PROPOSED

PERMIT APPLICATION REVIEW
COVERED SOURCE PERMIT (CSP) NO. 0548-01-C
APPLICATION FOR MODIFICATION NO. 0548-04

Company: Hawaiian Electric Company, Inc. (HECO)
Facility: Campbell Industrial Park Generating Station
Located at: 91-196 Hanua Street, Kapolei, Oahu

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

Contact: Ms. Karin Kimura
Company: HECO
Title: Senior Environmental Scientist
Phone: (808) 543-4522

Equipment:

Equipment	Manufacturer	Model No.	Serial No.	Capacity
Combustion Turbine Generator (CIP1)	Siemens Westinghouse Power Corporation	SGT6-3000E W501D5A	37A7724	135 MW
Combustion Turbine Generator (CIP2)	Siemens Westinghouse Power Corporation	SGT6-3000E W501D5A	Not Available	135 MW
Black Start Diesel Engine Generator (BSG1)	Kohler Power Systems Detroit Diesel/MTU	2250REOZDC 16V4000G83	5272003082	2,250 kW
Black Start Diesel Engine Generator (BSG2)	Kohler Power Systems Detroit Diesel/MTU	2250REOZDC 16V4000G83	5272003325	2,250 kW
Internal Floating Roof Storage Tank (Tank No. 1)	-------------------	------------------	------------------	1,880,000 gallons
Internal Floating Roof Storage Tank (Tank No. 2)	-------------------	------------------	------------------	1,880,000 gallons

1. Background.

1.1 HECO has submitted a permit application for a significant modification to CSP No. 0548-01-C for Campbell Industrial Park Generating Station for firing the combustion turbine generators on biodiesel as a primary fuel instead of naphtha or fuel oil No. 2. Permitted equipment for the facility includes two 135 MW Siemens Westinghouse Power Corporation simple cycle combustion turbine generators (CIP1 and CIP2), two 2,250 kW Kohler Power Systems black start diesel engine generators (BSG1 and BSG2), and two internal floating roof storage tanks. The Standard Industrial Classification Code for this facility is 4911 (Electrical Power Generation Through Combustion of Fossil Fuels). Changes incorporated into the permit pursuant to HECO's application for modification include:

a. A revision to the alternate operating scenario for alternate fuels that allows the Department to specify the minimum combustion turbine generator water-to-fuel ratios upon its approval of the use of an alternate fuel. Minimum water-to-fuel ratios are specified in the permit for controlling NO_X emissions with water injection based on manufacturer's recommendations for firing fuel oil No. 2 and naphtha. Preliminary results from test burns conducted on an SGT6-3000E combustion turbine showed that the CO emissions limits when firing biodiesel would not likely be met with the current water-to-fuel ratios specified for firing the combustion turbine generators on fuel oil No. 2 and naphtha.

b. Add provisions to allow the combustion turbine generators to operate at load levels greater than 10 megawatts above minimum operating load and below minimum operating load during maintenance and testing activities.

c. Specify that the applicable water-to-fuel ratio for operating hours where multiple standards apply is determined based on the condition that corresponded to the lowest water-to-fuel ratio.

1.2 Fuels fired at the generating station will be boidiesel as primary fuel for CIP1 and CIP2 and fuel oil No. 2 for BSG1 and BSG2. The sulfur content of the primary fuels fired by CIP1 and CIP2 will be limited to 0.05%. The sulfur content of fuel fired by BSG1 and BSG2 will be a low sulfur fuel in accordance with 40 CFR, Part 60, Subpart IIII.

1.3 Operating limits include a 24.8 x 10^6 MMBtu/yr total combined firing rate restriction for CIP1 and CIP2 and a 500 hr/yr operating restriction for BSG1 and BSG2.

1.4 HECO disclosed the following information:

a. The minimum operating load is determined by tuning the combustion turbine generator to identify the minimum load at which NO_X and CO emission limits and the minimum water-to-fuel ratio for the corresponding load can be met. Therefore, the minimum operating load in megawatts will vary with adjustments to the permitted water-to-fuel ratios and is likely to differ for alternate fuels.

b. For Attachment IIA, Special Condition A.3 of the permit, steam units at other plants include the following HECO boilers: Kahe Generating Station Units 1, 2, 3, 4, 5, and 6, Honolulu Generating Station Units 8 and 9, and Waiau Generating Station Units 3, 4, 5, 6, 7, and 8.

c. The combustion turbine generator base load is the maximum load of the unit at ambient temperatures.

d. The combustion turbine generator peak load is the maximum load of the unit at International Organization for Standardization (ISO) standard day conditions (59 ^oF, 60% relative humidity, and 1 atm).

2. Applicable Requirements.

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 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 CFR Part 60 - NSPS, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines is applicable to CIP1 and CIP2 because the heat input rate of the units at peak load is greater than 10 MMBtu/hr. Maximum heat input at peak load is 1,482.4 MMBtu/hr based on ISO standard day conditions (59 ^{O}F, 60% relative humidity, and 1 atm) and the HHV for fuel oil No. 2 as worst-case.

2.3 40 CFR Part 60 - NSPS, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines is applicable to BSG1 and BSG2 because the units were ordered after July 11, 2005 and manufactured after April 1, 2006.

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 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 1,880,000 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 ^{o}F.

2.5 40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants (NESHAP), 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. The total combined fuel firing rate for CIP1 and CIP2 is limited to 24.8 x 10^6 MMBtu/hr to restrict HAP emissions of manganese below the major source threshold of 10 TPY for any single HAP as worst-case scenario.

2.6 40 CFR Part 63 - (NESHAP), Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines is applicable to BSG1 and

BSG2 because the units are located at an area source of HAP emissions and the units were ordered after June 12, 2006. Pursuant to 40 CFR §63.6590 (c), new stationary reciprocating internal combustion engines (RICE) operating at area sources must meet the requirements of 40 CFR, Part 63, Subpart ZZZZ by meeting the requirements of 40 CFR, Part 60, Subpart IIII.

2.7 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.

2.8 A best available control technology (BACT) analysis is not required because potential emissions from changes proposed for the permit modification do not cause and increase in emissions.

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	701.0	≥250	≥100
PM-2.5	657.2	≥250	≥100
SO_2	4,403.8	≥2,500	≥100
NO_x	2,084.7	≥2,500	≥100
VOC	346.0	≥250	≥100
CO	3,521.5	≥2,500	≥1,000

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

2.10 Prevention of Significant Deterioration (PSD) review does not apply to this modification because changes proposed do not increase emissions above significant levels as defined in HAR, Section 11- 60.1.

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. One 5,000 gallon fuel oil No. 2 storage tank and other tanks less than 40,000 gallons in capacity are considered exempt pursuant to HAR, §11-60.1-82(f)(1).

c. A vapor mitigation system is considered exempt in accordance with HAR, §11-60.1-82(f)(7).

d. 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).

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

f. 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).

g. 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 are alternate operating scenarios proposed by the applicant:

a. Upon receiving written approval from the Department of Health, the permittee may operate CIP1 and CIP2 greater than 10 megawatts of the minimum operating load or below minimum operating load for maintenance and testing activities.

b. The permittee may operate CIP1 and CIP2 up to 110% of peak load for emergency load conditions, if equipment malfunction such as a sudden loss of a unit occurs. The time period of this operation shall not exceed 30 minutes in duration, and shall not exceed the maximum permitted emission limits. The reason for operating above peak load shall be clearly documented, with the event's date, time, duration, operating load, and resulting emission rates.

c. Upon receiving written approval from the Department of Health, CIP1 and CIP2 may be fired on fuel oil No. 2 with a maximum 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 based on fuel availability and/or economic impacts.

d. Upon receiving written approval from the Department of Health, CIP1 and CIP2 may be fired on alternate fuels (e.g., but not limited to, biodiesel, jet fuel, hydrogen, or ethanol instead of naphtha and fuel oil No. 2).

e. Upon receiving written approval from the Department of Health, the permittee may use specific fuel additives to control algae, lubricity, improve combustion, inhibit corrosion or other reasons.

f. Upon receiving written approval from the Department of Health, the permittee may replace CIP1, CIP2, BSG1, or BSG2 with an equivalent temporary replacement unit with equal or lesser emissions in the event of a failure or major overhaul of the equipment.

5. Air Pollution Control

5.1 Water injection will be used to control NO_X emissions from the combustion turbine generators. 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 for storing volatile organic liquid with high vapor pressure (e.g., naphtha). However, the tanks will be storing boidiesel with a low vapor pressure because HECO intends to fire the combustion turbine generators on biodiesel as the primary fuel.

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 for firing fuel oil No. 2 with 0.35% sulfur content as worst-case. 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 24.8×10^6 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 c)	fuel oil #2	83.3	10.5	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 d)	fuel oil #2	75.0	9.5	657.0[b,d]	657.0[b,d]
H_2SO_4	fuel oil #2	52.4	6.6	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 ^{o}F, 60% relative humidity, and firing fuel oil No. 2.
Also, a 24.8×10^6 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 ^{o}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 0.05% fuel sulfur content and a 163.7 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 22.9 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	1.153	0.146	0.6	10.5
NO_X	39.457	4.982	19.7	345.1
CO	5.187	0.655	2.6	45.6
VOC	0.660	0.083	0.3	5.3
PM	0.358	0.045	0.2	3.5
PM_{10} (see note a)	0.344	0.043	0.2	3.0
$PM_{2.5}$ (see note b)	0.322	0.040	0.2	2.8
H_2SO_4	0.159	0.201	0.1	1.4
Fluorides	2.00E-04	2.53E-05	1.00E-04	1.75E-03
Arsenic	2.52E-04	3.18E-05	1.26E-04	2.21E-03
Benzene	1.78E-02	2.24E-03	8.89E-03	0.156
Beryllium	3.46E-06	4.37E-07	1.73E-06	3.03E-05
Lead	3.21E-04	4.05E-05	1.60E-04	2.80E-03
Mercury	2.75E-05	3.47E-06	1.37E-05	2.40E-04
Manganese (max. single HAP)	1.81E-02	2.28E-03	9.05E-03	0.159
Total Haps	--------	--------	0.030	0.526

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 60 tank turnovers per year for each of the two storage tanks. The total combined gallon per year 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 the tanks to determine maximum potential HAP emissions. The vapor mass fraction data was obtained from Chevron Products Company's permit application submittal for its Port Allen Terminal that was 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	5.1	5.1	10.2
Hexane (n) [max. single HAP]	0.083	0.083	0.166
HAPs	0.194	0.194	0.388

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	0.6	10.5	-------	4,403.8	4,620.5
NO_X	2,065.0	2,162.6	19.7	345.1	-------	2,084.7	2,507.7
CO	3,518.9	3,518.9	2.6	45.6	-------	3,521.5	3,564.5
VOC	335.5	335.5	0.3	5.3	10.2	346.0	351.0
PM	730.0	730.0	0.2	3.5	-------	730.2	733.5
PM_{10}	700.8	700.8	0.2	3.0	-------	701.0	703.8
$PM_{2.5}$	657.0	657.0	0.2	2.8	-------	657.2	659.8
Manganese (max. single HAP)	9.8	10.3	9.05E-03	0.159	-------	9.81	10.5
Total Haps	22.3	23.3	0.030	0.526	0.388	22.7	24.2

7. Air Quality Assessment

7.1 An ambient air modeling impact analysis is not required because there are no changes proposed for the permit modification that increase emissions.

8. Significant Permit Conditions

8.1 CIP1 and CIP2 are intended to provide spinning reserve by being online and dispatched within 10 MW of the minimum operating load. Except during source performance tests and activities approved by the Department of Health pursuant to Condition 8.2, CIP1 and CIP2 may be dispatched at higher loads only when the steam units at other plants are not reasonably able to serve system needs. Steam units at other plants are HECO boilers: Kahe Generating Station Units 1, 2, 3, 4, 5, and 6, Honolulu Generating Station Units 8 and

9, and Waiau Generating Station Units 3, 4, 5, 6, 7, and 8. The Department of Health reserves the right to review dispatch records to determine compliance with this condition.

8.2 Upon receiving written approval from the Department of Health, the permittee may operate CIP1 and CIP2 greater than 10 megawatts above the minimum operating load or below minimum operating load for maintenance and testing activities.

Reason for 8.1 and 8.2: Existing permit conditions were updated to allow the combustion turbine generators to operate above 10 MW of the minimum operating load or below minimum operating load during maintenance and testing activities. The purpose of Condition 8.1 is ensure the combustion turbine generators are operated in accordance with HECO's proposal from the initial permit application. The BACT analysis determined installation of a heat recovery steam generator for allowing NO_X control with selective catalytic reduction to be economically infeasible. Operation at higher loads would provide a greater economic benefit to promote use of a heat recovery steam generator and SCR a BACT. The economic analysis was based on operating the combustion turbine generators as standby units running at minimum operating load until higher loads are necessary if electric generating units from other plants could not serve system needs. Condition 8.1 was also updated to define steam units at other plants.

8.3 The water injection system for CIP1 and CIP2 shall be used immediately upon completion of the startup sequence, and at all times thereafter when the combustion turbine generators are operating at minimum operating load and above. After completion of the start-up sequence, the minimum water-to-fuel mass ratios shall be maintained on a one-hour average basis in accordance with Condition Nos. 8.3 i and 8.3.ii.

i. When the combustion turbine generators are firing naphtha or fuel oil No. 2, the one-hour average water-to-fuel ratios shall be as follows:

WATER INJECTION SYSTEM MINIMUM WATER-TO-FUEL MASS RATIO		
Load	Load (MW)[a, b]	Ratio (lb water/lb fuel)
peak	135	1.10
base - < peak	116 - < 135	1.00
75% - < base	87 - < 116	1.00
50% - < 75%	58 - < 87	0.95
minimum operating load - < 50%	28 - < 58	0.80

Note a: Peak load is based on rated capacity at ISO standard day conditions (59 °F, 1 atm, and 60% relative humidity).
Note b: Minimum operating load, 50% load, 75% load, and base load are based on operating conditions at 86 °F, 1 atm, and 70% relative humidity.

i. The minimum one-hour average water-to-fuel ratios for firing alternate fuels shall be in accordance with that approved by the Department of Health pursuant to Condition Nos 8.5 and 8.6.

8.4 For operating hours during which multiple water-to-fuel mass ratios apply, the applicable water-to-fuel standard for that hour shall be determined based on the condition that corresponded to the lowest water-to-fuel mass ratio standard.

8.5 Upon receiving written approval from the Department of Health, CIP1 and CIP2 may be fired on alternate fuels (e.g., but not limited to, biodiesel, jet fuel, hydrogen, or ethanol instead of naphtha and fuel oil No. 2).

8.6 In requesting for approval to fire CIP1 and CIP2 on alternate fuels, the permittee shall, at a minimum, provide the Department of Health with information on the type of fuel proposed, reason for using the alternate fuel, emissions data, and the manufacturer's recommended water-to-fuel ratio and minimum operating load for compliance with the emission limits. The Department of Health may require an ambient air quality impact assessment for firing the alternate fuel and/or provide a conditional approval to impose additional monitoring, testing, record keeping, and reporting requirements. The Department of Health may establish minimum water-to-fuel ratio conditions in the permit for firing CIP1 and CIP2 on alternate fuels.

Reason for 8.3 through 8.6: Existing conditions were updated to allow the Department to specify water-to-fuel ratios in a letter when approving the use of alternate fuels for CIP1 and CIP2. Due to the differences in fuel characteristics, existing water-to-fuel ratios specified in the permit will likely cause an exceedance of the CO emission limits if these water-to-fuel ratios are applied to the generating units for firing biodiesel. HECO is also concerned that the water-to-fuel ratio and minimum operating load for meeting emission limits may change among biodiesel suppliers that may use a different biodiesel feed stocks. Therefore, water-to-fuel ratios will be specified by the Department on a case-by-case basis for firing alternate fuels based on the manufacturer's recommended water-to-fuel ratio and minimum operating load as determined from test firing the combustion turbine generators.

9. <u>Conclusion and Recommendation</u>

9.1 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. Recommend issuance of the covered source permit modification subject to the significant permit conditions and forty-five day EPA review period.

Mike Madsen
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