PROPOSED

PERMIT APPLICATION REVIEW
COVERED SOURCE PERMIT (CSP) NO. 0548-01-C
APPLICATION NO. 0548-01

Company: Hawaiian Electric Company, Inc. (HECO)

Facility: Campbell Industrial Park Generating Station
Located at: UTM - 592,526 Meters East and 2,356,666 Meters North, Zone 4 (Old Hawaiian)

Mailing Address: P.O. Box 2750
Honolulu, Hawaii 96840-0001

Responsible
Official: Mr. Thomas C. Simmons
Company: HECO
Title: Vice President, Power Supply
Phone: (808) 543-4304

Contact: Mr. Dan V. Giovanni
Company: HECO
Title: Manager, Power Supply Operations and Management
Phone: (808) 543-4236

Contact: Ms. Sherri-Ann Loo
Company: HECO
Title: Manager, Environmental Department
Phone: (808) 543-4500

Contact: Mr. Barry M. Nakamoto
Company: HECO
Title: Principal Environmental Scientist
Phone: (808) 543-4515
Fax: (808) 543-4511

Contact: Mr. Jim Clary
Company: Jim Clary & Associates
Title: Consultant
Phone: 214-707-3377

Contact: Mr. J. Stephen Beene
Company: Jim Clary & Associates
Title: Environmental Engineer
Phone: 972-386-5995, Ext. 4

1. Background.

1.1 HECO has applied for an initial covered source permit to construct and operate Campbell Industrial Park Generating Station. Two identical 135 MW simple cycle combustion turbine generators, units CIP1 and CIP2, manufactured by Siemens Westinghouse Power Corporation were selected among those considered for the project. Units not selected include 97.1 MW and 125 MW simple cycle combustion turbine generators manufactured by General Electric and Alstom, respectively. Two 1.5 MW Cummins black start diesel engine generators, units BSG1 and BSG2, will be used to start the combustion turbine generators when the grid is not able to provide power. The combustion turbine generators will be equipped with a water injection system for controlling NO_X emissions to a concentration not to exceed 42 ppmvd at 15% O_2. The facility will also have two tanks to store fuel for CIP1 and CIP2 that is delivered from refinery through a pipeline. The tanks will be constructed with internal floating roofs and tank seal systems for controlling VOCs. Intended operation for units CIP1 and CIP2 is to provide spinning reserve by being online to be dispatched when other units providing power to the grid are unable to serve system needs. Spinning reserve is that portion of an operating generating unit's output that is not serving demand (e.g., if a 100 MW unit is operating at 40 MW, it has 60 MW of spinning reserve). Units CIP1 and CIP2 will provide peaking capacity to HECO's system and burn naphtha or fuel oil No. 2 with maximum 0.05% by weight sulfur content as the primary fuel. Fuel oil No. 2 with maximum 0.35% by weight sulfur content will be fired as a primary fuel if there is insufficient supply of the low sulfur fuels or it is determined that the lower sulfur fuels are economically infeasible to use. The Standard Industrial Classification Code for this facility is 4911 (Electrical Power Generation Through Combustion of Fossil Fuels).

1.2 HECO has selected two identical 135 MW combustion turbine generators for the project. For operating the two units, a total combined firing rate limit of 24.8 x 10^6 MMBtu/yr is required to prevent triggering the major source threshold for any single hazardous air pollutant (HAP) of 10 TPY for manganese worst-case. As indicated in the application, No. 2 diesel is required for startup and shutdown of CIP1 and CIP2. Naphtha cannot be used for startup and shutdown due to its high vapor pressure that will result in vapor lock of the fuel pumps. Combustion turbine generators are listed as follows:

COMBUSTION TURBINES					
Unit	Manufacturer	Model No.	Nominal Rating(MW)	Maximum Fuel Use[a] (MMBtu/hr)	
				Naphtha	Fuel Oil No.2
CIP1 & CIP2	Siemens Westinghouse	SGT6-3000E	135 (peak load)	1,472.6	1,482.4

a: Based on maximum lb/hr fuel consumption from manufacturer's information and each fuel's HHV in Btu/lb at ISO standard day conditions (59 ^{O}F, 1 atm, 60% relative humidity).

1.3 Each black start diesel engine generator will be limited to 500 hours per year operation and fire fuel oil No. 2 with a maximum sulfur content of 0.4% by weight. Black start diesel engine generators proposed for the project are listed as follows:

BLACK START DIESEL ENGINE GENERATORS				
Unit	Manufacturer	Model No.	Capacity (kW)	Maximum Fuel Use (MMBtu/hr)
				Fuel Oil No.2
BSG1 & BSG2	Cummins	DFMB (generator) KTTA50-G2 (engine)	1,500	14.5

1.4 Fuel for the combustion turbine generators will be stored inside two internal floating roof storage tanks. The tank seal systems have not been selected yet. Tanks proposed for the project are as follows:

STORAGE TANKS		
Tank No.	Working Volume (gallons)	Tank Description
1 & 2	4,146,000	Internal Floating Roof

1.5 As indicated by HECO, a simple cycle plant has been chosen instead of a more fuel

efficient combined cycle plant because HECO's system at this time needs peaking/cycling capacity more than base load capacity. It was stated that the capital costs are higher for combined cycle operation due to the heat recovery steam generator, steam turbine, and other system components that are required. Also, there are limited opportunities to recover the additional capital cost through fuel efficiency for a system in need for peaking generation. It was indicated that if the system were in need of high duty cycle base load operation, the additional capital cost for a more fuel efficient combined cycle plant could be justified because many more barrels of fuel would be consumed during a given period. HECO also indicated that installation of a simple cycle plant does not preclude the addition of a combined cycle plant and any decision to add combined cycle operation will be determined by the facts and circumstances when a combined cycle plant is considered.

1.6 Conversation with Jim Clary & Associates disclosed the following information:

a. A 60 minute start up time is requested for the combustion turbine generators because the units are large and additional time may be required for the water injection system to stabilize. Manufacturer's information indicates combustion turbine generator start up times between 21-32 minutes.

b. It is requested that the number of startups for the combustion turbines not be limited; however, if a permit limit is required, at least 4 startups are requested for the combustion turbines. It is undesirable to start the units more than necessary due to wear and tear on equipment that results upon startup.

c. The following apply to the generating plant:

   i. CIP1 and CIP2 will have separate stacks;

   ii. BSG1 and BSG2 will have separate stacks; and

   iii. The two stacks for BSG1 and BSG2 will be attached to either the inside or outside of the stack servicing CIP1. As such, the diesel engine generators and combustion turbine generators will have separate flues without stack gases being merged.

d. Two black start diesel engine generators are necessary for starting one combustion turbine generator.

e. There are three existing tanks at the proposed Campbell Industrial Park Generating Station site that store fuel oil No. 6 for HECO's Kahe Generating Plant. The tanks are owned by HECO and operated by Chevron Products Company. The capacity of each tank is 345,000 barrels. The tanks are 210 feet in diameter and 56 feet high.

f. The higher heating value (HHV) and lower heating value (LHV) used to determine emissions from the combustion turbine generators are 19,570 Btu/lb and 18,400 Btu/lb for naphtha, respectively.

g. The HHV and LHV used to determine emissions from the combustion turbine generators are 19,700 Btu/lb and 18,450 Btu/lb for fuel oil No. 2, respectively.

h. Naphtha cannot be used for startup and shutdown of the combustion turbine generators due to its high vapor pressure that results in vapor lock of the fuel pumps servicing the units.

i. Siemens changed the Westinghouse combustion turbine generator model number from 5W501D5A to SGT6-3000E after the two companies were merged. There are no changes in manufacturing specifications with the change in model number for the 135 MW combustion turbine generators.

j. Water injection for the combustion turbine generators is initiated during startup and is fully functional within 15 minutes after units reach a minimum operating load of 28 MW or more. The total time from the start of fuel flow to when the water injection stabilizes will be less than 60 minutes. If water is injected into the turbine prior to minimum operating load, the flame will go out. The minimum operating load needed to meet NO_X emission limits may vary. As such, HECO will establish a minimum operating load for the combustion turbines during each source performance test.

k. It was requested that a startup sequence be defined as the time fuel use at the time the combustion turbine generator is brought up to minimum operating load (28 MW or more) for 15 consecutive minutes. Time is necessary at startup for the system to stabilize after water injection is initiated. The load will vary above and below minimum operating load after initiating water injection due to the additional mass of water being injected into the system.

l. The sulfur content of the fuel for CIP1 and CIP2 will be certified based on invoices from the fuel supplier.

2. <u>Applicable Requirements</u>.

2.1 Hawaii Administrative Rules (HAR)

Chapter 11-59, Ambient Air Quality Standards
Chapter 11-60.1, Subchapter 1, General Requirements
Chapter 11-60.1, Subchapter 2, General Prohibitions
- 11-60.1-31, Applicability
- 11-60.1-32, Visible emissions
- 11-60.1-38, Sulfur Oxides from Fuel Combustion
- 11-60.1-39, Storage of Volatile Organic Compounds

Chapter 11-60.1, Subchapter 5, Covered Sources
Chapter 11-60.1, Subchapter 6, Fees for Covered Sources, Noncovered Sources, and Agricultural Burning
- 11-60.1-111, Definitions
- 11-60.1-112, General fee Provisions for Covered Sources
- 11-60.1-113, Application Fees for Covered Sources

11-60.1-114, Annual fees for Covered Sources
Chapter 11-60.1, Subchapter 7, Prevention of Significant Deterioration Review
Chapter 11-60.1, Subchapter 8, Standards of Performance for Stationary Sources
11-60.1-161, New Source Performance Standards
Chapter 11-60.1, Subchapter 9, Hazardous Air Pollutant Sources

2.2 40 Code of Federal Regulations (CFR) Part 60 - New Source Performance Standard (NSPS), Subpart KKKK, Standards of Performance for Stationary Combustion Turbines is applicable because the heat input of the combustion turbine generators at peak load is greater than 10 MMBtu/hr. Maximum heat input at peak load is 1,482.4 MMBtu/hr based on International Organization for Standardization (ISO) standard day conditions (59 ^{O}F, 60% relative humidity, and 1 atm) and the HHV for fuel oil No. 2 worst-case. As such, the combustion turbine generators are subject to emission limits in 40 CFR, Part 60, §60.4320 (a) for NO_X and 40 CFR, Part 60, §60.4330 (b) for SO_2. The following also apply:

a. The proposed project should meet the 42 ppm NO_X emissions limit specified in 40 CFR, Part 60,§60.4320 (a) because the manufacturer guarantees a NO_X gas concentration not to exceed 42 ppm by volume for operation of the combustion turbine generators with water injection.

b. The proposed project meets the limit specified in 40 CFR, Part 60, §60.4330 (b) because the sulfur content of the fuels proposed is less than 0.4% by weight.

SO_2 emission standard for turbines located in noncontinental area is 0.42 lb SO_2/MMBtu

0.35% sulfur content fuel oil No. 2 complies with limit based on fuel HHV as follows:

(0.0035 lb S/0.0197 MMBtu)(64.06 lb SO_2/32.06 lb S) = 0.35 lb SO_2/MMBtu

0.05% sulfur content naphtha and fuel oil No. 2 complies with the limit based on the HHV of these fuels as follows:

<u>naphtha</u>

(0.0005 lb S/0.01957 MMBtu)(64.06 lb SO_2/32.06 lb S) = 0.051 lb SO_2/MMBtu

<u>fuel oil No. 2</u>

(0.0005 lb S/0.0197 MMBtu)(64.06 lb SO_2/32.06 lb S) = 0.051 lb SO_2/MMBtu

2.3 40 CFR Part 60, NSPS, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines is not applicable to the black start diesel engine generators because the units being considered for the project have been manufactured prior to April 1, 2006. If units are selected that are manufactured after April 1, 2006, a permit modification will be required to incorporate Subpart IIII requirements. A

permit modification to incorporate Subpart IIII requirements will also be required to selected units that are reconstructed or modified after July 11, 2005.

2.4 40 CFR Part 60 - NSPS, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 is applicable to the two tanks that will store fuel for the combustion turbine generators because the tanks are greater than 151 m^3 (greater than 40,000 gallons) and will be storing naphtha (whole straight run gasoline) worst-case with a true vapor pressure greater than 0.507 psi. The working volume of each fuel storage tank is 4,146,000 gallons. Per AP-42, Section 7.1 (9/97), the true vapor pressure of gasoline with Reid vapor pressure of 10, representative of naphtha, is 7.4 psi at 80 ^oF.

2.5 40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines is not applicable to this project because worst-case facility- wide HAP emissions are less than 10 TPY single HAP and 25 TPY combined HAP. A fuel restriction is proposed for operating two 135 MW combustion turbine generators to limit HAP emissions of manganese below the major source threshold of 10 TPY for any single HAP. As such, the facility is not subject to maximum achievable control technology (MACT) requirements.

2.6 The purpose of Compliance Assurance Monitoring (CAM) is to provide reasonable assurance that compliance is being achieved with large emission units that rely on air pollution control device equipment to meet an emissions limit or standard. Pursuant to 40 CFR, Part 64, for CAM to be applicable, the emissions unit must: (1) be located at a major source; (2) be subject to an emissions limit or standard; (3) use a control device to achieve compliance; (4) have potential pre-control emissions that are greater than the major source level; and (5) not otherwise be exempt from CAM. Although the combustion turbine generators rely on a water injection system to achieve compliance with the federal NO_X standard required by 40 CFR 60, Subpart KKKK and have potential pre-control emissions greater than the major source level for NO_X, CAM is not applicable to the combustion turbine generators because a continuous emission monitoring system (CEMS) will be used to determine compliance with the NO_X emissions standard. As such, the combustion turbine generators are exempt from CAM.

2.7.1 Prevention of Significant Deterioration (PSD) review applies to this project pursuant to HAR, Chapter 11-60.1, Subchapter 7 and 40 CFR §52.21 because the facility meets the following three criteria:

a. The facility is a major stationary source that has the potential to emit 250 TPY or more of a pollutant regulated under the Clean Air Act. A 100 TPY major source threshold for source category designated fossil fuel fired steam electric plants is not applicable because there are no steam generating units for this facility. Fugitive emissions are not included for the determination of major source applicability because the combustion turbine generators will be regulated under Subpart KKKK which is an NSPS standard that is not promulgated prior to August 7, 1980. See New Source Workshop Review Manual, Table A-2, Page A.14.

b. The facility is located in an attainment area. Campbell Industrial Park is an attainment area for all pollutants for which a national ambient air quality standard exists.

c. The proposed project emits sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), total particulate (PM), particulate less than 10 microns in diameter (PM_{10}), volatile organic compounds (VOCs), nitrogen oxides (NO_X), carbon monoxide (CO), beryllium (Be), benzene, and arsenic (As) in significant amounts as defined in HAR, §11-60.1-1. As such, these pollutants are subject to PSD review. See Paragraph 2.7.2 (a).

2.7.2 Pollutants subject to PSD review require the following evaluations pursuant to HAR, §11-60.1-140 - §11-60.1-148 and 40 CFR §52.21:

a. Application of best available control technology (BACT) is required for each pollutant exceeding significant amounts as shown in the table below. Mercury (Hg), lead (Pb), and fluorides are the only pollutants among those evaluated that do not exceed significant levels. The remaining pollutants (CO, NO_x,SO_2, H_2SO_4, PM, PM_{10}, VOCs , As, benzene, and Be) require PSD review. See Paragraphs 2.8.1 through 2.8.11 for top-down BACT analysis.

Pollutant	**Potential Emissions (TPY)[c]**			**Total Emissions (TPY)**	**Significant Emission Level (TPY)**
	CIP1 and CIP2	**BSG1 and BSG2**	**Tank 1 and Tank 2**		
CO	3,518.9[a]	5.3	---------	3,524.2	100
NO_X	2,065.0[b]	31.3	----------	2,096.3	40
SO_2	4,403.2[b]	2.9	----------	4,406.1	40
H_2SO_4	438.2[b]	0.4	----------	438.6	7
PM	730.0[a]	0.3	----------	730.3	25
PM_{10}	700.8[a]	0.3	----------	701.1	15
VOC	335.5[a]	0.3	11.6	347.4	40
Fluorides	0.126[b]	7.28E-05	----------	0.126	3
Arsenic	0.136[b]	7.98E-05	----------	0.136	Any Amount
Benzene	0.682[b]	5.63E-03	0.060	0.748	Any Amount
Beryllium	0.002[b]	1.09E-06	----------	0.002	0.0004
Lead	0.174[b]	1.02E-04	----------	0.174	0.6
Mercury	0.015[b]	8.70E-06	----------	0.015	0.1

a: Based on operating each unit at 25% load, 59 ^oF, 60% relative humidity, and firing fuel oil No. 2.
b: Based on operating each unit at peak load, 59 ^oF, 60% relative humidity, and firing fuel oil No. 2.
Also, a 24.8 x10^6 MMBtu/yr total combined firing limit was applied to determine the yearly emissions.
c: See Paragraph 6.1.3, 6.2.3, and 6.3 for emission rates.

b. A preliminary air dispersion modeling analysis is required to determine applicability to preconstruction monitoring and full air dispersion modeling for Class II Areas. All of

Hawaii is designated as a Class II Area, except for Haleakala and Volcanoes National Parks which are designated Class I Areas. See air quality assessment in Paragraph 7.1 and Paragraphs 7.2.1 through 7.2.4 for the preliminary air dispersion modeling analysis.

c. A full air dispersion modeling analysis is required for ambient air impacts that exceed significant impact thresholds as determined from the preliminary modeling analysis. See air quality assessment in Paragraph 7.1 and Paragraphs 7.3.1 through 7.3.5 for the full air dispersion modeling analysis.

d. An analysis is required to evaluate sources that would have an adverse impact on the air quality and/or visibility in a Class I area. See Section 8 for applicability to Class I area impact analysis.

e. An analysis is required to evaluate the emissions impact on soils and vegetation and to address the emissions impact due to economic growth associated with the project. See Section 9 for additional impact analysis.

2.8.1 Based on the BACT top-down analysis, HECO proposes the following as BACT for the combustion turbine generators:

a. Use of water injection for controlling NO_X to a concentration not to exceed 42 ppmvd at 15% O_2 for firing naphtha and fuel oil No. 2.

b. The firing of naphtha or fuel oil No. 2 with a maximum 0.05% by weight fuel sulfur content for controlling SO_2 and H_2SO_4 emissions for CIP1 and CIP2. An allowance to fire fuel oil No. 2 with a maximum sulfur content not to exceed 0.35% by weight was requested if the lower sulfur content fuels cannot be supplied in sufficient quantity or are economically unviable to use.

c. Use of combustion design features built into the units and the firing of low ash fuels for the control of particulate. Naphtha and fuel oil No. 2 proposed for CIP1 and CIP2 are in the range of low ash fuels as indicated by the RACT/BACT/LAER Clearinghouse .

d. Use of combustion design features built into the units for controlling CO, VOC, As, Be, and benzene emissions.

2.8.2 For controlling NO_X emissions from the combustion turbine generators, the BACT top-down procedure involved an evaluation of various alternative control technologies other than those proposed as BACT that include: (1) low nitrogen fuels, (2) dry low-NO_X combustor design, (3) selective non-catalytic reduction (SNCR), (4) non-selective catalytic reduction (NSCR), (5) catalytic absorption system for CO and NO_X (SCONO$_X$™), (6) Xonon™, (7) EnviroScrub's Pahlman™ Process, and (8) selective catalytic reduction (SCR). Conclusions from the BACT analysis of these technology alternatives are as follows:

a. Low-nitrogen fuel is not readily available in Hawaii. Therefore, firing a lower nitrogen fuel as a control option was not considered feasible.

b. Dry low-NO_X combustor design is not available for the combustion turbine generator models proposed that will be fired on liquid fuels. Dry low-NO_X burners are typically used for units firing natural gas as the primary fuel rather than liquid fuels.

c. SNCR was deemed infeasible for the combustion turbine generators based on the following:

   i. SNCR, including ammonia and urea injection, requires flue gas temperatures in the range of 1,500 ^{O}F to 2,000 ^{O}F. Specifications for the combustion turbine generators indicate exhaust temperatures ranging from 718 ^{O}F -1,049 ^{O}F.
   ii. SNCR is only 20 to 50 percent effective in controlling NO_X emissions and NO_X reduction rates decrease when the NO_X concentration is below 100 ppm.

d. NSCR was considered infeasible because this air pollution control is only effective when treating flue gas from fuel rich combustion processes and the flue gas must be nearly depleted of oxygen for effective operation. This condition does not exist for combustion turbines which operate with high levels of excess air (typically 14 to 16 percent O_2).

e. $SCONO_X$ was deemed infeasible for the combustion turbine generators based on the following:

   i. $SCONO_X$ requires flue gas temperatures in the range of 300 ^{O}F to 700 ^{O}F. Specifications for the combustion turbine generators indicate exhaust temperatures from 718 ^{O}F - 1,049 ^{O}F. The combustion turbine generator exhaust temperatures are higher than the acceptable range for $SCONO_X$. Injecting air into the exhaust stream to reduce the exhaust temperature to an acceptable level was considered infeasible because the maximum temperature reduction achieved with this method of cooling is about 100 ^{O}F.

   ii. The sulfur bearing fuels proposed for the project, such as 0.35% sulfur content fuel oil No. 2 worst-case, have been known to foul the $SCONO_X$ catalyst and render it ineffective. The catalyst converts CO to CO_2 and NO to NO_2, with NO_2 being adsorbed onto the surface of the catalyst. The vendor offers a sulfur removal system ($SCOSO_X$) that works in conjunction with the $SCONO_X$ system to remove sulfur compounds that would interfere with the $SCONO_X$ catalyst; however, the $SCOSO_X$ system operates in the same 300 ^{O}F to 700 ^{O}F temperature range as the $SCONO_X$ system.

f. The Xonon system was not considered a viable control option because it has not been developed for the combustion turbine generator model proposed for this project. The technology is unit specific and has only been applied to 1.4 MW Kawasaki M1A-13X gas turbines.

g. The Pahlman process, involving the injection of a low density powder into the flue gas stream that is removed with a baghouse, was not considered an option for controlling NO_X because the technology has not been demonstrated in either a full scale application or for combustion turbine generators.

h. Low temperature or conventional SCR was not considered an applicable technology for the simple cycle combustion turbine generators. Low temperature SCR is used when the turbine has a heat recovery steam generator where the exhaust gas is cooled. The low temperature catalyst is typically vanadium/titanium based and is effective at temperatures ranging from 500 ^{O}F to 850 ^{O}F. The combustion turbine generators proposed for the generating station operate at higher temperature ranges. As such, low temperature SCR was not considered feasible. Injecting air into the exhaust stream to reduce the exhaust temperature was considered infeasible because this method of cooling is typically used when the reduction in temperature is on the order of 50 ^{O}F or less.

i. High temperature SCR using zeolite catalysts was considered infeasible for the combustion turbine generators based on problems with the technology that include the following:

   i. The maximum exhaust temperature for the combustion turbines proposed are greater than 850 ^{O}F. Catalyst failures have occurred on simple cycle combustion turbines in applications with zeolite catalysts at temperatures above 850 ^{O}F. Specifications for the combustion turbine generators indicate exhaust temperatures ranging from 718 ^{O}F - 1,049 ^{O}F. Injecting air into the exhaust stream to reduce the exhaust temperature to an acceptable level was considered infeasible because the temperature reduction is typically used when the required cooling is on the order of 50 ^{O}F or less.

   ii. Operating experience with zeolite catalysts on oil-fired sources is limited, and the upper temperature limit and long-term performance characteristics of these catalysts have not been established. It was indicated that there are serious operating issues with SCR applications using high temperature catalysts at the Puerto Rico Electric Power Authority (PREPA) Cambalache Generating Station and Hawkeye's Greenport Generating Facility for simple cycle turbines fired exclusively on distillate oil. Also, the MECO/HECO demonstration program pilot testing showed that the high temperature catalyst performed poorly.

   iii. Excess particulate and ammonia emissions may occur from oxidation of SO_2 to SO_3 over the catalyst in combination with ammonia slip leading to ammonia salt formation or free ammonia as the exhaust gas cools.

   iv. Excess sulfuric acid formation from oxidation of SO_2 to SO_3 was identified as another potential problem for use of SCR with the sulfur bearing fuels proposed for CIP1 and CIP2.

   v. There were also concerns regarding catalyst life shortened by its deactivation as a result of the fuel type, fuel composition, and unique operating conditions of the combustion turbines.

2.8.3 For controlling SO_2 and H_2SO_4 emissions from the combustion turbine generators, the BACT top-down procedure involved an evaluation of various alternative control technologies other than those determined to be BACT that include flue gas desulfurization (FGD) and $SCOSO_X$. Conclusions from the evaluation of these technology alternatives are as follows:

a. FGD was not determined to be a viable control alternative based on the following:

   i. A search of the RACT/BACT/LEAR Clearinghouse since January 1993, showed no cases where FGD technology had been used on turbines that exclusively fire liquid fuels. Of the determinations from the search, no cases had add-on SO_2 control.

   ii. It was determined that high exhaust gas volumetric flow rates with low SO_2 and H_2SO_4 concentrations would increase FGD costs and pose operating difficulties for FGD technology applied to combustion turbine generators.

b. Use of $SCOSO_X$ was determined to be infeasible because the exhaust gas temperatures of the combustion turbine generators proposed are higher than the temperature range specified for reliable operation of the $SCOSO_X$ system.

2.8.4 Electrostatic precipitators and fabric filters as alternate control technologies were deemed infeasible for controlling particulate emissions from CIP1 and CIP2 because no application of these technologies exists for combustion turbine generators due to the high exhaust flow rates and low particulate loading.

2.8.5 The control of CO and VOCs with catalytic oxidation, a control method using a platinum/rhodium catalyst to oxidize CO and VOCs to CO_2, was determined to be infeasible for the combustion turbine generators based on problems with its application that include the following:

a. A search of the RACT/BACT/LAER Clearinghouse did not show any catalytic oxidation systems used for simple cycle combustion turbines that exclusively fire liquid fuels.

b. There are concerns of emissions of SO_3 and attendant H_2SO_4 formation due to oxidation of SO_2 because the catalyst that oxidizes CO and VOCs to CO_2 also oxidizes SO_2 to SO_3. Oxidation rate of SO_2 will increase with temperature and the formation of SO_3 will increase with fuel sulfur content.

c. There were also concerns with the performance of the catalyst when firing fuel with as much as 0.35% by weight sulfur content.

2.8.6 Because As, Be, and benzene will be emitted in trace quantities and there are no air pollution control technologies for combustion turbine generators to reduce emissions of these pollutants specifically, it was concluded that good combustion practice is BACT to minimize the formation of these pollutants. Also, for controlling As and Be as a particulate, add-on air pollution controls were considered infeasible (see Paragraph 2.8.4). For control of benzene, add-on air pollution controls were considered infeasible for VOCs (see Paragraph 2.8.5).

2.8.7 The Department requested HECO to address the feasibility of using a separate exhaust duct for firing an ultra-low sulfur fuel such as naphtha that could incorporate SCR and catalytic oxidation catalyst and alleviate complications associated with firing the higher sulfur content fuel such as 0.35% sulfur diesel. It was indicated in HECO's response that the dual exhaust approach could be considered an option for the application of catalytic oxidation. The approach would avoid excessive oxidation of SO_2 to sulfuric acid. However, it was stated that the dual exhaust would result in poor CO/VOC cost effectiveness. Also, the use of catalytic oxidation catalyst with fuel of 0.05% sulfur content would still result in the formation of 704 tons per year of sulfuric acid while reducing CO emissions by only 564 tons per year.

2.8.8 The Department, in correspondence with HECO, identified a permit from the Florida Department of Environmental Protection for two 50 MW simple-cycle combustion turbines with SCR and catalytic oxidation that fire oil as the primary fuel. The permit is for the City of Tallahassee Arvah B. Hopkins Station. It was indicated in response by HECO after researching the project, that the station will use a conventional vanadia/titania catalyst for the SCR system. The specified exhaust gas temperature is 826 ^{O}F; however, the original SCR design has been modified to include a small volume of tempering air to reduce the exhaust gas temperature ahead of the SCR system to below 800 ^{O}F. The change was made due to concerns about catalyst deactivation at temperatures above 800 ^{O}F. The site will also install a catalytic oxidation system to control CO and VOC. Plant operation date of the combustion turbines is July 2005. Based on the information from review of the project, key issues identified by HECO on SCR and catalytic oxidation feasibility for the Campbell Industrial Park Station include the following:

a. The exhaust temperatures for units proposed for the Campbell Industrial Park generating station may be up to 250 ^{O}F higher that those for the Tallahassee Arvah B. Hopkins Station. It is not practical to use tempering air to achieve that level of cooling.

b. A Zeolite-type SCR catalyst for NO_X control that would be required for the higher exhaust temperatures of units CIP1 and CIP2 has not been proven reliable on both oil and natural gas fired simple cycle units.

c. The higher exhaust temperatures for the Campbell Industrial Park Station would also be a factor in the performance of the catalytic oxidation system for control of CO and VOCs.

d. In applications where the simple cycle exhaust temperature is lower, more reliable SCR performance may be provided with use of a conventional vanadia/titania catalyst with different composition and functioning than a zeolite catalyst.

2.8.9 The Department became aware of a permit in Washington State for Fredonia Generating Station with 52-54 MW simple cycle combustion turbine generators firing natural gas and fuel oil that use SCR and catalytic oxidation as BACT. It was indicated by the permitting agency that dilution air is added upstream of the CO-catalyst/SCR system to keep temperatures below 850 ^{o}F. Maximum exhaust temperature for the proposed Campbell Industrial Park Generating Station units of 1,049 ^{o}F is higher than 850 ^{o}F. Also, tempering air to reduce maximum exhaust temperatures below 850 ^{o}F has been considered infeasible.

2.8.10 After it was found from discussion with ATS Express, LLC personnel that catalytic oxidation systems can operate at temperatures as high as 1250 ^{O}F, the Department requested HECO to address the feasibility of oxidation catalyst after reviewing the following simple cycle projects: (1) An FT-8 TwinPack unit at the Puget Sound Energy (PSE) Ferdonia Generating Station; (2) Two FT-8 TwinPack units (the Klamath Generating Peakers) operated by Klamath Energy, LLC; (3) Two LM-6000 units at the City of Tallahassee Arvah B. Hopkins Generating Station. HECO provided the following information from their evaluation:

a. The Puget Sound Energy (PSE) - Fredonia Station has two simple cycle units rated at 54 MW (natural gas) and 52 MW (distillate fuel). PSE will use ultra low sulfur (0.01% by weight) distillate fuel. Dilution air is added to keep the exhaust temperatures below 850 ^{O}F.

b. There are four units for Klamath Energy, LLC. There is an allowance for the facility to burn distillate oil as a back-up for natural gas. The distillate oil is limited to 0.05% sulfur content by weight. The hours of operation are limited to 4,000 hours per year for firing natural gas and 1,400 hours per year for firing distillate oil.

c. The Arvah B. Hopkins Generating Station turbines are permitted to fire oil for up to 4,000 hours per year and natural gas for up to 1,840 hours per year. The sulfur content of the fuel fired is limited to 0.05%. The exhaust temperatures are 826 ^{O}F based on manufacture's specifications. The actual design includes cooling air to limit the exhaust gas temperature to below 800 ^{O}F.

d. Based on information from the BACT analysis provided by HECO for their second application, it was concluded that the units in 2.8.10. a, 2.8.10.b, and 2.8.10.c are similar to the Greenport and Shoreham units that have already been evaluated. As such, no new issues are raised, and the operation of these facilities does not impact the

infeasibility of CO oxidation catalyst for the CIP application.

2.8.11 HECO evaluated the technical feasibility and cost effectiveness of a partial heat recovery steam generator (HRSG) for reducing exhaust temperatures from the proposed simple cycle units. It was determined that a partial HRSG approach would be technically feasible to cool exhaust from over 1,000 ^{O}F to 750 ^{O}F and would represent the lowest cost option for reducing temperatures to minimize thermal damage to the SCR catalyst. For the cost analysis, three operating scenarios were evaluated that included maximum operation (8,760 hr/yr per unit at peak load), high operation (2,450 hr/yr per unit at 56 MW), and low operation (650 hr/yr per unit at 33 MW). The cost effectiveness for the maximum operating scenario was $16,915/ton of NO_X removed. The cost effectiveness for the high and low operating scenarios was $76,794 and $380,798 per ton of NO_X removed, respectively. Because intended operation of the simple cycle combustion turbines is to provide spinning reserve by being online and dispatched within 10 MW of the minimum operating load (around 30 MW), the units were projected to be operated somewhere between the low and high operation scenarios. As such, HECO concluded that operating a partial HRSG to enable NO_X reduction with SCR would be economically infeasible.

2.9 The Consolidated Emissions Reporting Rule (CERR) is applicable because potential emissions from the generating station exceed reporting levels pursuant to 40 CFR 51, Subpart A for Type A sources (see table below).

CERR APPLICABILITY[a]			
Pollutant	Potential Emissions (TPY)	CERR Triggering Levels (TPY)	
		1 year cycle (Type A sources)	3 year cycle (Type B sources)
PM-10	701.1	≥250	≥100
PM-2.5	657.3	≥250	≥100
SO_2	4,406.1	≥2,500	≥100
NO_x	2,096.3	≥2,500	≥100
VOC	347.4	≥250	≥100
CO	3,524.2	≥2,500	≥1,000

a: See Paragraph 6.4 total emissions [limited] for emission rates.

2.10 The facility will be placed into the Compliance Data System (CDS) because this source is a covered source.

2.11 Annual emissions reporting is required because this facility is a covered source.

3. Insignificant Activities and Exemptions

3.1 The following are a list of insignificant activities identified by the applicant that meet the exemption criteria specified in HAR, §11-60.1-82(f):

a. Three (3) 345,000 barrel fixed roof storage tanks storing fuel oil No. 6 for HECO's Kahe Generating Station are considered exempt pursuant to HAR, §11-60.1-82(f)(7).

b. Storage tanks less than or equal to 40,000 gallons capacity are exempt pursuant to HAR, §11-60.1-82(f)(1).

c. Fuel burning equipment less than 1 MMBtu/hr, other than smoke house generators and gasoline fired industrial equipment, are exempt in accordance with HAR, §11-60.1-82(f)(2).

d. Standby emergency generators are exempt in accordance with HAR, §11-60.1-82(f)(5).

e. Paint spray booths that emit less than two tons per year of any regulated air pollutant are exempt pursuant to HAR, §11-60.1-82(f)(6).

f. Activities that emit less than 500 lb/yr of HAP, 25% of the significant amount of emissions as defined in HAR §11-60.1-1, 5 TPY CO, and 2 TPY of each regulated air pollutant other than CO, and which are determined on a case by case basis to be insignificant activities are exempt pursuant to HAR, §11-60.1-82(f)(7).

4. Alternate Operating Scenarios

4.1 The following alternate operating scenarios were proposed for an allowance to:

a. Operate CIP1 and CIP2 below minimum operating load during maintenance and testing activities;

b. Operate CIP1 and CIP2 up to 110% of peak load for emergency conditions;

c. Fire fuel oil No. 2 with up to 0.35% by weight sulfur content for a designated length of time if it is demonstrated that fuels with 0.05% by weight or lower maximum sulfur content can be eliminated as BACT for the units;

d. Switch fuels (e.g., use of biodiesel, jet fuel, or ethanol instead of naphtha and fuel oil No. 2) for the combustion turbine generators provided all permit conditions are met for the alternate fuel;

e. Use additives which may be blended with fuel to control algae, inhibit corrosion, increase burn efficiency, reduce emissions of certain pollutants, etc. provided all permit conditions are met; and

f. Replace CIP1, CIP2, BSG1, and BSG2 with an equivalent temporary replacement unit with equal or lesser emissions in the event of failure or major overhaul of the equipment.

4.2 HECO also requested an alternate operating scenario be incorporated for an allowance to operate the facility in such a manner to minimize emissions during unpredictable periods of equipment failure, upsets, or emergency conditions (for this alternate operating scenario, it was indicated that the facility will comply with the emergency provisions of HAR §11-60.1-97).

4.3 It was decided not to incorporate the alternate operating scenario listed in Paragraph 4.2 above. Emergency provision of HAR §11-60.1-97 have been repealed. Emergency provisions are specified in the standard conditions of a covered source permit. Enforcement actions regarding permit violations during emergency conditions will be handled by the Department on a case-by-case basis.

5. Air Pollution Control

5.1 Water injection will be used to control NO_X emissions from the combustion turbine generators to a concentration not to exceed 42 ppmvd. The air pollution control system injects demineralized water into the turbine generator's combustion chamber. The moisture acts as a heat sink, reducing the peak flame temperature and in turn reducing the formation of thermal NO_X. Thermal NO_X results during combustion from atmospheric air, consisting mostly of nitrogen, reacting with oxygen in the air to form NO_X.

5.2 Tanks storing fuel for the combustion turbine generators will be equipped with tank seal systems and internal floating roofs to control VOC and HAP emissions.

6. Project Emissions

6.1.1 Emissions of NO_X, CO, VOC, PM, PM_{10}, and $PM_{2.5}$ from the combustion turbine generators were based on the lb/hr emission rates from manufacturer's specifications. A mass balance calculation was used to determine SO_2 emissions from information on the fuel sulfur content and fuel flow rate in lb/hr. For H_2SO_4, it was assumed that 6.5% fuel sulfur converts to sulfuric acid mist based on information from General Electric. For fluorides, emissions were based on April 11, 1985 test results from an analysis of fuel oil No. 2 that indicated a 0.2 ppm fluoride concentration. Worst-case emission rates were based on ISO standard day conditions (59 ^oF and 60% relative humidity). A 24.8 x 10^6 MMBtu/yr total combined firing rate limit to ensure potential manganese emissions are kept below 10 TPY was also applied. It was assumed that 96% of the total particulate was PM-10 based on AP-42 Appendix B.2, Table B.2-2 for gasoline and diesel fired internal combustion engines. It was assumed that 90% of the total particulate was PM-2.5 based on AP-42 Appendix B.2, Table B.2-2 for gasoline and diesel fired internal combustion engines. Minimum load with water injection for the turbines is 25% of peak load. Emissions were also calculated based on operating conditions at 86 ^oF ambient temperature and 70% relative humidity for information that may be more representative of conditions in Hawaii. Emission estimates for the combustion turbine generators are shown in Enclosure (1).

6.1.2 Emission factors from AP-42, Section 3.1 (4/00), Stationary Gas Turbines were used to determine HAP emissions from the combustion turbine generators. Emission factors from AP-42, Section 3.4 (10/96), Large Stationary Diesel and All Stationary Dual-Fuel Engines were used to determine HAP emissions not listed in AP-42, Section 3.1. Emission factors for fuel oil No. 2 were used as worst-case because there are no emission factors for naphtha. For beryllium, emissions were based on April 11, 1985 test results from an analysis of fuel oil No. 2 that indicated a 0.003 ppm beryllium concentration. The g/s and lb/hr HAP emissions were based on a worst-case firing rate of 1,482.4 MMBtu/hr for firing fuel oil No. 2 at ISO standard day conditions. A 24.8 x 10^6 MMBtu/yr firing rate limit was applied to determine the total combined ton per year HAP emissions. Worst-case HAP emissions are shown in Enclosure (2).

6.1.3 Maximum potential emissions are shown in the table below for operation between 25% to peak load with application of water injection for controlling NO_X.

COMBUSTION TURBINE EMISSIONS					
Pollutant	Fuel Fired	Emission Rate Each Unit		Emission TPY (2 units)	
		lb/hr	g/s	Limited	No Limits
				Total Combined 24.8 x 10^6 MMBtu/yr (Siemens scenario only)	Total Combined 8,760 hr/yr
SO_2	fuel oil #2	526.3	66.4	4,403.2[a]	4,610.0[a]
NO_X	fuel oil #2	246.8	31.2	2,065.0[a]	2,162.6[a]
CO	fuel oil #2	401.7	50.7	3,518.9[b]	3,518.9[b]
VOC	fuel oil #2	38.3	4.8	335.5[b]	335.5[b]
PM (see note e)	fuel oil #2	83.3	10.522	730.0[b,c]	730.0[b,c]
PM_{10}	fuel oil #2	80	10.1	700.8[b]	700.8[b]
$PM_{2.5}$ (see note f)	fuel oil #2	75.0	9.5	657.0[b,d]	657.0[b,d]
H_2SO_4	fuel oil #2	52.4	6.61	438.2[a]	458.9[a]
Fluorides	fuel oil #2	0.015	1.90E-03	0.126[a]	0.132[a]
Arsenic	fuel oil #2	0.016	0.002	0.136[a]	0.142[a]
Benzene	fuel oil #2	0.082	0.010	0.682[a]	0.711[a]
Beryllium	fuel oil #2	2.26E-04	2.85E-05	0.002[a]	0.002[a]
Mercury	fuel oil #2	1.78E-03	2.25E-04	0.015[a]	0.016[a]
Lead	fuel oil #2	2.08E-02	2.62E-03	0.174[a]	0.182[a]
Manganese (max. single HAP)	fuel oil #2	1.171	0.148	9.8[a]	10.3[a]
Total Haps	fuel oil #2	--------	--------	22.3[a]	23.3[a]

a: Based on operating each unit at peak load, 59 °F, 60% relative humidity, and firing fuel oil No. 2.
Also, a 24.8 x10^6 MMBtu/yr total combined firing limit was applied to determine the emissions with operation limit.
b: Based on operating each unit at 25% load, 59 °F, 60% relative humidity, and firing fuel oil No. 2.
c: It was assumed that 96% of the total particulate was PM-10 based on AP-42 Appendix B.2, Table B.2-2 for gasoline and diesel fired internal combustion engines.
d: It was assumed that 90% of the total particulate was PM-2.5 based on AP-42 Appendix B.2, Table B.2-2 for gasoline and diesel fired internal combustion engines.

6.2.1 Emissions of NO_X, CO, VOC, PM, PM_{10}, and $PM_{2.5}$ from the black start diesel engine generators were based on the gram per second emission rates from manufacturer's specifications. A mass balance calculation was used to determine SO_2 emissions based on the maximum 0.4% fuel sulfur content and a 103.3 gal/hr fuel consumption for each diesel engine generator at maximum standby power rating. A fuel heating value of 140,000 Btu/gal and a fuel oil No. 2 density of 7.05 lb/gal (from AP-42, Appendix A) were used to determine worst-case emissions. For H_2SO_4, it was assumed that 13.83% of the SO_2 converts to sulfuric acid mist based on information from SCEC report from Maalaea M3. For fluorides, emissions were based on April 11, 1985 test results from an analysis of fuel oil No. 2 that indicated a 0.2 ppm fluoride concentration. It was assumed that 96% of the total particulate was PM-10 based on AP-42 Appendix B.2, Table B.2-2 for gasoline and diesel fired internal combustion engines. It was assumed that 90% of the total particulate was PM-2.5 based on AP-42 Appendix B.2, Table B.2-2 for gasoline and diesel fired internal combustion engines. Emission estimates are shown in Enclosure (3).

6.2.2 Emission factors from AP-42, Section 3.4 (10/96), Large Stationary Diesel and All Stationary Duel-Fuel Engines were used to determine HAP emissions from the black start diesel engine generators. Emission factors from AP-42, Section 3.1 (4/00), Stationary Gas Turbines were used to determine HAP emissions not listed in AP-42, Section 3.4. Emission factors for fuel oil No. 2 were used as worst-case because there are no emission factors for naphtha. Beryllium emissions were based on April 11, 1985 test results from a fuel oil No. 2 analysis that indicated 0.003 ppm beryllium concentration. The g/s and lb/hr emissions were based on a worst case firing rate of 14.5 MMBtu/hr for each diesel engine generator. Calculations are shown in Enclosure (4).

6.2.3 Maximum potential emissions for the black start diesel engine generators are shown in the table below.

BLACK START DIESEL ENGINE GENERATOR EMISSIONS				
Pollutant	Emission Rate Each Unit		Emission TPY (2 units)	
	lb/hr	g/s	Limited	No Limits
			500 hr/yr per generator	8,760 hr/yr per generator
SO_2	5.8	7.35E-01	2.9	50.8
NO_X	62.5	7.893	31.3	547.6
CO	10.6	1.338	5.3	92.8
VOC	0.684	0.086	0.3	6.0
PM	0.559	0.070	0.3	4.9
PM_{10} (see note a)	0.537	0.068	0.3	4.7
$PM_{2.5}$ (see note b)	0.503	0.063	0.3	4.4
H_2SO_4	0.805	1.02E-01	0.4	7.0
Fluorides	1.46E-04	1.84E-05	7.28E-05	1.27E-03
Arsenic	1.60E-04	2.01E-05	7.98E-05	1.39E-03
Benzene	1.13E-02	1.42E-03	5.63E-03	0.099
Beryllium	2.18E-06	2.76E-07	1.09E-06	1.91E-05
Lead	2.03E-04	2.56E-05	1.02E-04	1.79E-03
Mercury	1.74E-05	2.20E-06	8.70E-06	1.52E-04
Manganese (max. single HAP)	1.15E-02	1.45E-03	5.73E-03	0.100
Total Haps	--------	--------	0.019	0.333

a: It was assumed that 96% of the total particulate was PM-10 based on AP-42 Appendix B.2, Table B.2-2 for gasoline and diesel fired internal combustion engines.
b: It was assumed that 90% of the total particulate was PM-2.5 based on AP-42 Appendix B.2, Table B.2-2 for gasoline and diesel fired internal combustion engines.

6.3 Potential emissions from the internal floating roof storage tanks were based on storing naphtha (whole straight run gasoline) worst-case with a Reid vapor pressure of 11 psi and a 225,454,545 gallon per year total combined tank throughput which correlates to about 27 tank turnovers per year per tank. The total combined gallon/yr throughput is based on a 24.8 x 10^6 MMBtu/yr total combined firing rate limit and a heating value for naphtha that was indicated in the application to be 110,000 Btu/gallon. Vapor mass fractions of components for naphtha were multiplied by the total VOC emissions from each tank to

determine maximum potential HAP emissions. The vapor mass fraction data was obtained from Chevron Products Company's most recent permit application submittal for its Port Allen Terminal that has been processed under permit application No. 0080-06. Potential emissions from the tanks are shown in Enclosure (5) and summarized below.

TANK EMISSIONS			
Pollutant	Tank No. 1	Tank No. 2	Emissions (TPY)
VOC	5.8	5.8	11.6
Hexane (n) [max. single HAP]	0.095	0.095	0.189
HAPs	0.178	0.178	0.355

6.4 Worst-case yearly emissions of criteria pollutant and HAPs from operating permitted equipment at the facility are as follows (see tables from Paragraphs 6.1.3, 6.2.3, and 6.3 for emission rates):

FACILITY-WIDE EMISSIONS							
Pollutant	Emissions (TPY)						
	Combustion Turbines		Black Start Diesel Engine Generators		Tanks	Total Emissions [limited]	Total Emissions [no limits]
	limited	no limits	limited	no limits			
SO_2	4,403.2	4,610.0	2.9	50.8	-------	4,406.1	4,660.8
NO_X	2,065.0	2,162.6	31.3	547.6	-------	2,096.3	2,710.2
CO	3,518.9	3,518.9	5.3	92.8	-------	3,524.2	3,611.7
VOC	335.5	335.5	0.3	6.0	11.6	347.4	353.1
PM	730.0	730.0	0.3	4.9	-------	730.3	734.3
PM_{10}	700.8	700.8	0.3	4.7	-------	701.1	705.5
$PM_{2.5}$	657.0	657.0	0.3	4.4	-------	657.3	661.4
Manganese (max. single HAP)	9.8	10.3	5.73E-03	0.100	-------	9.8	10.4
Total Haps	22.3	23.3	0.019	0.333	0.355	22.7	24.0

7. Air Quality Assessment

7.1 A preliminary and full ambient air modeling impact analysis was performed for the combustion turbine generators and black start diesel engine generators. Modeling involved the use of ISC_RTDM. The model combines two EPA guideline models; ISCST3 (EPA 1995) and RTDM (Environmental Research and Technology 1987). The ISC_RTDM model program is capable of modeling simple, intermediate, and complex terrain receptors. ISC_RTDM is considered a refined model in simple terrain and a screening model in complex terrain. A CTDMPLUS model was used to determine impacts from HECO's Kahe Generating Plant that were added to the total impacts for the full air modeling analysis required for SO_2. The following apply to the ISC_RTDM modeling parameters:

a. One year of meteorological data collected from October 1, 1992 through September 30, 1993 from HECO's No. 064 monitoring station at Ewa Beach was used for the modeling analysis. The 64 meter wind speed and direction measurements were collected and used as representative stack top transport winds.

b. Selection of rural dispersion coefficients were used for the model based on the land use method of classification per 40 CFR, Part 51, Appendix W (it was found that more than 50% of the area in a 3 kilometer radius of the Campbell Industrial Park area is either water or agriculture).

c. Background concentrations of SO_2 and ozone for the various averaging periods for the full impact analysis were taken from the following monitoring locations to determine compliance with state and federal ambient air quality standards:

   i. SO_2 (3 hr, 24 hr) - collected in 2004 from the Makaiwa monitoring station;
   ii. O_3 (1hr) - collected in 2004 from the Sand Island monitoring station.

d. A good engineering practice (GEP) stack height analysis was conducted by evaluating nearby structures to determine whether or not stack emissions may be affected by downwash from the structures. Combustion turbine generator and black start diesel engine generator stacks are 210 feet high. All proposed structures for the project will be less than 83.5 feet tall (40% of the stack height). As such, CIP1, CIP2, BSG1, and BSG2 are not subject to downwash from structures proposed for the project. Additional off-property structures from AES and H-Power were evaluated using EPA's building profile input program (BPIP). The BPIP outputs show all project sources are located greater than 5L (where L is the lesser dimension between the structure's height and projected width) from the structures. Therefore, there are no downwash effects from these off-property structures.

e. The table below presents the emission rates and stack parameters used for the AAQIA for the combustion turbine generators at the various equipment loads. The range of loads are 25% to 100% of peak load.

SOURCE			EMISSION RATES				STACK PARAMETERS			
Equipment	Stack No.	Load	NO_2 (g/s)	SO_2 (g/s)	CO (g/s)	PM_{10} (g/s)	Velocity (m/s)	Temp. ^{O}K (^{O}F)	Height (m)	Dia. (m)
CIP1 or CIP2	1&2	Peak	31.1	66.4	9.01	6.82	39.0	826 (1,027)	64	5.37
		Base	29.6	63.3	10.7	6.83	38.0	810 (999)		
		75%	23.9	51.4	17.3	7.23	31.9	838 (1,049)		
		50%	17.9	38.3	38.8	10.0	27.1	775 (936)		
		25%	11.6	25.2	50.6	10.1	22.8	654 (718)		

f. The table below presents the emission rates and stack parameters used for the AAQIA for the black start diesel engine generators for various averaging periods. Each black start diesel engine generator is limited to 500 hr/yr operation and was assumed to operate at 100% load. The g/s emission rate for the annual averaging period was adjusted to account for a 500 hr/yr limit.

SOURCE			EMISSION RATES[a]				STACK PARAMETERS			
Equipment	Stack No.	Averaging Period	NO_2 (g/s)	SO_2 (g/s)	CO (g/s)	PM_{10} (g/s)	Velocity (m/s)	Temp. ^{O}K (^{O}F)	Height (m)	Dia. (m)
BSG1 or BSG2	3&4	1 hour	-------	--------	1.34	--------				
		3 hour	-------	0.731	-------	--------				
		8 hour	-------	--------	1.34	--------	49.8	739 (871)	64	0.356
		24 hour	-------	0.731	-------	0.0678				
		Annual	0.452[a]	0.042[a]	-------	0.00388[a]				

a: Maximum g/s emission rates factored by 500/8,760 to account for 500 hr/yr operation limit for each black start diesel engine generator.

7.2.1 A preliminary modeling analysis was conducted for pollutants exceeding significant emission levels for which monitoring and modeling thresholds exist. Significant emission levels were exceeded for CO, NO_x, SO_2, H_2SO_4, PM, PM_{10}, VOCs , As, benzene, and Be. Among these pollutants, monitoring and modeling thresholds exist for CO, NO_x, SO_2, PM, PM_{10}, VOCs , and Be. Other pollutants (H_2SO_4, As, and benzene) for which there are no modeling or monitoring threshold were addressed in air modeling assessments to determine compliance with air standards specified in HAR §11-60.1-179 for carcinogenic and non-carcinogenic HAPs. Sulfuric acid mist impacts were evaluated with thresholds provided by the Hazardous Evaluation and Emergency Response (HEER) Branch toxicologist. See Paragraphs 7.1 and 7.4.1 through 7.4.5 for the modeling assessments. The preliminary modeling analysis was conducted to determine: (1) whether or not preconstruction monitoring is required; (2) if further modeling from a full impact analysis is applicable; and (3) to define the impact area within which a full impact analysis must be carried out. The preliminary analysis compares the maximum impacts at worst-case operating scenarios with the modeling significant impact levels and the thresholds triggering preconstruction monitoring. If the monitoring thresholds are exceeded, preconstruction monitoring is required for that pollutant and averaging period. If the modeling significant impact level is exceeded, a full impact analysis for that pollutant and averaging period is required.

7.2.2 For the preliminary analysis, worst-case operating conditions were identified by evaluating CIP1 and CIP2 at 25% load to 100% peak load combined with BSG1 and BSG2 operating at 100% load. The ISC_RTDM program was used to predict maximum impacts in simple and complex terrain for the various operating conditions using coarse grid receptors in 250 meter increments. Fine grid receptors for simple terrain in 50 meter spacing and fine grid receptors for complex terrain in 25 meter spacing were added to areas of maximum impacts to ensure that the maximum impact was located. Maximum impacts after fine grid placement were compared to the modeling and monitoring thresholds.

7.2.3 Maximum project impacts from the preliminary modeling analysis are shown below for the 135 MW combustion turbine generators combined with operation of the black start diesel engine generators. The impacts are shown in comparison to the thresholds triggering preconstruction monitoring. Results show no exceedence of the monitoring thresholds for SO_2, CO, PM, PM_{10}, NO_2, and Be. As such, preconstruction monitoring is not required for these pollutants. Because VOC emissions for the proposed generating station are above

100 TPY, preconstruction monitoring is required for ozone (O_3). For preconstruction monitoring of ozone, the Department concurs with the use of O_3 concentrations measured at its Sand Island monitoring station to satisfy the monitoring requirements of HAR, §11-60.1-143 and 40 CFR §52.21(m).

MAXIMUM IMPACTS AND AMBIENT AIR MONITORING THRESHOLDS				
Pollutant	Averaging Period	[a]Maximum Impact (ug/m^3)	[b]Monitoring Level (ug/m^3)	Percent Threshold
SO_2	24 hour	11.6	13	89
PM (see note c)	24 hour	2.40	10	24
PM_{10}	24 hour	2.30	10	23
NO_2	Annual	0.391	14	3
CO	8 hour	27.0	575	5
Beryllium (see note d)	24- hour	4.98E-06	0.001	<1
O_3	see note e	---------	see note e	---------

a: Impacts are from operation of CIP1, CIP2, BSG1, and BSG2.
b: Air monitoring threshold listed in HAR, §11-60.1-133(e)(1) and New Source Review Workshop Manual, Table C-3, Page C.17.
c: PM impacts factored from PM_{10} impacts based on information from AP-42 that 96% of the total particulate is PM_{10}.
d: Beryllium impacts factored from SO_2 impacts based on g/s emission rate of pollutants as follows:

Be impact = $11.6\ (2.85 \times 10^{-5}/66.447) = 4.98 \times 10^{-6}$

e: No significant air quality concentration for ozone has been established. Instead, any net emissions increase of 100 tons per year of VOC requires an ambient impact analysis that includes pre-application monitoring data.

7.2.4 Maximum project impacts from the preliminary analysis are shown below for the combustion turbine generators combined with operation of the black start diesel engine generators in comparison to the modeling significant thresholds for Class II areas. Results indicate that the maximum impacts were above the 3-hour and 24-hour SO_2 significant impact levels. As such, a full impact modeling analysis is required for SO_2 for the 3-hour and 24-hour averaging periods (see Paragraphs 7.1 and 7.3.1 through 7.3.5). As per the New Source Review Workshop Manual (Page C.27), ambient air concentrations of the remaining pollutants that are below the air quality significant levels require no further modeling to determine compliance with state and federal ambient air quality standards or PSD Class II increment for that pollutant and averaging period. Also, because VOC emissions are greater than 100 TPY, a full ambient air quality impact analysis (AAQIA) is required for O_3 (see Paragraph 7.3.5).

MAXIMUM IMPACTS AND MODELING SIGNIFICANT LEVELS				
Pollutant	Averaging Period	[a]Maximum Impacts (ug/m^3)	[b]Modeling Significant Levels Class II Area (ug/m^3)	Percent Threshold
SO_2	3 hour 24 hour Annual	65.8 11.6 0.830	25 5 1	> 100 > 100 83
PM[c]	24 hour Annual	2.40 0.280	5 1	48 28
PM-10	24 hour Annual	2.30 0.269	5 1	46 27
NO_X	Annual	0.391	1	39
CO	1 hour 8 hour	197 27.0	2,000 500	10 5
O_3	see note (d)	---------	see note (d)	see note (d)

a: Impacts are from operation of CIP1, CIP2, BSG1, and BSG2.
b: Modeling Significant Level listed in New Source Review Workshop Manual, Table C-4, Page C.28.
c: PM emissions factored from PM_{10} emissions based on information from AP-42 that 96% of the total particulate is PM_{10}.
d: No significant ambient impact concentration has been established. Instead, any net emissions increase of 100 tons per year of VOC requires an ambient impact analysis. Because emissions are greater than 100 TPY VOC from this project, a full impact analysis for ozone is required.

7.2.5 For $PM_{2.5}$, Jim Clary & Associates indicated that EPA has not yet developed modeling techniques specific to the national ambient air quality standards for particulate matter smaller than 2.5 microns ($PM_{2.5}$). Also, to address the New Source Review (NSR) requirements while modeling techniques are being developed, EPA issued the memo "Interim Implementation of New Source Review Requirements for $PM_{2.5}$" dated October 21, 1997. EPA's memo states:

"It is administratively impracticable at this time to require sources and state permitting authorities to attempt to implement PSD permitting for $PM_{2.5}$. The EPA has projects underway that will address the current technical and informational deficiencies. Until these deficiencies are corrected, EPA believes that sources should continue to meet PSD and NSR program requirements for controlling PM_{10} air quality. Meeting these measures in the interim will serve as a surrogate approach for reducing $PM_{2.5}$ emissions and protecting air quality."

It was indicated that the Environmental Appeals Board affirmed the use of PM_{10} as a surrogate for $PM_{2.5}$ in its order denying review of PSD Appeal No 05-05, decided August 24, 2006. Therefore, according to this guidance, the proposed project will not significantly change the current $PM_{2.5}$ levels.

7.3.1 A full air dispersion modeling impact analysis was performed for the 3-hour and 24-hour SO_2 averaging periods that indicate a significant ambient air quality impact as shown in Paragraph 7.2.4. The full impact analysis expands the preliminary analysis with further modeling that includes additional emissions from existing sources combined with CIP1, CIP2, BSG1, and BSG2 to determine compliance with the state and federal ambient air quality standards and PSD Class II increments. As indicated in the application, downwash effects from existing structures were considered negligible due to the distance and elevation of the significant impact area. As such, building dimensions from existing Campbell Industrial Park structures were not provided for the full impact analysis.

7.3.2 For the full impact air dispersion modeling analysis to determine short-term SO_2 impacts, the impact area was that with maximum impacts above the modeling significant levels. The area of impact for the full air dispersion modeling analysis was defined with significant impact level isopleths for SO_2 of 5 μg/m^3 and 25 μg/m^3 for the 24-hour and 3-hour modeling significant levels, respectively. The isopleths defined the maximum radius of impact to be within a 12.5 kilometer and 14.3 kilometer radius from the generating station for the 24-hour and 3-hour averages, respectively. As such, an impact area with a radius of 14.3 kilometers from the Campbell Industrial Park Generating Station defines the significant impact area for the full impact analysis. Increment-affecting sources located within 50 kilometers of the impact area must be included in the increment inventory if the sources individually or collectively affect the amount of PSD increment consumed.

7.3.3 The full impact analysis used ISC_RTDM to determine compliance with state and federal ambient air quality standards for the 3-hour and 24-hour SO_2 impacts. Short-term highest second high SO_2 impacts for CIP1, CIP2, BSG1, and BSG2 combined with operation of existing Campbell Industrial Park sources were determined inside the significant impact area. Pursuant to HAR §11-59-4 and 40 CFR, Part 51, Appendix W, Paragraph 8.2.1, selection of the highest second high SO_2 concentration is allowed because short-term limiting concentrations are not to be exceeded more than once in any calendar year. A CTDMPLUS model was used for HECO's Kahe Generating Station to determine short-term SO_2 impacts with onsite meteorological data that is more representative than that from Campbell Industrial Park. The Kahe Generating Station, located west of the proposed project, was considered a source that may individually affect air impacts within the project's significant impact area. The maximum impact from the Kahe Generating Station, based on emissions from all sources at the plant, was determined separately and added to the ISC_RTDM results. Air impacts from the Kahe Generating Station were added to determine the total impact. Results from the full impact analysis, shown below, indicate compliance with state and federal ambient air quality standards for SO_2.

MAXIMUM IMPACTS COMPARED TO STATE AND FEDERAL AIR STANDARDS

Pollutant	Averaging Period	Maximum Impacts (μg/m^3)				Air Standard (ug/m^3)	Percent Standard
		[a]CIP	Kahe	Background	Total		
SO_2	3 hour	321	539	46	906	1,300	70
	24 hour	78	139	15	232	365	64

a: Impacts are from operation of CIP1, CIP2, BSG1, and BSG2 combined with operation of existing CIP sources.

7.3.4 The full impact analysis used ISC_RTDM to determine compliance with ambient air increments for SO_2. Conservatively, for PSD increment consumption, the analysis did not take credit for any baseline emissions from the existing Campbell Industrial Park sources. Short-term highest second high SO_2 impacts for CIP1, CIP2, BSG1, and BSG2 combined with operation of existing Campbell Industrial Park sources in the significant impact area were determined. Pursuant to HAR §11-60.1-134, for any period other than an annual period, the applicable maximum allowable increase may be exceeded during one such period per year at any one location. HECO's Kahe Generating Station, located west of the proposed project, was considered a source that may individually affect the amount of PSD increment consumed. A CTDMPLUS model was used for HECO's Kahe Generating Station to determine SO_2 impacts. Short-term first highest high SO_2 impacts from the Kahe Generating Station were added to the ISC_RTDM results to determine the total impact. Only increment consuming sources were considered (142 MW boiler unit 6, 2.5 MW black start diesel engine generator unit A, and 2.5 MW black start diesel engine generator unit B). Results from the full impact analysis, shown below, indicate compliance with PSD Class II increments for SO_2.

MAXIMUM IMPACTS AND PSD CLASS II INCREMENTS						
Pollutant	Averaging Period	Maximum Impacts (μg/m^3)			Class II Increment (μg/m^3)	Percent Increment
		[a]CIP	Kahe	Total		
SO_2	3 hour 24 hour	321 78	109 4	430 83	512 91	84 91

a: Impacts are from operation of CIP1, CIP2, BSG1, and BSG2 combined with operation of existing CIP sources.

7.3.5 An AAQIA for ozone is required because VOC emissions potentially exceed 100 TPY. EPA has not yet developed modeling techniques specific to the 8-hour ozone national ambient air quality standards. Therefore, the Texas Commission on Environmental Quality's 1-hour ozone screening technique was used as a surrogate for the 8-hour ozone standard PSD review. The Environmental Appeals Board affirmed the use of a 1-hour ozone impact analysis as a surrogate for the 8-hour ozone analysis in its order denying review of PSD Appeal No. 05-05, decided August 24, 2006. The procedure found the site to be NO_X dominated and there should not be a significant change to the current ozone levels in the local area. The project was demonstrated to be NO_X dominated as follows:

1) Calendar year 2004 air monitoring data from the Department's Sand Island monitoring station was used to determine if the ozone screening technique could be applied. The maximum background concentration is 110 ug/m^3 or (110 ug/m^3)(0.02404/molecular weight of 48) = 5.509×10^{-2} ppm or (5.509×10^{-2} ($10^9/10^6$) = 55 ppb.

2) The non methane organic carbon (NMOC)/NO_X ratio was determined based on estimated annual emissions that assume permit limits (see table from Paragraph 6.4).

$$NMOC/NO_X = 336 \text{ tpy NMOC}/2{,}096 \text{ tpy } NO_X = 0.16$$

3) The ratio was multiplied by 2.875 to determine whether the site is NO_X dominated.

$$(0.16)(2.875) = 0.5$$

4) Because the adjusted ratio is less than 2:1, the site is NO_X dominated and the demonstration is complete because there should not be a significant change to the current ozone levels in the local area.

7.4.1 An air modeling assessment using ISC_RTDM was conducted for CIP1, CIP2, BSG1, and BSG2 to determine compliance with standards specified in HAR §11-60.1-179 for non-carcinogenic and carcinogenic HAPs. For the modeling assessment, a 1 g/s emissions rate was proportioned among CIP1, CIP2, BSG1, and BSG2 with various maximum MMBtu/hr firing rates. The model output for the 8-hour and annual averaging period was multiplied by the total combined g/s emission rate for CIP1, CIP2, BSG1, and BSG2. Adjustment to the g/s emission rate was made to account for a 500 hr/yr limit on BSG1 and BSG2 for the annual averaging period. A 24.8 x 10^6 MMBtu/yr firing limit was accounted for in the g/s emission rate for CIP1 and CIP2 for the annual averaging period.

7.4.2 The predicted concentrations in the table below show that emission impacts from CIP1, CIP2, BSG1, and BSG2 are below the significant ambient air concentration for the 8-hour averaging period for each non-carcinogenic HAP. The time limited value-time weighted average (TLV-TWA) values were obtained from the worst-case concentration threshold among those listed in "Documentation of the Threshold Limit Values and Biological Exposure Indices, Sixth Edition", published by the American Conference of Governmental Hygienist (ACGIH) and the "2005 Guide to Occupational Exposure Values" compiled by the ACGIH. Maximum 8-hour model output was 0.212 µg/m^3per g/s.

COMPARISON OF 1/100 TLV-TWA TO 8-HOUR CONCENTRATION				
Pollutant	TLV-TWA (µg/m^3)	8-hour Impact (µg/m^3)	1/100 TLV-TWA (µg/m^3)	Percent Standard
Acrolein	230	6.29E-04	2.3	< 1
Lead	50	1.12E-03	0.5	< 1
Manganese	200	6.34E-02	2	3
Mercury	10	9.63E-05	0.1	< 1
Naphthalene	52,000	2.88E-03	520	< 1
Selenium	200	2.00E-03	2	< 1
Toluene	188,000	2.25E-02	1,880	< 1
Xylene	434,000	1.60E-02	4,340	< 1

7.4.3 The predicted concentrations in the table below show that emission impacts from CIP1, CIP2, BSG1, and BSG2 are below the significant ambient air concentration for the annual averaging period for each non-carcinogenic HAP. The TLV-TWA values were obtained from the worst-case concentration threshold among those listed in "Documentation of the Threshold Limit Values and Biological Exposure Indices, Sixth Edition" and the "2005 Guide to Occupational Exposure Values." Maximum annual model output was 0.00745 µg/m^{3}per g/s.

COMPARISON OF 1/420 TLV-TWA TO ANNUAL CONCENTRATION				
Pollutant	TLV-TWA (µg/m^3)	Annual Impact (µg/m^3)	1/420 TLV-TWA (µg/m^3)	Percent Standard
Acrolein	230	2.21E-05	0.548	< 1
Lead	50	3.73E-05	0.119	< 1
Manganese	200	2.11E-03	0.476	< 1
Mercury	10	3.20E-06	2.38E-02	< 1
Naphthalene	52,000	9.33E-05	124	< 1
Selenium	200	6.66E-05	0.476	< 1
Toluene	188,000	7.48E-04	448	< 1
Xylene	434,000	5.13E-04	1,033	< 1

7.4.4 An ambient air screening analysis in the table below shows that pollutant emissions from CIP1 CIP2, BSG1, and BSG2 are below the individual lifetime cancer risk of more than ten in one million assuming continuous exposure for seventy years as defined in HAR 11-60.1, Subchapter 9 for carcinogenic hazardous air pollutants. For the analysis, the ambient annual air concentration was compared to the Preliminary Remediation Goals (PRG) concentration. The 2004 Region 9 PRG table was used for the analysis which combines EPA toxicity values with "standard" exposure factors to estimate the risk to inhalation exposure to the carcinogenic hazardous air contaminant. The toxicity values are protective of humans, including sensitive groups, over a lifetime. Maximum annual model output was 0.00745 µg/m^{3}per g/s.

Ambient Air Screening Analysis Ratio of Annual Ambient Air Concentration to PRG Concentration						
Pollutant	Annual Impact (µg/m^3)	Ambient Air PRG (µg/m^3)	Cancer Risk[a]		Risk Standard	Percent Risk Standard
1,3-Butadiene	4.59E-05	6.1E-02	7.52E-10		---------	---------
Acetaldehyde	6.72E-05	8.7E-01	7.72E-11		---------	---------
Arsenic	2.93E-05	4.5E-04	6.51E-08		---------	--------
Benzene	1.48E-04	2.5E-01	5.92E-10		----------	---------
Beryllium	4.06E-07	8.0E-04	5.08E-10		----------	---------
Cadmium	1.28E-05	1.1E-03	1.16E-08		---------	---------
Chromium	2.93E-05	2.3E-05	1.27E-06		---------	---------
Formaldehyde	7.46E-04	1.5E-01	4.97E-09		---------	---------
Polycyclic Organic Matter[b]	1.07E-04	9.2E-04	1.16E-07		---------	---------
[a]Total---------->			1.47E-06		1E-05	15

a: Risk = [($conc_X/PRG_X$) + ($conc_Y/PRG_Y$) ($conc_Z/PRG_Z$) + ·····] x 10^{-6}.
b: PRG based on that for benzo[a]pyrene as worst-case polycyclic organic matter pollutant.

7.4.5 Because sulfuric acid mist exceeds significant emission levels, H_2SO_4 impacts were evaluated to determine compliance with air thresholds. Sulfuric acid mist is not among the 188 chemicals regulated under the Clean Air Act as a HAP and no federal or Hawaii State ambient air quality standards are specified for this pollutant. There are also no monitoring, modeling, or PSD increment thresholds specified for H_2SO_4. As such, the 24-hour California Ambient Air Quality Standard (CAAQS) for sulfates of 25 ug/m^3 was used to evaluate short term impacts. The maximum 8-hour impacts were used for comparison to the short-term CAAQS so that additional modeling runs would not have to be performed to determine 24-hour impacts specifically. Comparison of eight hour impacts to the 24-hour standard is conservative because the 8-hour impacts will be equal to or greater than actual 24-hour impacts. For evaluating annual impacts, the inhalation reference exposure level of 1 ug/m^3 for sulfuric acid, that is a "present all the time" threshold, was used. The 8-hour ISC_RTDM model output was 0.212 µg/m^{3}per g/s. The maximum annual ISC_RTDM model output for modeling CIPI, CIP2, and BSGI, and BSG2 together was 0.00745 µg/m^{3}per g/s. Results listed in the tables below show that 8-hour and annual impacts do not exceed air thresholds provided by HEER Branch toxicologist for H_2SO_4.

Pollutant	24 Hour Standard (ug/m^3)	8 Hour Impact (ug/m^3)	Percent Standard
H_2SO_4	25	2.85	11

Pollutant	Annual Standard (ug/m^3)	Annual Impact (ug/m^3)	Percent Standard
H_2SO_4	1	0.104	10

8. Class I Area Impact Analysis

8.1 A Class I area impact analysis is required for sources that would adversely affect the air quality related values (AQRVs) inside a Class I area. HECO has requested an exemption from the National Park Service for conducting an AQRV analysis because of the project's small impact due to its distance from the nearest national park. The nearest Class I area is Haleakala National Park which is 226 kilometers from the proposed Campbell Industrial Park Generating Station.

9. Additional Impact Analysis

9.1 It was stated that the generating station will accommodate planned normal economic growth and population growth on the island. Also, there will be little or no additional industrial, commercial, or residential growth as a result of the project. Therefore, it was concluded that no appreciable secondary air quality impacts are expected as a result of the generating station's operation. It was indicated that due to the higher efficiency of the proposed units for the generating station, there may be improvements in air quality because, in some portions of the island, less fuel efficient generating units may be retired or operated less.

9.2 The impacts on soils and vegetation were addressed in the application. Soils in the area of the proposed generating station were described as those from the Lualualei series that consist of well-drained soils on the coastal plains. Stated use of the soil is for sugarcane, truck crops, pasture, wildlife habitat, urban development, and military installations. The natural vegetation in area of the generating station was indicated to consist of Kiawe, Koa Haole, Bristly Foxtail, Uhaloa, and Finger Grass. Because air modeling assessments found maximum concentrations of SO_2, CO, NO_2, and PM/PM_{10} to be in compliance with the secondary ambient air quality standards established to prevent adverse impacts to the public and on vegetation, it was concluded that no adverse impacts on vegetation are expected to occur from the project. It was stated that due to area conditions, the quantities of particulate, sulfate, and nitrate that may be added to the soil and assimilated into the soil-plant system would be insignificant compared with those normally present in the soil or transported to the soil-plant environment via water or winds from the surroundings. It was concluded that soils in the area of influence of the proposed generating plant will not be adversely affected by the generating station's operation.

9.3 HECO sent a letter to the United States Department of Interior, Fish and Wildlife Service regarding the project's potential to impact endangered or threatened plants or animals. The Fish and Wildlife Service in their response determined that the proposed Campbell Industrial Park Generating Station will not affect federally listed threatened or endangered species. In addition, it was stated that there is no critical habitat in the project area.

10. Significant Permit Conditions

10.1 Except as provided in special conditions for use of alternate fuels and the firing of fuel oil No. 2 with maximum sulfur content of 0.35% by weight, CIP1 and CIP2 shall be fired on naphtha or fuel oil No. 2 with a maximum sulfur content not to exceed 0.05% by weight.

Reason for 10.1: This condition is required as part of BACT for SO_2. An allowance was provided to burn fuel oil No. 2 with as much as 0.35% by weight sulfur content and use alternate fuels to provide flexibility for operation because long term availability and economic impacts for firing the low sulfur fuels are uncertain.

10.2 CIP1 and CIP2 may be fired on fuel oil No. 2 with maximum sulfur content of 0.35% by weight after approval by the Department of Health if it can be shown that the 0.05% or lower maximum sulfur content fuels can be eliminated as BACT.

Reason for 10.2: This condition was incorporated, as requested by the applicant, to allow the firing of fuel oil No. 2 with up to 0.35% by weight sulfur content if the 0.05% sulfur content fuels are not available in sufficient amount to support the generating station or there are unacceptable economic impacts for firing the low sulfur content fuel. Air modeling assessments of CIP1, CIP2, BSG1, and BSG2 show compliance with state and federal air quality standards as well as PSD Class II increments for SO_2 based on operation of CIP1 and CIP2 at ISO standard day conditions and firing fuel oil No. 2 with a maximum sulfur content of 0.35% by weight.

10.3 BSG1 and BSG2 shall be fired only on fuel oil No. 2 with a maximum sulfur content not to exceed 0.4% by weight.

Reason for 10.3: The fuel sulfur content limit was proposed by the applicant and used in the modeling assessment to show compliance with the applicable thresholds.

10.4 The total combined fuel firing rate of all fuels fired by CIP1 and CIP2 shall not exceed 24.8 x 10^6 MMBtu in any rolling twelve-month (12-month) period based on the higher heating value (HHV) in Btu/lb determined for each fuel and the pounds of fuel fired.

Reason for 10.4: This condition is required to prevent the facility from triggering the major source threshold of any single HAP of 10 TPY for manganese worst-case.

10.5 The total operating hours of BSG1 shall not exceed 500 hours in any rolling twelve-month (12-month) period.

10.6 The total operating hours of BSG2 shall not exceed 500 hours in any rolling twelve-month (12-month) period.

Reason for 10.5 and 10.6: The hour limits were proposed by the applicant and used in the modeling assessment to show compliance with the applicable thresholds.

10.7 Impose limits on combustion turbine generator startup and shutdown.

Reason for 10.7: The condition is required to limit excessive emissions that occur at lower operation loads such as those for NO_X that result because the water injection is not operating during startup and shutdown sequences.

10.8 Impose minimum water-to-fuel mass ratio limits for the water injection systems.

Reason for 10.8: This condition is required to ensure maximum NO_X emissions control from the water injection system.

10.9 Impose maximum emissions limits as guaranteed by the manufacturer on NO_X, SO_2, PM/PM_{10}, CO, and VOCs for operation of the combustion turbines with water injection for firing naphtha and fuel oil No. 2.

Reason for 10.9: This condition is required in accordance with the BACT analysis.

10.10 Incorporate NSPS, Subpart KKKK regulations for CIP1 and CIP2.

Reason for 10.10: Subpart KKKK is applicable as determined in Paragraph 2.2. As part of the federal regulations, conditions were incorporated to require a CMS for monitoring the fuel to water ratio for proper NO_X control and CEMS to record the rolling average NO_x emissions. Subpart KKKK requires either a CMS to record water injection parameters or a CEMS to monitor NO_X emissions. For monitoring the fuel to water ratio, Subpart KKKK states that any unit operating hour in which no water or steam is injected into the turbine shall be considered an excess emission. Although the applicant requests as much as a 60 minute startup time for the combustion turbine generators without water injection, Subpart KKKK requirements are still met because a CEMS will be used to monitor NO_X emissions for all periods of operation, including startup, shutdown, and malfunction. As such, excess emissions reporting for the CMS servicing water injection is not applicable during periods of startup and shutdown. The Department is requiring continuous monitoring of the fuel to water ratio to minimize NO_x emissions while a CEMS is used to ensure the NO_x emission limits are not exceeded.

10.11 Incorporate NSPS, Subpart Kb regulations for Tank Nos. 1 and 2.

Reason for 10.11: Required as determined in Paragraph 2.4.

11. Conclusion and Recommendation

11.1 Actual emissions from the proposed Campbell Industrial Park Generating Station should be less than those estimated. Maximum potential emissions were based on operating the combustion turbine generators at ISO standard day conditions (59 ^{o}F and 60% relative humidity). Emissions determined for operation at 86 ^{o}F and 70% relative humidity, that may be more representative of conditions in Hawaii, are lower than those for ISO standard day conditions due to a lower combustion turbine generator fuel burning capacity at the higher ambient temperature and relative humidity. Conservatively, emissions from the black start diesel engine generators were based on operation at maximum rated capacity. Air modeling assessments for the combustion turbine generators operating with the black start diesel engine generators show compliance with the state and federal air quality standards and PSD Class II increment thresholds based on the higher emission rates at ISO standard day conditions and maximum unit capacities. Recommend issuance of the covered source permit subject to the significant permit conditions, a public hearing, the thirty day public comment period, and forty-five day EPA review period.

David Wong

Mike Madsen

August 11, 2006