

**Appendix D: Regional Haze Four-Factor Analysis
Kalaeloā Partners, L.P.**

Initial Four – Factor Analysis



PROJECT REPORT
Kalaeloa Partners, LP > Kalaeloa Cogeneration Plant



Regional Haze 4-Factor Analysis

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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 Kalaeloa Partners, LP (KPLP) for the two combined cycle combustion turbines at the Kalaeloa Cogeneration Plant (Kalaeloa). The combustion turbines (CT-1 and CT-2) currently use steam injection to control NO_x emissions and currently fire residual fuel oil with a maximum sulfur content of 0.5%.

This report considers the following emission reductions options that may be technically feasible for implementation, if needed, to show reasonable progress towards the RHR goal:

- Sulfur dioxide (SO₂) Emission Reduction – Switching from the existing residual oil to a residual/distillate blended fuel or distillate fuel could reduce SO₂ emissions at an estimated cost of over \$7,100 per ton of SO₂ reduced and an annual increase of \$10,000,000 to \$20,000,000 in fuel cost.
- Nitrogen Oxides (NO_x) Emission Reduction – Switching from the existing residual oil to a residual/distillate blended fuel or distillate fuel could reduce NO_x emissions at an estimated cost of \$11,000 per ton of NO_x reduced. Installing a selective catalytic reduction (SCR) system could reduce NO_x emissions at a cost ranging from \$5,600 to \$6,100 per ton of NO_x reduced.
- Particulate Matter (PM₁₀) Emission Reduction – Switching from the existing residual oil to a residual/distillate blended fuel or distillate fuel is the only feasible option for reducing PM₁₀ emissions. Due to the small magnitude of PM₁₀ emissions compared to SO₂ and NO_x emissions, the cost-effectiveness for PM₁₀ emissions will be worse than the cost-effectiveness for SO₂ and NO_x. Based on scaling the fuel switching cost-effectiveness for SO₂ and NO_x, the cost-effectiveness for PM₁₀ is more than \$20,000/ton of PM₁₀ reduced.

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period five-factor analyses for other facilities, and those analyses did not result in emission reduction requirements. Therefore, KPLP does not propose any emissions reductions.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), the U.S. Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final RHR. The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with 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), 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).

The second implementation planning period (2019-2028) for national regional haze efforts is currently underway and the EPA has provided guidance to the states for the development of the implementation plans.¹ For this planning period, 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*² provides the states guidance on methods for selecting the 20 percent most impaired days to track visibility and determining natural visibility conditions. However, the approach described in this guidance document does not attempt to account for haze formed from natural volcanic emissions. Specifically, the document states:

“The approach described in this guidance document does not attempt to account for haze formed from 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.”

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

² *Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program*, December 2018, EPA-454/R-18-010

The DOH acknowledges the impact of SO₂ from the Kilauea volcano in the *5-Year Regional Haze Progress Report For Federal Implementation Plan*³ 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 guidance is to identify the 20 percent most anthropogenically impaired days and the 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)). Due to the magnitude of SO₂ from the Kilauea volcano, it's imperative that the visibility impact of the Kilauea volcano be quantified and so that only anthropogenic impairment is targeted.

Step 3 of the EPA guidance is the selection of the emission sources for which an analysis of emission control measures will be completed for the second implementation period and explain the basis for these selections. The guidance gives the states many options for identifying these sources. The DOH is currently relying of work conducted by the Western Regional Air Partnership (WRAP). WRAP used 2014 National Emissions Inventory (NEI) and assessed each facility's preliminary 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 from each facility to a Class I area. This approach did not take into consideration the frequency or actual visibility impact on the Class I area which may vary based on more complex factors such as prevailing wind direction. The DOH has informed KPLP that Kalaeloa was identified, based on the Q/d analysis, as one of the sources potentially contributing to regional haze at the Haleakala National Park and Volcanoes National Park. This notice triggers a requirement to conduct a four-factor analysis, which will be introduced in greater detail below. This report provides the response to the DOH's request for a four-factor analysis.

In support of the SIP for the first planning period, regional haze modeling was conducted for several facilities⁴ located on the Island of Oahu. The modeling showed these facilities had an insignificant impact on visibility at Haleakala and Hawaii Volcanoes National Parks. Therefore, KPLP encourages DOH to consider actual visibility impacts in the SIP development process.

This report is intended to address DOH's request for a four-factor analysis to address its RHR planning needs. 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 remainder of this document analyzes these four factors with respect to Kalaeloa.

³ *5-Year Regional Haze Progress Report For Federal Implementation Plan, Hawaii State Department of Health, October 2017, EPA-R09-OAR-2018-0744-0004*

⁴ *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii, U.S. EPA Region 9, May 14, 2012. Table VI-3 provides visibility modeling results for the following Oahu facilities: Chevron Refinery, Tesoro Refinery, and Hawaiian Electric's Waiiau and Kahe power plants.*

3. SULFUR DIOXIDE FOUR-FACTOR ANALYSIS

Per DOH guidance, 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 in terms of pounds per million Btu of heat input (lb/MMBtu) and tons per year (TPY).

Table 3-1. Baseline SO₂ Emissions

Unit	Fuel Sulfur	SO ₂ Emissions	
		(lb/MMBtu)	(TPY)
CT1	0.45%	0.474	1,471.7
CT2	0.45%	0.474	1,333.6
Total			2,805.4

3.1. SULFUR DIOXIDE CONTROL OPTIONS

The characterization of emission controls available and potentially 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 are:

- Dry Sorbent Injection (DSI),
- Spray Dryer Absorber (SDA),
- Wet Scrubber,
- Circulating Dry Scrubber (CDS), and
- Fuel Switching.

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

3.1.1. Post-Combustion Controls

DSI, SDA, wet scrubber, and CDS are collectively known as flue gas desulfurization (FGD) systems. FGD applications have not been used historically for SO₂ control on oil-fired combustion turbines. As there are no known FGD applications for oil-fired combustion turbines, the performance of FGDs on oil-fired combustion turbines is unknown. EPA took this into account when evaluating the 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 FGD.⁵ Since there are no applications of FGD on oil-fired units in the U.S., FGDs are considered technically infeasible for the control of SO₂ from the Kalaeloa combustion turbines.

3.1.2. Fuel Switching

The Kalaeloa combustion turbines currently burn residual fuel oil with a maximum sulfur content of 0.5 percent by weight. The average sulfur content of the oil burned in 2017 was approximately 0.45 percent. Switching to a lower sulfur fuel would reduce SO₂ emissions in proportion to the reduction in fuel sulfur content. A lower sulfur residual fuel oil is not available on Hawaii. Lower sulfur content distillate fuels are available and could be burned in the combustion turbines. 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 Hawaii. Technically feasible options include blending the current residual fuel oil

⁵ 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.

with a commercially available lower sulfur distillate fuel or fully switching to a commercially available lower sulfur distillate fuel. The SO₂ four-factor analysis will evaluate both of these options.

3.2. FOUR-FACTOR ANALYSIS

As discussed above, fuel switching to a residual/distillate blended fuel or a lower sulfur diesel is the only feasible option to reduce SO₂ 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 switching to a 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 that the change would achieve. Kalaeloa currently obtains fuel oil from local suppliers. The differential fuel cost between the current residual oil and a common distillate fuel known as ultra-low sulfur diesel (ULSD) is estimated at \$10/bbl. The fuels are refined on Oahu and changes in quantities of residual oil and distillate fuels would require new contracts with fuel suppliers. This adds a level of uncertainty to the cost of compliance. Switching fuel would require changes to Kalaeloa's injectors and the fuel system; however, these capital expenses were not included in this analysis. Additionally, as distillate fuels have lower heating value per gallon than residual, such a change could potentially reduce the electric generating capacity of Kalaeloa under full-load conditions. The economic impact of this effect has not been included in this analysis.

Table 3-2 presents a summary of the cost effectiveness of switching from residual fuel to a residual/distillate blended fuel with a maximum sulfur content of 0.25%. The reduction in fuel sulfur is based on 50/50 blend of the current residual fuel and ULSD. 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/distillate blended fuel with a maximum sulfur content of 0.25% is \$7,900/ton SO₂ reduced and results in a \$10,000,000 annual increase in fuel cost.

Table 3-3 presents a summary of the cost effectiveness of switching from residual fuel to ULSD with a maximum sulfur content of 0.0015% (15 ppm). 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 0.0015% (15 ppm) is \$7,100/ton SO₂ and results in a \$20,000,000 annual increase in fuel cost.

3.2.2. Time Necessary to Achieve Compliance

If DOH determines that switching from residual oil to residual/distillate blended fuel or distillate fuel is needed to achieve reasonable progress, it is anticipated that this change could be implemented within 1 year.

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

Unit	Current Residual Oil (0.50% maximum Sulfur) ^A					Residual/Distillate Blend (0.25% 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 (\$/Gal)	Annual Increase in Fuel Cost ^C (\$/yr)	SO ₂ Cost Effectiveness (\$/ton)
CT1	0.45%	148,405	41,822,683	6,206,695	1,471.7	142,703	43,493,796	809.97	661.77	0.12	\$5,219,256	7,887
CT2	0.45%	148,405	37,897,493	5,624,177	1,333.6	142,703	39,411,767	733.96	599.66	0.12	\$4,729,412	7,887

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

^B Based on a blend of 50.0% residual oil and 50.0% diesel fuel and the weighted average of the 2017 fuel HHV and density for residual oil, AP-42 HHV and density for diesel, and contract fuel sulfur limits.

^C Based on a \$10/bbl cost deference between the current fuel and ULSD.

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

Unit	Current Residual Oil (0.50% maximum Sulfur) ^A					Diesel (0.0015% 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 (\$/Gal)	Annual Increase in Fuel Cost ^C (\$/yr)	SO ₂ Cost Effectiveness (\$/ton)
CT1	0.45%	148,405	41,822,683	6,206,695	1,471.7	137,000	45,304,345	6.21	1,465.53	0.23	\$10,419,999	7,110
CT2	0.45%	148,405	37,897,493	5,624,177	1,333.6	137,000	41,052,390	5.62	1,327.99	0.23	\$9,442,050	7,110

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

^B Based on 2017 average HHV and density for residual oil, AP-42 HHV and density for diesel, and contract fuel sulfur limits.

^C Based on a \$10/bbl cost deference between the current fuel and ULSD.

3.2.3. Energy and Non-Air Quality Environmental Impacts

The cost increase associated with fuel switching to diesel will increase the cost of the electricity produced by Kalaeloa. This increase will likely impact the price of electricity for Oahu customers. The change could also reduce the maximum electric generating capacity of the plant, which could have further electricity cost impacts and negatively impact the stability of Oahu's power grid, given Kalaeloa's important role in stabilizing power supplies during fluctuations in the extremely large proportion of power generation on the island that is from residential solar systems that cannot be centrally managed like conventional power plants.

3.2.4. Remaining Useful Life

The cost of compliance does not contain any capital cost. Therefore, the remaining useful lives of the Kalaeloa combustion turbines is not needed to annualize the capital cost.

3.3. SO₂ CONCLUSION

Switching to residual/distillate blended fuel with a maximum sulfur content of 0.25% or to ULSD with a maximum sulfur content of 0.0015% (15 ppm) will reduce SO₂ emissions for a cost of \$7,900/ton and \$7,100/ton, respectively. These costs are greater than the BART and reasonable progress thresholds established in the first planning period, which ranged from \$5,500/ton to \$5,600/ton.⁶ Switching to residual/distillate blended fuel with a maximum sulfur content of 0.25% will increase annual fuel cost by \$10,000,000. Switching to ULSD with a maximum sulfur content of 0.0015% (15 ppm) will increase annual fuel cost by \$20,000,000,

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Therefore, KPLP does not propose any SO₂ emissions reductions.

⁶ *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii*, U.S. EPA Region 9, May 14, 2012

4. NITROGEN DIOXIDE FOUR-FACTOR ANALYSIS

Per DOH guidance, 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 in terms of pounds per million Btu of heat input (lb/MMBtu) and tons per year (TPY).

Table 4-1. Baseline NO_x Emissions

Unit	NO _x Emissions	
	(lb/MMBtu)	(TPY)
CT1	0.417	1,293.0
CT2	0.425	1,193.9
Total		2,486.9

4.1. NITROGEN 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. 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 vs. 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. Fuel NO_x emissions from firing residual oil are greater than fuel NO_x from firing a distillate fuel.

The most common NO_x control technologies for fuel oil fired combustion turbines are:

- Water/Steam Injection,
- Switching to a fuel oil with a lower nitrogen content (residual/distillate blended fuel or distillate fuel), and
- Selective Catalytic Reduction (SCR).

The feasibility of these controls is in the following sections.

4.1.1. Water/Steam Injection

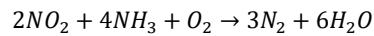
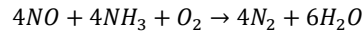
The combustion turbines are currently equipped with this technology; they operate with steam injection which controls NO_x emissions to 130 ppmvd @ 15% O₂. Additional reductions from water/steam injection are not possible with the current fuel.

4.1.2. Fuel Switching

Distillate fuels contains less fuel-bound nitrogen than residual oil, therefore switching to a residual/distillate blended fuel or distillate fuel would lower NO_x emissions. Water injection is routinely used to reduce NO_x emissions from distillate fuel fired combustions turbines to 42 ppmvd @ 15% O₂. For the 50/50 blend of the current residual fuel and ULSD the estimated emission reduction is based on the midpoint between the current limit (130 ppmvd @ 15% O₂) and the expected emissions level for distillate fuel (42 ppmvd @ 15% O₂). Switching to a 50/50 blend of the current residual fuel and ULSD and ULSD is feasible and the four factors are addressed in Section 4.2.

4.1.3. Selective Catalytic Reduction

SCR refers to the process in which NO_x in the exhaust gas (which is composed of both NO and NO₂) 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, and an ammonia storage and 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. KPLP is not aware of any SCR systems on residual fuel fired combustion turbines. Therefore, the application of SCR on residual fuel fired combustion turbines is unproven. Additionally, significant engineering work that is beyond the scope of this analysis is necessary to evaluate other feasibility risks associated with a possible SCR retrofit, such as determining if there is adequate space available in the proper location for the additional equipment to be installed as necessary to interact with the exhaust with proper temperature and mixing conditions. However, the four factors are addressed in Section 4.2. Given its unproven status for this source type, for this analysis SCR is assumed to reduce NO_x emissions by 70%.

4.2. FOUR-FACTOR ANALYSIS

As discussed above, switching to a residual/distillate blended fuel or distillate fuel or installing SCR are options 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 switching to a residual/distillate blended fuel or distillate fuel or installing SCR are discussed in the following sections.

4.2.1. Cost of Compliance

The cost effectiveness of fuel switching was determined by calculating the annual increase in fuel cost from switching to a residual/distillate blended fuel or distillate fuel divided by the expected reduction in NO_x emissions. The cost effectiveness of switching to a distillate fuel is based on a controlled NO_x emissions level of 42 ppmvd @ 15% O₂. The cost effectiveness of switching to a 50/50 blend of the current residual fuel and ULSD is based on a controlled NO_x emissions level of 86 ppmvd @ 15% O₂ (the midpoint between the current limit of 130 ppmvd @ 15% O₂ and the expected emissions level for distillate fuel [42 ppmvd @ 15% O₂]). Switching fuel would require changes to Kalaeloa's injectors and the fuel system. However, these capital expenses were not included in the analysis. Additionally, as distillate fuels have lower heating value per gallon than residual, such a change could potentially reduce the electric generating capacity of Kalaeloa under full-load conditions. The economic impact of this effect has not been included in this analysis. The cost effectiveness of SCR is based on a 70% reduction in NO_x emissions.

Table 4-2 presents a summary of the cost effectiveness of fuel switching and adding SCR. The cost effectiveness of fuel switching is determined by dividing the annual cost increase in fuel by the annual reduction in NO_x emissions. The annual increase in fuel cost is as discussed in Section 3.2.1. The cost effectiveness of fuel switching exceeds \$11,000/ton of NO_x.

Table 4-2. NO_x Cost Effectiveness of Fuel Switching and SCR

Unit	Control Option	2017 NO_x Emissions (tpy)	Controlled Emissions Level (ppmvd @ 15% O₂)	Controlled NO_x Emissions^A (tpy)	NO_x Reduced (tpy)	Annual Cost^B (\$/yr)	NO_x Cost Effectiveness (\$/ton)
CT1	Residual/Distillate Blend	1,293	86	855.35	437.62	\$5,219,256	\$11,926
	Distillate	1,293	42	417.73	875.25	\$10,419,999	\$11,905
	SCR	1,293	39	387.89	905.08	\$5,103,052	\$5,638
CT2	Residual/Distillate Blend	1,194	86	789.80	404.08	\$4,729,412	\$11,704
	Distillate	1,194	42	385.71	808.16	\$9,442,050	\$11,683
	SCR	1,194	39	358.16	835.71	\$5,103,052	\$6,106

^A Controlled emissions are based on the ratio of the permit limit of 130 ppmvd @ 15% O₂ to the listed controlled emissions level.

^B Annual cost for switching to a residual/distillate blend or distillate are from Tables 3-1 and 3-2. The annual SCR cost is documented in Appendix A.

The cost effectiveness of SCR ranges from \$5,600/ton to \$6,100/ton of NO_x. The SCR costing is based on generic EPA control costing⁷ which does not consider Hawaii's remote location. Hawaii's remote location results in additional shipping and higher construction cost. Due to the uncertainty a retrofit factor of 2.0 was applied to the annual SCR cost. Appendix A contains the SCR costing details.

4.2.2. Time Necessary to Achieve Compliance

If DOH determines that switching from residual oil to a residual/distillate blended fuel or distillate fuel is needed to achieve reasonable progress, it is anticipated that this change could be implemented within 1 year.

If DOH determines that added SCR is needed and feasible to achieve reasonable progress, it is anticipated that this change could be implemented within 3 years.

4.2.3. Energy and Non-Air Quality Environmental Impacts

The cost increase associated with fuel switching will increase the cost of the electricity produced by Kalaeloa. This increase will likely impact the price of electricity for Oahu customers.

The addition of SCR reduces the efficiency of the system and add operating cost that will increase the cost of the electricity produced by Kalaeloa. This increase will likely impact the price of electricity for Oahu customers. In addition, Additionally, the use and storage of aqueous ammonia is a safety hazard; when there is a potential for more than 10,000 lbs to be at a given site, the risk is regulated by the CAA's 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.

Additionally, SCR releases 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 participates in secondary downwind reactions 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. Therefore, ammonia slip from a possible SCR system could at least partially counteract some of the benefit achieved by the NO_x reductions the system could generate.

4.2.4. Remaining Useful Life

The cost of compliance for fuel switching does not contain any capital cost. Therefore, the remaining useful lives of the Kalaeloa combustion turbines is not needed to annualize the capital cost.

The Kalaeloa units do not have any set retirement date. The estimated lifetime of an SCR control system is 20 years. This estimate has been incorporated in the cost analysis to calculate the total annualized cost of the control.

4.3. NO_x CONCLUSION

The cost effectiveness of fuel switching exceeds \$11,000/ton of NO_x and results in a \$10,000,000 to \$20,000,000 increase in annual fuel cost. The application of SCR on residual fuel fired combustion turbines is unproven. However, the cost effectiveness of SCR ranges from \$5,600/ton to \$6,100/ton of

⁷ *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

NO_x. The cost-effectiveness of SCR is similar to the BART analysis conducted for boilers during the first planning period. For the first planning period, EPA concluded that SCR was not cost effective.⁸

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Therefore, KPLP does not propose any NO_x emissions reductions.

⁸ *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii*, U.S. EPA Region 9, May 14, 2012

5. PARTICULATE MATTER FOUR-FACTOR ANALYSIS

Per DOH guidance, 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 in terms of pounds per million Btu of heat input (lb/MMBtu) and tons per year (TPY).

Table 5-1. Baseline PM₁₀ Emissions

Unit	PM ₁₀ Emissions	
	(lb/MMBtu)	(TPY)
CT1	0.0380	118.1
CT2	0.0380	106.7
Total		224.8

5.1. PARTICULATE MATTER CONTROL OPTIONS

The characterization of emission controls available and applicability to the source is a necessary step before the four factors can be analyzed. PM₁₀ emissions from combustion turbines result from incomplete combustion and noncombustible trace constituents in the fuel. PM₁₀ emissions are comprised of both "filterable" and "condensable" PM₁₀. Filterable PM₁₀ is that portion of the total PM₁₀ that exists in the stack in either solid or liquid state and can be measured on a filter. Condensable PM₁₀ is that portion of the total PM₁₀ that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM₁₀ is composed of organic and inorganic compounds and is generally considered to be less than 1.0 micrometers in aerodynamic diameter.

U.S. EPA's BACT/RACT/LAER clearinghouse does not list any post-combustion controls for combustion turbines. PM₁₀ emissions from combustion turbines are controlled by good combustion practices. However, switching from residual fuel to a residual/distillate blended fuel or distillate fuel is expected to reduce PM₁₀ emissions.

5.2. FOUR-FACTOR ANALYSIS

Since the magnitude of the PM₁₀ emissions are approximately 10 times lower than the SO₂ and NO_x emissions and fuel switching is the only option, a separate four-factor analysis is not required for PM₁₀. Based on scaling the fuel switching cost-effectiveness for SO₂ and NO_x, the cost-effectiveness for PM₁₀ will be greater than \$20,000/ton of PM₁₀.

5.3. PM₁₀ CONCLUSION

For the first planning period, EPA concluded that PM₁₀ controls of \$13,000/ton were not cost-effective.⁹ The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Therefore, KPLP does not propose any PM₁₀ emissions reductions.

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

APPENDIX A : DETAILED SCR COSTING

Appendix Table A-1. SCR Costing

Parameter		CT1	CT2
MW		86.0	86.0
Max Heat Input	(MMBtu/hr)	900	900
Capital Recovery Factor (CRF)		0.09	0.09
Cost Index: Chemical Engineering Plant Cost Index (CEPCI)			
	2018	603.1	
	1990	357.6	
Total Capital Investment (Eq. 1 - 1990 dollars)	(\$)	\$4,637,762	\$4,637,762
Capital Cost (2018 dollars)	(\$)	\$7,821,684	\$7,821,684
Annualized Capital Cost (2018 dollars)	(\$/yr)	\$738,312	\$738,312
Total Annual Cost (Eq. 2 - 1990 dollars)	(\$/yr)	\$1,512,893	\$1,512,893
Hawaii Retrofit Cost Factor		2.00	2.00
Total Annual Cost (2018 Dollars)	(\$/yr)	\$5,103,052	\$5,103,052
Baseline (2017) NO _x Emissions	(tpy)	1,293	1,194
SCR Level of Control		70%	70%
Controlled NO _x Emissions	(tpy)	388	358
NO _x Reduction	(tpy)	905	836
NO_x Cost Effectiveness	(\$/ton)	\$5,638.21	\$6,106.22

Total capital investment (1990 dollars) = 4744 x (MMBtu/hr) + 368162 Equation 1

Total Annual Cost (1990 dollars) = 1522.5 x (MMBtu/hr) + 142643 Equation 2

Capital Recovery Factor (CRF) = $[1 \times (1+i)^a] / [(1+i)^a - 1]$ CRF = 0.09

Where:

I = Interest Rate (7% interest)

a = Equipment life (20 yrs)

Source: *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

Comments on Four – Factor Analysis

Madsen, Michael A

From: Madsen, Michael A
Sent: Friday, February 28, 2020 3:59 PM
To: Walsh, Jeffrey
Cc: Gorman, Erin; Stephen Beene; Hamamoto, Dale; Takamoto, Clayton Scott; Rossio, Marianne Fuji
Subject: RE: [EXTERNAL] RE: Update request: BART- 4 Factor Regional Haze KPLP Project
Attachments: noxdoc.pdf; gasturb.pdf

Jeff,

Thank you for the opportunity to review the subject draft four-factor analysis. This email is a follow-up to the February 18, 2020 conference call concerning the analysis. After preliminary review and discussions with EPA on the draft four-factor analysis, we have the following comments:

- 1) Please evaluate the feasibility of the following control measures for reducing emissions from the combustion turbines:
 - a. Low-NOx Burners (LNBs). On page 20 of the first attached document it is indicated that combining the use of LNB with closely controlled air/fuel and water/steam injection can yield emissions as low as 10 ppm from gas turbines.
 - b. Selective Non-Catalytic Reduction (SNCR). Please refer to pages 5-190 and 5-191 of the second attached document.
 - c. Use of naphtha as an alternate fuel.
- 2) Provide further review of natural gas as an alternate fuel. We are aware that The Gas Company dba Hawaii Gas has plans to import liquified natural gas.
- 3) What year are the dollar figures in for all costs?
- 4) What is the assumed installation year for SCR?
- 5) How often do the combustion turbines operate at full load?
- 6) It is not logical to directly compare the best available retrofit technology (BART) reference cost to current costs directly because they are from different years.
- 7) Provide the source(s) of information for stating that the differential fuel cost between the current residual oil and ultra-low sulfur diesel (ULSD) is \$10/barrel.

Also, for addressing the comments, we have agreed to extend the deadline for submitting the four-factor analysis until **March 31, 2020**.

If you have any questions, please feel free to contact me.

Mike Madsen, P.E.
Environmental Engineer, Clean Air Branch
Hawaii Department of Health

Office: [REDACTED] | Fax: [REDACTED]



Revised Four – Factor Analysis



**KALAELOA
PARTNERS, LP**

Clean and Efficient Energy

91-111 KALAELOA BOULEVARD • KAPOLEI, HAWAII 96707

Dear Mike,

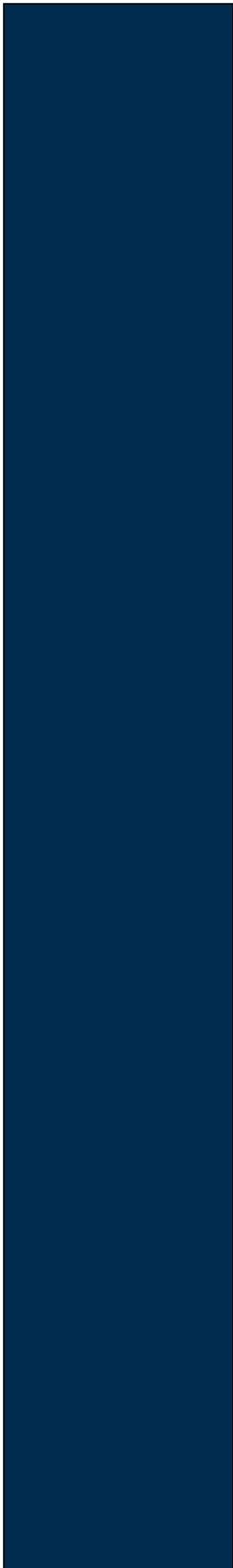
Enclosed, please find the requested Regional Haze Rule Four-Factor Analysis for the Kalaeloa Partners L.P., Kalaeloa Cogeneration Plant (KPLP). The Department of Health (DOH) was provided an initial draft of the Four-Factor Analysis on February 13, 2020. As a follow-up to the initial draft Four-Factor Analysis transmittal, a phone meeting between the DOH and KPLP was held on February 18, 2020. Following the meeting, the DOH provided initial comments to KPLP on February 28, 2020. Responses to the February 28, 2020 comments have been addressed in the enclosed Four-Factor Analysis.

On March 23, 2020, the DOH provided additional comments from the National Park Service (NPS). The NPS comments are related to the selective catalytic reduction (SCR) costing and cost effectiveness calculation provided in the initial draft Four-Factor Analysis. The first NPS comment requests a vendor quote specific to adding SCR to KPLP. The remaining four comments are related to inputs to the SCR cost effectiveness calculation. Due to current travel restriction related to the COVID-19 pandemic, it is unclear on the time needed to fully evaluate the ability of obtaining a site-specific vendor quote. Due to the unique nature of KPLP, additional resources would be required to assess the space constraints and operational data needed to develop a site-specific cost estimate. Once the travel restrictions are lifted, KPLP will provide an update to DOH on progress in this area.

If you have any questions or need any additional information, please don't hesitate to contact me. KPLP appreciates DOH's flexibility in responding to the comments mentioned above until logistical issues due to COVID-19 are resolved.

Best Regards

Jeff Walsh March 27th
Jeff Walsh



PROJECT REPORT
Kalaeloa Partners, LP > Kalaeloa Cogeneration Plant



Regional Haze 4-Factor Analysis

TRINITY CONSULTANTS
20 Corporate Park Drive, Suite 200
Irvine, CA 92606

March 2020

Project 190501.0203



EHS solutions delivered uncommonly well

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1. EXECUTIVE SUMMARY

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 Kalaeloa Partners, LP (KPLP) for the two combined cycle combustion turbines at the Kalaeloa Cogeneration Plant (Kalaeloa). The combustion turbines (CT-1 and CT-2) currently use steam injection to control NO_x emissions and currently fire residual fuel oil with a maximum sulfur content of 0.5%. The combustion turbines are currently used to provide baseload generation and operate at a utilization rate ranging from 60% to 70%.

This report considers the following emission reductions options that may be technically feasible for implementation, if needed, to show reasonable progress towards the RHR goal:

- Sulfur dioxide (SO₂) Emission Reduction – Switching from the existing residual oil to a residual/distillate blended fuel or distillate fuel could reduce SO₂ emissions at an estimated cost of over \$7,100 per ton of SO₂ reduced in current dollars and an annual increase of \$10,000,000 to \$20,000,000 in fuel cost.
- Nitrogen Oxides (NO_x) Emission Reduction – Switching from the existing residual oil to a residual/distillate blended fuel or distillate fuel could reduce NO_x emissions at an estimated cost of \$11,000 per ton of NO_x reduced in current dollars. Installing a selective catalytic reduction (SCR) system could reduce NO_x emissions at a cost ranging from \$5,600 to \$6,100 per ton of NO_x reduced in 2018 dollars.
- Particulate Matter (PM₁₀) Emission Reduction – Switching from the existing residual oil to a residual/distillate blended fuel or distillate fuel is the only feasible option for reducing PM₁₀ emissions. Due to the small magnitude of PM₁₀ emissions compared to SO₂ and NO_x emissions, the cost-effectiveness for PM₁₀ emissions will be worse than the cost-effectiveness for SO₂ and NO_x. Based on scaling the fuel switching cost-effectiveness for SO₂ and NO_x, the cost-effectiveness for PM₁₀ is more than \$20,000/ton of PM₁₀ reduced in current dollars.

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period five-factor analyses for other facilities, and those analyses did not result in emission reduction requirements. Therefore, KPLP does not propose any emissions reductions.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), the U.S. Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final RHR. The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with 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), 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).

The second implementation planning period (2019-2028) for national regional haze efforts is currently underway and the EPA has provided guidance to the states for the development of the implementation plans.¹ For this planning period, 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*² provides the states guidance on methods for selecting the 20 percent most impaired days to track visibility and determining natural visibility conditions. However, the approach described in this guidance document does not attempt to account for haze formed from natural volcanic emissions. Specifically, the document states:

“The approach described in this guidance document does not attempt to account for haze formed from 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.”

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

² *Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program*, December 2018, EPA-454/R-18-010

The DOH acknowledges the impact of SO₂ from the Kilauea volcano in the *5-Year Regional Haze Progress Report For Federal Implementation Plan*³ 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 guidance is to identify the 20 percent most anthropogenically impaired days and the 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)). Due to the magnitude of SO₂ from the Kilauea volcano, it's imperative that the visibility impact of the Kilauea volcano be quantified and so that only anthropogenic impairment is targeted.

Step 3 of the EPA guidance is the selection of the emission sources for which an analysis of emission control measures will be completed for the second implementation period and explain the basis for these selections. The guidance gives the states many options for identifying these sources. The DOH is currently relying of work conducted by the Western Regional Air Partnership (WRAP). WRAP used 2014 National Emissions Inventory (NEI) and assessed each facility's preliminary 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 from each facility to a Class I area. This approach did not take into consideration the frequency or actual visibility impact on the Class I area which may vary based on more complex factors such as prevailing wind direction. The DOH has informed KPLP that Kalaeloa was identified, based on the Q/d analysis, as one of the sources potentially contributing to regional haze at the Haleakala National Park and Volcanoes National Park. This notice triggers a requirement to conduct a four-factor analysis, which will be introduced in greater detail below. This report provides the response to the DOH's request for a four-factor analysis.

In support of the SIP for the first planning period, regional haze modeling was conducted for several facilities⁴ located on the Island of Oahu. The modeling showed these facilities had an insignificant impact on visibility at Haleakala and Hawaii Volcanoes National Parks. Therefore, KPLP encourages DOH to consider actual visibility impacts in the SIP development process.

This report is intended to address DOH's request for a four-factor analysis to address its RHR planning needs. 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 remainder of this document analyzes these four factors with respect to Kalaeloa.

³ *5-Year Regional Haze Progress Report For Federal Implementation Plan, Hawaii State Department of Health, October 2017, EPA-R09-OAR-2018-0744-0004*

⁴ *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii, U.S. EPA Region 9, May 14, 2012. Table VI-3 provides visibility modeling results for the following Oahu facilities: Chevron Refinery, Tesoro Refinery, and Hawaiian Electric's Waiiau and Kahe power plants.*

3. SULFUR DIOXIDE FOUR-FACTOR ANALYSIS

Per DOH guidance, 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 in terms of pounds per million Btu of heat input (lb/MMBtu) and tons per year (TPY).

Table 3-1. Baseline SO₂ Emissions

Unit	Fuel Sulfur	SO ₂ Emissions	
		(lb/MMBtu)	(TPY)
CT1	0.45%	0.474	1,471.7
CT2	0.45%	0.474	1,333.6
Total			2,805.4

3.1. SULFUR DIOXIDE CONTROL OPTIONS

The characterization of emission controls available and potentially 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 are:

- Dry Sorbent Injection (DSI),
- Spray Dryer Absorber (SDA),
- Wet Scrubber,
- Circulating Dry Scrubber (CDS), and
- Fuel Switching.

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

3.1.1. Post-Combustion Controls

DSI, SDA, wet scrubber, and CDS are collectively known as flue gas desulfurization (FGD) systems. FGD applications have not been used historically for SO₂ control on oil-fired combustion turbines. As there are no known FGD applications for oil-fired combustion turbines, the performance of FGDs on oil-fired combustion turbines is unknown. EPA took this into account when evaluating the 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 FGD.⁵ Since there are no applications of FGD on oil-fired units in the U.S., FGDs are considered technically infeasible for the control of SO₂ from the Kalaeloa combustion turbines.

3.1.2. Fuel Switching

The Kalaeloa combustion turbines currently burn residual fuel oil with a maximum sulfur content of 0.5 percent by weight. The average sulfur content of the oil burned in 2017 was approximately 0.45 percent by weight. Switching to a lower sulfur fuel would reduce SO₂ emissions in proportion to the reduction in fuel sulfur content. A lower sulfur residual fuel oil is not available on Hawaii. Lower sulfur content distillate fuels are available and could be burned in the combustion turbines. Ultra-low sulfur diesel (ULSD) is a common distillate fuel and has a maximum sulfur content of 0.0015 percent (15 ppm) by weight.

⁵ 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.

Natural gas and naphtha have less sulfur than the existing residual fuel oil. The supply of these fuels is not sufficient to support the Kalaeloa combustion turbines. Par Hawaii is the only refinery in Hawaii and cannot supply the required naphtha volume. The typical sulfur content of Naphtha ranges from 30 ppm to 100 ppm which is greater than ULSD.⁶ Hawaii Gas is the only natural gas supplier in Hawaii. Hawaii Gas's natural gas supply is currently limited to residential and commercial uses. The sulfur content of natural gas is similar to ultra-low sulfur diesel (ULSD)⁷; therefore, switching to natural gas will not result in significantly lower emissions than switching to USLD. In addition, switching the Kalaeloa combustion turbines to natural gas would require the addition of natural gas supply lines and new burners. Based on these factors switching to naphtha and natural gas are not considered technically feasible options to reduce SO₂ emissions.

Technically feasible options include blending the current residual fuel oil with a commercially available lower sulfur distillate fuel or fully switching to a commercially available lower sulfur distillate fuel. The SO₂ four-factor analysis will evaluate both of these options.

3.2. FOUR-FACTOR ANALYSIS

As discussed above, fuel switching to a residual/distillate blended fuel or a lower sulfur diesel is the only feasible option to reduce SO₂ 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 switching to a 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 that the change would achieve. Kalaeloa currently obtains fuel oil from local suppliers. The differential fuel cost between the current residual oil and ULSD is estimated at \$10/bbl based on a comparison of 2018 fuel prices for imported comparable fuels available on the Asian market. Table 3-2 lists the 2018 monthly average fuel prices and cost differentials. Kalaeloa's fuel purchases follow these prices. The fuels are refined on Oahu and changes in quantities of residual oil and distillate fuels would require new contracts with fuel suppliers. This adds a level of uncertainty to the cost of compliance. Switching fuel would require changes to Kalaeloa's injectors and the fuel system; however, these capital expenses were not included in this analysis. Additionally, as distillate fuels have lower heating value per gallon than residual, such a change could potentially reduce the electric generating capacity of Kalaeloa under full-load conditions. The economic impact of this effect has not been included in this analysis.

⁶ <https://www.bakerobrien.com/bakerobrien3/assets/File/BakerOBrien%20-%20AFPM%20-%20The%20Light%20Naphtha%20Surplus%20and%20the%20Potential%20Impact%20of%20Tier%203%20Sulfur.pdf>

⁷ According to EPA's prevailing definition of "pipeline natural gas" as defined in Part 72 and Part 75, it has a maximum sulfur content of 0.5 grains per 100 cubic foot. Based on the AP-42 Appendix A density of natural gas of 1 pound per 23.8 cubic foot, or 17 parts per million by weight.

Table 3-2. Differential Fuel Cost

Month	LSFO		ULSD	Differential
	\$/MT	\$/bbl	\$/bbl	\$/bbl
Jan-18	438.07	65.78	81.84	16.06
Feb-18	443.55	66.60	78.06	11.46
Mar-18	449.42	67.49	78.38	10.89
Apr-18	462.92	69.51	84.28	14.77
May-18	514.68	77.28	90.53	13.24
Jun-18	524.61	78.78	87.40	8.62
Jul-18	523.11	78.55	86.88	8.33
Aug-18	511.70	76.84	88.51	11.67
Sep-18	520.67	78.18	93.80	15.61
Oct-18	556.00	83.49	97.25	13.76
Nov-18	496.26	74.52	82.29	7.77
Dec-18	414.16	62.19	70.01	7.82
Average	487.93	73.27	84.94	11.67

Source: The listed prices are from S&P Global Platts for fuel exported from Singapore for the products closest to LSFO (HSFO 180 CST with sulfur adjustment) and ULSD (Gasoil 10 ppm). The listed prices do not include taxes and shipping cost.

Table 3-3 presents a summary of the cost effectiveness of switching from residual fuel to a residual/distillate blended fuel with a maximum sulfur content of 0.25%. The reduction in fuel sulfur is based on a 50/50 blend of the current residual fuel and ULSD. 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/distillate blended fuel with a maximum sulfur content of 0.25% is \$7,900/ton SO₂ in current dollars and results in a \$10,000,000 annual increase in fuel cost.

Table 3-4 presents a summary of the cost effectiveness of switching from residual fuel to ULSD with a maximum sulfur content of 0.0015% (15 ppm). 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 0.0015% (15 ppm) is \$7,100/ton SO₂ in current dollars and results in a \$20,000,000 annual increase in fuel cost.

3.2.2. Time Necessary to Achieve Compliance

If DOH determines that switching from residual oil to residual/distillate blended fuel or distillate fuel is needed to achieve reasonable progress, it is anticipated that this change could be implemented within 1 year.

3.2.3. Energy and Non-Air Quality Environmental Impacts

The cost increase associated with fuel switching to diesel will increase the cost of the electricity produced by Kalaeloa. This increase will likely impact the price of electricity for Oahu customers. The change could also reduce the maximum electric generating capacity of the plant, which could have further electricity cost impacts and negatively impact the stability of Oahu's power grid, given Kalaeloa's important role in stabilizing power supplies during fluctuations in the extremely large proportion of power generation on the island that is from residential solar systems that cannot be centrally managed like conventional power plants.

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

Unit	Current Residual Oil (0.50% maximum Sulfur) ^A					Residual/Distillate Blend (0.25% 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 (\$/Gal)	Annual Increase in Fuel Cost ^C (\$/yr)	SO ₂ Cost Effectiveness (\$/ton)
CT1	0.45%	148,405	41,822,683	6,206,695	1,471.7	142,703	43,493,796	809.97	661.77	0.12	\$5,219,256	7,887
CT2	0.45%	148,405	37,897,493	5,624,177	1,333.6	142,703	39,411,767	733.96	599.66	0.12	\$4,729,412	7,887

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

^B Based on a blend of 50.0% residual oil and 50.0% diesel fuel and the weighted average of the 2017 fuel HHV and density for residual oil, AP-42 HHV and density for diesel, and contract fuel sulfur limits.

^C Based on a \$10/bbl cost deference between the current fuel and ULSD. The annual costs of fuel switching are based on current dollars.

Table 3-4. SO₂ Cost Effectiveness of Switching to Distillate Fuel

Unit	Current Residual Oil (0.50% maximum Sulfur) ^A					Diesel (0.0015% 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 (\$/Gal)	Annual Increase in Fuel Cost ^C (\$/yr)	SO ₂ Cost Effectiveness (\$/ton)
CT1	0.45%	148,405	41,822,683	6,206,695	1,471.7	137,000	45,304,345	6.21	1,465.53	0.23	\$10,419,999	7,110
CT2	0.45%	148,405	37,897,493	5,624,177	1,333.6	137,000	41,052,390	5.62	1,327.99	0.23	\$9,442,050	7,110

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

^B Based on 2017 average HHV and density for residual oil, AP-42 HHV and density for diesel, and contract fuel sulfur limits.

^C Based on a \$10/bbl cost deference between the current fuel and ULSD. The annual costs of fuel switching are based on current dollars.

3.2.4. Remaining Useful Life

The cost of compliance does not contain any capital cost. Therefore, the remaining useful lives of the Kalaeloa combustion turbines is not needed to annualize the capital cost.

3.3. SO₂ CONCLUSION

Switching to residual/distillate blended fuel with a maximum sulfur content of 0.25% or to ULSD with a maximum sulfur content of 0.0015% (15 ppm) will reduce SO₂ emissions for a cost of \$7,900/ton and \$7,100/ton in current dollars, respectively. These costs are greater than the BART and reasonable progress thresholds established in the first planning period, which ranged from \$5,700/ton to \$5,800/ton in 2018 dollars.⁸ Switching to residual/distillate blended fuel with a maximum sulfur content of 0.25% will increase annual fuel cost by \$10,000,000. Switching to ULSD with a maximum sulfur content of 0.0015% (15 ppm) will increase annual fuel cost by \$20,000,000,

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Therefore, KPLP does not propose any SO₂ emissions reductions.

⁸ *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii*, U.S. EPA Region 9, May 14, 2012. The listed cost thresholds are scaled from 2012 dollars to 2018 dollars using the Chemical Engineering Plant Cost Index (2018 dollars = (603.1/584.6) x 2012 dollars).

4. NITROGEN OXIDES FOUR-FACTOR ANALYSIS

Per DOH guidance, 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 in terms of pounds per million Btu of heat input (lb/MMBtu) and tons per year (TPY).

Table 4-1. Baseline NO_x Emissions

Unit	NO _x Emissions	
	(lb/MMBtu)	(TPY)
CT1	0.417	1,293.0
CT2	0.425	1,193.9
Total		2,486.9

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 vs. 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. Fuel NO_x emissions from firing residual oil are greater than fuel NO_x from firing a distillate fuel.

Potential NO_x control technologies for fuel oil fired combustion turbines are:

- Low NO_x Burners - Dry Low NO_x (DLN) combustion design,
- Selective Non-Catalytic Reduction (SNCR),
- Water/Steam Injection,
- Switching to a fuel oil with a lower nitrogen content (residual/distillate blended fuel or distillate fuel), and
- Selective Catalytic Reduction (SCR).

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

4.1.1. Dry Low NO_x Combustion Design

Low NO_x burner technology utilizes advanced burner design to reduce NO_x formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. DLN is a gas-turbine combustion technology that enables gas-turbine combustors to produce low NO_x emission levels without diluents (such as water or steam) or catalysts. DLN technology utilizes a lean premixed flame as opposed to a turbulent diffusion flame, therefore requiring the use of natural gas or other gaseous fuels. Since fuel oil (residual or distillate) cannot be easily premixed, it is not suitable as a DLN fuel.⁹ Therefore, this technology is not technically feasible for the Kalaeloa combustion turbines.

4.1.2. Selective Non-Catalytic Reduction

SNCR is an add-on technology that reduces NO_x by injecting ammonia or urea into exhaust gases similar to SCR. Without the catalyst that defines SCR, SCR must operate at a higher temperature (1600° to

⁹ Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines Technologies & Cost Effectiveness, Northeast States for Coordinated Air Use Management, December 2000.

2200°F) for the reduction reaction to occur. Since SNCR does not require a catalyst, this process is more attractive than SCR from an economic standpoint. The operating temperature window, however, is not compatible with gas turbine exhaust temperatures, which do not exceed 1100°F. Additionally, the residence time required for the reaction is approximately 100 milliseconds, which is too slow for gas turbine operating flow velocities.¹⁰ Therefore, this technology is not technically feasible for the Kalaeloa combustion turbines.

4.1.3. Water/Steam Injection

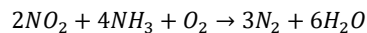
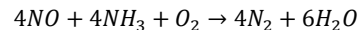
The combustion turbines are currently equipped with this technology; they operate with steam injection which controls NO_x emissions to 130 ppmvd @ 15% O₂. Additional reductions from water/steam injection are not possible with the current fuel.

4.1.4. Fuel Switching

Distillate fuels contains less fuel-bound nitrogen than residual oil, therefore switching to a residual/distillate blended fuel or distillate fuel would lower NO_x emissions. Water injection is routinely used to reduce NO_x emissions from distillate fuel fired combustions turbines to 42 ppmvd @ 15% O₂. For the 50/50 blend of the current residual fuel and ULSD the estimated emission reduction is based on the midpoint between the current limit (130 ppmvd @ 15% O₂) and the expected emissions level for distillate fuel (42 ppmvd @ 15% O₂). Switching to a 50/50 blend of the current residual fuel and ULSD and ULSD is feasible and the four factors are addressed in Section 4.2.

4.1.5. Selective Catalytic Reduction

SCR refers to the process in which NO_x in the exhaust gas (which is composed of both NO and NO₂) 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, and an ammonia storage and 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. KPLP is not aware of any SCR systems on residual fuel fired combustion turbines. Therefore, the application of SCR on residual fuel fired combustion turbines is unproven. Additionally, significant engineering work that is beyond the scope of this analysis is necessary to evaluate other feasibility risks associated with a possible SCR retrofit, such as determining if there is adequate space available in the proper location for the additional equipment to be installed as necessary to interact with the exhaust with proper temperature and mixing conditions. However, the four factors are addressed in Section 4.2. Given its unproven status for this source type, for this analysis SCR is assumed to reduce NO_x emissions by 70%.

4.2. FOUR-FACTOR ANALYSIS

As discussed above, switching to a residual/distillate blended fuel or distillate fuel or installing SCR are feasible options 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:

¹⁰ *Alternative Control Techniques Document - NO_x Emissions from Stationary Gas Turbines*, EPA-453/R-93-007, January 1993.

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 to a residual/distillate blended fuel or distillate fuel or installing SCR are discussed in the following sections.

4.2.1. Cost of Compliance

The cost effectiveness of fuel switching was determined by calculating the annual increase in fuel cost from switching to a residual/distillate blended fuel or distillate fuel divided by the expected reduction in NO_x emissions. The cost effectiveness of switching to a distillate fuel is based on a controlled NO_x emissions level of 42 ppmvd @ 15% O₂. The cost effectiveness of switching to a 50/50 blend of the current residual fuel and ULSD is based on a controlled NO_x emissions level of 86 ppmvd @ 15% O₂ (the midpoint between the current limit of 130 ppmvd @ 15% O₂ and the expected emissions level for distillate fuel [42 ppmvd @ 15% O₂]). Switching fuel would require changes to Kalaeloa's injectors and the fuel system. However, these capital expenses were not included in the analysis. Additionally, as distillate fuels have lower heating value per gallon than residual, such a change could potentially reduce the electric generating capacity of Kalaeloa under full-load conditions. The economic impact of this effect has not been included in this analysis. The cost effectiveness of SCR is based on a 70% reduction in NO_x emissions.

Table 4-2 presents a summary of the cost effectiveness of fuel switching and adding SCR. The cost effectiveness of fuel switching is determined by dividing the annual cost increase in fuel by the annual reduction in NO_x emissions. The annual increase in fuel cost is as discussed in Section 3.2.1. The cost effectiveness of fuel switching exceeds \$11,000/ton of NO_x in current dollars.

The cost effectiveness of SCR ranges from \$5,600/ton to \$6,100/ton of NO_x in 2018 dollars. The SCR costing is based on generic EPA control costing¹¹ which does not consider Hawaii's remote location and the space constraints of the site. Hawaii's remote location results in additional shipping and higher construction cost. Due to this uncertainty a retrofit factor of 2.0 was applied to the annual SCR cost. Appendix A contains the SCR costing details.

4.2.2. Time Necessary to Achieve Compliance

If DOH determines that switching from residual oil to a residual/distillate blended fuel or distillate fuel is needed to achieve reasonable progress, it is anticipated that this change could be implemented within 1 year.

If DOH determines that added SCR is needed and feasible to achieve reasonable progress, it is anticipated that this change could be implemented within 3 years of the SIP being finalized. Provided the SIP is finalized in July of 2022, SCR could be installed by July 2025.

¹¹ *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

Table 4-2. NO_x Cost Effectiveness of Fuel Switching and SCR

Unit	Control Option	2017 NO_x Emissions (tpy)	Controlled Emissions Level (ppmvd @ 15% O₂)	Controlled NO_x Emissions^A (tpy)	NO_x Reduced (tpy)	Annual Cost^B (\$/yr)	NO_x Cost Effectiveness (\$/ton)
CT1	Residual/Distillate Blend	1,293	86	855.35	437.62	\$5,219,256	\$11,926
	Distillate	1,293	42	417.73	875.25	\$10,419,999	\$11,905
	SCR	1,293	39	387.89	905.08	\$5,103,052	\$5,638
CT2	Residual/Distillate Blend	1,194	86	789.80	404.08	\$4,729,412	\$11,704
	Distillate	1,194	42	385.71	808.16	\$9,442,050	\$11,683
	SCR	1,194	39	358.16	835.71	\$5,103,052	\$6,106

^A Controlled emissions are based on the ratio of the permit limit of 130 ppmvd @ 15% O₂ to the listed controlled emissions level.

^B Annual costs for switching to a residual/distillate blend or distillate are from Tables 3-1 and 3-2. The annual costs of fuel switching are based on current dollars. The annual SCR cost is documented in Appendix A. The annual costs of SCR have been scaled to 2018 dollars using the Chemical Engineering Plant Cost Index.

4.2.3. Energy and Non-Air Quality Environmental Impacts

The cost increase associated with fuel switching will increase the cost of the electricity produced by Kalaeloa. This increase will likely impact the price of electricity for Oahu customers.

The addition of SCR reduces the efficiency of the system and add operating cost that will increase the cost of the electricity produced by Kalaeloa. This increase will likely impact the price of electricity for Oahu customers. In addition, Additionally, the use and storage of aqueous ammonia is a safety hazard; when there is a potential for more than 10,000 lbs to be at a given site, the risk is regulated by the CAA's 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.

Additionally, SCR releases 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 participates in secondary downwind reactions 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. Therefore, ammonia slip from a possible SCR system could at least partially counteract some of the benefit achieved by the NO_x reductions the system could generate.

4.2.4. Remaining Useful Life

The cost of compliance for fuel switching does not contain any capital cost. Therefore, the remaining useful lives of the Kalaeloa combustion turbines is not needed to annualize the capital cost.

The Kalaeloa units do not have any set retirement date. As part of current negotiations to extend Kalaeloa's Purchase Power Agreement (PPA) with Hawaiian Electric, a 20-year life expansion analysis is required. For consistency with the PPA negotiations, a 20-year capital recovery period is used to calculate the total annualized cost of the SCR system.

4.3. NO_x CONCLUSION

The cost effectiveness of fuel switching exceeds \$11,000/ton of NO_x and results in a \$10,000,000 to \$20,000,000 increase in annual fuel cost. The application of SCR on residual fuel fired combustion turbines is unproven. However, the cost effectiveness of SCR ranges from \$5,800/ton to \$6,300/ton of NO_x in 2018 dollars. The cost-effectiveness of SCR is similar to the BART analysis conducted for boilers during the first planning period. For the first planning period, EPA concluded that SCR was not cost effective.¹²

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Therefore, KPLP does not propose any NO_x emissions reductions.

¹² *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii*, U.S. EPA Region 9, May 14, 2012. The listed cost thresholds are scaled from 2012 dollars to 2018 dollars using the Chemical Engineering Plant Cost Index (2018 dollars = (603.1/584.6) x 2012 dollars).

5. PARTICULATE MATTER FOUR-FACTOR ANALYSIS

Per DOH guidance, 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 in terms of pounds per million Btu of heat input (lb/MMBtu) and tons per year (TPY).

Table 5-1. Baseline PM₁₀ Emissions

Unit	PM ₁₀ Emissions	
	(lb/MMBtu)	(TPY)
CT1	0.0380	118.1
CT2	0.0380	106.7
Total		224.8

5.1. PARTICULATE MATTER CONTROL OPTIONS

The characterization of emission controls available and applicability to the source is a necessary step before the four factors can be analyzed. PM₁₀ emissions from combustion turbines result from incomplete combustion and noncombustible trace constituents in the fuel. PM₁₀ emissions are comprised of both "filterable" and "condensable" PM₁₀. Filterable PM₁₀ is that portion of the total PM₁₀ that exists in the stack in either solid or liquid state and can be measured on a filter. Condensable PM₁₀ is that portion of the total PM₁₀ that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM₁₀ is composed of organic and inorganic compounds and is generally considered to be less than 1.0 micrometers in aerodynamic diameter.

U.S. EPA's BACT/RACT/LAER clearinghouse does not list any post-combustion controls for combustion turbines. PM₁₀ emissions from combustion turbines are controlled by good combustion practices. However, switching from residual fuel to a residual/distillate blended fuel or distillate fuel is expected to reduce PM₁₀ emissions.

5.2. FOUR-FACTOR ANALYSIS

Since the magnitude of the PM₁₀ emissions are approximately 10 times lower than the SO₂ and NO_x emissions and fuel switching is the only option, a separate four-factor analysis is not required for PM₁₀. Based on scaling the fuel switching cost-effectiveness for SO₂ and NO_x, the cost-effectiveness for PM₁₀ will be greater than \$20,000/ton of PM₁₀.

5.3. PM₁₀ CONCLUSION

For the first planning period, EPA concluded that PM₁₀ controls of \$13,400/ton in 2018 dollars were not cost-effective.¹³ The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Therefore, KPLP does not propose any PM₁₀ emissions reductions.

¹³ *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii*, U.S. EPA Region 9, May 14, 2012. The listed cost threshold is scaled from 2012 dollars to 2018 dollars using the Chemical Engineering Plant Cost Index (2018 dollars = (603.1/584.6) x 2012 dollars).

APPENDIX A : DETAILED SCR COSTING

Appendix Table A-1. SCR Costing

Parameter		CT1	CT2
MW		86.0	86.0
Max Heat Input	(MMBtu/hr)	900	900
Capital Recovery Factor (CRF)		0.09	0.09
Cost Index: Chemical Engineering Plant Cost Index (CEPCI)			
	2018	603.1	
	1990	357.6	
Total Capital Investment (Eq. 1 - 1990 dollars)	(\$)	\$4,637,762	\$4,637,762
Capital Cost (2018 dollars)	(\$)	\$7,821,684	\$7,821,684
Annualized Capital Cost (2018 dollars)	(\$/yr)	\$738,312	\$738,312
Total Annual Cost (Eq. 2 - 1990 dollars)	(\$/yr)	\$1,512,893	\$1,512,893
Hawaii Retrofit Cost Factor		2.00	2.00
Total Annual Cost (2018 Dollars)	(\$/yr)	\$5,103,052	\$5,103,052
Baseline (2017) NO _x Emissions	(tpy)	1,293	1,194
SCR Level of Control		70%	70%
Controlled NO _x Emissions	(tpy)	388	358
NO _x Reduction	(tpy)	905	836
NO_x Cost Effectiveness	(\$/ton)	\$5,638.21	\$6,106.22

Total capital investment (1990 dollars) = 4744 x (MMBtu/hr) + 368162 Equation 1

Total Annual Cost (1990 dollars) = 1522.5 x (MMBtu/hr) + 142643 Equation 2

Capital Recovery Factor (CRF) = $[1 \times (1+i)^a] / [(1+i)^a - 1]$ CRF = 0.09

Where:

I = Interest Rate (7% interest)

a = Equipment life (20 yrs)

Source: *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

Comments on Revised Four – Factor Analysis



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

In reply, please refer to:
File:

20-316E CAB
File No. 0214

July 8, 2020

Mr. Jeffrey Walsh
General Manager
Kalaeloa Partners, L.P.
91-111 Kalaeloa Boulevard
Kapolei, Hawaii 96707

Dear Mr. Walsh:

**Subject: Four-Factor Analysis for Regional Haze
Covered Source Permit No. 0214-01-C
Kalaeloa Partners, L.P.
223.5 MW Kalaeloa Cogeneration Plant
Located At: 91-111 Kalaeloa Boulevard, Kapolei, Oahu**

The Department of Health, Clean Air Branch (CAB) acknowledges receipt of the subject four-factor analysis on March 28, 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. Mike Madsen of my staff at

[REDACTED]

Sincerely,

A handwritten signature in cursive script, appearing to read "Marianne Rossio".

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

MM:rkb

Attachments

- c: Debra Miller, National Park Service, Air Resources Division
- Don Shepherd, National Park Service, Air Resources Division
- Melanie Peters, National Park Service, NPS-Air

Attachment I

After additional review and feedback from National Park Service (NPS) and Environmental Protection Agency (EPA), Region 9, we have the following comments on the four-factor analysis for Combustion Turbines CT-1 and CT-2:

- a. The cost per ton of sulfur dioxide (SO₂) and nitrogen oxide (NO_x) removed was provided for switching fuel from residual low sulfur fuel oil No. 6 to ultralow sulfur diesel (ULSD); however, there was no cost analysis provided for particulate matter less than ten (10) microns in diameter (PM₁₀). Please provide the cost per ton of PM₁₀ reduced for switching from residual low sulfur fuel oil No. 6 to ULSD. Also, provide the cost per total combined tons of SO₂, NO_x, and PM₁₀ reduced for the fuel switch.
- b. Sections 3.2.3 and 4.2.3 indicate 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 (RH-FIP), it is not something we can generally take into consideration for the regional haze analysis in this second planning period.
- c. The cost for SCR is provided in 2018 dollars. Please provide SCR costs in 2019 dollars.
- d. The NPS provided feedback on your four-factor analysis. Please address comments in Attachment 2 from the NPS that were emailed to you on March 23, 2020.
- e. For the fourth NPS comment, the current prime interest rate (currently at 3.25%) should be used to estimate the cost 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 hasn't been seven (7%) or higher in the past twelve (12) years. A three percent (3%) interest rate may also be considered.
- f. Section 2 of the four-factor analysis noted that Hawaii's 2017 Regional Haze Progress Report acknowledged the impact of SO₂ from the Kilauea Volcano. While the report states that a majority of the visibility degradation in Hawaii's National Parks was due to the ongoing release of SO₂ from the volcano, 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 per day and an annual total SO₂ emission rate of about 17,119 tons per year which is far lower than the SO₂ emissions reported for the volcano in the progress report of around two (2) million tons per year. 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 the Kilauea eruption activity ended in September 2018, point sources screened for four-factor analysis now play a more significant part in SO₂ visibility impacts.

Madsen, Michael A

Subject: RE: Comments on Draft Regional Haze Four Factor Analysis for Kalaeloa Partners, L.P.

From: Madsen, Michael A [REDACTED]

Sent: Monday, March 23, 2020 12:46 PM

To: Walsh, Jeffrey [REDACTED]

Cc: marianne rossio [REDACTED]; Gorman, Erin [REDACTED]; Stephen Beene

[REDACTED]; Hamamoto, Dale [REDACTED]; Takamoto, Clayton

Subject: Comments on Draft Regional Haze Four Factor Analysis for Kalaeloa Partners, L.P.

Jeff,

We provided a copy of your draft four-factor analysis to the National Park Service (NPS). The NPS provided the following feedback:

1. Your draft four-factor analysis uses a 1990 vintage cost estimate for selective catalytic reduction (SCR) and the Chemical Engineering Plant Cost Index (CEPCI) to escalate the cost. According to the Environmental Protection Agency (EPA) Office of Air Quality Planning and Standards (OAQPS) Cost Control Manual (CCM), this should be avoided. Instead, Kalaeloa Partners, L.P. should obtain a current vendor quote for adding SCR to its combustion turbines.
2. Appendix A, Table A-1, SCR Costing in your four-factor analysis specifies a "Hawaii Retrofit Cost Factor". As indicated by the NPS, there is no such thing as a Hawaii Retrofit Factor. While the cost of living in Hawaii is high, the retrofit difficulty is not a function of the cost of living. Instead, the retrofit factor reflects the relative difficulty in a retrofit at a specific site. The CCM recommends that the retrofit factor be fully justified and should not exceed 1.5. The Hawaii Retrofit Cost Factor in Table A-1 of your four-factor analysis is 2.0.
3. The SCR control efficiency is underestimated. Control efficiency with SCR for nitrogen oxide is typically higher than 90%.
4. The 7% interest rate is too high. The CCM recommends using the current prime interest rate. The current prime interest rate was 5.5% at the time the NPS provided comments.
5. The 20-year equipment life is too short for SCR. The CCM recommends 30 years for SCR on a combustion turbine.

If you have any questions, please feel free to contact me.

Mike Madsen, P.E.
Environmental Engineer, Clean Air Branch
Hawaii Department of Health

[REDACTED]
[REDACTED]



Response to Comments on Revised Four – Factor Analysis



91-111 KALAELOA BOULEVARD • KAPOLEI, HAWAII 96707

RESPONSE TO COMMENTS
AND
REGIONAL HAZE 4-FACTOR ANALYSIS

August 10, 2020

Mr. Mike Madsen
Hawaii State Department of Health - Clean Air Branch
Hale Ola Bldg., Room #130
2827 Waimano Home Road
Pearl City, HI 96782

Re: CSP No.0214-01C
Kalaeloa Partners, L.P., Kalaeloa Cogeneration Plant

Dear Mr. Madsen,

Enclosed, please find the responses to the Department of Health (DOH) comments, dated July 8, 2020, and the National Park Service (NPS) comments, dated March 23, 2020. In addition, the revised Regional Haze Rule Four-Factor Analysis for the Kalaeloa Cogeneration Plant is enclosed.

I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all the information not identified by me as confidential in nature shall be treated by the Department of Health as public record.

Sincerely,

A handwritten signature in black ink, appearing to read 'Jeff Walsh', is written over a light blue horizontal line.

Jeff Walsh
General Manager
Kalaeloa Partners, L.P.

Attachment 1 - Responses to DOH's July 8, 2020 Comments

- a. The cost per ton of sulfur dioxide (SO₂) and nitrogen oxide (NO_x) removed was provided for switching fuel from residual low sulfur fuel oil No. 6 to ultralow sulfur diesel (ULSD); however, there was no cost analysis provided for particulate matter less than ten (10) microns in diameter (PM₁₀). Please provide the cost per ton of PM₁₀ reduced for switching from residual low sulfur fuel oil No. 6 to ULSD. Also, provide the cost per total combined tons of SO₂, NO_x, and PM₁₀ reduced for the fuel switch.

Response – The requested cost per ton of PM₁₀ reduced for switching from residual low sulfur fuel oil No. 6 to ULSD has been added to the revised report. A summary of the cost per ton of SO₂, NO_x, and PM₁₀ reduced from fuel switching is provided below.

Unit	Control Option	SO ₂ Cost	NO _x Cost	PM ₁₀ Cost
		Effectiveness ^A (\$/ton)	Effectiveness ^B (\$/ton)	Effectiveness ^C (\$/ton)
CT1	Residual/Distillate Blend	7,886.9	11,926.4	129,172.0
	Distillate	7,110.0	11,905.2	128,942.9
CT2	Residual/Distillate Blend	7,886.9	11,704.1	129,981.1
	Distillate	7,110.0	11,683.4	129,345.5

^A SO₂ cost effectiveness from Tables 3-3 and 3-4 of the Regional Haze Four-Factor Analysis, revised August 2020.

^B NO_x cost effectiveness from Table 4-2 of the Regional Haze Four-Factor Analysis, revised August 2020.

^C PM₁₀ cost effectiveness from Table 5-2 of the Regional Haze Four-Factor Analysis, revised August 2020.

- b. Sections 3.2.3 and 4.2.3 indicate 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 (RH-FIP), it is not something we can generally take into consideration for the regional haze analysis in this second planning period.

Response – KPLP encourages DOH to use the flexibility in the SIP guideline to consider additional factors when developing the long-term strategy.

- c. The cost for SCR is provided in 2018 dollars. Please provide SCR costs in 2019 dollars.

Response – The SCR costs have been adjusted to the 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI) for 2019.

- d. The NPS provided feedback on your four-factor analysis. Please address comments in Attachment 2 from the NPS that were emailed to you on March 23, 2020.

Response – The NPS comments are addressed in Attachment 2.

- e. For the fourth NPS comment, the current prime interest rate (currently at 3.25%) should be used to estimate the cost 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 hasn't been seven (7%) or higher in the past twelve (12) years. A three percent (3%) interest rate may also be considered.

Response - The cost analysis follows the Office of Management and Budget (OMB) and the EPA 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.”^[1]

For this analysis, which evaluates equipment costs that may take place more than 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 cost manual 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 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.^[2] However, the 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.”^[3]

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.”^[4]

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.”^[5]

^[1] 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/epacmcostestimationmethodchapter_7thedition_2017.pdf

^[2] 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=sheet&label=include&layout=seriescolumn&from=01/01/2000&to=12/31/2020>

^[3] 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

^[4] OMB Circular A-4, <https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf> - “

^[5] 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

- f. Section 2 of the four-factor analysis noted that Hawaii's 2017 Regional Haze Progress Report acknowledged the impact of SO₂ from the Kilauea Volcano. While the report states that a majority of the visibility degradation in Hawaii's National Parks was due to the ongoing release of SO₂ from the volcano, 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 per day and an annual total SO₂ emission rate of about 17,119 tons per year which is far lower than the SO₂ emissions reported for the volcano in the progress report of around two (2) million tons per year. 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 the Kilauea eruption activity ended in September 2018, point sources screened for four-factor analysis now play a more significant part in SO₂ visibility impacts.

Response – The first step of the EPA SIP guidance is identifying the 20 percent most anthropogenically impaired days, which requires factoring out volcanic impacts. We understand that volcanic activity has reduced since the September 2018. The reduction in volcanic activity should be visible in the 2019 IMPROVE monitoring data. We encourage DOH to review the 2019 IMPROVE monitoring data to assist with defining the level of anthropogenic impairment.

Attachment 2 - Responses to NPS's March 23, 2020 Comments

1. Your draft four-factor analysis uses a 1990 vintage cost estimate for selective catalytic reduction (SCR) and the Chemical Engineering Plant Cost Index (CEPCI) to escalate the cost. According to the Environmental Protection Agency (EPA) Office of Air Quality Planning and Standards (OAQPS) Cost Control Manual (CCM), this should be avoided. Instead, Kalaeloa Partners, L.P. should obtain a current vendor quote for adding SCR to its combustion turbines.

Response - Detailed engineering studies, not just vendor quotes, are needed to provide SCR costing independent of the CCM. Due to time and logistical constraints a detailed engineering study cannot be provided. However, the details of the SCR costing have been expanded using the methods listed in the CCM, Section 4, Chapter 2 for SCR costing.

2. Appendix A, Table A-1, SCR Costing in your four-factor analysis specifies a "Hawaii Retrofit Cost Factor". As indicated by the NPS, there is no such thing as a Hawaii Retrofit Factor. While the cost of living in Hawaii is high, the retrofit difficulty is not a function of the cost of living. Instead, the retrofit factor reflects the relative difficulty in a retrofit at a specific site. The CCM recommends that the retrofit factor be fully justified and should not exceed 1.5. The Hawaii Retrofit Cost Factor in Table A-1 of your four-factor analysis is 2.0.

Response - The revised SCR costing contains itemized retrofit costs and the itemized retrofit costs do not exceed a factor of 1.5.

3. The SCR control efficiency is underestimated. Control efficiency with SCR for nitrogen oxide is typically higher than 90%.

Response - The Kalaeloa combustion turbines currently burn residual fuel and based on our research SCR has never been installed on a combustion turbine burning residual fuel. Based on this, SCR is unproven for this application. Therefore, the application of SCR to the Kalaeloa combustion turbines is not a typical application. The use of a 90% control efficiency would result in a controlled emissions level of approximately 13 ppmvd @ 15% O₂ which is lower than the current permit limit of 15 ppmvd @ 15% O₂ for smaller LM2500 combustion turbines firing distillate fuels in Hawaii. In addition, the SCR installations on the LM2500 combustion turbines were part of the original design. Based on these facts the control efficiency of 70% was retained.

4. The 7% interest rate is too high. The CCM recommends using the current prime interest rate. The current prime interest rate was 5.5% at the time the NPS provided comments.

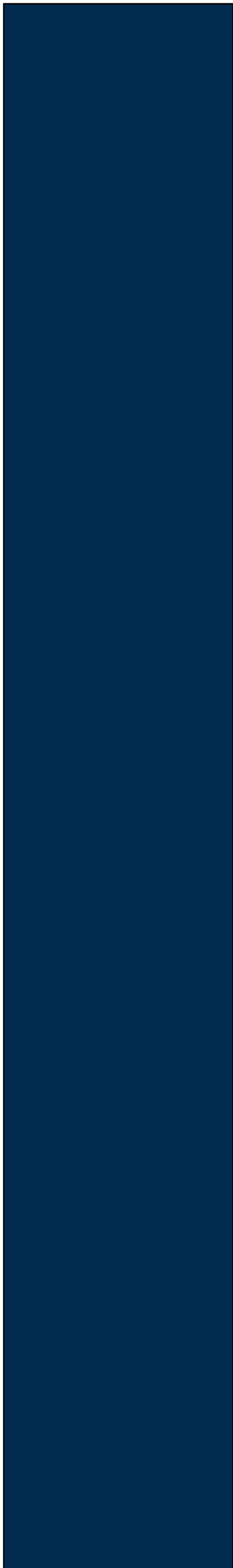
Response - See response to DOH comment e.

5. The 20-year equipment life is too short for SCR. The CCM recommends 30 years for SCR on a combustion turbine.

Response - The revised SCR costing is based on a 30-year capital recovery period.

Attachment 3 - Revised Regional Haze Four-Factor Analysis

Revised Four – Factor Analysis



PROJECT REPORT
Kalaeloa Partners, LP > Kalaeloa Cogeneration Plant



Regional Haze 4-Factor Analysis

TRINITY CONSULTANTS
20 Corporate Park Drive, Suite 200
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March 2020
Revised August 2020

Project 190501.0203



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1. EXECUTIVE SUMMARY

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 Kalaeloa Partners, LP (KPLP) for the two combined cycle combustion turbines at the Kalaeloa Cogeneration Plant (Kalaeloa). The combustion turbines (CT-1 and CT-2) currently use steam injection to control NO_x emissions and currently fire residual fuel oil with a maximum sulfur content of 0.5%. The combustion turbines are currently used to provide baseload generation and operate at a utilization rate ranging from 60% to 70%.

This report considers the following emission reductions options that may be technically feasible for implementation, if needed, to show reasonable progress towards the RHR goal:

- Sulfur dioxide (SO₂) Emission Reduction – Switching from the existing residual oil to a residual/distillate blended fuel or distillate fuel could reduce SO₂ emissions at an estimated cost of over \$7,100 per ton of SO₂ reduced in current dollars and an annual increase of \$10,000,000 to \$20,000,000 in fuel cost.
- Nitrogen Oxides (NO_x) Emission Reduction – Switching from the existing residual oil to a residual/distillate blended fuel or distillate fuel could reduce NO_x emissions at an estimated cost of over \$11,000 per ton of NO_x reduced in current dollars. Installing a selective catalytic reduction (SCR) system could reduce NO_x emissions at a cost ranging from \$6,300 to \$6,900 per ton of NO_x reduced in 2019 dollars.
- Particulate Matter (PM₁₀) Emission Reduction – Switching from the existing residual oil to a residual/distillate blended fuel or distillate fuel is the only feasible option for reducing PM₁₀ emissions. Due to the small magnitude of PM₁₀ emissions compared to SO₂ and NO_x emissions, the cost-effectiveness for PM₁₀ emissions will be worse than the cost-effectiveness for SO₂ and NO_x. Based on scaling the fuel switching cost-effectiveness for SO₂ and NO_x, the cost-effectiveness for PM₁₀ is more than \$125,000/ton of PM₁₀ reduced in current dollars.

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period five-factor analyses for other facilities, and those analyses did not result in emission reduction requirements. Therefore, KPLP does not propose any emissions reductions.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), the U.S. Congress set a nation-wide goal to restore national parks and wilderness areas to natural conditions by remedying existing anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final RHR. The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with 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), 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).

The second implementation planning period (2019-2028) for national regional haze efforts is currently underway and the EPA has provided guidance to the states for the development of the implementation plans.¹ For this planning period, 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*² provides the states guidance on methods for selecting the 20 percent most impaired days to track visibility and determining natural visibility conditions. However, the approach described in this guidance document does not attempt to account for haze formed from natural volcanic emissions. Specifically, the document states:

“The approach described in this guidance document does not attempt to account for haze formed from 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.”

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

² *Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program*, December 2018, EPA-454/R-18-010

The DOH acknowledges the impact of SO₂ from the Kilauea volcano in the *5-Year Regional Haze Progress Report For Federal Implementation Plan*³ 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 guidance is to identify the 20 percent most anthropogenically impaired days and the 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)). Due to the magnitude of SO₂ from the Kilauea volcano, it's imperative that the visibility impact of the Kilauea volcano be quantified and so that only anthropogenic impairment is targeted.

Step 3 of the EPA guidance is the selection of the emission sources for which an analysis of emission control measures will be completed for the second implementation period and explain the basis for these selections. The guidance gives the states many options for identifying these sources. The DOH is currently relying on work conducted by the Western Regional Air Partnership (WRAP). WRAP used 2014 National Emissions Inventory (NEI) and assessed each facility's preliminary 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 from each facility to a Class I area. This approach did not take into consideration the frequency or actual visibility impact on the Class I area which may vary based on more complex factors such as prevailing wind direction. The DOH has informed KPLP that Kalaeloa was identified, based on the Q/d analysis, as one of the sources potentially contributing to regional haze at the Haleakala National Park and Volcanoes National Park. This notice triggers a requirement to conduct a four-factor analysis, which will be introduced in greater detail below. This report provides the response to the DOH's request for a four-factor analysis.

In support of the SIP for the first planning period, regional haze modeling was conducted for several facilities⁴ located on the Island of Oahu. The modeling showed these facilities had an insignificant impact on visibility at Haleakala and Hawaii Volcanoes National Parks. Therefore, KPLP encourages DOH to consider actual visibility impacts in the SIP development process.

This report is intended to address DOH's request for a four-factor analysis to address its RHR planning needs. 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 remainder of this document analyzes these four factors with respect to Kalaeloa.

³ *5-Year Regional Haze Progress Report For Federal Implementation Plan, Hawaii State Department of Health, October 2017, EPA-R09-OAR-2018-0744-0004*

⁴ *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii, U.S. EPA Region 9, May 14, 2012. Table VI-3 provides visibility modeling results for the following Oahu facilities: Chevron Refinery, Tesoro Refinery, and Hawaiian Electric's Waiau and Kahe power plants.*

3. SULFUR DIOXIDE FOUR-FACTOR ANALYSIS

Per DOH guidance, 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 in terms of pounds per million Btu of heat input (lb/MMBtu) and tons per year (TPY).

Table 3-1. Baseline SO₂ Emissions

Unit	Fuel Sulfur	SO ₂ Emissions	
		(lb/MMBtu)	(TPY)
CT1	0.45%	0.474	1,471.7
CT2	0.45%	0.474	1,333.6
Total			2,805.4

3.1. SULFUR DIOXIDE CONTROL OPTIONS

The characterization of emission controls available and potentially 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 are:

- Dry Sorbent Injection (DSI),
- Spray Dryer Absorber (SDA),
- Wet Scrubber,
- Circulating Dry Scrubber (CDS), and
- Fuel Switching.

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

3.1.1. Post-Combustion Controls

DSI, SDA, wet scrubber, and CDS are collectively known as flue gas desulfurization (FGD) systems. FGD applications have not been used historically for SO₂ control on oil-fired combustion turbines. As there are no known FGD applications for oil-fired combustion turbines, the performance of FGDs on oil-fired combustion turbines is unknown. EPA took this into account when evaluating the 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 FGD.⁵ Since there are no applications of FGD on oil-fired units in the U.S., FGDs are considered technically infeasible for the control of SO₂ from the Kalaeloa combustion turbines.

3.1.2. Fuel Switching

The Kalaeloa combustion turbines currently burn residual fuel oil with a maximum sulfur content of 0.5 percent by weight. The average sulfur content of the oil burned in 2017 was approximately 0.45 percent by weight. Switching to a lower sulfur fuel would reduce SO₂ emissions in proportion to the reduction in fuel sulfur content. A lower sulfur residual fuel oil is not available on Hawaii. Lower sulfur content distillate fuels are available and could be burned in the combustion turbines. Ultra-low sulfur diesel (ULSD) is a common distillate fuel and has a maximum sulfur content of 0.0015 percent (15 ppm) by weight.

⁵ *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.

Natural gas and naphtha have less sulfur than the existing residual fuel oil. The supply of these fuels is not sufficient to support the Kalaeloa combustion turbines. Par Hawaii is the only refinery in Hawaii and cannot supply the required naphtha volume. The typical sulfur content of Naphtha ranges from 30 ppm to 100 ppm which is greater than ULSD.⁶ Hawaii Gas is the only natural gas supplier in Hawaii. Hawaii Gas's natural gas supply is currently limited to residential and commercial uses. The sulfur content of natural gas is similar to ultra-low sulfur diesel (ULSD)⁷; therefore, switching to natural gas will not result in significantly lower emissions than switching to USLD. In addition, switching the Kalaeloa combustion turbines to natural gas would require the addition of natural gas supply lines and new burners. Based on these factors switching to naphtha and natural gas are not considered technically feasible options to reduce SO₂ emissions.

Technically feasible options include blending the current residual fuel oil with a commercially available lower sulfur distillate fuel or fully switching to a commercially available lower sulfur distillate fuel. The SO₂ four-factor analysis will evaluate both of these options.

3.2. FOUR-FACTOR ANALYSIS

As discussed above, fuel switching to a residual/distillate blended fuel or a lower sulfur diesel is the only feasible option to reduce SO₂ 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 switching to a 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 that the change would achieve. Kalaeloa currently obtains fuel oil from local suppliers. The differential fuel cost between the current residual oil and ULSD is estimated at \$10/bbl based on a comparison of 2018 fuel prices for imported comparable fuels available on the Asian market. Table 3-2 lists the 2018 monthly average fuel prices and cost differentials. Kalaeloa's fuel purchases follow these prices. The fuels are refined on Oahu and changes in quantities of residual oil and distillate fuels would require new contracts with fuel suppliers. This adds a level of uncertainty to the cost of compliance. Switching fuel would require changes to Kalaeloa's injectors and the fuel system; however, these capital expenses were not included in this analysis. Additionally, as distillate fuels have lower heating value per gallon than residual, such a change could potentially reduce the electric generating capacity of Kalaeloa under full-load conditions. The economic impact of this effect has not been included in this analysis.

⁶ <https://www.bakerobrien.com/bakerobrien3/assets/File/BakerOBrien%20-%20AFPM%20-%20The%20Light%20Naphtha%20Surplus%20and%20the%20Potential%20Impact%20of%20Tier%203%20Sulfur.pdf>

⁷ According to EPA's prevailing definition of "pipeline natural gas" as defined in Part 72 and Part 75, it has a maximum sulfur content of 0.5 grains per 100 cubic foot. Based on the AP-42 Appendix A density of natural gas of 1 pound per 23.8 cubic foot, or 17 parts per million by weight.

Table 3-2. Differential Fuel Cost

Month	LSFO		ULSD	Differential
	\$/MT	\$/bbl	\$/bbl	\$/bbl
Jan-18	438.07	65.78	81.84	16.06
Feb-18	443.55	66.60	78.06	11.46
Mar-18	449.42	67.49	78.38	10.89
Apr-18	462.92	69.51	84.28	14.77
May-18	514.68	77.28	90.53	13.24
Jun-18	524.61	78.78	87.40	8.62
Jul-18	523.11	78.55	86.88	8.33
Aug-18	511.70	76.84	88.51	11.67
Sep-18	520.67	78.18	93.80	15.61
Oct-18	556.00	83.49	97.25	13.76
Nov-18	496.26	74.52	82.29	7.77
Dec-18	414.16	62.19	70.01	7.82
Average	487.93	73.27	84.94	11.67

Source: The listed prices are from S&P Global Platts for fuel exported from Singapore for the products closest to LSFO (HSFO 180 CST with sulfur adjustment) and ULSD (Gasoil 10 ppm). The listed prices do not include taxes and shipping cost.

Table 3-3 presents a summary of the cost effectiveness of switching from residual fuel to a residual/distillate blended fuel with a maximum sulfur content of 0.25%. The reduction in fuel sulfur is based on a 50/50 blend of the current residual fuel and ULSD. 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/distillate blended fuel with a maximum sulfur content of 0.25% is \$7,900/ton SO₂ in current dollars and results in a \$10,000,000 annual increase in fuel cost.

Table 3-4 presents a summary of the cost effectiveness of switching from residual fuel to ULSD with a maximum sulfur content of 0.0015% (15 ppm). 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 0.0015% (15 ppm) is \$7,100/ton SO₂ in current dollars and results in a \$20,000,000 annual increase in fuel cost.

3.2.2. Time Necessary to Achieve Compliance

If DOH determines that switching from residual oil to residual/distillate blended fuel or distillate fuel is needed to achieve reasonable progress, it is anticipated that this change could be implemented within 1 year.

3.2.3. Energy and Non-Air Quality Environmental Impacts

The cost increase associated with fuel switching to diesel will increase the cost of the electricity produced by Kalaeloa. This increase will likely impact the price of electricity for Oahu customers. The change could also reduce the maximum electric generating capacity of the plant, which could have further electricity cost impacts and negatively impact the stability of Oahu's power grid, given Kalaeloa's important role in stabilizing power supplies during fluctuations in the extremely large proportion of power generation on the island that is from residential solar systems that cannot be centrally managed like conventional power plants.

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

Unit	Current Residual Oil (0.50% maximum Sulfur) ^A					Residual/Distillate Blend (0.25% maximum Sulfur) ^B						
	2017	Fuel		2017	2017	Fuel	Annual	Controlled	SO ₂	Fuel Cost	Annual	SO ₂
	Average Sulfur Content (%)	Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Annual Heat Input (MMBtu/yr)	SO ₂ Emissions (tpy)	Heating Value (HHV) (Btu/gal)	Fuel Usage (gal/yr)	SO ₂ Emissions (tpy)	Reduced (tpy)	Differential ^C (\$/Gal)	Increase in Fuel Cost ^C (\$/yr)	Cost Effectiveness (\$/ton)
CT1	0.45%	148,405	41,822,683	6,206,695	1,471.7	142,703	43,493,796	809.97	661.77	0.12	\$5,219,256	7,887
CT2	0.45%	148,405	37,897,493	5,624,177	1,333.6	142,703	39,411,767	733.96	599.66	0.12	\$4,729,412	7,887

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

^B Based on a blend of 50.0% residual oil and 50.0% diesel fuel and the weighted average of the 2017 fuel HHV and density for residual oil, AP-42 HHV and density for diesel, and contract fuel sulfur limits.

^C Based on a \$10/bbl cost difference between the current fuel and ULSD. The annual costs of fuel switching are based on current dollars.

Table 3-4. SO₂ Cost Effectiveness of Switching to Distillate Fuel

Unit	Current Residual Oil (0.50% maximum Sulfur) ^A					Diesel (0.0015% maximum Sulfur) ^B						
	2017	Fuel		2017	2017	Fuel	Annual	Controlled	SO ₂	Fuel Cost	Annual	SO ₂
	Average Sulfur Content (%)	Heating Value (HHV) (Btu/gal)	Annual Fuel Usage (gal/yr)	Annual Heat Input (MMBtu/yr)	SO ₂ Emissions (tpy)	Heating Value (HHV) (Btu/gal)	Fuel Usage (gal/yr)	SO ₂ Emissions (tpy)	Reduced (tpy)	Differential ^C (\$/Gal)	Increase in Fuel Cost ^C (\$/yr)	Cost Effectiveness (\$/ton)
CT1	0.45%	148,405	41,822,683	6,206,695	1,471.7	137,000	45,304,345	6.21	1,465.53	0.23	\$10,419,999	7,110
CT2	0.45%	148,405	37,897,493	5,624,177	1,333.6	137,000	41,052,390	5.62	1,327.99	0.23	\$9,442,050	7,110

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

^B Based on 2017 average HHV and density for residual oil, AP-42 HHV and density for diesel, and contract fuel sulfur limits.

^C Based on a \$10/bbl cost difference between the current fuel and ULSD. The annual costs of fuel switching are based on current dollars.

3.2.4. Remaining Useful Life

The cost of compliance does not contain any capital cost. Therefore, the remaining useful lives of the Kalaeloa combustion turbines is not needed to annualize the capital cost.

3.3. SO₂ CONCLUSION

Switching to residual/distillate blended fuel with a maximum sulfur content of 0.25% or to ULSD with a maximum sulfur content of 0.0015% (15 ppm) will reduce SO₂ emissions for a cost of \$7,900/ton and \$7,100/ton in current dollars, respectively. These costs are greater than the BART and reasonable progress thresholds established in the first planning period, which ranged from \$5,700/ton to \$5,800/ton in 2019 dollars.⁸ Switching to residual/distillate blended fuel with a maximum sulfur content of 0.25% will increase annual fuel cost by \$10,000,000. Switching to ULSD with a maximum sulfur content of 0.0015% (15 ppm) will increase annual fuel cost by \$20,000,000,

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Therefore, KPLP does not propose any SO₂ emissions reductions.

⁸ *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii*, U.S. EPA Region 9, May 14, 2012. The listed cost thresholds are scaled from 2012 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (2019 dollars = (607.5/584.6) x 2012 dollars).

4. NITROGEN OXIDES FOUR-FACTOR ANALYSIS

Per DOH guidance, 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 in terms of pounds per million Btu of heat input (lb/MMBtu) and tons per year (TPY).

Table 4-1. Baseline NO_x Emissions

Unit	NO _x Emissions	
	(lb/MMBtu)	(TPY)
CT1	0.417	1,293.0
CT2	0.425	1,193.9
Total		2,486.9

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 vs. 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. Fuel NO_x emissions from firing residual oil are greater than fuel NO_x from firing a distillate fuel.

Potential NO_x control technologies for fuel oil fired combustion turbines are:

- Low NO_x Burners - Dry Low NO_x (DLN) combustion design,
- Selective Non-Catalytic Reduction (SNCR),
- Water/Steam Injection,
- Switching to a fuel oil with a lower nitrogen content (residual/distillate blended fuel or distillate fuel), and
- Selective Catalytic Reduction (SCR).

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

4.1.1. Dry Low NO_x Combustion Design

Low NO_x burner technology utilizes advanced burner design to reduce NO_x formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. DLN is a gas-turbine combustion technology that enables gas-turbine combustors to produce low NO_x emission levels without diluents (such as water or steam) or catalysts. DLN technology utilizes a lean premixed flame as opposed to a turbulent diffusion flame, therefore requiring the use of natural gas or other gaseous fuels. Since fuel oil (residual or distillate) cannot be easily premixed, it is not suitable as a DLN fuel.⁹ Therefore, this technology is not technically feasible for the Kalaeloa combustion turbines.

4.1.2. Selective Non-Catalytic Reduction

SNCR is an add-on technology that reduces NO_x by injecting ammonia or urea into exhaust gases similar to SCR. Without the catalyst that defines SCR, SCR must operate at a higher temperature (1600° to

⁹ *Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines Technologies & Cost Effectiveness*, Northeast States for Coordinated Air Use Management, December 2000.

2200°F) for the reduction reaction to occur. Since SNCR does not require a catalyst, this process is more attractive than SCR from an economic standpoint. The operating temperature window, however, is not compatible with gas turbine exhaust temperatures, which do not exceed 1100°F. Additionally, the residence time required for the reaction is approximately 100 milliseconds, which is too slow for gas turbine operating flow velocities.¹⁰ Therefore, this technology is not technically feasible for the Kalaeloa combustion turbines.

4.1.3. Water/Steam Injection

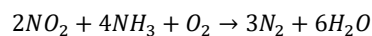
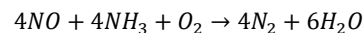
The combustion turbines are currently equipped with this technology; they operate with steam injection which controls NO_x emissions to 130 ppmvd @ 15% O₂. Additional reductions from water/steam injection are not possible with the current fuel.

4.1.4. Fuel Switching

Distillate fuels contains less fuel-bound nitrogen than residual oil, therefore switching to a residual/distillate blended fuel or distillate fuel would lower NO_x emissions. Water injection is routinely used to reduce NO_x emissions from distillate fuel fired combustions turbines to 42 ppmvd @ 15% O₂. For the 50/50 blend of the current residual fuel and ULSD the estimated emission reduction is based on the midpoint between the current limit (130 ppmvd @ 15% O₂) and the expected emissions level for distillate fuel (42 ppmvd @ 15% O₂). Switching to a 50/50 blend of the current residual fuel and ULSD and ULSD is feasible and the four factors are addressed in Section 4.2.

4.1.5. Selective Catalytic Reduction

SCR refers to the process in which NO_x in the exhaust gas (which is composed of both NO and NO₂) 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, and an ammonia storage and 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. KPLP is not aware of any SCR systems on residual fuel fired combustion turbines. Therefore, the application of SCR on residual fuel fired combustion turbines is unproven. Additionally, significant engineering work that is beyond the scope of this analysis is necessary to evaluate other feasibility risks associated with a possible SCR retrofit, such as determining if there is adequate space available in the proper location for the additional equipment to be installed as necessary to interact with the exhaust with proper temperature and mixing conditions. However, the four factors are addressed in Section 4.2. Given its unproven status for this source type, for this analysis SCR is assumed to reduce NO_x emissions by 70%.

4.2. FOUR-FACTOR ANALYSIS

As discussed above, switching to a residual/distillate blended fuel or distillate fuel or installing SCR are feasible options 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:

¹⁰ *Alternative Control Techniques Document - NO_x Emissions from Stationary Gas Turbines*, EPA-453/R-93-007, January 1993.

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 to a residual/distillate blended fuel or distillate fuel or installing SCR are discussed in the following sections.

4.2.1. Cost of Compliance

The cost effectiveness of fuel switching was determined by calculating the annual increase in fuel cost from switching to a residual/distillate blended fuel or distillate fuel divided by the expected reduction in NO_x emissions. The cost effectiveness of switching to a distillate fuel is based on a controlled NO_x emissions level of 42 ppmvd @ 15% O₂. The cost effectiveness of switching to a 50/50 blend of the current residual fuel and ULSD is based on a controlled NO_x emissions level of 86 ppmvd @ 15% O₂ (the midpoint between the current limit of 130 ppmvd @ 15% O₂ and the expected emissions level for distillate fuel [42 ppmvd @ 15% O₂]). Switching fuel would require changes to Kalaeloa's injectors and the fuel system. However, these capital expenses were not included in the analysis. Additionally, as distillate fuels have lower heating value per gallon than residual, such a change could potentially reduce the electric generating capacity of Kalaeloa under full-load conditions. The economic impact of this effect has not been included in this analysis. The cost effectiveness of SCR is based on a 70% reduction in NO_x emissions.

Table 4-2 presents a summary of the cost effectiveness of fuel switching and adding SCR. The cost effectiveness of fuel switching is determined by dividing the annual cost increase in fuel by the annual reduction in NO_x emissions. The annual increase in fuel cost is discussed in Section 3.2.1. The cost effectiveness of fuel switching exceeds \$11,000/ton of NO_x in current dollars.

The cost effectiveness of SCR ranges from \$6,300/ton to \$6,800/ton of NO_x in 2019 dollars. The SCR costing is based on methods listed in the EPA's Cost Control Manual, Section 4, Chapter 2 for SCR costing.¹¹ Appendix A contains the SCR costing details.

4.2.2. Time Necessary to Achieve Compliance

If DOH determines that switching from residual oil to a residual/distillate blended fuel or distillate fuel is needed to achieve reasonable progress, it is anticipated that this change could be implemented within 1 year.

If DOH determines that added SCR is needed and feasible to achieve reasonable progress, it is anticipated that this change could be implemented within 3 years of the SIP being finalized. Provided the SIP is finalized in July of 2022, SCR could be installed by July 2025.

¹¹ U.S. EPA CCM, Section 4, Chapter 2, Selective Catalytic Reduction (SCR), Sixth and Seventh Editions (<https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual>)

Table 4-2. NO_x Cost Effectiveness of Fuel Switching and SCR

Unit	Control Option	2017 NO_x Emissions (tpy)	Controlled Emissions Level (ppmvd @ 15% O₂)	Controlled NO_x Emissions^A (tpy)	NO_x Reduced (tpy)	Annual Cost^B (\$/yr)	NO_x Cost Effectiveness (\$/ton)
CT1	Residual/Distillate Blend	1,293	86	855.35	437.62	\$5,219,256	\$11,926
	Distillate	1,293	42	417.73	875.25	\$10,419,999	\$11,905
	SCR	1,293	39	387.89	905.08	\$5,735,511	\$6,337
CT2	Residual/Distillate Blend	1,194	86	789.80	404.08	\$4,729,412	\$11,704
	Distillate	1,194	42	385.71	808.16	\$9,442,050	\$11,683
	SCR	1,194	39	358.16	835.71	\$5,735,511	\$6,863

^A Controlled emissions are based on the ratio of the permit limit of 130 ppmvd @ 15% O₂ to the listed controlled emissions level.

^B Annual costs for switching to a residual/distillate blend or distillate are from Tables 3-3 and 3-4. The annual costs of fuel switching are based on current dollars. The annual SCR cost is documented in Appendix A. The annual costs of SCR have been scaled to 2019 dollars using the Chemical Engineering Plant Cost Index.

4.2.3. Energy and Non-Air Quality Environmental Impacts

The cost increase associated with fuel switching will increase the cost of the electricity produced by Kalaeloa. This increase will likely impact the price of electricity for Oahu customers.

The addition of SCR reduces the efficiency of the system and add operating cost that will increase the cost of the electricity produced by Kalaeloa. This increase will likely impact the price of electricity for Oahu customers. In addition, Additionally, the use and storage of aqueous ammonia is a safety hazard; when there is a potential for more than 10,000 lbs to be at a given site, the risk is regulated by the CAA's 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.

Additionally, SCR releases 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 participates in secondary downwind reactions 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. Therefore, ammonia slip from a possible SCR system could at least partially counteract some of the benefit achieved by the NO_x reductions the system could generate.

4.2.4. Remaining Useful Life

The cost of compliance for fuel switching does not contain any capital cost. Therefore, the remaining useful lives of the Kalaeloa combustion turbines is not needed to annualize the capital cost.

The Kalaeloa units do not have any set retirement date. As part of current negotiations to extend Kalaeloa's Purchase Power Agreement (PPA) with Hawaiian Electric, a 20-year life expansion analysis is required. Although a 20-year capital recovery period would be consistent with the PPA negotiations, the SCR costing is based on a 30-year capital recovery period to calculate the total annualized cost of the SCR system.

4.3. NO_x CONCLUSION

The cost effectiveness of fuel switching exceeds \$11,000/ton of NO_x and results in a \$10,000,000 to \$20,000,000 increase in annual fuel cost. The application of SCR on residual fuel fired combustion turbines is unproven. However, the cost effectiveness of SCR ranges from \$6,300/ton to \$6,800/ton of NO_x in 2019 dollars. The cost-effectiveness of SCR is similar to the BART analysis conducted for boilers during the first planning period. For the first planning period, EPA concluded that SCR was not cost effective.¹²

The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Therefore, KPLP does not propose any NO_x emissions reductions.

¹² *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii*, U.S. EPA Region 9, May 14, 2012. The listed cost thresholds are scaled from 2012 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (2019 dollars = (607.5/584.6) x 2012 dollars).

5. PARTICULATE MATTER FOUR-FACTOR ANALYSIS

Per DOH guidance, 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 in terms of pounds per million Btu of heat input (lb/MMBtu) and tons per year (TPY).

Table 5-1. Baseline PM₁₀ Emissions

Unit	PM ₁₀ Emissions	
	(lb/MMBtu)	(TPY)
CT1	0.0380	118.1
CT2	0.0380	106.7
Total		224.8

5.1. PARTICULATE MATTER CONTROL OPTIONS

The characterization of emission controls available and applicability to the source is a necessary step before the four factors can be analyzed. PM₁₀ emissions from combustion turbines result from incomplete combustion and noncombustible trace constituents in the fuel. PM₁₀ emissions are comprised of both "filterable" and "condensable" PM₁₀. Filterable PM₁₀ is that portion of the total PM₁₀ that exists in the stack in either solid or liquid state and can be measured on a filter. Condensable PM₁₀ is that portion of the total PM₁₀ that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM₁₀ is composed of organic and inorganic compounds and is generally considered to be less than 1.0 micrometers in aerodynamic diameter.

U.S. EPA's BACT/RACT/LAER clearinghouse does not list any post-combustion controls for combustion turbines. PM₁₀ emissions from combustion turbines are controlled by good combustion practices. However, switching from residual fuel to a residual/distillate blended fuel or distillate fuel is expected to reduce PM₁₀ emissions.

5.2. FOUR-FACTOR ANALYSIS

Since fuel switching is the only option, a separate detailed four-factor analysis is not required for PM₁₀. The time necessary to achieve compliance, the energy and non-air quality environmental impact of compliance, and the remaining useful life for fuel switching is addressed in Section 3.2. Table 5-2 presents the cost effectiveness of fuel switching. The cost effectiveness of fuel switching is determined by dividing the annual cost increase in fuel by the annual reduction in PM₁₀ emissions. The annual increase in fuel cost is discussed in Section 3.2.1. The cost effectiveness of fuel switching exceeds \$125,000/ton of PM₁₀ in current dollars.

5.3. PM₁₀ CONCLUSION

For the first planning period, EPA concluded that PM₁₀ controls of \$13,500/ton in 2019 dollars were not cost-effective.¹³ The results of the four-factor analysis are consistent with the conclusions reached for the first planning period. Therefore, KPLP does not propose any PM₁₀ emissions reductions.

¹³ *Technical Support Document for the Proposed Action on the Federal Implementation Plan for the Regional Haze Program in the State of Hawaii*, U.S. EPA Region 9, May 14, 2012. The listed cost threshold is scaled from 2012 dollars to 2019 dollars using the Chemical Engineering Plant Cost Index (2019 dollars = (607.5/584.6) x 2012 dollars).

Table 5-2. PM₁₀ Cost Effectiveness of Fuel Switching

Unit	Control Option	2017 PM₁₀ Emissions (tpy)	Controlled Emissions Level^A (lb/MMBtu)	Controlled PM₁₀ Emissions^B (tpy)	PM₁₀ Reduced (tpy)	Annual Cost^C (\$/yr)	PM₁₀ Cost Effectiveness (\$/ton)
CT1	Residual/Distillate Blend	118.1	0.025	77.6	40.4	\$5,219,256	\$129,172
	Distillate	118.1	0.012	37.2	80.8	\$10,419,999	\$128,943
CT2	Residual/Distillate Blend	106.7	0.025	70.4	36.4	\$4,729,412	\$129,981
	Distillate	106.7	0.012	33.7	73.0	\$9,442,050	\$129,346

^A The controlled emission level for distillate is from AP-42 Table 3.1-2a, dated April 2000. The controlled emission level for the 50/50 residual/distillate blend is based on the average of the AP-42 emission factor for distillate and 2017 emission factor.

^B Controlled emissions are based on the ratio of the 2017 emission factor (0.038 lb/MMBtu) to the listed controlled emissions level.

^C Annual costs for switching to a residual/distillate blend or distillate are from Tables 3-3 and 3-4. The annual costs of fuel switching are based on current dollars.

APPENDIX A : DETAILED SCR COSTING

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

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/hr ^b 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-hr ^f		\$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 ^h =	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.

Appendix Table A-3. SCR Purchase Equipment Cost

Parameter	Variable	Calculation	Value per CT	Units	Reference
Exhaust Parameters					
Heat Input Rate	Q_h		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	$q_{thexhaust}$	$Q_{fuel} \times Q_h \times (460 + T)/(460 + 700) \eta_{scr} =$	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	$NO_{x_{in}}$		0.421	lb/MMBtu	2017 CT1 and CT2 Average Emission Factor
NO _x Removal Efficiency	η_{NO_x}		70	%	70% control efficiency per EPA Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
Outlet Concentration	$NO_{x_{out}}$		0.126	lb/MMBtu	
Available Cost Data					
Capital Cost of Ammonia Catalyst	CC_{catal}		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 _x MW	M_{NO_x}		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	$\Delta P_{catalyst}$	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	$A_{catalyst}$	$q_{thexhaust}/(16ft/sec \times 60 sec/min)$	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	$NO_{x_{adj}}$	$(0.8524 + (0.3208 * NO_{x_{in}}))$	0.99		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.25
NO _x Efficiency Adjustment	η_{adj}	$(0.2869 + (1.058 * \eta_{NO_x}))$	1.03		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.23
Volume of Catalyst	Vol_{catal}	$2.81 * Q_h * \eta_{adj} * NO_{x_{adj}} * Slip_{adj} * T_{adj} / n_{scr}$	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	$m_{reagent}$	$(NO_{x_{in}} * Q_h * \eta_{NO_x} * SRF * M_{reagent}) / (M_{NO_x})$	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	$f(NH_3)$	$(\$41.1 / (lb/hr)) * m_{reagent} / Q_{by} - \$47.3 / MMBtu/hr$	-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	$f(Vol)$	$Vol_{catal} * CC_{catal}$	781,056	\$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.43 - 2019 dollars
Purchase Equipment Cost	PEC	$Q_h [3,380 / MMBtu/hr * f(h_{scr}) + f(NH_3)] + f(new) + f(bypass) + (3500 / Q_h)^{0.35} * f(Vol)$	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

Control Cost Worksheets and DOH-CAB Revisions

Changes Summarized

3.25 % interest rate for controls

Combined Cost Effectiveness of Fuel Switching (Tables 6-1 & 6-2)

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

Unit	Current Residual Oil (0.50% maximum Sulfur) ^A					Residual/Distillate Blend (0.25% maximum Sulfur) ^B						
	2017 Average Sulfur Content	Fuel Heating Value (HHV)	Annual Fuel Usage	2017 Annual Heat Input	2017 SO ₂ Emissions	Fuel Heating Value (HHV)	Annual Fuel Usage	Controlled SO ₂ Emissions	SO ₂ Reduced	Fuel Cost Differential ^C	Increase in Fuel Cost ^C	SO ₂ Cost Effectiveness
	(%)	(Btu/gal)	(gal/yr)	(MMBtu/yr)	(tpy)	(Btu/gal)	(gal/yr)	(tpy)	(tpy)	(\$/Gal)	(\$/yr)	(\$/ton)
CT1	0.45%	148,405	41,822,683	6,206,695	1,471.7	142,703	43,493,796	809.97	661.77	0.12	\$ 5,219,256	7,887
CT2	0.45%	148,405	37,897,493	5,624,177	1,333.6	142,703	39,411,767	733.96	599.66	0.12	\$ 4,729,412	7,887

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

^B Based on a blend of 50.0% residual oil and 50.0% diesel fuel and the weighted average of the 2017 fuel HHV and density for residual oil, AP-42 HHV and density for diesel, and contract fuel sulfur limits.

^C Based on a \$10/bbl cost difference between the current fuel and ULSD. The annual costs of fuel switching are based on current dollars.

Table 3-4. SO2 Cost Effectiveness of Switching to Distillate Fuel

Unit	Current Residual Oil (0.50% maximum Sulfur) ^A					Diesel (0.0015% maximum Sulfur) ^B						
	2017 Average Sulfur Content	Fuel Heating Value (HHV)	Annual Fuel Usage	2017 Annual Heat Input	2017 SO ₂ Emissions	Fuel Heating Value (HHV)	Annual Fuel Usage	Controlled SO ₂ Emissions	SO ₂ Reduced	Fuel Cost Differential ^C	Annual Increase in Fuel Cost ^C	SO ₂ Cost Effectiveness
	(%)	(Btu/gal)	(gal/yr)	(MMBtu/yr)	(tpy)	(Btu/gal)	(gal/yr)	(tpy)	(tpy)	(\$/Gal)	(\$/yr)	(\$/ton)
CT1	0.45%	148,405	41,822,683	6,206,695	1,471.7	137,000	45,304,345	6.21	1,465.53	0.23	\$ 10,419,999	7,110
CT2	0.45%	148,405	37,897,493	5,624,177	1,333.6	137,000	41,052,390	5.62	1,327.99	0.23	\$ 9,442,050	7,110

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

^B Based on 2017 average HHV and density for residual oil, AP-42 HHV and density for diesel, and contract fuel sulfur limits.

^C Based on a \$10/bbl cost difference between the current fuel and ULSD. The annual costs of fuel switching are based on current dollars.

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Table 4-2. NOx Cost Effectiveness of Fuel Switching and SCR

Unit	Control Option	2017 NO _x Emissions (tpy)	Controlled Emissions Level (ppmvd @ 15% O ₂)	Controlled NO _x Emissions ^A (tpy)	NO _x Reduced (tpy)	Annual Cost ^B (\$/yr)	NO _x Cost Effectiveness (\$/ton)
CT1	Residual/Distillate Blend	1,293	86	855.35	437.62	\$ 5,219,256	\$ 11,926
	Distillate	1,293	42	417.73	875.25	\$ 10,419,999	\$ 11,905
	SCR	1,293	39	387.89	905.08	\$ 5,735,511	\$ 6,337
CT2	Residual/Distillate Blend	1,194	86	789.80	404.08	\$ 4,729,412	\$ 11,704
	Distillate	1,194	42	385.71	808.16	\$ 9,442,050	\$ 11,683
	SCR	1,194	39	358.16	835.71	\$ 5,735,511	\$ 6,863

^A Controlled emissions are based on the ratio of the permit limit of 130 ppmvd @ 15% O₂ to the listed controlled emissions level.

^B Annual costs for switching to a residual/distillate blend or distillate are from Tables 3-3 and 3-4. The annual costs of fuel switching are based on current dollars. The annual SCR cost is documented in Appendix A. The annual costs of SCR have been scaled to 2019 dollars using the Chemical Engineering Plant Cost Index.

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Table 4-2. NO_x Cost Effectiveness of Fuel Switching and SCR

Unit	Control Option	2017 NO _x Emissions (tpy)	Controlled Emissions Level (ppmvd @ 15% O ₂)	Controlled NO _x Emissions ^A (tpy)	NO _x Reduced (tpy)	Annual Cost ^B (\$/yr)	NO _x Cost Effectiveness (\$/ton)
CT1	Residual/Distillate Blend	1,293	86	855.35	437.62	\$ 5,219,256	\$ 11,926
	Distillate	1,293	42	417.73	875.25	\$ 10,419,999	\$ 11,905
	SCR	1,293	39	387.89	905.08	\$ 5,096,085	\$ 5,631
CT2	Residual/Distillate Blend	1,194	86	789.80	404.08	\$ 4,729,412	\$ 11,704
	Distillate	1,194	42	385.71	808.16	\$ 9,442,050	\$ 11,683
	SCR	1,194	39	358.16	835.71	\$ 5,096,085	\$ 6,098

^A Controlled emissions are based on the ratio of the permit limit of 130 ppmvd @ 15% O₂ to the listed controlled emissions level.

^B Annual costs for switching to a residual/distillate blend or distillate are from Tables 3-3 and 3-4. The annual costs of fuel switching are based on current dollars. The annual SCR cost is documented in Appendix [Table A-2 \(DOH Changed Spreadsheet\)](#). The annual costs of SCR have been scaled to 2019 dollars using the Chemical Engineering Plant Cost Index.

[DOH-CAB Changed Spreadsheet](#)

Table 5-2. PM₁₀ Cost Effectiveness of Fuel Switching

Unit	Control Option	2017 PM ₁₀ Emissions (tpy)	Controlled Emissions Level ^A (lb/MMBtu)	Controlled PM ₁₀ Emissions ^B (tpy)	PM ₁₀ Reduced (tpy)	Annual Cost ^C (\$/yr)	PM ₁₀ Cost Effectiveness (\$/ton)
CT1	Residual/Distillate Blend	118.1	0.025	77.6	40.4	\$ 5,219,256	\$ 129,172
	Distillate	118.1	0.012	37.2	80.8	\$ 10,419,999	\$ 128,943
CT2	Residual/Distillate Blend	106.7	0.025	70.4	36.4	\$ 4,729,412	\$ 129,981
	Distillate	106.7	0.012	33.7	73.0	\$ 9,442,050	\$ 129,346

^A The controlled emission level for distillate is from AP-42 Table 3.1-2a, dated April 2000. The controlled emission level for the 50/50 residual/distillate blend is based on the average of the AP-42 emission factor for distillate and 2017 emission factor.

^B Controlled emissions are based on the ratio of the 2017 emission factor (0.038 lb/MMBtu) to the listed controlled emissions level.

^C Annual costs for switching to a residual/distillate blend or distillate are from Tables 3-3 and 3-4. The annual costs of fuel switching are based on current dollars.

[Original Submitted Spreadsheet](#)

**Table 6-1 SO₂, NO_x, and PM₁₀ Combined Cost Effectiveness
of Switching to a Residual/Distillate Blended Fuel**

Unit	SO ₂ Reduced (tpy)	NO _x Reduced (tpy)	PM ₁₀ Reduced (tpy)	Combined Reduced (tpy)	Increase in Fuel Cost (\$/yr)	Combined Cost Effectiveness (\$/ton)
CT1	661.77	437.62	40.4	1,139.79	\$ 5,219,256	\$ 4,579
CT2	599.66	404.08	36.4	1,040.14	\$ 4,729,412	\$ 4,547

**Table 6-2 SO₂, NO_x, and PM₁₀ Combined Cost Effectiveness
of Switching to Distillate Fuel**

Unit	SO ₂ Reduced (tpy)	NO _x Reduced (tpy)	PM ₁₀ Reduced (tpy)	Combined Reduced (tpy)	Increase in Fuel Cost (\$/yr)	Combined Cost Effectiveness (\$/ton)
CT1	1,465.53	875.25	80.8	2,421.58	\$ 10,419,999	\$ 4,303
CT2	1,327.99	808.16	73.0	2,209.15	\$ 9,442,050	\$ 4,274

[DOH-CAB Changed Spreadsheet](#)

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.

[Original Submitted Spreadsheet](#)

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.

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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.

DOH-CAB Changed Spreadsheet

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	$q_{fuelgas}$	$Q_{fuel} \times Q_b \times (460 + T)/(460 + 700)n_{scr} =$	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	$NO_{x,in}$		0.421	lb/MMBtu	2017 CT1 and CT2 Average Emission Factor
NO _x Removal Efficiency	η_{NO_x}		70	%	70% control efficiency per EPA Air Pollution Control Technology Fact Sheet, SCR, EPA-452/F-03-032
Outlet Concentration	$NO_{x,out}$		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_{NO_x}		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

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Appendix Table A-3. SCR Purchase Equipment Cost

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	$\Delta P_{catalyst}$	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	$A_{catalyst}$	$q_{fluegas}/(16ft/sec \times 60 sec/min)$	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 NOx Adjustment	NOx_{adj}	$(0.8524 + (0.3208 * NOx_{in}))$	0.99		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.25
NOx Efficiency Adjustment	η_{adj}	$(0.2869 + (1.058 * \eta_{NOx}))$	1.03		Per 2019 EPA Cost Manual, Chapter 2 Selective Catalytic Reduction, Equation 2.23
Volume of Catalyst	Vol_{cat}	$2.81 * Q_b * \eta_{adj} * NOx_{adj} * Slip_{adj} * T_{adj} / n_{scr}$	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	$m_{reagent}$	$(NOx_{in} * Q_b * \eta_{NOx} * SRF * M_{reagent}) / (M_{NOx})$	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

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Appendix Table A-3. SCR Purchase Equipment Cost

Direct Costs					
SCR height Adjustment	$f(h_{scr})$	$\$6.12/(\text{ft}\cdot\text{MMBtu}/\text{hr})\cdot h_{scr} - \$187.9/\text{MMBtu}/\text{hr}$	128	$\$/(\text{MMBtu}/\text{hr})$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.37 - 1998 dollars
Ammonia Flow Adjustment	$f(\text{NH}_3)$	$(\$411/(\text{lb}/\text{hr})\cdot m_{\text{reagent}}/Q_b) - \$47.3/\text{MMBtu}/\text{hr}$	-0.227	$\$/(\text{MMBtu}/\text{hr})$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.38 - 1998 dollars
New "Boiler" Adjustment	$f(\text{new})$	0 for retrofit (negative adjustment for new boilers)	0	$\$/(\text{MMBtu}/\text{hr})$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.40 - 1998 dollars
New Bypass	$f(\text{bypass})$	No Bypass Added	0	$\$/(\text{MMBtu}/\text{hr})$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.42 - 1998 dollars
Catalyst Cost	$f(\text{Vol})$	$\text{Vol}_{\text{cat}}\cdot\text{CC}_{\text{initial}}$	781,056	\$	Per 2002 EPA Cost Manual Chapter 2 Selective Catalytic Reduction, Equation 2.43 - 2019 dollars
Purchase Equipment Cost	PEC	$Q_b[3,380/\text{MMBtu}/\text{hr} + f(h_{scr}) + f(\text{NH}_3) + f(\text{new}) + f(\text{bypass})](3500/Q_b)^{0.35} + f(\text{Vol})$	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

[Original Submitted Spreadsheet](#)

Final Conclusion and Action

Control costs summarized in the table below were based on a four-factor analysis of Kalaeloa Partners, L.P. Power Plant after the facility was identified with Q/d to significantly affect visibility in the national parks. The cost per ton of pollutant removed, highlighted in green, are costs after changes were made to worksheets by DOH-CAB to align with EPA guidance and comments provided by EPA and the FLM's. For costs highlighted in green, the DOH-CAB assumed a remaining useful life thirty (30) years for SCR and twenty (20) years for all other controls. A 3.25% prime interest rate was used versus a 7% interest rate.

Table C. Four-Factor Analysis for Kalaeloa Partners, L.P. Power Plant Oahu			
Unit	Description	Primary Fuel	Control Measures & Cost per Ton ^{a,b,c}
CT-1	86 MW Combustion Turbine	Fuel Oil No. 6 with 0.5% maximum sulfur content	Fuel switch to residual/ULSD fuel blend with 0.25% maximum sulfur content - \$7,887/ton SO ₂ for CT1 &CT2 Fuel switch to residual/ULSD fuel blend with 0.0015% maximum sulfur content - \$7,110/ton SO ₂ for CT1 &CT2 Fuel switch to residual/distillate fuel blend with 0.25% maximum sulfur content - \$4,579/ton SO ₂ , NO _x , and PM ₁₀ combined for CT-1 and \$4,547/ton SO ₂ , NO _x , and PM ₁₀ combined for CT-2 Fuel switch to ULSD with 0.0015% maximum sulfur content - \$4,303/ton SO ₂ , NO _x , and PM ₁₀ combined for CT-1 and \$4,274/ton SO ₂ , NO _x , and PM ₁₀ combined for CT-2
CT-2	86 MW Combustion Turbine	Fuel Oil No. 6 with 0.5% maximum sulfur content	SCR for CT-1 - \$6,337 (\$5,631)/ton NO _x SCR for CT-2 - \$6,836 (\$6,098)/ton NO _x

- a. MW-megawatt, SCR-selective catalytic reduction, ULSD-ultra-low sulfur diesel.
- b. Total combined reduction for fuel switch to residual/distillate blend with 0.25% maximum sulfur content is based on a fuel cost increase of \$5,219,256 for CT-1 and \$4,729,412 for CT-2, 661.77 tons of SO₂, 437.62 tons of NO_x, and 40.40 tons of PM₁₀ removed for CT-1, and 599.66 tons of SO₂, 404.08 tons of NO_x, and 36.40 tons of PM₁₀ removed for CT-2.
- c. Total combined reduction for fuel switch to ULSD with 0.0015% maximum sulfur content is based on a fuel cost increase of \$10,419,999 for CT-1 and \$9,442,050 for CT-2, 1,465.53 tons of SO₂, 875.25 tons of NO_x, and 80.80 tons of PM₁₀ removed for CT-1, and 1,327.99 tons of SO₂, 808.16 tons of NO_x, and 73.00 tons of PM₁₀ removed for CT-2.

Due to the low relative potential of the Kalaeloa Partners, L.P. Power Plant to contribute to visibility impairment at the Class I Areas as identified in the WEP/AOI analysis after initial Q/d screening, control measures identified in the four-factor analysis to be cost effective are not required. Note that prevailing trade winds transport pollutants from point sources on Oahu located down-wind of the Class I Areas a majority of the time. Unlike Q/d, the more sophisticated WEP/AOI analysis inherently accounts for meteorological data, such as wind patterns, and the specific light extinction contribution of each particle species.