PROPOSED

PERMIT APPLICATION REVIEW
COVERED SOURCE PERMIT (CSP) NO. 0232-01-C
Renewal Application No. 0232-04
Application for Modification No. 0232-03

Applicant: Maui Electric Company, Ltd. (MECO)

Facility: Kahului Generating Station
Location: 200 Hobron Avenue, Kahulul, Maui
UTM – 763,673 Meters East and 2,313,143 Meters North, Zone 4 (Old Hawaiian)

Mailing Address: P.O. Box 398
Kahului, Hawaii 96733

Equipment:

Unit	Description
K-1	5.0 MW (nominal), 94 MMBtu/hr, Combustion Engineering boiler, serial no. 13413, with electric igniters;
K-2	5.0 MW (nominal), 94 MMBtu/hr, Combustion Engineering boiler, serial no. 15345, with total combined 2.5 ft^3/hr capacity gas fired igniters;
K-3	11.5 MW (nominal), 172 MMBtu/hr, Combustion Engineering boiler, serial no. 17343, with total combined 2.5 ft^3/hr capacity gas fired igniters; and
K-4	12.5 MW (nominal), 181 MMBtu/hr, Babcock and Wilcox boiler, serial no. PF13030, with 10 ft^3/hr capacity gas fired igniters.

Responsible Official: Mr. Michael P. Ribao
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Contact: Ms. Sherri-Ann Loo
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1. Background

1.1 HECO has submitted permit applications on behalf of MECO for the renewal and modification of CSP No. 0232-01-C for Kahului Generating Station. The facility is equipped with four (4) boilers sharing the same exhaust stack that operate to generate electricity for the power grid. Three (3) 28,000 barrel vertical fixed roof storage tanks supply fuel oil No. 6 to the boilers. The boilers are also permitted to burn fuel oil No. 2 and specification used oil. The applicant requested that the allowable specification used oil consumption for the boilers be increased from 150,000 gallons per year to 300,000 gallons per year. The applicant also requested an allowance to accept specification used oil from other sources and to add used biodiesel to the list of specification used oil fired by the boilers. The Standard Industrial Classification Code for this facility is 4911 (Electrical Power Generation Through Combustion of Fossil Fuels).

1.2 The Department is currently evaluating best available retrofit technology (BART) applicability for Kahului Generating Station as part of the regional haze rule for regulating sources with the potential to impair visibility in Class I areas. Haleakala National Park on Maui is a Class I area.

2. Applicable Requirements

2.1 Hawaii Administrative Rules (HAR)

- Title 11 Chapter 59, Ambient Air Quality Standards
- Title 11 Chapter 60.1, Air Pollution Control
  - Subchapter 1 – General Requirements
  - 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
  - Subchapter 5 – Covered Sources
  - 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
    - 11-60.1-116 Application Fee Credit for Covered Sources

2.2 40 Code of Federal Regulations (CFR), Part 60 – New Source Performance Standard (NSPS), Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971 is not applicable because the boilers were constructed prior to August 17, 1971.

2.3 40 CFR, Part 60 – NSPS, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978 is not applicable because the boilers are less than 250 MMBtu/hr in capacity and were constructed prior to September 18, 1978.

2.4 40 CFR, Part 60 – NSPS, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units is not applicable to boilers at the facility over 100 MMBtu/hr heat rate input capacity because this equipment was constructed prior to June 19, 1984.

2.5 40 CFR, Part 60 – NSPS, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units is not applicable because the boilers were constructed prior to June 9, 1989.

2.6 The facility is not a major source for hazardous air pollutants (HAPs) and is not subject to National Emissions Standards for Hazardous Air Pollutants (NESHAPS) or Maximum Achievable Control Technology (MACT) requirements under 40 CFR, Parts 61 and 63.

2.7 The change to fire the boilers on used boidiesel as an additional fuel does not subject the boilers to NSPS requirements because the boilers could accommodate the fuel prior to the effective date of the standards. The boilers are already permitted to burn specification used oil and the used boidiesel must meet permit conditions specified for used oil to burn the alternate fuel.

2.8 The change to increase the specification used oil consumption from 150,000 gallons per year to 300,000 gallons per year does not subject the boilers to NSPS requirements because the change does not increase the facility's lb/hr emission rate for any pollutant.

2.9 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 boilers are located at a major source, the CAM regulation is not applicable because the boilers are not subject to an emissions limit or standard as defined in the CAM regulation.

2.10 Prevention of significant deterioration (PSD) review applies to new major stationary sources and major modifications to these types of sources. The facility is grandfathered from the PSD regulations because the boilers were constructed prior to January 6, 1975. Although the applicant proposes a change to fire the boilers on used boidiesel, the facility remains grandfathered from the PSD regulations because the boilers were capable of accommodating the fuel before January 6, 1975. Also, the change to increase the specification used oil consumption for the boilers from 150,000 gallons per year to 300,000 gallons per year does not subject the facility to PSD regulations because the increase in emissions resulting from the change is below major source and significant emissions thresholds as defined in HAR, §11-60.1-131 and §11-60.1-1, respectively.

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

2.12 The consolidated emissions reporting rule (CERR) is applicable because potential emissions from the facility exceed reporting levels pursuant to 40 CFR 51, Subpart A for Type A sources (see table below).

CERR APPLICABILITY			
Pollutant	Facility Emissions	CERR Triggering Levels (TPY)	
		1 year cycle (type A sources)	3 year cycle (type B sources)
PM_{10}	1,206.6	≥ 250	≥ 100
$PM_{2.5}$	687.4	≥ 250	≥ 100
SO_2	4,161.3	≥ 2,500	≥ 100
NO_X	1,472.0	≥ 2,500	≥ 100
VOC	1.5	≥ 250	≥ 100
CO	157.0	≥ 2,500	≥ 1,000

Pb	0.147	---------	≥ 5

2.13 A best available control technology (BACT) analysis is required for new sources or modifications to existing sources that would result in a net emission increase above significant levels as defined in HAR, §11-60.1-1. There are no modifications proposed for this facility that cause an increase in emissions above the significant emission levels. As such, a BACT analysis is not required.

2.14 The facility is not a synthetic minor source because the facility is already a major source with pollutant emissions greater than 100 TPY for any single air pollutant.

3. Insignificant Activities

3.1 Insignificant activities identified by the applicant are as follows:

a. A 400 kW Waukesha black start diesel engine generator is considered an insignificant activity pursuant to HAR §11-60.1-82(f)(7). As indicated by the applicant, the diesel engine does not supply power to the grid and only operates during emergencies to start the boilers when there is a power outage. Also, this diesel engine generator operates on average about 56 hours per year.

b. Three 27,976 barrel fuel oil No. 6 storage tanks are considered insignificant activities pursuant to HAR §11-60.1-82(f)(7) due to the low vapor pressure of the fuel oil No. 6.

c. A 35,300 gallon used lube oil storage tank (Tank No. 5) is an insignificant activity pursuant to HAR §11-60.1-82(f)(1).

d. A 9,492 gallon fuel oil No. 2 storage tank (Tank No. 6) is an insignificant activity pursuant to HAR §11-60.1-82(f)(1).

e. A 460 gallon diesel tank for the black start diesel engine generator is an insignificant activity pursuant to HAR §11-60.1-82(f)(1).

f. A 500 gallon propane tank for boiler igniter fuel is an insignificant activity pursuant to HAR §11-60.1-82(f)(1).

g. 250 gallon tote tank(s) for specification used oil qualify as an insignificant activity pursuant to HAR §11-60.1-82(f)(1).

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

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

j. Other activities that emit less than 500 lb/yr of HAP, 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 will be incorporated into the permit:

a. The permittee may fire the boilers on alternate fuels provided the permittee demonstrates compliance with all applicable state and federal requirements and conditions of this permit.

b. The permittee may use additives that may be blended with fuel to control algae, inhibit corrosion, enhance combustion, etc.

c. The permittee may temporarily replace boilers with an equivalent replacement unit with equal or lesser emissions in the event of failure or major overhaul of the boilers.

5. Air Pollution Controls

5.1 No air pollution controls are proposed for the boilers.

6. Project Emissions

6.1 Boiler emissions of nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds VOCs, particulate matter (PM), particulate matter less than 10 microns in diameter (PM_{10}), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), sulfur dioxide (SO_2), sulfuric acid (H_2SO_4), and hazardous air pollutants (HAPs) were evaluated. The NO_X, CO, VOC, PM, PM_{10}, and $PM_{2.5}$ emissions were based on AP-42 emissions factors from Section 1.3 (9/98), Fuel Oil Combustion. Emission estimates were based on emission factors or firing fuel oil No. 6 as worst-case scenario that were increased by a factor of safety. A mass balance calculation was used to determine SO_2 emissions based on the maximum allowable fuel sulfur content of 2.0% by weight for fuel oil No. 6, a fuel oil No. 6 heating value 18,161 Btu/lb, and each boiler's maximum heat rate input. The H_2SO_4 emission rate was based on the information from source testing that indicated H_2SO_4 emissions are proportional to 13.12% of the SO_2 emission rate. It was assumed that 45% of the total particulate was $PM_{2.5}$ and 79% of the total particulate was PM_{10} based on AP-42, Appendix B.2, Table B.2-2 (Page B.2-12) for boilers firing a mixture of fuel including petroleum. HAP emissions were based on AP-42 emission factors form Section 1.3 (9/98) and the concentration limits specified for specification used oil. Emissions are estimated in Enclosures (1) and (2) and summarized in the tables below.

94 MMBtu/hr Boiler Emissions (Unit K-1)			
Pollutant	Boiler Emissions		Boiler Emissions (TPY)
	lb/hr	g/s	8,760 hr/yr operation
SO_2	206.843	26.117	906.0
H_2SO_4	27.138	3.426	118.9
NO_X	54.219	6.846	237.5
CO	6.223	0.786	27.3
VOC	-------	--------	1.5
PM	36.171	4.567	158.4
PM_{10}	28.575	3.608	125.2

$PM_{2.5}$	16.277	2.055	71.3
HAPs	-------	-------	0.503

94 MMBtu/hr Boiler Emissions (Unit K-2)			
Pollutant	Boiler Emissions		Boiler Emissions (TPY)
	lb/hr	g/s	8,760 hr/yr operation
SO_2	206.843	26.117	906.0
H_2SO_4	27.138	3.426	118.9
NO_X	54.219	6.846	237.5
CO	6.223	0.786	27.3
VOC	-------	--------	1.5
PM	63.958	8.075	280.1
PM_{10}	50.527	6.380	221.3
$PM_{2.5}$	28.781	3.634	126.1
HAPs	-------	-------	0.503

172 MMBtu/hr Boiler Emissions (Unit K-3)			
Pollutant	Boiler Emissions		Boiler Emissions (TPY)
	lb/hr	g/s	8,760 hr/yr operation
SO_2	378.479	47.788	604.8
H_2SO_4	49.656	6.270	217.5
NO_X	106.210	13.410	465.2
CO	11.386	1.438	49.9
VOC	-------	--------	3.8
PM	138.082	17.435	604.8
PM_{10}	109.084	13.773	477.8
$PM_{2.5}$	62.137	7.846	272.2
HAPs	-------	-------	0.921

181 MMBtu/hr Boiler Emissions (Unit K-4)			
Pollutant	Boiler Emissions		Boiler Emissions (TPY)
	lb/hr	g/s	8,760 hr/yr operation
SO_2	398.283	50.288	1,744.5
H_2SO_4	52.255	6.598	228.9
NO_X	121.415	15.330	531.8
CO	11.982	1.513	52.5
VOC	-------	--------	4.0
PM	110.482	13.950	483.9
PM_{10}	87.281	11.020	382.3
$PM_{2.5}$	49.717	6.277	217.8
HAPs	-------	-------	0.969

6.2 Emission rates for firing boilers on propane ignition fuel will be negligible. Although the emission factors in lb/MMBtu for CO and VOCs for firing propane are greater than those listed in Enclosures (1) and (2) for firing fuel oil No. 6, the emission rates for firing propane will be negligible due to the design of the igniter system. As indicated by HECO, boiler K-2 has three burners for its igniter system with a 0.83 ft^3/hr propane flow rate per burner (2.5 ft^3/hr total combined flow rate). Boiler K-3 has for burners for its igniter system with 0.83 ft^3/hr propane flow rate per burner (3.3 ft^3/hr total combined flow rate). Also, boiler K-4 is equipped with 4 burners having a 2.5 ft^3/hr propane ignition fuel flow rate per burner (10 ft^3/hr total flow rate). Based on the propane flow rate that is limited by the design of the fuel igniter system and AP-42 emission factors from Section 1.5 (07/08), the CO and VOC emission rates are as follows:

<u>Boilers K-2:</u>

CO emission lb/hr = (2.5 ft^3/hr)(2,516 Btu/ft^3)(7.5 lb/1,000 gal)(gal/90,500 Btu) = 5.2 x 10^{-4} lb/hr

VOC emission lb/hr = (2.5 ft^3/hr)(2,516 Btu/ft^3)(1.0 lb/1000 gal)(gal/90,500 Btu) = 7.0 x 10^{-5} lb/hr

<u>Boilers K-3:</u>

CO emission lb/hr = (3.3 ft^3/hr)(2,516 Btu/ft^3)(7.5 lb/1,000 gal)(gal/90,500 Btu) = 6.9 x 10^{-4} lb/hr

VOC emission lb/hr = (3.3 ft^3/hr)(2,516 Btu/ft^3)(1.0 lb/1,000 gal)(gal/90,500 Btu) = 9.2 x 10^{-5} lb/hr

<u>Boiler K-4:</u>

CO emission lb/hr = (10 ft^3/hr)(2,516 Btu/ft^3)(7.5 lb/1,000 gal)(gal/90,500 Btu) = 2.1 x 10^{-3} lb/hr

VOC emission lb/hr = (10 ft^3/hr)(2,516 Btu/ft^3)(1.0 lb/1000 gal)(gal/90,500 Btu) = 2.8 x 10^{-4} lb/hr

6.3 Potential emissions from permitted equipment are listed below as follows:

TOTAL FACILITY EMISSIONS					
Pollutant	Potential Emissions (TPY)				Potential Emissions (TPY) (8,760 hr/yr)
	K-1	K-2	K-3	K-4	
SO_2	906.0	906.0	604.8	1,744.5	4,161.3
H_2SO_4	118.9	118.9	217.5	228.9	684.2
NO_X	237.5	237.5	465.2	531.8	1,472.0
CO	27.3	27.3	49.9	52.5	157.0
VOC	1.5	1.5	3.8	4.0	10.8
PM	158.4	280.1	604.8	483.9	1,527.2
PM_{10}	125.2	221.3	477.8	382.3	1,206.6
$PM_{2.5}$	71.3	126.1	272.2	217.8	687.4
Total HAPs	0.503	0.503	0.921	0.969	3.0

7. Air Quality Assessment

7.1 An Ambient air quality impact analysis (AAQIA) is not required for the boilers because no changes are proposed for the boilers that significantly increase emissions. The addition of used biodiesel to the list of fuels that may be fired by the boilers will not increase potential emissions. Although available literature indicates a 13% increase in NO_x emissions for firing boidiesel in comparison to that for firing fuel oil No. 2, maximum potential NO_x emissions will not increase because worst-case NO_x emissions were based on burning fuel oil No. 6. The NO_x emission factor from AP-42, Section 1.3 (9/98) for firing fuel oil No. 6 is greater than 13% of that for firing fuel oil No. 2 . Existing permit conditions allow the boilers to be fired on either fuel oil No. 6, fuel oil No. 2, or specification used oil. Also, the increase in emissions of arsenic, cadmium, chromium, and lead for increasing the specification used oil consumption from 150,000 gallons per year to 300,000 gallons per year is negligible. As such, the Department will not require an air modeling assessment for the boilers.

8. Significant Permit Conditions

8.1 The boilers shall only be fired on one or a combination of the following fuels:

1) Fuel oil No. 6 with a maximum sulfur content not to exceed 2.0% by weight.

2) Fuel oil No. 2 with a maximum sulfur content not to exceed 0.05% by weight; and

3) Specification used oil meeting the requirements specified in the permit for the fuel.

8.2. Boiler K-2, K-3, and K-4 igniters may be fired on liquefied petroleum gas (e.g., propane, propylene, and butane).

8.3 The total combined consumption of specification used oil fired by the boilers shall not exceed 300,000 gallons in any rolling twelve-month (12-month) period.

Reason for 8.1 to 8.3: These conditions were incorporated based on what the applicant proposed for operating the boilers. The ambient air modeling assessment from the initial application was based the types of fuels proposed for the boilers to predict maximum air impacts.

8.4 For any six (6) minute averaging period, each boiler shall not exhibit visible emissions of forty (40) percent opacity or greater, except as follows: during startup, shutdown, or equipment breakdown, each boiler may exhibit visible emissions greater than forty (40) percent opacity but not exceeding sixty (60) percent opacity for a period aggregating not more than six (6) minutes in any sixty (60) minute period.

Reason for 8.4: This condition is required pursuant to HAR, §11-60.1-32(b) because the boilers were constructed prior to March 20, 1972.

8.5 Incorporate performance testing requirements for determining opacity and mass emission rates of NO_X, CO, PM, PM_{10}, $PM_{2.5}$, and VOCs.

Reason for 8.5: Incorporate source performance test requirements for the boilers to provide information on pollutant emissions for a pending BART analysis and the State's emissions inventory. Source testing will resolve uncertainties with using AP-42 emission factors for estimating potential emissions. The applicant used multiplication factors to increase AP-42 emission factors for estimating emissions because AP-42 emission factors may underestimate the emission rate of a unit. Sources test data can also be used for air quality modeling assessments during the BART review.

9. Conclusion and Recommendation:

9.1 Maximum potential emissions were based on worst-case conditions (boilers operating simultaneously at maximum capacity on a continuous basis). Actual emissions of the units will vary depending on operating load. Changes proposed in the permit applications to fire the boilers on used boidiesel as an alternate fuel and to increase the specification used oil consumption for the boilers do not subject the facility to NSPS requirements or the PSD regulations. Recommend issuance of the covered source permit subject to the significant permit conditions, the thirty day public comment period, and forty-five day EPA review period.

Mike Madsen October 19, 2009