified by the IMPROVE monitoring data. The multiple-year average of the nitrate haze impact for worst 20% days at the two areas is approximately Mm-1, or less than 0.5 delta-dv. This total nitrate haze impact is less than the de minimis contribution threshold used to eliminate a single source from consideration for controls during the First Decadal Review period.

Due to the low haze impact of NO_x (even if every source in the state and the volcano was eliminated), the state of Hawai'i should limit the haze precursors control evaluations to SO₂ for the Second Decadal Review. A similar conclusion was reached during the First Decadal Review, for which the EPA did not consider NO_x controls to be material. The State of Hawai'i Department of Health should work with the EPA to provide this technical justification to remove NO_x as a haze precursor for the state of Hawai'i.

⁸ Mather, T., 2004. A Volcanic Breath of Life? Chemistry World, 30 November 2004 Featured Article. <https://www.chemistryworld.com/features/a-volcanic-breath-of-life/3004482.article>.

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Figure B-9: Monthly Variation of Nitrate Particulate Concentrations for Selected IMPROVE Sites from EPA 2019 Modeling Report



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4. PM Species Haze Composition Analysis

In their Federal Implementation Plan Technical Support Document⁹, EPA noted that “due to the overwhelming contribution of sulfate to visibility impairment at the nearby Hawaii Volcanoes Class I area, it is unlikely that reductions in these pollutants [NO_x and PM]...would have a measurable impact on visibility at that area.”

It is clear from a review of the haze speciation shown in Figures B-2 through B-5 that the contribution to haze of direct particulate species such as elemental carbon, soil, and coarse mass is relatively low. Furthermore, emissions of coarse PM mass (ash) from the volcanic activity can be very high (clearly evident from photos of volcanic activity) to the extent that it may result in aviation alerts. These emissions can be much greater than emissions from power plants and can constitute a significant portion of the direct PM-caused haze shown in Figures B-2 through B-5. The remaining human-caused haze due to direct PM emissions is therefore a very small component of the total haze, and this determination is consistent with EPA’s 2012 assessment.

5. Predominant Trade Winds in Hawai‘i

The EPA’s FIP for Hawai‘i for the First Decadal Review (77 FR 61478, October 9, 2012) acknowledged the direction of the predominant trade winds in Hawai‘i and thus did not require controls on upwind sources (i.e., sources on O‘ahu and Maui). Figure B-10 shows the locations of the Hawaiian Electric sources and the national parks, along with wind rose plots for airports on Maui and O‘ahu. The wind rose plots show that the wind is almost always from the northeast and rarely blows from the Hawaiian Electric facilities on O‘ahu or Maui toward either of Hawai‘i’s Class 1 areas.

The EPA CALPUFF modeling conducted for the First Decadal Review confirms the expected low impacts from sources on Maui, even though the sources were relatively close to Haleakalā National Park. This result is due to the fact, as stated above, that winds rarely blow the emissions from sources downwind from the parks back to the parks, and the CALPUFF modeling confirmed the low impact from occasional periods when the wind may blow toward the parks from the sources modeled. The Western Regional Air Partnership (“WRAP”) Q/d analysis that included several sources on the islands of O‘ahu and Maui in the four-factor analysis did not consider the wind patterns. A review of past modeling and the EPA’s 2012 FIP should lead to a dismissal of those sources from inclusion in four-factor analyses for the second decadal review period.

The geometry and wind roses shown in Figure B-10 and previous CALPUFF modeling both indicate that Hawaiian Electric generating stations on O‘ahu and Maui would have minimal impact to Class 1 area haze. Because of this, and the minimal impact of NO_x due to nitrate chemistry, consideration of

⁹ EPA, May 14, 2012. Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii. EPA docket EPA-R09-OAR-2012-0345-0002 via www.regulations.gov.

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potential additional pollution controls at Hawaiian Electric facilities for Regional Haze progress should be limited to SO₂ for sources on Hawai'i Island.

6. Natural Sources of SO₂ From Volcanic Activity

Volcanic activity on the Hawai'i Island represents a unique and challenging complication to understanding haze in Hawai'i Class I areas. The Kilauea volcano on Hawai'i Island has been active for several years, and the levels of SO₂ emissions are being monitored by the United States Geological Survey. As shown in Figure B-11¹⁰ (related to the SO₂ National Ambient Air Quality Standards implementation and monitoring), there were over 2 million tons of SO₂ emissions from volcanic activity on Hawai'i Island in the year 2014, compared to roughly 2,000 tons of power plant SO₂ emissions for that year. As noted in a *Frontiers in Earth Science* 2018 article¹¹, the volcanic SO₂ emissions have been relatively steady at levels close to 2 million TPY for the period of 2014 to 2017. The volcanic SO₂ emissions have decreased after the Kilauea eruption ended in September 2018, but remain significant. The USGS preliminary estimates of annual volcanic emissions of SO₂ for 2019 are 17,119 tons/year¹².

The extremely high and variable levels of natural SO₂ emissions present a significant challenge for defining "impaired" haze days because the same pollutant (i.e., SO₂) is emitted by volcanic activity and the power plants and other combustion sources. Therefore, the RHR glidepath for the two Class I areas in Hawai'i is difficult to establish if naturally-caused haze is to be excluded from the analysis.

There appears to be very little anthropogenic haze impairment remaining at Haleakalā National Park because there are very few sources on Maui upwind of the park and there are no land masses upwind of Maui for thousands of kilometers. For Hawai'i Island, the largest sources of SO₂ are natural sources that are part of (or adjacent to) the park.

Even the anthropogenic sources (from power plants) are projected to be phased out well before the end point of the RHR (i.e., 2064) by Hawai'i's State Renewable Portfolio Standards Law ("RPS") implementing requirements to convert 100% of the state's electrical generation to renewable energy sources. This RPS law (Hawai'i Revised Statute §269-92) will substantially reduce emissions of haze precursors by 2045. Further details of the past and future benefits of the RPS requirements are detailed in separate Appendix C.

¹⁰ <https://www.epa.gov/sites/production/files/2016-03/documents/hi-epa-tds-r2.pdf>.

¹¹ Elias, T., C. Kern, K. Horton, A. Sutton, and H. Garbeil, 2018. Measuring SO₂ Emission Rates at Kilauea Volcano, Hawai'i, Using an Array of Upward-Looking UV Spectrometers, 2014–2017. *Front. Earth Sci.* 6:214. doi: 10.3389/feart.2018.00214. <https://www.frontiersin.org/articles/10.3389/feart.2018.00214/full>.

¹² Hawaii Dept. of Health comment letter to Hawaiian Electric Light Company regarding Puna Generating Station Four Factor Analysis; July 8, 2020.

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Figure B-10: Geography of Hawaiian Electric Sources Asked to Conduct Four-Factor Analyses and PSD Class I Areas, with Wind Roses

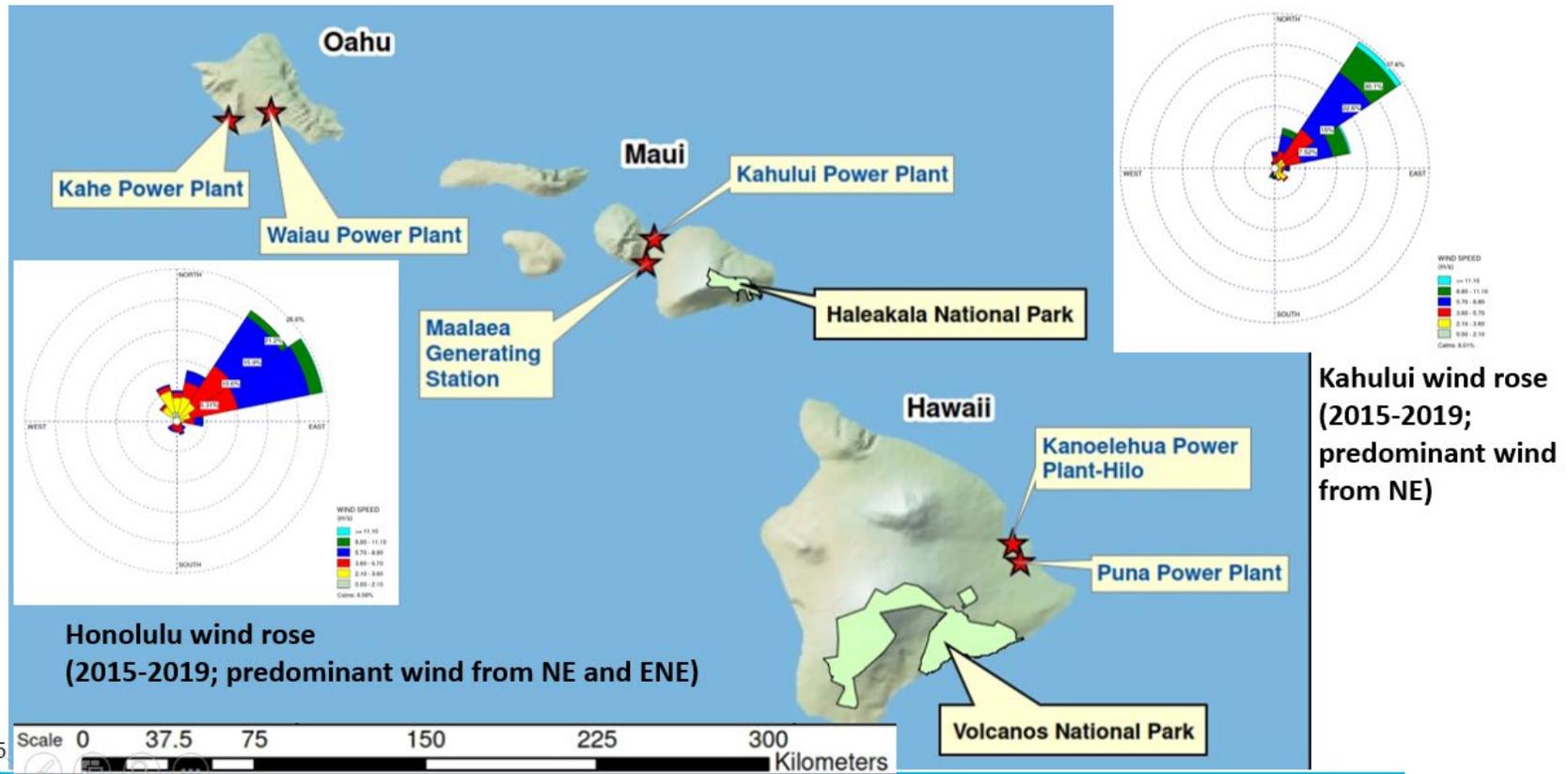
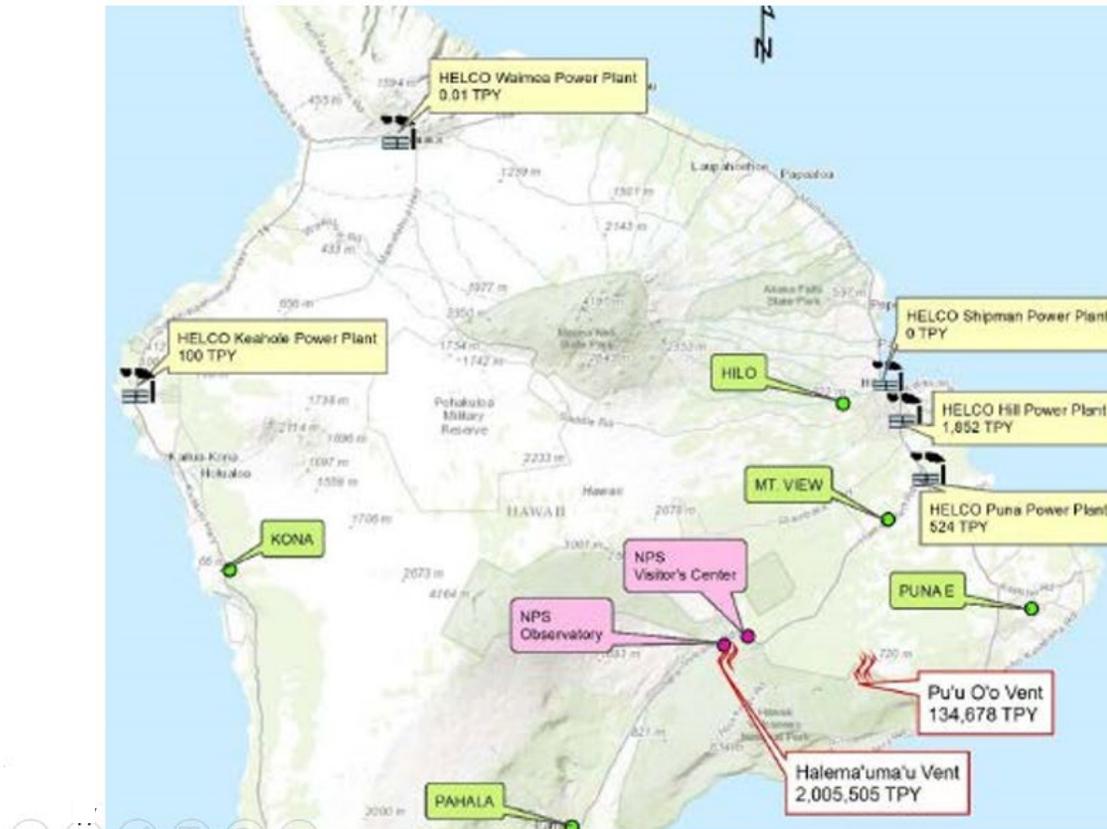


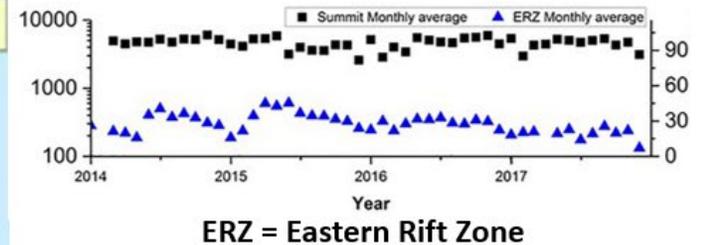
Figure B-11: Geography of Hawaiian Electric Sources Asked to Conduct Four-Factor Analyses and PSD Class I Areas, with Wind Roses



2017 SO₂ Emissions (from NEI)

site name	TPY SO ₂
HELCO - Keahole Power Plant	81.94
HELCO - Waimea Power Plant	0.00
HELCO - Kanoelehua Power Plant/ HILL	2167.18
HELCO - Puna Power Plant	186.84

2014-2017 Volcano SO₂ Emissions average about 1.86 Million TPY



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7. Conclusions

The state of Hawai'i is isolated from all other states and has very unique regional haze issues due, in part, to its tropical climate, the prevalent trade winds, very large natural emissions of haze precursors, and statewide commitment to renewable energy.

- Emission sources on O'ahu and Maui are downwind of Hawai'i's Class 1 areas and do not contribute to haze issues, such that additional emission controls would not contribute to further reasonable progress at either of Hawai'i's Class 1 area National Parks. This is consistent with the EPA's First Decadal Review findings.
- Additionally, NO_x emissions do not significantly contribute to haze in Hawai'i due the nitrate chemistry and Hawai'i's warm climate, and additional NO_x controls would likewise not contribute to further reasonable progress. Therefore, NO_x should not be regulated as a contributing precursor to haze in Hawai'i; especially from O'ahu and Maui sources that are downwind of the parks. If they are reviewed as precursors, consideration should be given to their insignificant contribution when evaluating possible controls.
- Direct PM emissions constitute a very small portion of the haze associated with the worst 20% haze days in the Hawai'i Class 1 areas. Furthermore, significant portions of the observed haze in the categories of elemental carbon, soil, and coarse mass are due to volcanic emissions. Therefore, further PM controls on power plant sources would not have a significant benefit for visibility at these Class 1 areas.
- For the above reasons, the only pollutant that should be considered for possible haze controls in the state of Hawai'i is SO₂ which is consistent with the findings of the First Decadal Review. Furthermore, the only Hawaiian Electric sources to be considered for a four factor analysis for SO₂ should be those that are predominantly upwind of a Class I area which include only the Puna and Kanoelehua-Hill Generating Stations on Hawai'i Island.
- Hawai'i's Class I area haze impacts are principally due to natural sources. Volcanic emissions of precursor SO₂ during the 2014-2017 period of analysis were three orders of magnitude greater than the anthropogenic emissions on Hawai'i Island. Since these natural emissions are the principal cause of haze at the two Class 1 areas in the state and are difficult to distinguish from the relatively small amount of anthropogenically-caused haze, photochemical grid modeling is not practical or even needed. The definition of "impaired days" for Hawai'i Volcanoes National Park as referenced in some of the figures in this report is uncertain due to the overwhelming influence of natural emissions of SO₂.
- For Haleakalā National Park, with the lack of upwind anthropogenic sources, it could be reasonably concluded that natural conditions are already attained, and no further Reasonable Progress modeling (or controls) is needed. For Hawai'i Volcanoes National Park, the only United

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States anthropogenic potential sources are those upwind of the park on Hawai'i Island; all other sources in the state are not contributing to haze at the Class 1 areas.

- Implementation of Hawai'i's RPS (discussed in detail in Appendix C) will provide a dramatic reduction of virtually all power plant haze-causing emissions in the state of Hawai'i well before the year 2064. This Hawai'i state law established enforceable requirements that a certain percentage of electricity must be generated from renewable energy sources by the end of identified benchmark years leading to 100percent renewable energy by 2045. The interim targets are 30 percent by 2020, 40 percent by 2030, and 70 percent by 2040 which provide an RPS "glide path" for EGUs that mirrors the RHR visibility improvement glide path for the next few decades. No separate new regional haze measures for EGUs are needed to assure reasonable progress for this decadal period.

Plans for renewable energy sources, the likely reduction in utilization of fossil-fueled electric generation in this interim period, the unique climate and wind patterns, and the difficulty of addressing the high volcanic emissions should be considered in the current planning for the Second Decadal Review process for the state of Hawai'i.

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APPENDIX C: HAWAII'S RENEWABLE PORTFOLIO STANDARDS CONTRIBUTION TO REGIONAL HAZE PROGRESS

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Appendix C: Hawai'i's Renewable Portfolio Standards ("RPS") Contribution to Regional Haze Progress

AECOM Project Number: 60626547

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March 30, 020

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Hawai'i's Renewable Portfolio Standards ("RPS")

Contribution to Regional Haze Progress

1. Executive Summary

Hawai'i's ongoing conversion of fossil-fueled electric generation to renewable energy sources as mandated by the Hawai'i Revised Statute ("HRS") §269-92 Renewable Portfolio Standards ("RPS") is significantly decreasing emissions from Hawai'i's electric generating stations. Past actual and expected future decreases in usage of fossil-fueled electric generating units ("EGUs") are achieving emissions reductions at a rate consistent with, or faster than, the reasonable progress goals of the Regional Haze Rule ("RHR"). Emissions from the majority of Hawai'i's electric generating plants are not a significant contributor to haze at Class I areas (for reasons explained in Appendix B). Further, their very low impact is being mitigated under the RPS state law. This rate of progress from the RPS law can be relied upon for further emissions reductions from EGUs in the coming years and thus separate further requirements for EGU controls under the RHR are not needed at this time. The following sections of this appendix provide a background on the RPS requirements and progress to date, and high confidence of continued progress consistent with the goals of the RHR.

2. Renewable Portfolio Standards

In 2002 the Hawai'i RPS legislation set voluntary goals for converting the islands' electrical generation from fossil fuels to renewable energy. In 2005, the RPS was set into law as binding requirements for Hawai'i electric utility companies. The law requires that electric utilities in Hawai'i achieve 100% of their electric generation from renewable energy sources by 2045 and meet a series of interim limits for the percentages of their electricity sales that must be provided by renewables (e.g., 30% renewable by 2020, and 40% by 2030, etc.). Renewable energy sources such as solar, hydro and wind energy have no direct emissions. Others such as biomass combustion have significantly lower emissions (especially sulfur dioxide ("SO₂")) than fossil fuels. Consequently, the RPS law results in steady progress in emissions reductions from electric utilities creating, in effect, an "RPS glidepath" providing dramatic reduction of electric generating unit emissions by mid-century.

The RPS program, although not directly related to the Regional Haze Rule, is providing emissions reductions and improvements to air quality consistent with the goals of the RHR.

Table C-1 shows the interim and final RPS for EGUs along with the Regional Haze adjusted glidepath emissions reductions goals¹.

¹ Regional Haze Adjusted Glidepath assumes consistent reductions in haze precursor emissions impacts from all U.S. anthropogenic sources from the baseline average of 2000-2004 to zero impacts in 2064, i.e. natural background.

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Table C-1 Comparison of RPS and Regional Haze Glidepaths

Year	RPS Renewable Requirement % of Electricity Sales	Regional Haze Glidepath % Visibility Improvement
2010	10%	8%
2015	15%	17%
2020	30%	25%
2030	40%	42%
2040	70%	58%
2045	100%	67%
2065		100%

This table illustrates that the emissions reductions from EGUs under the RPS are similar to the visibility goals of the Regional Haze Program in the intermediate years and become much more stringent in later years. The RPS seeks to achieve 100% renewable electrical supply by 2045, which is twenty years earlier than the RHR target of 2065 to achieve natural background visibility in Class I areas.

3. Historical RPS Achievement

Hawaiian Electric², and other electric utility providers in Hawai‘i, have made excellent progress in developing and supporting renewable energy sources. Figure C-1 below shows the percentage of all electrical sales statewide provided by renewable sources since the RPS inception (green columns).³ It also shows as a line illustrating the RPS interim standards (with proportional progress assumed between RPS milestone years). This figure illustrates that Hawai‘i EGUs have made significant progress to date and have been ahead of the RPS interim targets.

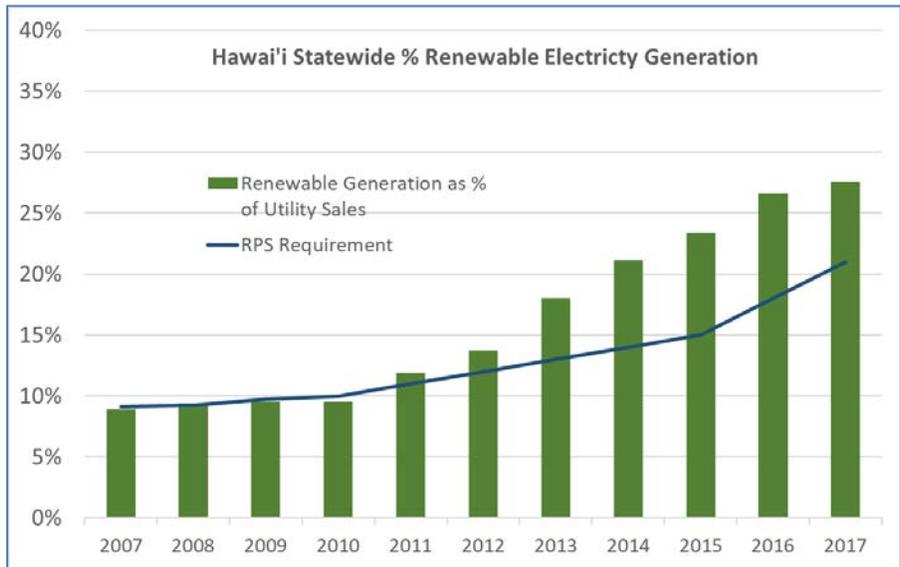
Hawaiian Electric represents majority of Hawai‘i’s electric generation. Figure C-2 shows the renewable energy source percentages for this same period specifically for Hawaiian Electric. The data follows the same trend as the statewide figures and this figure also shows a breakdown of the type of renewable energy technology used.

² “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.

³ Hawai‘i Public Utility Commission (PUC), “Report to the 2019 Legislature on Hawai‘i’s Renewable Portfolio Standards”, Dec. 2018 https://puc.hawaii.gov/wp-content/uploads/2018/12/RPS-2018-Legislative-Report_FINAL.pdf.

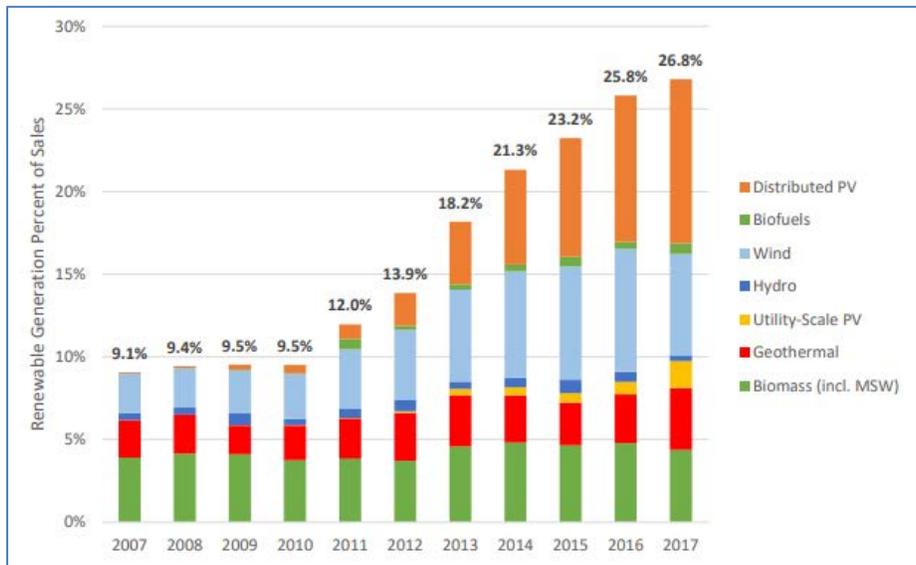
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Figure C-1 Statewide Renewable Portfolio Progress



Source: https://puc.hawaii.gov/wp-content/uploads/2018/12/RPS-2018-Legislative-Report_FINAL.pdf

Figure C-2 Hawaiian Electric Companies RPS Achievement by Generation Technology⁴



⁴ PUC Dec. 2018 Report, Figure 2, page 7.

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4. Future RPS Achievability

To date, Hawai'i's electric utilities have generally met or exceeded the RPS requirements. Continued progress consistent with RPS is expected to continue. Projects and plans are already in place to continue this rapid RPS shift to renewable energy sources for the period of interest of the next decadal period of the RHR. In its December 2018 report to the state legislature, the Hawai'i Public Utility Commission ("PUC") indicated that "future renewable projects under construction or planned for the HECO Companies and KIUC should ensure that the state remains on track for meeting the 2020 and 2030 RPS targets."⁵

Figure C-3 below shows Hawaiian Electric's projection of percent renewables through 2030 presented in the December 2018 PUC report. This projected progress remains well ahead of the RPS requirements which also is ahead of the requirements of the Regional Haze glidepath goals.

Figure C-3 Hawaiian Electric Companies RPS Expectation by 2030 Technology⁶

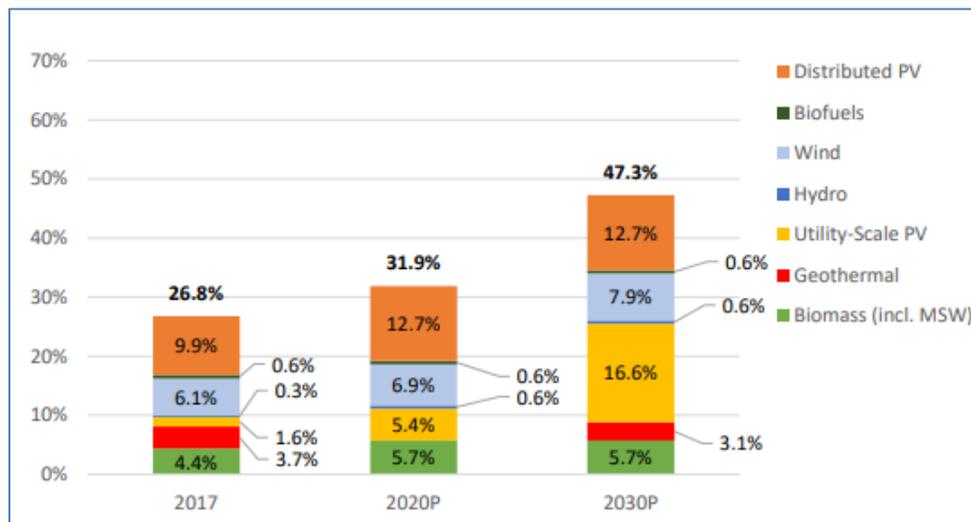


Table C-2 below shows the past actual and future forecast for Hawaiian Electric from the previous two figures (from PUC's 2018 report) together with the requirements of RPS and the goals of the RHR. Hawaiian Electric's renewable energy progress and forecast is ahead of both programs. Additionally, Hawaiian Electric has an internal target to achieve 100% renewables by 2040, five years ahead of the RPS requirement and 25 years ahead of the RHR goals.

⁵ PUC Dec. 2018 Report, page 2.

⁶ PUC Dec. 2018 Report, Figure 2, page 16.

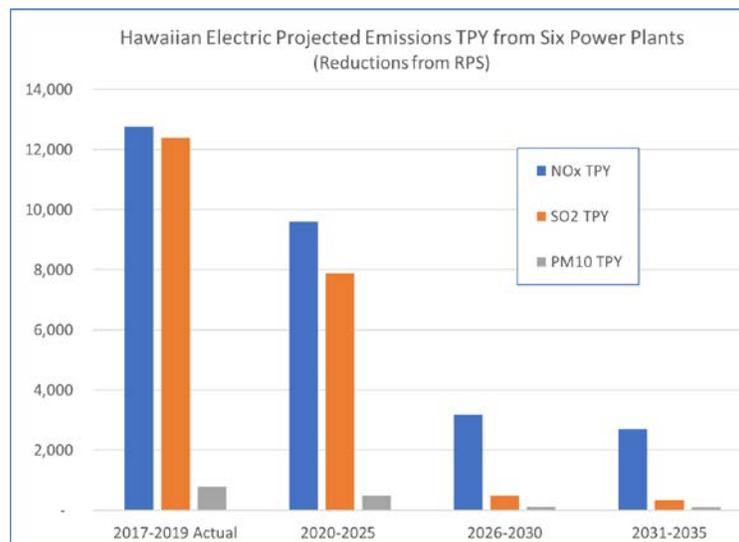
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Table C-2 Comparison of RPS and Regional Haze Glidepaths

Year	RPS Renewable Requirement % of Electricity Sales	Regional Haze Glidepath % Visibility Improvement	Hawaiian Electric % Renewables
2010	10%	8%	9.5% (actual)
2015	15%	17%	23.2% (actual)
2020	30%	25%	31.9% (projection)
2030	40%	42%	47.3% (projection)
2040	70%	58%	100% (goal)
2045	100%	67%	100% (goal)

Hawaiian Electric’s latest projections show an even more rapid shift to renewable energy sources than forecasted in 2018. This will continue to decrease Hawaiian Electric facility emissions. For example, Figure C-4 illustrates Hawaiian Electric’s latest forecast emissions trends for total nitrogen oxides (“NOx”), sulfur dioxide (“SO₂”) and Particulate Matter (“PM₁₀”) emissions (in tons per year “TPY”) from the six power plants (Waiau and Kahe Generating Stations on Oahu, Kahului and Maalaea on Maui, and Kanoiehua-Hill and Puna on Hawai’i) requested to conduct Four-Factor Analyses by the Hawai’i Department of Health (“DOH”). These dramatic emissions decreases illustrate the expected progress from RPS alone – without any additional RHR measures. The forecast emissions shown in Figure C-4 was derived from recent fuel consumption projections based on the resource plans and planning assumptions submitted to the PUC as part of Hawaiian Electric’s 2016 Power Supply Improvement Plan (“PSIP”) which was accepted by the PUC and recent renewable project applications.

Figure C-4 Hawaiian Electric NOx Forecast Emissions



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The emissions reduction is quite rapid and most of the projected reduction by Hawaiian Electric are expected to be in place prior to 2028, the next Regional Haze planning milestone.

Although this projection is based on reasonable assumptions, plans are subject to change as there is some uncertainty regarding future projections and forecast assumptions. For this reason and due to energy security issues, Hawaiian Electric cannot commit to specific dates for particular emissions reductions or final retirements of any specific generating station. Nevertheless, Hawaiian Electric is on an aggressive path to end fossil-fueled generation and replace it with renewable energy sources – especially during this next decadal period. This progress should be sufficient for Hawaiian Electric’s contribution to the state’s efforts regarding reasonable progress of the RHR for the current Regional Haze decadal review.

5. Reliance on RPS for this Regional Haze Decadal Review

The RPS requirements are part of Hawai’i state law. An electric utility failing to meet the RPS requirements is subject to enforcement action and penalties by the PUC unless the PUC determines the electric utility is unable to meet the RPS due to factors beyond its reasonable control. However, given the progress to date of the Hawai’i electric utilities acquiring renewable generation and expectations for planned renewable projects in the near future, it is reasonable to expect that RPS will result in continued steady progress, at least through 2030.

The DOH can rely on the RPS for regional haze progress without having to impose separate RHR requirements in facility permits. This is supported by EPA guidance which states that “Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions; energy efficiency, renewable energy, or other such programs where there is a documented commitment to participate and verifiable basis for quantifying any change in future emissions due to operational changes may be another.”⁷

Even if progress were slower than currently expected, it would not prevent the RPS from being relied upon as the major EGU contribution to meeting Hawai’i’s regional haze goals. The time perspective of the Regional Haze Program is long. Making wise decisions that help achieve the long-term goals is important. Hawai’i electric utilities are currently focusing resources on advancing renewable energy projects that will permanently displace fossil-fueled unit generation and fossil-fueled combustion emissions. These ongoing RPS efforts help achieve the long-term goals of the RHR and provide permanent emissions reductions and other societal benefits. In contrast, new investments in conventional emissions controls on aging fossil-fueled units provide only modest short-term benefits impose additional costs on rate payers and will have no lasting value when those units are deactivated or retired.

⁷ Guidance on Regional Haze State Implementation Plans for the Second Implementation Period – August 2019 at page 17. https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.

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APPENDIX D: FUEL COST

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Appendix Table D-1. Residual High Sulfur Fuel Oil Cost

Date	Residual High Sulfur Fuel Oil ^A	
	(\$/BBL)	(\$/gal)
Jan-18	\$57.52	\$1.37
Feb-18	\$63.81	\$1.52
Mar-18	\$68.78	\$1.64
Apr-18	\$61.32	\$1.46
May-18	\$63.74	\$1.52
Jun-18	\$69.26	\$1.65
Jul-18	\$75.84	\$1.81
Aug-18	\$75.73	\$1.80
Sep-18	\$76.56	\$1.82
Oct-18	\$76.16	\$1.81
Nov-18	\$76.50	\$1.82
Dec-18	\$85.79	\$2.04
Jan-19	\$74.99	\$1.79
Feb-19	\$62.02	\$1.48
Mar-19	\$62.73	\$1.49
Apr-20	\$71.38	\$1.70
May-19	\$75.30	\$1.79
Jun-19	\$72.39	\$1.72
Jul-19	\$70.54	\$1.68
Aug-19	\$62.92	\$1.50
Sep-19	\$62.28	\$1.48
Oct-19	\$59.26	\$1.41
Nov-19	\$59.61	\$1.42
Dec-19	\$58.81	\$1.40
2018-19 Annual Average	\$68.47	\$1.63

^A Fuel cost from the 2019 and 2018 Energy Cost Recovery Filings submitted to the Hawai'i Public Utilities Commission.

(<https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/energy-cost-filings/hawaii-island-energy-cost-filings>)

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Appendix Table D-2. Ultra-Low Sulfur Diesel (ULSD) Import Cost

Description	Value	Units
Platts 2018 Price ^A	86.75	\$/BBL
2019 Inflation	1.5	%
Platts 2019 Price	88.05	\$/BBL
Freight ^B	5.51	\$/BBL
Terminalling Fee ^B	2.00	\$/BBL
Total ULSD Import Cost ^C	95.56	\$/BBL
	2.28	\$/Gal

^A S&P Global Platts - Oilgram Price Report, listed price is Singapore spot price for Gasoil 10 ppm which is comparable to ULSD. (https://www.spglobal.com/platts/plattscontent/_assets/_files/en/productservices/market-reports/oilgram-proce-report-060818.pdf)

^B Hawaiian Electric Fuels Division Estimate

^C Platts 2019 spot price plus freight and terminalling fees.

Appendix Table D-3. Diesel (0.4% Maximum Sulfur) Import Cost

Description	Value	Units
Platts 2018 Price ^A	85.12	\$/BBL
2019 Inflation	1.5	%
Platts 2019 Price	86.40	\$/BBL
Freight ^B	5.51	\$/BBL
Terminalling Fee ^B	2.00	\$/BBL
Total ULSD Import Cost ^C	93.91	\$/BBL
	2.24	\$/Gal

^A S&P Global Platts - Oilgram Price Report, listed price is Singapore spot price for Gasoil 0.25% S which is comparable to the current diesel supply. (https://www.spglobal.com/platts/plattscontent/_assets/_files/en/productservices/market-reports/oilgram-proce-report-060818.pdf)

^B Hawaiian Electric Fuels Division Estimate.

^C Platts 2019 spot price plus freight and terminalling fees.

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Control Cost Worksheets and DOH-CAB Revisions

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Changes Summarized

3.25 % interest rate for controls

30 year equipment life for SCR

20 year equipment life for all other controls*

SNCR retrofit factor of 1

Hawaii Island Construction Cost Multiplier from 1.84 to 1.

* Equipment life of wet scrubbers were reassess at 30 years based on upcoming revision to the cost control manual.

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Table 3-1. 2017 Fuel Property and Fuel Usage and Baseline SO₂ Emissions

Unit	Primary Fuel	2017 Annual Average Fuel Properties ^A			2017 Annual Fuel Usage ^B		SO ₂ Emissions	
		Sulfur Content	HHV (Btu/gal)	Density (lb/gal)	Volume (gal/yr)	Heat Input (MMBtu/yr)	(lb/MMBtu) ^C	(TPY) ^D
		Boiler	Residual Oil	1.69%	150,985	8.33	1,304,562	196,969
CT-3	Diesel	0.054%	136,533	6.96	763,193	104,201	5.51E-02	2.9
Total							186.9	

^A Calendar year 2017 annual average residual oil sulfur content.

^B To account for ignition fuels and used oil usage the equivalent annual residual oil usage for the Boiler was calculated from the 2017 annual average fuel properties and reported SO₂ emissions.

^C The SO₂ emission factors are based on 100% conversion of fuel sulfur to SO₂ and the calendar year 2017 annual average fuel density and higher heating value.

^D Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

Table 4-1 Baseline NO_x Emissions

Unit	Primary Fuel	NO _x Emissions		
		Primary Fuel Emissions Factor (lb/MMBtu) ^A	Adjusted Emission Factor (lb/MMBtu) ^B	(TPY) ^C
		Boiler	Residual Oil	0.213
CT-3	Diesel	0.131	--	6.8
Total				29.5

^A Calendar year 2017 emission factors from the 2018 Emissions Fee Report.

^B The adjusted emission factor include emissions from the ignition fuels and used oil.

^C Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

Table 5-1 Baseline PM₁₀ Emissions

Unit	Primary Fuel	PM ₁₀ Emissions		
		Primary Fuel Emissions Factor (lb/MMBtu) ^A	Adjusted Emission Factor (lb/MMBtu) ^B	(TPY) ^C
		Boiler	Residual Oil	0.0983
CT-3	Diesel	0.0201	--	1.05
Total				10.8

^A Calendar year 2017 emission factors from the 2018 Emissions Fee Report.

^B The adjusted emission factor include emissions from the ignition fuels and used oil.

^C Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

Supporting Information
Permitted Heatermitted Output
Input (MMBtu/h Nominal (MW))

249	15.5
275	20.0

Unit	Description
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.

Unit	Description
CT-3	20 MW Nominal (24.66 MW Peak Load) General Electric Combustion Turbine, Model No. LM 2500, Serial No. 481-651, 275 MMBtu/hr

HELCO 2017 Fuel Analyses Summary

Destination	Fuel	Time Period	Volume Received	Sulfur Content		Average Nitrogen Content	Minimum Cetane Index	Average Higher Heating Value	Average Density	# of Samples
				Maximum	Average					
--	--	--	(bbl)	(wt. %)	(wt. %)	(wt. %)	--	(Btu/gal)	(lb/gal)	--
Big Island	Diesel	Jan - Jun	241,854	0.070	0.059	0.0049				16
		Jul - Dec	264,537	0.080	0.050	0.0058				18
		Jan - Dec	506,392	0.080	0.054	0.0054		136,533	6.96	34
	Bunker	Jan - Jun	202,129	1.82	1.73					17
		Jul - Dec	192,424	1.91	1.66					16
		Jan - Dec	394,552	1.91	1.69			150,985	8.33	33
--	--	--	(gal)	(wt. %)	(wt. %)	(wt. %)	--	(Btu/gal)	(lb/gal)	--
Kanoelehua_ULSD	ULSD	Jan - Jun	23,743	0.0007	0.0004		44.000			3
		Jul - Dec	--	--	--		--			0
		Jan - Dec	23,743	0.0007	0.0004		44.000	138,563	7.10	3

Table 3-2. SO₂ Cost Effectiveness of Switching to a Residual Oil/Diesel Blended Fuel

Unit	Current Residual Oil ^A					Residual Oil/Diesel Blend (1.0% maximum Sulfur) ^B						
	2017 Average Sulfur Content (%)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	2017 Annual Heat Input (MMBtu/yr)	2017 SO ₂ Emissions ^D (tpy)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Controlled SO ₂ Emissions (tpy)	SO ₂ Reduced (tpy)	Fuel Cost Differential ^C (\$/Gal) (\$/year)	SO ₂ Cost Effectiveness (\$/ton)	
Boiler	1.69%	150,985	1,304,562	196,969	184.0	141,953	1,387,568	103.61	80.39	0.38	527,276	6,559

^A Based on 2017 average fuel properties and fuel usage.
^B Based on a blend of 37.5% residual oil and 62.5% diesel fuel and the weighted average of the 2017 fuel HHV and density and contract fuel sulfur limits (2.0% for residual oil and 0.4% for diesel).
^C See Appendix D for fuel cost.
^D Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

Table 3-3. SO₂ Cost Effectiveness of Switching to Diesel

Unit	Current Residual Oil ^A					Diesel (0.4% maximum Sulfur) ^B						
	2017 Average Sulfur Content (%)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	2017 Annual Heat Input (MMBtu/yr)	2017 SO ₂ Emissions ^D (tpy)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Controlled SO ₂ Emissions (tpy)	SO ₂ Reduced (tpy)	Fuel Cost Differential ^C (\$/Gal) (\$/year)	SO ₂ Cost Effectiveness (\$/ton)	
Boiler	1.69%	150,985	1,304,562	196,969	184.0	136,533	1,442,648	40.18	143.82	0.61	880,015	6,119

^A Based on 2017 average fuel properties and fuel usage.
^B Based on 2017 average HHV and density and contract fuel sulfur limit (0.4%).
^C See Appendix D for fuel cost.
^D Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

Table 3-4. SO₂ Cost Effectiveness of Switching to a Residual Oil/ULSD Blended Fuel

Unit	Current Residual Oil ^A					Residual Oil/ULSD Blend (1.0% maximum Sulfur) ^B						
	2017 Average Sulfur Content (%)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	2017 Annual Heat Input (MMBtu/yr)	2017 SO ₂ Emissions ^D (tpy)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Controlled SO ₂ Emissions (tpy)	SO ₂ Reduced (tpy)	Fuel Cost Differential ^C (\$/Gal) (\$/year)	SO ₂ Cost Effectiveness (\$/ton)	
Boiler	1.69%	150,985	1,304,562	196,969	184.0	144,774	1,360,530	104.98	79.02	0.33	448,975	5,682

^A Based on 2017 average fuel properties and fuel usage.
^B Based on a blend of 50.0% residual oil and 50.0% ULSD fuel and the weighted average of the 2017 fuel HHV and density and contract fuel sulfur limits.
^C See Appendix D for fuel cost.
^D Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

Table 3-5. SO₂ Cost Effectiveness of Switching to ULSD

Unit	Current Residual Oil					ULSD (0.0015% maximum Sulfur)						
	2017 Average Sulfur Content (%)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	2017 Annual Heat Input (MMBtu/yr)	2017 SO ₂ Emissions ^D (tpy)	Fuel Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Controlled SO ₂ Emissions (tpy)	SO ₂ Reduced (tpy)	Fuel Cost Differential ^C (\$/Gal) (\$/year)	SO ₂ Cost Effectiveness (\$/ton)	
Boiler	1.69%	150,985	1,304,562	196,969	184.0	138,563	1,421,516	0.15	183.85	0.65	923,985	5,026

^A Based on 2017 average fuel properties and fuel usage.
^B Based on 2017 average HHV and density and contract fuel sulfur limit.
^C See Appendix D for fuel cost.
^D Calendar year 2017 actual emissions from the 2018 Criteria Pollutant Annual Fee Summary for Covered Sources (Form F-1CP).

Summary Calculations

	Total Cost	30-yr Cost
Residual Oil/Diesel (0.4% Max)	\$500,000	\$15,000,000
Diesel (0.4% Max)	\$900,000	\$27,000,000
Residual Oil/ULSD (0.0015% Max)	\$400,000	\$12,000,000
ULSD (0.0015% Max)	\$900,000	\$27,000,000

Fuel Property Data and Fuel Cost Supporting Calculations

Fuel	2017 Annual Average ¹		Sulfur Limit	Fuel Cost ²		Blend				Blend Cost \$/Gal	
	(lb/gal)	(Btu/gal)		% S	\$/BBL	\$/Gal	(lb/gal)	(Btu/gal)	% S		SO ₂ EF
Residual Oil	8.33	150,985	2.00%	68.46	1.63	37.5%	7.47	141,953	1.00%	1.052	2.01
Diesel	6.96	136,533	0.40%	94.08	2.24	62.5%					

¹ Calendar year 2017 annual average fuel properties from company records.
² See Appendix D for fuel cost.

Diesel Property Data and Fuel Cost Supporting Calculations

Fuel	2017 Annual Average ¹		Sulfur Limit	SO ₂ EF
	(lb/gal)	(Btu/gal)		
Diesel	6.96	136,533	0.40%	0.408

¹ Calendar year 2017 annual average fuel properties from company records.

Fuel Property Data and Fuel Cost Supporting Calculations

Fuel	2017 Annual Average ¹		Sulfur Limit	Fuel Cost ²		Blend				Blend Cost \$/Gal	
	(lb/gal)	(Btu/gal)		% S	\$/BBL	\$/Gal	(lb/gal)	(Btu/gal)	% S		SO ₂ EF
Residual Oil	8.33	150,985	2.00%	68.46	1.63	50.0%	7.72	144,774	1.00%	1.066	1.96
ULSD	7.10	138,563	0.0015%	95.76	2.28	50.0%					

¹ Calendar year 2017 annual average fuel properties from company records.
² See Appendix D for fuel cost.

Diesel Property Data and Fuel Cost Supporting Calculations

Fuel	2017 Annual Average ¹		Sulfur Limit	SO ₂ EF
	(lb/gal)	(Btu/gal)		
ULSD	7.10	138,563	0.0015%	0.0015

¹ Calendar year 2017 annual average fuel properties from company records.

HELCO 2017 Fuel Analyses Summary

Destination	Fuel	Time Period	Volume Received (bb)	Sulfur Content		Average Nitrogen Content (wt. %)	Minimum Cetane Index	Average Higher Heating Value (Btu/gal)	Average Density (lb/gal)	# of Samples
				Maximum (wt. %)	Average (wt. %)					
Big Island	Diesel	Jan - Jun	241,854	0.070	0.039	0.1543	--			16
		Jul - Dec	264,537	0.080	0.050	0.0058				18
		Jan - Dec	506,392	0.080	0.054	0.0054		136,533	6.96	34
Bunker	Jan - Jun	Jan - Jun	202,129	1.82	1.73					17
		Jul - Dec	192,424	1.91	1.66					16
		Jan - Dec	394,552	1.91	1.69			150,985	8.33	33
--	--	--	(gal)	(wt. %)	(wt. %)	(wt. %)	--	(Btu/gal)	(lb/gal)	--
Kanoelehua_ULSD	ULSD	Jan - Jun	23,743	0.0007	0.0004	--	44,000			3
		Jul - Dec	--	--	--	--	--			0
		Jan - Dec	23,743	0.0007	0.0004	--	44,000	138,563	7.10	3

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Table 4-2. NO_x Reduction from Fuel Switching

Fuel Scenario	AP-42 NO_x Emission Factors^A	Percent NO_x Reduction
	Tangentially-Fired Boilers	from Fuel Switching^B
	(lb/MMBtu)	Boiler
Residual Oil	0.213	--
Distillate (ULSD)	0.171	20%
50/50 Blend	--	10%

^A The listed emission factors are from AP-42, Table 1.3-1, dated May 2010.

^B The percent reduction is based on the ratio of AP-42 emissions factors for residual fuel oil and No. 2 fuel oil.

Table 4-3. Control Effectiveness of Technically Feasible NO_x Control Technologies

Control Technology	Estimated Controlled Level
	(lb/MMBtu)
SCR+Combustion Controls	0.05
SCR	0.03 - 0.10
LNB & OFA	0.15 - 0.20
FGR	0.15 - 0.20
LNB	0.15 - 0.20
SNCR+Combustion Controls	0.13 - 0.20
SNCR	0.15 - 0.20
OFA	0.20 - 0.30
Fuel Switching	0.18 - 0.21

Table 4-4. NO_x Cost Effectiveness Summary

Unit	Control Option	2017	Controlled	2017	Controlled	NO _x	Total	Cost
		NO _x Emissions ^A (tpy)	Emission Level ^{B,C} (lb/MMBtu)	Annual Heat Input (MMBtu/yr)	NO _x Emissions (tpy)	Reduced (ton/yr)	Annual Cost ^{D,E} (\$/yr)	Effectiveness (\$/ton)
Boiler	Residual Oil/ULSD Blend ^D	22.7	0.21	196,969	20.4	2.3	448,975	197,786
	ULSD ^D	22.7	0.18	196,969	18.2	4.5	923,985	203,521
	Combustion Controls	22.7	0.15	196,969	14.8	7.9	106,472	13,431
	SNCR	22.7	0.15	196,969	14.8	7.9	232,356	29,311
	SNCR+Combustion Controls	22.7	0.13	196,969	12.8	9.9	338,828	34,235
	SCR	22.7	0.10	196,969	9.8	12.9	766,652	59,655
	SCR+Combustion Controls	22.7	0.05	196,969	4.9	17.8	873,124	49,119

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

^B The controlled emission level for fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 4-2.

^C Controlled emission levels based on “Alternative Control Techniques (ACT) Document – NO_x Emissions from Utility Boiler” EPA, 1994.

^D Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-4 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 a more cost-effective SO₂ solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

^E See Appendix A for the total annual cost calculations for combustion controls, SCR and SNCR.

Summary Calculations

Control Option	Total Cost	
	Annual	30-yr
Residual Oil/ULSD Blend	\$400,000	\$12,000,000
ULSD	\$900,000	\$27,000,000
Combustion Controls	\$100,000	\$3,000,000
SNCR	\$200,000	\$6,000,000
SNCR+Combustion Controls	\$300,000	\$9,000,000
SCR	\$800,000	\$24,000,000
SCR+Combustion Controls	\$900,000	\$27,000,000

Table 4-4. NO_x Cost Effectiveness Summary

Unit	Control Option	2017 NO _x Emissions ^A (tpy)	Controlled Emission Level ^{B,C} (lb/MMBtu)	2017 Annual Heat Input (MMBtu/yr)	Controlled NO _x Emissions (tpy)	NO _x Reduced (ton/yr)	Total Annual Cost ^{D,E} (\$/yr)	Cost Effectiveness (\$/ton)
Boiler	Residual Oil/ULSD Blend ^D	22.7	0.21	196,969	20.4	2.3	448,975	197,786
	ULSD ^D	22.7	0.18	196,969	18.2	4.5	923,985	203,521
	Combustion Controls	22.7	0.15	196,969	14.8	7.9	93,419	11,785
	SNCR	22.7	0.15	196,969	14.8	7.9	179,320	22,621
	SNCR+Combustion Controls	22.7	0.13	196,969	12.8	9.9	272,739	27,558
	SCR	22.7	0.10	196,969	9.8	12.9	301,722	23,478
	SCR+Combustion Controls	22.7	0.05	196,969	4.9	17.8	395,141	22,229

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

^B The controlled emission level for fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 4-2.

^C Controlled emission levels based on “Alternative Control Techniques (ACT) Document – NO_x Emissions from Utility Boiler” EPA, 1994.

^D Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-4 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 a more cost-effective SO₂ solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

^E See Appendix A for the total annual cost calculations for combustion controls, SCR and SNCR.

Summary Calculations

Control Option	Total Cost	
	Annual	30-yr
Residual Oil/ULSD Blend	\$400,000	\$12,000,000
ULSD	\$900,000	\$27,000,000
Combustion Controls	\$100,000	\$3,000,000
SNCR	\$200,000	\$6,000,000
SNCR+Combustion Controls	\$300,000	\$9,000,000
SCR	\$300,000	\$9,000,000
SCR+Combustion Controls	\$400,000	\$12,000,000

Table 5-2. PM₁₀ Reduction from Fuel Switching

Fuel Scenario	AP-42 PM ₁₀	
	Emission Factors ^A (lb/MMBtu)	Percent PM ₁₀ Reduction from Fuel Switching ^B
Residual Oil	0.1540	--
Distillate (No. 2 Fuel Oil)	0.0236	85%
50/50 Blend	--	43%

^A The listed emission factors are from AP-42, Tables 1.3-1 and 1.3-2, dated May 2010.

^B The percent reduction is based on the ratio of AP-42 emissions factors for residual fuel oil and No. 2 fuel oil.

Table 5-3. PM₁₀ Cost Effectiveness Summary

Unit	Control Option	2017	Level of Control ^B (%)	Controlled PM ₁₀ Emissions (tpy)	PM ₁₀ Reduced (ton/yr)	Total Annual Cost ^{C,D} (\$/yr)	Cost Effectiveness (\$/ton)
		PM ₁₀ Emissions ^A (tpy)					
Boiler	Wet Scrubber	9.8	50	4.9	4.9	174,674	35,648
	Residual Oil/ULSD Blend ^D	9.8	43	5.6	4.2	448,975	106,544
	ULSD ^D	9.8	85	1.5	8.3	923,985	110,923
	Wet ESP	9.8	90	1.0	8.8	4,382,441	496,875

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

^B Wet scrubber and wet ESP controlled emission levels based on AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1. The controlled emission level for fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 5-2.

^C See Appendix A for total annual cost calculations for wet scrubber and wet ESP.

^D Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-4 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 a more cost-effective SO₂ solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

Summary Calculations

Control Option	Total Cost	
	Annual	30-yr
Wet Scrubber	\$200,000	\$6,000,000
Residual Oil/ULSD Blend	\$400,000	\$12,000,000
ULSD	\$900,000	\$27,000,000
Wet ESP	\$4,400,000	\$132,000,000

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Table 5-2. PM₁₀ Reduction from Fuel Switching

Fuel Scenario	AP-42 PM ₁₀	Percent PM ₁₀ Reduction from Fuel Switching ^B
	Emission Factors ^A (lb/MMBtu)	
Residual Oil	0.1540	--
Distillate (No. 2 Fuel Oil)	0.0236	85%
50/50 Blend	--	43%

^A The listed emission factors are from AP-42, Tables 1.3-1 and 1.3-2, dated May 2010.

^B The percent reduction is based on the ratio of AP-42 emissions factors for residual fuel oil and No. 2 fuel oil.

Table 5-3. PM₁₀ Cost Effectiveness Summary (20 Yrs Life)

Unit	Control Option	2017	Level of Control ^B	Controlled PM ₁₀ Emissions (tpy)	PM ₁₀ Reduced (ton/yr)	Total Annual Cost ^{C,D} (\$/yr)	Cost Effectiveness (\$/ton)
		PM ₁₀ Emissions ^A (tpy)					
Boiler	Wet Scrubber	9.8	50	4.9	4.9	167,422	34,168
	Residual Oil/ULSD Blend ^D	9.8	43	5.6	4.2	448,975	106,544
	ULSD ^D	9.8	85	1.5	8.3	923,985	110,923
	Wet ESP	9.8	90	1.0	8.8	3,959,231	448,892

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

^B Wet scrubber and wet ESP controlled emission levels based on AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1. The controlled emission level for fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 5-2.

^C See Appendix A for total annual cost calculations for wet scrubber and wet ESP.

^D Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-4 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 a more cost-effective SO₂ solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

Summary Calculations

Control Option	Total Cost	
	Annual	30-yr
Wet Scrubber	\$200,000	\$6,000,000
Residual Oil/ULSD Blend	\$400,000	\$12,000,000
ULSD	\$900,000	\$27,000,000
Wet ESP	\$4,000,000	\$120,000,000

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Table 5-2. PM₁₀ Reduction from Fuel Switching

Fuel Scenario	AP-42 PM ₁₀	
	Emission Factors ^A (lb/MMBtu)	Percent PM ₁₀ Reduction from Fuel Switching ^B
Residual Oil	0.1540	--
Distillate (No. 2 Fuel Oil)	0.0236	85%
50/50 Blend	--	43%

^A The listed emission factors are from AP-42, Tables 1.3-1 and 1.3-2, dated May 2010.

^B The percent reduction is based on the ratio of AP-42 emissions factors for residual fuel oil and No. 2 fuel oil.

Table 5-3. PM₁₀ Cost Effectiveness Summary (30 Yrs Life)

Unit	Control Option	2017	Level of	Controlled	PM ₁₀	Total	Cost
		PM ₁₀ Emissions ^A (tpy)	Control ^B (%)	PM ₁₀ Emissions (tpy)	Reduced (ton/yr)	Annual Cost ^{C,D} (\$/yr)	Effectiveness (\$/ton)
Boiler	Wet Scrubber	9.8	50	4.9	4.9	157,535	32,150
	Residual Oil/ULSD Blend ^D	9.8	43	5.6	4.2	448,975	106,544
	ULSD ^D	9.8	85	1.5	8.3	923,985	110,923
	Wet ESP	9.8	90	1.0	8.8	3,959,231	448,892

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

^B Wet scrubber and wet ESP controlled emission levels based on AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.3.4.1. The controlled emission level for fuel switching to a 50/50 residual oil/ULSD blend or ULSD is from Table 5-2.

^C See Appendix A for total annual cost calculations for wet scrubber and wet ESP.

^D Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-4 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 a more cost-effective SO₂ solution than switching to a residual oil/0.4% maximum sulfur diesel blend or 0.4% maximum sulfur diesel.

Summary Calculations

Control Option	Total Cost	
	Annual	30-yr
Wet Scrubber	\$200,000	\$6,000,000
Residual Oil/ULSD Blend	\$400,000	\$12,000,000
ULSD	\$900,000	\$27,000,000
Wet ESP	\$4,000,000	\$120,000,000

Table 6.1. Total Cost Effectiveness of Fuel Switching

Unit	Control Option	SO₂ Reduced^A (ton/yr)	NO_x Reduced^A (ton/yr)	PM₁₀ Reduced^A (ton/yr)	Total SO₂, NO_x, and PM₁₀ Reduced (ton/yr)	Total Annual Cost^B (\$/yr)	Cost Effectiveness (\$/ton)
Boiler	Residual Oil/ULSD Blend	79.0	2.3	4.2	85.5	\$448,975	\$5,251
	ULSD	183.9	4.5	8.3	196.7	\$923,985	\$4,697

^A The SO₂, NO_x, and PM₁₀ reduced are from Tables 3-4 and 3-5, Table 4-4, and Table 5-3, respectively.

^B Annual costs for switching to a residual oil/ULSD blend or ULSD are from Tables 3-4 and 3-5. The annual costs of fuel switching are based on 2019 dollars.

Appendix Table A-1. Combustion Controls Capital and O&M Cost Estimate

Parameters/Costs	Equation	Boiler
Boiler design capacity, mmBtu/hr (C)		249
Boiler Type		Tangential
2017 Annual Heat Input, MMBtu/yr (H)		196,969
Unit Size, kW (kW)		15,500
Unit Size, MW (MW)		15.5
Capital recovery factor a. Equipment CRF, 30-yr life, 7% interest	$= [I \times (1+i)^a] / [(1+i)^a - 1]$, where I = interest rate, a = equipment life	0.08
Cost Index (CI) ^A a. 2019 b. 2004	607.5 444.2	
Total Capital Investment ^{B,C} TCI (\$)	$= \$18/\text{kW} \times \text{kW} \times (300/\text{MW})^{0.359} \times (\text{CI}_{2019}/\text{CI}_{2004}) - \text{Tangential}$	\$1,105,425
Direct Annual Operating Costs \$/yr Variable O&M Costs ^D	$= \$0.03 \text{ mills}/\text{kW-hr}/1000 \times (1 \text{ kW-hr}/10,000 \text{ Btu}) \times \text{H} \times 10^6 \text{ Btu}/\text{mmBtu} \times (\text{CI}_{2019}/\text{CI}_{2004}) - \text{Tangential}$	\$808
Indirect Annual Costs, \$/yr 1. Fixed O&M Costs ^E 2. Capital recovery	$= \$0.27/\text{kW} \times \text{Nameplate capacity (MW)} \times (1000 \text{ kW}/\text{MW}) \times (300/\text{MW})^{0.359} \times (\text{CI}_{2019}/\text{CI}_{2004}) - \text{Tangential}$ $= \text{Equipment CRF} \times \text{TCI}$	\$16,581 \$89,082
Total Annual Cost \$/yr	$= \text{Direct Annual Costs} + \text{Indirect Annual Costs}$	\$106,472

Life	Interest %
30	7

A mill is equal to 1/1,000 of a U.S. dollar, or 1/10 of one cent. Mills per kilowatt-hour (kWh) equals dollars per megawatt-hour (MWh). To convert mills per kWh to cents per kWh, divide mills per kWh by 10.

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.

^A Cost Index: Chemical Engineering Plant Cost Index (CEPCI). Chemical Engineering Journal.

^B TCI for LNB and LNB w/over fire air for tangential 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_x control.

^C Scaling factor = $(300/\text{Nameplate capacity})^{0.359}$

^D The variable O&M costs for LNB and LNB w/over fire air for tangential 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_x control.

^E The fixed O&M costs for LNB and LNB w/over fire air for tangential boilers ranges from \$0.09/kW to \$0.36/kW, the high end of the range was used due to Hawaii's remote location.

Appendix Table A-1. Combustion Controls Capital and O&M Cost Estimate

Parameters/Costs	Equation	Boiler
Boiler design capacity, mmBtu/hr (C)		249
Boiler Type		Tangential
2017 Annual Heat Input, MMBtu/yr (H)		196,969
Unit Size, kW (kW)		15,500
Unit Size, MW (MW)		15.5
Capital recovery factor		
a. Equipment CRF, 20-yr life, 3.25% interest	$= [I \times (1+i)^a] / [(1+i)^a - 1]$, where I = interest rate, a = equipment life	0.07
Cost Index (CI) ^A		
a. 2019	607.5	
b. 2004	444.2	
Total Capital Investment ^{B,C}		
TCI (\$)	$= \$18/\text{kW} \times \text{kW} \times (300/\text{MW})^{0.359} \times (\text{CI}_{2019}/\text{CI}_{2004}) - \text{Tangential}$	\$1,105,425
Direct Annual Operating Costs \$/yr		
Variable O&M Costs ^D	$= \$0.03 \text{ mills}/\text{kW-hr}/1000 \times (1 \text{ kW-hr}/10,000 \text{ Btu}) \times \text{H} \times 10^6 \text{ Btu}/\text{mmBtu} \times (\text{CI}_{2019}/\text{CI}_{2004}) - \text{Tangential}$	\$808
Indirect Annual Costs, \$/yr		
1. Fixed O&M Costs ^E	$= \$0.27/\text{kW} \times \text{Nameplate capacity (MW)} \times (1000 \text{ kW}/\text{MW}) \times (300/\text{MW})^{0.359} \times (\text{CI}_{2019}/\text{CI}_{2004}) - \text{Tangential}$	\$16,581
2. Capital recovery	= Equipment CRF x TCI	\$76,030
Total Annual Cost \$/yr	= Direct Annual Costs + Indirect Annual Costs	\$93,419

Life	Interest %
20	3.25

A mill is equal to 1/1,000 of a U.S. dollar, or 1/10 of one cent. Mills per kilowatt-hour (kWh) equals dollars per megawatt-hour (MWh). To convert mills per kWh to cents per kWh, divide mills per kWh by 10.

Source: All costs were estimated using Section 4.3 and Appendix D of the WRAP guidance document, *Analysis of Combustion Controls for Reducing NOx*

^A Cost Index: Chemical Engineering Plant Cost Index (CEPCI). Chemical Engineering Journal.

^B TCI for LNB and LNB w/over fire air for tangential boilers ranges from \$6/kW to \$24/kW, the high end of the range was used due to Hawaii's remote

^C Scaling factor = $(300/\text{Nameplate capacity})^{0.359}$

^D The variable O&M costs for LNB and LNB w/over fire air for tangential boilers ranges from 0.05 mills/kW-hr to 0.08 mills/kW-hr, the high end of the

^E The fixed O&M costs for LNB and LNB w/over fire air for tangential boilers ranges from \$0.09/kW to \$0.36/kW, the high end of the range was used due

Appendix Table A-2. Boiler SCR Capital and O&M Cost Estimate

			Boiler
MW			15.5
Baseline NOx Emission Rate (lb/MMBtu)			0.23
2017 Annual Heat Input, MMBtu/yr			196,969
Max Heat Input (MMBtu/hr)			249
Capital Recovery Factor (CRF)			0.08
Cost Index ^A			
	2019	607.5	
	1999	390.6	
B =	(lb/MMBtu)		0.23
C =	(%)		90
A =	(kW)		15,500
Z (Eq. 1) =			0.87
Capital Cost (Eq. 2)	(\$/kW)		\$202
Capital Cost (2019)	(\$)		\$4,863,425
Hawai'i Island Construction Cost Multiplier ^B			1.840
Hawai'i Island Capital Cost (2019)			\$8,948,702
Annualized Capital Cost	(\$/yr)		\$721,144
G =			0.09
H =	(MMBtu/hr)		249
D =	(\$/kW)		\$314
Fixed O&M ^C (Eq. 3)	(\$/yr)		\$32,099
Variable O&M Cost (Eq. 4)	(\$/yr)		\$13,410
Total Annual Cost	(\$/yr)		\$766,652

Life	Intrest %
30	7

$$Z = \left[\frac{B}{1.5} \right]^{0.05} \left[\frac{C}{100} \right]^{0.4} \quad \text{Equation 1}$$

$$D = 75 \left\{ 300,000 \frac{Z}{A} \right\}^{0.35} \quad \text{Equation 2}$$

Where:

- D = Capital cost (\$/kW)
- B = NO_x (lb/10⁶ Btu) at the inlet of the SCR reactor
- C = NO_x removal efficiency (%)
- A = Plant capacity (kW)

$$E = D \times A \times C \quad \text{Equation 3}$$

Where:

- E = Fixed O&M cost (\$/yr)
- D = Capital cost (\$/kW) from Equation 1
- A = Plant capacity (kW)
- C = A constant, 0.0066 yr⁻¹

$$F = G \left\{ 225 \times \left[0.37B \times H \times \left(\frac{C}{100} \right) \times \left(\frac{8760}{2000} \right) \right] \times 1.005 \times 1.05 + 0.025 \times D \times A \times Z + 1.45 \times A \right\} \quad \text{Equation 4}$$

Where:

- F = Variable O&M Cost (\$/yr)
- G = Annual capacity factor (expressed as a fraction)
- B = Inlet NO_x (lb/MMBtu); range of 0.15 - 2.5 lb/MMBtu
- H = Heat input (MMBtu/hr)
- C = NO_x removal efficiency; range of 80-95%
- D = Capital cost (\$/kW)
- A = Plant capacity (kW)

Capital Recovery Factor (CRF) = $\frac{I \times (1+i)^a}{[(1+i)^a - 1]}$ CRF = 0.08

Where:

- I = Interest Rate (7% interest)
- a = Equipment life (30 yrs)

Source: *Cost of Selective Catalytic Reduction (SCR) Application for NO_x 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, pluverized coal can burn similar to oil, and thus combustion control system options for both fuel types are similar.

^A Cost Index: Chemical Engineering Plant Cost Index (CEPCI). Chemical Engineering Journal.

^B The Hawai'i Island construction cost multiplier is based on cost of construction geographical multipliers from the *RSMeans 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.

^C Fixed Costs include elements such as labor, station power, capital additions/improvements

Appendix Table A-2. Boiler SCR Capital and O&M Cost Estimate

			Boiler
MW			15.5
Baseline NO _x Emission Rate (lb/MMBtu)			0.23
2017 Annual Heat Input, MMBtu/yr			196,969
Max Heat Input (MMBtu/hr)			249
Capital Recovery Factor (CRF)			0.05
Cost Index ^A			
	2019	607.5	
	1999	390.6	
B =	(lb/MMBtu)		0.23
C =	(%)		90
A =	(kW)		15,500
Z (Eq. 1) =			0.87
Capital Cost (Eq. 2)	(\$/kW)		\$202
Capital Cost (2019)	(\$)		\$4,863,425
Hawai'i Island Construction Cost Multiplier ^B			1.000
Hawai'i Island Capital Cost (2019)			\$4,863,425
Annualized Capital Cost	(\$/yr)		\$256,214
G =			0.09
H =	(MMBtu/hr)		249
D =	(\$/kW)		\$314
Fixed O&M ^C (Eq. 3)	(\$/yr)		\$32,099
Variable O&M Cost (Eq. 4)	(\$/yr)		\$13,410
Total Annual Cost	(\$/yr)		\$301,722

Life	Intrest %
30	3.25

$$Z = \left[\left(\frac{B}{1.5} \right)^{0.05} \left(\frac{C}{100} \right)^{0.4} \right] \text{ Equation 1}$$

$$D = 75 \left\{ 300,000 \frac{Z}{A} \right\}^{0.35} \text{ Equation 2}$$

Where:

- D = Capital cost (\$/kW)
- B = NO_x (lb/10⁶ Btu) at the inlet of the SCR reactor
- C = NO_x removal efficiency (%)
- A = Plant capacity (kW)

$$E = D \times A \times C \text{ Equation 3}$$

Where:

- E = Fixed O&M cost (\$/yr)
- D = Capital cost (\$/kW) from Equation 1
- A = Plant capacity (kW)
- C = A constant, 0.0066 yr⁻¹

$$F = G \left\{ 225 \times \left[0.37B \times H \times \left(\frac{C}{100} \right) \times \left(\frac{8760}{2000} \right) \right] \times 1.005 \times 1.05 + 0.025 \times D \times A \times Z + 1.45 \times A \right\} \text{ n 4}$$

Where:

- F = Variable O&M Cost (\$/yr)
- G = Annual capacity factor (expressed as a fraction)
- B = Inlet NO_x (lb/MMBtu); range of 0.15 - 2.5 lb/MMBtu
- H = Heat input (MMBtu/hr)
- C = NO_x removal efficiency; range of 80-95%
- D = Capital cost (\$/kW)
- A = Plant capacity (kW)

$$\text{Capital Recovery Factor (CRF)} = \left[1 \times (1+i)^a \right] / \left[(1+i)^a - 1 \right]$$

CRF = 0.05

Where:

- i = Interest Rate (3.25% interest)
- a = Equipment life (30 yrs)

Source: *Cost of Selective Catalytic Reduction (SCR) Application for NO_x 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, pluerized coal can burn similar to oil, and thus combustion control system options for both fuel types are similar.

^A Cost Index: Chemical Engineering Plant Cost Index (CEPCI). Chemical Engineering Journal.

^B The Hawai'i Island 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.*

^C Fixed Costs include elements such as labor, station power, capital additions/improvements

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Appendix Table A-3. Scrubber Capital and O&M Cost Estimate

Parameters/Costs	Equation/Reference	Boiler
Exhaust Temperature (K)	T_{stack}	422.0
Exhaust Temperature (F)	Converted from degrees K	299.9
Exhaust Moisture Content (%)	MS - Typical Values	12.00%
Exhaust Flow Rate (m^3/s) ¹	CSP Application	79.5
Exhaust Flow Rate (ACFM) ¹	Converted from (m^3/s)	168,429
Exhaust Flow Rate (SCFM)	$ACFM * ((68+460)/(T_{stack}+460))$	117,025
m_{wv} (lb/min)	$SCFM * MC * 18/385$	657
m_a (lb/min)	$SCFM * (1-MC) * 29/385$	4,815
humidity ratio	m_{wv}/m_a	0.14
humid volume (ft^3/min)	h (Estimated from psychrometric chart)	23.00
Q_{SAT}	$h * m_a$	110,738.88
Purchased Equipment Cost (Tables 2.5 and 2.6 for a Stainless Steel Low Energy scrubber, 2002 Dollars)	$1.15 * (150 * Q_{SAT}^{0.56})$	\$115,238
Direct Costs - Table 2.8		
Purchased equipment costs		
Packaged Unit (A1)	As estimated, AA	\$115,238
Auxiliary Costs (A2)	$A2 = 0.1 * A1$	\$11,524
Equipment Costs (A)	$A = A1 + A2$	\$126,762
Instrumentation	0.10 A	\$12,676
Sales taxes	0.03 A	\$3,803
Freight	0.05 A	\$6,338
Purchased Equipment cost, PEC	B = 1.18 A	\$149,579
Direct Installation Costs		
Foundation & supports	0.06 B	\$8,975
Handling & erection	0.40 B	\$59,832
Electrical	0.01 B	\$1,496
Piping	0.05 B	\$7,479
Insulation for ductwork	0.03 B	\$4,487
Painting	0.01 B	\$1,496
Direct Installation Costs, DIC	0.56 B	\$83,764
Total Direct Costs, TDC	PEC + DIC	\$233,344

TABLE 2.2-2 BASELINE STACK PARAMETERS

Unit	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
CT-1	8.5	1.50	22.80	719.15
Hill 5	39.9	1.52	14.60	489.95
Hill 6	39.9	2.29	11.67	407.6
D-11	6.4	0.46	58.60	666.0
D-15	6.6	0.81	23.30	678.0
D-16	6.6	0.81	23.30	678.0
D-17	6.6	0.81	23.30	678.0

Note: The stack parameters are from the CSP Renewal Application, dated November 2008.

TABLE 2.2-2 BASELINE STACK PARAMETERS

Unit	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
CT-3 (Peak Load)	76.2	2.44	38.40	821
PBSG1	76.2	0.25	57.40	725
Boiler	51.8	3.15	10.20	422

Note: The stack parameters are from the CSP Renewal Application, dated November 2006.

Indirect Costs (installation) Table 2.8		
Engineering	0.10 B	\$14,958
Construction & field expenses	0.10 B	\$14,958
Contractor fees	0.10 B	\$14,958
Start-up	0.01 B	\$1,496
Performance test	0.01 B	\$1,496
Model study	--	
Contingencies	0.03B	\$4,487
Total Indirect Costs, IC	0.35 B	\$52,353
Cost Index ⁵		
a. 2019	607.5	
b. 2002	395.6	
Capital recovery factor (CRF)	CRF = $[1 \times (1+i)^a] / [(1+i)^a - 1]$, where I = interest rate, a = equipment life	0.08
	a. Equipment CRF, 30-yr life, 7% interest	
Total Capital Investment (2019 Dollars)	(TDC + IC) * (Retrofit factor of 1.4) * (CI₂₀₁₉/CI₁₉₉₉) (Retrofit factor based on average provided for ESP on Page 3-41). No specific factor provided for scrubber, so factor for ESP was relied on.	\$614,219
Annual Costs		
Direct Annual Costs - Section 3.4.1		
Operating Labor		
Operator	3hr/shift*2shifts/day*360 days/yr * \$20/hr	\$43,200
Supervisor	15% of operator	\$6,480
Maintenance		
Labor	Assumed similar labor requirements as to that required for ESP per Section 6, Page 3-47 of OAQPS Cost manual (\$20.00/hr, 7.5 h/wk, 44 wk/yr)	\$6,600
Material	100% of maintenance labor	\$6,600
Utilities	Utilities currently not estimated due to variability	
Total Direct Annual Cost		\$62,880
Annual Indirect Costs, IC		
Administrative charges	2% of Total Capital Investment	\$12,284
Property tax	1% of Total Capital Investment	\$6,142
Insurance	1% of Total Capital Investment	\$6,142
Overhead	60% of total labor and material costs	\$37,728
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	\$49,498
Total Indirect Annual Costs		\$111,794
Total Annual Cost		\$174,674

Life	Interest %
30	7%

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 2 - Wet Scrubbers for Particulate Matter, dated July 2002 (EPA/452/B-02-001).

¹ Exhaust parameters from Cover Source Permit Application.

² From Chemical Engineering Plant Cost Index (CEPCI)

Appendix Table A-3. Scrubber Capital and O&M Cost Estimate (20 Yrs Life)

Parameters/Costs	Equation/Reference	Boiler
Exhaust Temperature (K)	T_{stack}	422.0
Exhaust Temperature (F)	Converted from degrees K	299.9
Exhaust Moisture Content (%)	MS - Typical Values	12.00%
Exhaust Flow Rate (m^3/s) ¹	CSP Application	79.5
Exhaust Flow Rate (ACFM) ¹	Converted from (m^3/s)	168,429
Exhaust Flow Rate (SCFM)	$ACFM * ((68+460)/(T_{stack}+460))$	117,025
m_{wv} (lb/min)	$SCFM * MC * 18/385$	657
m_a (lb/min)	$SCFM * (1-MC) * 29/385$	4,815
humidity ratio	m_{wv}/m_a	0.14
humid volume (ft^3/min)	h (Estimated from psychrometric chart)	23.00
Q_{SAT}	$h * m_a$	110,738.88
Purchased Equipment Cost (Tables 2.5 and 2.6 for a Stainless Steel Low Energy scrubber, 2002 Dollars)	$1.15 * (150 * Q_{SAT}^{0.56})$	\$115,238
Direct Costs - Table 2.8		
Purchased equipment costs		
Packaged Unit (A1)	As estimated, AA	\$115,238
Auxiliary Costs (A2)	$A2 = 0.1 * A1$	\$11,524
Equipment Costs (A)	$A = A1 + A2$	\$126,762
Instrumentation	0.10 A	\$12,676
Sales taxes	0.03 A	\$3,803
Freight	0.05 A	\$6,338
Purchased Equipment cost, PEC	B = 1.18 A	\$149,579
Direct Installation Costs		
Foundation & supports	0.06 B	\$8,975
Handling & erection	0.40 B	\$59,832
Electrical	0.01 B	\$1,496
Piping	0.05 B	\$7,479
Insulation for ductwork	0.03 B	\$4,487
Painting	0.01 B	\$1,496
Direct Installation Costs, DIC	0.56 B	\$83,764
Total Direct Costs, TDC	PEC + DIC	\$233,344
Indirect Costs (installation) Table 2.8		
Engineering	0.10 B	\$14,958
Construction & field expenses	0.10 B	\$14,958
Contractor fees	0.10 B	\$14,958
Start-up	0.01 B	\$1,496
Performance test	0.01 B	\$1,496
Model study	--	
Contingencies	0.03B	\$4,487
Total Indirect Costs, IC	0.35 B	\$52,353
Cost Index ⁵		
a. 2019	607.5	
b. 2002	395.6	
Capital recovery factor (CRF)	$CRF = [I * (1+i)^a] / [(1+i)^a - 1]$, where I = interest rate, a = equipment life a. Equipment CRF, 20-yr life, 3.25% interest	0.07
Total Capital Investment (2019 Dollars)	(TDC + IC) * (Retrofit factor of 1.4) * (CI₂₀₁₉/CI₁₉₉₉) (Retrofit factor based on average provided for ESP on Page 3-41). No specific factor provided for scrubber, so factor for ESP was relied on.	\$614,219

Appendix Table A-3. Scrubber Capital and O&M Cost Estimate (20 Yrs Life)

Annual Costs		
Direct Annual Costs - Section 3.4.1		
Operating Labor		
Operator	3hr/shift*2shifts/day*360 days/yr * \$20/hr	\$43,200
Supervisor	15% of operator	\$6,480
Maintenance		
Labor	Assumed similar labor requirements as to that required for ESP per Section 6, Page 3-47 of OAQPS Cost manual (\$20.00/hr, 7.5 h/wk, 44 wk/yr)	\$6,600
Material		\$6,600
Utilities	Utilities currently not estimated due to variability	
Total Direct Annual Cost		\$62,880
Annual Indirect Costs, IC		
Administrative charges	2% of Total Capital Investment	\$12,284
Property tax	1% of Total Capital Investment	\$6,142
Insurance	1% of Total Capital Investment	\$6,142
Overhead	60% of total labor and material costs	\$37,728
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	\$42,245
Total Indirect Annual Costs		\$104,542
Total Annual Cost		\$167,422

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 2 - Wet Scrubbers for Particulate Matter, dated July 2002 (EPA/452/B-02-001).

¹ Exhaust parameters from Cover Source Permit Application.

² From Chemical Engineering Plant Cost Index (CEPCI)

TABLE 2.2-2 BASELINE STACK PARAMETERS

Unit	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
CT-1	8.5	1.50	22.80	719.15
Hill 5	39.9	1.52	14.60	489.95
Hill 6	39.9	2.29	11.67	407.6
D-11	6.4	0.46	58.60	666.0
D-15	6.6	0.81	23.30	678.0
D-16	6.6	0.81	23.30	678.0
D-17	6.6	0.81	23.30	678.0

Note: The stack parameters are from the CSP Renewal Application, dated November 2008.

TABLE 2.2-2 BASELINE STACK PARAMETERS

Unit	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
CT-3 (Peak Load)	76.2	2.44	38.40	821
PBSG1	76.2	0.25	57.40	725
Boiler	51.8	3.15	10.20	422

Note: The stack parameters are from the CSP Renewal Application, dated November 2006.

Appendix Table A-3. Scrubber Capital and O&M Cost Estimate (30 Yrs Life)

Parameters/Costs	Equation/Reference	Hill 5	Hill 6
Exhaust Temperature (K)	T_{stack}	490.0	407.6
Exhaust Temperature (F)	Converted from degrees K	422.2	274.0
Exhaust Moisture Content (%)	MS - Typical Values	12.00%	12.00%
Exhaust Flow Rate (m^3/s) ¹	CSP Application	26.5	48.1
Exhaust Flow Rate (ACFM) ¹	Converted from (m^3/s)	56,135	101,845
Exhaust Flow Rate (SCFM)	$ACFM * ((68+460)/(T_{stack}+460))$	33,596	73,261
m_{wv} (lb/min)	$SCFM * MC * 18/385$	188	411
m_a (lb/min)	$SCFM * (1-MC) * 29/385$	1,382	3,014
humidity ratio	m_{wv}/m_a	0.14	0.14
humid volume (ft^3/min)	h (Estimated from psychrometric chart)	23.00	23.00
Q_{SAT}	$h * m_a$	31,791.11	69,325.39
Purchased Equipment Cost (Tables 2.5 and 2.6 for a Stainless Steel Low Energy scrubber, 2002 Dollars)	$1.15 * (150 * Q_{SAT}^{0.56})$	\$57,290	\$88,652
Direct Costs - Table 2.8			
Purchased equipment costs			
Packaged Unit (A1)	As estimated, AA	\$57,290	\$88,652
Auxiliary Costs (A2)	$A2 = 0.1 * A1$	\$5,729	\$8,865
Equipment Costs (A)	$A = A1 + A2$	\$63,019	\$97,517
Instrumentation	0.10 A	\$6,302	\$9,752
Sales taxes	0.03 A	\$1,891	\$2,926
Freight	0.05 A	\$3,151	\$4,876
Purchased Equipment cost, PEC	B = 1.18 A	\$74,363	\$115,070
Direct Installation Costs			
Foundation & supports	0.06 B	\$4,462	\$6,904
Handling & erection	0.40 B	\$29,745	\$46,028
Electrical	0.01 B	\$744	\$1,151
Piping	0.05 B	\$3,718	\$5,754
Insulation for ductwork	0.03 B	\$2,231	\$3,452
Painting	0.01 B	\$744	\$1,151
Direct Installation Costs, DIC	0.56 B	\$41,643	\$64,439
Total Direct Costs, TDC	PEC + DIC	\$116,006	\$179,510
Indirect Costs (installation) Table 2.8			
Engineering	0.10 B	\$7,436	\$11,507
Construction & field expenses	0.10 B	\$7,436	\$11,507
Contractor fees	0.10 B	\$7,436	\$11,507
Start-up	0.01 B	\$744	\$1,151
Performance test	0.01 B	\$744	\$1,151
Model study	--		
Contingencies	0.03B	\$2,231	\$3,452
Total Indirect Costs, IC	0.35 B	\$26,027	\$40,275
Cost Index ⁵			
a. 2019	607.5		
b. 2002	395.6		
Capital recovery factor (CRF)	$CRF = [I * (1+i)^a] / [(1+i)^a - 1]$, where I = interest rate, a = equipment life	0.05	0.05
	a. Equipment CRF, 30 yr life, 3.25% interest		
Total Capital Investment (2019 Dollars)	(TDC + IC) * (Retrofit factor of 1.4) * (CI₂₀₁₉/CI₁₉₉₉) (Retrofit factor based on average provided for ESP on Page 3-41). No specific factor provided for scrubber, so factor for ESP was relied on.	\$305,356	\$472,514
Annual Costs			
Direct Annual Costs - Section 3.4.1			
Operating Labor			
Operator	3hr/shift*2shifts/day*360 days/yr * \$20/hr	\$43,200	\$43,200
Supervisor	15% of operator	\$6,480	\$6,480
Maintenance			
	Assumed similar labor requirements as to that required for ESP per Section 6, Page 3-47 of OAQPS Cost manual		
Labor	(\$20.00/hr, 7.5 h/wk, 44 wk/yr)	\$6,600	\$6,600
Material	100% of maintenance labor	\$6,600	\$6,600
Utilities	Utilities currently not estimated due to variability		
Total Direct Annual Cost		\$62,880	\$62,880
Annual Indirect Costs, IC			
Administrative charges	2% of Total Capital Investment	\$6,107	\$9,450
Property tax	1% of Total Capital Investment	\$3,054	\$4,725
Insurance	1% of Total Capital Investment	\$3,054	\$4,725
Overhead	60% of total labor and material costs	\$37,728	\$37,728
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	\$16,087	\$24,893

Appendix Table A-3. Scrubber Capital and O&M Cost Estimate (30 Yrs Life)

Total Indirect Annual Costs		\$66,029	\$81,521
Total Annual Cost		\$128,909	\$144,401

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 2 - Wet Scrubbers for Particulate Matter, dated July 2002 (EPA/452/B-02-001).

¹ Exhaust parameters from Cover Source Permit Application.

² From Chemical Engineering Plant Cost Index (CEPCI)

Company Records

TABLE 2.2-2 BASELINE STACK PARAMETERS

Unit	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
CT-1	8.5	1.50	22.80	719.15
Hill 5	39.9	1.52	14.60	489.95
Hill 6	39.9	2.29	11.67	407.6
D-11	6.4	0.46	58.60	666.0
D-15	6.6	0.81	23.30	678.0
D-16	6.6	0.81	23.30	678.0
D-17	6.6	0.81	23.30	678.0

Note: The stack parameters are from the CSP Renewal Application, dated November 2008.

Appendix Table A-4. Wet ESP Capital and O&M Cost Estimate

Parameters/Costs	Equation	Boiler
Average High Exhaust Flow Rate (m ³ /s) ¹		79.5
Average High Exhaust Flow Rate (ACFM) ¹		168,429
Annual Operating Time (hrs, θ')		8,760
ESP efficiency (from white paper)		90%
ESP Plate Area (ft ²) ⁴	ESCA = -ln(p)/w _e × 5.080 × Q	6,274
Purchased Equipment Cost (Table 3.14 for 90% Control Efficiency and 15,000 ACFM bins)	\$25.5/acfm	\$4,294,946
Basic Equipment Costs -Table 3.12	0.45 × Equipment Cost	\$1,932,726
Direct Costs - Table 3.16		
Purchased equipment costs		
ESP + auxiliary equipment (A)	As estimated, A	\$6,227,672
Instrumentation	0.10 A	\$622,767
Sales taxes	0.03 A	\$186,830
Freight	0.05 A	\$311,384
Purchased Equipment cost, PEC	B = 1.18 A	\$7,348,653
Direct Installation Costs		
Foundation & supports	0.04 B	\$293,946
Handling & erection	0.50 B	\$3,674,326
Electrical	0.08 B	\$587,892
Piping	0.01 B	\$73,487
Insulation for ductwork	0.02B	\$146,973
Painting	0.02B	\$146,973
Direct Installation Costs, DIC	0.67 B	\$4,923,597
Total Direct Costs, TDC	PEC + DIC	\$12,272,250
Indirect Costs (installation) Table 3.16		
Engineering	0.20B	\$1,469,731
Construction & field expenses	0.20B	\$1,469,731
Contractor fees	0.10B	\$734,865
Start-up	0.01B	\$73,487
Performance test	0.01B	\$73,487
Model study	0.02B	\$146,973
Contingencies	0.03B	\$220,460
Total Indirect Costs, IC	0.57B	\$4,188,732
Cost Index ⁵		
a. 2019	607.5	
b. 1999	390.6	
Capital recovery factor (CRF)	CRF = [1 × (1+i) ^a] / [(1+i) ^a - 1], where I = interest rate, a = equipment life a. Equipment CRF, 30-yr life, 7% interest	0.08
Total Capital Investment (2019 Dollars)	(TDC + IC) * (Retrofit factor of 1.4) * (CI₂₀₁₉/CI₁₉₉₉) (Retrofit factor based on average provided for ESP on Page 3-41).	\$35,842,460
Annual Costs		
Direct Annual Costs - Section 3.4.1		
Operating Labor		
Operator	2hr/shift*2shifts/day*365 days/yr * \$20/hr	\$29,200
Supervisor	15% of operator	\$4,380
Maintenance		
Labor	For ESP plate area < 50,000 ft ² = \$4125	\$4,125
Utilities	Utilities currently not estimated due to variability	
Total Direct Annual Cost		\$37,705
Annual Indirect Costs, IC		
Administrative charges	2% of Total Capital Investment	\$716,849
Property tax	1% of Total Capital Investment	\$358,425
Insurance	1% of Total Capital Investment	\$358,425
Overhead	60% of total labor and material costs	\$22,623
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	\$2,888,415
Total Indirect Annual Costs		\$4,344,736
TOTAL ANNUAL COST		\$4,382,441

Life	Interest %
30	7%

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 3 - Electrostatic Precipitators, dated September 1999 (EPA/452/B-02-001).

¹ Exhaust parameters from Cover Source Permit Application.

² Electricity cost from U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.

³ Water cost from Maui County (<https://www.mauicounty.gov/216/Water-Charges>) lowest general rate.

⁴ For ESP Plate Area (Section 3.2.1):

p = 1 - (Control Efficiency %)

5.080 ft²/kacfm = 1 (s/m)

w_e = effective migration velocity (m/s), assume w_e = 31.4 cm/s for Bituminous coal fly ash for a design efficiency of 95% from Table 3.3

(no listings for 90% efficiency or fuel oil)

Q = system flow rate (kacfm)

⁵ From Chemical Engineering Plant Cost Index (CEPCI)

Appendix Table A-4. Wet ESP Capital and O&M Cost Estimate

Parameters/Costs	Equation	Boiler
Average High Exhaust Flow Rate (m ³ /s) ¹		79.5
Average High Exhaust Flow Rate (ACFM) ¹		168,429
Annual Operating Time (hrs, θ ¹)		8,760
ESP efficiency (from white paper)		90%
ESP Plate Area (ft ²) ⁴	$ESCA = -\ln(p)/w_e \times 5.080 \times Q$	6,274
Purchased Equipment Cost (Table 3.14 for 90% Control Efficiency and 15,000 ACFM bins)	\$25.5/acfm	\$4,294,946
Basic Equipment Costs - Table 3.12	$0.45 \times \text{Equipment Cost}$	\$1,932,726
Direct Costs - Table 3.16		
Purchased equipment costs		
ESP + auxiliary equipment (A)	As estimated, A	\$6,227,672
Instrumentation	0.10 A	\$622,767
Sales taxes	0.03 A	\$186,830
Freight	0.05 A	\$311,384
Purchased Equipment cost, PEC	B = 1.18 A	\$7,348,653
Direct Installation Costs		
Foundation & supports	0.04 B	\$293,946
Handling & erection	0.50 B	\$3,674,326
Electrical	0.08 B	\$587,892
Piping	0.01 B	\$73,487
Insulation for ductwork	0.02B	\$146,973
Painting	0.02B	\$146,973
Direct Installation Costs, DIC	0.67 B	\$4,923,597
Total Direct Costs, TDC	PEC + DIC	\$12,272,250
Indirect Costs (installation) Table 3.16		
Engineering	0.20B	\$1,469,731
Construction & field expenses	0.20B	\$1,469,731
Contractor fees	0.10B	\$734,865
Start-up	0.01B	\$73,487
Performance test	0.01B	\$73,487
Model study	0.02B	\$146,973
Contingencies	0.03B	\$220,460
Total Indirect Costs, IC	0.57B	\$4,188,732
Cost Index ⁵		
a. 2019	607.5	
b. 1999	390.6	
Capital recovery factor (CRF)	$CRF = [I \times (1+i)^a] / [(1+i)^a - 1]$, where I = interest rate, a = equipment life a. Equipment CRF, 20-yr life, 3.25% interest	0.07
Total Capital Investment (2019 Dollars)	(TDC + IC) * (Retrofit factor of 1.4) * (CI₂₀₁₉/CI₁₉₉₉) (Retrofit factor based on average provided for ESP on Page 3-41).	\$35,842,460
Annual Costs		
Direct Annual Costs - Section 3.4.1		
Operating Labor		
Operator	2hr/shift*2shifts/day*365 days/yr * \$20/hr	\$29,200
Supervisor	15% of operator	\$4,380
Maintenance		
Labor	For ESP plate area < 50,000 ft ² = \$4125	\$4,125
Utilities		
	Utilities currently not estimated due to variability	
Total Direct Annual Cost		\$37,705
Annual Indirect Costs, IC		
Administrative charges	2% of Total Capital Investment	\$716,849
Property tax	1% of Total Capital Investment	\$358,425
Insurance	1% of Total Capital Investment	\$358,425
Overhead	60% of total labor and material costs	\$22,623
Annualized Capital Cost	Capital Recovery Factor * Total Capital Investment	\$2,465,204
Total Indirect Annual Costs		\$3,921,526
TOTAL ANNUAL COST		\$3,959,231

Life	Interest %
20	3%

Source: All cost were estimated using EPA Air Pollution Control Cost Manual (APCCM), 6th Edition, Section 6, Chapter 3 - Electrostatic Precipitators, dated September 1999 (EPA/452/B-02-001).

¹ Exhaust parameters from Cover Source Permit Application.

² Electricity cost from U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.

³ Water cost from Maui County (<https://www.mauicounty.gov/216/Water-Charges>) lowest general rate.

⁴ For ESP Plate Area (Section 3.2.1):

$p = 1 - (\text{Control Efficiency } \%)$

$5.080 \text{ ft}^2/\text{kacfm} = 1 \text{ (s/m)}$

$w_e = \text{effective migration velocity (m/s)}$, assume $w_e = 31.4 \text{ cm/s}$ for Bituminous coal fly ash for a design efficiency of 95% from Table 3.3

(no listings for 90% efficiency or fuel oil)

$Q = \text{system flow rate (kacfm)}$

⁵ From Chemical Engineering Plant Cost Index (CEPCI)

Appendix Table D-1. Residual High Sulfur Fuel Oil Cost

Date	Residual High Sulfur Fuel Oil ^A	
	(\$/BBL)	(\$/gal)
Jan-18	\$57.52	\$1.37
Feb-18	\$63.81	\$1.52
Mar-18	\$68.78	\$1.64
Apr-18	\$61.32	\$1.46
May-18	\$63.74	\$1.52
Jun-18	\$69.26	\$1.65
Jul-18	\$75.84	\$1.81
Aug-18	\$75.73	\$1.80
Sep-18	\$76.56	\$1.82
Oct-18	\$76.16	\$1.81
Nov-18	\$76.50	\$1.82
Dec-18	\$85.79	\$2.04
Jan-19	\$74.99	\$1.79
Feb-19	\$62.02	\$1.48
Mar-19	\$62.73	\$1.49
Apr-20	\$71.38	\$1.70
May-19	\$75.30	\$1.79
Jun-19	\$72.39	\$1.72
Jul-19	\$70.54	\$1.68
Aug-19	\$62.92	\$1.50
Sep-19	\$62.28	\$1.48
Oct-19	\$59.26	\$1.41
Nov-19	\$59.61	\$1.42
Dec-19	\$58.81	\$1.40
2018-19 Annual Average	\$68.47	\$1.63

^A Fuel cost from the 2019 and 2018 Energy Cost Recovery Filings submitted to the Hawai'i Public Utilities Commission.

(<https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/energy-cost-filings/hawaii-island-energy-cost-filings>)

Appendix Table D-2. Ultra-Low Sulfur Diesel (ULSD) Import Cost

Description	Value	Units
Platts 2018 Price ^A	86.75	\$/BBL
2019 Inflation	1.5	%
Platts 2019 Price	88.05	\$/BBL
Freight ^B	5.51	\$/BBL
Terminalling Fee ^B	2.00	\$/BBL
Total ULSD Import Cost ^C	95.56	\$/BBL
	2.28	\$/Gal

^A S&P Global Platts - Oilgram Price Report, listed price is Singapore spot price for Gasoil 10 ppm which is comparable to ULSD. (https://www.spglobal.com/platts/plattscontent/_assets/_files/en/productservices/market-reports/oilgram-proce-report-060818.pdf)

^B Hawaiian Electric Fuels Division Estimate

^C Platts 2019 spot price plus freight and terminalling fees.

Appendix Table D-3. Diesel (0.4% Maximum Sulfur) Import Cost

Description	Value	Units
Platts 2018 Price ^A	85.12	\$/BBL
2019 Inflation	1.5	%
Platts 2019 Price	86.40	\$/BBL
Freight ^B	5.51	\$/BBL
Terminalling Fee ^B	2.00	\$/BBL
Total ULSD Import Cost ^C	93.91	\$/BBL
	2.24	\$/Gal

^A S&P Global Platts - Oilgram Price Report, listed price is Singapore spot price for Gasoil 0.25% S which is comparable to the current diesel supply. (https://www.spglobal.com/platts/plattscontent/_assets/_files/en/productservices/market-reports/oilgram-proce-report-060818.pdf)

^B Hawaiian Electric Fuels Division Estimate.

^C Platts 2019 spot price plus freight and terminalling fees.

Air Pollution Control Cost Estimation Spreadsheet For Selective Non-Catalytic Reduction (SNCR)

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 Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NO_x emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NO_x to form nitrogen and water.

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 SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 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#cccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, 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 methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, and the reagent consumption. This approach provides study-level estimates ($\pm 30\%$) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR 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, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. 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 reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. 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 selected coal, select the type of coal burned from the drop down menu. The NO_x emissions rate, weight percent coal ash 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.

Step 4: Complete all of the cells highlighted in yellow. 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 0.015 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 *SNCR 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 SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Fuel Oil

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 249 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 150,985 Btu/gallon

What is the estimated actual annual fuel consumption? 1,304,562 gallons/year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 11.0000 MMBtu/MW

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight
or
Select the appropriate SO₂ emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units burning fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. 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.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost (\$/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,876	1.89
Lignite	0	0.82	13.6	6,626	1.24

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR}) 365 days

Inlet NO_x Emissions (NO_{x,i}) to SNCR 0.230 lb/MMBtu

Outlet NO_x Emissions (NO_{x,o}) from SNCR 0.15 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR) 1.22

Concentration of reagent as stored (C_{stored}) 29 Percent

Density of reagent as stored (ρ_{stored}) 56 lb/ft³

Concentration of reagent injected (C_{inj}) 10 percent

Number of days reagent is stored ($t_{storage}$) 14 days

Estimated equipment life 20 Years

Select the reagent used Ammonia

Plant Elevation 10 Feet above sea level

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SNCR:

Desired dollar-year CEPCI for 2019	2019			
	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	7	Percent		
Fuel (Cost _{fuel})	10.80	\$/MMBtu		Actual Data Used
Reagent (Cost _{reag})	0.293	\$/gallon for a 29 percent solution of ammonia		Default Value Used
Water (Cost _{water})	0.0042	\$/gallon		Default Value Used
Electricity (Cost _{elec})	0.0676	\$/kWh*		Actual Data Used
Ash Disposal (for coal-fired boilers only) (Cost _{ash})		\$/ton		

CEPCI = Chemical Engineering Plant Cost Index

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) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources and 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)	\$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf)	
Water Cost (\$/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf .)	
Electricity Cost (\$/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost (\$/MMBtu)	10.796	2019 Fuel Cost	
Ash Disposal Cost (\$/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/gal)	150,985	2017 Annual Average	
Interest Rate (%)	7	Office of Management and Budget (OMB) default social interest for capital projects	

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial What type of fuel does the unit burn? Fuel Oil

Is the SNCR for a new boiler or retrofit of an existing boiler?

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 249 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 150,985 Btu/gallon

What is the estimated actual annual fuel consumption? 1,304,562 gallons/year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 11.0000 MMBtu/MW

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

or

Select the appropriate SO₂ emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units burning fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. 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.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost (\$/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,876	1.89
Lignite	0	0.82	13.6	6,626	1.24

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR}) 365 days

Inlet NO_x Emissions (NO_{x,i}) to SNCR 0.230 lb/MMBtu

Outlet NO_x Emissions (NO_{x,o}) from SNCR 0.15 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR) 1.22

Concentration of reagent as stored (C_{stored}) 29 Percent

Density of reagent as stored (ρ_{stored}) 56 lb/ft³

Concentration of reagent injected (C_{inj}) 10 percent

Number of days reagent is stored ($t_{storage}$) 14 days

Estimated equipment life 20 Years

Select the reagent used Ammonia

Plant Elevation 10 Feet above sea level

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SNCR:

Desired dollar-year CEPCI for 2019	2019			
	607.5	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	3.25	Percent		
Fuel (Cost _{fuel})	10.80	\$/MMBtu		Actual Data Used
Reagent (Cost _{reag})	0.293	\$/gallon for a 29 percent solution of ammonia		Default Value Used
Water (Cost _{water})	0.0042	\$/gallon		Default Value Used
Electricity (Cost _{elec})	0.0676	\$/kWh*		Actual Data Used
Ash Disposal (for coal-fired boilers only) (Cost _{ash})		\$/ton		

CEPCI = Chemical Engineering Plant Cost Index

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) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources and 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)	\$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf)	
Water Cost (\$/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf .)	
Electricity Cost (\$/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost (\$/MMBtu)	10.796	2019 Fuel Cost	
Ash Disposal Cost (\$/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/gal)	150,985	2017 Annual Average	
Interest Rate (%)	3.25	Current prime interest rate	

SNCR Design Parameters

The following design parameters for the SNCR 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) =	HHV x Max. Fuel Rate =	249	MMBtu/hour	
Maximum Annual fuel consumption (m_{fuel}) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/HHV =$	14,446,714	gallons/year	
Actual Annual fuel consumption (m_{actual}) =		1,304,562	gallons/year	
Heat Rate Factor (HRF) =	$NPHR/10 =$	1.10		
Total System Capacity Factor (CF_{total}) =	$(m_{actual}/m_{fuel}) \times (tSNCR/365) =$	0.09	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{total} \times 8760 =$	791	hours	
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	35	percent	
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	19.92	lb/hour	
Total NO _x removed per year =	$(NO_{x_{in}} \times EF \times Q_B \times t_{op})/2000 =$	7.88	tons/year	
Coal Factor ($Coal_c$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/HHV =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	$14.7 \text{ psia}/P =$			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 10 feet above 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		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

Reagent Data:

Type of reagent used: Ammonia Molecular Weight of Reagent (MW) = 17.03 g/mole
 Density = 56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NO_{x_{in}} \times Q_B \times NSR \times MW_R)/(MW_{NO_x} \times SR) =$ (where SR = 1 for NH ₃ ; 2 for Urea)	26	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol} =$	89	lb/hour
	$(m_{sol} \times 7.4805)/\text{Reagent Density} =$	11.9	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24 \text{ hours/day})/\text{Reagent Density} =$	4,100	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i \frac{(1+i)^n}{(1+i)^n - 1} =$ Where n = Equipment Life and i = Interest Rate	0.0944

Parameter	Equation	Calculated Value	Units	
Electricity Usage:				
Electricity Consumption (P) =	$(0.47 \times NO_{x_{in}} \times NSR \times Q_B)/NPHR =$	3.0	kw/hour	
Water Usage:				
Water consumption (q_w) =	$(m_{sol}/\text{Density of water}) \times ((C_{stored}/C_{inj}) - 1) =$	20	gallons/hour	
Fuel Data:				
Additional fuel required to evaporate water in injected reagent ($\Delta Fuel$) =	$H_v \times m_{reagent} \times ((1/C_{inj}) - 1) =$	0.21	MMBtu/hour	
Ash Disposal:				
Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1 \times 10^6)/HHV =$	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

SNCR Design Parameters

The following design parameters for the SNCR 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*

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	249	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	14,446,714	gallons/year
Actual Annual fuel consumption (Mactual) =		1,304,562	gallons/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.10	
Total System Capacity Factor (CF_{total}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	0.09	fraction
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	791	hours
NOx Removal Efficiency (EF) =	$(\text{NO}_{x\text{in}} - \text{NO}_{x\text{out}})/\text{NO}_{x\text{in}} =$	35	percent
NOx removed per hour =	$\text{NO}_{x\text{in}} \times \text{EF} \times Q_B =$	19.92	lb/hour
Total NO _x removed per year =	$(\text{NO}_{x\text{in}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	7.88	tons/year
Coal Factor (Coal _c) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)		
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$		
Elevation Factor (ELEVF) =	$14.7 \text{ psia}/P =$		
Atmospheric pressure at 10 feet above 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	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NO}_{x\text{in}} \times Q_B \times \text{NSR} \times \text{MW}_R)/(\text{MW}_{\text{NO}_x} \times \text{SR}) =$ (whre SR = 1 for NH ₃ ; 2 for Urea)	26	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}}/C_{\text{sol}} =$	89	lb/hour
	$(m_{\text{sol}} \times 7.4805)/\text{Reagent Density} =$	11.9	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day})/\text{Reagent Density} =$	4,100	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

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	0.0688

Parameter	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$(0.47 \times \text{NO}_{x\text{in}} \times \text{NSR} \times Q_B)/\text{NPHR} =$	3.0	kW/hour
Water Usage:			
Water consumption (q_w) =	$(m_{\text{sol}}/\text{Density of water}) \times ((C_{\text{stored}}/C_{\text{inj}}) - 1) =$	20	gallons/hour
Fuel Data:			
Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.21	MMBtu/hour
Ash Disposal:			
Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta\text{fuel} \times \% \text{Ash} \times 1 \times 10^6)/\text{HHV} =$	0.0	lb/hour

Not applicable; factor applies only to coal-fired boilers
 Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR (SNCR _{cost}) =	\$636,075 in 2019 dollars
Air Pre-Heater Costs (APH _{cost})* =	\$0 in 2019 dollars
Balance of Plant Costs (BOP _{cost}) =	\$957,564 in 2019 dollars
Total Capital Investment (TCI) =	\$2,071,731 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs (SNCR_{cost})

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times \text{CoalF} \times \text{BTF} \times \text{ELEV} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times \text{ELEV} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times \text{CoalF} \times \text{BTF} \times \text{ELEV} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times \text{ELEV} \times \text{RF}$$

SNCR Capital Costs (SNCR _{cost}) =	\$636,075 in 2019 dollars
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times \text{CoalF})^{0.78} \times \text{AHF} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times \text{CoalF})^{0.78} \times \text{AHF} \times \text{RF}$$

Air Pre-Heater Costs (APH _{cost}) =	\$0 in 2019 dollars
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* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{RF}$$

Balance of Plant Costs (BOP _{cost}) =	\$957,564 in 2019 dollars
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Annual Costs

Total Annual Cost (TAC)

$$TAC = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$35,852 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$196,504 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$232,356 in 2019 dollars

Direct Annual Costs (DAC)

$$DAC = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	0.015 x TCI =	\$31,076 in 2019 dollars
Annual Reagent Cost =	$Q_{sol} \times \text{Cost}_{reag} \times t_{op} =$	\$2,761 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{elect} \times t_{op} =$	\$160 in 2019 dollars
Annual Water Cost =	$Q_{water} \times \text{Cost}_{water} \times t_{op} =$	\$67 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{fuel} \times t_{op} =$	\$1,789 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{ash} \times t_{op} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$35,852 in 2019 dollars

Indirect Annual Cost (IDAC)

$$IDAC = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$932 in 2019 dollars
Capital Recovery Costs (CR) =	$\text{CRF} \times \text{TCI} =$	\$195,571 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$196,504 in 2019 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NO}_x \text{ Removed/year}$$

Total Annual Cost (TAC) =	\$232,356 per year in 2019 dollars
NO _x Removed =	8 tons/year
Cost Effectiveness =	\$29,491 per ton of NO_x removed in 2019 dollars

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR (SNCR _{cost}) =	\$636,075 in 2019 dollars
Air Pre-Heater Costs (APH _{cost}) * =	\$0 in 2019 dollars
Balance of Plant Costs (BOP _{cost}) =	\$957,564 in 2019 dollars
Total Capital Investment (TCI) =	\$2,071,731 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs (SNCR_{cost})

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times \text{CoalF} \times \text{BTF} \times \text{ELEV} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times \text{ELEV} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_g \times HRF)^{0.42} \times \text{CoalF} \times \text{BTF} \times \text{ELEV} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_g/NPHR) \times HRF)^{0.42} \times \text{ELEV} \times \text{RF}$$

SNCR Capital Costs (SNCR _{cost}) =	\$636,075 in 2019 dollars
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times \text{CoalF})^{0.78} \times \text{AHF} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_g \times HRF \times \text{CoalF})^{0.78} \times \text{AHF} \times \text{RF}$$

Air Pre-Heater Costs (APH _{cost}) =	\$0 in 2019 dollars
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* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_g)^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_g/NPHR)^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{RF}$$

Balance of Plant Costs (BOP _{cost}) =	\$957,564 in 2019 dollars
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Annual Costs

Total Annual Cost (TAC)

$$TAC = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$35,852 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$143,467 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$179,320 in 2019 dollars

Direct Annual Costs (DAC)

$$DAC = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	0.015 x TCI =	\$31,076 in 2019 dollars
Annual Reagent Cost =	$Q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$2,761 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$160 in 2019 dollars
Annual Water Cost =	$Q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$67 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$1,789 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$35,852 in 2019 dollars

Indirect Annual Cost (IDAC)

$$IDAC = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$932 in 2019 dollars
Capital Recovery Costs (CR) =	$\text{CRF} \times \text{TCI} =$	\$142,535 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$143,467 in 2019 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NO}_x \text{ Removed/year}$$

Total Annual Cost (TAC) =	\$179,320 per year in 2019 dollars
NO _x Removed =	8 tons/year
Cost Effectiveness =	\$22,760 per ton of NO_x removed in 2019 dollars

Appendix Table A-1. SCR Capital Cost

Capital Cost Summary	Capital Cost per CT
DIRECT COSTS	
Purchased Equipment and Direct Installation Costs	
Purchase Equipment Cost ^a	\$8,700,828
Instrumentation (20% of Equipment Cost) ^b	\$1,740,166
Taxes (4.7120% for the City and County of Honolulu)	\$409,983
Freight (10% of equipment cost) ^b	\$870,083
TOTAL DIRECT CAPITAL COST (DCC)^b	DCC = \$11,721,060
INDIRECT COSTS	
Engineering (10% of PEC) ^c	\$1,172,106
General Facilities (5% of PEC) ^c	\$586,053
Process Contingency (5% of PEC) ^c	\$586,053
INSTALLATION AND RETROFIT COST	
Foundations & Supports (15% of PEC)	\$1,758,159
Handling & Erection (20% of PEC)	\$2,344,212
Electrical (5% of PEC)	\$586,053
Piping (4% of PEC)	\$468,842
Insulation for Ductwork (5% of PEC)	\$586,053
Painting (1% of PEC)	\$117,211
TOTAL INDIRECT CAPITAL COST (ICC)	ICC = \$8,204,742
PROJECT CONTINGENCY (15% of ICC + DCC) (PC)^c	PC = \$2,988,870
OTHER PREPRODUCTION COSTS	
Preproduction Cost (2% of (DCC+ ICC + PC)) ^c	\$458,293
TOTAL CAPITAL INVESTMENT (TCI = DC + IC + PC + Other Cost)	TCI = \$22,914,672

^a See - Appendix Table A-3.

^b U.S. EPA CCM, Section 1, Chapter 2, Table 2.4, "Cost Estimation: Concepts and Methodology," Seventh Edition, November 2017.

^c U.S. EPA CCM, Section 4.2, Chapter 2, Table 2.5, "Selective Catalytic Reduction (SCR)," Sixth Edition, October 2000.

Appendix Table A-2. SCR Annual Cost

Annual Cost Summary				Annual Cost per CT
DIRECT ANNUAL COSTS				
OPERATION AND MAINTENANCE^a				
Maintenance (1.5% of TCI)				\$343,720
REAGENT (29% Ammonia Solution)				
Requirement	355 lb/hrb at	\$78.00 per ton ^c		\$121,435
CATALYST				
Catalyst Replacement ^d				\$260,352
Catalyst Life (years)			1.0	
Annual Interest Rate (%)			7.0%	
Future Worth Factor			1.0	
Total Annual Catalyst Replacement Cost				\$260,352
UTILITIES				
HRF	Plant Heat Rate	10.465 MMBtu/MWh	/10	1.0465
Electricity ^e	491 kW at	\$0.251 per kW-hrf		\$1,077,671
FUEL PENALTY				
Fuel Cost	1.745 \$/galg	6.0 inches of pressure drop ^b		
	11.67 \$/MMBtu	0.150 MWh/inch ^g		\$962,903
TOTAL DIRECT ANNUAL COSTS (DAC)				DAC = \$2,766,081
INDIRECT OPERATING COSTS^a				
Overhead (60% of O&M Costs)				\$206,232
Administrative Charges (2% of TCI)				\$458,293
Property Taxes (1% of TCI)				\$229,147
Insurance (1% of TCI)				\$229,147
Capital Recovery (CRF x TCI)				
30 years @	7.0% interest	CRF ⁱ =	0.0806	\$1,846,611
TOTAL INDIRECT ANNUAL COSTS (IAC)				IAC = \$2,969,430
TOTAL ANNUALIZED COST (TAC = DAC + IAC)				TAC = \$5,735,511

^a EPA CCM, Section 4.2, Chapter 2, "Selective Catalytic Reduction (SCR)," Sixth Edition, October 2000.

^b See - Appendix Table A-3.

^c June 2019 EPA Cost Manual Spreadsheet - Default

^d See - Appendix Table A-3. Based on replacing 1/3 of the catalyst every year.

^e U.S. EPA CCM, Section 4, Chapter 2, Eq. 2.60, "Selective Catalytic Reduction," Seventh Edition, June 2019.

^f U.S. Energy Information Administration. Electric Power Monthly with Data for December 2019. Table 5.6.a for Hawaii Industrial Sector.

^g Based on the average LSFO cost from Table 3-2.

^h Engineering estimate

ⁱ Based on EPA's social interest rate from the U.S. EPA CCM, Section 1, Chapter 2, "Cost Estimation: Concepts and Methodology," Seventh Edition, November 2017.

Table 2.4: Cost Ranges for Freight, Sales Tax, and Instrumentation

Cost	% of Total Equipment Cost, FOB	
	Range	Typical
Freight	0.01 - 0.10	0.05
Sales Tax	0 - 0.08	0.03
Instrumentation	0.05- 0.30	0.10

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Appendix Table A-1. SCR Capital Cost

Capital Cost Summary	Capital Cost per CT	
DIRECT COSTS		
Purchased Equipment and Direct Installation Costs		
Purchase Equipment Cost ^a		\$8,700,828
Instrumentation (20% of Equipment Cost) ^b		\$1,740,166
Taxes (4.7120% for the City and County of Honolulu)		\$409,983
Freight (10% of equipment cost) ^b		\$870,083
<hr/>		
TOTAL DIRECT CAPITAL COST (DCC)^b	DCC =	\$11,721,060
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INDIRECT COSTS		
Engineering (10% of PEC) ^c		\$1,172,106
General Facilities (5% of PEC) ^c		\$586,053
Process Contingency (5% of PEC) ^c		\$586,053
INSTALLATION AND RETROFIT COST		
Foundations & Supports (15% of PEC)		\$1,758,159
Handling & Erection (20% of PEC)		\$2,344,212
Electrical (5% of PEC)		\$586,053
Piping (4% of PEC)		\$468,842
Insulation for Ductwork (5% of PEC)		\$586,053
Painting (1% of PEC)		\$117,211
<hr/>		
TOTAL INDIRECT CAPITAL COST (ICC)	ICC =	\$8,204,742
<hr/>		
PROJECT CONTINGENCY (15% of ICC + DCC) (PC)^c	PC =	\$2,988,870
<hr/>		
OTHER PREPRODUCTION COSTS		
Preproduction Cost (2% of (DCC+ ICC + PC)) ^c		\$458,293
<hr/>		
TOTAL CAPITAL INVESTMENT (TCI = DC + IC + PC + Other Cost)	TCI =	\$22,914,672

^a See - Appendix Table A-3.

^b U.S. EPA CCM, Section 1, Chapter 2, Table 2.4, "Cost Estimation: Concepts and Methodology," Seventh Edition, November 2017.

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Appendix Table A-2. SCR Annual Cost

Annual Cost Summary				Annual Cost per CT
DIRECT ANNUAL COSTS				
OPERATION AND MAINTENANCE ^a				
Maintenance (1.5% of TCI)				\$343,720
REAGENT (29% Ammonia Solution)				
Requirement	355 lb/hrb at	\$78.00 per ton ^c		\$121,435
CATALYST				
Catalyst Replacement ^d				\$260,352
Catalyst Life (years)				1.0
Annual Interest Rate (%)				7.0%
Future Worth Factor				1.0
Total Annual Catalyst Replacement Cost				\$260,352
UTILITIES				
HRF	Plant Heat Rate	10.465 MMBtu/MWh	/10	1.0465
Electricity ^e	491 kW at	\$0.251 per kW-hrf		\$1,077,671
FUEL PENALTY				
Fuel Cost	1.745 \$/galg	6.0 inches of pressure drop ^b		
	11.67 \$/MMBtu	0.150 MWh/inch ^g		\$962,903
TOTAL DIRECT ANNUAL COSTS (DAC)				DAC = \$2,766,081
INDIRECT OPERATING COSTS ^a				
Overhead (60% of O&M Costs)				\$206,232
Administrative Charges (2% of TCI)				\$458,293
Property Taxes (1% of TCI)				\$229,147
Insurance (1% of TCI)				\$229,147
Capital Recovery (CRF x TCI)				
30 years @	3.25% interest	CRF ⁱ =	0.0527	\$1,207,184
TOTAL INDIRECT ANNUAL COSTS (IAC)				IAC = \$2,330,003
TOTAL ANNUALIZED COST (TAC = DAC + IAC)				TAC= \$5,096,085

^a EPA CCM, Section 4.2, Chapter 2, "Selective Catalytic Reduction (SCR)," Sixth Edition, October 2000.

^b See - Appendix Table A-3.

^c June 2019 EPA Cost Manual Spreadsheet - Default

^d See - Appendix Table A-3. Based on replacing 1/3 of the catalyst every year.

^e U.S. EPA CCM, Section 4, Chapter 2, Eq. 2.60, "Selective Catalytic Reduction," Seventh Edition, June 2019.

^f U.S. Energy Information Administration. Electric Power Monthly with Data for December 2019. Table 5.6.a for Hawaii Industrial Sector.

^g Based on the average LSFO cost from Table 3-2.

^h Engineering estimate

ⁱ Based on EPA's social interest rate from the U.S. EPA CCM, Section 1, Chapter 2, "Cost Estimation: Concepts and Methodology," Seventh Edition, November 2017.

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

Appendix Table A-3. SCR Purchase Equipment Cost

Parameter	Variable	Calculation	Value per CT	Units	Reference
Exhaust Parameters					
Heat Input Rate	Q _b		900.0	MMBtu/hr	
SCR Inlet Operating Temperature	T		650	deg F	June 2019 EPA Cost Manual Spreadsheet - Default
	q _{fuel}	Base case fuel gas volumetric flow rate factor	484	ft ³ /min-MMBtu/hour	June 2019 EPA Cost Manual Spreadsheet - Default
Exhaust Flow	q _{fluegas}	Q _{fuel} × Q _b × (460 + T)/(460 + 700)n _{scr} =	416,824	acfm	Per 2019 EPA Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction - Eq 2.14
Operating Hours Per Year	AOH		8,760	hours	
Inlet Concentration	NO _{xin}		0.421	lb/MMBtu	2017 CT1 and CT2 Average Emission Factor
NO _x Removal Efficiency	η _{NOx}		70	%	70% control efficiency per EPA Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
Outlet Concentration	NO _{xout}		0.126	lb/MMBtu	
Available Cost Data					
Capital Cost of Ammonia Catalyst	CC _{initial}		227	\$/ft ³	June 2019 EPA Cost Manual Spreadsheet - Default
Chemical Properties and Constants					
Ammonia MW	M _{reagent}		17.03	g/mol	June 2019 EPA Cost Manual Spreadsheet - Default
NO ₂ MW	M _{NOx}		46.01	g/mol	June 2019 EPA Cost Manual Spreadsheet - Default
Ammonia Solution Concentration	C _{sol}		29.0	%	June 2019 EPA Cost Manual Spreadsheet - Default
Ratio of Equivalent Moles of NH ₃ per mole of NO _x	SRF		1.05	mol NH ₃ :mol NO _x	June 2019 EPA Cost Manual Spreadsheet - Default
Constant 1	C1		7	ft	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.3.12
Constant 2	C2		9	ft	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.3.12
SCR Design Data					
Empty Catalyst Layers	n _{empty}		1	layers	Allows for partial catalyst replacement
Nominal Height of Each Catalyst Layer	h' _{layer}		3.1	ft	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.3.12
Number SCR Chambers	n _{scr}		1	chamber	Value assumed for lowest capital cost
Allowable Slip	Slip		2	ppm	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.2.2. Minimum range of allowable slip.
Pressure Drop due to Duct	ΔP _{duct}		3	in	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.5
Pressure Drop due to Catalyst	ΔP _{catalyst}	Pressure Drop for each Catalyst Layer	1	in	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.5
Operating Life of Catalyst in Hours	h _{catalyst}		24,000	hours	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Section 2.5
Cross Sectional Area of Catalyst	A _{catalyst}	q _{fluegas} /(16ft/sec × 60 sec/min)	434	ft ²	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.28.
Cross Sectional area of SCR reactor	A _{SCR}	A _{catalyst} × 1.15 (15% greater than A _{catalyst})	499	ft ²	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.29.
Temp Adjustment	T _{adj}	15.16-(0.03937*T)+(0.0000274*(T ²))	1.15	deg F	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.27
Slip Adjustment	Slip _{adj}	(1.2835-(0.0567*Slip))	1.17		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.24
Inlet NO _x Adjustment	NO _{xadj}	(0.8524+(0.3208*NO _{xin}))	0.99		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.25
NO _x Efficiency Adjustment	η _{adj}	(0.2869+(1.058*η _{NOx}))	1.03		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.23
Volume of Catalyst	Vol _{cat}	2.81*Q _b *η _{adj} *NO _{xadj} *Slip _{adj} *T _{adj} /n _{scr}	3,441	ft ³	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.22
Height of catalyst layer	h _{layer}	Vol _{catalyst} /(N _{layer} *A _{catalyst})+1	4	ft	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.32
Number of catalyst layers	n _{layer}	Vol _{catalyst} /(h' _{layer} *A _{catalyst})	3	layers	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.31
Total Number of catalyst layers	n _{total}	n _{layer} + n _{empty}	4	layers	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.33
Height of SCR	h _{scr}	n _{total} *(C1+h' _{layer})+C2	52	ft	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.34
Mass flow of reagent	m _{reagent}	(NO _{xin} *Q _b *η _{NOx} *SRF*M _{reagent})/(M _{NOx})	103	lb/hr	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.35
Mass flow of solution	m _{sol}	m _{reagent} /C _{sol}	355	lb/hr	Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.36
Direct Costs					
SCR height Adjustment	f(h _{scr})	\$6.12/(ft-MMBtu/hr)*h _{scr} - \$187.9/MMBtu/hr	128	\$(/MMBtu/hr)	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.37 - 1998 dollars
Ammonia Flow Adjustment	f(NH3)	(\$411/(lb/hr)*m _{reagent} /Q _b) - \$47.3/MMBtu/hr	-0.227	\$(/MMBtu/hr)	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.38 - 1998 dollars
New "Boiler" Adjustment	f(new)	0 for retrofit (negative adjustment for new boilers)	0	\$(/MMBtu/hr)	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.40 - 1998 dollars
New Bypass	f(bypass)	No Bypass Added	0	\$(/MMBtu/hr)	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.42 - 1998 dollars
Catalyst Cost	f(Vol)	Vol _{cat} *CC _{initial}	781,056	\$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.43 - 2019 dollars
Purchase Equipment Cost	PEC	Q _b [3,380/MMBtu/hr+f(h _{scr})+f(NH3)+f(new)+f(bypass)](3500/Q _b) ^{0.35} +f(Vol)	8,700,828	\$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.36 - 2019 dollars ¹

¹ Chemical Engineering Plant Cost Index:

Year	Index
1998	389.5
2019	607.5

Air Pollution Control Cost Estimation Spreadsheet For Selective Non-Catalytic Reduction (SNCR)

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 Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NO_x emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NO_x to form nitrogen and water.

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 SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 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#cccinfo>.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, 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 methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NO_x reduction, and the reagent consumption. This approach provides study-level estimates ($\pm 30\%$) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR 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, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. 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 reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. 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 selected coal, select the type of coal burned from the drop down menu. The NO_x emissions rate, weight percent coal ash 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.

Step 4: Complete all of the cells highlighted in yellow. 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 0.015 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 *SNCR 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 SNCR.

Appendix Table A-5. Puna Boiler - SNCR Costing

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 SNCR for a new boiler or retrofit of an existing boiler?

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?

What is the higher heating value (HHV) of the fuel?

What is the estimated actual annual fuel consumption?

Is the boiler a fluid-bed boiler?

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Enter the sulfur content (%S) = percent by weight
or
the appropriate SO₂ emission rate:

Ash content (%Ash): percent by weight

Not applicable to units burning fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. 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.

	Fraction of Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost (\$/MMBtu)
Bituminous	0	1.85	9.23	11,241	2.4
Sub-bituminous	0	0.81	5.84	9,235	1.85
Lignite	0	0.82	9.8	6,624	1.35

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{oper})

Inlet NO_x Emissions (NO_{x,i}) to SNCR

Outlet NO_x Emissions (NO_{x,o}) from SNCR

Estimated Normalized Stoichiometric Ratio (NSR)

Concentration of reagent as stored (C_{stored})

Density of reagent as stored (ρ_{stored})

Concentration of reagent injected (C_{inj})

Number of days reagent is stored (t_{stored})

Estimated equipment life

Select the reagent used

Plant Elevation

50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SNCR:

Desired dollar-year CEPCI for 2019

CEPCI for 2019 Enter the CEPCI value for 2019 2016 CEPCI CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

Fuel Cost (C_{fuel}) Actual Data Used

Reagent Cost (C_{reagent}) Default Value Used

Water Cost (C_{water}) Default Value Used

Electricity Cost (C_{elec}) Actual Data Used

Ash Disposal (for coal-fired boilers only) (C_{ash})

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 and 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)	0.293 (gallon of 29% Ammonia)	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf)	
Water Cost (\$/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf .)	
Electricity Cost (\$/kWh)	0.2521	U.S. Energy Information Administration. Electric Power Monthly with Data for September 2019. Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost (\$/MMBtu)	10.796	2019 Fuel Cost	
Ash Disposal Cost (\$/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/gal)	150,985	2017 Annual Average	
Interest Rate (%)	7	Office of Management and Budget (OMB) default social interest for capital projects	

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 SNCR for a new boiler or retrofit of an existing boiler?

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? MMBtu/hour

What is the higher heating value (HHV) of the fuel? Btu/gallon

What is the estimated actual annual fuel consumption? gallons/year

Is the boiler a fluid-bed boiler?

Enter the net plant heat input rate (NPHR) MMBtu/MW

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

Not applicable to units burning fuel oil or natural gas

Type of coal burned:

Enter the sulfur content (%) = percent by weight or the appropriate SO₂ emission rate:

Ash content (%Ash): percent by weight

Not applicable to units burning fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. 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.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost (\$/MMBtu)
Bituminous	0	1.84	0.21	11,841	2.2
Sub-Bituminous	0	0.41	5.89	8,926	1.88
Lignite	0	0.82	13.5	6,026	1.76

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR}) days

Inlet NO_x Emissions (NO_{x,i}) to SNCR lb/MMBtu

Outlet NO_x Emissions (NO_{x,o}) from SNCR lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

Concentration of reagent as stored (C_{stored}) Percent

Density of reagent as stored (ρ_{stored}) lbs/ft³

Concentration of reagent injected (C_{inj}) percent

Number of days reagent is stored (t_{stored}) days

Estimated equipment life Years

Select the reagent used

Plant Elevation Feet above sea level

50% urea solution	71 lbs/ft ³
29.4% aqueous NH ₃	56 lbs/ft ³

Enter the cost data for the proposed SNCR:

	2019	2016 CEPCI
Desired dollar-year CEPCI for 2019	607.5	541.7
Annual Interest Rate (i)	3.25	Percent
Fuel (Cost _{fuel})	10.80	\$/MMBtu
Reagent (Cost _{reagent})	0.293	\$/gallon for a 29 percent solution of ammonia
Water (Cost _{water})	0.0042	\$/gallon
Electricity (Cost _{electricity})	0.0676	\$/kWh*
Ash Disposal (for coal-fired boilers only) (Cost _{ash})		\$/ton

CEPCI = Chemical Engineering Plant Cost Index

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 and 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)	\$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf)	
Water Cost (\$/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saww.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf .)	
Electricity Cost (\$/kWh)	0.2521	U.S. Energy Information Administration, Electric Power Monthly with Data for September 2019, Table 5.6.a for Hawaii Industrial Sector.	
Fuel Cost (\$/MMBtu)	10.796	2019 Fuel Cost	
Ash Disposal Cost (\$/ton)	-	Not applicable	Not Applicable
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable
Higher Heating Value (HHV) (Btu/gal)	150,985	2017 Annual Average	
Interest Rate (%)	3.25	Current prime interest rate	

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Appendix Table A-5. Puna Boiler - SNCR Costing

SNCR Design Parameters

The following design parameters for the SNCR 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) =	HHV x Max. Fuel Rate =	249	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	14,446,714	gallons/year
Actual Annual fuel consumption (Mactual) =		1,304,562	gallons/year
Heat Rate Factor (HRF) =	NPHR/10 =	1.10	
Total System Capacity Factor (CF_{total}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	0.09	fraction
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	791	hours
NOx Removal Efficiency (EF) =	$(\text{NO}_{x_{\text{in}}} - \text{NO}_{x_{\text{out}}})/\text{NO}_{x_{\text{in}}} =$	35	percent
NOx removed per hour =	$\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B =$	19.92	lb/hour
Total NO _x removed per year =	$(\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	7.88	tons/year
Coal Factor (Coal_f) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)		
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$		
Elevation Factor (ELEV F) =	14.7 psia/P =		
Atmospheric pressure at 10 feet above 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	

Not applicable; factor applies only to coal-fired boilers
 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://spaceflightssystemsgov.nasa.gov/education/rocket/atmos.html>.

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NO}_{x_{\text{in}}} \times Q_B \times \text{NSR} \times \text{MW}_R)/(\text{MW}_{\text{NO}_x} \times \text{SR}) =$ (whre SR = 1 for NH ₃ ; 2 for Urea)	26	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}}/C_{\text{sol}} =$	89	lb/hour
	$(m_{\text{sol}} \times 7.4805)/\text{Reagent Density} =$	11.9	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day})/\text{Reagent Density} =$	4,100	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

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	0.0944

Parameter	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$(0.47 \times \text{NO}_{x_{\text{in}}} \times \text{NSR} \times Q_B)/\text{NPHR} =$	3.0	kW/hour
Water Usage:			
Water consumption (q_w) =	$(m_{\text{sol}}/\text{Density of water}) \times ((C_{\text{stored}}/C_{\text{inj}}) - 1) =$	20	gallons/hour
Fuel Data:			
Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.21	MMBtu/hour
Ash Disposal:			
Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta\text{fuel} \times \% \text{Ash} \times 1 \times 10^6)/\text{HHV} =$	0.0	lb/hour

Not applicable - Ash disposal cost applies only to coal-fired boilers

SNCR Design Parameters

The following design parameters for the SNCR 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) =	HHV x Max. Fuel Rate =	249	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	14,446,714	gallons/year	
Actual Annual fuel consumption (Mactual) =		1,304,562	gallons/year	
Heat Rate Factor (HRF) =	$\text{NPHR}/10 =$	1.10		
Total System Capacity Factor (CF_{total}) =	$(\text{Mactual}/\text{Mfuel}) \times (\text{tSNCR}/365) =$	0.09	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	791	hours	
NOx Removal Efficiency (EF) =	$(\text{NO}_{x_{\text{in}}} - \text{NO}_{x_{\text{out}}})/\text{NO}_{x_{\text{in}}} =$	35	percent	
NOx removed per hour =	$\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B =$	19.92	lb/hour	
Total NO _x removed per year =	$(\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	7.88	tons/year	
Coal Factor (Coal _r) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEV _F) =	$14.7 \text{ psia}/P =$			Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.
Atmospheric pressure at 10 feet above 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		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

Reagent Data:

Type of reagent used: Ammonia Molecular Weight of Reagent (MW) = 17.03 g/mole
 Density = 56 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NO}_{x_{\text{in}}} \times Q_B \times \text{NSR} \times \text{MW}_R)/(\text{MW}_{\text{NO}_x} \times \text{SR}) =$ (where SR = 1 for NH ₃ ; 2 for Urea)	26	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}}/C_{\text{sol}} =$	89	lb/hour
	$(m_{\text{sol}} \times 7.4805)/\text{Reagent Density} =$	11.9	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day})/\text{Reagent Density} =$	4,100	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i \frac{(1+i)^n}{(1+i)^n - 1} =$ Where n = Equipment Life and i = Interest Rate	0.0688

Parameter	Equation	Calculated Value	Units	
Electricity Usage:				
Electricity Consumption (P) =	$(0.47 \times \text{NO}_{x_{\text{in}}} \times \text{NSR} \times Q_B)/\text{NPHR} =$	3.0	kw/hour	
Water Usage:				
Water consumption (q_w) =	$(m_{\text{sol}}/\text{Density of water}) \times ((C_{\text{stored}}/C_{\text{inj}}) - 1) =$	20	gallons/hour	
Fuel Data:				
Additional fuel required to evaporate water in injected reagent (ΔFuel) =	$H_v \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.21	MMBtu/hour	
Ash Disposal:				
Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta\text{fuel} \times \% \text{Ash} \times 1 \times 10^6)/\text{HHV} =$	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

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Appendix Table A-5. Puna Boiler - SNCR Costing

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$636,075 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	\$957,564 in 2019 dollars
Total Capital Investment (TCI) =	\$2,071,731 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$636,075 in 2019 dollars
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2019 dollars
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* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_x\text{Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_x\text{Removed/hr})^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_x\text{Removed/hr})^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_x\text{Removed/hr})^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	\$957,564 in 2019 dollars
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Appendix Table A-5. Puna Boiler - SNCR Costing

Annual Costs		
Total Annual Cost (TAC)		
TAC = Direct Annual Costs + Indirect Annual Costs		
Direct Annual Costs (DAC) =		\$35,852 in 2019 dollars
Indirect Annual Costs (IDAC) =		\$196,504 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC		\$232,356 in 2019 dollars
Direct Annual Costs (DAC)		
DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)		
Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$31,076 in 2019 dollars
Annual Reagent Cost =	$Q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$2,761 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$160 in 2019 dollars
Annual Water Cost =	$Q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$67 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$1,789 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$35,852 in 2019 dollars
Indirect Annual Cost (IDAC)		
IDAC = Administrative Charges + Capital Recovery Costs		
Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$932 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$195,571 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$196,504 in 2019 dollars
Cost Effectiveness		
Cost Effectiveness = Total Annual Cost/ NOx Removed/year		
Total Annual Cost (TAC) =		\$232,356 per year in 2019 dollars
NOx Removed =		8 tons/year
Cost Effectiveness =		\$29,491 per ton of NOx removed in 2019 dollars

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$636,075 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	\$957,564 in 2019 dollars
Total Capital Investment (TCI) =	\$2,071,731 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times \text{CoalF} \times \text{BTF} \times \text{ELEV} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times \text{ELEV} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times \text{CoalF} \times \text{BTF} \times \text{ELEV} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times \text{ELEV} \times \text{RF}$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$636,075 in 2019 dollars
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times \text{CoalF})^{0.78} \times \text{AHF} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times \text{CoalF})^{0.78} \times \text{AHF} \times \text{RF}$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2019 dollars
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* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{RF}$$

Balance of Plant Costs (BOP_{cost}) =	\$957,564 in 2019 dollars
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Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$35,852 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$143,467 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$179,320 in 2019 dollars

Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$31,076 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$2,761 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$160 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$67 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$1,789 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$0 in 2019 dollars
Direct Annual Cost =		\$35,852 in 2019 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$932 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$142,535 in 2019 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$143,467 in 2019 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$179,320 per year in 2019 dollars
NOx Removed =	8 tons/year
Cost Effectiveness =	\$22,760 per ton of NOx removed in 2019 dollars