PROPOSED (6/18/04)

Significant Modification to a Covered Source Review Summary

Application File No.:	0212-19
Permit No.:	0212-01-C
Applicant:	Tesoro Hawaii Corporation
Facility Title:	Petroleum Refinery Located at 91-325 Komohana Street, Kapolei, Oahu
Mailing Address:	Tesoro Hawaii Corporation 733 Bishop Street, Suite 2800 P.O. Box 3379 Honolulu, HI 96842-0001
Responsible Official:	Mr. James Kappel Vice President, Refinery Manager Tesoro Hawaii Corporation 91-325 Komohana Street Kapolei, HI 96707
Point of Contact:	Mr. Theodore K. Metrose Manager, Refinery Environmental Affairs Tesoro Hawaii Corporation
Application Date:	Significant Modification application dated October 14, 2003 Revised application dated December 26, 2003 Additional information dated May 4, 2003

Proposed Project:

SICC 2911 (Petroleum Refining)

This permit modification would increase the utilization of package boiler SG1103 by removing the 1150 hours per year operating limitation. Limits will still be imposed on package boiler SG1103 principally to keep it from exceeding the PSD significance thresholds.

A permit modification application fee of $1000.00 for a significant modification was submitted by the applicant on October 14, 2003 and processed.

Background:

Prior to issuance of the Title V permit, the PSD permit HI 83-01, Condition IX restricted the operation of package boiler SG1103 to 800 hours per year and it was not to be operated simultaneously with the cogeneration gas turbine TU2301. Limiting the operation of the package boiler SG1103 was based on EPA's concern in 1983 related to SO_2 increment consumption. To a large degree those concerns were addressed by putting a 0.5% sulfur limit on fuel oil used in the crude heaters and steam generators.

Due to a shortage of refinery steam, an application was submitted on November 23, 1994 to modify the PSD permit to allow package boiler SG1103 to be operated while operating the cogeneration gas turbine TU2301 for up to 1600 hours per year. Modeling conducted in support of the PSD permit application with both the cogeneration gas turbine TU2301 and package boiler SG1103 continuously operating demonstrated that there would not be an exceedance of the ambient air quality standards. On March 2, 2000 this application was revised such that package boiler SG1103 could be operated just up to 1150 hours per year. The application was moderated because of concerns that SO_x emissions would have exceeded PSD significance thresholds if fuel oil with a 0.5 wt % sulfur content was burned at maximum rates for more than 1150 hours. Although the application was originally for a modification of the PSD permit, the revised operating constraint was reflected in the Initial Title V permit issued on July 6, 2000. Tesoro Hawaii currently operates package boiler SG1103 in accordance with Attachment II (I) of its Title V permit. Special Condition No. C.4.a states that "the packaged boiler SG1103 shall not operate at other than standby for more than 1150 hours per year" and Special Condition No. C.1 mandates that only RFG be burned while in standby mode. There is no longer a specific prohibition on running package boiler SG1103 and the cogeneration gas turbine TU2301 simultaneously.

Process Description:

The package boiler SG1103 is rated at 126 MMBtu/hr. The packaged boiler was designed to produce 100,000 lbs/hr of 235 psi steam. It can be fired on either RFG or liquid fuel or a combination of both. Other sources of steam include SG1102 and the cogeneration unit (TU2301). Steam is also purchased from Kalaeloa Partners, an adjacent privately owned and operated power plant. A major driver for removing the operating time limits from package boiler SG1103 is that on occasion, Kalaeloa Partners may not produce sufficient steam due to scheduled maintenance or an equipment breakdown. Lack of steam supply could severely limit or curtail refinery operations.

Proposed Permit Modification:

There will be no physical modifications made to the package boiler. Only operating conditions in the permit will be modified, such that packaged boiler SG1103 may be operated more often. The limitation on the hours of operation will be removed and replaced with fuel consumption limits. The maximum amount of liquid fuel potentially used will be unchanged as result of this proposed modification. The proposed liquid fuel limit of 1,073,333 gals/yr was based on operating packaged boiler SG1103 at a rated capacity of 126 MMBtu/hr (933 gals/hr) for

1150 hours/yr. Since packaged boiler SG1103 will operate without restriction as to the number of hours, annual emissions will increase on a potential to emit (PTE) permitted basis, principally because there will be greater potential to burn RFG. However, the increase in potential emissions will be constrained by the boiler's rated capacity, a new limit on the amount of RFG (127 MMSCF/yr) that may be burned, new mass and concentration rate limits and by existing limits on the sulfur content of the fuel.

Applicable Requirements:

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 Prohibition
  - HAR 11-60.1-31 Applicability
  - HAR 11-60.1-38 Sulfur Oxides from Fuel Combustion
- Subchapter 5 Covered Sources
- Subchapter 6 Fees for Covered Sources, Noncovered Sources, and Agricultural Burning
  - HAR 11-60.1-111 Definitions
  - HAR 11-60.1-112 General Fee Provisions for Covered Sources
  - HAR 11-60.1-113 Application Fees for Covered Sources
  - HAR 11-60.1-114 Annual Fees for Covered Sources
  - HAR 11-60.1-115 Basis of Annual Fees for Covered Sources
- Subchapter 8 Standards of Performance for Stationary Sources

Federal Requirements
40 CFR Part 60 - Standards of Performance for New Stationary Sources (NSPS)
- Subpart A - General Provisions
- Subpart J - Standards of Performance for Petroleum Refineries

Non-Applicable Requirements:

Hawaii Administrative Rules (HAR)
Title 11, Chapter 60.1 Air Pollution Control
- Subchapter 7 Prevention of Significant Deterioration
- Subchapter 9 Hazardous Air Pollutant Sources
  - HAR 11.60.1-174 Maximum Achievable Control Technology (MACT) Emission Standards

Federal Requirements
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants (NESHAPS)

40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories (Maximum Achievable Control Technologies (MACT) Standards)
- Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

Best Available Control Technology (BACT):

A Best Available Control Technology (BACT) analysis is required for new covered sources or significant modifications to covered sources that have the potential to cause a net increase in air pollutant emissions above significant levels as defined in HAR §11-60.1-1. The net emissions increases from the proposed modification are shown in the table below. The net emissions increase for each pollutant was below the significant level. Therefore, a BACT analysis was not triggered.

Pollutant	Proposed Potential to Emit (tpy)	Past 2-yr Actual Average (2001-2002) Emissions (tpy)	Net Emission Increase (tpy)	Significant Level (tpy)
SO_2	41.21	2.44	38.77	40
NO_x	50.59	10.86	39.73	40
CO	15.57	3.01	12.56	100
VOC	0.64	0.18	0.46	40
PM	4.87	0.45	4.43	25
PM_{10}	4.29	0.33	3.95	15
Lead	8.6 E-04	1.9 E-04	6.7 E-04	0.6
Beryllium	1.6 E-05	3.5 E-06	1.3 E-05	0.0004
Mercury	8.4 E-05	2.1 E-05	6.3 E-05	0.1

Prevention of Significant Deterioration (PSD):

This significant modification is not subject to PSD review as the modification does not result in any net emission increases above PSD significant levels as shown in the table below:

Pollutant	Proposed Potential to Emit (tpy)	Past 2-yr Actual Average (2001-2002) Emissions (tpy)	Net Emission Increase (tpy)	PSD Significant Level (tpy)
SO_2	41.21	2.44	38.77	40
NO_x	50.59	10.86	39.73	40
CO	15.57	3.01	12.56	100
VOC	0.64	0.18	0.46	40
PM	4.87	0.45	4.43	25
PM_{10}	4.29	0.33	3.95	15
Lead	8.6 E-04	1.9 E-04	6.7 E-04	0.6
Beryllium	1.6 E-05	3.5 E-06	1.3 E-05	0.0004
Mercury	8.4 E-05	2.1 E-05	6.34 E-05	0.1

Consolidated Emissions Reporting Rule (CERR):

40 CFR Part 51, Subpart A - Emission Inventory Reporting Requirements, determines CER based on the emissions of criteria air pollutants from Type A and Type B point sources (as defined in 40 CFR Part 51, Subpart A), that emit at the CER triggering levels as shown in the table below.

Pollutant	Type A CER Triggering Levels [1,2] (tpy)	Type B CER Triggering Levels [1] (tpy)	Pollutant	In-house Total Facility Triggering Levels [3] (tpy)
NO_x	≥2500	≥100	NO_x	≥25
SO_x	≥2500	≥100	SO_x	≥25
CO	≥2500	≥1000	CO	≥250
PM_{10}	≥250	≥100	PM/PM_{10}	≥25
VOC	≥250	≥100	VOC	≥25
Pb		≥5	HAPS	≥5

[1] Based on actual emissions
[2] Type A sources are a subset of Type B sources and are the larger emitting sources by pollutant
[3] Based on potential emissions

This facility emits above the Type A CER (VOC) and in-house triggering levels. Therefore, CER and in-house reporting requirements are applicable.

Compliance Data System (CDS):

No change from Covered Source Permit 0212-01-C.

Compliance Assurance Monitoring (CAM):

40 CFR Part 64

Applicability of the CAM rule is determined on a pollutant specific basis for each affected emission unit. Each determination is based upon a series of evaluation criteria. In order for an emission unit to be subject to CAM, each emission unit must:

- Be located at a major source per Title V of the Clean Air Act Amendments of 1990;
- Be subject to federally enforceable applicable requirements;
- Be fitted with an “active” air pollution control device;
- Have pre-control device potential emissions that exceed applicable major source thresholds; and
- Not be subject to certain regulations that specifically exempt it from CAM.

Emission units are any part or activity of a stationary source that emits or has the potential to emit any air pollutant.

This emission unit is not subject to CAM because it is not fitted with an "active" air pollution control device to control SO_2 emissions. Sulfur oxide emissions per 40 CFR Part 60, Subpart J, are controlled by limiting H_2S in the refinery fuel gas which is considered "passive" control.

Synthetic Minor Source:

No change from Covered Source Permit 0212-01-C.

Insignificant Activities:

No change from Covered Source Permit 0212-01-C.

Alternate Operating Scenarios:

No change from Covered Source Permit 0212-01-C.

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Project Emissions:

Potential Emissions - Criteria Air Pollutants

	SO_2 [1]	NO_x [2]	CO [3]	PM [4]	PM_{10} [4]	VOC [5]
Max. Liquid Fuel Use (gallons/yr)	1,073,333	1,073,333	1,073,333	1,073,333	1,073,333	1,073,333
Max. Liquid Fuel Input (MMBtu/yr)	144,900	144,900	144,900	144,900	144,900	144,900
Emission Factor (lb/1000 gal)	73.6	43.2	15.0	7.8	6.7	0.28
Emission Factor (lb/MMBtu)	0.55	0.32	0.11	0.058	0.050	0.002
Liquid Fuel Emission Rate (lb/hr)	68.69	40.32	14.00	7.29	6.27	0.26
Liquid Fuel Emissions (lb/yr)	78,997	46,368	16,100	8,388	7,214	300
Liquid Fuel Emissions (tpy)	**39.50**	**23.18**	**8.05**	**4.19**	**3.61**	**0.15**
Max. RFG Use (MSCF/yr)	126,919	126,919	126,919	126,919	126,919	126,919
Max. RFG Heat Input (MMBtu/yr)	182,700	182,700	182,700	182,700	182,700	182,700
Emission Factor (lb/MMSCF)	26.9	431.9	118.5	10.7	10.7	7.8
Emission Factor (lb/MMBtu)	0.019	0.30	0.082	0.007	0.007	0.005
RFG Emission Rate (lb/hr)	2.36	37.8	10.4	0.94	0.94	0.68
RFG Emissions (lb/yr)	3,418	54,810	15,046	1,361	1,361	985
RFG Emissions (tpy)	**1.71**	**27.41**	**7.52**	**0.68**	**0.68**	**0.49**
Total Emissions - Liquid Fuel and RFG (tpy)	**41.21**	**50.59**	**15.57**	**4.87**	**4.29**	**0.64**

Potential Emissions - Hazardous Air Pollutants

	Liquid Fuel Emission Factor [6] (lb/1000 gal)	Liquid Fuel Emissions (lb/yr)	Liquid Fuel Emissions (tpy)	RFG Emission Factor [7] (lb/MMSCF)	RFG Emissions (lb/yr)	RFG Emissions (tpy)	Total Emissions Liquid Fuel and RFG (tpy)
Antimony	5.25 E-03	5.6	2.8 E-03		-		2.8 E-03
Arsenic	1.32 E-03	1.4	7.1 E-04	2.824 E-04	0.4	1.8 E-05	7.3 E-04
Beryllium	2.78 E-05	0.03	1.5 E-05	1.694 E-05	2.2 E-03	1.1 E-06	1.6 E-05
Cadmium	3.98 E-04	0.4	2.1 E-04	1.553 E-03	0.2	9.9 E-05	3.1 E-04
Chromium	8.45 E-04	0.9	4.5 E-04	1.976 E-03	0.25	1.3 E-04	5.8 E-04
Cobalt	6.02 E-03	6.5	3.3 E-03	1.186 E-04	0.02	7.5 E-06	3.3 E-03
Lead	1.51 E-03	1.6	8.1 E-04	7.059 E-04	0.09	4.5 E-05	8.6 E-04
Manganese	3.00 E-03	3.2	1.6 E-03	5.365 E-04	0.07	3.5 E-05	1.6 E-03
Mercury	1.13 E-04	0.1	6.1 E-05	3.671 E-04	0.05	2.3 E-05	8.4 E-05
Nickel	8.45 E-02	90.7	4.5 E-02	2.965 E-03	0.38	1.9 E-04	4.5 E-02
Phosphorus	9.46 E-03	10.2	5.1 E-03		-		5.1 E-03
Selenium	6.83 E-04	0.7	3.7 E-04	3.388 E-05	4.3 E-03	2.2 E-06	3.7 E-04
Benzene	2.14 E-04	0.2	1.2 E-04	2.965 E-03	0.38	1.9 E-04	3.1 E-04
1,4 Dichloro benzene (p)		0	0	1.694 E-03	0.22	1.1 E-04	1.1 E-04
Ethylbenzene	6.36 E-05	0.1	3.4 E-05		-		3.4 E-05
Formaldehyde	3.30 E-02	35.4	1.8 E-02	1.059 E-01	13.45	6.7 E-03	2.5 E-02
Naphthalene	1.13 E-03	1.2	6.1 E-04	8.612 E-04	0.11	5.5 E-05	6.7 E-04
Toluene	6.20 E-03	6.7	3.4 E-03	4.800 E-03	0.61	3.1 E-04	3.7 E-03
o - Xylene	1.09 E-04	0.1	5.9 E-05		-		5.9 E-05
POM (excluding Naphthalene)	6.057 E-05	0.1	3.3 E-05	1.220 E-04	0.02	7.7 E-06	4.1 E-05
Total HAPs			8.3 E-02			7.9 E-03	9.1 E-02

Notes:
Boiler Heat Input = 126 MMBtu/hr (HHV)
Liquid Fuel Consumption Rate = 933 gal/hr and 1,073,333 gal/yr
RFG Consumption Rate = 87,530 SCF/hr and 126,919 MSCF/yr
Liquid Fuel Sulfur Content = 0.50% by weight (permit limit)
RFG H_2S = 162 ppm (permit limit)
Liquid Fuel = 135,000 Btu/gal (based on 2001-2002 annual averages)
Liquid Fuel = 7.36 lb/gal (based on 2001-2002 annual averages)
RFG = 1440 Btu/SCF (based on 2001-2002 annual averages)
Emission factors used based on 126 MMBtu/hr Industrial Boiler.
Liquid fuel burning based on no.6 oil or residual oil as a worst case scenario.

1 SO_2 Emission Factor
Fuel Oil Combustion
Mass balance method used:
SO_2 = 7.36 lb/gal * 0.005 * 64/32 = 73.6 lb/1000 gal
Fuel Gas Combustion
SO_2 = 162 ppm * 64 lb/lb-mol / 385 SCF/lb-mol = 26.9 lb/MMSCF

2 NO_x Emission Factor
Fuel Oil Combustion
Ebasco Services Boiler Specification, 4/7/83, Based on best engineering estimate for emission factor
NO_x = 0.32 lb/MMBtu
Fuel Gas Combustion
Ebasco Services Boiler Specification, 4/7/83, Based on best engineering estimate for emission factor
NO_x = 0.30 lb/MMBtu

3 CO Emission Factor
Fuel Oil Combustion
Mass limit from existing permit limit
CO = 14.0 lb/hr
Fuel Gas Combustion
AP-42, Natural Gas Combustion, Table 1.4-1, (7/98), Large wall-fired boilers/Uncontrolled
CO = 84 lb/MMSCF* 1440 Btu/SCF / 1020 Btu/SCF = 118.5 lb/MMSCF

4 PM/PM_{10} Emission Factor
Fuel Oil Combustion
AP-42, Fuel Oil Combustion, Table 1.3-1, (9/98), No. 6 oil and Table 1.3-5
PM = 9.19 * 0.5 + 3.22 = 7.8 lb/1000 gal
PM_{10} = 7.17 (1.12 * 0.5 +0.37) = 6.7 lb/1000 gal
Fuel Gas Combustion
AP-42, Natural Gas Combustion, Table 1.4-2, (7/98)
PM/ PM_{10} = 7.6 lb/MMSCF * 1440 Btu/SCF /1020 Btu/SCF = 10.7 lb/MMSCF

5 VOC Emission Factor
Fuel Oil Combustion
AP-42, No. 6 oil, Table 1.3-3, (9/98), Emission Factors for Nonmethane TOC from Uncontrolled Fuel Oil Combustion
VOC (NMTOC) = 0.28 lb/1000 gallons
Fuel Gas Combustion
AP-42, Natural Gas Combustion, Table 1.4-2, (7/98)
VOC = 5.5 lb/MMSCF

6 HAPs Emission Factors
AP-42, Tables 1.3-9/11, (9/98), Fuel Oil Combustion

7 HAPs Emission Factors
AP-42, Tables 1.4-2/3/4, (9/98), Natural Gas Combustion, Converted Natural Gas Emission Factors to RFG Emission Factors using ratio of 1440/1020

Past Actual Emissions (2001-2002) - Criteria Air Pollutants

	SO_2 [1]	NO_x [2]	CO [3]	PM [4]	PM_{10} [4]	VOC [5]
Max. Liquid Fuel Use (gallons/yr)	224,098	224,098	224,098	224,098	224,098	224,098
Emission Factor (lb/1000 gal)	21.3	24	5	2	1	0.2
Liquid Fuel Emissions (lb/yr)	4766.7	5378.3	1120.5	448.2	224.1	44.8
Liquid Fuel Emissions (tpy)	**2.38**	**2.69**	**0.56**	**0.22**	**0.11**	**0.02**
Max. RFG Use (MSCF/yr)	41,363	41,363	41,363	41,363	41,363	41,363
Max. RFG Heat Input (MMBtu/yr)	59,542	59,542	59,542	59,542	59,542	59,542
Emission Factor (lb/MMSCF)	2.66	395.16	118.55	10.73	10.73	7.76
Emission Factor (lb/MMBtu)	0.0018	0.2745	0.0824	0.0075	0.0075	0.0054
RFG Emissions (lb/yr)	110.0	16344.7	4903.4	443.6	443.6	321.1
RFG Emissions (tpy)	**0.06**	**8.17**	**2.45**	**0.22**	**0.22**	**0.16**
Total Emissions - Liquid Fuel and RFG (tpy)	**2.44**	**10.86**	**3.01**	**0.45**	**0.33**	**0.18**

Past Actual Emissions (2001-2002) - Hazardous Air Pollutants

	Liquid Fuel Emission Factor [6] (lb/1000 gal)	Liquid Fuel Emissions (lb/yr)	Liquid Fuel Emissions (tpy)	RFG Emission Factor [7] (lb/MMSCF)	RFG Emissions (lb/yr)	RFG Emissions (tpy)	Total Emissions Liquid Fuel and RFG (tpy)
Beryllium	2.78 E-05	6.2 E-03	3.1 E-06	1.694 E-05	7.0 E-04	3.5 E-07	3.5 E-06
Lead	1.51 E-03	3.4 E-01	1.7 E-04	7.059 E-04	2.9 E-02	1.5 E-05	1.9 E-04
Mercury	1.13 E-04	2.5 E-02	1.3 E-05	3.671 E-04	1.5 E-02	7.6 E-06	2.1 E-05

Notes:

Liquid Fuel Consumption Rate (2001-2002 average) = 224,098 gal/yr
RFG Consumption Rate (2001-2002 average) = 41,363 MSCF/yr
Liquid Fuel Sulfur Content = 0.14% by weight (based on 2001-2002 annual averages)
RFG H_2S = 16 ppm (based on 2001-2002 annual averages)
Liquid Fuel = 135,000 Btu/gal (based on 2001-2002 annual averages)
Liquid Fuel = 7.36 lb/gal (based on 2001-2002 annual averages)
RFG = 1440 Btu/SCF (based on 2001-2002 annual averages)

Emission factors used based on 126 MMBtu/hr Industrial Boiler.
Liquid fuel burning based on no.2 oil or distillate oil (because actual fuel is a distillate w/ low nitrogen)

[1] SO_2 Emission Factor
Fuel Oil Combustion
Mass balance method used:
$S0_2$ = 7.36 lb/gal * 0.0014 * 64/32 = 21.3 lb/1000 gal
Fuel Gas Combustion
SO_2 = 16 ppm * 64 lb/lb-mol / 385 SCF/lb-mol = 2.66 lb/MMSCF

[2] NO_x Emission Factor
Fuel Oil Combustion
AP-42, Fuel Oil Combustion, Table 1.3-1, (9/98), No. 2 oil
NO_x = 24 lb/1000 gal
Fuel Gas Combustion
AP-42, Natural Gas Combustion, Table 1.4-1, (7/98), Large wall-fired boilers/Uncontrolled
NO_x = 280 lb/MMSCF x 1440 Btu/SCF / 1020 Btu/SCF = 395.16 lb/MMSCF

[3] CO Emission Factor
Fuel Oil Combustion
AP-42, Fuel Oil Combustion, Table 1.3-1, (9/98), No. 2 oil
CO = 5 lb/1000 gal
Fuel Gas Combustion
AP-42, Natural Gas Combustion, Table 1.4-1, (7/98), Large wall-fired boilers/Uncontrolled
CO = 84 lb/MMSCF* 1440 Btu/SCF / 1020 Btu/SCF = 118.5 lb/MMSCF

[4] PM/PM_{10} Emission Factor
Fuel Oil Combustion
AP-42, Fuel Oil Combustion, Table 1.3-1, (9/98), No. 2 oil and Table 1.3-6
PM = 2 lb/1000 gal
PM_{10} = 1 lb/1000 gal
Fuel Gas Combustion
AP-42, Natural Gas Combustion, Table 1.4-2, (7/98)
PM/ PM_{10} = 7.6 lb/MMSCF * 1440 Btu/SCF /1020 Btu/SCF = 10.7 lb/MMSCF

[5] VOC Emission Factor
Fuel Oil Combustion
AP-42, Distillate Oil Fired, Table 1.3-3, (9/98), Emission Factors for Nonmethane TOC from Uncontrolled Fuel Oil Combustion
VOC (NMTOC) = 0.2 lb/1000 gallons
Fuel Gas Combustion
AP-42, Natural Gas Combustion, Table 1.4-2, (7/98)
VOC = 5.5 lb/MMSCF

[6] HAPs Emission Factors
AP-42, Tables 1.3-9/11, (9/98), Fuel Oil Combustion

[7] HAPs Emission Factors
AP-42, Tables 1.4-2/3/4, (9/98), Natural Gas Combustion, Converted Natural Gas Emission Factors to RFG Emission Factors using ratio of 1440/1020

Air Quality Assessment:

An ambient air quality impact analysis (AAQIA) is required for significant modifications to existing covered sources, with the inclusion of background air quality data. The applicant assessed the proposed modification using the following methodology. To quantify the impact of the proposed modification on the ambient air quality standards, projections were made using the modeling assessment from the initial Title V application and adjusting the emission rates to account for the operational change. The projections were made on a worst-case PTE basis. Adjustments were made to the annual emission rates principally to account for the potential that more RFG may be burned, once the operating hour limit is removed. Even though annual NO_x emissions from SG1103 would potentially double, due to burning more RFG, ambient NO_x emission from the refinery as a whole plus the background air quality data are still projected to be less than 95% of the State ambient air quality standard. Maximum hourly emission rates were for most part unchanged from those projected in the Title V modeling because the maximum emissions still occur when the boiler is being fired entirely on fuel oil (at full rate). Background air quality data from Kapolei (2002) was then added to the predicted concentrations and compared to the State ambient air quality standard. This methodology provided very conservative results since the background air quality data includes the emissions from the existing refinery.

SG1103 Maximum Hourly PTE and Impact

PTE Emissions	SO_2	NO_x	CO	PM	PM_{10}	VOC
Proposed Modification Maximum Hourly Emission Rate, RFG (lb/hr)	2.36	37.80	10.38	0.94	0.94	0.68
Proposed Modification Maximum Hourly Emission Rate, Liquid Fuel (lb/hr)	68.69	40.32	14.00	7.29	6.27	0.26
Proposed Modification Maximum Hourly Emission Rate, Liquid Fuel [1] (g/s)	8.66	5.08	1.76	0.92	0.79	0.03
Title V Model Maximum Hourly Emission Rate, Liquid Fuel (g/s)	8.72	4.22	1.76	not modeled	0.71	not modeled
Change in Maximum Hourly Emission Rate (Proposed vs. Title V model) (g/s)	-0.06	0.86	0.0	not modeled	0.08	not modeled
Maximum Emission Rate from all Refinery Sources used in Title V Model (g/s)	107.77	88.51	16.35	not modeled	7.90	not modeled
Maximum Emission Rate from all Sources with SG1103 Modification adjustment (g/s)	107.71	89.37	16.35	not modeled	7.98	not modeled
Emission Ratio: Modified/Title V	0.999	1.010	1.000	not modeled	1.010	not modeled
Air Quality Impact						
Title V Model Prediction ($\mu g/m^3$)	897 (3-hr) 270 (24-hr)	N/A	1210 (1-hr) 328 (8-hr)	N/A	41.7 (24-hr)	N/A
Proposed Modification Predicted Concentration ($\mu g/m^3$)	896 (3-hr) 270 (24-hr)	N/A	1210 (1-hr) 330.8 (8-hr)	N/A	42.1 (24-hr)	N/A
Background Concentration [2] ($\mu g/m^3$)	47 (3-hr) 9 (24-hr)	N/A	2166 (1-hr) 1810 (8-hr)	N/A	55 (24-hr)	N/A
Total Concentration ($\mu g/m^3$)	943 (3-hr) 279 (24-hr)	N/A	3376 (1-hr) 2140.8 (8-hr)	N/A	97.1 (24-hr)	N/A
State Ambient Air Quality Standard ($\mu g/m^3$)	1300 (3-hr) 365 (24-hr)	N/A	10,000 (1-hr) 5,000 (8-hr)	N/A	150 (24-hr)	N/A
% of Standard [3]	72.5% 76.4%	N/A	33.8% 42.8%	N/A	64.7%	N/A

1 Liquid fuel burning generates the highest emission levels for all criteria pollutants
2 Kapolei data (2002)
3 Only the State ambient air quality standards are shown as they are more restrictive than the Federal standards

SG1103 Annual PTE and Impact

PTE Emissions	SO_2	NO_x	CO	PM	PM_{10}	VOC
Proposed Modification Total Liquid Fuel and RFG Emissions (tpy)	41.21	50.59	15.57	4.87	4.29	0.64
Proposed Modification Total Liquid Fuel and RFG Emissions (g/s)	1.19	1.46	0.45	0.14	0.12	0.02
Emissions used in Title V Model (g/s)	1.59	0.77	0.32	not modeled	0.13	not modeled
Change in Maximum Annualized Emission Rate (Proposed vs. Title V model) [1] (g/s)	-0.40	0.69	0.13	not modeled	-0.01	not modeled
Total Emissions from all Refinery Sources used in Title V Model (g/s)	86.68	85.07	14.91	not modeled	7.32	not modeled
Total Emissions from all Sources with SG1103 Modification adjustment (g/s)	86.28	85.76	15.04	not modeled	7.31	not modeled
Emission Ratio: Modified/Title V	0.995	1.008	1.009	not modeled	0.999	not modeled
Air Quality Impact						
Title V Model Prediction (µg/m^3)	54.7 (annual)	57.1 (annual)	N/A	N/A	4.9 (annual)	N/A
Proposed Modification Predicted Concentration (µg/m^3)	54.4 (annual)	57.6 (annual)	N/A	N/A	4.9 (annual)	N/A
Background Concentration [2] (µg/m^3)	1 (annual)	9 (annual)	N/A	N/A	14 (annual)	N/A
Total Concentration (µg/m^3)	55.4 (annual)	66.6 (annual)	N/A	N/A	18.9 (annual)	N/A
State Ambient Air Quality Standard (µg/m^3)	80.0 (annual)	70.0 (annual)	N/A	N/A	80.0 (annual)	N/A
% of Standard [3]	69.3%	95.1%	N/A	N/A	23.6%	N/A

[1] SO_2 is lower than original Title V model because Title V assumed SG1103 burned liquid fuel with a 0.5% by weight sulfur content for 1600 hours vs 1150 hours as currently permitted. NO_x and CO emissions increased because of the potential to burn more RFG

[2] Kapolei data (2002)

[3] Only the State ambient air quality standards are shown as they are more restrictive than the Federal standards

Significant Permit Conditions:

This modification consists of the following significant permit conditions:

- Fuel oil referenced as liquid fuel.
- Deleted references to backup and standby modes of operation.
- NO_x emission limit when burning liquid fuel of 40.3 lbs/hr or 0.32 lbs/hr (2-hr average).
- NO_x emission limit when burning RFG of 37.8 lbs/hr or 0.30 lbs/MMBtu (2-hr average).
- CO emission limit when burning liquid fuel of 14.0 lbs/hr (2-hr average).
- CO emission limit when burning RFG of 10.4 lbs/hr (2-hr average).
- 1,073.333 gallons per year (12-month rolling average) maximum liquid fuel consumption
- 127 million standard cubic feet per year (12-month rolling average) maximum RFG consumption based on high heating value of 1440 Btu/scf

The following permit conditions in the covered source permit were modified. As is custom when modifying regulatory language, new language is underlined, while [deleted language is shown in brackets].

1. Attachment II(I), Special Condition No. C.1 - Fuel Usage and Specifications

   c. The package boiler SG1103 [in backup mode] shall be fired only on liquid fuel [oil] with a sulfur content not to exceed 0.5% by weight, RFG or a combination of both fuels. [In standby mode, the package boiler SG1103 shall be fired only on RFG.]

   Reason: This modification eliminates the limitation of SG1103 being used strictly as a backup or standby boiler. Its operation and emissions will be limited by the amount of fuel it is allowed to burn, regardless of whether the package boiler is operating at maximum rates or in a standby mode or as a backup to other steam generators. Also, to ensure operational flexibility, the term fuel oil is being replaced with the more general term liquid fuel, which includes distillate fuel. The burning of the lighter and less viscous distillate fuel, when available, can enhance burner operation and lower emissions as well.

2. Attachment II(I), Special Condition No. C.3.b - Emission Limits for NO_x (as NO_2)

   v. When the package boiler SG1103 is firing liquid fuel oil, the more stringent of [33.5] 40.3 lbs/hr (2-hour average) or [0.26] 0.32 lbs/MMBtu (2-hour average).

   vi. When the package boiler SG1103 is firing refinery fuel gas (RFG) the more stringent of 37.8 lbs/hr (2-hour average) or 0.30 lbs/MMBtu (2-hour average).

   Reason: The NO_x conditions are being modified to use the manufacturer's performance data (0.32 lbs/MMBtu when burning liquid fuel and 0.30 lbs/MMBtu when burning RFG) that was provided in the original PSD permit application HI 83-01, since this provides the best engineering estimate of the performance of the burners. The emission factor that was used in the original PSD permit (0.26 lbs/MMBtu) was based on an AP-42 emission factor. The original PSD permit application was not consistent in the use of emission factors as the BACT analysis used the manufacturer's data. Also, the original PSD permit did not include emission limits on the burning of RFG since it was assumed relatively little RFG would be burned.

3. Attachment II(I), Special Condition No. C.3.c - Emission Limits for CO

   ii. When [From] the package boiler SG1103 is firing on liquid fuel, - 14.0 lbs/hr (2- hour average).

   iii. When the package boiler SG1103 is firing refinery fuel gas (RFG), 10.4 lbs/hr (2- hour average).

   Reason: The CO conditions are being modified to establish limits for both liquid fuel and refinery fuel gas. Maximum mass emission limits remain unchanged for firing on liquid fuel. A new maximum mass emission limit is being established for when the package boiler is fired on refinery fuel gas. The emission factors used for the limits are based on AP-42 emission factors.

4. Attachment II(I), Special Condition No. C.4 - Operational and Emission Limitations

   a. The package boiler SG103 shall not [operate at other than standby for more than 1150 hours per year] consume more than 1,073,333 gallons of liquid fuel and 127 million standard cubic feet of RFG per year based on a rolling twelve (12) month average. The maximum fuel consumption limit for RFG is based on a high heating value of (HHV) of 1440 Btu/scf. In the event of significant variation in the HHV, the maximum fuel consumption limit shall be as follows:

   Maximum fuel consumption (scf/hr) = 126 MMBtu/hr / HHV of RFG (Btu/scf)

   Reason: This permit condition is being modified for increased operational flexibility. The current hourly limitation on normal boiler operation is being removed and replaced by fuel consumption limits on both the liquid fuel and RFG being burned. However, the net increase in emissions is below the PSD threshold limits. The fuel consumption limits provide an enforceable limit on the annual emission rates to help ensure that the ambient air quality will not be degraded since the current permit condition is silent on the number of hours that the boiler can run on RFG in standby mode.

5. Attachment II(I), Special Condition No. D.1 - Monitoring and Recordkeeping Requirements

   a. The permittee shall maintain and operate a continuous monitoring system to monitor and record the fuel consumption and ratio of water to fuel being fired in the gas turbine TU2301. This system shall be accurate to within ± 5.0 percent. The system shall meet EPA monitoring requirements (40 CFR §60.13).

b. The permittee shall maintain and operate non-resetting fuel meters to record the amount of liquid fuel and RFG fired in the package boiler SG1103.

(Auth.: HAR §11-60.1-3, §11-60.1-90, §11-60.1-161; 40 CFR §60.334)[1]

Reason: This permit condition is being modified to add fuel consumption monitoring requirements for the package boiler.

6. Attachment II(I), Special Condition No. D.4 - Monitoring and Recordkeeping Requirements

Sulfur Content in the Liquid Fuel [and Fuel Oil]

The sulfur content of the liquid fuel [and fuel oil] shall be tested in accordance with the most current American Society for Testing and Materials (ASTM) methods. ASTM Method D4294-83 is a suitable alternative to Method D129-64 for determining the sulfur content. The liquid fuel [and fuel oil] sulfur content shall be verified by having a representative sample of each batch of liquid fuel [and fuel oil] analyzed for sulfur content by weight or at least once per **month**. When reformate is used as a fuel to TU2301, the sulfur analysis of the feed to the reformer is sufficient to satisfy this requirement. ASTM D4045 is an acceptable analytical method for determining sulfur content of naphtha and reformate.

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90, §11-60.1-161; 40 CFR §60.335) [1]

Reason: The term fuel oil is being replaced with the more general term liquid fuel, which includes distillate fuel.

7. Attachment II(I), Special Condition No. D.6 - Monitoring and Recordkeeping Requirements

d. Total quantity of liquid fuel [oil] (barrels) and RFG (MMSCF) fired by the package boiler SG1103 on a monthly and [annual] rolling twelve (12) month basis. The HHV of the RFG fired shall also be recorded.

Reason: This permit condition is being modified for recordkeeping of the new fuel restrictions for the package boiler.

8. Attachment II(I), Special Condition No. E.2 - Notification and Reporting Requirements

The permittee shall submit **semi-annually** written reports to the Department of Health for monitoring purposes. The reports shall be submitted **within sixty (60) days** *after the end of each semi-annual calendar period (January 1 to June 30 and July 1 to December 31)* and shall include the following:

a. Any opacity exceedance as determined by the required V.E. monitoring. Each exceedance reported shall include the date, six (6) minute average opacity reading, possible reason for exceedance, duration of exceedance, and corrective actions taken. If there were no exceedances, the permittee shall submit in writing a statement indicating that for each equipment there were no exceedances for that semi-annual period.

The enclosed **Monitoring Report Form: Visible Emissions** or an equivalent form shall be used.

b. The sulfur content by weight and hydrogen sulfide content (as applicable for each fuel) of the liquid fuel[,] <u>and</u> RFG [and fuel oil] burned in the gas turbine TU2301 and package boiler SG1103.

<u>c. The total quantity of liquid fuel (barrels) and RFG (MMSCF) fired by the package boiler SG1103 on a monthly and rolling twelve (12) month basis. The HHV of the RFG shall also be reported. The enclosed **Monitoring Report Form: Fuel Consumption - Package Boiler** or an equivalent form shall be used.</u>

[c]<u>d</u>. Any deviations from permit requirements shall be clearly identified.

(Auth.: HAR §11-60.1-3, §11-60.1-32, §11-60.1-90, SIP §11-60-24[2])

Reason: The term fuel oil is being replaced with the more general term liquid fuel, which includes distillate fuel. Also, added semi-annual reporting requirements for the new fuel restrictions for the package boiler.

9. Attachment II(I), Special Condition No. F.1 - Testing Requirements

The permittee shall conduct or cause to be conducted performance tests on the cogeneration gas turbine/duct burner and the package boiler. Performance test shall be conducted for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon monoxide (CO). All performance tests shall be conducted at the maximum operating capacity of the equipment being tested, or at other operating loads as may be specified by the Department of Health. Performance test shall be conducted on an annual basis or at such times as may be specified by the Department of Health.

<u>Performance testing for the package boiler shall be conducted only while firing the package boiler on either liquid or gaseous fuel, but not both at the same time. The fuel type used during testing shall be based on the fuel which represents the majority of the BTU input to the package boiler over the preceding 12-month period.</u>

(Auth.: HAR §11-60.1-3, §11-60.1-11, §11-60.1-90)

Reason: This permit condition is required to ensure that the emission data collected during the source test may be directly compared to the fuel-specific permit limits.

10. Added Monitoring Report Form: Fuel Consumption - Package Boiler to the permit.

Reason: This form is for Attachment II(I), Special Condition No. E.2.c.

Conclusion and Recommendations:

Recommend issuance of the significant modification to existing Covered Source Permit No. 0212-01-C based on the significant permit conditions shown above. The proposed project will increase the refinery's operational flexibility and help maintain compliance with all State and Federal regulations, including PSD regulations and the State and National ambient air quality standards. A 30-day public comment period and a 45-day EPA review period are also required before issuance of the permit modification.

Reviewer: Darin Lum
Date: 6/04